COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

APPLICATION OF KENTUCKY UTILITIES COMPANY FOR AN ADJUSTMENT OF BASE RATES	)))	**CASE NO. 2009-00548**

VOLUME 4 OF 5

DIRECT TESTIMONY AND EXHIBITS

Filed: January 29, 2010

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Vol. No.	Tab No.	Filing Requirement	Description	Sponsoring Witness
1	10	807 KAR 5:001 Section 10(2)	*Notice of Intent. Utilities with gross annual revenues greater than $1,000,000 shall file with the commission a written notice of intent to file a rate application at least four (4) weeks prior to filing their application. The notice of intent shall state whether the rate application shall be supported by a historical test period or a fully forecasted test period. This notice shall be served upon the Attorney General, Utility Intervention and Rate Division.*	Mr. Bellar
1	11	807 KAR 5:001 Section 10(3)	*Form of notice to customers. Every utility filing an application pursuant to this section shall notify all affected customers in the manner prescribed herein. The notice shall include the following information: (a) The amount of the change requested in both dollar amounts and percentage change for each customer classification to which the proposed rate change will apply; (b) The present rates and the proposed rates for each customer class to which the proposed rates would apply; (c) Electric, gas, water and sewer utilities shall include the effect upon the average bill for each customer class to which the proposed rate change will apply; (d) Local exchange companies shall include the effect upon the average bill for each customer class for the proposed rate change in basic local service; (e) A statement that the rates contained in this notice are the rates proposed by (name of utility); however, the Public Service Commission may order rates to be charged that differ from the proposed rates contained in this notice; (f) A statement that any corporation, association, or person with a substantial interest in the matter may, by written request, within thirty (30) days after publication or mailing of this notice of the proposed rate changes request to intervene; intervention may be granted beyond the thirty (30) day period for good cause shown; (g) A statement that any person who has been granted intervention by the commission may obtain copies of the rate application and any other filings made by the utility by contacting the utility through a name and address and phone number stated in this notice; (h) A statement that any person may examine the rate application and any other filings made by the utility at the main office of the utility or at the commission's office indicating the addresses and telephone numbers of both the utility and the commission; and (i) The commission may grant a utility with annual gross revenues greater than $1,000,000, upon written request, permission to use an abbreviated form of published notice of the proposed rates provided the notice includes a coupon which may be used to obtain all of the information required herein.*	Mr. Bellar

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1	12	807 KAR 5:001 Section 10(4)(a)	*Manner of notification. Sewer utilities shall give the required typewritten notice by mail to all of their customers pursuant to KRS 278.185.*	Mr. Bellar
1	13	807 KAR 5:001 Section 10(4)(b)	*Manner of notification. Applicants with twenty (20) or fewer customers affected by the proposed general rate adjustment shall mail the required typewritten notice to each customer no later than the date the application is filed with the commission.*	Mr. Bellar
1	14	807 KAR 5:001 Section 10(4)(c)	*Manner of notification. Except for sewer utilities, applicants with more than twenty (20) customers affected by the proposed general rate adjustment shall give the required notice by one (1) of the following methods: 1. A typewritten notice mailed to all customers no later than the date the application is filed with the commission; 2. Publishing the notice in a trade publication or newsletter which is mailed to all customers no later than the date on which the application is filed with the commission; or 3. Publishing the notice once a week for three (3) consecutive weeks in a prominent manner in a newspaper of general circulation in the utility's service area, the first publication to be made within seven (7) days of the filing of the application with the commission.*	Mr. Bellar
1	15	807 KAR 5:001 Section 10(4)(d)	*Manner of notification. If the notice is published, an affidavit from the publisher verifying the notice was published, including the dates of the publication with an attached copy of the published notice, shall be filed with the commission no later than forty-five (45) days of the filed date of the application.*	Mr. Bellar
1	16	807 KAR 5:001 Section 10(4)(e)	*Manner of notification. If the notice is mailed, a written statement signed by the utility's chief officer in charge of Kentucky operations verifying the notice was mailed shall be filed with the commission no later than thirty (30) days of the filed date of the application.*	Mr. Bellar
1	17	807 KAR 5:001 Section 10(4)(f)	*Manner of notification. All utilities, in addition to the above notification, shall post a sample copy of the required notification at their place of business no later than the date on which the application is filed which shall remain posted until the commission has finally determined the utility's rates.*	Mr. Bellar
1	18	807 KAR 5:001 Section 10(4)(g)	*Manner of notification. Compliance with this subsection shall constitute compliance with 807 KAR 5:051, Section 2.*	Mr. Bellar
1	19	807 KAR 5:001 Section 10(5)	*Notice of hearing scheduled by the commission upon application by a utility for a general adjustment in rates shall be advertised by the utility by newspaper publication in the areas that will be affected in compliance with KRS 424.300*	Mr. Bellar

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1	20	807 KAR 5:001 Section 10(6)(a)	*A complete description and quantified explanation for all proposed adjustments, with proper support for any proposed changes in price or activity levels, and any other factors which may affect the adjustment.*	Mr. Rives
1	21	807 KAR 5:001 Section 10(6)(b)	*If the utility has gross annual revenues greater than $1,000,000, the prepared testimony of each witness the utility proposes to use to support its application.*	Mr. Bellar
1	22	807 KAR 5:001 Section 10(6)(c)	*If the utility has gross annual revenues less than $1,000,000, the prepared testimony of each witness the utility proposes to use to support its application or a statement that the utility does not plan to submit any prepared testimony.*	Mr. Rives
1	23	807 KAR 5:001 Section 10(6)(d)	*A statement estimating the effect that the new rates will have upon the revenues of the utility including, at minimum, the total amount of revenues resulting from the increase or decrease and the percentage of the increase or decrease.*	Mr. Conroy
1	24	807 KAR 5:001 Section 10(6)(e)	*If the utility provides electric, gas, water, or sewer service the effect upon the average bill for each customer classification to which the proposed rate change will apply.*	Mr. Conroy
1	25	807 KAR 5:001 Section 10(6)(f)	*If the utility is a local exchange company, the effect upon the average bill for each customer class for the proposed rate change in basic local service.*	Mr. Bellar
1	26	807 KAR 5:001 Section 10(6)(g)	*An analysis of customers' bills in such detail that revenues from the present and proposed rates can be readily determined for each customer class.*	Mr. Conroy
1	27	807 KAR 5:001 Section 10(6)(h)	*A summary of the utility's determination of its revenue requirements based on return on net investment rate base, return on capitalization, interest coverage, debt service coverage, or operating ratio, with supporting schedules.*	Mr. Rives
1	28	807 KAR 5:001 Section 10(6)(i)	*A reconciliation of the rate base and capital used to determine its revenue requirement.*	Mr. Rives
1	29	807 KAR 5:001 Section 10(6)(j)	*A current chart of accounts if more detailed that the Uniform System of Accounts prescribed by the commission.*	Ms. Charnas
1	30	807 KAR 5:001 Section 10(6)(k)	*The independent auditor's annual opinion report, with any written communication from the independent auditor to the utility which indicates the existence of a material weakness in the utility's internal controls.*	Mr. Rives
2	31	807 KAR 5:001 Section 10(6)(l)	*The most recent Federal Energy Regulatory Commission or Federal Communication Commission audit reports.*	Ms. Scott

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2	32	807 KAR 5:001 Section 10(6)(m)	*The most recent Federal Energy Regulatory Commission Form 1 (electric), Federal Energy Regulatory Commission Form 2 (gas), or Automated Reporting Management Information System Report (telephone) and Public Service Commission Form T (telephone);*	Ms. Scott
2	33	807 KAR 5:001 Section 10(6)(n)	*A summary of the utility's latest depreciation study with schedules by major plant accounts, except that telecommunications utilities that have adopted the commission's average depreciation rates shall provide a schedule that identifies the current and test period depreciation rates used by major plant accounts. If the required information has been filed in another commission case a reference to that case's number and style will be sufficient.*	Ms. Charnas
2	34	807 KAR 5:001 Section 10(6)(o)	*A list of all commercially available or in-house developed computer software, programs, and models used in the development of the schedules and work papers associated with the filing of the utility's application. This list shall include each software, program, or model; what the software, program, or model was used for; identify the supplier of each software, program, or model; a brief description of the software, program, or model; the specifications for the computer hardware and the operating system required to run the program.*	Ms. Scott
2	35	807 KAR 5:001 Section 10(6)(p)	*Prospectuses of the most recent stock or bond offerings.*	Mr. Rives
2	36	807 KAR 5:001 Section 10(6)(q)	*Annual report to shareholders, or members, and statistical supplements covering the two (2) most recent years from the utility's application filing date.*	Mr. Rives
3	37	807 KAR 5:001 Section 10(6)(r)	*The monthly managerial reports providing financial results of operations for the twelve (12) months in the test period.*	Ms. Scott
3	38	807 KAR 5:001 Section 10(6)(s)	*Securities and Exchange Commission's annual report for the most recent two (2) years, Form 10-Ks and any Form 8-Ks issued within the past two (2) years, and Form 10-Qs issued during the past six (6) quarters updated as current information becomes available.*	Mr. Rives

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3	43	807 KAR 5:001 Section 10(7)(b)	*Upon good cause shown, a utility may request pro forma adjustments for known and measurable changes to ensure fair, just and reasonable rates based on the historical test period. The following information shall be filed with applications requesting pro forma adjustments or a statement explaining why the required information does not exist and is not applicable to the utility's application: (b) The most recent capital construction budget containing at least the period of time as proposed for any pro forma adjustment for plant additions.*	Ms. Charnas
3	44	807 KAR 5:001 Section 10(7)(c)	*Upon good cause shown, a utility may request pro forma adjustments for known and measurable changes to ensure fair, just and reasonable rates based on the historical test period. The following information shall be filed with applications requesting pro forma adjustments or a statement explaining why the required information does not exist and is not applicable to the utility's application: (c) For each proposed pro forma adjustment reflecting plant additions provide the following information: 1. The starting date of the construction of each major component of plant; 2. The proposed in-service date; 3. The total estimated cost of construction at completion; 4. The amount contained in construction work in progress at the end of the test period; 5. A schedule containing a complete description of actual plant retirements and anticipated plant retirements related to the pro forma plant additions including the actual or anticipated date of retirement; 6. The original cost, cost of removal and salvage for each component of plant to be retired during the period of the proposed pro forma adjustment for plant additions; 7. An explanation of any differences in the amounts contained in the capital construction budget and the amounts of capital construction cost contained in the pro forma adjustment period; and 8. The impact on depreciation expense of all proposed pro forma adjustments for plant additions and retirements;*	Ms. Charnas
3	45	807 KAR 5:001 Section 10(7)(d)	*Upon good cause shown, a utility may request pro forma adjustments for known and measurable changes to ensure fair, just and reasonable rates based on the historical test period. The following information shall be filed with applications requesting pro forma adjustments or a statement explaining why the required information does not exist and is not applicable to the utility's application: (d) The operating budget for each period encompassing the pro forma adjustments.*	Ms. Scott

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3	46	807 KAR 5:001 Section 10(7)(e)	*Upon good cause shown, a utility may request pro forma adjustments for known and measurable changes to ensure fair, just and reasonable rates based on the historical test period. The following information shall be filed with applications requesting pro forma adjustments or a statement explaining why the required information does not exist and is not applicable to the utility's application: (e) The number of customers to be added to the test period-end level of customers and the related revenue requirements impact for all pro forma adjustments with complete details and supporting work papers.*	Mr. Seelye

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

APPLICATION OF KENTUCKY UTILITIES COMPANY FOR AN ADJUSTMENT OF BASE RATES	)))	**CASE NO. 2009-00548**

In the Matter of:

APPLICATION OF LOUISVILLE GAS AND ELECTRIC COMPANY FOR AN ADJUSTMENT OF ITS ELECTRIC AND GAS BASE RATES	))))	**CASE NO. 2009-00549**

TESTIMONY OF
VICTOR A. STAFFIERI
CHAIRMAN OF THE BOARD, CHIEF EXECUTIVE OFFICER AND PRESIDENT
LOUISVILLE GAS AND ELECTRIC COMPANY AND
KENTUCKY UTILITIES COMPANY

Filed: January 29, 2010

Q. Please state your name, position and business address.

A. My name is Victor A. Staffieri. I am the Chairman of the Board, Chief Executive Officer and President of Louisville Gas and Electric Company ("LG&E") and Kentucky Utilities Company ("KU") (collectively, "Companies"), and an employee of E.ON U.S. Services, Inc. My business address is 220 West Main Street, Louisville, Kentucky 40202.

Q. Please describe your employment history, education and civic involvement.

A. I joined LG&E Energy in March 1992 as Senior Vice President, General Counsel, and Corporate Secretary. Since then, I have served in a number of positions at LG&E Energy (now E.ON U.S. LLC), LG&E, and KU. I assumed my current position on May 1, 2001. Descriptions of my employment history, educational background, professional appearances and civic involvement are contained in the Appendix attached hereto.

Q. Have you testified before this Commission on other occasions?

A. Yes. I testified before this Commission in the Companies' last two base rate cases.[1] I have also testified in various other cases, including three proceedings regarding changes in the ownership of LG&E and KU.[2]

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[1] Case No. 2008-00252, *In the Matter of: Application of Louisville Gas and Electric Company for an Adjustment of its Electric and Gas Base Rates* and in Case No. 2008-00251, *In the Matter of: Application of Kentucky Utilities Company for an Adjustment of Base Rates*; Case No. 2003-00433, *In the Matter of: An Adjustment of the Gas and Electric Rates, Terms and Conditions of Louisville Gas and Electric Company* and in Case No. 2003-00434, *In the Matter of: An Adjustment of the Electric Rates, Terms and Conditions of Kentucky Utilities Company.*

[2] See e.g.., Case No. 2001-104, *In the Matter of: Joint Application of E.ON AG, Powergen plc, LG&E Energy Corp., Louisville Gas and Electric Company and Kentucky Utilities Company For Approval of an Acquisition*; Case No. 2000-095, *In the Matter of: Joint Application of Powergen plc, LG&E Energy Corp., Louisville Gas and Electric Company and Kentucky Utilities Company For Approval of a Merger;* Case No. 97-300, *In the Matter of: Joint Application of Louisville Gas and Electric Company and Kentucky Utilities Company for Approval of Merger.*

Q. What is the purpose of your testimony?

A. I will provide a general overview of the cases, including why LG&E and KU are proposing to adjust their base rates at this time and why the adjustments should be approved. I will also note the significant levels of investment in facilities to provide service to customers that the Companies have continued to make since the Companies' last base rate proceedings. Additionally, I will cover LG&E's and KU's continued efforts to perform their functions in an environmentally conscious manner, as well as the Companies' enduring commitment to the communities we serve, especially through our assistance to low-income customers.

Q. Please identify the other witnesses offering direct testimony on behalf of the Companies in these cases and generally describe the subject matter of each such testimony.

A. LG&E and KU are offering direct testimony from the following witnesses:

- Paul W. Thompson, Senior Vice President, Energy Services – Mr. Thompson will describe the investments in and construction of generation and transmission facilities which demonstrate the need for the proposed adjustment in base rates at this time, as well as the increased efforts to ensure that our customers receive reliable service at a low cost to both customers and the environment through enhanced measures to perform functions in an environmentally conscious manner;
- Chris Hermann, Senior Vice President, Energy Delivery – Mr. Hermann will describe how the Companies have been able to provide safe, reliable and cost-effective services for our electric and gas distribution businesses and retail operations and will explain the investments in enhancing customer service, as

well as the restoration expenses necessitated by the recent weather events, all of which support the need for the proposed adjustment in base rates at this time;

- S. Bradford Rives, Chief Financial Officer – Mr. Rives will describe why the financial condition of the Companies require the requested increase in base rates, present the financial exhibits to LG&E's and KU's applications, discuss the Companies' accounting records, describe the calculation of LG&E's and KU's adjusted net operating income for the twelve-month period ended October 31, 2009, support the different valuations of the Companies' property, and support certain reference schedules supporting the Companies' applications;
- Valerie L. Scott, Controller – Ms. Scott will support certain pro forma adjustments to the Companies' operating income for the twelve months ended October 31, 2009, demonstrate that those adjustments are known and measurable and, therefore, reasonable, and support certain reference schedules supporting the Companies' applications;
- Shannon L. Charnas, Director of Utility Accounting and Reporting – Ms. Charnas will support certain pro forma adjustments to the Companies' operating income and rate base for the twelve months ended October 31, 2009, demonstrate that those adjustments are known and measurable and, therefore, reasonable, and support certain reference schedules supporting the Companies' applications;
- Ronald L. Miller, Director, Corporate Tax – Mr. Miller will support certain pro forma adjustments to the Companies' operating income for the twelve months ended October 31, 2009, demonstrate that those adjustments are known and measurable and, therefore, reasonable;

- Daniel K. Arbough, Director, Corporate Finance and Treasurer – Mr. Arbough will discuss LG&E's and KU's current and target capital structure, as well as explain bond financing issues;
- William E. Avera, President, FINCAP, Inc. – Dr. Avera will present the results of his analysis, which demonstrates that the return on equity for the proxy groups of utilities and non-utility companies is from 10.5% to 12.5%. Additionally, Dr. Avera will present his recommendation that the Commission adopt an 11.5% allowed return on equity ("ROE") for both LG&E's electric and gas operations and KU's electric operations;
- Lonnie E. Bellar, Vice President, State Regulation and Rates – Mr. Bellar will support certain exhibits that are required by the Commission's regulations, explain the revenue effects and impact to customers, present LG&E's and KU's recommendation for the allocation of proposed increases among the customer classes, describe how LG&E's and KU's cost-recovery mechanisms affect base rates, and explain certain pro forma adjustments to the Companies' operating income for the twelve months ended October 31, 2009;
- W. Steven Seelye, Principal and Senior Consultant, The Prime Group, LLC – Mr. Seelye will support certain pro forma adjustments to the Companies' operating income for the twelve months ended October 31, 2009, demonstrate that those adjustments are known, measurable and reasonable, support certain reference schedules supporting the Companies' applications, and present the results of his cost-of-service study;

- Robert M. Conroy, Director, Rates – Mr. Conroy will explain and support certain exhibits that are required by the Commission's regulations, describe certain proposed pro forma adjustments and discuss LG&E's and KU's proposed changes to the tariffs and electric and gas rates; and
- John Wolfram, Director, Marketing and Customer Service – Mr. Wolfram will explain the Companies' new service offering for Low Emission Vehicles, describe the proposed revisions to LG&E's and KU's terms and conditions, and discuss the Companies' offerings, initiatives, and programs aimed at assisting customers or enhancing customer service.

Q. Have LG&E and KU continued to make significant investments in facilities to serve their customers since the last rate cases?

A. Yes. To ensure that our customers continue to receive the reliable service they have come to expect, LG&E and KU have continued to make significant investments in its generation, transmission and distribution facilities that are of historic scale, including the construction of a state-of-the-art coal-fired generating unit in Trimble County, Kentucky. The Companies' substantial investments in generation and transmission facilities, which are discussed in detail in Mr. Thompson's testimony, are approximately $391 million since April 30, 2008, the end of the test year in the last rate case. In like fashion, as discussed in the testimony of Mr. Hermann, the Companies have made approximately $234 million in capital investments to their electric and gas distribution facilities, $123 million for LG&E and $111 million for KU. Thus, the Companies have invested over $698 million in facilities to serve customers since their last rate case.

Q. Have there been challenges to the delivery of service?

A. Yes. In September 2008 the Companies' service areas were greatly affected by a windstorm from the remnants of Hurricane Ike. The windstorm resulted in over 375,000 LG&E and KU customers losing service. Our employees worked tirelessly to restore service and repair the significant damage to the distribution facilities. Less than five months later, in January and February 2009, another major weather event occurred, this time inundating much of the Companies' service areas in ice and snow. This storm, described by Governor Steve Beshear as the "worst natural disaster" in the modern history of the Commonwealth, left over 400,000 LG&E and KU customers without service and required the largest use of restoration workers in the Companies' history. These two weather events, which were of extraordinary magnitude, caused significant challenges to the delivery of service and necessitated significant restoration expenses. The restoration costs of these storms will be discussed more fully in Mr. Hermann's testimony, along with the improvements LG&E and KU are making to respond to such contingencies in the future and to further harden their distribution system.

However, I want to compliment the Commission's extensive and objective investigation into and report on the 2008 and 2009 storms. Many of the Commission's recommendations contained in the report are practices already undertaken by or in the planning stages for the Companies. We are committed to work with the Commission in implementing these recommendations.

Q. Have LG&E and KU taken steps since their last base rate proceedings to control costs?

A. Yes. Controlling costs is a predominant value in our culture. This philosophy governs the Companies' business practices in the construction, operation and maintenance of our systems and services. As discussed in the testimonies of Messrs. Thompson and Hermann, the Companies have made every effort to contain the increasing costs of providing reliable service and, LG&E and KU continuously endeavor to implement initiatives that increase the efficiency of our existing assets and avoid price increases where possible.

Q. Please describe the proposed increase in base rates.

A. LG&E is requesting a 12.1%, or $94.6 million a year increase in its electric base rates, and a 7.7%, or $22.6 million a year, increase in its gas base rates. The monthly impact of the requested increase in base rates will increase an average residential electric bill by 12.2%, or approximately $8.92, for a customer using 992 kWh of electricity. The monthly impact of the requested increase in gas base rates will increase an average residential gas bill by 8.7%, or approximately $4.65, for a customer using 58 Ccf of gas.

KU is requesting an 11.5%, or $135.3 million a year increase in its base rates. The monthly impact of the requested increase in base rates will increase an average residential electric bill by 13.5%, or approximately $11.70, for a customer using 1,230 kWh of electricity.

The testimonies of Mr. Rives, Ms. Scott, Ms. Charnas, Mr. Miller, Mr. Arbough, Mr. Seelye, Mr. Conroy, and Mr. Bellar provide a comprehensive accounting of LG&E's and KU's revenue requirements and how the calculation were determined. Mr. Avera's testimony supports LG&E's and KU's proposed rate of return on equity through an extensive cost of capital analysis. The testimonies of these witnesses demonstrate that LG&E and KU are not presently earning a fair and reasonable return and propose a just and reasonable increase in base rates.

Q. If LG&E's and KU's requested rate adjustment becomes effective, will customers still receive a good value for the service received?

A. Yes. As mentioned, the Companies understand the effect any rate increase has on their customers, but this necessary increase will ensure that customers continue to receive the dependable service they have rightfully come to expect. LG&E's and KU's significant investments in facilities, which have resulted in a decline in the Companies' financial condition, are essential to the continued delivery of highly reliable service.

LG&E and KU are proud to have been nationally recognized by J.D. Power & Associates each year for their customer satisfaction and have been ranked first in the Midwest Region in its residential survey eight times since 1999. These awards demonstrate that our customers have consistently ranked the Companies highly in areas such as price/value, power quality and reliability, billing and payment, customer service and overall company image.

Thus, while the Companies keenly appreciate the effect of any rate increase on our customers, they will continue to receive a good value for their service, as the Companies' significant investments in facilities and customer service capabilities make certain that reliable energy delivery and outstanding customer service will continue.

Q. Please describe the Companies' commitment to the protection of the environment and their efforts in that regard.

A. LG&E and KU are committed to performing their operations in an environmentally conscious manner so that customers can receive reliable service at low financial and environmental costs. The Companies have effectuated this goal through initiatives in three main areas. First, LG&E and KU continue to utilize environmentally sound methods of doing business. For example, when Trimble County Unit 2 is placed in commercial operation later this year, it will be among the most efficient and low emission coal-fired units in the nation. In addition, the Transmission Control and Data Center in Simpsonville, Kentucky, employs state-of-the-art energy-efficiency features.

Second, the Companies continue to invest in research endeavors purposed upon reducing carbon emissions and other significant energy issues. For example, LG&E and KU have jointly agreed to provide $200,000 per year for ten years to the Carbon Management Research Group, pertaining to carbon and carbon dioxide management in coal-fired generating units in Kentucky. The Companies have also pledged $1.8 million to the Kentucky Consortium for Carbon Storage in support of its efforts to investigate the feasibility of geologic storage in Kentucky of carbon dioxide produced by coal-fired generation within the state. In addition to investing in local research projects, the Companies have also made a significant pledge and have taken a leadership role in the FutureGen project, which is a global partnership consisting of public and private entities that was organized to design and operate the world's first coal-fired generating unit with near-zero emissions. All of these investments are discussed in further detail in Mr. Thompson's testimony.

Finally, the Companies have also implemented initiatives that increase customers' awareness of their energy consumption, as well as measures that assist in reducing their energy usage. Examples of these programs include the Green Energy Program, which allows customers to voluntarily offset their carbon impact through the purchase of renewable energy credits. Over 1,400 customers are currently participating in this program. LG&E continues use of the Responsive Pricing and Smart Metering Pilot Program, which is a three-year pilot program approved by the Commission in 2007 that allows 2,000 customers to better understand and control their electricity usage through various types of equipment, such as Smart Meters and Programmable Thermostats. The Companies continue to provide on-site residential and commercial energy audits to demonstrate where the most energy is being used. The Companies performed approximately 1800 audits in 2009. Also, as of December 31, 2009, there were approximately 117,000 LG&E and KU customers currently participating in the Demand Conservation program, which decreases energy consumption and the customers' utility bills. These programs are discussed more fully in Mr. Hermann's and Mr. Wolfram's testimony. Finally, the Companies have ensured that customers are able to better understand their environmental impact by providing an explanation on each customer's monthly bill of how much carbon dioxide the customer's usage has produced.

Q. Please describe the Companies' commitment to the community.

A. Our commitment to the communities in which we serve is long-standing and truly part of LG&E's and KU's culture. This commitment is evidenced through our employees' giving of their time and talent throughout our service area to improve the quality of life in the communities in which they work and live. For example, our employees currently serve on over 150 boards representing a wide range of community interests. Also, for three consecutive years, LG&E and KU employees have contributed more than $1 million annually to the Companies' Power of One initiative, which is a structured program for employee volunteering that was established in 2004. These generous contributions are distributed to nonprofit organizations throughout the Companies' service areas.

In addition to the efforts of our employees, the E.ON U.S. Foundation continues to contribute to our communities through supporting education, diversity initiatives, the environment, and health and safety programs. The E.ON U.S. Foundation was established in 1994 and has since awarded $20 million to hundreds of organizations to support benevolent endeavors across the Commonwealth. In 2009, over $750,000 was awarded to various nonprofit organizations, universities and colleges to support causes ranging from child advocacy to reading and art programs. All of these donations are funded solely by our shareholders.

Q. What steps have the Companies taken to assist low-income customers with their energy bills?

A. LG&E and KU have long assisted low-income customers with their utility bills through several programs the Companies have developed, many of which are administered with non-profit organizations throughout our service area. One such initiative is the Winter Blitz, in which community volunteers –including many LG&E and KU employees and their families—"weatherize" the homes of low-income, disabled and elderly persons in our service area. To date, over 3,000 homes have been weatherized.

Although LG&E and KU have well-established initiatives to assist low-income customers, the Companies have intensified their efforts in response to these challenging economic times. For example, the Companies are matching all donations to Community Winterhelp and the WinterCare Energy Assistance Fund, which aids low-income customers throughout the winter heating season, at an increased rate of one dollar for every one dollar customers donate from November 1, 2009, through March 31, 2010.

Q. Do you have any final comments?

A. Please let me reiterate that the decision to seek a base rate increase was not made lightly, as the Companies take their obligation to provide reliable service at a low-cost very seriously. Although the Companies have aggressively attempted to contain costs, base rate increases are necessary at this time so that LG&E and KU can continue the high standard of service that customers have come to expect.

Q. Does this complete your testimony?

A. Yes, it does.

VERIFICATION

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

The undersigned, **Victor A. Staffieri**, being duly sworn, deposes and says that he is Chairman of the Board, Chief Executive Officer and President of Kentucky Utilities Company and an employee of E.ON U.S. Services, Inc., and that he has personal knowledge of the matters set forth in the foregoing testimony, and that the answers contained therein are true and correct to the best of his information, knowledge and belief.

Victor A. Staffieri

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 22nd day of January 2010.

_______________(SEAL)
Notary Public

My Commission Expires:

6/3/2010

APPENDIX

Victor A. Staffieri

Chairman, Chief Executive Officer and President
E.ON U.S. LLC

Mr. Staffieri is Chairman, CEO and President of Louisville Gas and Electric Company, Kentucky Utilities Company and E.ON U.S. LLC. Mr. Staffieri is also a member of E.ON AG's Executive Committee.

Civic Activities

Boards

Metro United Way – Chairman Metro Campaign 2002
Leadership Louisville – Board of Directors – June 2006 – 2008
Louisville Area Chamber of Commerce – Board of Directors -- 1994-1997; 2000-2003; Chairman 1997
MidAmerica Bancorp – Board of Directors – 2000 - 2002
Muhammad Ali Center – Board of Directors – 2003 - 2006
Kentucky Country Day – Board of Directors – 1996 - 2002
Bellarmine University – Board of Trustees – 1995 - 1998, 2000 - 2006
Executive Committee – 1997 - 1998
Finance Committee – 1995 - 1997, 2000 - 2003
Strategic Planning Committee – 1997

Industry Affiliations

Edison Electric Institute, Washington, DC - Board of Directors -- June 2001 - Present
Electric Power Research Institute, Palo Alto, CA - Board of Directors -- May 2001 – April 2002

Other

Louisville Area Chamber of Commerce -- African-American Affairs Committee -- 1996-1997
Louisville Area Chamber of Commerce -- Vice Chairman, Finance and Administration Steering Committee -- 1995
Jefferson County/Louisville Area Chamber of Commerce Family Business Partnership Co-Chair – 1996-1997
The National Conference - Dinner Chair -- 1997
Chairman of the Coordination Council for Economic Development Activities
-- Regional Economic Development Strategy -- 1997
Metro United Way - Cabinet Member -- 1995 and 2000 Campaigns
--Chairman – Kentucky Chamber of Commerce Education Task Force - 2008
--Member – Governor's Task Force on Higher Education - 2009

Education

Fordham University School of Law, J.D. -- 1980
Yale University, B.A. – 1977

Previous Positions

LG&E Energy LLC, Louisville KY
March 1999 - April 2001 -- President and Chief Operating Officer
May 1997 - February 1999 -- Chief Financial Officer
December 1995 - May 1997 -- President, Distribution Services Division
December 1993 - May 1997 -- President, Louisville Gas and Electric Company
December 1992 - December 1993 -- Senior Vice President - Public Policy, and General Counsel
March 1992 - November 1992 -- Senior Vice President, General Counsel and Corporate Secretary

Long Island Lighting Company, Hicksville, NY
1989-1992 -- General Counsel and Secretary
1988-1989 -- Deputy General Counsel
1986-1988 -- Assistant General Counsel
1985-1986 -- Managing Attorney
1984-1985 -- Senior Attorney
1980-1984 -- Attorney

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

APPLICATION OF KENTUCKY UTILITIES COMPANY FOR AN ADJUSTMENT OF BASE RATES	)))	CASE NO. 2009-00548

In the Matter of:

APPLICATION OF LOUISVILLE GAS AND ELECTRIC COMPANY FOR AN ADJUSTMENT OF ITS ELECTRIC AND GAS BASE RATES	))))	CASE NO. 2009-00549

TESTIMONY OF
PAUL W. THOMPSON
SENIOR VICE PRESIDENT, ENERGY SERVICES
LOUISVILLE GAS AND ELECTRIC COMPANY AND
KENTUCKY UTILITIES COMPANY

Filed: January 29, 2010

Q. **Please state your name, position and business address.**

A. My name is Paul W. Thompson. I am the Senior Vice President, Energy Services of Louisville Gas and Electric Company ("LG&E") and Kentucky Utilities Company ("KU") (collectively, the "Companies"), and an employee of E.ON U.S. Services, Inc. My business address is 220 West Main Street, Louisville, Kentucky 40202.

Q. **Please describe your educational and professional background.**

A. I received a Bachelor of Science degree in Mechanical Engineering from the Massachusetts Institute of Technology in 1979 and a Master of Business Administration from the University of Chicago in Finance and Accounting in 1981. Before joining LG&E Energy (now E.ON U.S.) in 1991, I worked eleven years in the oil, gas and energy-related industries in positions of financial management, general management and sales. A complete statement of my work experience and education is contained in the Appendix attached hereto.

Q. **Please describe your duties and responsibilities as Senior Vice President, Energy Services.**

A. I am responsible for power generation functions, electric transmission, and fuels and energy marketing activities. For purposes of this testimony, I will refer to the above functions collectively as "Energy Services."

Q. **Have you previously testified before this Commission?**

A. Yes. I testified in LG&E's 2008 rate application, Case No. 2008-00252, *In re the Matter of: Application of Louisville Gas and Electric Company for an Adjustment of Its Electric and Gas Base Rates*, and KU's 2008 rate application, Case No. 2008-00251, *In re the Matter of: Application of Kentucky Utilities Company for an*

Adjustment of Base Rates. Additionally, I testified in *In re the Matter of: The Application of Big Rivers Electric Corporation, E.ON U.S. LLC, Western Kentucky Energy Corp., and LG&E Energy Marketing Inc. for Approval of Transaction* in Case No. 2007-00455. I also filed testimony in the Commission's investigation of LG&E's and KU's membership in the Midwest Independent Transmission System Operator, Inc., *In the Matter of: Investigation into the Membership of Louisville Gas and Electric Company and Kentucky Utilities Company in the Midwest Independent Transmission System Operator, Inc.*, Case No. 2003-0266. I testified in LG&E's 2003 rate application, Case No. 2003-0433, *In re the Matter of: An Adjustment of the Gas and Electric Rates, Terms and Conditions of Louisville Gas and Electric Company*, and KU's 2003 rate application, Case No. 2003-0434, *In re the Matter of: An Adjustment of the Electric Rates, Terms and Conditions of Kentucky Utilities Company*. Finally, I testified in the merger proceedings of LG&E and KU before the Kentucky Public Service Commission in Case No. 1997-0300, *In the Matter of: Application of Louisville Gas and Electric Company and Kentucky Utilities Company for Approval of a Merger under KRS 278.020.*

Q. Please provide an overview of your testimony and why an increase in base rates is needed at this time.

A. In this testimony I will describe Energy Services' capital investments in and construction of generation and transmission facilities to serve our customers, which are of historic scale and are one of the principal causes for the deterioration of the Companies' financial health. The Companies' construction efforts are wholly designed to further serve our customers through the development of generation units that produce energy in the most efficient manner and transmission facilities that enhance reliability. The Companies have invested over $698 million dollars since the last rate case in facilities to serve customers, including $391 million in generation and transmission facilities. With this additional investment to serve customers, operating expenses associated with these new facilities such as property taxes and insurance have increased as well. In addition to these significant capital investments, Energy Services has continued its efforts to perform its functions in an environmentally conscious manner. Through constructing new facilities and endeavoring to lessen their environmental impact, LG&E and KU are striving to ensure that customers continue to receive an exceptional value in electric service through the delivery of reliable service at a low cost to both customers and the environment.

In the construction of new generation and transmission facilities, every effort to contain costs and remain within the original budget has been made. As a result of these efforts, the facilities are being constructed at a cost below the national average. The cost efficient measures that have been taken, however, are no longer sufficient to offset the increasing cost of the Companies' service obligations which have been exacerbated by significant restoration expenses as a result of unprecedented weather events that affected LG&E's and KU's service areas. As demonstrated in my testimony and the testimonies of Messrs. Rives and Hermann, LG&E and KU must implement a base rate increase in order to sustain the costs of providing customers the reliable service they have come to expect.

Q. In general, what is Energy Services' major corporate objective?

A. Energy Services has four major, and overlapping, objectives: (i) to maximize the performance and investment life of the Companies' electric generation and transmission assets; (ii) to maintain sound operating and maintenance practices that promote reliable operations, high efficiency, and a safe working environment; (iii) to continue to provide high value electric service to LG&E and KU customers; and (iv) to operate as a good steward of the environment.

Generation Systems

Q. Please describe LG&E's generation system.

A. LG&E owns and operates approximately 3,200 MW of generating capacity with a net book value of approximately $1.1 billion. LG&E's generation system consists primarily of three coal-fired generating stations – Cane Run and Mill Creek, both located in Jefferson County, and Trimble County. All of these stations are equipped with flue gas desulfurization systems or "scrubbers" to reduce sulfur dioxide, allowing the units to burn lower-cost, higher-sulfur content coal. LG&E also owns and operates multiple natural gas-fired combustion turbines, which supplement the system during peak periods, and the Ohio Falls hydroelectric station, which provides baseload supply, subject to river flow constraints.

Q. Please describe KU's generation system.

A. KU owns and operates approximately 4,500 MW of generating capacity with a net book value of approximately $1.6 billion. KU's generation system consists primarily of four generating stations – Ghent in Carroll County, Tyrone in Woodford County, E.W. Brown in Mercer County and Green River in Muhlenberg County. The installation of scrubbers on all KU coal-fired units has continued, except for the much smaller Green River 3 and 4 and Tyrone 3 units. The scrubbers installed on all of the Ghent units are in operation with only minor punchlist-type items remaining. The scrubber to service the E.W. Brown units will be in operation by November 2010. KU also owns and operates multiple natural gas fired-combustion turbines, which supplement the system during peak periods, and a hydroelectric generating station at Dix Dam, located next to the Dix System Control Center.

Q. Are LG&E's and KU's generation systems operated jointly?

A. Yes. LG&E and KU, as owners and operators of interconnected electric generation, and transmission facilities, achieve economic benefits through joint operation as a single interconnected and centrally dispatched system and have operated jointly since the acquisition of KU Energy Corporation by LG&E Energy in 1998. In addition, the Companies implemented joint integrated resource planning and acquisition as a result of the merger. A map of LG&E's and KU's generating units is attached as Thompson Exhibit 1.

The joint dispatch of the generation units continues to produce energy efficiencies through joint dispatch capabilities and intercompany sales of power. These efficiencies have enabled the Companies to provide a higher value of electric service to our customers.

Trimble County Unit No. 2.

Q. Please describe the investments in and construction of generation facilities which support the need for an adjustment of base rates at this time.

A. On November 1, 2005, in Case No. 2004-00507, LG&E and KU were granted a certificate of public convenience and necessity ("CPCN") to construct Trimble County Unit No. 2 ("TC2"). The Companies are currently in the latter phase of constructing TC2, a super-critical, pulverized coal-fired generating unit utilizing state-of-the-art technology to accomplish the dual goals of extraordinary efficiency and low environmental impact. It is currently scheduled for commercial operation in June 2010, and once in commercial operation, TC2 will have a net generation capacity of 760 MW, of which the Companies will own 75%, or approximately 570 MW. LG&E will be entitled to 19% or approximately 108 MW, and KU will be entitled to 81% or approximately 462 MW. A recent aerial photograph showing the construction of TC2 is attached as Thompson Exhibit 2. Also, aerial photographs of the Trimble County Generation Station are attached as Thompson Exhibit 3.

The construction of TC2 is the most significant ongoing generation investment. The total projected cost to the Companies in constructing TC2 is approximately \$965 million, with \$871 million required for the generation unit. Through October 2009, the Companies have invested \$815 million in TC2 generation, with \$322 million having been expended since the last base rate application. As a result of significant economic changes in the construction industry during the building of TC2, such as increased labor costs, the total projected cost of TC2 has increased by approximately 9% from original estimates in 2004.

Despite the increase, the construction of TC2 has been very cost efficient, which will allow our customers to enjoy its benefits on schedule. The cost of the unit per kW, when compared to its generation capacity, is projected to be $1,528 per kW, well below the current market estimate of $2,400-$3,000 per kW. When the $125 million tax credit which LG&E and KU received for TC2 is taken into account, the estimated cost is $1,308 per kW. This makes TC2 a leader in terms of dollars per kW among other plants currently under construction in the United States, which ensures that TC2 will provide customers with reliable service at a great value.

Q. Please describe how TC2 will achieve extraordinary efficiency while minimizing its environmental impact.

A. In designing TC2, the Companies were aware of the ever-increasing need to protect and preserve the environment. TC2 utilizes the latest technology, such as state-of-the-art air pollution control equipment, to maximize its electrical output while reducing its environmental impact. TC2 incorporates more environmental control technologies than any other coal fired unit in Kentucky. TC2 releases significantly fewer regulated emissions than Trimble County Unit No. 1, which became operable in 1991, while generating over 40% more electricity with approximately 20% better heat rate efficiency. As a result of TC2's efficiency and environmental advances, the Companies were awarded a $125 million tax credit under the Qualifying Advanced Coal Project Credit.

Q. What is the projected commercial in-service date for TC2?

A. The contract commercial in-service date for TC2 is June 2010. Bechtel, the entity constructing the TC2 generating unit, has significant financial incentive to complete

TC2 in June 2010 due to the substantial liquidated damages provision in its contract. Construction is on a tight schedule and many milestones have been achieved, as all major equipment has been delivered, the new cooling tower has been placed into operation, the water treatment upgrades are completed, the coal blending facility has been commissioned and the new auxiliary boiler has been installed and placed into operation. Commissioning operations and check out began in November, which are operations that lead up to the final phase of full load generation testing. First fire on fuel oil is expected to begin in February 2010, with the first fire on coal expected in April, 2010. Full load performance testing is expected to occur during May and June 2010 prior to the commercial in-service date.

Q. Have there been reductions in available generation supply since TC2's CPCN was granted?

A. Yes. Since TC2's CPCN was granted, the Companies' generating supply has decreased by over 3,200 GWh annually. First, the available supply has decreased as KU no longer purchases energy from Electric Energy, Inc. ("EE Inc"). In 2006, KU's power supply agreement with EE Inc expired under its own terms and the majority owners of EE Inc, over KU's objection, elected to pursue market-based pricing authority. Under a long-standing agreement, KU had been purchasing 200 MW of relatively low-cost base load energy, the equivalent of approximately 1,450 GWh of energy each year.

Secondly, Owensboro Municipal Utility ("OMU") has terminated its purchase power contract with KU effective May, 2010. KU had purchased OMU's excess energy (approximately 200 MWat OMU's peak), and, at the time of the TC2 CPCN approval, planned to purchase approximately 1,775 GWh of energy annually from OMU. The OMU contract was a long-standing resource for low cost energy and OMU's termination of the contract, over KU's objection, will result in a loss to KU's baseload power supply.

Q. Has the recession affected the Companies' load since TC2's CPCN was granted?

A. Yes. The Companies have continuously prepared load forecasts during the construction of TC2 and monitored their actual loads. The most recent load forecast is attached as Thompson Exhibit 4. The Companies' electricity sales forecast is lower as a result of the economic recession. Driven primarily by reductions in energy usage by industrial customers, the Companies' 2011 energy requirements (2011 is the first full year of TC2 operation) are forecasted to be approximately 4,000 GWh less than the 2011 level forecasted at the time of the TC2 CPCN.

Q. Does the public convenience and necessity require TC2 today, given this revised view of native load energy requirements and generating supply?

A. Absolutely. Combining the reduction in native load energy requirements with the loss of base load energy from OMU and EE Inc, the Companies' 2011 energy supply with TC2 exceeds the forecast in the TC2 CPCN by only 800 GWh, or 2% of the Companies' 2011 energy requirements. TC2 is expected to provide the Companies with over 4,000 GWh of energy in 2011 effectively replacing the energy lost from OMU and EE Inc while also displacing higher-cost energy in the company's supply to native load customers. Customers will benefit from <u>all</u> of the low cost energy produced by TC2, as it is expected to be the lowest cost unit in the system and therefore the first unit in the merit order of economic dispatch. In the first full year of operation the Companies' project fuel and purchase power offsets from TC2 to be in excess of $67 million growing to over $80 million in 2012. Indeed, customers will begin to benefit from TC2 this spring, prior to its commercial operation, when the coal cost associated with the test power from this unit is reflected in the calculation of the fuel adjustment clause. Without TC2, the Companies cannot ensure an adequate energy supply at a reasonable cost to provide customers with reliable electric service.

Q. What is the impact on the Companies' reserve margin when TC2 begins commercial operation in 2010?

A. The addition of a base load unit to a generation system typically increases the reserve margin for a limited period of time due to the size of the base load capacity and the critical need to maintain an adequate reserve margin during the construction of the new base load unit. This impact was reflected in the CPCN proceeding and is expected to occur this summer when TC2 is placed into commercial operation. Although there have been changes in both load and generation resources since the CPCN was granted in 2005, the impact of the addition of TC2 on the Companies' reserve margin remains very similar to the impact presented at the proceeding for the CPCN. The most recent projection is that the reserve margin will be 22.6% when TC2 begins commercial operation in 2010, instead of the 19.3% forecast in the TC2 CPCN.

In addition, due to the reduction in the annual peak hour load due to the Companies' DSM programs, the resulting load shape is now flatter than projected in the CPCN case, thereby increasing the need for a generation resource that supports base load requirements. TC2 is an excellent base load generation resource for this purpose. TC2 is a generation asset primarily targeted at meeting the demand of base load by providing low cost energy around the clock, not only the demands at *the* peak hour.

The addition of a base load unit typically increases the reserve margin for a period of time. This is so because adding base load generation necessarily involves adding larger blocks of generating capacity than, for example, a combustion turbine. More importantly, due to the need to maintain an adequate reserve margin at all times, especially during the construction of the base load unit, the addition of a base load unit inevitably adds to the reserve margin. To avoid this increase would require the utility to maintain an unreasonable reserve margin during the construction of the base load unit or rely heavily on short-term purchase power.

Efficiency Initiatives

Q. Please describe what is meant by the phrase "asset management."

A. As used by Energy Services, the term "asset management" refers to a business discipline for maximizing the performance of long-term generation and transmission assets through management of the assets' life cycles. The dual goals of asset management are to increase the efficiency of the assets while continuing to provide reliable service. Asset management allows for realization of these goals in the most cost-effective manner possible.

Q. Can you provide examples of the Companies' asset management initiatives for their generation systems?

A. Yes. LG&E and KU continue to modernize and expand the use of digital control technology (Distributed Control Systems or DCS) in its generation facilities, as new systems have recently been installed in the Ghent units and Trimble County Unit No 1. DCS provides the Companies with enhanced control over the many interconnected operations occurring within the generation fleet, while also providing improved coordination and monitoring over these processes. The technology provides the advantages of centralized control, while preserving the ability for localized control.

LG&E and KU continue to utilize a Predictive Maintenance Program that increases the reliability of the Companies' equipment while ensuring that maintenance is cost-effective. Through the Predictive Maintenance Program, assessments of the equipment's condition are made such that maintenance occurs only when necessary to maintain the equipment's optimum performance. Unlike a time-based maintenance program, maintenance only occurs when issues have been identified, reducing unnecessary repairs and maintenance costs. Additionally, the Predictive Maintenance Program provides better data analysis and reporting, as well as enhanced equipment troubleshooting and diagnostics. Consequently, Energy Services is able to minimize maintenance costs while ensuring the continued reliability of its equipment.

The Companies have also instituted a Corrosion Fatigue Program, which seeks to improve the Companies' response to corrosion fatigue, as well as its proactive capabilities in preventing corrosion occurrences. The Program is intended to improve the Companies' response through enhanced identification of LG&E and KU boilers susceptible to corrosion fatigue, prioritization and implementation of inspections and implementation of mitigation measures as required. The Program also includes boiler feedwater chemistry management as it relates to future corrosion fatigue occurrences.

LG&E and KU have also implemented a Catalyst Management Program designed to manage the life-cycle cost of selective catalytic reduction ("SCR") catalysts throughout the Companies' fleet. The purpose of the program is to maximize the performance of SCR NOx reduction equipment, ensure compliance with NOx emission regulations, such as the Clean Air Interstate Rule, and achieve the lowest available operating costs.

Performance of the Generation Systems

Q. Please describe the reliability of LG&E's and KU's generation systems over the last several years.

A. LG&E and KU have a tradition of excellent generation performance. This is evidenced through Energy Services' weighted average Equivalent Forced Outage Rate ("EFOR") and capacity factors. The EFOR, a commonly used industry standard to measure the reliability of coal-fired generating units, has historically remained below the industry average. LG&E's and KU's EFOR during the test year averaged 4.96% and 6.13%, respectively. These numbers are well below the most recent three-year national average of 8.32%.

Q. Please describe the Companies' capacity factor trend over the last several years.

A. For many years, LG&E's and KU's steam capacity factor for coal-fired baseload generating units has trended consistently upward. LG&E's capacity factor has consistently remained above 78% since 2005. KU's average capacity factor for the same period has been over 66%. Although KU's average is lower, KU's steam capacity factor has increased steadily in recent years as a result of the continued installation of scrubbers, on KU's generating units. LG&E's units are already fully scrubbed. Despite the consistent upward trend, both LG&E's and KU's capacity factor decreased in 2009 due to the general economic downturn. The capacity factor results over this time period, however, demonstrate excellent performance.

Q. How do LG&E and KU benchmark the reliability of their generation performance to others in the industry?

A. Through utilizing the EFOR metric, LG&E and KU benchmark the performance of each individual generating unit and then combine the data to construct a combined system metric. Once the data is compiled, LG&E and KU establish the preferred performance quartile for each unit based upon the age of each asset and other factors relevant to efficiency. Once the target performance quartiles have been decided, the Companies compare each unit's rolling three-year EFOR to the rolling three-year EFORs of similarly sized coal units within the North American Electric Reliability Council's ("NERC") Reliability First Corporation ("RFC") region. NERC's RFC region is an appropriate basis for comparison as the generating units in that region are similar to LG&E's and KU's with regard to design, fuel quality and environmental controls.

Q. How has Energy Services' combined system compared to those of the benchmark groups described above?

A. The combined system EFOR demonstrates that the Companies' generation systems are operating reliably and efficiently. The Companies' overall system EFOR has consistently achieved top quartile or second quartile performance. In the most recent three-year rolling EFOR, which was from 2005-2007, top quartile performance was at 4.77% and second quartile performance was 7.11%. During this same period the Companies' overall system EFOR was 5.8%. The Companies are continuing their efforts to again reach top quartile performance levels.

Q. Please describe any contingency reserves that the Companies maintain.

A. In order to ensure a continued tradition of outstanding reliability, the Companies maintain contingency reserves, in which the Companies pool excess capacity with the excess capacity of other reserve sharing group members to ensure reliable service even when there are unexpected variations in customer demand and unplanned or unforced outages of generating equipment. The Companies had previously belonged to the Midwest Contingency Reserve Sharing Group ("MCRSG"), but under the terms of the MCRSG Agreement, the contract terminated on December 31, 2009.

In order to ensure continued access to adequate contingency reserves, the Companies entered into a reserve sharing group effective January 1, 2010, with East Kentucky Power Cooperative, Inc. and the Tennessee Valley Authority. The formation of this reserve sharing group was the most cost-effective manner in which to ensure sufficient contingency reserves. The Companies, under the terms of the agreement, are required to maintain 201 MW of capacity reserves, with the Companies being able to control how much of the 201 MW are spinning and supplemental reserves, respectively. As part of establishing the new reserve sharing group, the Companies were required to invest approximately $100,000 for their share of software development costs.

Transmission Systems

Q. Please describe LG&E's transmission system.

A. LG&E serves approximately 391,000 electricity customers over its transmission and distribution network extending across 9 counties in Kentucky. LG&E's transmission plant covers approximately 900 circuit miles, and has a net book value of approximately $110 million.

Q. Please describe KU's transmission system.

A. KU serves approximately 513,000 electricity customers over a transmission and distribution network extending across 77 counties in Kentucky. KU's transmission plant covers approximately 4,300 circuit miles, and has a net book value of approximately $202 million.

Q. Are LG&E's and KU's transmission systems operated jointly?

A. Yes. LG&E and KU, as owners and operators of interconnected electric transmission facilities, achieve economic and reliability benefits through joint operation as a single interconnected and centrally dispatched system and have operated jointly following the acquisition of KU Energy Corporation by LG&E Energy in 1998. The joint operation of the transmission systems has resulted in increased reliability and efficiency. In turn, the Companies are enabled to provide a higher value of electric service to our customers. Additionally, the Companies implemented joint transmission planning as a result of the merger.

Q. Please describe the investments in and construction of transmission facilities which support the need for an adjustment of base rates at this time.

A. The Companies are building significant additional transmission facilities in conjunction with the TC2 project. The Companies are constructing a 345 kV transmission line, approximately 42 miles in length, running from LG&E's Mill Creek Generating Station ("Mill Creek Station") through Jefferson County, Bullitt County, Meade County and Hardin County to KU's Hardin County Substation near Elizabethtown, Kentucky. LG&E will own that portion of the line beginning at the Mill Creek Station and running to the east boundary of the Fort Knox Military Reservation, and KU will own the remainder of the line from the east boundary of the Fort Knox Military Reservation to the Hardin County Substation.

The projected completion date for the Mill Creek to Hardin County transmission line is June 2010. Construction is almost complete except for three small segments in Hardin County. Construction in this area has been delayed as a result of litigation involving proposed right-of-way acquisitions. On December 22, 2009, the Commission granted a CPCN for the construction of the temporary lines in Case No. 2009-00325, *In the Matter of: Application of Kentucky Utilities Company Concerning the Need to Obtain Certificates of Public Convenience and Necessity for the Construction of Temporary Transmission Facilities in Hardin County, Kentucky.* While construction is complete in the remaining areas of the line unaffected by the pending litigation, construction of temporary facilities around the properties involved in the litigation began in January 2010.

Also in conjunction with TC2, the Companies have interconnected the TC plant to a 345 kV transmission line in Indiana owned by Duke Energy Indiana and Duke Energy Ohio, which necessitated crossing the Ohio River.

In addition to the construction of the new transmission line, the Companies have been upgrading transmission facilities in Anderson, Carroll, Fayette, Franklin, Trimble and Woodford counties.

The Companies have currently spent over $87 million on TC2 related transmission construction since the project began. The Companies have been able to efficiently manage increases in the cost of materials while staying within 10% of the sanctioned budget. The only significant deviation from the original estimates has been the unanticipated costs of the construction of the "work-around" segments necessitated by the litigation in Hardin County, and the higher than expected cost of the line crossing the Ohio River, due to the extremely rough terrain that was encountered.

Q. Please describe the operation and performance of the current transmission facilities.

A. Energy Services places great emphasis on the reliability of its transmission facilities. So do the Federal Energy Regulatory Commission ("FERC") and the North American Electric Reliability Corporation ("NERC"). Together, they have steadily increased reliability requirements for operating transmission systems. And, their compliance monitoring and enforcement activities associated with the measurement and enforcement of compliance standards has steadily increased as well. To satisfy its obligations, Energy Services has increased its activities to ensure reasonable compliance with both the FERC/NERC reliability requirements and their monitoring and oversight activities.

In addition, to further ensure continued reliability, the Companies invested $26 million in the construction of a new Transmission Control and IT Data Center. The facility, located in Simpsonville, Kentucky, became fully operational in August 2008 and is designed to operate continuously, 24 hours a day, 365 days a year. It is designed to address both transmission control and IT data needs for the Companies. The facility consolidated LG&E's and KU's old and outdated transmission control centers and will aid in the more efficient coordination of the Companies' combined transmission systems. The Companies maintain one of the previous control centers, the Dix System Control Center, for backup system control. Also, the Transmission Control Center is designed to ensure compliance with the cyber security standards that were approved by FERC in January 2008 and the NERC Board of Trustees in 2006. The Data Center was constructed to ensure reliability and improve efficiencies as the facility is designed to withstand an extended outage and transitions disaster recovery control from a third-party contract to internal capability. The design of the facility is hallmarked by reliability, as it is constructed to withstand a F4 tornado and the equipment is redundant and physically separated. Energy efficiency was also vital to the design of the facility, which utilizes motion sensor lighting, scalable facility components and a free cooling system that utilizes external air temperatures to assist in the cooling process.

Q. Have there been challenges to the operation of the transmission systems?

A. Yes. The ice and wind storms that occurred from January 26 through February 11, 2009 ("Winter Storm") caused unprecedented damage to LG&E's and KU's transmission systems and a consequent disruption of transmission service and operations. Governor Steve Beshear described the ice storm portion of the Winter Storm, which consisted of three days of accumulating ice, as the "worst natural disaster" in the modern history of the Commonwealth. By January 28, measurable ice accumulation ranged from a quarter of an inch to three inches. Ice accumulation of such a substantial nature greatly affected the integrity of LG&E's and KU's lines. At peak, the accumulation resulted in 404,000 LG&E and KU customers being without power. The magnitude of the damage was vast, as a full 100% of the transmission substations in western portions of KU's service area were affected and 40% of the transmission substations in KU's central regions were affected. As for LG&E, 33% of the transmission substations were impacted. Over 100 transmission lines sustained actual damage or were otherwise affected. In LG&E's and KU's transmission system, 188 towers and poles had to be replaced and 368 spans of line were out of service. Not even two full days after the last customer affected by the initial ice accumulation was restored, a windstorm occurred on February 11, also causing damage to the transmission system.

The Companies began restoration efforts immediately on January 26, attempting to mitigate the effects of the continuing ice accumulation and restore service to customers when possible. The restoration effort, which at peak involved 6,016 employees, contractors and mutual assistance personnel, is the largest restoration effort ever undertaken by the Companies. Mutual assistance personnel are workers from other utility companies who assist in restoration efforts when needed. The Companies belong to several mutual assistance groups such that adequate personnel will be available in the event a significant restoration effort is required.

Due to the severity of the damage to LG&E's and KU's equipment, contractors were retained through March 13 to complete repairs.

In restoring service and repairing the significant damage to its equipment as a result of the Winter Storm, the Companies spent $148 million, $17 million of which was spent on Transmission. Nearly 95% of the costs to repair the Transmission system involved capital investments.

Safety Performance and Recognitions

Q. Please discuss the Companies' safety performance in the areas of generation, construction and transmission.

A. The Companies hold the safety of its employees paramount. An emphasis on safety has long been part of Energy Services' culture. For the 12 months ended October 31, 2009, Energy Services' recordable injury incident rate ("RIIR") under OSHA regulations is 1.02, which is almost 71% below the comparable national utility average of 3.5. The RIIR for contractors for the 12 months ended October 31, 2009, is 1.95, less than one-half of the national average for construction. The emphasis on safety is also reflected in the numerous recognitions Energy Services has received since 2008. LG&E has reached several milestones, such as the Ohio Falls hydroelectric station operating for twenty years without a single lost-time incident. In 2008, the employees working at the Cane Run generating unit received the Governor's Health and Safety Award in recognition of 250,000 hours worked without an incident. In July 2009, the Mill Creek plant achieved one year with no recordable injuries for employees and contractors. KU's employees have performed comparably as the Brown and Tyrone stations have had eleven years without a lost-time incident and two years without a single recordable incident. The Ghent scrubber construction project has operated for 4.5 million hours without a lost-time incident and the Brown scrubber construction project has also operated for 700,000 hours without a lost-time incident. Finally, the Companies' Transmission employees have had seven injury-free years. Despite these significant achievements, Energy Services continues its efforts to ensure that its employees are working as safely as possible.

Q. Please describe any new safety initiatives Energy Services has implemented.

A. Although injury rates are well below the national average, Energy Services continues to look for innovative measures to ensure best practices are being followed. In 2009, Energy Services conducted a full-day seminar attended by nearly 800 managers, employees and contractors that emphasized the importance of teamwork and the value of shared knowledge in improving safety. Further, Energy Services conducts quarterly safety meetings with its contractors to further improve safety practices. Additionally, Energy Services has begun emphasizing the reporting of "near miss" incidents. The reported data will be compiled and evaluated as an innovative means to detect safety issues before an incident occurs. Finally, a newly implemented safety planning model will measure the effectiveness of proactive initiatives, such as the reporting of "near miss" accidents.

Clean Coal and Renewable Generation

Q. What efforts are the Companies making in the arena of clean coal and renewable generation?

A. LG&E and KU have made a significant pledge to FutureGen, which is the world's most advanced clean coal project. FutureGen is a public-private partnership, created at the Department of Energy's request, to design, build, and operate the world's first coal-fueled, near-zero emissions power plant, at an estimated net project cost of $2.25 billion. The Department of Energy demonstrated its commitment to the project in June 2009 by reaffirming its decision to provide financial support through the next phase of development. The commercial-scale plant will prove the scientific feasibility and economic affordability of producing low-cost electricity and hydrogen from coal while nearly eliminating emissions. It will be a "living laboratory," supporting testing and commercialization of technologies focused on generating clean power and fully integrated carbon capture and storage. In so doing, FutureGen will create unprecedented opportunities for scientific exploration, education, and stakeholder engagement. FutureGen is currently approximately three years ahead of other fully integrated near zero emission power generation projects using saline aquifers for carbon dioxide sequestration. All investments by LG&E and KU in FutureGen are currently treated as below-the-line costs.

In addition to collaborating with global entities in the FutureGen project, LG&E and KU have also invested locally in furtherance of advancing carbon storage in Kentucky. LG&E and KU have both invested in the Carbon Management Research Group ("CMRG") and the Kentucky Consortium for Carbon Storage ("KCCS"). CMRG is a partnership between the private sector, state government and academia, administered by the University of Kentucky Center for Applied Energy Research, pertaining to carbon and carbon dioxide management in coal-fired generating units in Kentucky. The Companies have jointly agreed to invest up to

$200,000 annually for 10 years in this project. The Commission, in Case No. 2008-00308 approved the establishment of a regulatory asset with regard to this investment.

KCCS is a partnership between government and private industry stakeholders created by the Kentucky Geological Survey and the Governor's Office of Energy Policy (now the Department of Energy Development and Independence) to investigate the feasibility of geologic storage of carbon dioxide produced by coal-fired generating units in Kentucky. The Companies jointly agreed to provide KCCS with up to $1.8 million in funding over two years. The Commission, in Case No. 2008-00308 approved the establishment of a regulatory asset with regard to this investment.

As the interest in renewable energy has intensified in the last several years, the Companies have been investigating ways in which to diversify their supply mix with renewable resources. For example, in 2009, the Companies undertook a pilot initiative by entering into two purchase power agreements for output from wind farms. The first contract is with Grand Ridge Energy LLC for 99 MW. The second contract is with Grand Ridge Energy IV LLC for 10.5 MW. Both are under review in pending investigation before the Commission and the subject of consumer group opposition.

In addition to investing in FutureGen and expanding their use of renewable resources, the Companies have also taken an active informational role in explaining the "carbon footprint" Kentuckians are leaving and ways in which to reduce the impact. A presentation is available on the Companies' website outlining Kentucky's carbon emissions, the feasibility of alternative energy sources and current legislative initiatives to reduce emissions. A copy of this presentation is attached as Thompson Exhibit 5.

Q. Do you have any closing thoughts?

A. Yes. As I stated at the outset of this testimony, Energy Services' mission is predicated on four fundamental and overlapping objectives: (i) maximizing the performance and investment life of the Companies' electric generation and transmission assets; (ii) maintaining sound operating and maintenance practices that promote both reliable and efficient operations and a safe working environment; (iii) providing high-value electric service to the Companies' customers; and (iv) operating as a good steward of the environment. While these objectives have been achieved through the commitment of its employees, the Companies cannot continue to deliver the quality electric service customers have rightfully come to expect without increasing its base rates. The substantial investments required to provide an adequate and reliable supply, coupled with unanticipated and significant storm restorations, are cost pressures that prohibit the Companies from adequately recovering its costs under its existing base rates.

Q. Does this conclude your testimony?

A. Yes.

VERIFICATION

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

The undersigned, **Paul W. Thompson**, being duly sworn, deposes and says that he is Senior Vice President, Energy Services for Kentucky Utilities Company and Louisville Gas and Electric Company and an employee of E.ON U.S. Services, Inc., and that he has personal knowledge of the matters set forth in the foregoing testimony, and that the answers contained therein are true and correct to the best of his information, knowledge and belief.

Paul W. Thompson
Paul W. Thompson

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 22nd day of January 2010.

Tammy J. Elzy (SEAL)
Notary Public

My Commission Expires:

November 9, 2010

Appendix A

Paul W. Thompson

Senior Vice President, Energy Services
E.ON U.S. LLC
220 West Main Street
Louisville, KY 40202

Industry Affiliations

FutureGen Industrial Alliance, Board Member and former Chairman of the Board
Center for Applied Energy Research, Advisory Board Member
American Coalition for Clean Coal Electricity, Board Member
Electric Energy Inc., Board Member
Ohio Valley Electric Corporation, Board Member

Civic Activities

Jefferson County Public Education Foundation Board
University of Kentucky College of Engineering, *Project Lead The Way*, Council Member
Greater Louisville Inc. Board Member
Louisville Downtown Development Corporation Board, Finance Committee Chair
Louisville Free Public Library Foundation Board, Chairman
  Chair, Annual Appeal 2002 & 2003
  Co-Chair Annual Children's Reading Appeal 1999, 2000, & 2001
March of Dimes 1997 & 1998 - Honorary Chair
Habitat for Humanity - Representing LG&E as co-sponsor
Friends of the Waterfront Board 1998 – 2002
Leadership Louisville -- 1997-98

Education

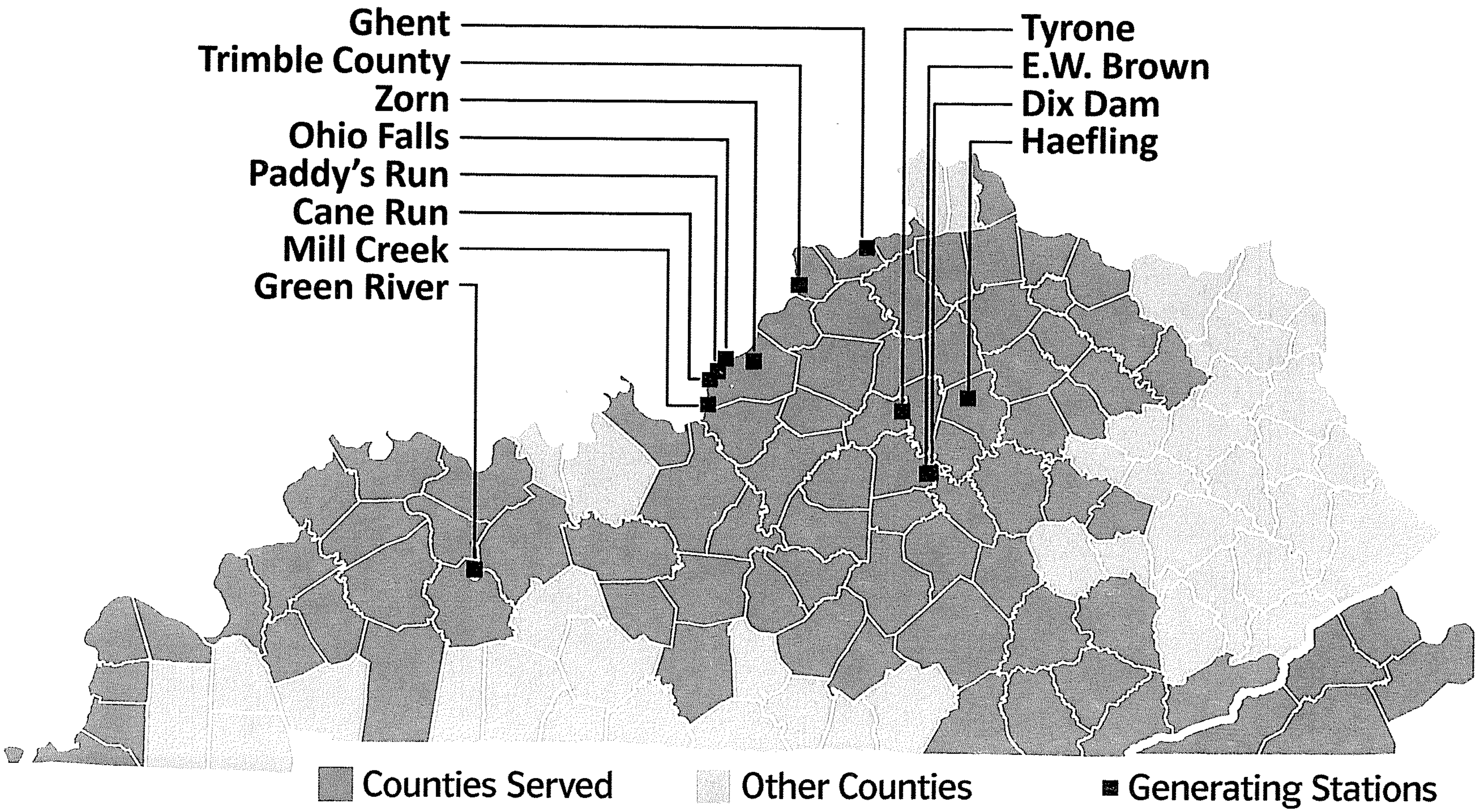
University of Chicago, MBA in Finance and Accounting -- 1981
Massachusetts Institute of Technology (MIT), BS in Mechanical Engineering -- 1979

Previous Positions

LG&E Energy Marketing, Louisville, KY
  1998 - 1999 – Group Vice President
Louisville Gas and Electric Company, Louisville, KY
  1996 - 1998 – Vice President, Retail Electric Business
LG&E Energy Corp., Louisville, KY
  1994 - 1996 (Sept.) – Vice President, Business Development
  1994 - 1994 (July) – Louisville Gas & Electric Company, Louisville, KY
    General Manager, Gas Operations
  1991 - 1993 – Director, Business Development
Koch Industries Inc.
  1990 - 1991 – Koch Membrane Systems, Boston, MA
    National Sales Manager, Americas
  1989 - 1990 – John Zink Company, Tulsa, OK
    Vice President, International
Lone Star Technologies (a former Northwest Industries subsidiary)
  1988 - 1989 – John Zink Company, Tulsa, OK
    Vice Chairman
  1986 - 1988 – Hydro-Sonic Systems, Dallas, TX
    General Manager
  1986 – 1986 (July) — Ft. Collins Pipe, Dallas, TX, General Manager
  1985 - 1986 – Lone Star Technologies, Dallas, TX
    Assistant to Chairman
  1980 - 1985 – Northwest Industries, Chicago, IL

LG&E KU

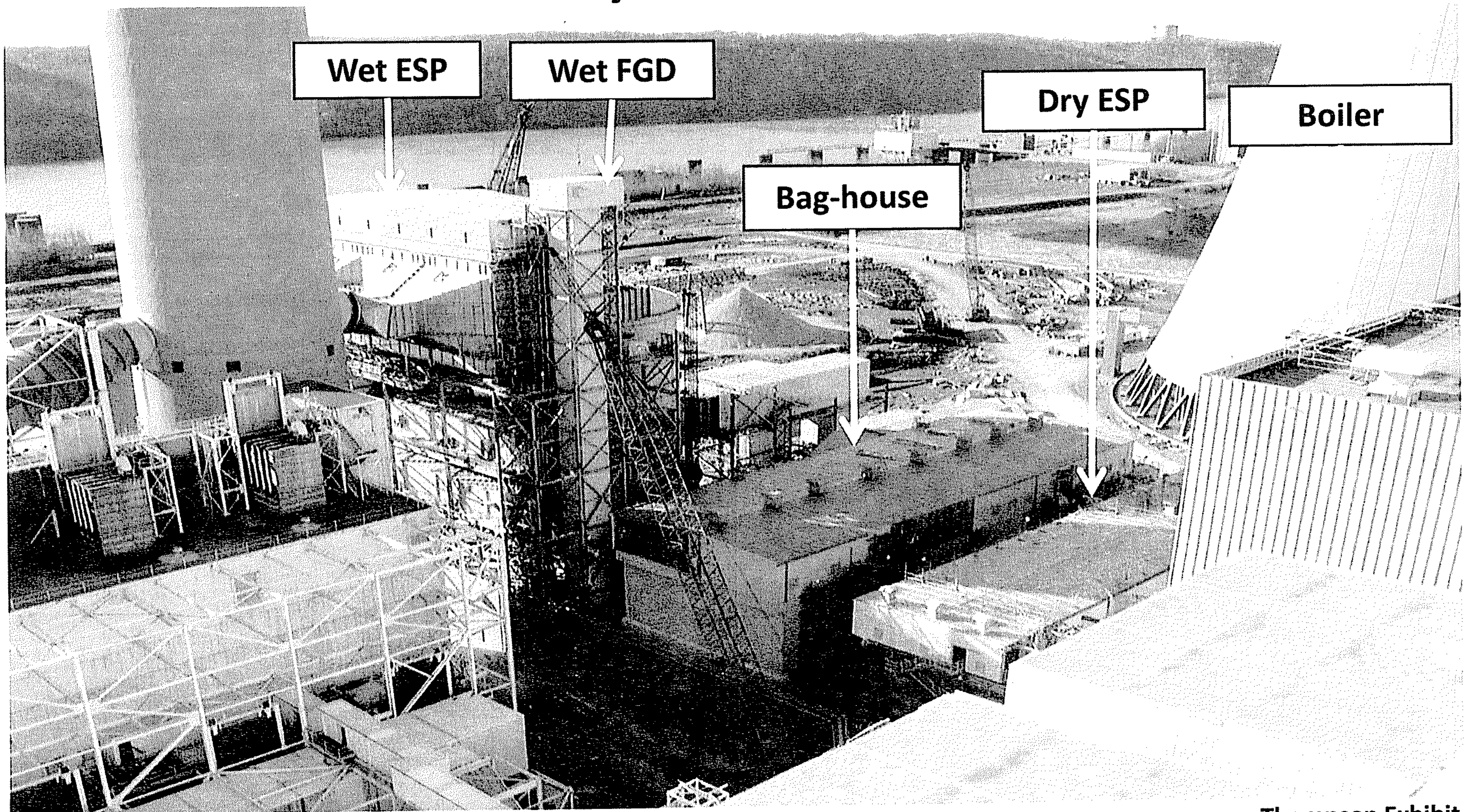
e·on companies



LG&E KU

e·on companies

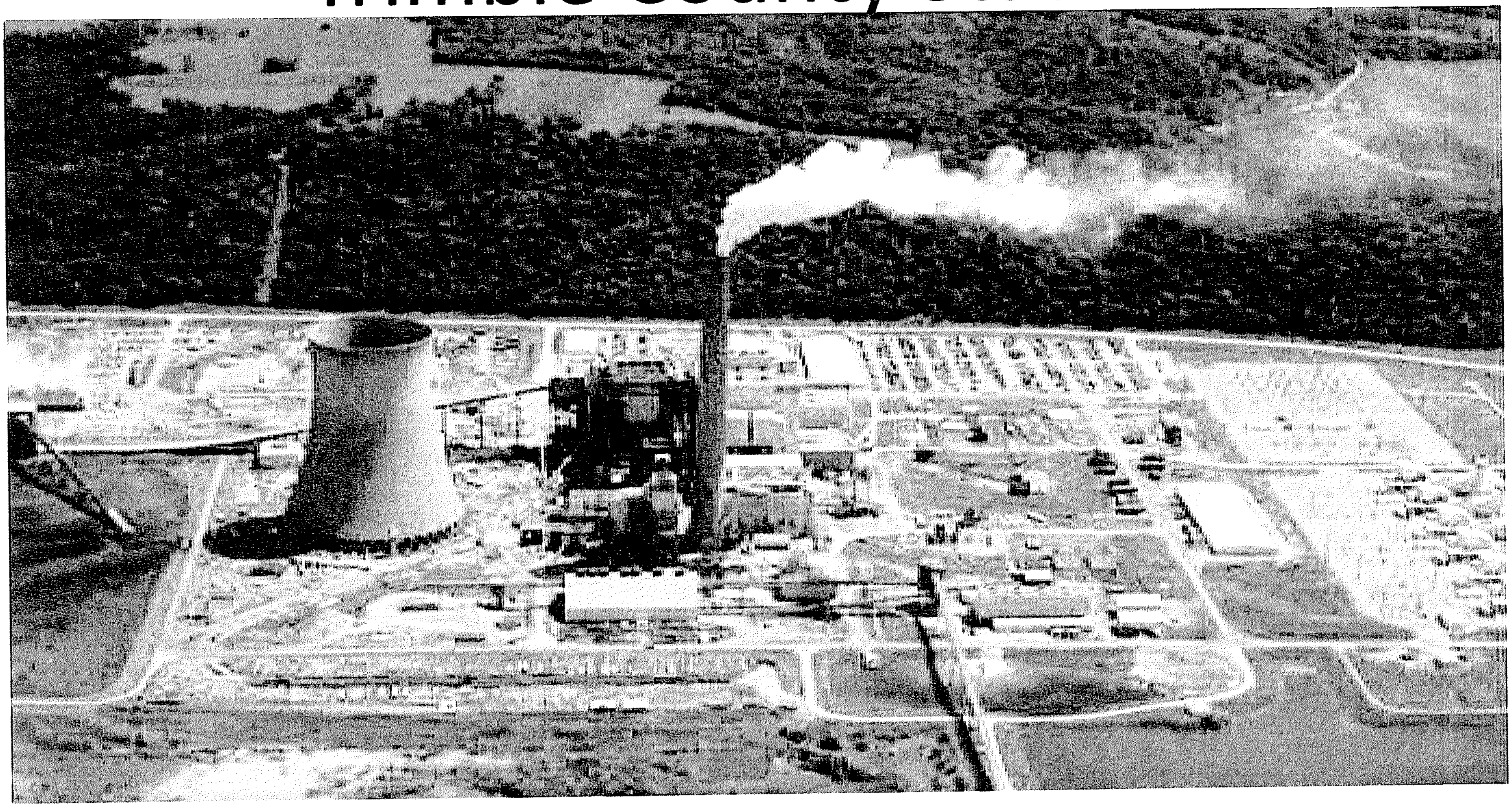
Trimble County Unit 2 Construction



LG&E KU

e·on companies

Trimble County Station

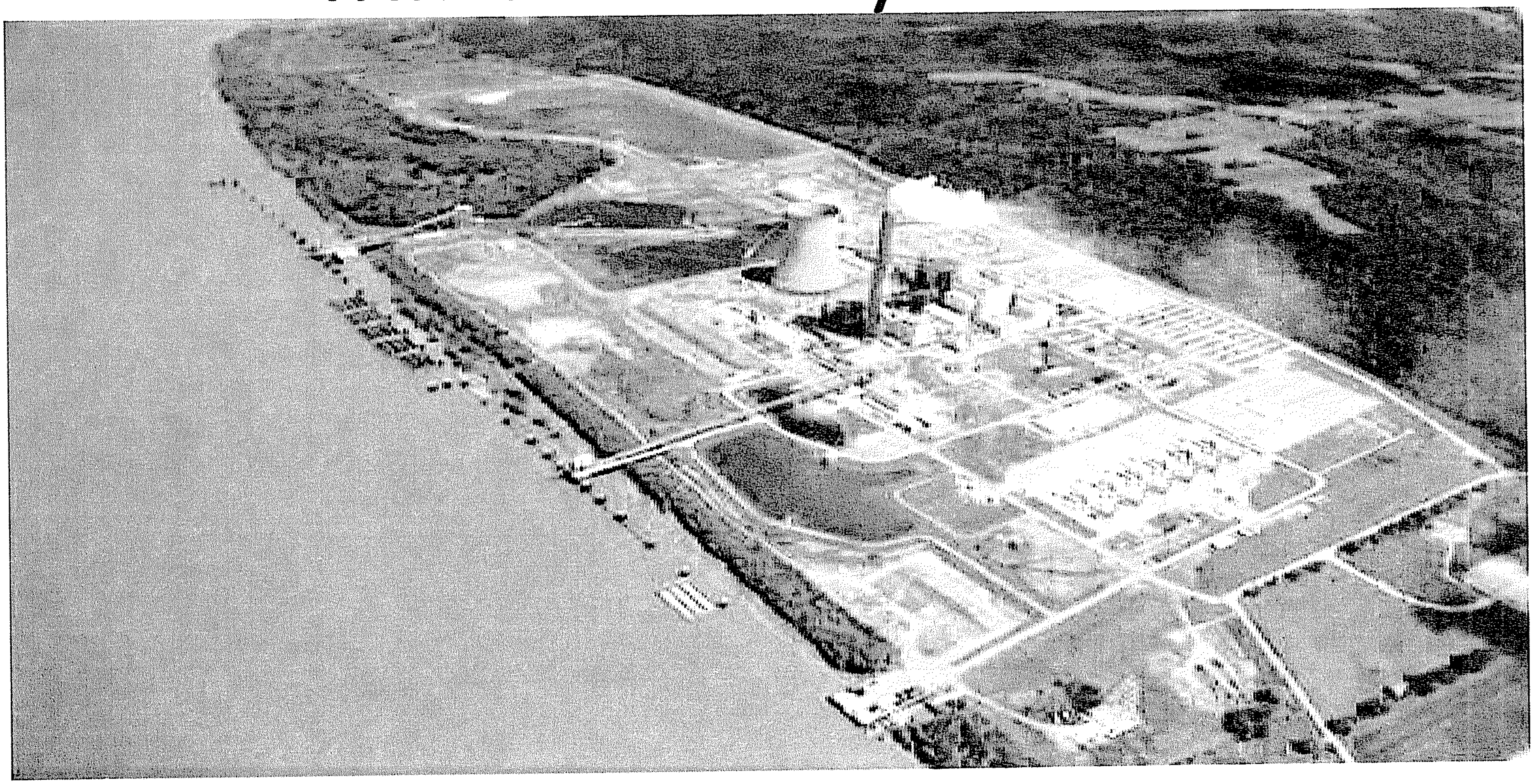


Thompson Exhibit 3
Page 1 of 2

LG&E KU

e·on companies

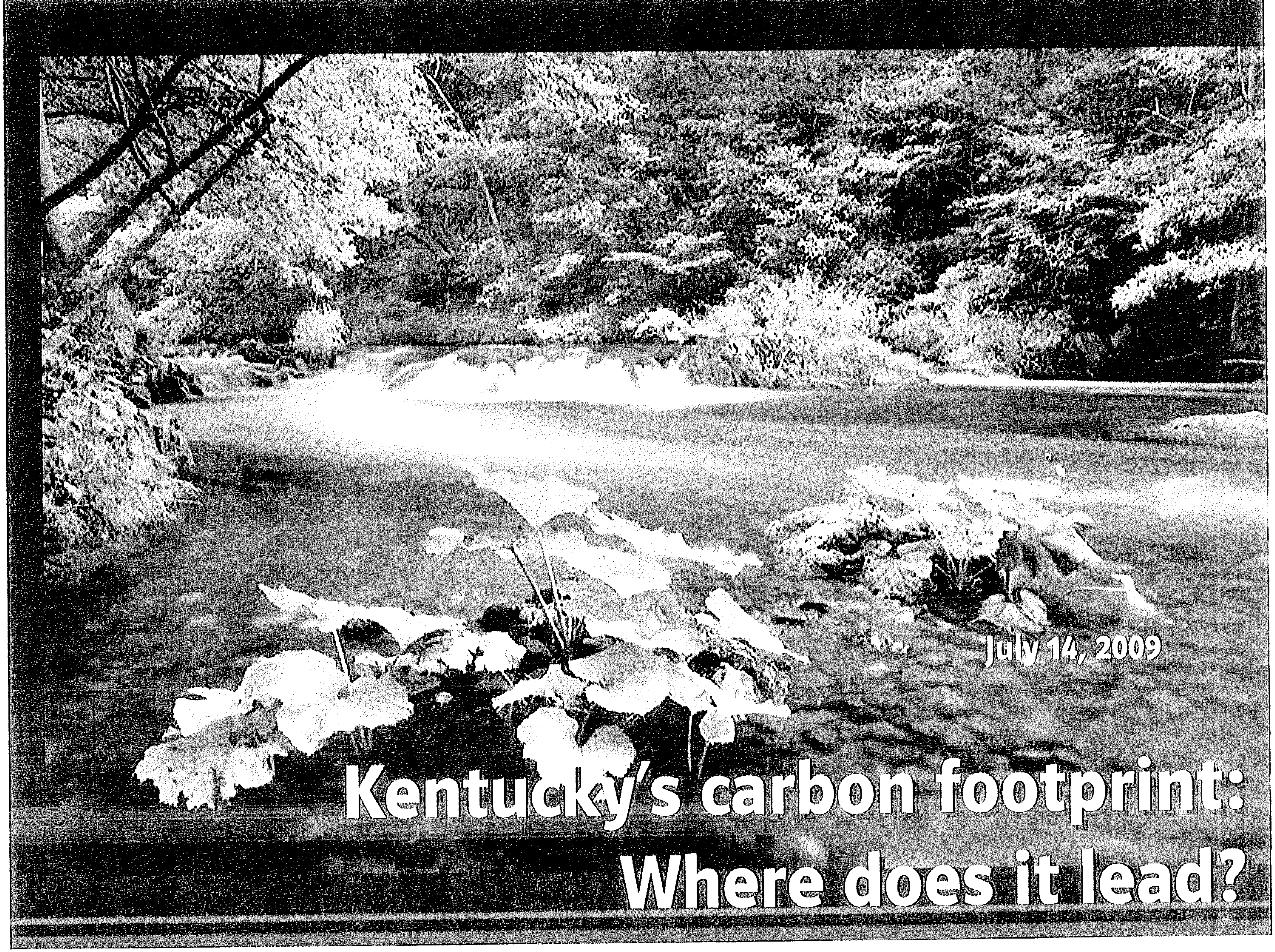
Trimble County Station



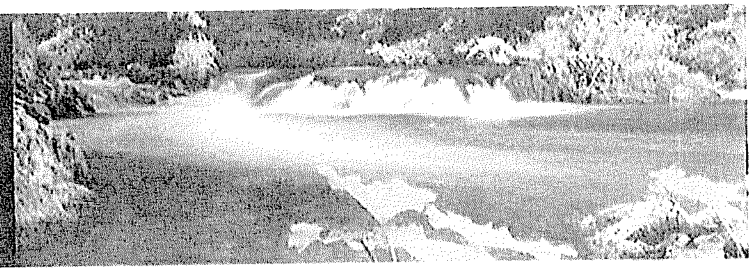
Louisville Gas and Electric Company and Kentucky Utilities Company
Energy Requirments 2010 - 2039

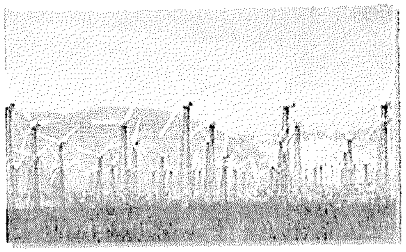
Year	Energy Requirements (GWh)
2010	33906.60
2011	34890.25
2012	35954.04
2013	36740.98
2014	37306.79
2015	37902.26
2016	38428.96
2017	38848.06
2018	39392.20
2019	39976.33
2020	40544.28
2021	40980.20
2022	41545.24
2023	42077.48
2024	42733.27
2025	43293.56
2026	43867.10
2027	44444.45
2028	45122.14
2029	45673.33
2030	46244.89
2031	46744.71
2032	47296.60
2033	47845.79
2034	48379.65
2035	48918.59
2036	49520.46
2037	50089.89
2038	50633.59
2039	50613.49

Thompson Exhibit 5

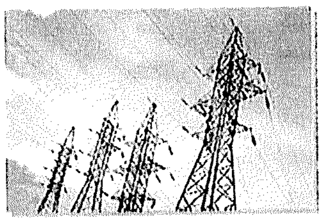

July 14, 2009
Kentucky's carbon footprint:
Where does it lead?

Tough issues, tough solutions

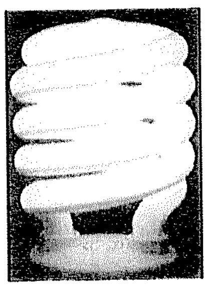




- Renewable Energy

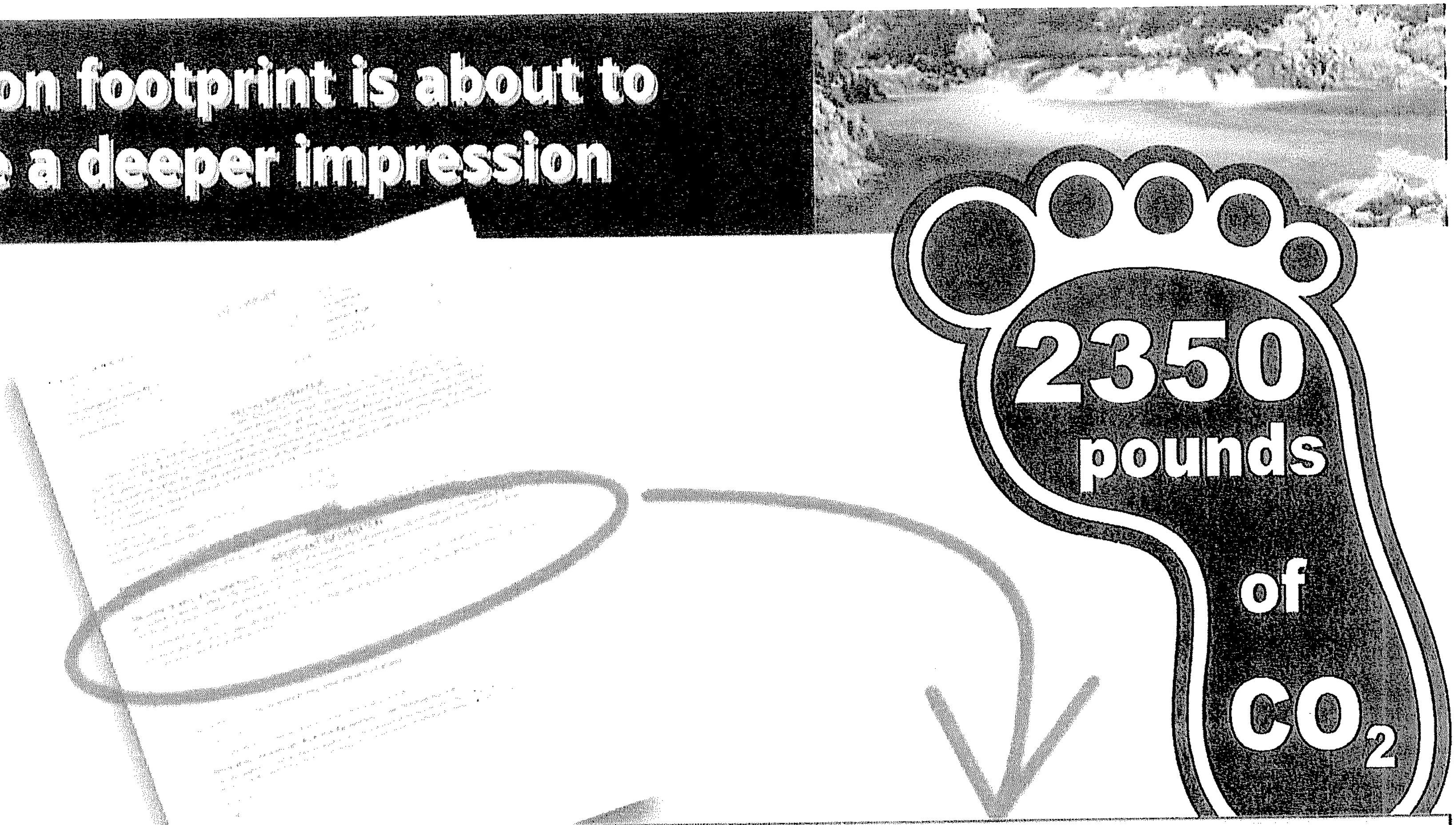


- Carbon Tax (or Cap and Trade)
- Transmission Grid



- Efficient Use of Electricity

Carbon footprint is about to leave a deeper impression



IMPORTANT INFORMATION

The power to save. It's in your hands. The amount of electricity you consumed during this billing cycle resulted in the production of approximately 2350 pounds of CO2.

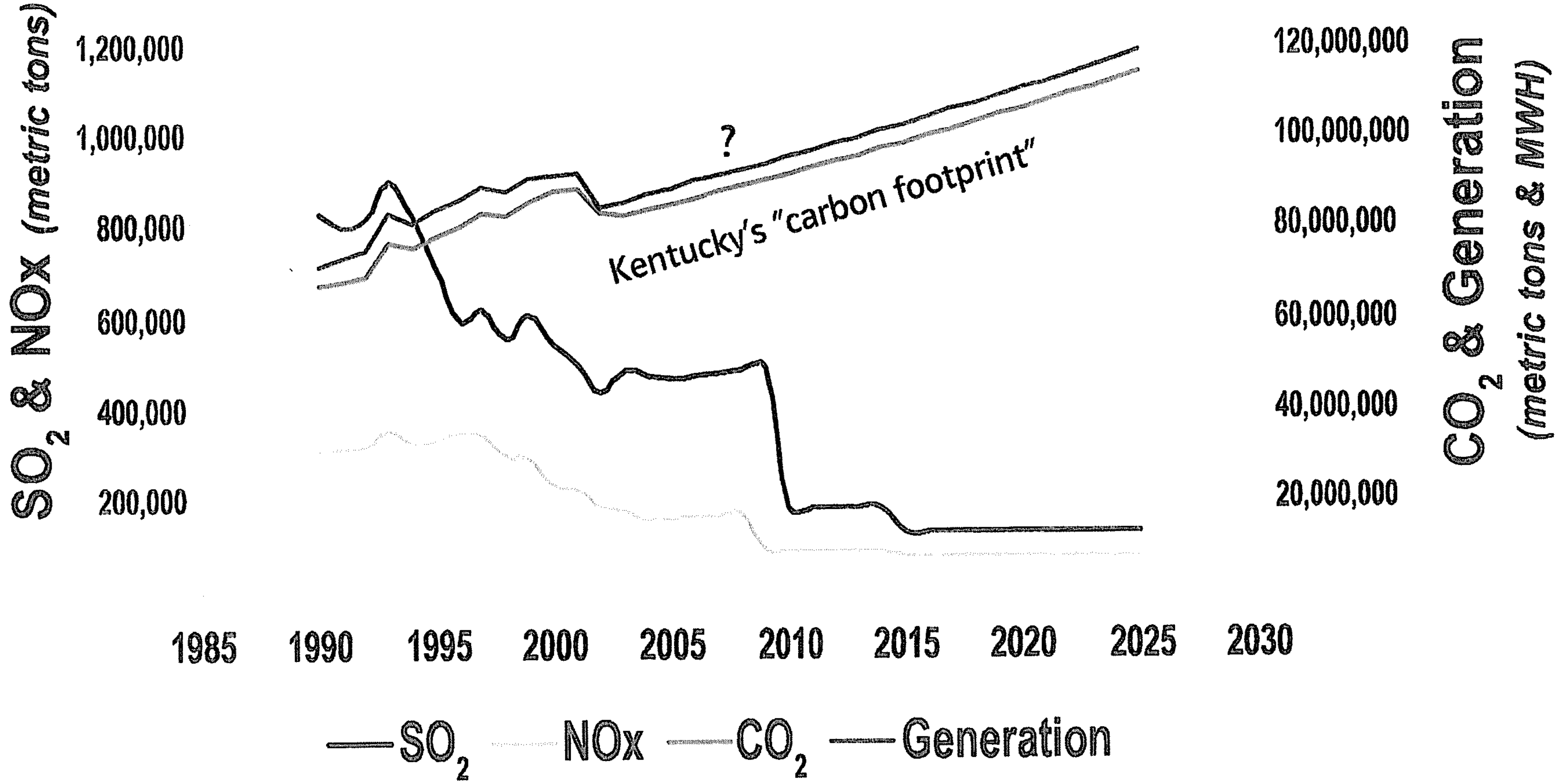
You can reduce the impact of these emissions by joining our Demand Conservation program, which allows you to help us reduce the need for generating electricity at peak times. Visit our website at www.eon-us.com or call 1-866-356-5467 for more information or to sign up today.

To request a copy of your rate schedule, please call (502) 589-1444.

LG&E KU

Past successes, future challenges

CO_2 emissions: **100 times** larger issue than SO_2/NOx



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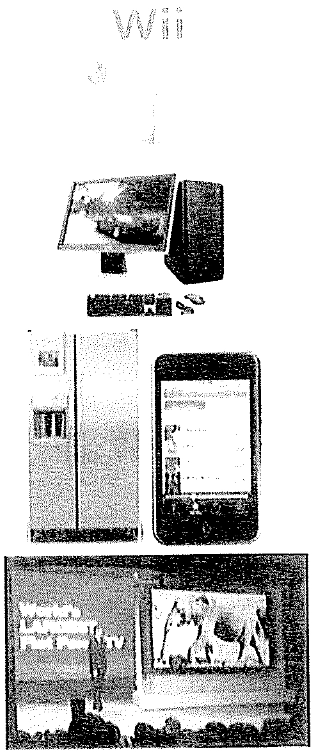
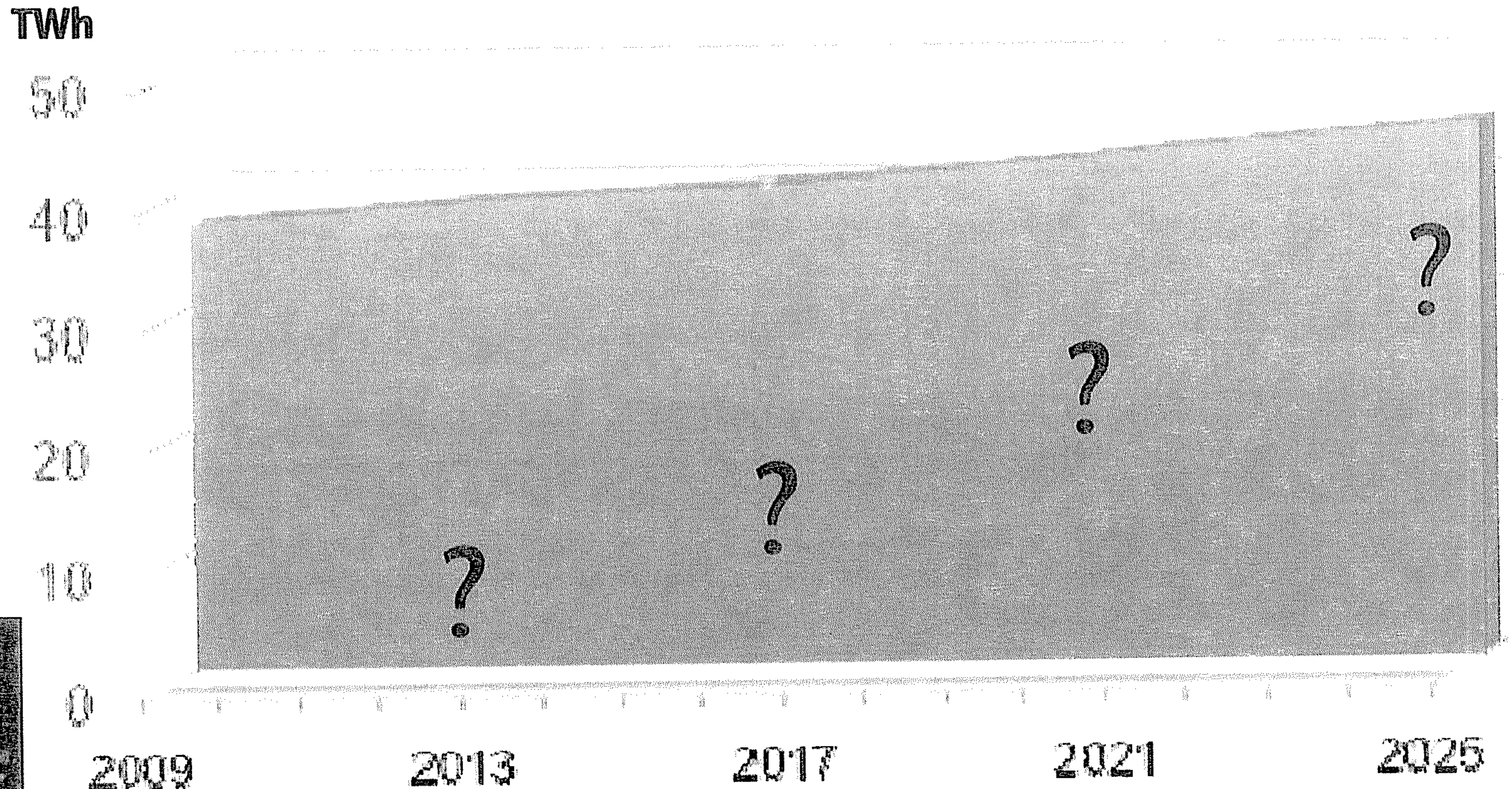
Sources: U.S. DOE Energy Information Administration for historic emissions and generation. U.S. EPA for future SO_2 and NOx state budgets. In-house projections of generation and CO_2 based on 1.5% annual growth. 2007 data.

Your growth in electric usage

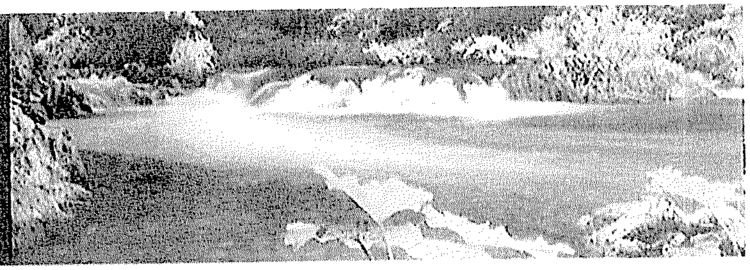




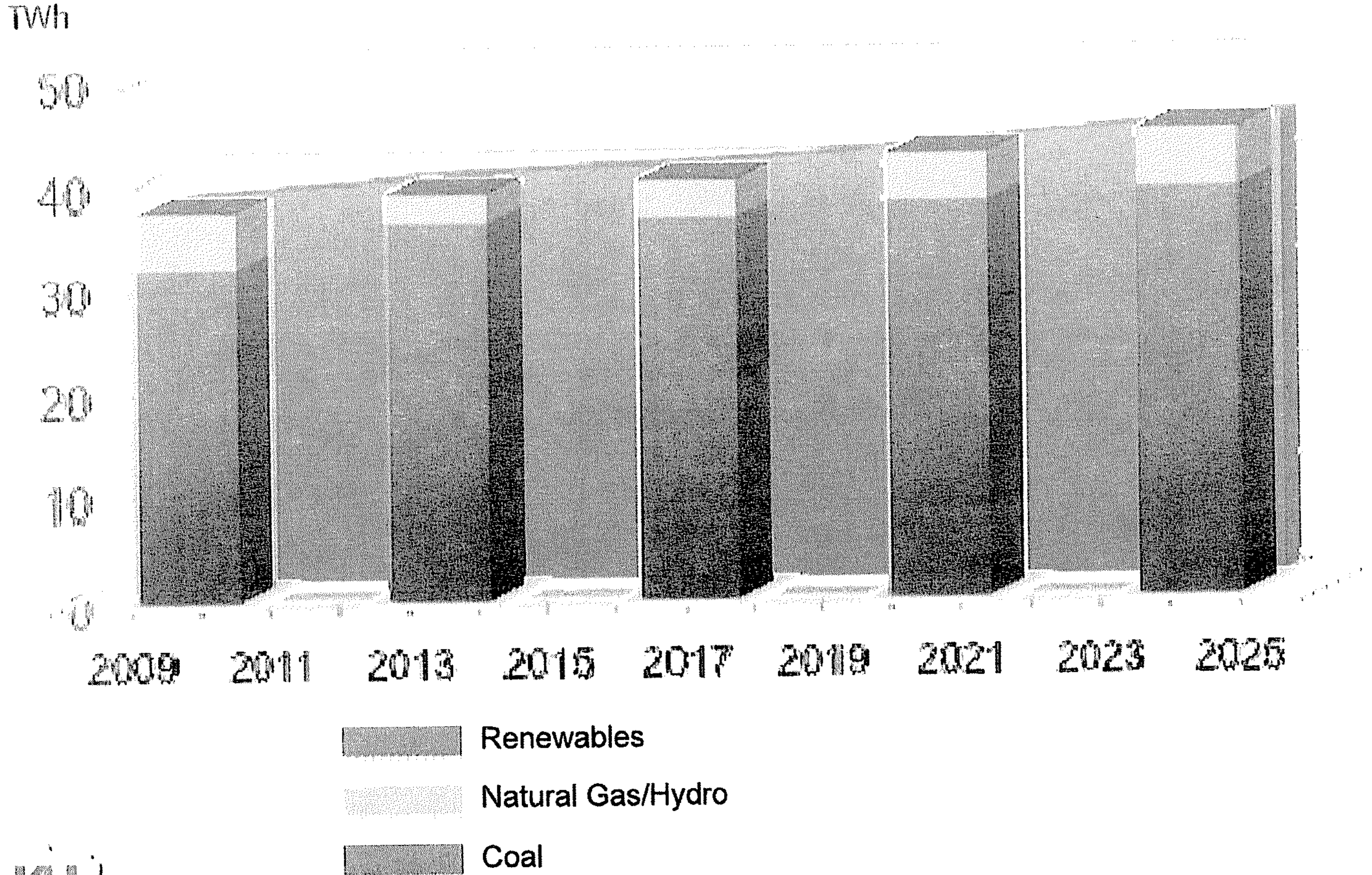
PROJECTED ELECTRIC DEMAND BY LG&E/KU CUSTOMERS

SOURCE: 2008 Integrated Resource Plan

How we plan to meet your electric demand



95% OF THE ELECTRICITY YOU USE COMES FROM COAL-FIRED POWER PLANTS



SOURCE: 2008 Integrated Resource Plan

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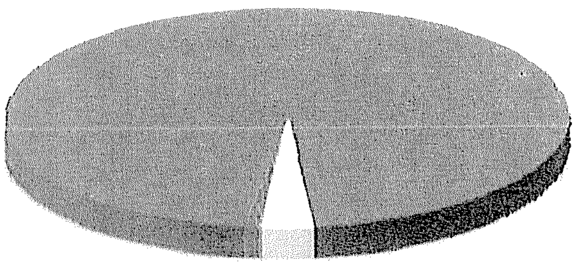
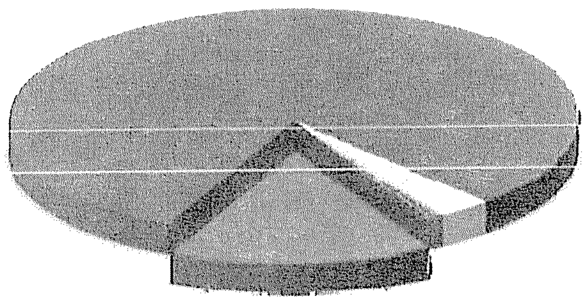
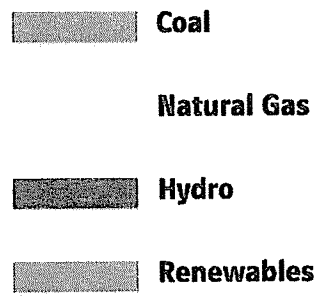
"Renewable portfolio standards"

Currently Zero Renewables



Under 2020 Federal Proposals





Note: Existing hydro does not count toward renewable mandates.

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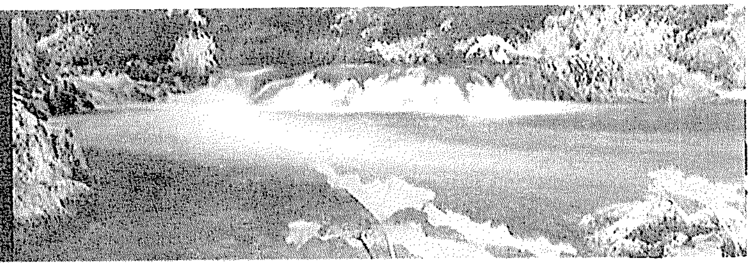
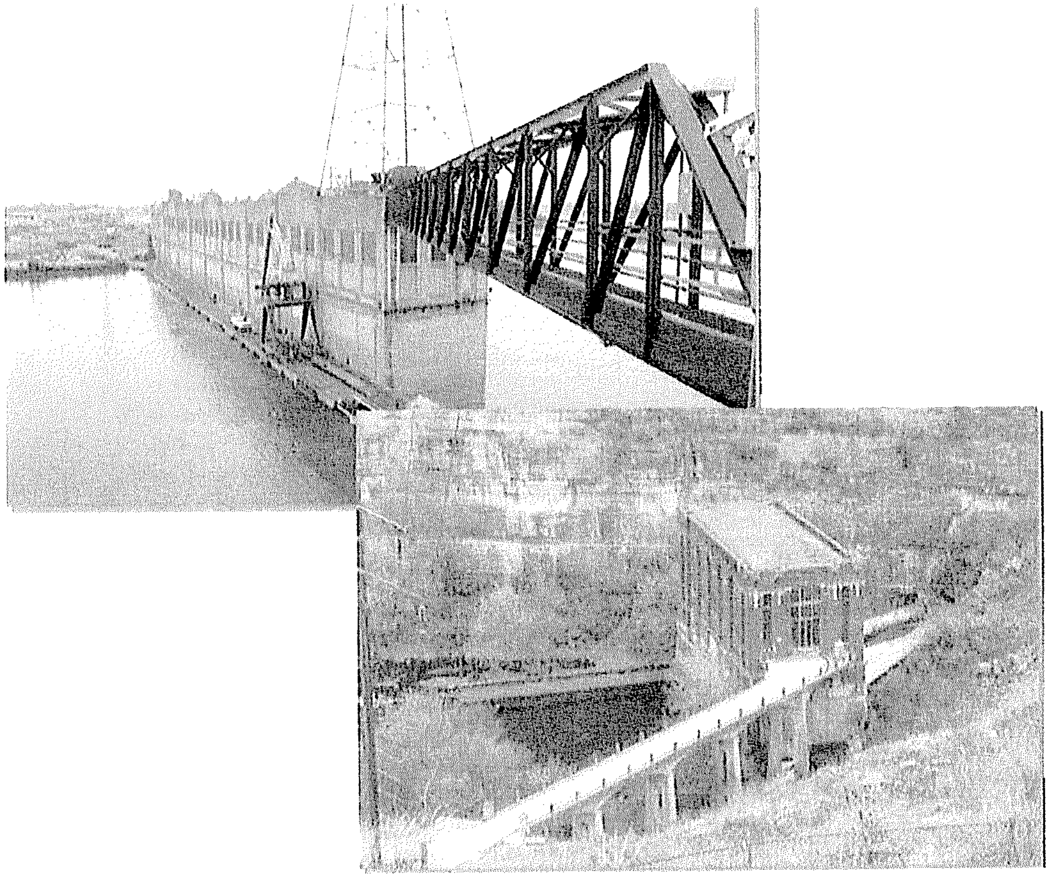
Considerations — hydro





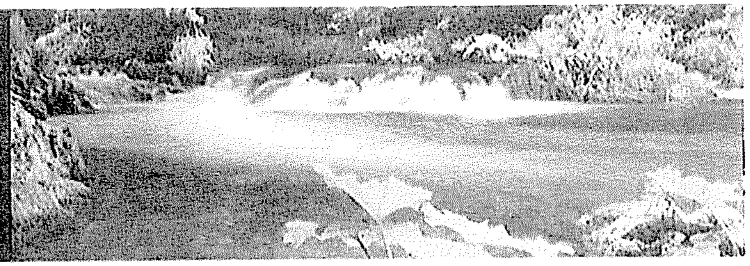
Annual availability equivalent up to 40 percent of continuous maximum capability

Many legal/regulatory entities involved with different missions – recreation, transportation, nature preserves

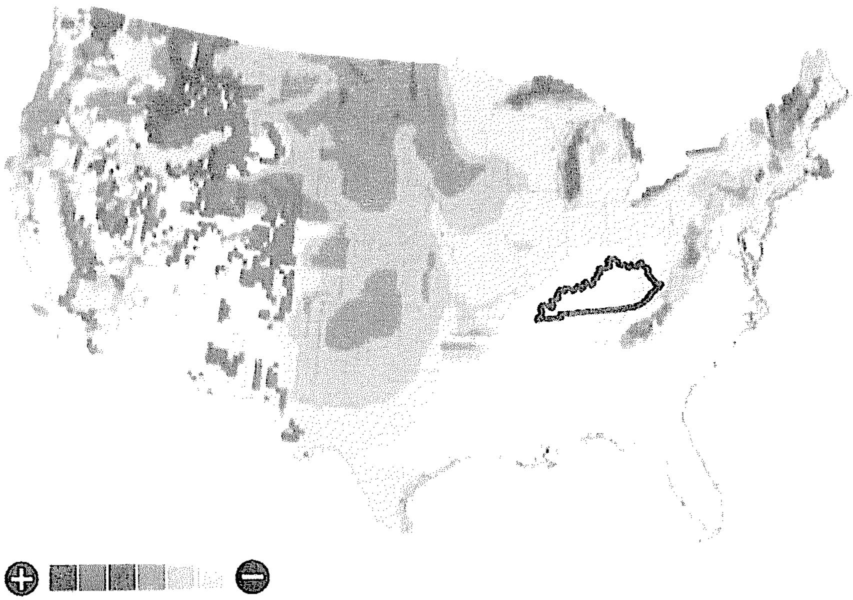
Low operating cost — "no fuel"

Most hydro locations are already being used

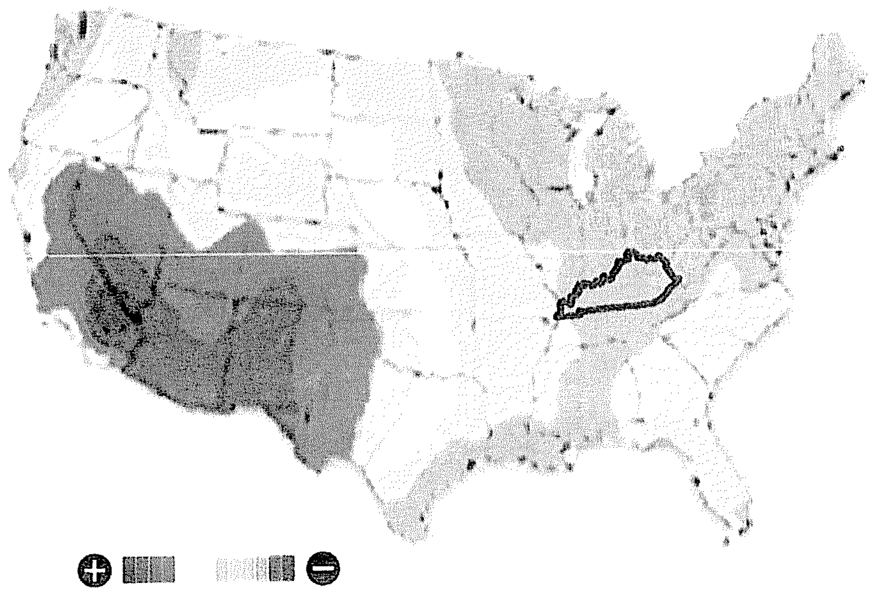
Considerations — wind and solar



Wind



Solar

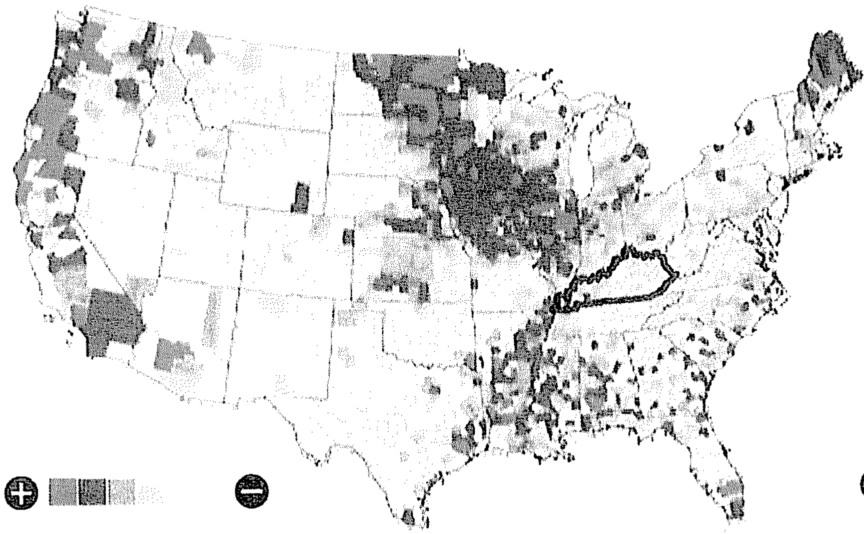


Why not Florida?
Frequent afternoon thunderstorms

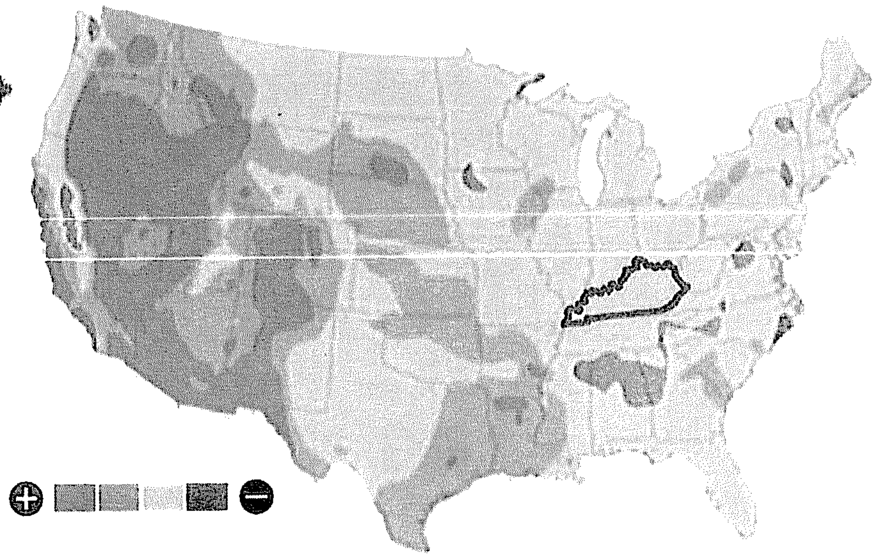
SOURCES: Dept. of Energy
National Renewable Energy Laboratory

Considerations — biomass and geothermal

Biomass

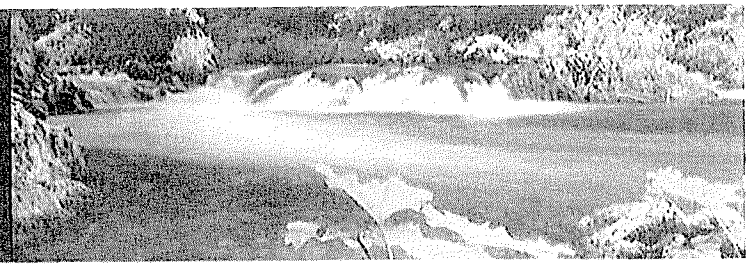


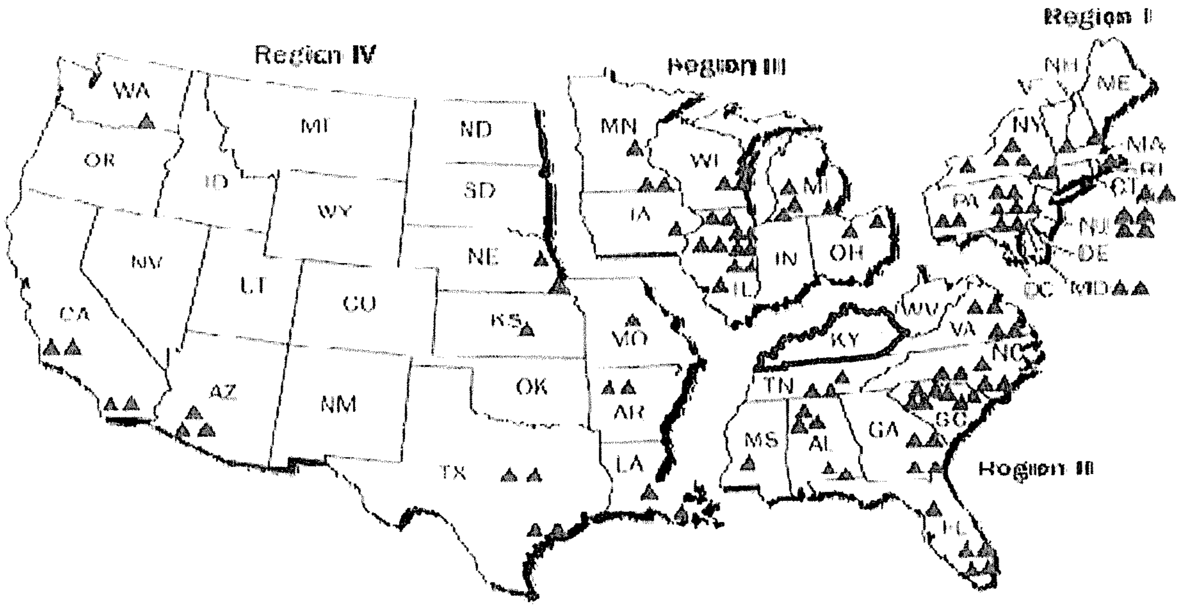
Geothermal



SOURCES: Dept. of Energy
National Renewable Energy Laboratory

The nuclear option





Nuclear plants currently licensed to operate
SOURCE: Nuclear Regulatory Commission

Zero-carbon option

Enormous investment of time and money

Critical that there be a strong public and political consensus

Disposal still an issue

Nuclear currently prohibited in Ky.

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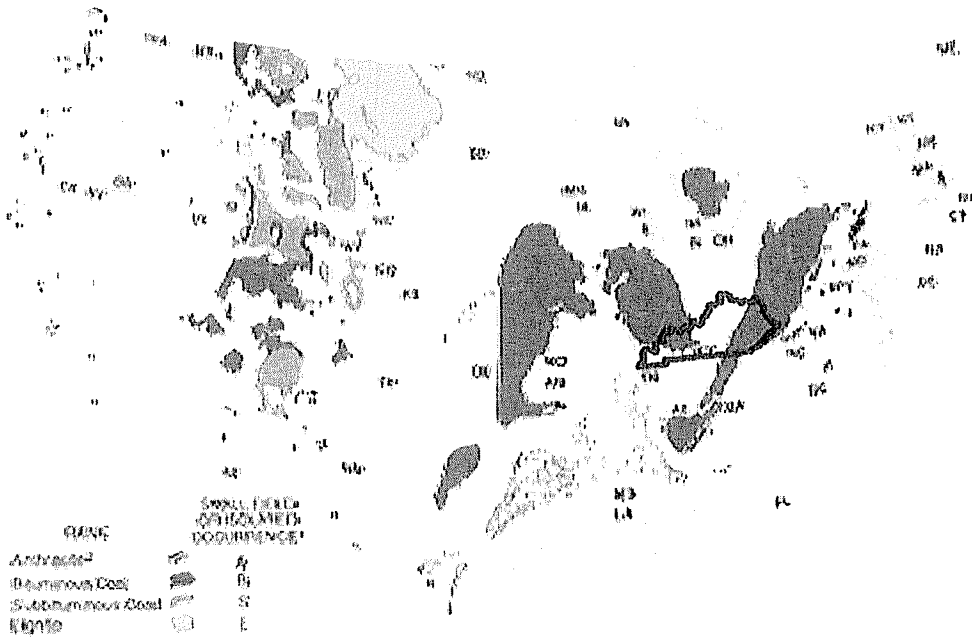
Considerations — coal



SOURCE: Dept. of Energy

One of the most widely-used fuels for electrical generation — 90% availability

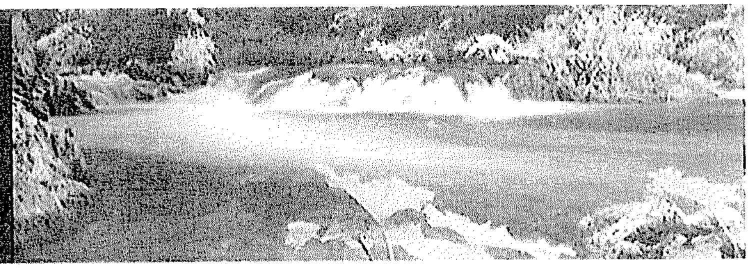
50% of U.S. power produced today

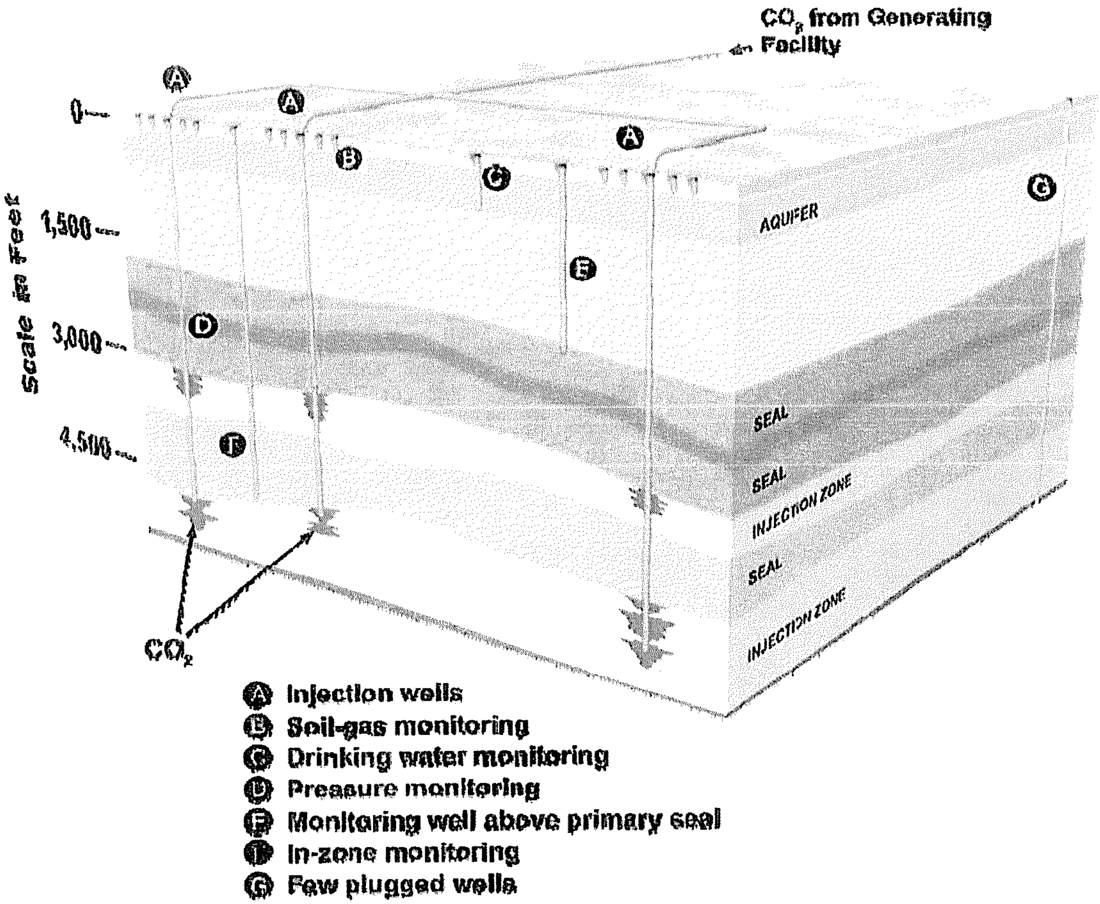
95% of Ky. power produced today

One of the largest fixed-source producers of CO_2

Relatively low transportation costs (river barge)

Carbon capture & sequestration





What's involved....

"Bury" the problem

Deep underground wells — depleted oil fields

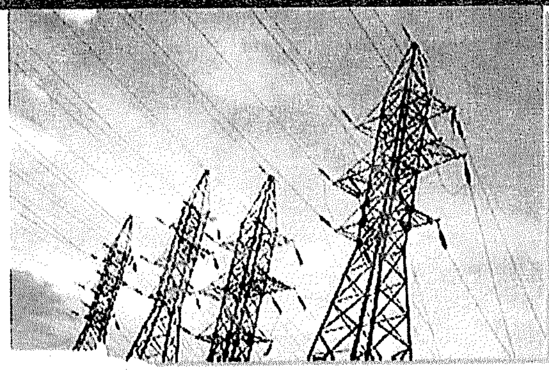
Significant investments in new technology, pumping systems

Promising option, but no large-scale commercial application yet

"NUMBY"

SOURCE: FutureGen Alliance

If we can't make it, why not just *move* it?



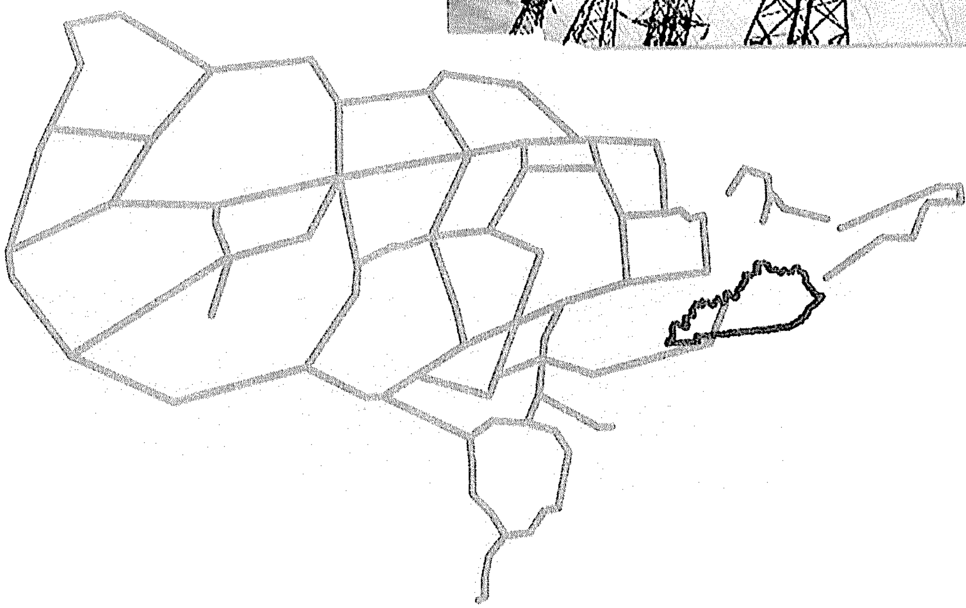
"Costs" of transmission...

Current grid is stretched — would require major new construction at large capital cost

Risks of over-reliance on single highway (Canadian blackout)

Development/approval time

NIMBY



Transmission grid system needed to support new renewable power development

SOURCE: Dept. of Energy
National Renewable Energy Laboratory

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Carbon tax ("cap & trade")

Federal proposal to "sell" allowances to CO_2 producers

Concept: All utilities will bid or compete for allowances, market sets price

Previously stated goals:

- Create new revenue stream for federal budget ($80B/year for 8 years)
- Create economic rationale for industry to move more quickly to renewable power

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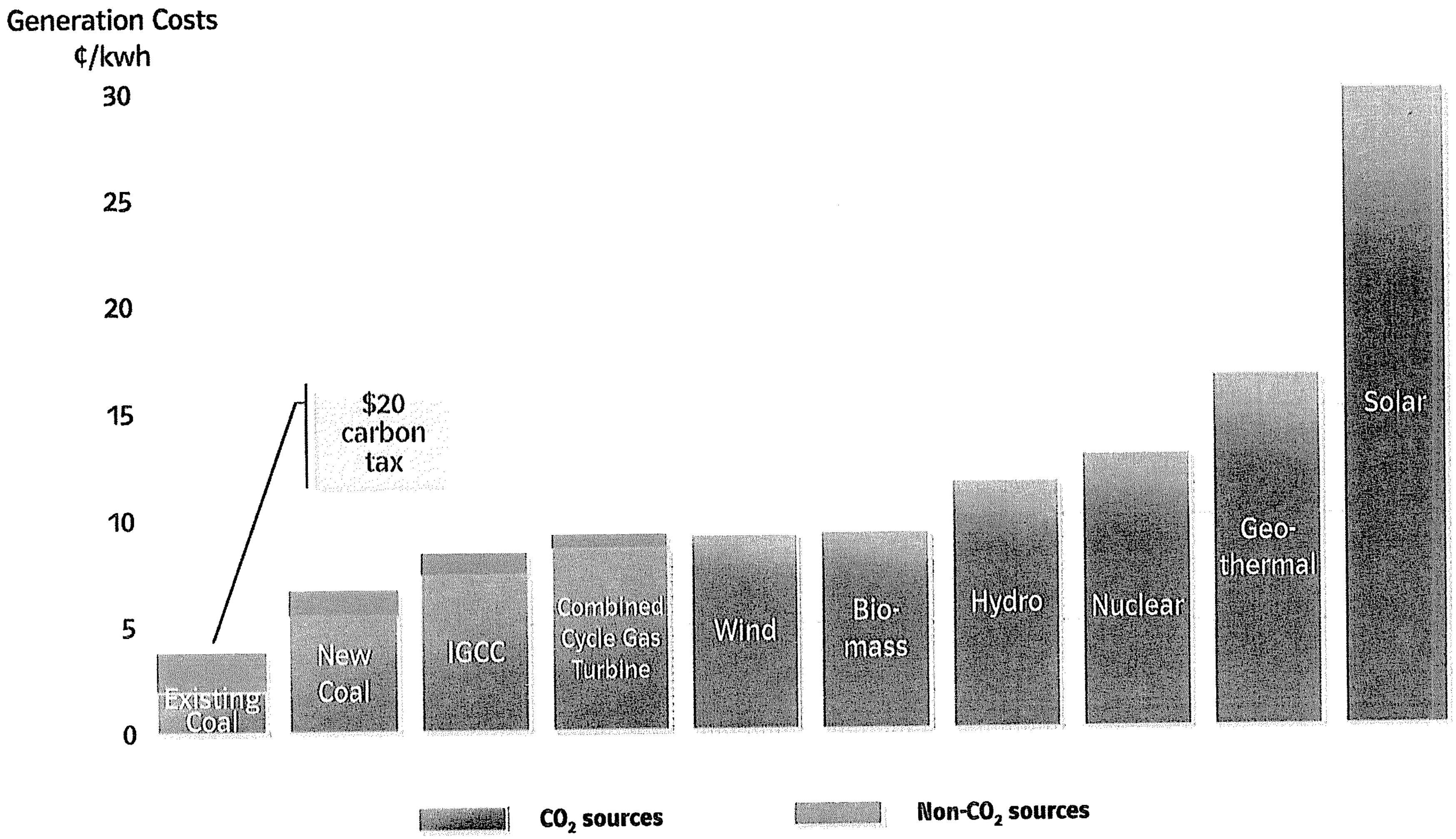
Cost Comparison



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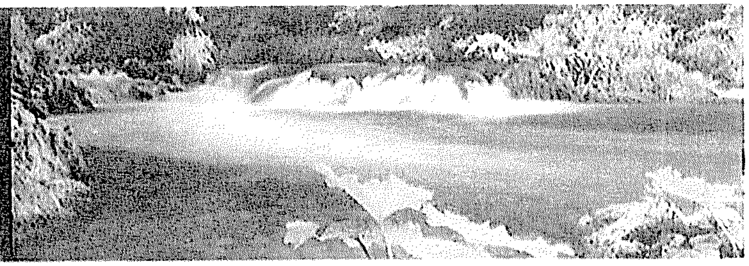
American Clean Energy and Security Act of 2009



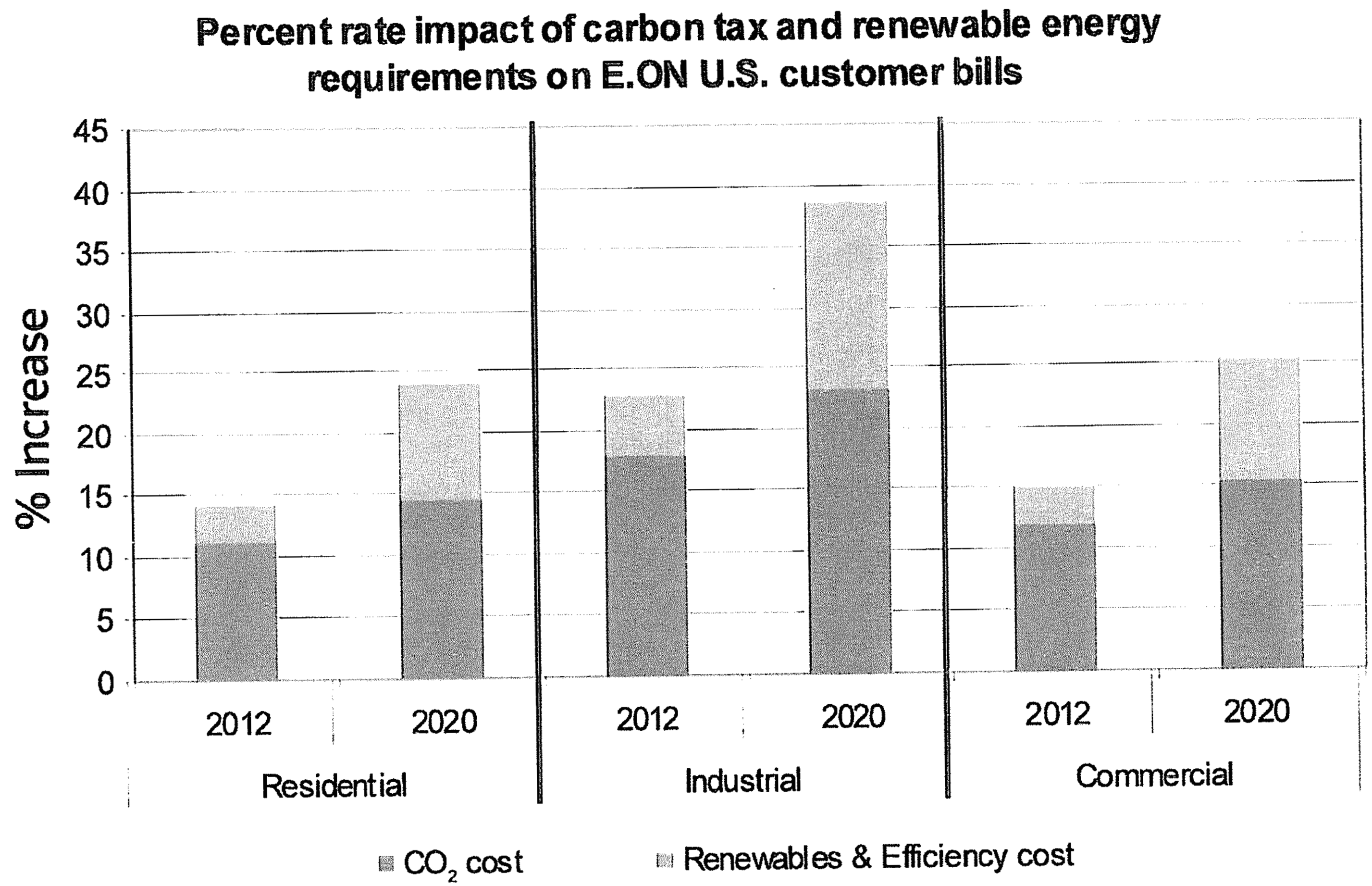
- Passed House on June 26, 2009.
- Mandates a 17 percent reduction in greenhouse gases by 2020 and 83 percent by 2050 from 2005 levels.
- Moves to Senate for vote later this year.
- Current form contains elements that are a step in the right direction.

To further mitigate costs to our customers, additional elements E.ON U.S. would like to see included in the bill are:

- Modified near- and mid-term greenhouse gas reduction targets and timetables.
- Inclusion of a price "ceiling" on emission allowance costs.
- Extension of the phase-out period for the allocation of allowances.

LG&E KU

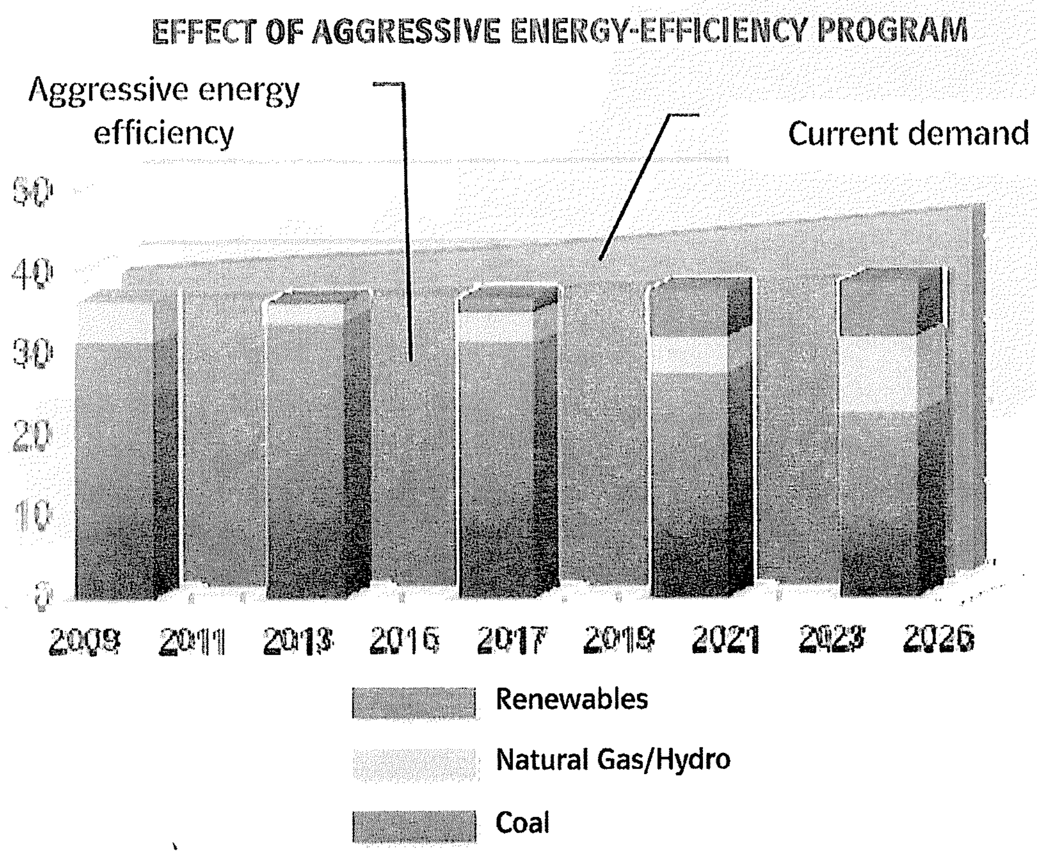
Estimated costs



- Percentage increases calculated using 2008 rates applied to 2020 projected sales
- CO2 allowance is calculated at $20 a ton, allocation methodology is 41% purchase in 2012, 53% purchase in 2020
- Assumes utilities meet the CERES target entirely through purchase of Alternative Compliance Payments (ACPs) set in the bill at 2.5 cents per KWH in 2010 (and subsequently indexed).

LG&E KU

Reducing demand — the challenge



SOURCE: 2008 Integrated Resource Plan

What it would take…

15+% reduction in demand

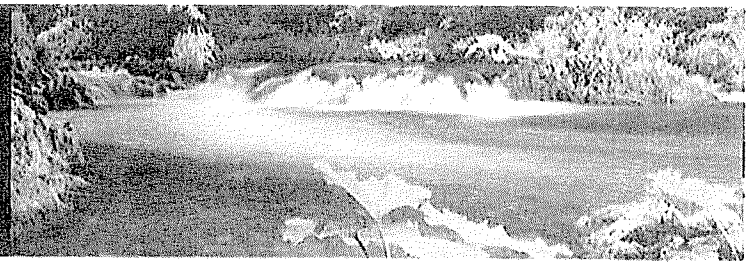
Unprecedented consumer commitment to energy efficiency

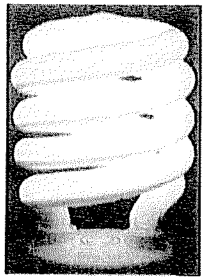
Commitment to "smart grid"

Less coal in total generation mix, less exposure to carbon tax, but high cost of purchased or developed renewable power sources

LG&E KU

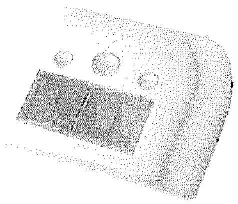
Energy Efficiency Initiatives



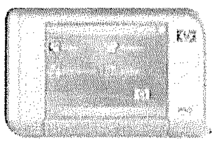


- E.ON U.S. is investing more than $25 million in energy efficiency programs annually – at least $182 million over the life of the program

  Examples:
  - -- Enhanced energy audits
  - -- Commercial rebates
  - -- Residential lighting



- Expected to reduce the need for additional generation by more than 500 megawatts



- Conserve Energy During Heavy Demand
  - -- Load control program – partnership with customers that allows us to cycle off AC units during peak demand
  - -- Smart meter pilot program –helps customers manage their usage

LG&E KU

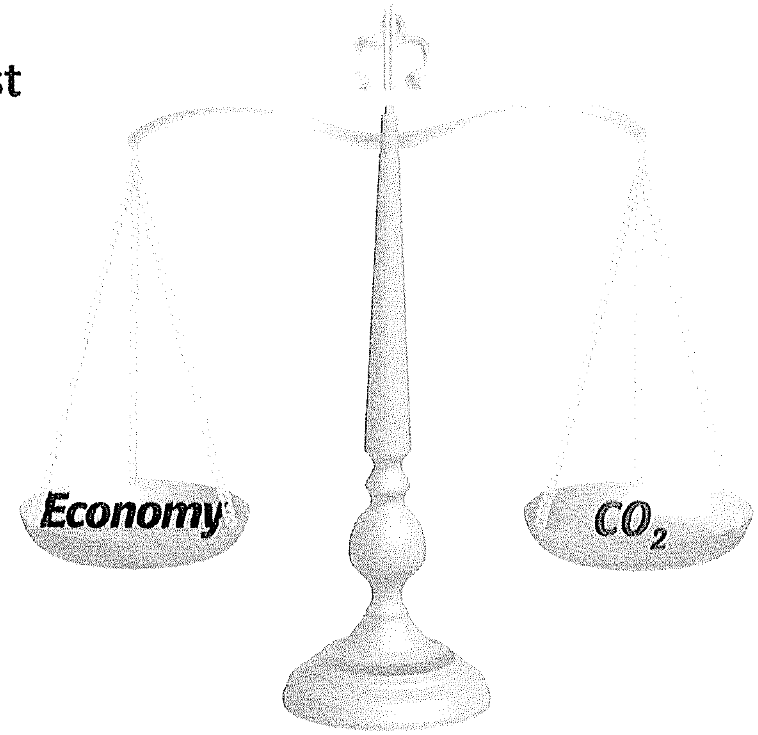
What are "the next steps?"

- Understand that rising energy costs will be a way of life for years to come – consider everything you do with that in mind
- Make major, sustained commitment to energy efficiency
- E.ON U.S. – to address issues of carbon capture and sequestration with help of policy-makers
- E.ON U.S. – share information and work constructively with policy-makers

LG&E KU

Balanced Outcome

- Insist on a thorough evaluation of cost
- Allow technology to catch up
- Demand an equitable allocation of carbon credits
- Be efficient – seek incentives for efficiencies



"To build may have to be the slow and laborious task of years.

To destroy can be the thoughtless act of a single day."

— Winston Churchill

LG&E KU

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

APPLICATION OF KENTUCKY UTILITIES COMPANY FOR AN ADJUSTMENT OF BASE RATES	)))	**CASE NO. 2009-00548**

In the Matter of:

APPLICATION OF LOUISVILLE GAS AND ELECTRIC COMPANY FOR AN ADJUSTMENT OF ITS ELECTRIC AND GAS BASE RATES	))))	**CASE NO. 2009-00549**

TESTIMONY OF
CHRIS HERMANN
SENIOR VICE PRESIDENT – ENERGY DELIVERY
LOUISVILLE GAS AND ELECTRIC COMPANY AND
KENTUCKY UTILITIES COMPANY

Filed: January 29, 2010

Q. **Please state your name, position and business address.**

A. My name is Chris Hermann. I am Senior Vice President – Energy Delivery for Louisville Gas and Electric Company ("LG&E") and Kentucky Utilities Company ("KU") (collectively, the "Companies") and am employed by E.ON U.S. Services, Inc., a service company subsidiary wholly-owned by E.ON U.S., LLC ("E.ON U.S."). My business address is 220 West Main Street, Louisville, Kentucky 40202.

Q. **Please describe your educational and professional background.**

A. I received a B.S. degree in Mechanical Engineering from the University of Louisville in 1970. I joined LG&E that same year and have spent my entire career at LG&E and E.ON U.S. In 1978, I began working as the Plant Manager for the LG&E Cane Run generating station. I held a number of other positions before assuming my current duties in 2003. A complete statement of my work experience and education is contained in Appendix A attached hereto.

Q. **Please describe your duties and responsibilities as Senior Vice President - Energy Delivery and the mission of the Energy Delivery division.**

A. As Senior Vice President - Energy Delivery, I am responsible for Energy Delivery, which includes the gas and electric distribution functions for LG&E, the electric distribution functions for KU, and the retail operations for both KU and LG&E. Our mission is simple and constant. We strive to provide safe, reliable, cost-effective service to our customers.

Q. **Have you previously appeared before this Commission?**

A. Yes. I have appeared before this Commission in informal conferences and participated in the merger proceedings of LG&E and KU before the Commission in Case No. 97-300, *In* *the Matter of: Joint Application of Louisville Gas and Electric Company and Kentucky Utilities Company for Approval of a Merger.* I also testified in LG&E's 2003 rate application, Case No. 2003-0433, *In re the Matter of: An Adjustment of the Gas and Electric Rates, Terms and Conditions of Louisville Gas and Electric Company,* and KU's 2003 rate application, Case No. 2003-0434, *In re the Matter of: An Adjustment of the Electric Rates, Terms and Conditions of Kentucky Utilities Company.* I also testified in LG&E's 2008 rate application, Case No. 2008-00252, *In re the Matter of: Application of Louisville Gas and Electric Company for an Adjustment of Its Electric and Gas Base Rates*, and KU's 2008 rate application, Case No. 2008-00251, *In re the Matter of: Application of Kentucky Utilities Company for an Adjustment of Base Rates.*

Q. What is the purpose of your testimony?

A. I will explain in my testimony how the Companies have been able to provide safe, reliable and cost-effective services for our electric and gas distribution business and retail operations while continuing our efforts to provide quality customer service. I will also describe how Energy Delivery responded to the unprecedented weather events that recently affected the Companies' service area. Finally, I will explain why a rate increase is needed at this time as it relates to Energy Delivery.

Energy Distribution Systems

Q. Please describe LG&E's electric and gas distribution businesses.

A. LG&E's electric distribution business serves approximately 391,000 electric customers in Jefferson County and 8 surrounding counties. The electric distribution assets we manage include over 90 substations (of which more than 30 are shared with the transmission system) and over 3,900 miles of overhead and about 2,300 miles of underground electric lines. LG&E's service area covers approximately 700 square miles. Our electricity is produced primarily by our coal-fired generating stations which are discussed in greater detail in the testimony of Paul Thompson. LG&E's gas distribution business serves approximately 317,000 gas customers in Jefferson County and 16 surrounding counties. The gas distribution assets we manage include approximately 4,200 miles of gas distribution pipe, over 380 miles of transmission pipe, and five underground gas storage fields.

Q. Please describe KU's distribution business.

A. KU's distribution business serves approximately 513,000 electric customers in 77 counties in Kentucky. The electric distribution assets we manage include over 475 substations (of which more than 50 are shared with the transmission system) and over 16,000 miles of electric lines, with approximately 2,150 miles of such line being underground. KU's service area covers approximately 6,600 noncontiguous square miles. Our electricity is produced primarily by our coal-fired generating stations which are discussed in greater detail in the testimony of Mr. Thompson.

Q. Will you please describe how the Energy Delivery division operates and maintains the distribution networks that serve the Companies' customers?

A. Yes. We deliver electricity and gas to our customers by operating and maintaining the electric and gas distribution infrastructure required to provide safe and reliable service. We also provide retail and customer service to our residential, commercial and industrial customers and support economic development efforts in the Commonwealth.

The cornerstone of our distribution and retail operations continues to be our commitment to the delivery of safe and reliable service at a low cost to our customers. We remain dedicated to providing high quality customer service through refining our current programs and implementing innovative practices. Finally, recognizing our customers' increased environmental awareness, we have responded by providing our customers with opportunities to manage their use through our energy efficiency programs.

Application for Increase in Base Rates

Q. Why are the Companies now seeking a base rate increase?

A. Energy Delivery strives to contain the increasing cost of providing the safe and reliable service our customers have come to expect. Since the last rate case, Energy Delivery has made approximately $234 million in capital investments to its electric and gas distribution facilities, $123 million for LG&E and $111 million for KU. With these additional investments to serve customers, costs, such as property taxes and insurance, have increased as well. As S. Bradford Rives' testimony indicates, the Companies' operation and maintenance costs and capital investments have compromised our ability to earn a reasonable return on our investment.

In addition, the substantial operation and maintenance costs and capital investments resulting from the two storms that recently impacted our service area have contributed to the decline in the Companies' financial health. The first storm occurred on September 14, 2008, which developed from the remnants of Hurricane Ike ("2008 Wind Storm"). The second occurred from January 26 through February 14, 2009, and involved an ice, snow and wind storm ("2009 Winter Storm"). Both of these storms and their impacts are discussed in more detail below.

Energy Delivery's Safety Record

Q. Please discuss Energy Delivery's commitment to safety.

A. Energy Delivery is committed to ensuring the health and safety of its employees and the public. To effectuate this commitment, a culture of safety has been established within our workforce that ensures our "No Compromise" policy is reflected in our attitudes and behaviors. This policy has been in effect since 2001 and unequivocally affirms that safety is our preeminent operating priority. LG&E and KU continue to utilize programs such as random field audits, safety "tailgate" meetings and quarterly safety meetings to ensure the policy is operating as it should. As a result of these concerted efforts, in 2009 Energy Delivery's employees achieved a 1.32 recordable injury incident rate under OSHA regulations, which is well below the comparable utility employee industry average of 4.1 and comparable to the Edison Electric Institute Top Performer designation of 1.25.

As a result of our efforts, Energy Delivery continues to receive numerous safety awards, which are listed in Appendix B. While these awards demonstrate that LG&E and KU are certainly leaders among utility companies in safety performance, we continually seek improvement so that our employees are working in the safest possible manner.

Energy Delivery equally values the safety of its contractors and consequently holds its contractors to the same high standard of safety practices. As a result of making safety a focus of its relationship with its contractors, in 2009 Energy Delivery's contractors had a recordable injury incident rate of 1.53, well below the industry average of 5.90 for utility contractors. Further, the number of employee and contractor safety audits performed continues to grow, and is now well over 5,700 per year, helping to ensure best practices are being employed.

Energy Delivery's Performance

Q. How have the Companies performed in the area of electric reliability?

A. The period since the last rate case has presented some of the greatest challenges to Energy Delivery in my career. This is especially so due to the unprecedented storms in 2008 and 2009. I am proud to say that the employees and contractors for LG&E and KU rose to the occasion with uncompromising focus and dedication.

Q. Do LG&E and KU measure its Energy Distribution performance by objective criteria?

A. Yes. LG&E and KU track the reliability of their distribution facilities through analyzing performance metrics such as the Customer Average Interruption Duration Index ("CAIDI"), which measures the average electric service interruption duration per interrupted customer for the specified period and system. CAIDI is calculated by utilizing two other measurements, System Average Interruption Duration Index ("SAIDI") and System Average Interruption Frequency Index ("SAIFI"). SAIDI measures the average electric service interruption duration in minutes per customer for the specified period and system, while SAIFI measures the average electric service interruption frequency per customer for the specified period and system. The Companies track their performance monthly, which provides valuable information regarding their distribution reliability on a short-term basis, while allowing for aggregation to evaluate historical trends. Prior to the 2008 Wind Storm and the 2009 Winter Storm, LG&E and KU had been seeing improvements in these metrics owing to some of the specialized reliability programs (such as focusing on poorly performing circuits and utilizing technology to identify faulted circuits; both of which are discussed in more detail below) that we had put in place. However, residual damage from these two events has had a significant and detrimental impact on these reliability metrics.

Q. Please describe some of the residual impacts from these storms on electric reliability.

A. The residual impacts of these two storms are taking the form of increased outages. For example, the two storms with their strong winds and heavy ice significantly weakened a number of trees, but did not bring them down during either of the storms. As time passes, the weakened trees become more likely to fall, and we are literally continuing to see fall-out from these two storms in even subsequent minor or "blue-sky" events. Typically, these events affect equipment, such as lightning arrestors, cross arms, or transformers, which were weakened or damaged, but which could not be identified at the time, and now fail during even minor events. Our experience leads us to conclude that these residual storm effects can be expected to continue to negatively impact our SAIDI and SAIFI metrics for some time into the future.

Q. Have there been challenges with regard to electric reliability?

A. Yes. As the result of the two severe weather events, LG&E and KU faced significant challenges to electricity delivery as damage to the distribution facilities was extensive, requiring substantial restoration efforts. The weather events caused the largest reported outages in the Companies' history, even surpassing the effects of the 1974 tornado in Louisville.

Q. Have the Companies had an opportunity to examine the report issued by the Commission on November 19, 2009, relating to the 2008 Wind Storm and 2009 Winter Storm?

A. Yes, we are carefully examining the Commission's report. However, and preliminarily, we believe that we are already taking a number of the actions discussed in the report. For example, the Companies already participate in emergency planning exercises and have access to satellite-based telecommunications. Further, the Companies already conduct formal inspections following major outages and have a fully functional Outage Management System. In regard to the recommendations that are not currently undertaken, the Companies are committed to working with the Commission to review and understand its recommendations.

Q. Please describe the 2008 Wind Storm that occurred in September 2008 and its effect on electricity delivery.

A. The 2008 Wind Storm affected much of LG&E's service area and a portion of KU's service area. Although the remnants of Hurricane Ike were forecasted to pass well north of Kentucky, the remnant dropped southward, bringing hurricane-force wind gusts of up to 80 mph. The 2008 Wind Storm resulted in the then-largest documented electric outage in LG&E's history, as 301,000 customers, representing approximately 75% of all customers, were affected. KU's service area was also affected, as 75,000 customers, representing approximately 15% of all customers, were also without service.

The 2008 Wind Storm caused significant damage to the Companies' distribution and transmission systems. The Companies immediately began restoration efforts as a Level IV alert was issued, signifying the highest level of storm response.[1] Employees

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[1] A Level IV emergency exists when there is a significant problem with the general health and welfare of residents caused by a system wide disaster or extremely severe weather which will require more than 3 days to be resolved. During such an event, the Companies closely cooperate with state and local governments. Like a Level III alert, and in addition to employees and regular contractors, outside contractors are employed and assistance from other utilities through regional mutual assistance groups is requested. Additionally, employees throughout the Companies are called upon to assist in more routine duties in order to relieve linemen and other personnel involved directly in service restoration.

were quickly dispatched to identify and isolate damaged areas and ensure the safety of the public with regard to the tremendous number of downed lines. The Companies immediately recalled over 200 personnel that had been deployed to the Texas Gulf Coast region pursuant to mutual assistance agreements to assist with storm restoration efforts from Hurricane Gustav, a prior storm. As it was quickly evident that additional personnel were required, the Companies began garnering assistance from regional mutual assistance groups. The Companies are a member (through its parent E.ON U.S.) of three regional mutual assistance groups, in which the member utility companies send available personnel to assist when significant restoration efforts are required.[2] At its peak, 2,943 employees and contractors were engaged, which was then the Companies' largest deployment of personnel ever undertaken in a restoration effort. Restoration efforts were prioritized for critical agencies and community facilities, such as hospitals, in accordance with the Terms and Conditions set forth in the tariffs on file with the Commission. As a result of the tremendous efforts of those working to restore service, all LG&E customers' service was restored by September 24 and all KU customers' service was restored by September 21. As part of its restoration efforts, LG&E replaced 555 utility poles and 207 transformers, while KU replaced 143 utility poles and 133 transformers. As the amount of damage to distribution infrastructure was vast, restoration costs for LG&E totaled about $32.9 million, KU experienced costs of about $4.7 million.

During the restoration efforts, the safety of employees, contractors and the public remained the first priority. Energy Delivery was committed to ensuring that the "No Compromise" approach to safety was utilized by employees and contractors alike during

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[2] LG&E and KU belong to the following regional mutual assistance groups: Southeastern Electric Exchange, Great Lakes Mutual Assistance, and Midwest Mutual Assistance.

those difficult and challenging days. To ensure the safety of personnel who were not employees of LG&E and KU, all personnel were trained under the Passport program[3] to ensure consistent safety practices among the workforce.

In order to communicate with customers, governmental officials, and the public at large, the Companies relied upon a comprehensive restoration plan established prior to the 2008 Wind Storm that was reviewed and updated by the Companies. Understanding the importance of providing estimated system-wide restoration times, on the day following the storm, the Companies made it clear to the public that some customers may not have service restored for up to two weeks. As restoration progressed, information regarding the number of lines remaining down, the number of crews working, the importance of generator safety and other essential information was disseminated. To reach the public, LG&E and KU conveyed announcements on television, radio stations and their website. Additionally, LG&E and KU conducted numerous press briefings and conducted tours with work crews for media, government officials and the members and staff of the Commission.

Q. Please describe the 2009 Winter Storm that occurred from January 26 to February 11, 2009 and its effect on electricity delivery.

A. The 2009 Winter Storm was so severe that Governor Steve Beshear described the storm as the "worst natural disaster" in the modern history of the Commonwealth and was the first time the entire Kentucky National Guard was activated. From January 26 to 28, snow and ice accumulated up to three inches on trees and utility lines, with ice and snow accumulation on the ground as high as ten inches in some areas of the state. Many trees

[3] The Passport program is a process that certifies that contract workers have sufficient safety training so as to safely work on LG&E's and KU's systems.

and limbs fell due to the ice accumulation, which resulted in a loss of service for many persons across the state. At peak, 205,000 LG&E customers lost service, representing approximately 51% of all customers, while 199,000 KU customers were without service, representing approximately 40% of all customers. Cumulatively, the number of customers affected represented the largest outage in the Companies' history, exceeding even the number of customers affected by the 2008 Wind Storm less than five months earlier.

In addition to damaging LG&E's and KU's distribution systems, the 2009 Winter Storm caused unprecedented damage to the transmission system, which further complicated restoration efforts. KU's service area was particularly affected, as 100% of the transmission substations in the western portion of its service area were affected by damage and 40% of the transmission substations in the central region were also affected. 33% of LG&E's substations were affected. As outages started to occur, restoration efforts began immediately as personnel began to isolate damaged electric facilities and restore as much power as possible. Restoration efforts were prioritized for critical agencies and community facilities, such as hospitals, in accordance with the Terms and Conditions set forth in the tariffs on file with the Commission. Such efforts were hindered by continually deteriorating weather conditions, resulting in additional outages. By Wednesday, January 28, the Companies issued a Level IV storm response as it became clear that the damage had exceeded that of the 2008 Wind Storm months prior.

As additional personnel would be required, LG&E and KU began participating in conference calls with our regional mutual assistance groups to secure additional contractors. At peak, 6,016 restoration workers, comprised of employees, contractors and mutual assistance crews from 21 states were engaged in restoring service. This was the single largest use of restoration workers in the Companies' history. Through the workers' efforts, all service to LG&E customers was restored by February 7 and all KU customers' service was restored by February 9. Although service was restored, contractor resources were retained for several weeks to repair the damaged infrastructure. The damage was extensive with the Companies expending about $148 million as of October 31, 2009.[4]

Energy Delivery had to ensure the safety of the thousands of transient workers involved in the restoration efforts, as well as the safety of its employees and the general public. In order to ensure that all restoration workers were espousing the "No Compromise" approach to safety, LG&E and KU required all workers (other than employees and contractors who had already received the training) to complete Passport training, which certifies the contract worker has received sufficient safety training to work safely on LG&E's and KU's systems.

Throughout the restoration process, every effort was made to keep customers, government officials and the public informed. LG&E and KU ran "safety crawls" on television throughout the restoration process, which provided important safety and restoration information. The Companies participated in daily press briefings, with targeted press releases being issued daily. LG&E and KU also coordinated closely with the Commission throughout the restoration process. On February 9, 2009, the last customers were returned to the distribution network.

[4] As of October 31, 2009, LG&E expended about $56 million in restoration costs (about $55 million for distribution infrastructure and about $1 million for transmission infrastructure), while KU incurred costs of about $92 million (about $76 million in distribution infrastructure and about $16 million in transmission infrastructure).

Incredibly, on February 11—not even two full days after the last customers' service had been restored—a wind storm occurred with gusts of over 60 mph. Although the damage from this part of the 2009 Winter Storm did not compare to the damage from the previous 2008 Wind Storm or the ice accumulation of two weeks prior, it was significant as 37,000 LG&E customers lost service, in addition to 44,000 KU customers.

Importantly, our experiences from the 2008 Wind Storm and the 2009 Winter Storm served us well during our recent restoration efforts following the December 2009 Mountain Snow Storm where we restored power to approximately 16,000 Kentucky customers in about 7 days in difficult terrain with no injuries or accidents. Local authorities have favorably recognized our efforts in that restoration.

Q. Following the storms, did the Companies conduct a review to evaluate their responses?

A. Yes. The Companies' efforts in restoring service provided a meaningful opportunity for internal review of our storm response practices. This review allowed for recognition of areas in which our restoration efforts were proficient, as well as areas in which improvement is possible. The Companies engaged Davies Consulting, Inc. to assess the feasibility and relative benefits in further "hardening" the electric system, as well as converting the overhead electric systems to underground construction. While the report indicated that fully converting the electric systems to underground is cost-prohibitive, the report provided several hardening options that the Companies are currently considering. One alternative outlined in the Davies report relates to hazard tree removal outside of LG&E's and KU's typical tree trimming programs. The cost of this alternative could add about $5.6 million per year in operation and maintenance costs (about $3.8 million for

KU and about $1.8 million for LG&E) not previously incurred by the Companies. This adjustment is further discussed in the testimony of Lonnie Bellar.

In addition to examining potential improvements to the electric system, the Companies also evaluated their responses to customer concerns and questions throughout the restoration efforts. One principal area identified for improvement was customer communications. As technology has progressed, customers' expectations regarding the immediacy of information understandably have changed. Namely, customers are seeking estimated restoration times ("ERT") that are frequently updated throughout the restoration process.

Q. What steps have LG&E and KU taken to improve the communication of this kind of information?

A. Once this area was identified, the Companies began implementing measures to improve communications with customers regarding restoration efforts. Several initiatives have already been implemented, such as displaying service area maps online when major events occur. The maps indicate where outages are concentrated across the service area. In recognition of customers' increased reliance on online services, outages can now be reported on the Companies' websites. Finally, the Companies have created a "Twitter" social networking account that can be used to update customers regarding outages and restoration efforts. This allows the Companies to quickly disseminate information that is receivable through the Internet or cell phone.

In addition to the programs already in place, the Companies are planning further improvements. The Companies plan to provide ERT information online during major storm events that will be searchable by location. The ERT information will be updated consistently throughout the restoration process, providing updated information on a daily basis. The Companies are also looking for innovative ways to reach customers during major events, such as through text messaging and email.

Q. Are there any other actions LG&E and KU have taken to ensure reliability?

A. Yes. LG&E and KU have implemented several programs to ensure the reliability of their distribution systems. One such initiative is the Worst Performing Circuits program, in which the Companies annually analyze and rank the reliability performance of all distribution circuits. Reliability data is received from the Outage Management System, which tracks and compiles outage information. Through utilizing SAIFI and other metrics, the worst performing circuits are identified and targeted for improvement through vegetation management initiatives and other reliability projects. The purpose of the program is not only to improve the individual circuits that have been identified, but also to reduce the number of circuits whose performance deviates substantially from the mean value of all circuits.

LG&E and KU also employ a Vegetation Management Plan that emphasizes flexibility in recognition of variances within their service areas with regard to growth and tree density. This multi-cycle strategy better enables the Companies to maintain a proactive trim cycle while balancing the reactive needs of the circuits identified as "Worst Performing." The goal is to maintain an average trim cycle for the Companies of 5 years or less, while ensuring that all circuits identified as "Worst Performing" are trimmed in the year that they have been so identified.

Additionally, LG&E and KU are increasing the use of Faulted Circuit Indicators, which is a cost-effective device that allows for partial restorations more quickly when outages occur. The devices can readily identify where a fault has occurred, which simplifies restoration efforts and enhances the employees' ability to avoid hazardous areas. Finally, the Companies have implemented a plan to mitigate animal-related outages. Devices designed to prevent animals from reaching and affecting critical equipment are installed on all new equipment. As a result of this effort, fewer animal-related outages are expected to occur, which should lead to increased reliability and decreased maintenance costs as equipment damage is reduced.

Q. Are there any other actions the Companies have taken to maintain or improve their performance?

A. Yes. A new customer information system known as the Customer Care Solution system ("CCS") was fully implemented in April 2009. Implementing CCS was a substantial undertaking, with about $45 million having been invested since the last rate case, and a total investment of about $83 million as of October 31, 2009. This commitment required significant time, planning and resources from the Companies, but is well worthwhile due to the many advantages of CCS. This is described in John Wolfram's testimony.

Q. Are there any particular challenges for safety and reliability specific to LG&E's gas business?

A. Yes. With regard to LG&E's gas business, since 1996, LG&E has installed 386 miles of distribution main as part of its large scale main replacement effort, including 25 miles since LG&E's last gas rate case. The main replacement program helps ensure continued safety, improved reliability, enhanced operating efficiencies, and lower operating costs for LG&E's gas customers. There are 229 miles yet to be replaced in LG&E's gas system. LG&E is also in the process of upgrading other components of the gas system, including gas regulation and measurement facilities and storage field infrastructure. As with the main replacement program, these upgrades will enhance reliability and safety.

LG&E's gas transmission business must comply with the Pipeline Safety Improvement Act of 2002. In complying, LG&E has already identified all High Consequence Areas in its gas transmission lines, conducted risk analyses of its pipeline segments and began baseline assessments of covered pipeline segments. After conducting an analysis of the feasibility of the inspection methods permissible under the federal regulations, modifications have been made on certain pipelines to allow for in-line inspections and preparations for similar projects on other pipelines have been made. To comply with these pipeline integrity requirements, \$1.9 million has been spent on capital investments and \$1.8 million has been spent on operation and maintenance costs since the last rate case.

Also, LG&E must comply with the Pipeline Inspection, Protection, Enforcement and Safety Act of 2006 ("2006 PIPES Act"), which requires natural gas distribution operators to establish a distribution integrity management program as well as implement control room management procedures in order to mitigate safety risks. Final regulations regarding control room management and distribution integrity were issued in December 2009. In order to comply with the 2006 PIPES Act, LG&E has begun working with industry organizations to develop a written program.

Customer Satisfaction

Q. Please describe the Companies' performance in customer satisfaction.

A. Both LG&E and KU have been nationally recognized over the last decade as among the leaders in customer satisfaction. In 2009, KU was ranked second by J.D. Power &

Associates in its Midsize Midwest residential survey of the nation's electric utilities and LG&E was ranked fourth. This reflects a slight decline relative to the period from 1999 to 2007, during which the combined Companies were ranked both first in the Midwest and among the top ten in the nation in the J.D. Power residential survey eight out of nine times. The Companies have performed comparably in the Midwest midsize business electric survey. While customer satisfaction indices have been broadly on the decline for the utility industry at large, KU and LG&E remain competitive with other investor-owned utilities in the region. The J.D. Power electric study focuses on power quality and reliability, price, billing and payment, corporate citizenship, communications, and customer service.

Environmental Stewardship

Q. Please describe LG&E's and KU's initiatives that allow customers to reduce their environmental impact.

A. As the public's concern in protecting the environment continues to grow, the Companies have developed several initiatives that facilitate our customers' interest. Among the initiatives is the Green Energy Program[5], which allows customers to offset their carbon impact through the purchase of renewable energy certificates or "green tags." Residential and commercial customers can voluntarily participate; there are currently over 1,100 LG&E and 650 KU customers participating in the program.

The Companies have implemented a portfolio of Demand-Side Management Energy Efficiency programs for residential and commercial customers. For example, for

[5] On November 30, 2009, LG&E and KU petitioned the Commission for an order approving limited modifications to the Companies' Green Energy programs, including transferring the responsibility for purchasing renewable energy credits from the current vendor to the Companies themselves. The Commission is currently reviewing this request in Case No 2009-00467.

a $25 fee, LG&E and KU will perform an on-site Residential Energy Audit, which determines where energy is being used in the household and the most cost-effective ways to save. In 2009, over 650 on-site audits were completed for LG&E residential customers and about 400 such audits were completed for KU residential customers. Beginning in September 2009, customers can also participate at no fee in an on-line residential audit, in which the customer accesses the tool through the E.ON U.S. website and enters information about the home and usage habits. The tool then utilizes the customer's actual historical energy usage and compiles a detailed report outlining the areas in which energy savings are possible.

LG&E and KU also perform on-site Commercial Audits at no fee for eligible customers. In 2009, over 350 on-site commercial audits were completed for LG&E and over 400 on-site commercial audits were completed for KU customers. Along with a written report providing the details of the recommended energy conservation measures, the customer is also informed of Commercial Rebate Incentives available from LG&E and KU applicable to those recommended measures in the areas of lighting, refrigeration/cooling and pumps/motors.

The Companies also allow residential and small commercial customers to help reduce system electric demand through the Demand Conservation direct load control program. Customers can presently choose to have a control device placed on their central air conditioning unit or heat pump. If customers elect to have a control device installed, the Companies credit their monthly utility bill $5 per month per air conditioner or heat pump during the four summer months (June through September).[6] Customers may also

[6] Until recently customers also had the option of utilizing a free programmable thermostat which included a load control function. While customers using the programmable thermostat did not receive a bill credit, the thermostat,

choose to have a control device placed on their electric water heater and pool pump. The Companies credit their monthly utility bill $2 per month during the four summer months for each of those devices. During 2009, approximately 69,000 LG&E and 48,000 KU customers participated in the Demand Conservation program.

Also, LG&E continues its use of the Responsive Pricing and Smart Metering Pilot Program, which is a three-year pilot program approved by the Commission in 2007. Implementation began in January 2008 and continues through December 2010. The program allows 2,000 customers served under Residential and General Service Rates to better understand and control their electricity usage through various types of equipment, such as Smart Meters and programmable thermostats that can automatically reduce electricity usage during peak hours. Also, In-Home Energy Use Displays and Time of Use Rate allow customers to see, in real time, their electricity usage which provides customers with the information necessary to better understand their energy consumption. LG&E files annual reports to update the Commission on the status of the pilot program, the most recent of which was filed on April 1, 2009. The next annual report will be filed with the Commission on April 1, 2010.

LG&E and KU also offer a high-efficiency lighting program to residential electric customers. The purpose of the program is to reduce energy use and demand by gaining customer acceptance and usage of high-efficiency lighting, primarily compact fluorescent

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when programmed, would allow the customer to better manage energy consumption. In December 2009 the Companies halted installation of those programmable thermostats while they investigated a potential safety concern with the devices. Then, during the week of January 18, 2010, the Companies began replacing the existing programmable thermostats in customers' buildings as a proactive measure, even as the investigation into the thermostats continued. The replacement thermostats do not contain load control capabilities, but those affected customers will have the option to continue in the Demand Conservation program through installation of a control device on their air conditioning unit or heat pump. The Companies are currently investigating other options for reinstituting programmable thermostats with load control functionality as part of their Demand Conservation programs in the future.

light bulbs ("CFLs"). The program uses a combination of customer education, store and manufacturer coupons, and direct mail delivery of CFLs.

Also in place is an HVAC diagnostic and tune-up program targeted to residential and small commercial customers. This program educates customers about the energy efficiency gains possible when the HVAC unit is well-tuned and maintained, encourages customers to conduct regular maintenance on the unit, provides a diagnostic inspection at a small fee to the customer, and then provides a network of qualified dealers who are available to perform a tune-up if needed also for a small fee. These HVAC dealers, along with dealers in the areas of lighting, insulation, windows, doors, duct work, motors, and pumps are also maintained on a Dealer Referral Network provided on the E.ON U.S. website available to all customers. This list has been developed to provide additional resources to customers who seek to make energy efficiency improvements but are not sure what dealers perform the type of work needed.

The Companies have taken significant steps toward improving the energy efficiency of new homes being built in their service territories through the offering of a New Residential ENERGY STAR Construction program. This program educates builders and home buyers on the energy savings potential with building above required building code to the ENERGY STAR level. The program also provides training and certification opportunities to Home Energy Rating System ("HERS") Raters, who are needed to certify the efficiency of the newly built homes and provides incentives to offset the cost associated with building to the ENERGY STAR level.

All of these energy efficiency programs are supported through a Customer Education and Public Information program, which seeks to educate consumers about the need for energy efficiency and provide meaningful tools by which to accomplish the goal of using energy more wisely.

Low Income Customer Initiatives

Q. Do LG&E and KU offer any particular programs to assist low income customers?

A. Yes. For many years, the Companies have provided low income customers assistance in addition to the programs and protections required by the Commission's regulations and have worked with various low income customer advocacy groups to support the needs of low income customers.

Q. Please describe programs aimed at assistance for low-income customers.

A. In recognition of many customers' difficulties in paying their utility bills LG&E and KU have developed several initiatives to assist low-income customers. WeCare (Weatherization, Conservation Advice and Recycling Energy) is an energy efficiency program designed to create savings for low-income customers through energy education and implementation of energy conservation measures. All WeCare participants receive an energy audit of their home and an energy conservation educational session.

LG&E's and KU's applications to extend the Home Energy Assistance ("HEA") program for five years were granted by the Commission on September 14, 2008 in Case No. 2007-00337 and in Case No. 2007-00338. HEA provides hardship assistance to low-income customers through the collection of 15 cents per residential meter per month. In order to participate, customers must be enrolled in the federal Low Income Home Energy Assistance Program.

Additionally, LG&E and KU partner with other organizations to provide additional support. For example, LG&E participates in Community Winterhelp, a nonprofit corporation comprised of community ministries, which provides assistance to low-income individuals during the winter season. KU participates in the WinterCare Energy Assistance Fund, a state-wide energy assistance fund supported privately by utilities and community action agencies, that provides assistance to low-income persons with their utility expenses during the winter season. Beginning November 1, 2009, LG&E and KU will match all customer donations to Community Winterhelp and the WinterCare Energy Assistance Fund at a match of $1 dollar for every $1 dollar given, which is four times the traditional match. The increased match will last through March 31, 2010.

LG&E has also continued its involvement with Project Warm, an independent non-profit organization that draws on community volunteers to "weatherize" the homes of low-income, elderly and disabled persons in our service area during the annual "Winter Blitz". To date, more than 3,000 homes have been weatherized. Many LG&E employees and their families participate each year. In addition, weatherization activities also include free workshops designed to instruct customers on how to weatherize their own homes, with all participants receiving a free weatherization kit. The workshops are held in late fall at schools and community centers where our customers in need are located in order to provide the weatherizing information before the onset of winter temperatures. Since 2005, KU, in conjunction with the Lexington Community Action Council, has also participated in an annual "Winter Blitz," in which KU employees and their family members weatherize the homes of low-income, elderly and disabled persons in the service area.[7]

These and other customer offerings are described further in the testimony of Mr. Wolfram.

[7] In 2009, the "WinterBlitz" became the "CAC Repair Affair".

Q. Please briefly summarize your testimony.

A. Energy Delivery strives to provide excellent customer service while ensuring reliable electric and gas delivery. As a result of the investments that the Companies have made and the significant restoration efforts that were required by the severe weather events that impacted their service areas, the Companies' current rates no longer allow for a reasonable return on their investment. As such, an increase in base rates is needed at this time.

Q. Does this conclude your testimony?

A. Yes.

VERIFICATION

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

The undersigned, **Chris Hermann**, being duly sworn, deposes and says that he is Senior Vice President, Energy Delivery for Kentucky Utilities Company and Louisville Gas and Electric Company and an employee of E.ON U.S. Services, Inc., and that he has personal knowledge of the matters set forth in the foregoing testimony, and that the answers contained therein are true and correct to the best of his information, knowledge and belief.

C Hermann
Chris Hermann

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 22nd day of January 2010.

Tammy J. Elzy (SEAL)
Notary Public

My Commission Expires:

November 9, 2010

Appendix A

Chris Hermann
Senior Vice President -- Energy Delivery
E.ON U.S.

Current Major Accountabilities

- Business strategies and budgets that support E.ON U.S and E.ON financial and best practice targets.
- Natural gas and electric distribution operations focused on network enhancement, operation and maintenance.
- Service restoration and emergency operations that minimize adverse customer impact.
- Retail business and customer service functions, including metering, customer call center and business office operations, marketing, revenue collection and economic development.
- Real estate and right-of-way, facilities management, office services, corporate fleet and critical security operations.
- International electric distribution and gas transmission best practices for E.ON worldwide.

Previous Accountabilities

Chris began his career with Louisville Gas and Electric in 1966 as a college worker, returned for engineering co-op assignments through 1969, then joined LG&E in 1970 as a plant staff engineer. During his company career, Chris also has been responsible for generation, transmission, fuel procurement, plant construction, load dispatch, engineering services, supply chain, and business integration.

Present Civic Activities

- University of Louisville Speed Scientific School
  - Chair Board Operating Sub-Committee 2009
  - Board of Industrial Advisors Chair 1993-1994
- Kentucky State Parks Foundation
  - Board Member
  - Chair Membership Committee
- Metro United Way
  - Board of Directors
  - Tocqueville Steering Committee
- Kentucky Chamber of Commerce
  - Board Member
  - Executive Committee,
  - Vice Chair Administration
- Teach Kentucky Mentor

Professional/Trade Memberships

- Southern Gas Association Board Member.
- American Gas Association Board Member, Safety Task Force Board Member and Strategic Planning Committee Member.
- American Society of Mechanical Engineers.

Education

- University of Louisville, B.S. in Mechanical Engineering: 1970
- Duke University, Program for Management Development: 1991
- Harvard University, Program on Negotiations: 1994
- Edison Electric Institute, Program on Senior Middle Management: 1995-1996
- E.ON Academy Executive Program Leading Corporate Transformation at Harvard University: 2003

Appendix B

Energy Delivery's Safety Awards and Recognition

2009

- Royal Society for the Prevention of Accidents Award for Occupational Safety – Distribution, Retail and Metering.

- Kentucky Gas Association Accident Prevention Award

- National Safety Council's Fleet Awards Program's "Significant Improvement Award" for fleet safety performance in 2009. This award recognizes fleets that have reduced their number of preventable accidents a minimum of 20%.

- Southern Gas Association Safety Achievement Award System, Regulation and Operations for completing 15 years without a lost workday injury.

- The American Gas Association's Leader Accident Prevention Award for achieving a total DART incident rate below the industry average for 2008 in the category of Medium Combination Companies.

- Governor Steve Beshear appointed Ken Sheridan, Manger, Safety and Technical Training, to a second term on the Kentucky Apprenticeship and Training Council.

2008

- Royal Society for the Prevention of Accidents Award for Occupational Safety – Distribution, Retail and Metering.

- Pineville Substation and Maintenance Group worked 250,000 employee hours with no lost time. Governor's award presentation was made by the Deputy Secretary of labor.

- Gas Distribution and Maintenance – Southern Gas Association Safety Award for 500,000 employee hours with no lost time.

- The Center Storage – Southern Gas Association Safety Award for 25 years without a lost time incident.

- Central Substation received EEI Safety Achievement Award for completing more than one million hours without a lost workday.

- 2007 American Gas Association Safety Achievement Award for attaining the lowest DART incident rate among large sized, combination energy companies.

- KGA Accident Prevention Award for companies with more than 150 employees. The award is for the lowest work day rate.

2007

- Royal Society for the Prevention of Accidents (RoSPA) Gold Award for Occupational Safety, Distribution Operations.

- Royal Society for the Prevention of Accidents (RoSPA) Gold Award for Occupational Safety, Retail Business.

- Royal Society for the Prevention of Accidents (RoSPA) Gold Award for Occupational Safety, Retail Metering.

- EEI Award for Substation Field Operations – over 1.4 million hours worked without a lost time injury. The last lost-time injury was logged nearly 50 years ago.

- EEI Award for Retail Metering – 2 million hours worked without lost-time incident.

- EEI Award for LG&E Field Service - 1 million hours worked without lost-time incident.

- EEI Award for KU Field Service – 500,000 work hours without lost-time Incident.

- Earlington Operations completed five years without lost time incident.

- American Gas Association industry leader accident prevention certificate.

- Earlington Substation completed five years without any recordables.

- EEI Safety Achievement Award for Louisville Distribution Control - 250,000 hours without a lost time incident.

- EEI Safety Achievement Award for Downtown Network – 250,000 hours without a lost time incident.

- KGA Accident Prevention Award for Excellence and Safety for 2006.

- MEA – Accident Prevent Award Winner.

- Kentucky Governor's Health and Safety for working 250,000 hours without a lost time recordable injury at Muldraugh.

- EEI award for the Pineville SCM – 250,000 hours without a lost time recordable injury.

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

APPLICATION OF KENTUCKY UTILITIES COMPANY FOR AN ADJUSTMENT OF BASE RATES	)))	CASE NO. 2009-00548

TESTIMONY OF
S. BRADFORD RIVES
CHIEF FINANCIAL OFFICER
KENTUCKY UTILITIES COMPANY

Filed: January 29, 2010

Q. Please state your name, position and business address.

A. My name is S. Bradford Rives. I am the Chief Financial Officer for Kentucky Utilities Company ("KU" or "Company') and an employee of E.ON U.S. Services Inc., which provides services to KU and Louisville Gas and Electric Company ("LG&E") (collectively, "Companies"). My business address is 220 West Main Street, Louisville, Kentucky. A statement of my professional history and education is attached as an appendix hereto.

Q. Have you previously testified before this Commission?

A. Yes. I have previously testified before this Commission in rate proceedings, administrative investigations, and environmental surcharge proceedings. Most recently I testified in the Companies' latest base rate proceedings, Case Nos. 2008-00251 (KU) and 2008-00252 (LG&E).

Q. What are the purposes of your testimony?

A. The purposes of my testimony are: (1) to describe why KU's financial condition requires the requested increase in base rates; (2) to present the Financial Exhibits to KU's application; (3) to review KU's accounting records; (4) to describe the calculation of KU's adjusted net operating income for the twelve month period ended October 31, 2009; (5) to discuss KU's capitalization and weighted cost of capital; and (6) to support the different valuations of KU's property required under KRS 278.290, such as KU's rate base.

<u>KU's Current Financial Condition</u>

Q. How would you describe KU's present financial circumstances?

A. As pointed out in the testimonies of Victor A. Staffieri, Paul Thompson, and Chris Hermann, KU's operational performance remains strong. As my testimony will demonstrate, however, its financial condition has declined due to its continual and significant investment in facilities to serve customers. Indeed, KU is engaged in the most intensive construction and capital investment campaign in its history. Even with the ongoing initiatives to control costs and improve efficient operations described by Messrs. Thompson and Hermann, this capital investment in facilities to serve customers has pushed KU's financial results below a reasonable level for the twelve-month period ending October 31, 2009. The ongoing investment in facilities since the end of the test period will only exacerbate KU's financial condition

It is essential that KU achieve and maintain a strong financial condition to allow it to continue to raise capital at reasonable rates so that it can continue to invest in facilities to provide safe, reliable service to its customers. Despite KU's initiatives to control costs and improve its already-efficient operations, KU's revenues must be adjusted to reflect its increasing cost of providing service in order to effectively meet its service obligations both now and in the future. KU's current financial condition is not in the best interest of its shareholders or its customers. Approval of this rate increase is necessary to improve the Company's financial health.

Q. Has KU's investment in utility plant increased since April 30, 2008, the test period used by the Commission in Case No. 2008-00251?

A. Yes, it has increased dramatically. The following table shows KU's investment in net utility plant has increased by approximately $696 million since April 30, 2008:

Net Utility Plant

	April 30, 2008	October 31, 2009	Increase
Utility plant	$5,151,234,451	$5,975,896,410	$824,661,959
Accumulated depreciation	$1,972,362,645	$2,101,470,902	$129,108,257
Net utility plant	$3,178,871,806	$3,874,425,508	$695,553,702

Q. Is KU presently earning a fair, just, and reasonable return on its investment in electric operations?

A. No. Based on the analyses presented in William E. Avera's testimony, the cost of equity for the proxy groups of utilities and non-utility companies is on the order of 10.50 percent to 12.50 percent. He has recommended the Commission adopt an 11.5 percent allowed return on equity ("ROE") for KU's electric operations. This equity return is necessary for the Company to regain and preserve its financial health. KU's actual electric return, however, fell short of Dr. Avera's recommendation. For the twelve months ended October 31, 2009, KU's electric operations earned an adjusted return on equity of 6.35 percent, well below the recommended 11.5 percent ROE, and an adjusted return on capital of 5.55 percent.

PSC Financial Exhibits

Q. Are you supporting the information required by Commission regulation 807 KAR 5:001, Section 6 – Financial Exhibit?

A. Yes. The Financial Exhibit required by this regulation was filed with KU's Application in this case and includes the required financial information for the twelve months ended October 31, 2009.

Q. Are you supporting the information required by Commission regulation 807 KAR 5:001, Section 10(6)(a)-(v) – The Historical Test Period?

A. Yes. I am sponsoring the following Schedules for the corresponding Filing Requirements:

• Description of Adjustments	Section 10(6)(a)	Tab 20
• Testimony (Revenues > $1.0 mm)	Section 10(6)(b)	Tab 21
• Testimony (Revenues < $1.0 mm)	Section 10(6)(c)	Tab 22
• Revenue Requirements Determination	Section 10(6)(h)	Tab 27
• Reconcile Rate Base & Capitalization	Section 10(6)(i)	Tab 28
• Annual Auditor's Opinion(s)	Section 10(6)(k)	Tab 30
• Stock or Bond Prospectuses	Section 10(6)(p)	Tab 35
• Annual Reports to Shareholders	Section 10(6)(q)	Tab 36
• SEC Reports (10Ks, 10Qs and 8Ks)	Section 10(6)(s)	Tab 38

Accounting Records

Q. Are the accounting records of KU kept in accordance with the Uniform System of Accounts prescribed by the Federal Energy Regulatory Commission and adopted by the Kentucky Public Service Commission?

A. Yes. The records are kept in accordance with the Uniform System of Accounts prescribed for electric public utilities.

Q. Does KU file monthly and annual operating reports presenting financial results with the Kentucky Public Service Commission?

A. Yes. They are also provided in KU's Application in Filing Requirements Tabs 32 and 37 and are supported by the testimony of Valerie L. Scott in this case.

Q. Is an audit of the financial statements of KU performed annually by independent public accountants?

A. Yes. PricewaterhouseCoopers ("PwC") audits KU's financial statements annually. The most recent opinion of our external auditor is provided in Filing Requirements Tab 30. PwC should complete its audit of KU's 2009 financial statements before April 1, 2010.

<u>Net Operating Income</u>

Q. Please describe Rives Exhibit 1 and its purpose.

A. Rives Exhibit 1 shows electric operating revenues, operating expenses, and net operating income per books for the twelve months ended October 31, 2009. The test year must be adjusted to reflect known and measurable changes in revenues and expenses that can be expected to occur during the period the proposed rates will be effective. This Exhibit sets forth adjustments for known and measurable changes, and eliminates unrepresentative conditions in order to "*pro form*" or make the test year suitable for use in determining the deficiency of current electric revenues. This Exhibit also includes adjustments to remove the effects of other rate mechanisms in order to limit the deficiency determination to base revenues.

A further description of, and support for, each adjustment is contained in supporting Reference Schedules 1.00 through 1.46 of this Exhibit.

Q. Briefly describe the nature of the pro forma adjustments you have made to KU's electric operations for the test year ended October 31, 2009, shown on Rives Exhibit 1.

A. For the electric operations as reflected in the twelve month period ended October 31, 2009, KU has made adjustments which:

a) Eliminate the effect of unbilled revenues (Reference Schedule 1.00),

b) Remove the impact of items included in other rate mechanisms (Reference Schedules 1.01-1.03, 1.05, 1.09, and 1.10),

c) Annualize year-end facts and circumstances and adjust for other known and measurable changes to revenues and expenses (Reference Schedules 1.04, 1.06, 1.07, 1.12, 1.14-1.20, and 1.31),

d) Adjust for other unusual, non-recurring, or out-of-period items in the test year (Reference Schedules 1.08, 1.11, 1.13, 1.21-1.30, 1.32-1.38, 1.44, and 1.45), and

e) Adjust for federal and state income tax expenses for these pro-forma adjustments (Reference Schedules 1.41-1.43).

Q. Please explain the adjustment to operating revenues shown in Reference Schedule 1.00 of Rives Exhibit 1.

A. This adjustment has been made to eliminate the effect of unbilled revenues. The Commission approved a similar adjustment in Case No. 2003-00434, and KU proposed such an adjustment in Case No. 2008-00251. This adjustment was prepared by Lonnie E. Bellar and is discussed in his testimony.

Q. Please explain the adjustment to operating revenues shown in Reference Schedule 1.01 of Rives Exhibit 1.

A. The Commission's February 5, 2009 Order in Case No. 2008-00251 recognized that KU's merger surcredit mechanism would terminate when the rates that order approved went into effect on February 6, 2009. This adjustment therefore removes the effect of the merger surcredit from the test year. This adjustment was prepared by Mr. Bellar and is discussed in his testimony.

Q. Please explain the adjustment to operating revenues shown in Reference Schedule 1.02 of Rives Exhibit 1.

A. On its own terms, the VDT surcredit terminated concurrently with the filing of KU's application in its most recent base rate proceeding, Case No. 2008-00251, which application KU filed on July 29, 2008. This adjustment was prepared by Mr. Bellar and is discussed in his testimony.

Q. Please explain the adjustment to operating revenues and expenses shown in Reference Schedule 1.03 of Rives Exhibit 1.

A. This adjustment has been made to account for the timing mismatch in fuel cost expenses and revenues under the Fuel Adjustment Clause ("FAC") for the twelve months ended October 31, 2009. The Commission approved a similar adjustment in Case No. 2003-00434, and KU proposed such an adjustment in Case No. 2008-00251. This adjustment was prepared by Robert M. Conroy and is discussed in his testimony.

Q. Please explain the adjustment to operating revenues shown in Reference Schedule 1.04 of Rives Exhibit 1.

A. Reference Schedule 1.04 presents the adjustment necessary to annualize the base rate revenues the Commission approved in its February 5, 2009 Order in Case No. 2008-00251, which base rates went into effect on February 6, 2009.

Reference Schedule 1.04 further presents the adjustment necessary to annualize the full twelve months of the test year for the "roll-in" or incorporation of FAC revenues as directed by the Commission's June 3, 2009 Order in Case No. 2008-

00520. The Commission approved a similar adjustment in Case No. 2003-00434, and KU proposed such an adjustment in Case No. 2008-00251.

This adjustment was prepared by Mr. Conroy and is discussed in his testimony.

Q. Please explain the adjustment to operating revenues and expenses shown in Reference Schedule 1.05 of Rives Exhibit 1.

A. This adjustment removes Environmental Cost Recovery mechanism ("ECR") revenues and expenses from net operating income because those revenues and expenses are addressed by a separate rate mechanism. As Mr. Conroy explains in greater detail, KU is proposing in this proceeding to eliminate its 2001 and 2003 ECR Plans from its monthly ECR filings on a going-forward basis, and has calculated this adjustment accordingly. The Commission approved a similar adjustment in Case No. 2003-00434, and KU proposed such an adjustment in Case No. 2008-00251.

This adjustment was prepared by Mr. Conroy and is discussed in his testimony.

Q. Please explain the adjustment to operating revenues and expenses shown in Reference Schedule 1.06 of Rives Exhibit 1.

A. This adjustment has been made to reflect a full year of the ECR incorporation into base rates or "roll-in" as required in the Commission's December 2, 2009 Order in Case No. 2009-00310. The Commission approved a similar adjustment in Case No. 2003-00434, and KU proposed such an adjustment in Case No. 2008-00251. This adjustment was prepared by Mr. Conroy and is discussed in his testimony.

Q. Please explain the adjustment to operating revenues and expenses shown in Reference Schedule 1.07 of Rives Exhibit 1.

A. .KU has included in this adjustment a reduction to revenues associated with ECR-related off-system and intercompany sales revenues. KU performed this adjustment in a manner generally consistent with the methodology prescribed in the Commission's Order on rehearing in Case No. 98-474 dated June 1, 2000, and in the manner used in Cases No. 2003-00434 and 2008-00251. This adjustment was prepared by Mr. Conroy and is discussed in his testimony.

Q. Please explain the adjustment to operating revenues and expenses shown in Reference Schedule 1.08 of Rives Exhibit 1.

A. This adjustment has been made to eliminate net brokered and financial swap revenues. Net revenues associated with brokered and financial swap transactions are eliminated in determining base rates because these transactions do not utilize company generation or transmission assets. Labor and labor related costs associated with executing these transactions are also eliminated. KU proposed a similar adjustment in its most recent base rate case, Case No. 2008-00251 and a similar adjustment was also approved by the Commission in Case No. 2003-00434 and Case No. 98-474. This adjustment was prepared by Ms. Scott and is discussed in her testimony.

Q. Please explain the adjustment to operating revenues shown in Reference Schedule 1.09 of Rives Exhibit 1.

A. This adjustment is necessary to eliminate accrued revenues associated with the ECR, MSR, FAC, and Demand-Side Management ("DSM") rate mechanisms. The

Commission approved a similar adjustment in Case No. 2003-00434, and KU proposed such an adjustment in Case No. 2008-00251. This adjustment was prepared by Shannon L. Charnas and is discussed in her testimony.

Q. Please explain the adjustment to operating revenues and expenses shown in Reference Schedule 1.10 of Rives Exhibit 1.

A. This adjustment has been made to remove the impact of the revenues and expenses associated with KU's DSM mechanism from the test year revenues and expenses. The impact of rate mechanisms, like the demand-side management mechanism, should be removed from the test year revenues when assessing the adequacy of base rates. The Commission approved a similar adjustment in Case No. 2003-00434, and KU proposed such an adjustment in Case No. 2008-00251. This adjustment was prepared by Mr. Conroy and is discussed in his testimony.

Q. Please explain the adjustment to operating revenues and expenses shown in Reference Schedule 1.11 of Rives Exhibit 1.

A. This adjustment has been made to reflect weather normalized electric sales margins. KU proposed such an adjustment in Case No. 2008-00251. This adjustment was prepared by W. Steven Seelye and is discussed in his testimony.

Q. Please explain the adjustment to operating revenues and expenses shown in Reference Schedule 1.12 of Rives Exhibit 1.

A. This adjustment has been made to annualize revenues based on actual customers at October 31, 2009. The Commission approved a similar adjustment in Case No. 2003-00434, and LG&E proposed such an adjustment in Case No. 2008-00251. This adjustment was prepared by Mr. Seelye and is discussed in his testimony.

Q. Please explain the adjustment to operating revenues shown in Reference Schedule 1.13 of Rives Exhibit 1.

A. This adjustment reflects the change in revenue due to billing corrections and certain customers switching rates. KU's sister utility, LG&E, proposed such an adjustment in Case No. 2008-00252. Mr. Conroy prepared this adjustment and discusses it in his testimony.

Q. Please explain the adjustment to operating revenues shown in Reference Schedule 1.14 of Rives Exhibit 1.

A. In KU's most recent base rate case, Case No. 2008-00251, the Commission approved the implementation of a late payment charge for KU (LG&E has had such a charge for years). This adjustment annualizes the revenue impact of the late payment charge. Mr. Bellar prepared this adjustment and discusses it in his testimony.

Q. Please explain the adjustment to operating expenses shown in Reference Schedule 1.15 of Rives Exhibit 1.

A. This adjustment includes a full year's depreciation expense on net plant in service, excluding depreciation on assets set up for asset retirement obligations and depreciation on ECR assets, as of October, 31, 2009. The rates reflect KU's continued use of Average Service Life methodology and are the ones found reasonable by the Commission in its latest rate case, 2008-00251. This part of the adjustment was prepared by Ms. Charnas and is discussed in her testimony.

The remainder of this adjustment is to reflect the depreciation expense of KU's portion of the TC2 Construction Work In Progress ("CWIP") balance at the end of the test period. The depreciation rates used in this adjustment are those the

Companies proposed in Case No. 2009-00329 (supported in that case by the expert testimony of John Spanos and approved by the Commission on an interim basis through its order dated December 23, 2009), and the adjustment reflects the application of those rates to the CWIP balance as of the end of the test year associated with KU's portion of the TC2 assets because the unit will be in commercial operation before KU's proposed base rates go into effect.

TC2 represents a significant addition to KU's plant in service. The adjustment recognizes the known and measurable fixed cost associated with the commercialization of TC2 before the rates authorized in this case take effect. The TC2-related portions of this adjustment were prepared by Mr. Bellar and are discussed in his testimony.

Q. Please explain the adjustment to operating expenses shown in Reference Schedule 1.16 of Rives Exhibit 1.

A. This adjustment has been made to reflect increases in labor and labor-related costs as applied to the twelve months ended October 31, 2009, and includes specific adjustments for labor, payroll taxes, and KU's 401(k) contribution. The Commission approved a similar adjustment in Case Nos. 2003-00434 and 2000-00080, and LG&E proposed such an adjustment in Case No. 2008-00251. This adjustment was prepared by Ms. Scott and is discussed in her testimony.

Q. Please explain the adjustment to operating expenses shown in Reference Schedule 1.17 of Rives Exhibit 1.

A. This adjustment is necessary to annualize pension, post-retirement, and other post-employment benefit expenses. Amounts included in this adjustment will be updated when final 2010 expense calculations are received from Mercer in early 2010. The Commission approved a similar adjustment in Case Nos. 2003-00434 and 2000-00080, and KU proposed such an adjustment in Case No. 2008-00251. This adjustment was prepared by Ms. Scott and is discussed in her testimony.

Q. Please explain the adjustment to operating expenses shown in Reference Schedule 1.18 of Rives Exhibit 1.

A. The Company renews its property insurance policy on November 1 each year. The adjustment reflected on the schedule shows the increase in the insurance premium from the test year to the period of November 1, 2009, to October 31, 2010, which increase resulted from higher estimated replacement costs for the Company's facilities. Daniel K. Arbough prepared this adjustment and discusses it in his testimony.

Q. Please explain the adjustment to operating expenses shown in Reference Schedule 1.19 of Rives Exhibit 1.

A. The adjustment shown in Reference Schedule 1.19 reflects the cost of a new pollution liability policy the Company purchased effective November 2009. The policy is designed to protect against all types of pollution risks, but most notably the risk of ash pond failures similar to that experienced by the Tennessee Valley Authority ("TVA") in December 2008 at its Kingston Fossil Plant. Mr. Arbough prepared this adjustment and discusses it in his testimony.

Q. Please explain the adjustment to operating expenses shown in Reference Schedule 1.20 of Rives Exhibit 1.

A. This adjustment reflects the possible addition of a "Hazard Tree Program" to the Company's existing vegetation management regimen. The program is based upon a system-hardening study LG&E and KU commissioned following the 2008 Wind Storm and the 2009 Winter Storm. Mr. Bellar prepared this adjustment and discusses it in his testimony.

Q. Please explain the adjustment to operating expenses shown in Reference Schedule 1.21 of Rives Exhibit 1.

A. This adjustment has been made to reflect a normalized level of storm damage expenses based upon a ten-year average adjusted for inflation. KU proposed a similar adjustment in its most recent base rate case, Case No. 2008-00251 and a similar adjustment was also approved by the Commission in Case No. 2003-00434. Ms. Scott prepared this adjustment and discusses it in her testimony.

Q. Please explain the adjustment to operating expenses shown in Reference Schedule 1.22 of Rives Exhibit 1.

A. This adjustment is made to normalize the expense levels in Account 925 "Injuries and Damages." The Commission approved a similar adjustment in Case No. 2003-00434, and KU proposed such an adjustment in Case No. 2008-00251. This adjustment was prepared by Ms. Charnas and is discussed in her testimony.

Q. Please explain the adjustment to operating expenses shown in Reference Schedule 1.23 of Rives Exhibit 1.

A. This adjustment eliminates advertising expenses pursuant to 807 KAR 5:016 that are primarily institutional and promotional in nature. The Commission approved a similar adjustment in Case No. 2003-00434, and KU proposed such an adjustment in Case No. 2008-00251. This adjustment was prepared by Ms. Charnas, and is discussed in her testimony.

Q. Please explain the adjustment to operating expenses shown in Reference Schedule 1.24 of Rives Exhibit 1.

A. This adjustment is necessary to exclude the expenses incurred in the test year associated with the Company's mainframe, which was retired in November 2009. Ms. Charnas prepared this adjustment and discusses it in her testimony.

Q. Please explain the adjustment to operating expenses shown in Reference Schedule 1.25 of Rives Exhibit 1.

A. This adjustment concerns a remaining component of the Companies' withdrawal from the Midwest Independent Transmission System Operator, Inc. ("MISO"), which withdrawal the Commission authorized in Case No. 2003-00266. In its February 5, 2009 Order in KU's most recent base rate case, Case No. 2008-00251, the Commission authorized KU to defer any post-April 30, 2008 revenues related to MISO Schedule 10 expenses, as well as future adjustments to the MISO exit fee, as regulatory liabilities to be amortized in a future rate case. This is that "future rate case," which is why KU is proposing this adjustment. It was prepared by Ms. Scott and is discussed in her testimony.

Q. **Please explain the adjustment to operating expenses shown in Reference Schedule 1.26 of Rives Exhibit 1.**

A. In Case No. 2008-00251, the Commission authorized the creation of a regulatory asset for the costs associated with the transmission depancaking settlement agreement between the Companies and East Kentucky Power Cooperative, Inc. The Commission further approved a five-year amortization of the asset, to begin in March 2009; this adjustment annualizes that amortization. This adjustment was prepared by Ms. Scott and is discussed in her testimony.

Q. **Please explain the adjustment to operating expenses shown in Reference Schedule 1.27 of Rives Exhibit 1.**

A. This adjustment is necessary to recover the expenses KU incurred as a result of the windstorm that occurred in September 2008. The Commission approved the establishment of a regulatory asset with regard to these expenses in Case No. 2008-00457. Ms. Scott prepared the adjustment and discusses it in her testimony.

Q. **Please explain the adjustment to operating expenses shown in Reference Schedule 1.28 of Rives Exhibit 1.**

A. This adjustment is necessary to recover the expenses KU incurred as result of the winter storm that occurred in January and February 2009. The Commission approved the establishment of a regulatory asset with regard to these expenses in Case No. 2009-00174. Ms. Scott prepared the adjustment and discusses it in her testimony.

Q. Please explain the adjustment to operating expenses shown in Reference Schedule 1.29 of Rives Exhibit 1.

A. This adjustment is necessary to recover the costs of KU's investment in the Kentucky Consortium for Carbon Storage. The Commission approved the establishment of a regulatory asset with regard to this investment in Case No. 2008-00308. KU proposes to amortize this regulatory asset over a period of four years, which corresponds to the duration of the project. Mr. Bellar prepared this adjustment and discusses it in his testimony.

Q. Please explain the adjustment to operating expenses shown in Reference Schedule 1.30 of Rives Exhibit 1.

A. This adjustment is necessary to recover the costs of KU's investment in the Carbon Management Resource Group. The Commission approved the establishment of a regulatory asset with regard to this investment in Case No. 2008-00308. KU proposes to amortize this regulatory asset over a period of ten years, which corresponds to the duration of the project. Mr. Bellar prepared this adjustment and discusses it in his testimony.

Q. Please explain the adjustment to operating expenses shown in Reference Schedule 1.31 of Rives Exhibit 1.

A. This adjustment has two components. The first is necessary to include amortization of the expenses incurred in conjunction with this base rate case; the second annualizes the amortization of the 2008 rate case costs. The Commission approved a similar adjustment in Case Nos. 2003-00434 and 2000-00080, and KU proposed such an adjustment in Case No. 2008-00251. This adjustment was prepared by Ms. Charnas and is discussed in her testimony.

Q. Please explain the adjustment to operating expenses shown in Reference Schedule 1.32 of Rives Exhibit 1.

A. The Companies recently made a $2.27 million one-time payment to the Southwest Power Pool, Inc. ("SPP") under a recent settlement agreement concerning SPP's provision of Independent Transmission Organization services to the Companies. KU's portion of the settlement expense was $1,452,783. This adjustment removes the portion of the settlement amount that does not relate to test-year operating expenses. Mr. Bellar prepared this adjustment and discusses it in his testimony.

Q. Please explain the adjustment to operating expenses shown in Reference Schedule 1.33 of Rives Exhibit 1.

A. This adjustment is to remove from operating expenses the costs incurred as a result of resettlements related to the MISO Revenue Sufficiency Guarantee ("RSG"). This adjustment is necessary to remove from operating expenses the amount KU had paid to the MISO during the test year that relates to prior period's transactions. Ms. Scott prepared this adjustment and discusses it in her testimony.

Q. Please explain the adjustment to operating expenses shown in Reference Schedule 1.34 of Exhibit 1.

A. The adjustment removes the expense associated with the cost of the Owensboro Municipal Utilities ("OMU") contract in the test year. OMU terminated the contract effective May 2010. Mr. Bellar prepared this adjustment and discusses it in his testimony.

Q. Please explain the adjustment to operating expenses shown in Reference Schedule 1.35 of Rives Exhibit 1.

A. This adjustment is to remove from operating income the amount collected from the OMU litigation settlement. While litigation with OMU was ongoing, OMU did not pay certain amounts as required under its contract with KU. This adjustment is necessary to reflect reversal of the uncollectible account expense that the settlement effectively paid. Ms. Scott prepared this adjustment and discusses it in her testimony.

Q. Please explain the adjustment to operating expenses shown in Reference Schedule 1.36 of Rives Exhibit 1.

A. KU had an agreement with Dynegy Power Marketing, Inc., to purchase unit firm capacity and an exclusive call option for the energy from Unit 1 at the Bluegrass Generating Station in Oldham County, Kentucky. The agreement expired in August 2009. This adjustment therefore removes from the test year the expense associated with the Dynegy contract. Mr. Bellar prepared this adjustment and discusses it in his testimony.

Q. Please explain the adjustment to operating expenses shown in Reference Schedule 1.37 of Rives Exhibit 1.

A. This adjustment is to remove the amortization expense related to the regulatory asset that the Commission approved in Case No. 2003-00434 for the restoration expenses associated with the 2003 Ice Storm, which regulatory asset KU has now fully amortized. Ms. Scott prepared this adjustment and discusses it in her testimony.

Q. Please explain the adjustment to operating expenses shown in Reference Schedule 1.38 of Rives Exhibit 1.

A. Reference Schedule 1.38 contains three adjustments: the first removes the Kentucky coal credit received by the Company during the test year and applied to property tax expense; the second reduces property tax expense due to a lower property value assessment approved by the Kentucky Department of Revenue; and the third increases property tax expense associated with assets KU purchased from LG&E related to their respective ownership shares in TC2. Ronald L. Miller prepared these adjustments and discusses them in his testimony.

Q. Please explain the calculation shown in Reference Schedule 1.41 of Rives Exhibit 1.

A. Reference Schedule 1.41 shows the calculation of KU's composite federal and state income tax rate. The method for calculating the composite tax rate KU uses in this schedule is similar to the method KU used its most recent base rate case, Case No. 2008-00251, and to the method the Commission approved in Case No. 2003-00434. This schedule was prepared by Mr. Miller and is discussed in his testimony.

Q. Please explain the adjustment to operating expenses shown in Reference Schedule 1.42 of Rives Exhibit 1.

A. This adjustment is for federal and state income taxes corresponding to the annualization and adjustment of year-end interest expense. The Commission has traditionally recognized the income tax effects of adjustments to interest expense through an interest synchronization adjustment. The Commission approved a similar adjustment in Case Nos. 2003-00434 and 2000-00080, and KU proposed such an adjustment in Case No. 2008-00251. This adjustment was prepared by Mr. Miller and is discussed in his testimony.

Q. **Please explain the adjustment to operating expenses shown in Reference Schedule 1.43 of Rives Exhibit 1.**

A. This adjustment is for income tax true-ups and adjustments made during the test year that relate to prior periods. The Commission approved a similar adjustment in Case No. 2003-00434, and KU proposed such an adjustment in Case No. 2008-00251. This adjustment was prepared by Mr. Miller and is discussed in his testimony.

Q. **Please explain the adjustment to operating expenses shown in Reference Schedule 1.44 of Rives Exhibit 1.**

A. This adjustment restates test-year income tax expenses for the production activities deduction. The production activities deduction statutory rate in effect for the test year was 6%; however the rate will increase to 9% in calendar year 2010. This adjustment calculates the deduction based on the test year taxable income at the new 9% rate. Mr. Miller prepared this adjustment and discusses it in his testimony.

Q. **Please explain the adjustment to operating expenses shown in Reference Schedule 1.45 of Exhibit 1.**

A. This adjustment relates to the annual amount of the permanent reduction in depreciable tax basis required by the Internal Revenue Code and attributable to the Advanced Coal Investment Tax Credit awarded to KU and LG&E for TC2. Mr. Miller prepared this adjustment and discusses it in his testimony.

Capitalization and Weighted Average Cost of Capital

Q. Have you prepared an exhibit showing KU's capitalization as of October 31, 2009?

A. Yes. Rives Exhibit 2 shows KU's capitalization at October 31, 2009, for electric operations. Mr. Arbough, Treasurer for KU, presents testimony on KU's current and target capitalizations, as well as on relevant bond financing issues.

Q. Can you explain what is contained in Rives Exhibit 2?

A. Yes. Rives Exhibit 2 shows the calculation of KU's adjusted capitalization for electric operations as of October 31, 2009, as well as the weighted average cost of capital to apply to the adjusted capitalization. As indicated on Rives Exhibit 2, the requested rate of return on electric capitalization as of October 31, 2009, is 8.32 percent, based on the proposed 11.5 percent return on common equity.

Q. Please explain the calculation of the capitalization on Rives Exhibit 2.

A. Column 1 of Rives Exhibit 2 contains the components of capitalization as recorded on the Company's books and records as of the end of the test year, October 31, 2009. Column 2 of Rives Exhibit 2 calculates the relative capitalization percentages of each component of capitalization to the total capitalization (e.g., line 1, column 1 divided by line 4, column 1 equals line 1, column 2). Columns 3 through 6 are adjustments to capitalization that are totaled (with column 3) in column 7 of Rives Exhibit 2. These four adjustments are to show the increase in capitalization associated with the Joint Use Assets LG&E transferred to KU in December 2009, which I describe more fully below; and to remove undistributed subsidiary earnings, KU's equity investment in Electric Energy Inc., KU's investment in Ohio Valley Electric Corporation, and other investments consistent with the adjustments approved in the Commission's Order in

Case No. 2003-00434 and proposed by KU in Case No. 2008-00251. Column 8 calculates adjusted total company capitalization by adding the capitalization adjustments in Column 7 to Column 1. Column 9 of Exhibit 2 contains the allocation factor to jurisdictionalize KU's Kentucky capitalization. The factor in column 9 was calculated based on net original cost rate base as shown on Rives Exhibit 3. Column 10 calculates the relative Kentucky jurisdictional capitalization components by multiplying column 8 by the factor in column 9. Column 11 calculates the relative capitalization percentages of each component of capitalization to the total capitalization (e.g., line 1, column 10 divided by line 4, column 10 equals line 1, column 11). Column 12 removes KU's ECR rate base, as more fully explained below, which is reflected in column 13, the Adjusted Kentucky Jurisdictional Capitalization. Each row of column 16, the Cost of Capital, is the product of the corresponding rows of columns 14, the Adjusted Capital Structure, and column 15, the Annual Cost Rate of each source of capital.

Q. Has KU ensured that its subsidiary earnings, deferred taxes associated with those earnings, and non-utility property have been properly accounted for in Exhibit 2?

A. Yes. In a manner consistent with its response to the Attorney General's first data request (dated August 27, 2008), Question 34 in Case No. 2008-00251, KU has ensured that: (1) its equity in its subsidiary earnings have been deducted from capitalization only once; (2) its equity in its subsidiary earnings have been adjusted by the amount of deferred taxes associated with those earnings; and (3) its capitalization has been reduced by the amount of its non-utility property. These are reflected in KU's adjustments to capitalization related to subsidiaries, Columns 4-6.

Q. Please explain the adjustment made in Column 3 of Rives Exhibit 2, "Trimble County Joint Use Assets Transfer."

A. As described in the Companies' July 30, 2009 letter to the Commission's Executive Director, in December 2009, LG&E transferred to KU an undivided ownership interest in certain assets at the Trimble County Generating Station necessary to the operation of Trimble County Unit No. 2 ("TC2 Joint Use Assets"), in which unit KU owns 81% of the Companies' collective 75% ownership share. The net book value of the assets transferred was $48.4 million. This adjustment accordingly increases short-term debt, long-term debt, and common equity by the corresponding amounts. Ms. Charnas discusses this adjustment to capitalization more fully in her testimony.

Q. Does Rives Exhibit 2 contain an adjustment to capitalization to remove the ECR amounts?

A. Yes. In Column 12, the environmental surcharge rate base is removed from capitalization using the methodology the Commission approved in Case Nos. 1998-00474 and 2003-00434. Removing the environmental surcharge rate base from the capital structure is necessary because KU is recovering a return on its investment through the environmental surcharge. The amount of ECR rate base removed from capitalization in Column 12 has had deferred taxes and income tax credits deducted from it. As discussed in Mr. Conroy's testimony, the amount of ECR rate base removed also reflects the elimination of the 2001 and 2003 ECR Plans from KU's monthly ECR filings.

Q. Please explain how the weighted average cost of capital is calculated on Rives Exhibit 2.

A. Column 14 (Adjusted Capital Structure) of Rives Exhibit 2 calculates the respective capitalization percentages for the components of adjusted capitalization from column 13 (e.g., line 1, column 13 divided by line 4, column 13 equals line 1, column 14). Column 15 (Annual Cost Rate) includes the embedded costs of the components of capital, including the proposed return on equity. The annual rate used for Short Term Debt is the actual rate as of October 31, 2009. The annual cost rate for Long Term Debt is the embedded cost of the outstanding pollution control bonds and inter-company loans outstanding as of October 31, 2009. The inter-company loans were first approved by the Commission in its April 30, 2003 Order in Case No. 2003-00059. The Commission has subsequently approved the Company's requests for additional inter-company loans in numerous financing cases. The cost of equity is the amount recommended by Dr. Avera and supported in his testimony. Column 16 then calculates the weighted average cost of capital by multiplying column 14 by column 15, resulting in 8.32 percent.

Property Valuation

Q. What are the property valuation measures to be considered by the Commission for ratemaking purposes?

A. Section 278.290 of the Kentucky Revised Statutes requires the Commission to give due consideration to three quantifiable values: original cost, cost of reproduction as a going concern and capital structure. The Commission is also required to consider the history and development of the utility and its property and other elements of value long recognized for ratemaking purposes.

Q. Have you prepared an exhibit showing KU's net original cost rate base as of October 31, 2009?

A. Yes. Page 1 of Rives Exhibit 3 shows KU's net original cost rate base at October 31, 2009. Page 2 of Rives Exhibit 3 shows the calculation of the allowance for cash working capital. The 45-day (1/8) methodology was used in computing the allowance for cash working capital.

Q. Please explain rows 8 and 9 of Rives Exhibit 3, Page 1 concerning asset retirement obligation net assets and regulatory liabilities.

A. In Case No. 2003-00427, the Commission issued an order on December 23, 2003, approving a stipulation between KU and the intervenors in that proceeding, which stipulation requested the Commission's approval for:

> 1) Approving the regulatory assets and liabilities associated with adopting SFAS No. 143 and going forward;[1]
>
> 2) Eliminating the impact on net operating income in the 2003 ESM annual filing caused by adopting SFAS No. 143;
>
> 3) To the extent accumulated depreciation related to the cost of removal is recorded in regulatory assets or regulatory liabilities, reclassifying such amounts to accumulated depreciation for rate-making purposes of calculating rate base; and
>
> 4) Excluding from rate base the ARO [Asset Retirement Obligation] assets, related ARO asset accumulated depreciation, ARO liabilities, and remaining regulatory assets associated with the adoption of SFAS No. 143.[2]

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[1] The Financial Accounting Standards Board, which promulgates the U.S. Generally Accepted Accounting Principles, has renamed SFAS No. 143; it is now Accounting Standards Codification ("ASC") 410-20.

[2] *In the Matter of Application of Kentucky Utilities Company for an Order Approving an Accounting Adjustment to be Included in Earnings Sharing Mechanism Calculations for 2003,* Case No. 2003-00427, Order at 3 (December 23, 2003).

In Case No. 2003-00434, KU excluded ARO assets from rate base.[3] The Commission approved the exclusion in its June 30, 2004 Order in that proceeding.[4] KU proposed a similar adjustment in its most recent base rate case, Case No. 2008-00251.

Consistent with the approach described by the Commission's orders cited above and its past approach to ARO assets in its most recent base rate case, in this application KU is excluding the ARO-related net assets and regulatory liabilities as shown in rows 8 and 9 of Rives Exhibit 3, Page 1.

Q. Please explain the adjustment made in row 10 of Rives Exhibit 3, Page 1, "Investment Tax Credit."

A. As approved in the Commission's order in Case No. 2007-00178, it is proper for KU to exclude from rate base the amount of investment tax credits it receives.[5] The deduction from rate base associated with the investment tax credits KU has received is shown in row 10 of Rives Exhibit 3, Page 1.

Q. Have you prepared an exhibit showing KU's pro forma rate base as of October 31, 2009?

A. Yes. Rives Exhibit 4 shows KU's pro forma rate base as of October 31, 2009. This exhibit reflects the adjustments I previously described in connection with Exhibit 2 concerning the environmental surcharge rate base and Trimble County joint use assets transfer adjustments. In addition, the rate base impact of the annualized depreciation expense adjustment and cash working capital amount associated with the operations

[3] *In the Matter of an Adjustment of the Electric Rates, Terms, and Conditions of Kentucky Utilities Company*, Case No. 2003-00434, KU Response No. 38 to Commission Staff's Third Set of Data Requests (March 11, 2004).
[4] *In the Matter of an Adjustment of the Electric Rates, Terms, and Conditions of Kentucky Utilities Company*, Case No. 2003-00434, Order at 21 (June 30, 2004).
[5] *In the Matter of Application of Kentucky Utilities Company for an Order Authorizing Inclusion of Investment Tax Credits in Calculation of Environmental Surcharge and Declaring Appropriate Rate-Making Methods for Base Rates*, Case No. 2007-00178, Order at 6-7 (September 7, 2007).

and maintenance expense adjustments are reflected. This exhibit also contains the adjustments I previously described in connection with Rives Exhibit 3 concerning the asset retirement obligation items and the investment tax credit.

Q. Have you prepared an exhibit showing KU's estimated net reproduction cost rate base as of October 31, 2009?

A. Yes. The estimated net reproduction cost rate base at October 31, 2009, is shown on Rives Exhibit 5. The calculation of the reproduction cost of plant less depreciation used in developing the reproduction cost rate base shown in Rives Exhibit 5 was calculated under my supervision and is shown on Rives Exhibit 6.

Q. Please explain Rives Exhibit 6.

A. Rives Exhibit 6 shows KU's estimated reproduction (or current) cost of utility plant and the applicable accumulated depreciation on the reproduction cost of utility plant as of October 31, 2009. The net estimated reproduction cost at October 31, 2009, is approximately $2.9 billion greater, on a total company basis, than the net original historical cost as recorded on KU's books. The current costs were determined principally by indexing the surviving plant and equity using the Handy-Whitman Index of Public Utility Construction Costs and the Consumer Price Index.

Q. Have you prepared an exhibit showing the calculation of the actual and proposed rate of return on net original cost rate base, pro forma rate base, and reproduction cost rate base for the twelve months ended October 31, 2009?

A. Yes. Rives Exhibit 7 shows the actual electric rate of return earned for the twelve months ended October 31, 2009, was 6.03 percent on jurisdictional net original cost rate base, 6.19 percent on jurisdictional pro forma rate base, and 3.31 percent on jurisdictional reproduction cost rate base. Using the adjusted net operating income from Rives Exhibit 1 and the revenue increase in the application, results in a requested rate of return of 8.03 percent on jurisdictional net original cost rate base, 8.25 percent on jurisdictional pro forma rate base, and 4.41 percent on jurisdictional reproduction cost rate base.

Q. **Have you prepared an exhibit showing the calculation of the overall revenue deficiency at October 31, 2009 for KU?**

A. Yes. Rives Exhibit 8 shows the calculation of the revenue deficiency at October 31, 2009 for KU to be $135,285,293.

Q. **Have you prepared an exhibit showing the calculation of Kentucky jurisdictional rate of return on common equity for the twelve months ended October 31, 2009?**

A. Yes. Rives Exhibit 9 shows the return for KU's Kentucky retail jurisdictional electric operations for the twelve months ended October 31, 2009, is 5.54 percent, including a 6.33 percent return on common equity.

Q. **What is KU's recommendation for the Commission in this proceeding?**

A. Kentucky Utilities Company recommends the Commission approve the recovery of the revenue deficiency of $135,285,293 through the proposed changes in electric base rates.

Q. **Does this conclude your testimony?**

A. Yes.

VERIFICATION

COMMONWEALTH OF KENTUCKY)
) SS:
COUNTY OF JEFFERSON)

The undersigned, **S. Bradford Rives**, being duly sworn, deposes and says that he is Chief Financial Officer for Kentucky Utilities Company and an employee of E.ON U.S. Services, Inc., and that he has personal knowledge of the matters set forth in the foregoing testimony, and that the answers contained therein are true and correct to the best of his information, knowledge and belief.

S B Rives

S. Bradford Rives

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 22nd day of January 2010.

Tammy J. Elzy (SEAL)
Notary Public

My Commission Expires:

November 9, 2010

APPENDIX A

S. Bradford Rives
Chief Financial Officer
E.ON U.S. LLC
220 West Main Street
Louisville, Kentucky 40202
(502) 627-3990

Civic Activities

FM Global – Advisory Board
Lincoln Heritage Council, Boy Scouts of America – Executive Board and Treasurer
Metro United Way of Louisville Board of Directors
National Kidney Foundation of Kentucky – Chair of National Kidney Foundation Golf Classic
St. Xavier High School Board of Directors
University of Louisville Business School Advisory Board

Professional/Trade Memberships

American Institute of Certified Public Accountants (AICPA)
Financial Executives Institute
Kentucky Bar Association
Kentucky Society of Certified Public Accountants
Louisville Bar Association

Education

University of Louisville School of Law, J.D. (cum laude) -- 1988
University of Kentucky, B.S. in Accounting -- 1980

Previous Positions

E.ON U.S. LLC (formerly LG&E Energy Corp.), Louisville, KY

Dec 2000 – Sep 2003, Senior Vice President, Finance and Controller
Feb 1999 – Dec 2000 – Senior Vice President, Finance and Business Development
Mar 1996 – Feb 1999 – Vice President, Finance and Controller
Jan 1996 – Mar 1996 – Vice President, Finance, Non Utility Business
Mar 1995 – Dec 1995 – Vice President, Controller and Treasurer (LG&E Power)
Jun 1994 – Mar 1995 – Vice President and Treasurer (LG&E Power)
Jan 1994 – Jun 1994 – Associate General Counsel
Jan 1993 – Dec 1993 – Director, Business Development
Feb 1992 – Dec 1992 – Assistant Treasurer
Oct 1991 – Feb 1992 – Director, Corporate Finance

Louisville Gas and Electric Company, Louisville, KY
1990-1991 – Director, Corporate Finance
1989-1990 – Director, Corporate Tax
1985-1989 – Manager, Tax Accounting
1983-1985 – Assistant Manager, Tax Accounting

Arthur Andersen and Company, Louisville, KY
1982-1983 – Audit Senior
1980-1982 – Audit Staff

KENTUCKY UTILITIES

Adjustments to Operating Revenues, Operating Expenses and Net Operating Income
For the Twelve Months Ended October 31, 2009

	Reference Schedule (1)	Operating Revenues (2)	Operating Expenses (3)	Net Operating Income (4)
1. Jurisdictional amount per books		1,221,660,614	1,030,540,469	$ 191,120,145
2. Adjustments for known changes and to eliminate unrepresentative conditions:				
3. Adjustment to eliminate unbilled revenues	1.00	(3,744,529)	-	(3,744,529)
4. Adjustment to eliminate Merger Surcredit	1.01	2,800,345	-	2,800,345
5. Adjustment to eliminate Value Delivery Surcredit	1.02	42	-	42
6. To adjust mismatch in fuel cost recovery	1.03	(49,848,679)	(42,231,035)	(7,617,644)
7. To adjust base rates and FAC to reflect a full year of the base rate change and FAC roll-in	1.04	(3,710,701)	-	(3,710,701)
8. Adjustment to eliminate Environmental Surcharge revenues and expenses	1.05	(92,924,384)	(30,936,828)	(61,987,556)
9. To adjust base rate revenues and expenses to reflect a full year of the ECR roll-in	1.06	87,584,103	22,359,078	65,225,025
10. Off-system sales revenue adjustment for the ECR calculation	1.07	(3,722,927)	-	(3,722,927)
11. To eliminate net brokered and financial swap revenues and expenses	1.08	(256,817)	(6,096)	(250,721)
12. To eliminate ECR, MSR, FAC, and DSM accruals	1.09	283,654	-	283,654
13. To eliminate DSM revenue and expenses	1.10	(12,940,085)	(7,500,349)	(5,439,736)
14. To reflect weather normalized electric sales margins	1.11	2,986,579	1,489,506	1,497,073
15. Adjustment to annualize year-end customers	1.12	9,724,872	5,885,824	3,839,048
16. To adjust for customer billing corrections and rate switching	1.13	(186,358)	-	(186,358)
17. Adjustment to revenues for late payment charge	1.14	3,141,664	-	3,141,664
18. Adjustment to reflect annualized depreciation expenses	1.15	-	19,212,820	(19,212,820)
19. Adjustment to reflect increases in labor and labor related costs	1.16	-	784,464	(784,464)
20. Adjustment for pension, post retirement, and post employment costs	1.17	-	(139,829)	139,829
21. Adjustment to reflect the increase in property insurance expense	1.18	-	373,107	(373,107)
22. Adjustment to reflect new pollution liability insurance expense	1.19	-	574,164	(574,164)
23. Adjustment for hazard tree program	1.20	-	3,791,496	(3,791,496)
24. Adjustment to reflect normalized storm damage expense	1.21	-	(1,267,873)	1,267,873

KENTUCKY UTILITIES

Adjustments to Operating Revenues, Operating Expenses and Net Operating Income
For the Twelve Months Ended October 31, 2009

	Reference Schedule (1)	Operating Revenues (2)	Operating Expenses (3)	Net Operating Income (4)
25. Adjustment for injuries and damages FERC account 925	1.22	-	200,710	(200,710)
26. Adjustment to eliminate advertising expenses pursuant to Commission Rule 807 KAR 5:016	1.23	-	(799,431)	799,431
27. Adjustment for expenses related to retired mainframe	1.24	-	(843,623)	843,623
28. Adjustment for MISO Exit Fee regulatory asset	1.25	-	(83,909)	83,909
29. Adjustment for EKPC regulatory asset	1.26	-	1,785,051	(1,785,051)
30. Adjustment for 2008 Wind storm regulatory asset	1.27	-	2,454,286	(2,454,286)
31. Adjustment for 2009 Winter storm regulatory asset	1.28	-	11,447,352	(11,447,352)
32. Adjustment for KCCS regulatory asset	1.29	-	360,504	(360,504)
33. Adjustment for CMRG regulatory asset	1.30	-	1,940	(1,940)
34. Adjustment to reflect amortization of rate case expenses	1.31	-	595,187	(595,187)
35. Adjustment for Southwest Power Pool settlement expenses	1.32	-	(896,454)	896,454
36. Adjustment to remove out of period adjustment for resettlements related to MISO RSG	1.33	-	(510,123)	510,123
37. Adjustment to reflect expiration of OMU contract	1.34	-	(15,673,235)	15,673,235
38. Adjustment for reversal of OMU uncollectible account expense	1.35	-	1,754,505	(1,754,505)
39. Adjustment to remove reserve margin demand purchases	1.36	-	(1,339,238)	1,339,238
40. Adjustment to expenses for 2003 Ice storm amortization	1.37	-	(527,718)	527,718
41. To adjust property tax expense	1.38	-	1,199,643	(1,199,643)
42. These adjustments left intentionally blank	1.39 - 1.40			
43. Total of above adjustments		(60,813,222)	(28,486,104)	(32,327,118)

KENTUCKY UTILITIES

Adjustments to Operating Revenues, Operating Expenses and Net Operating Income
For the Twelve Months Ended October 31, 2009

		Reference Schedule (1)	Operating Revenues (2)	Operating Expenses (3)	Net Operating Income (4)
44. Federal and state income taxes corresponding to base revenue and expense adjustments and above adjustments -	36.9264 %	1.41		(11,937,234)	11,937,234
45. Federal and state income taxes corresponding to annualization and adjustment of year-end interest expense		1.42		(548,031)	548,031
46. Prior income tax true-ups and adjustments		1.43		1,126,171	(1,126,171)
47. Adjustment for domestic production activities deduction		1.44		(457,757)	457,757
48. Adjustment for tax basis depreciation reduction		1.45		1,442,607	(1,442,607)
49. This adjustment left intentionally blank		1.46			
50. Total adjustments			(60,813,222)	(38,860,348)	(21,952,874)
51. Adjusted Net Operating Income			1,160,847,392	991,680,121	$ 169,167,271

Exhibit 1
Reference Schedule 1.00
Sponsoring Witness: Bellar

KENTUCKY UTILITIES

Adjustment to Eliminate Unbilled Revenues

1. Unbilled revenues at October 31, 2008	$	50,124,000
2. Unbilled revenues at October 31, 2009		(53,868,529)
3. Decrease in book revenues due to unbilled revenues	$	(3,744,529)

Exhibit 1
Reference Schedule 1.01
Sponsoring Witness: Bellar

KENTUCKY UTILITIES

Adjustment to Eliminate Merger Surcredit
For the Twelve Months Ended October 31, 2009

1. Actual Merger Surcredit refunded	$ (2,800,345)
2. Merger Surcredit revenue adjustment	$ 2,800,345

Exhibit 1
Reference Schedule 1.02
Sponsoring Witness: Bellar

KENTUCKY UTILITIES

Adjustment to Eliminate Value Delivery Surcredit
For the Twelve Months Ended October 31, 2009

1. Actual Value Delivery Surcredit and ESM refunded	$	(42)
2. Value Delivery Surcredit revenue adjustment	$	42

Exhibit 1
Reference Schedule 1.03
Sponsoring Witness: Conroy

KENTUCKY UTILITIES

To Adjust Mismatch in Fuel Cost Recovery
For the Twelve Months Ended October 31, 2009

Expense Month	Revenue Form A Page 5 of 6 Line 3	Expense Form A* Page 5 of 6 Line 8
Nov-08	7,161,750	3,457,004
Dec-08	2,617,813	6,620,436
Jan-09	4,080,402	5,529,020
Feb-09	6,594,389	8,560,589
Mar-09	4,237,573	5,358,776
Apr-09	8,186,876	2,729,326
May-09	4,611,651	(1,175,992)
Jun-09	3,221,469	5,255,165
Jul-09	(1,124,681)	1,869,873
Aug-09	5,934,903	2,946,059
Sep-09	1,735,424	872,983
Oct-09	2,591,110	207,796
Total	$ 49,848,679	$ 42,231,035
Adjustment	$ (49,848,679)	$ (42,231,035)

* NOTE : Expenses are recovered in the second succeeding month. For example, January 2009 would be reflected in March 2009.

Exhibit 1
Reference Schedule 1.04
Sponsoring Witness: Conroy

KENTUCKY UTILITIES

To Adjust Base Rates and FAC to Reflect a Full Year of the Base Rate Change and FAC Roll-In
For the Twelve Months Ended October 31, 2009

1. Adjustment to base rate revenues to reflect a full year of the Base Rate Case (1)	$	(4,290,974)
2. Adjustment to base rate revenues to reflect a full year of the FAC Roll-In (2)		19,182,666
3. Adjustment to FAC revenues to reflect a full year of the FAC roll-in (2)		(18,602,393)
4. Net adjustment	$	(3,710,701)

(1) Base rates pursuant to Commission's Order dated February 5, 2009 in Case No. 2008-00251.
(2) FAC roll-in pursuant to Commission's Order dated June 3, 2009 in Case No. 2008-00520.

Exhibit 1
Reference Schedule 1.05
Sponsoring Witness: Conroy

KENTUCKY UTILITIES

Adjustment to Eliminate Environmental Surcharge Revenues and Expenses
For the Twelve Months Ended October 31, 2009

Expense Month	Revenues Environmental Compliance Plans (1)	Expenses Environmental Compliance Plans (2)	Expenses Eliminate '01 & '03 Plans	Net (Col. 1 - 2 - 3)
Nov-08	$ 5,235,307	$ 3,244,938	$ (640,504)	
Dec-08	6,771,154	3,768,559	(921,761)	
Jan-09	7,615,494	3,638,786	(742,696)	
Feb-09	6,688,271	2,778,893	(838,239)	
Mar-09	5,529,205	3,353,094	(847,266)	
Apr-09	5,801,057	3,796,462	(833,003)	
May-09	6,846,073	3,784,709	(906,790)	
Jun-09	9,264,170	3,886,965	(767,336)	
Jul-09	9,580,287	3,773,914	(808,842)	
Aug-09	8,912,825	5,063,328	(779,079)	
Sep-09	10,484,635	4,072,334	(847,471)	
Oct-09	10,195,905	4,116,193	(821,548)	
	$ 92,924,384	$ 45,278,175	$ (9,754,534)	
Kentucky Jurisdiction (Ref. Sch. Allocators)		87.088%	87.088%	
Total	$ 92,924,384	$ 39,431,857	$ (8,495,029)	$ 61,987,556
Adjustment	$ (92,924,384)	$ (39,431,857)	$ 8,495,029	$ (61,987,556)

(1) ES Form 3.00, Column 6.

(2) ES Form 2.00, Total Pollution Control Operations Expense less Proceeds from By-Product and Allowance Sales. August 2009 Expenses include prior period adjustment as shown on Attachments 1 and 2 of the monthly filing.

Exhibit 1
Reference Schedule 1.06
Sponsoring Witness: Conroy

KENTUCKY UTILITIES

To Adjust Base Rate Revenues and Expenses to Reflect a Full Year of the ECR Roll-In
For the Twelve Months Ended October 31, 2009

1. Adjustment to base rate revenues to reflect a full year of the ECR roll-in	$	87,584,103
2. Adjustment to expenses to reflect a full year of the ECR roll-in (1)	$	22,359,078

(1) Only reflects ECR plan amounts which will continue after effective date of new base rates in this proceeding.

NOTE: ECR Roll-in pursuant to Commission's Order dated December 2, 2009 in Case No. 2009-00310.

Determination of Expenses Roll-In (Attachment to Response to Question No. 6 (a)(c)):		
a. Total Pollution Control Operating Expenses	$	34,445,958
b. Less Total Pollution Control Operating Expenses '01 & '03 Plans		(9,072,379)
c. Less Gross Proceeds from By-Product & Allowance Sales		300,541
d. Total Expenses Roll-In excluding '01 & '03 Plans	$	25,674,120
e. Kentucky Jurisdiction (Ref. Sch. Allocators)		87.088%
f. Adjustment	$	22,359,078

Exhibit 1
Reference Schedule 1.07
Sponsoring Witness: Conroy

KENTUCKY UTILITIES

Off-System Sales Revenue Adjustment for the ECR Calculation
For the Twelve Months Ended October 31, 2009

	(1)	(2)	(3)	(4)
	KU Off-System Sales Revenue	Monthly Environmental Surcharge Factor (1)	Average Environmental Surcharge Factor	Off-System Sales Environmental Cost (Col. 1 * 3)
Nov-08	$ 16,763,550	7.38%	9.52%	$ 1,595,890
Dec-08	10,407,202	6.50%	9.52%	990,766
Jan-09	4,800,653	6.54%	9.52%	457,022
Feb-09	2,308,018	6.52%	9.52%	219,723
Mar-09	2,365,975	9.27%	9.52%	225,241
Apr-09	1,258,387	9.89%	9.52%	119,798
May-09	3,233,654	11.69%	9.52%	307,844
Jun-09	706,503	9.68%	9.52%	67,259
Jul-09	286,233	11.58%	9.52%	27,249
Aug-09	336,928	11.94%	9.52%	32,076
Sep-09	335,449	11.20%	9.52%	31,935
Oct-09	2,310,656	12.03%	9.52%	219,974
Total	$ 45,113,208			$ 4,294,777
Average		9.52%		
Kentucky Jurisdiction (Ref. Sch. Allocators)				86.685%
Total				$ 3,722,927
Adjustment				$ (3,722,927)

(1) ES Form 1.00

Exhibit 1
Reference Schedule 1.08
Sponsoring Witness: Scott

KENTUCKY UTILITIES

To Eliminate Net Brokered and Financial Swap Revenues and Expenses
For the Twelve Months Ended October 31, 2009

1. Brokered and Financial Swap Revenues	$	380,466	
2. Brokered and Financial Swap Expenses recorded in revenues		84,202	
3. Net Brokered and Financial Swap Revenues		296,264	
4. Kentucky Jurisdiction (Ref. Sch. Allocators)		86.685%	
5. Kentucky Jurisdiction Net Brokered and Financial Swap Revenues	$	256,817	
6. Kentucky Jurisdiction Net Brokered and Financial Swap Revenues adjustment	$	(256,817)	
7. Operating Expenses related to Brokered and Financial Swap		7,032	*
8. Kentucky Jurisdiction (Ref. Sch. Allocators)		86.685%	
9. Kentucky Jurisdiction Brokered and Financial Swap Operating Expenses	$	6,096	
10. Kentucky Jurisdiction Net Brokered and Financial Swap Operating Expenses adjustment	$	(6,096)	
11. Net Kentucky Jurisdictional adjustment (Line 6 - Line 10)	$	(250,721)	

*NOTE: Reflects 6.15% of total labor and labor related costs from regulated trading sales activities.

Exhibit 1
Reference Schedule 1.09
Sponsoring Witness: Charnas

KENTUCKY UTILITIES

To Eliminate ECR, MSR, FAC and DSM Accruals
For the Twelve Months Ended October 31, 2009

1. ECR Accrued Revenue in Accounts 440-445	$	8,535,405
2. MSR Accrued Revenue in Accounts 440-445		(29,000)
3. FAC Accrued Revenue in Accounts 440-445		(5,106,000)
4. DSM Accrued Revenue in Accounts 440-445		(3,684,059)
5. Total Kentucky Jurisdictional Accrued Revenues	$	(283,654)
6. Total Adjustment	$	283,654

Exhibit 1
Reference Schedule 1.10
Sponsoring Witness: Conroy

KENTUCKY UTILITIES

To Eliminate DSM Revenues and Expenses
For the Twelve Months Ended October 31, 2009

1. DSM Revenue adjustment	$	(12,940,085)
2. DSM Expense adjustment		(7,500,349)
3. Net Adjustment	$	(5,439,736)

Exhibit 1
Reference Schedule 1.11
Sponsoring Witness: Seelye

KENTUCKY UTILITIES

Adjustment to Reflect Weather Normalized Electric Sales Margins
For the Twelve Months Ended October 31, 2009

1. Revenue adjustment	$	2,986,579
2. Expense adjustment		1,489,506
3. Net adjustment	$	1,497,073

Exhibit 1
Reference Schedule 1.12
Sponsoring Witness: Seelye

KENTUCKY UTILITIES

Adjustment to Annualize Year-End Customers
At October 31, 2009

1. Revenue adjustment	$	9,724,872
2. Expense adjustment		5,885,824
3. Net adjustment	$	3,839,048

Exhibit 1
Reference Schedule 1.13
Sponsoring Witness: Conroy

KENTUCKY UTILITIES

To Adjust for Customer Billing Corrections and Rate Switching
As Applied to the Twelve Months Ended October 31, 2009

1. Major Account Billing Corrections		(14,320)
2. Rate switch - LP to TOD		(172,038)
3. Total Adjustment	$	(186,358)

Exhibit 1
Reference Schedule 1.14
Sponsoring Witness: Bellar

KENTUCKY UTILITIES

Adjustment to Revenues for Late Payment Charge
For the Twelve Months Ended October 31, 2009

1. Late Payment Charge Revenues (April to October 2009)	$	4,398,330
2. Estimated 5 months of Late Payment Charges		3,141,664
3. Annual Amount of Late Payment Charges	$	7,539,994
4. Total Adjustment (Line 3 - Line 1)	$	3,141,664

Exhibit 1
Reference Schedule 1.15
Sponsoring Witness: Charnas / Bellar

KENTUCKY UTILITIES

Adjustment To Reflect Annualized Depreciation Expenses
At October 31, 2009

1. Annualized direct depreciation expense under current rates	$ 104,822,876
2. Annualized depreciation for 2001 and 2003 ECR plans to be eliminated	7,323,072
3. Annualized direct depreciation expense for TC2 joint use assets transferred from TC1 under proposed TC2 rates	3,168,122
4. Annualized direct depreciation expense for TC2 cooling tower transferred from TC1 under proposed TC2 rates	495,091
5. Annualized direct depreciation expense for TC2 assets under proposed TC2 rates as of 10/31/09 CWIP balance	18,121,245
6. Annualized direct depreciation expense for TC2 transmission assets under current rates as of 10/31/09 CWIP balance	912,721
7. Total annualized depreciation expense	$ 134,843,127
8. Depreciation expense per books for test year	$ 135,678,764
9. Depreciation expense for asset retirement costs (ARO)	(299,753)
10. Depreciation for environmental cost recovery (ECR) plans (1)	(22,450,815)
11. Depreciation expense per books excluding ARO and ECR	$ 112,928,197
12. Total Adjustment to reflect annualized depreciation expense (Line 7 - Line 11)	21,914,931
13. Kentucky Jurisdiction (Ref. Sch. Allocators)	87.670%
14. Kentucky Jurisdictional adjustment	$ 19,212,820

(1) Reflects the elimination of the 2001 and 2003 ECR Plans. Only reflects ECR plan amounts which will continue after effective date of new base rates in this proceeding.

KENTUCKY UTILITIES

Adjustment to Reflect Increases in Labor and Labor-Related Costs
As Applied to the Twelve Months Ended October 31, 2009

1	Wages (Page 2)	$ 793,717
2	Payroll Taxes (Page 3)	56,389
3	401(k) (Page 4)	29,368
4	Total	879,474
5	Kentucky Jurisdiction (Ref. Sch. Allocators)	89.197%
6	Kentucky Jurisdictional Adjustment	$ 784,464

KENTUCKY UTILITIES

Adjustment to Reflect Increases in Labor and Labor-Related Costs
As Applied to the Twelve Months Ended October 31, 2009

			Operating	Construction/ Other	Total
1	Labor for 12 months ended October 31, 2009:				
2	Base		$ 75,037,402	$ 29,495,439	$ 104,532,841
3	Overtime and Premium		12,184,059	3,003,390	15,187,449
4	Less: Labor Related to 2009 Winter Storm Restoration Regulatory Asset (b)		(3,464,137)	(48,307)	(3,512,444)
5	TIA		7,432,930	2,652,131	10,085,061
6	Total Labor (Sum of Lines 2 - 5)		$ 91,190,254	$ 35,102,653	$ 126,292,907
7	Total labor Excluding TIA (Line 6 - Line 5)		$ 83,757,324	$ 32,450,522	$ 116,207,846
8	Total Operating and Construction/Other %		72.1%	27.9%	100.0%
9	Annualized base labor at October 31, 2009:				
10	Union				$ 9,372,293
11	Exempt KU				11,396,218
12	Hourly				28,888,808
13	Non-Exempt				11,645,936
14	Exempt Servco (allocated to KU)		(48.3% of total)		38,746,168
15	Non-Exempt Servco (allocated to KU)		(48.3% of total)		5,308,412
16	Total Annualized Labor (Sum of Lines 10 - 15)				105,357,835
17	Union Overtime/Premiums (a)				3,596,063
18	Union Wage Increase Applied to Union Overtime Annualized for 2009 (11/1/08-7/18/09 OT labor x 3.5%)				89,960
19	Non-Exempt/Hourly/Servco Overtime/Premium (a)				11,591,386
20	Wage Increase Applied to Hourly Overtime/Premium Annualized for 2008 (11/1/08 - 7/18/09 OT labor x 3.5%)				250,232
21	Wage Increase Applied to Non-Exempt/Servco Overtime/Premium Annualized for 2008 (11/1/08 - 2/28/09 OT labor x 3.5%)				19,031
22	Less: Labor Related to 2009 Winter Storm Restoration Regulatory Asset (Line 4) (b)				(3,512,444)
23	Less: Wage Increase Applied to Labor Related to 2009 Winter Storm Restoration Regulatory Asset (Line 22 x 3.5%)				(122,936)
24	Total Annualized Labor (Sum of Lines 16 - 23)				$ 117,269,127
25	Operating Labor for 12 months ended October 31, 2009 (Line 7)				$ 83,757,324
26	Operating Labor based on annualized labor	$ 117,269,127 x	72.1%		84,551,041
27	Labor Adjustment Total (Line 26 - Line 25)				$ 793,717

(a) Represents actual numbers taken from the Company's financial records for the 12 months ended October 31, 2009.

(b) All labor related to the 2009 winter storm restoration regulatory asset is assumed to be overtime and premiums

KENTUCKY UTILITIES

Adjustments to Reflect Increases in Payroll Taxes
As Applied to the Twelve Months Ended October 31, 2009

1	Operating Labor increase (Page 2 Line 27)	$	793,717
2	Percentage of wages that do not exceed Social Security (OASDI) limit		91.2%
3	Operating Labor increase subject to Social Security tax (Line 1 x Line 2)	$	723,870
4	Medicare Tax (Line 1 x 1.45%)	$	11,509
5	Social Security Tax (Line 3 x 6.2%)		44,880
6	Payroll Tax adjustment (Line 4 + Line 5)	$	56,389

KENTUCKY UTILITIES

Adjustment to Reflect Increases in Company Contribution to 401(k)
As Applied to the Twelve Months Ended October 31, 2009

1	Direct total payroll for 12 months ended 10/31/09 before deducting storm-related labor (Page 2 Line 6 - Page 2 Line 4)	$ 129,805,351
2	Total 401(k) Company Contribution for 12 months ended 10/31/09	4,764,961
3	401(k) Company Contribution as a percent of payroll (Line 2 / Line 1)	3.7%
4	Operating Labor increase (Page 2 Line 27)	793,717
5	401(k) Company Contribution operating increase (Line 3 x Line 4)	$ 29,368

Revised Exhibit 1
Reference Schedule 1.17
Sponsoring Witness: Scott

KENTUCKY UTILITIES

To Adjust for Pension, Post Retirement, and Post Employment
For the Twelve Months Ended October 31, 2009

	Pension	Post Retirement	Post Employment	Total
1. Pension, Post Retirement and Post Employment expenses in test year	$ 17,472,538	$ 5,189,047	$ 451,037	$ 23,112,622
2. Pension, Post Retirement, and Post Employment expenses annualized for Preliminary 2010 Mercer Study (a)	17,472,538	5,219,369	263,951	22,955,858
3. Total adjustment (Line 2 - Line 1)	$ -	$ 30,322	$ (187,086)	$ (156,764)
4. Kentucky Jurisdiction (Ref. Sch. Allocators)				89.197%
5. Kentucky Jurisdictional adjustment				$ (139,829)

(a) Current test year Pension expenses are representative, however this amount will be updated when Mercer Study is complete in early 2010.

Exhibit 1
Reference Schedule 1.18
Sponsoring Witness: Arbough

KENTUCKY UTILITIES

Adjustment to Reflect the Increase in Property Insurance Expense
For the Twelve Months Ended October 31, 2009

1. Property Insurance expense in test year	$	3,160,811
2. Property Insurance renewal premium for 2009/2010		3,587,892
3. Total Adjustment	$	427,081
4. Kentucky Jurisdiction (Ref. Sch. Allocators)		87.362%
5. Net Adjustment	$	373,107

Exhibit 1
Reference Schedule 1.19
Sponsoring Witness: Arbough

KENTUCKY UTILITIES

Adjustment to Reflect New Pollution Liability Insurance Expense
For the Twelve Months Ended October 31, 2009

1. New Pollution Liability Insurance Policy premium for 2009/2010	$	643,703
2. Kentucky Jurisdiction (Ref. Sch. Allocators)		89.197%
3. Kentucky Jurisdictional adjustment	$	574,164

Exhibit 1
Reference Schedule 1.20
Sponsoring Witness: Bellar

KENTUCKY UTILITIES

Adjustment for Hazard Tree Program
For the Twelve Months Ended October 31, 2009

1. Hazard Tree Program Incremental Expense-Total Company	$	5,864,342
2. Company Allocation		70.00%
3. Hazard Tree Program Incremental Expense-KU	$	4,105,039
4. Kentucky Jurisdiction (Ref. Sch. Allocators)		92.362%
5. Kentucky Jurisdictional adjustment	$	3,791,496

Exhibit 1
Reference Schedule 1.21
Sponsoring Witness: Scott

KENTUCKY UTILITIES

Adjustment to Reflect Normalized Storm Damage Expense
For the Twelve Months Ended October 31, 2009

1. Storm damage provision based upon ten year average	$	3,126,648
2. Storm damage expenses incurred during the 12 months ended October 31, 2009		4,472,214
3. Adjustment		(1,345,566)
4. Kentucky Jurisdiction (Ref. Sch. Allocators)		94.226%
5. Kentucky Jurisdictional adjustment (see Note)	$	(1,267,873)

Year		Expense (a)		CPI-All Urban Consumers		Amount
2009	$	4,472,214	(b)	1.0000	$	4,472,214
2008		6,967,233	(b)	0.9927		6,916,372
2007		2,035,000		1.0308		2,097,678
2006		4,114,000		1.0602		4,361,663
2005		2,538,000		1.0944		2,777,587
2004		4,120,000		1.1315		4,661,780
2003		1,434,000		1.1616		1,665,734
2002		1,460,495		1.1881		1,735,214
2001		1,102,683		1.2069		1,330,828
2000		1,005,000		1.2412		1,247,406
Total					$	31,266,476
Ten Year Average					$	3,126,648

NOTE: The Adjustment amount reflected is overstated due to the inadvertent inclusion of certain expenses in the source data. The adjustment should be a reduction in expense of $1,076,306, rather than a reduction in expense of $1,267,873. The Company has not revised the adjustment due to timing considerations for the filing and the lower expense amount is beneficial to customers in the calculation of the revenue deficiency in the application. See Scott Exhibit 1 for a revised schedule.

(a) 2009 expense is for 12 months ended October 31, 2009. All other years expenses are for calendar year.

(b) 2008 and 2009 expenses do not include 2008 Wind Storm and 2009 Winter Storm expenses that were recorded as regulatory assets.

Exhibit 1
Reference Schedule 1.22
Sponsoring Witness: Charnas

KENTUCKY UTILITIES

Adjustment for Injuries and Damages FERC Account 925
For the Twelve Months Ended October 31, 2009

1. Injury/Damage provision based upon ten year average	$	1,858,370
2. Injury/Damage expenses incurred during the 12 months ended October 31, 2009		1,633,351
3. Adjustment		225,019
4. Kentucky Jurisdiction (Ref. Sch. Allocators)		89.197%
5. Kentucky Jurisdictional adjustment	$	200,710

Year	Amount (a)	CPI-All Urban Consumers	Adjusted Amount
2009	$ 1,633,351	1.0000	$ 1,633,351
2008	1,226,235	0.9927	1,217,283
2007	1,178,212	1.0308	1,214,501
2006	1,690,654	1.0602	1,792,431
2005	2,268,036	1.0944	2,482,139
2004	1,080,732	1.1315	1,222,848
2003	1,776,006	1.1616	2,063,009
2002	2,510,515	1.1881	2,982,743
2001	1,609,827	1.2069	1,942,900
2000	1,637,520	1.2412	2,032,490
Total			$ 18,583,695
Ten Year Average			$ 1,858,370

(a) 2009 expense is for 12 months ended October 31, 2009.
All other years expenses are for calendar year.

Exhibit 1
Reference Schedule 1.23
Sponsoring Witness: Charnas

KENTUCKY UTILITIES

Adjustment to Eliminate Advertising Expenses
Pursuant to Commission Rule 807 KAR 5:016
For the Twelve Months Ended October 31, 2009

1. Uniform System of Accounts - Account No. 930.1 General Advertising Expenses	$	777,091
2. Account No. 913 Advertising Expenses		65,214
3. Total		842,305
4. Kentucky Jurisdiction (Ref. Sch. Allocators)		94.910%
5. Kentucky Jurisdictional amount	$	799,431
6. Kentucky Jurisdictional adjustment	$	(799,431)

Exhibit 1
Reference Schedule 1.24
Sponsoring Witness: Charnas

KENTUCKY UTILITIES

Adjustment for Expenses related to Retired Mainframe
For the Twelve Months Ended October 31, 2009

1. Expenses related to Retired Mainframe for Twelve Months Ended October 31, 2009	$ 945,798
2. Adjustment	$ (945,798)
3. Kentucky Jurisdiction (Ref. Sch. Allocators)	89.197%
4. Kentucky Jurisdictional adjustment	$ (843,623)

Exhibit 1
Reference Schedule 1.25
Sponsoring Witness: Scott

KENTUCKY UTILITIES

Adjustment for MISO Exit Fee Regulatory Asset
For the Twelve Months Ended October 31, 2009

1. Kentucky Jurisdiction MISO Exit Fee Regulatory Asset at April 30, 2008			$	9,809,894
2. Less Cumulative Schedule 10 Regulatory Liability (May 2008 - Feb 2009)				(3,030,277)
3. Cumulative MISO Exit Fee Refund Regulatory Liability at October 31, 2009	$	(761,794)		
4. Kentucky Jurisdiction		86.537%		
5. Less Kentucky Jurisdiction Cumulative MISO Exit Fee Refund Regulatory Liability (Line 3 x Line 4)				(659,234)
6. Kentucky Jurisdictional Net MISO Exit Fee Regulatory Asset (before amortization) at October 31, 2009 (Line 1 + Line 2 + Line 5)			$	6,120,384
7. Amortization period in years				5
8. Amortization per year			$	1,224,077
9. Amortization recorded in test year (March - October 2009)				1,307,986
10. Adjustment to Test Year Amortization			$	(83,909)

Exhibit 1
Reference Schedule 1.26
Sponsoring Witness: Scott

KENTUCKY UTILITIES

Adjustment for EKPC Transmission Settlement
For the Twelve Months Ended October 31, 2009

1. Kentucky Jurisdictional EKPC Settlement Regulatory Asset	$	1,673,485
2. Amortization period in years		5
3 Amortization per year	$	334,697
4. Amortization recorded in test year (March - October 2009)		223,131
5. Reverse credit to expense to establish regulatory asset		(1,673,485)
6. Total Adjustment	$	1,785,051

Exhibit 1
Reference Schedule 1.27
Sponsoring Witness: Scott

KENTUCKY UTILITIES

Adjustment for 2008 Wind Storm Regulatory Asset
For the Twelve Months Ended October 31, 2009

1. Kentucky Jurisdictional 2008 Wind Storm Regulatory Asset	$	2,195,516
2. Amortization period in years		5
3. Amortization per year	$	439,103
4. Amortization recorded in test year		-
5. Reverse net credits during the test year to establish the regulatory asset	$	2,015,183
6. Total Adjustment	$	2,454,286

Exhibit 1
Reference Schedule 1.28
Sponsoring Witness: Scott

KENTUCKY UTILITIES

Adjustment for 2009 Winter Storm Regulatory Asset
For the Twelve Months Ended October 31, 2009

1. Kentucky Jurisdictional 2009 Winter Storm Regulatory Asset	$	57,253,874
2. Adjustment to 2009 Winter Storm Regulatory Asset made in Nov '09		(17,115)
3. Subtotal	$	57,236,759
4. Amortization period in years		5
5. Amortization per year	$	11,447,352
6. Amortization recorded in test year		-
7. Total Adjustment	$	11,447,352

Exhibit 1
Reference Schedule 1.29
Sponsoring Witness: Bellar

KENTUCKY UTILITIES

Adjustment for KCCS Regulatory Asset
For the Twelve Months Ended October 31, 2009

1. KCCS Regulatory Asset recorded as of 10/31/2009	$	807,697
2. KCCS payment made December 2009		114,263
3. Total KCCS Regulatory Asset at 12/31/2009	$	921,960
4. Amortization period in years		4
5. Adjustment for annual amortization	$	230,490
6. Reverse credit for reclass to regulatory asset		130,014
7. Adjustment for annual amortization	$	360,504

Exhibit 1
Reference Schedule 1.30
Sponsoring Witness: Bellar

KENTUCKY UTILITIES

Adjustment for CMRG Regulatory Asset
For the Twelve Months Ended October 31, 2009

1. CMRG Regulatory Asset	$	2,000,000
2. Company Allocation		51.22%
3. Kentucky Jurisdictional CMRG Regulatory Asset	$	1,024,400
4. Amortization period in years		10
5. Annual amortization	$	102,440
6. Expense recorded during test year		100,500
7. Adjustment for annual amortization (Line 5 - Line 6)	$	1,940

Exhibit 1
Reference Schedule 1.31
Sponsoring Witness: Charnas

KENTUCKY UTILITIES

Adjustment for Rate Case Amortization
For the Twelve Months Ended October 31, 2009

1. Total Estimated cost of 2009 Rate Case	$	1,325,000
2. Amortization period in years		3
3. Annual amortization		441,667
4. 2009 Rate Case amortization included in test year		-
5. Net Adjustment for 2009 Rate Case expenses		441,667
6. 2008 Rate Case Annual amortization		460,559
7. 2008 Rate Case Annual amortization included in test year		(307,039)
8. Net Adjustment for 2008 Rate Case expenses		153,520
9. Total Adjustment (Line 5 + Line 8)	$	595,187

Exhibit 1
Reference Schedule 1.32
Sponsoring Witness: Bellar

KENTUCKY UTILITIES

Adjustment for Southwest Power Pool Settlement Expenses
For the Twelve Months Ended October 31, 2009

1. SPP ITO Settlement Expenses in test year (reflects 3.5 years)	$	1,452,873
2. SPP ITO Settlement Expenses to remain in test year (12 months)		415,107
3. Adjustment (Line 2 - Line 1)	$	(1,037,767)
4. Kentucky Jurisdiction (Ref. Sch. Allocators)		86.383%
5. Kentucky Jurisdictional adjustment	$	(896,454)

Exhibit 1
Reference Schedule 1.33
Sponsoring Witness: Scott

KENTUCKY UTILITIES

Adjustment to Remove Out of Period Adjustment for Resettlements Related to MISO RSG For the Twelve Months Ended October 31, 2009

1. Resettlements related to MISO RSG charges incurred during the 12 months ended October 31, 2009	$	590,536
2. Adjustment	$	(590,536)
3. Kentucky Jurisdiction (Ref. Sch. Allocators)		86.383%
4. Kentucky Jurisdictional adjustment	$	(510,123)

Exhibit 1
Reference Schedule 1.34
Sponsoring Witness: Bellar

KENTUCKY UTILITIES

Adjustment for Expiration of OMU Contract
For the Twelve Months Ended October 31, 2009

1.	OMU Demand charges incurred during the 12 months ended October 31, 2009	$ 18,143,888
2.	Adjustment	$ (18,143,888)
3.	Kentucky Jurisdiction (Ref. Sch. Allocators)	86.383%
4.	Kentucky Jurisdictional adjustment	$ (15,673,235)

Exhibit 1
Reference Schedule 1.35
Sponsoring Witness: Scott

KENTUCKY UTILITIES

Adjustment for Reversal of Uncollectible Account Expense due to Collection of OMU Litigation Settlement
For the Twelve Months Ended October 31, 2009

1.	Amount collected from OMU for reversal of uncollectible account expense during the 12 months ended October 31, 2009	$ (1,855,068)
2.	Kentucky Jurisdiction (Ref. Sch. Allocators)	94.579%
3.	Kentucky Jurisdictional amount	$ (1,754,505)
4.	Kentucky Jurisdictional adjustment	$ 1,754,505

Exhibit 1
Reference Schedule 1.36
Sponsoring Witness: Bellar

KENTUCKY UTILITIES

Adjustment to Remove Reserve Margin Demand Purchases
For the Twelve Months Ended October 31, 2009

1.	Reserve Margin Demand Purchases incurred during the 12 months ending October 31, 2009	$ 1,550,349
2.	Kentucky Jurisdiction (Ref. Sch. Allocators)	86.383%
3.	Kentucky Jurisdictional amount	$ 1,339,238
4.	Kentucky Jurisdictional Adjustment	$ (1,339,238)

Exhibit 1
Reference Schedule 1.37
Sponsoring Witness: Scott

KENTUCKY UTILITIES

Adjustment for 2003 Ice Storm Regulatory Asset Amortization
For the Twelve Months Ended October 31, 2009

1. Amortization recorded in Test Year	$	527,718
2. Kentucky Jurisdictional 2003 Ice Storm Regulatory Asset		527,718
3. Remaining Balance	$	-
4. Total Adjustment	$	(527,718)

Exhibit 1
Reference Schedule 1.38
Sponsoring Witness: Miller

KENTUCKY UTILITIES

Adjustment for Property Taxes
For the Twelve Months Ended October 31, 2009

1. Property tax expense adjustment due to coal tax credit received	$	1,612,129
2. Reduction in Property tax expense due to lower assessment		(318,239)
3. Additional Property tax expense due to Trimble Co. joint use assets transfer		72,571
4. Total Property Tax adjustment	$	1,366,461
5. Kentucky Jurisdiction (Ref. Sch. Allocators)		87.792%
6. Kentucky Jurisdictional adjustment	$	1,199,643

Exhibit 1
Reference Schedule 1.39-1.40
Sponsoring Witness: Bellar

KENTUCKY UTILITIES

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Exhibit 1
Reference Schedule 1.41
Sponsoring Witness: Miller

KENTUCKY UTILITIES

Calculation of Composite Federal and Kentucky Income Tax Rate
(Based on Law in Effect January 1, 2010)

1. Assume pre-tax income of			$ 100.0000
2. State income tax at 6.00%			5.6956
3. Taxable income for Federal income tax before production deduction			94.3044
Production Rate		9%	
Allocation to Production Income		0.5973	
Allocated Production Rate		5.38%	
4. Less: Production tax deduction (5.38% of Line 3)			5.0736
5. Taxable income for Federal income tax (Line 3 - Line 4)			89.2308
6. Federal income tax at 35% (Line 5 x 35%)			31.2308
7. Total State and Federal income taxes (Line 2 + Line 6)			$ 36.9264
8. Therefore, the composite rate is:			
9. Federal	31.2308%		
10. State	5.6956%		
11. Total	36.9264%		

State Income Tax Calculation

1. Assume pre-tax income of	$ 100.0000
2. Less: Production tax deduction	5.0736
3. Taxable income for State income tax	94.9264
4. State Tax Rate	6.0000%
5. State Income Tax	5.6956

Exhibit 1
Reference Schedule 1.42
Sponsoring Witness: Miller

KENTUCKY UTILITIES

Calculation of Current Tax Adjustment Resulting From "Interest Synchronization"

1. Adjusted Jurisdictional Capitalization - Exhibit 2	$	3,054,543,620
2. Weighted Cost of Debt - Exhibit 2		2.13%
3. "Interest Synchronization"	$	65,061,779
4. Kentucky Jurisdictional Interest per books (excluding other interest)		63,577,661
5. "Interest Synchronization" adjustment (Line 4 - 3)	$	(1,484,118)
6. Composite Federal and State tax rate		36.9264%
7. Current tax adjustment from "Interest Synchronization"	$	(548,031)

Exhibit 1
Reference Schedule 1.43
Sponsoring Witness: Miller

KENTUCKY UTILITIES

Adjustment for Prior Period Income Tax True-Ups and Adjustments
For the Twelve Months Ended October 31, 2009

1. Prior Year Income Tax True-up:		
2. Federal Tax expense (benefit)	$	582,801
3. State Tax expense (benefit)		(1,006,502)
4. Total Income Tax True-up	$	(423,701)
5. Other Tax adjustments:		
6. Kentucky Coal Credit		(1,680,990)
7. Total Other Tax adjustments:	$	(1,680,990)
8. Federal benefit for State Tax adjustments		953,222
9. Total adjustments (Line 4 + Line 7 + Line 8)	$	(1,151,469)
10. Kentucky Jurisdiction (Ref. Sch. Allocators)		97.803%
11. Kentucky Jurisdiction amount (Line 9 x Line 10)	$	(1,126,171)
12. Kentucky Jurisdiction adjustment	$	1,126,171

Exhibit 1
Reference Schedule 1.44
Sponsoring Witness: Miller

KENTUCKY UTILITIES

Adjustment for Domestic Production Activities Deduction
For the Twelve Months Ended October 31, 2009

1. Test year federal taxable income	$ 85,716,537
2. Percent of production assets to total	59.7%
3. Qualified Production Activities income (Line 1 x Line 2)	$ 51,172,773
4. Production Activities Deduction rate (effective January 1, 2010)	9.0%
5. Production Activities Deduction (Line 3 x Line 4)	$ 4,605,550
6. Production Activities Deduction in test year	3,402,362
7. Adjustment for Production Activities Deduction (Line 5 - Line 6)	$ 1,203,188
8. Statutory tax rate	38.9%
9. Production Activities Deduction tax adjustment (line 7 x Line 8)	$ 468,040
10. Kentucky Jurisdiction (Ref. Sch. Allocators)	97.803%
11. Kentucky Jurisdictional amount	$ 457,757
12. Kentucky Jurisdiction adjustment	$ (457,757)

Exhibit 1
Reference Schedule 1.45
Sponsoring Witness: Miller

KENTUCKY UTILITIES

Adjustment for Tax Basis Depreciation Reduction
For the Twelve Months Ended October 31, 2009

1. Permanent difference due to loss of depreciable tax basis	$ 1,475,013
2. Kentucky Jurisdiction (Ref. Sch. Allocators)	97.803%
3. Kentucky Jurisdictional adjustment	$ 1,442,607

Exhibit 1
Reference Schedule 1.46
Sponsoring Witness: Bellar

KENTUCKY UTILITIES

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Exhibit 1
Reference Schedule 1.47
Sponsoring Witness: Miller

KENTUCKY UTILITIES

Calculation of Revenue Gross Up Factor
(Based on Law in Effect January 1, 2010)

1. Assume pre-tax income of	$ 100.000000
2. Bad Debt at .2800%	0.280000
3. PSC Assessment at .1538%	0.153800
4. Production Tax Credit (Reference Schedule 1.41)	5.073578
5. Taxable income for State income tax	94.492622
6. State income tax at 6.00%	5.669557
7. Taxable income for Federal income tax	88.823065
8. Federal income tax at 35%	31.088073
9. Total Bad Debt, PSC Assessment, State and Federal income taxes (Line 2 + Line 3 + Line 6 + Line 8)	37.191430
10. Assume pre-tax income of	$ 100.000000
11. Gross Up Revenue Factor	62.808570

KENTUCKY UTILITIES

Kentucky Jurisdictional Allocators
At October 31, 2009

Title	Reference Schedule	Factor	Allocation Based On
ECR Operating Expense	1.05, 1.06	87.088%	Composite rate developed from steam depreciation allocator (86.755%) and net plant allocator for property tax (88.110%)
Brokered and Off-System Energy	1.07, 1.08	86.685%	Ratio of Kentucky retail kilowatt-hour sales to Total Company kilowatt-hour sales
Depreciation	1.15	87.670%	Composite rate developed by dividing Kentucky retail depreciation by Total Company depreciation
Labor	1.16	89.197%	Direct labor
Pension and Post Retirement and Benefits	1.17	89.197%	Direct labor
Property Insurance	1.18	87.362%	Plant
Liability Insurance	1.19	89.197%	Direct labor
Hazard Tree Program	1.20	92.362%	Tree Miles
Distribution O&M (Storm Damages)	1.21	94.226%	Distribution plant
Injuries/Damages	1.22	89.197%	Direct labor
Advertising Expense	1.23	94.910%	Retail energy
Retired Mainframe	1.24	89.197%	Direct labor
SPP Settlement, OMU, Reserve Margin, and MISO RSG Resettlement	1.32, 1.33, 1.34, 1.36	86.383%	Demand (12 CP)
OMU Uncollectible	1.35	94.579%	Cust904
Property Taxes	1.38	87.792%	Net Plant
Income Taxes	1.42-1.45	97.803%	Income tax expense

KENTUCKY UTILITIES

Capitalization at October 31, 2009

		Per Books 10-31-09 (1)	Capital Structure (2)	Trimble County Joint Use Assets Transfer (3)	Undistributed Subsidiary Earnings (4)	Investment in EEI (Col 2 x Col 5 Line 4) (5)	Investments in OVEC and Other (Col 2 x Col 6 Line 4) (6)	Adjustments to Total Co. Capitalization (Sum of Col 3 - Col 6) (7)	Adjusted Total Company Capitalization (Col 1 + Col 7) (8)	Jurisdictional Rate Base Percentage (Exhibit 3 Line 19) (9)	Kentucky Jurisdictional Capitalization (Col 8 x Col 9) (10)
1.	Short Term Debt	$ 19,665,954	0.55%	$ 266,095	$ -	$ (7,127)	$ (4,621)	$ 254,347	$ 19,920,301	87.15%	$ 17,360,542
2.	Long Term Debt	1,631,779,405	45.52%	22,022,972	-	(589,848)	(382,487)	21,050,637	1,652,830,042	87.15%	1,440,441,382
3.	Common Equity	1,933,128,508	53.93%	26,091,802	(6,207,858)	(698,825)	(453,153)	18,731,966	1,951,860,473	87.15%	1,701,046,402
4.	Total Capitalization	$ 3,584,573,867	100.00%	$ 48,380,869	$ (6,207,858)	$ (1,295,800)	$ (840,261)	$ 40,036,950	$ 3,624,610,816		$ 3,158,848,326

		Kentucky Jurisdictional Capitalization (10)	Capital Structure (11)	Environmental Compliance Plans (a) (Col 11 x Col 12 Line 4) (12)	Adjusted Kentucky Jurisdictional Capitalization (Col 10 + Col 12) (13)	Adjusted Capital Structure (14)	Annual Cost Rate (15)	Cost of Capital (Col 15 x Col 14) (16)
1.	Short Term Debt	$ 17,360,542	0.55%	$ (573,676)	$ 16,786,866	0.55%	0.22%	0.00%
2.	Long Term Debt	1,440,441,382	45.60%	(47,562,946)	1,392,878,436	45.60%	4.68%	2.13%
3.	Common Equity	1,701,046,402	53.85%	(56,168,084)	1,644,878,318	53.85%	11.50%	6.19%
4.	Total Capitalization	$ 3,158,848,326	100.00%	$ (104,304,706)	$ 3,054,543,620	100.00%		8.32%

(a) Environmental Compliance Plans:

Total Jurisdictional ECR Rate Base at 10/31/09	$ 1,120,801,977
Less: Juris ECR Rate Base '01 and '03 Plans	149,293,659
Less: Juris ECR Rate Base Roll-In '05 and '06 Plans	867,203,612
Jurisdictional ECR Post '03 Rate Base	$ 104,304,706

KENTUCKY UTILITIES

Net Original Cost Kentucky Jurisdictional Rate Base
At October 31, 2009

Title of Account (1)	Kentucky Jurisdictional Rate Base (2)	Other Jurisdictional Rate Base (3)	Total Company Rate Base (4)
1. Utility Plant at Original Cost	$ 5,196,890,719	$ 779,005,691	$ 5,975,896,410
2. Deduct:			
3. Reserve for Depreciation	1,824,368,838	277,102,064	2,101,470,902
4. Net Utility Plant	3,372,521,881	501,903,627	3,874,425,508
5. Deduct:			
6. Customer Advances for Construction	2,365,522	14,190	2,379,712
7. Accumulated Deferred Income Taxes	298,216,001	42,501,896	340,717,897
8. Asset Retirement Obligation-Net Assets	3,839,326	605,213	4,444,539
9. Asset Retirement Obligation-Regulatory Liabilities	3,543,696	558,611	4,102,307
10. Investment Tax Credit (a)	84,059,458	14,251,644	98,311,102
11. Total Deductions	392,024,003	57,931,553	449,955,556
12. Add:			
13. Materials and Supplies (b)	105,065,854	16,109,584	121,175,438
14. Prepayments (b)(c)	3,231,585	441,303	3,672,888
15. Emission Allowances (b)	670,815	105,746	776,561
16. Cash Working Capital (page 2)	80,258,812	6,887,593	87,146,405
17. Total Additions	189,227,066	23,544,226	212,771,292
18. Total Net Original Cost Rate Base	$ 3,169,724,944	$ 467,516,300	$ 3,637,241,244
19. Percentage of Rate Base to Total Company Rate Base	87.15%	12.85%	100.00%

(a) Reflects investment tax credit treatment per Case No. 2007-00178.

(b) Average for 13 months.

(c) Excludes PSC fees.

KENTUCKY UTILITIES

Calculation of Cash Working Capital
At October 31, 2009

Title of Account (1)	Kentucky Jurisdictional Rate Base (2)	Other Jurisdictional Rate Base (3)	Total Company Rate Base (4)
1. Operating and maintenance expense for the 12 months ended October 31, 2009	$ 819,700,590	$ 119,746,509	$ 939,447,099
2. Deduct:			
3. Electric Power Purchased	177,630,092	27,375,153	205,005,245
4. Total Deductions	$ 177,630,092	$ 27,375,153	$ 205,005,245
5. Remainder (Line 1 - Line 4)	$ 642,070,498	$ 92,371,356	$ 734,441,854
6. Cash Working Capital	$ 80,258,812	$ 6,887,593	$ 87,146,405

Kentucky Jurisdictional (12 1/2% of Line 5)
Other Jurisdictional comprised of FERC, Tennessee, and Virginia Jurisdictional methodologies.

KENTUCKY UTILITIES

Pro Forma Kentucky Jurisdictional Rate Base
At October 31, 2009

Title of Account (1)	Kentucky Jurisdictional Rate Base (a) (2)	Kentucky Jurisdictional Pro Forma Adjustments (b) (3)	Kentucky Jurisdictional Pro Forma Rate Base (4) (2 + 3)
1. Utility Plant at Original Cost	$ 5,196,890,719	$ (39,139,918)	$ 5,157,750,801
2. Deduct:			
3. Reserve for Depreciation	1,824,368,838	53,850,252 (a)	1,878,219,090
4. Net Utility Plant	3,372,521,881		3,279,531,710
5. Deduct:			
6. Customer Advances for Construction	2,365,522		2,365,522
7. Accumulated Deferred Income Taxes	298,216,001	(9,997,697)	288,218,304
8. Asset Retirement Obligation-Net Assets	3,839,326		3,839,326
9. Asset Retirement Obligation-Regulatory Liabilities	3,543,696		3,543,696
10. Investment Tax Credit	84,059,458	(527,382)	83,532,076
11. Total Deductions	392,024,003		381,498,924
12. Add:			
13. Materials and Supplies	105,065,854	195,500	105,261,354
14. Prepayments	3,231,585		3,231,585
15. Emission Allowances	670,815	(1,045,828)	(375,013)
16. Cash Working Capital	80,258,812	(1,129,931)	79,128,881
17. Total Additions	189,227,066		187,246,807
18. Total Net Original Cost Rate Base	$ 3,169,724,944		$ 3,085,279,593

(a) Exhibit 3, Column 2

(b) Supporting Schedule-Exhibit 4, Column 5

KENTUCKY UTILITIES

Pro Forma Adjustments to Kentucky Jurisdictional Rate Base
At October 31, 2009

	Title of Account (1)	Environmental Compliance Plans (2)	Trimble County Joint Use Assets Transfer (3)	Kentucky Jurisdictional Expense Adjustments (4)	Total Kentucky Jurisdictional Pro Forma Adjustments (5) (2 + 3 + 4)
1	Utility Plant at Original Cost	$ (128,896,051)	$ 89,756,133	$ -	$ (39,139,918)
2	Deduct:				
3	Reserve for Depreciation	(12,954,773)	47,592,205	19,212,820 (d)	53,850,252
4	Net Utility Plant	(115,941,278)	42,163,927 (b)	(19,212,820)	(92,990,171)
5	Deduct:				
6	Customer Advances for Construction	-	-	-	-
7	Accumulated Deferred Income Taxes	(9,997,697)	-	-	(9,997,697)
8	Asset Retirement Obligation-Net Assets	-	-	-	-
9	Asset Retirement Obligation-Regulatory Liabilities	-	-	-	-
10	Investment Tax Credit	(3,030,890)	2,503,508 (c)	-	(527,382)
11	Total Deductions	(13,028,587)	2,503,508	-	(10,525,079)
12	Add:				
13	Materials and Supplies	195,500	-	-	195,500
14	Prepayments	-	-	-	-
15	Emission Allowances	(1,045,828)	-	-	(1,045,828)
16	Cash Working Capital	(541,687)	-	(588,244) (e)	(1,129,931)
17	Total Additions	(1,392,015)	-	(588,244)	(1,980,259)
18	Total Net Original Cost Rate Base	$ (104,304,706) (a)	$ 39,660,419	$ (19,801,064)	$ (84,445,351)

(a) Adjustment to remove Environmental Compliance Plans (Exhibit 2 Col 12).

(b) Adjustment to reflect Trimble County joint use assets transfer (Exhibit 2 Col 3 x Exhibit 2 Col 9)

(c) Adjustment to reflect Trimble County joint use assets transfer Investment Tax Credit ($2,927,259 x 85 504% Juris Factor)

(d) Adjustment to reflect annualized depreciation expenses (Reference Schedule 1 15).

(e) Using the 1/8th formula and change in Operation and Maintenance Expenses adjusted for FAC roll-in, Purchase Power and ECR expense adjustments ((Exhibit 1 Col 3, Line 43 - Line 8 - Line 9 - Line 18 - Line 37 - Line 39 - Line 41 - Ref Sch 1.04 Line 3) / 8).

KENTUCKY UTILITIES

Estimated Net Reproduction Cost Kentucky Jurisdictional Rate Base
At October 31, 2009

Title of Account (1)	Kentucky Jurisdictional Rate Base (2)	Other Jurisdictional Rate Base (3)	Total Company Rate Base (4) (2 + 3)
1. Utility Plant at Estimated Reproduction Cost	$ 10,077,257,090	$ 1,454,969,715	$ 11,532,226,805
2. Deduct:			
3. Reserve for Depreciation	4,106,282,125	609,885,669	4,716,167,794
4. Net Utility Plant	5,970,974,965	845,084,046	6,816,059,011
5. Deduct:			
6. Customer Advances for Construction	2,365,522	14,190	2,379,712
7. Accumulated Deferred Income Taxes	298,216,001	42,501,896	340,717,897
8. Asset Retirement Obligation-Net Assets	3,839,326	605,213	4,890,630
9. Asset Retirement Obligation-Regulatory Liabilities	3,543,696	558,611	(2,254,925)
10. Investment Tax Credit (a)	84,059,458	14,251,644	98,311,102
11. Total Deductions	392,024,003	57,931,553	444,044,416
12. Add:			
13. Materials and Supplies (b)	105,065,854	16,109,584	85,963,079
14. Prepayments (b)(c)	3,231,585	441,303	1,664,279
15. Emission Allowances (b)	670,815	105,746	223,085
16. Cash Working Capital	80,258,812	6,887,593	87,146,405
17. Total Additions	189,227,066	23,544,226	174,996,848
18. Total Net Reproduction Cost Rate Base	$ 5,768,178,028	$ 810,696,718	$ 6,547,011,443

(a) Reflects investment tax credit treatment per Case No. 2007-00178.
(b) Average for 13 months.
(c) Excludes PSC fees.

Exhibit 6
Sponsoring Witness: Rives
Page 1 of 1

KENTUCKY UTILITY COMPANY

Estimated Reproduction (or Current) Cost of Utility Plant
And Applicable Reserve for Depreciation at October 31, 2009

	Original Cost 10/31/2009 (1)	Effect of Changing Prices (a) (2)	At 10/31/2009 (3)	Jurisdictional Factor (4)	Kentucky Jurisdictional Plant at 10/31/2009 (5)	Other Jurisdictional Plant at 10/31/2009 (6)
1. Plant in Service						
2. Electric Plant :						
3. Steam Production	$ 2,251,114,627	$ 2,246,357,970	$ 4,497,472,597	86.383%	$ 3,885,051,753	$ 612,420,844
4. Hydraulic Production	12,391,689	147,663,137	160,054,826	86.383%	138,260,160	21,794,666
5. Other Production	523,083,680	325,059,806	848,143,486	86.383%	732,651,788	115,491,698
6. Transmission	524,301,418	1,128,492,999	1,652,794,417	79.820%	1,319,260,503	333,533,914
7. Distribution	1,299,952,635	1,634,548,780	2,934,501,416	94.226%	2,765,063,304	169,438,112
8. General	112,388,421	70,808,934	183,197,355	89.197%	163,406,545	19,790,810
9. Intangible	51,555,904	3,398,769	54,954,673	87.361%	48,008,952	6,945,721
10. Total Plant in Service	4,774,788,375	5,556,330,395	10,331,118,770		9,051,703,005	1,279,415,765
11. Construction Work In Progress	1,201,108,035	-	1,201,108,035	85.384%	1,025,554,085	175,553,950
12. Total Utility Plant	$ 5,975,896,410	$ 5,556,330,395	$ 11,532,226,805		$ 10,077,257,090	$ 1,454,969,715
13. Less Reserve for Depreciation:						
14. Steam Production	$ 1,023,704,993	$ 1,021,541,881	$ 2,045,246,874	86.383%	$ 1,766,745,607	$ 278,501,267
15. Hydraulic Production	8,411,524	100,234,277	108,645,801	86.383%	93,851,502	14,794,299
16. Other Production	143,925,835	89,439,808	233,365,644	86.383%	201,588,244	31,777,400
17. Transmission	319,804,378	688,338,785	1,008,143,162	79.820%	804,699,872	203,443,290
18. Distribution	542,071,962	681,596,421	1,223,668,383	94.226%	1,153,013,770	70,654,613
19. General	52,039,347	32,786,747	84,826,094	89.197%	75,662,331	9,163,763
20. Intangible	11,512,863	758,974	12,271,837	87.361%	10,720,799	1,551,038
21. Total Reserve for Depreciation	$ 2,101,470,902	$ 2,614,696,892	$ 4,716,167,794		$ 4,106,282,125	$ 609,885,669
22. Total Utility Plant less Reserve for Depreciation	$ 3,874,425,508	$ 2,941,633,503	$ 6,816,059,011		$ 5,970,974,965	$ 845,084,046

(a) Based on Handy -Whitman Index

KENTUCKY UTILITIES

Rates of Return - Actual and Requested
Pro-Formed for the Rate Increase
For the Twelve Months Ended October 31, 2009

			Total (1)
1. Kentucky Jurisdictional Net Original Cost Rate Base - Exhibit 3		$	3,169,724,944
2. Kentucky Jurisdictional Pro Forma Rate Base - Exhibit 4		$	3,085,279,593
3. Kentucky Jurisdictional Reproduction Cost Rate Base - Exhibit 5		$	5,768,178,028
4. Kentucky Jurisdictional Net Operating Income - Actual - Exhibit 1		$	191,120,145
5. Rate of Return (Actual):			
6. On Kentucky Jurisdictional Net Original Cost Rate Base			6.03%
7. On Kentucky Jurisdictional Pro Forma Rate Base			6.19%
8. On Kentucky Jurisdictional Reproduction Cost Rate Base			3.31%
9. Kentucky Jurisdictional Adjusted Net Operating Income - Exhibit 1		$	169,167,271
10. Revenue Increase Applied for - Exhibit 8			135,285,293
11. Income Taxes - Exhibit 1, Reference Schedule 1.41	36.9264 %		(49,955,959)
12. Adjusted Kentucky Jurisdictional Net Operating Income Pro-formed for Rate Increase		$	254,496,605
13. Rate of Return (Pro-forma):			
14. On Kentucky Jurisdictional Net Original Cost Rate Base			8.03%
15. On Kentucky Jurisdictional Pro Forma Rate Base			8.25%
16. On Kentucky Jurisdictional Reproduction Cost Rate Base			4.41%

KENTUCKY UTILITIES

Calculation of Overall Revenue Deficiency/(Sufficiency) at October 31, 2009

1. Adjusted Kentucky Jurisdictional Capitalization (Exhibit 2, Col 13)	$ 3,054,543,620
2. Total Cost of Capital (Exhibit 2, Col 16)	8.32%
3. Net Operating Income Found Reasonable (Line 1 x Line 2)	$ 254,138,029
4. Pro-forma Net Operating Income	169,167,271
5. Net Operating Income Deficiency/(Sufficiency)	$ 84,970,758
6. Gross Up Revenue Factor - Exhibit 1, Reference Schedule 1.47	0.62808570
7. Overall Revenue Deficiency/(Sufficiency)	$ 135,285,293

KENTUCKY UTILITIES

Kentucky Jurisdictional Rate of Return on Common Equity
For the Twelve Months Ended October 31, 2009

	Adjusted Kentucky Jurisdictional Capitalization (Exhibit 2 Col 13) (1)	Percent of Total (2)	Annual Cost Rate (Exhibit 2 Col 15) (3)	Weighted Cost of Capital (Col 2 x Col 3) (4)
1. Short Term Debt	$16,786,866	0.55%	0.22%	0.00%
2. Long Term Debt	$1,392,878,436	45.60%	4.68%	2.13%
3. Common Equity	$1,644,878,318	53.85%	6.33% (a)	3.41% (b)
4. Total Capitalization	$3,054,543,620	100.00%		5.54%
5. Pro-forma Net Operating Income				$169,167,271 (c)
6. Net Operating Income / Total Capitalization				5.54% (d)

Notes: (a) - Column 4, Line 3 / Column 2, Line 3
(b) - Column 4, Line 4 - Line 1 - Line 2
(c) - Exhibit 1, Line 51, Column 4
(d) - Column 4, Line 5 divided by Column 1, Line 4

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

APPLICATION OF KENTUCKY UTILITIES COMPANY FOR AN ADJUSTMENT OF BASE RATES	)))	**CASE NO. 2009-00548**

TESTIMONY OF
VALERIE L. SCOTT
CONTROLLER
KENTUCKY UTILITIES COMPANY

Filed: January 29, 2010

Q. Please state your name, position and business address.

A. My name is Valerie L. Scott. I am the Controller for Kentucky Utilities Company ("KU" or the "Company"), and an employee of E.ON U.S. Services, Inc., which provides services to KU and Louisville Gas & Electric Company ("LG&E"). My business address is 220 West Main Street, Louisville, Kentucky. A statement of my qualifications is included in the Appendix attached hereto.

Q. Have you testified previously before the Commission?

A. Yes, I testified in KU's rate application in Case No. 2008-00251, *In re Application of Kentucky Utilities Company for an Adjustment of Base Rates* and LG&E's rate application in Case No. 2008-00252, *In re Application of Louisville Gas and Electric Company for an Adjustment of Base Rates*. I also testified in KU's rate application in Case No. 2003-00434, *In re the Matter of an Adjustment of the Electric Rates, Terms and Conditions of Kentucky Utilities Company* and LG&E's rate application in Case No. 2003-00433, *In re the Matter of an Adjustment of the Gas and Electric Rates, Terms and Conditions of Louisville Gas and Electric Company*. I have also testified in environmental surcharge proceedings.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to support certain pro forma adjustments to KU's operating income for the twelve months ended October 31, 2009. The pro forma adjustments are described on the Reference Schedules attached to Rives Exhibit 1. My testimony demonstrates that these adjustments are known and measurable and, therefore, reasonable. My testimony also supports certain Schedules supporting KU's application.

Q. Are you supporting the information required by Commission regulation 807 KAR 5:001, Section 10(6)(a)-(v) – The Historical Test Period?

A. Yes. I am sponsoring the following Schedules for the corresponding Filing Requirements:

- FERC Audit Reports — Section 10(6)(l) — Tab 31
- FERC Form 1 — Section 10(6)(m) — Tab 32
- Computer Software, Hardware, etc. — Section 10(6)(o) — Tab 34
- Monthly Management Reports — Section 10(6)(r) — Tab 37
- Affiliate, et. al., Allocations/Charges — Section 10(6)(t) — Tab 39

Q. Are you supporting the information required by Commission regulation 807 KAR 5:001, Section 10(7)(a) – (d) – Pro Forma Adjustments?

A. Yes. I am sponsoring the following Schedules for the corresponding Filing Requirements:

- Financial Statements with Adjustments — Section 10(7)(a) — Tab 42
- Operating Budget for the period encompassing the Pro Forma Adjustments — Section 10(7)(d) — Tab 45

Q. Please explain the adjustment to operating revenues and expenses shown in Reference Schedule 1.08 of Rives Exhibit 1.

A. This adjustment has been made to eliminate net brokered and financial swap revenues. Net revenues associated with brokered and financial swap transactions are eliminated in determining base rates because these transactions do not utilize company generation or transmission assets. Labor and labor related costs associated with executing these transactions are also eliminated. KU proposed a similar adjustment in its most recent base rate case, Case No. 2008-00251 and a similar adjustment was also approved by the Commission in Case No. 2003-00434 and Case No. 98-474.

Q. Please explain the adjustment to operating expenses shown in Reference Schedule 1.16 of Rives Exhibit 1.

A. This adjustment has been made to reflect increases in labor and labor-related costs as applied to the twelve months ended October 31, 2009, and includes specific adjustments for labor, payroll taxes, and KU's 401(k) contribution. Page 1 of 4 presents an overview of the adjustment.

Page 2 of 4 of Reference Schedule 1.16 of Rives Exhibit 1 shows the adjustment for labor expenses. The adjustment reflects the annualized base labor at October 31, 2009, of all union, hourly and non-union KU employees and certain E.ON U.S. Services Inc. ("Servco") employees as of that date. Overtime labor costs were adjusted by applying wage increases that became effective during the test year to overtime worked during the test year before the effective date of the increases. Overtime labor included in the regulatory asset for the 2009 winter storm has been excluded in calculating the increase in labor and labor-related costs. The adjustment conforms labor costs for the applicable employees to the rates that were in effect as of the end of the test year.

Page 3 of 4 of Reference Schedule 1.16 of Rives Exhibit 1 shows the calculation of the component of the labor adjustment to reflect the increases in the Federal Insurance Contributions Act ("FICA") employer payroll taxes due to the increase in labor costs. The Medicare tax rate was applied to the entire increase since all wages are subject to this tax. The same percentage of wages subject to Social Security taxes experienced during the twelve months ended October 31, 2009 was applied to the increased labor cost.

Finally, page 4 of Reference Schedule 1.16 of Rives Exhibit 1 shows the increase in the Company contribution for the 401(k) plan as a result of the increased operating labor using the same contribution percentage as experienced during the twelve months ended October 31, 2009. Although KU has not increased its contribution percentage, the total amount of KU's 401(k) contribution has increased as a result of increased labor costs.

KU proposed a similar adjustment in its most recent base rate case, Case No. 2008-00251 and a similar adjustment was also approved by the Commission in Case No. 2003-00434 and Case No. 2000-00080.

Q. **Please explain the adjustment to operating expenses shown in Reference Schedule 1.17 of Rives Exhibit 1.**

A. This adjustment is necessary to adjust the post-retirement and post-employment benefit expenses for the test year to the 2010 annualized cost as calculated in November 2009 by Mercer, the Company's actuarial consultant. Based on a review of Mercer's November calculations of pension expense and subsequent earnings on plan investments, the Company determined the net periodic pension expense recorded in the test year was representative and proposed no adjustment. KU proposed a similar adjustment in its most recent base rate case, Case No. 2008-00251 and a similar adjustment was also approved by the Commission in Case No. 2003-00434 and Case No. 2000-00080.

Amounts included in this adjustment will be updated when final 2010 expense calculations are received from Mercer in early 2010.

Q. Please explain the adjustment to operating expenses shown in Reference Schedule 1.21 of Rives Exhibit 1.

A. This adjustment has been made to reflect a normalized level of storm damage expenses based upon a ten-year average adjusted for inflation. Because a full year of data is not available for 2009, the 2009 expense is for twelve months ending October 31, 2009; all other expense years are calendar years. KU proposed a similar adjustment in its most recent base rate case, Case No. 2008-00251 and a similar adjustment was also approved by the Commission in Case No. 2003-00434. The calculation of the adjustment shown on Reference Schedule 1.21 of Rives Exhibit 1, included in the proposed increase in base rates, results in an amount which is less than the amount the Company could request in its application. The Company has not revised the adjustment due to timing considerations for the filing and the lower expense amount is beneficial to customers in the calculation of the revenue deficiency in the application. See Scott Exhibit 1 for a revised schedule.

Q. Please explain the adjustment to operating expenses shown in Reference Schedule 1.25 of Rives Exhibit 1.

A. This adjustment is to reflect the continued amortization of the Midwest Independent Transmission System Operator, Inc. ("MISO") exit fee and related revenues and refunds. In KU's most recent rate case, Case No. 2008-00251, the Commission permitted KU to net the deferred MISO exit fee against the MISO Schedule 10 administrative fees recovered through base rates post-exit and to amortize this net amount over a five-year period. The Commission also permitted KU to continue deferring the MISO Schedule 10 administrative fees recovered through base rates from May 1, 2008 until the date rates from that case became effective, February 6, 2009, and to defer subsequent periodic refunds of a portion of the MISO exit fee. KU requests to net the regulatory liabilities from revenues related to MISO Schedule 10 expenses that were deferred from May 1, 2008 until February 5, 2009, and the deferred periodic refunds of the MISO exit fee, against the net regulatory asset established in Case No. 2008-00252, and to amortize this revised net regulatory asset for five years from the effective date of the change in rates. KU proposes to adjust the test year amortization to an annual amount based on this revised net regulatory asset pursuant to the same adjustment the Commission found reasonable in Case No. 2008-00251.

Q. **Please explain the adjustment to operating expenses shown in Reference Schedule 1.26 of Rives Exhibit 1.**

A. This adjustment reflects the annual amortization of the East Kentucky Power Cooperative transmission depancaking settlement costs and reverses the impact of recording a regulatory asset in the test year for expenses recorded prior to the test year. The settlement costs resulted from KU's exit from the MISO. In KU's most recent rate case, Case No. 2008-00251, the Commission approved the deferral and a five-year amortization for these costs beginning March 2009. This adjustment reflects the annual amortization expense for these costs, as well as reversing the credit to expense recorded to establish the regulatory asset during the test period.

Q. Please explain the adjustment to operating expenses shown in Reference Schedule 1.27 of Rives Exhibit 1.

A. This adjustment is necessary to recover the deferred operating and maintenance expenses KU incurred as a result of the windstorm that occurred in September 2008. The Commission approved the establishment of a regulatory asset with regard to these expenses in Case No. 2008-00457. The adjustment to operating expenses represents the amortization of this regulatory asset over a five year period consistent with the Orders in Case No. 2003-00434 and Case No. 6220. This adjustment also reverses the timing differences between the impact of recording the regulatory asset in the test year and recording the related costs prior to the test year.

Q. Please explain the adjustment to operating expenses shown in Reference Schedule 1.28 of Rives Exhibit 1.

A. This adjustment is necessary to recover the deferred operating and maintenance expenses KU incurred as a result of the winter storm that occurred in January and February 2009. The Commission approved the establishment of a regulatory asset with regard to these expenses in Case No. 2009-00174. The adjustment amortizes this regulatory asset over a five year period consistent with the Orders in Case No. 2003-00434 and Case No. 6220.

Q. Please explain the adjustment to operating expenses shown in Reference Schedule 1.33 of Rives Exhibit 1.

A. This adjustment is to remove from operating expenses the costs incurred as a result of resettlements related to the MISO Revenue Sufficiency Guarantee ("RSG"). MISO adjusted its members' RSG charges for the period August 10, 2007 through

November 9, 2008, to eliminate certain transactions from the calculation, resulting in additional charges to KU during the test year. This adjustment is necessary to remove from operating expenses the amount KU had paid to the MISO during the test year that relates to prior period's transactions.

Q. Please explain the adjustment to operating expenses shown in Reference Schedule 1.35 of Rives Exhibit 1.

A. This adjustment is to remove from operating income the amount collected from the Owensboro Municipal Utilities ("OMU") litigation settlement. While litigation with OMU was ongoing, OMU did not pay certain amounts as required under its contract with KU. In response to the non-payment, a reserve account was created prior to the test year in the amount of the potentially uncollectible receivable. During the test year, as a result of the settlement with OMU on this issue, these amounts were paid to KU and the reserve account established prior to the test year was reversed. This adjustment is necessary to reflect reversal in the test year of the reserve recorded prior to the test year.

Q. Please explain the adjustment to operating expenses shown in Reference Schedule 1.37 of Rives Exhibit 1.

A. This adjustment is to remove the amortization costs related to the regulatory asset that the Commission approved in Case No. 2003-00434 for the restoration expenses associated with the 2003 Ice Storm. The costs were to be amortized over five years. As the regulatory asset was fully amortized in June 2009 and there is no remaining balance, this cost is non-recurring and must be removed from the test year.

Q. Does this conclude your testimony?

A. Yes, it does.

VERIFICATION

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

The undersigned, **Valerie L. Scott**, being duly sworn, deposes and says that she is Controller for Kentucky Utilities Company and an employee of E.ON U.S. Services, Inc., and that she has personal knowledge of the matters set forth in the foregoing testimony, and that the answers contained therein are true and correct to the best of her information, knowledge and belief.

Valerie L. Scott
Valerie L. Scott

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 22nd day of January 2010.

Tammy J. Elzy (SEAL)
Notary Public

My Commission Expires:

November 9, 2010

APPENDIX A

Valerie L. Scott
Controller
E.ON U.S. LLC
220 West Main Street
Louisville, Kentucky 40202
(502) 627-3660

Professional Memberships:

American Institute of Certified Public Accountants (AICPA)
Kentucky Society of Certified Public Accountants (KSCPA)
Accounting Standards Committee, Edison Electric Institute (EEI)
Chief Accounting Officers, Edison Electric Institute (EEI)
Accounting Executive Advisory Committee, Edison Electric Institute (EEI)

Education:

University of Louisville, Masters of Business Administration (with high distinction), 1994
University of Louisville, Bachelor of Science in Commerce with a major in Accounting (with honors), 1978

Previous Positions with E.ON U.S. LLC:

- August 2002 – December 2004 – Director, Financial Planning & Accounting – Utility Operations
- February 1999 – August 2002 – Director, Trading Controls & Energy Marketing Accounting
- May 1998 – February 1999 – Manager, Trading Controls and Manager, Financial Planning, Reporting and Special Projects
- July 1993 – May 1998 – Manager, Corporate Internal Auditing
- October 1991 – July 1993 – Senior Staff Accountant

Previous Positions prior to E.ON U.S. LLC:

- 1986 – 1990 Frankenthal Group, Controller
- 1978 – 1986 Arthur Young & Company (now Ernst & Young)
  - 1978 – 1979 Audit Staff
  - 1979 – 1983 Audit Senior
  - 1983 – 1986 Audit Manager

Exhibit 1
Reference Schedule 1.21 (Revised)
Sponsoring Witness: Scott

KENTUCKY UTILITIES

Adjustment to Reflect Normalized Storm Damage Expense
For the Twelve Months Ended October 31, 2009

1. Storm damage provision based upon ten year average	$	3,102,356
2. Storm damage expenses incurred during the 12 months ended October 31, 2009		4,244,616
3. Adjustment		(1,142,260)
4. Kentucky Jurisdiction		94.226%
5. Kentucky Jurisdictional adjustment	$	(1,076,306)

Year		Expense (a)		CPI-All Urban Consumers		Amount
2009	$	4,244,616	(b)	1.0000	$	4,244,616
2008		6,951,799	(b)	0.9927		6,901,051
2007		2,035,000		1.0308		2,097,678
2006		4,114,000		1.0602		4,361,663
2005		2,538,000		1.0944		2,777,587
2004		4,120,000		1.1315		4,661,780
2003		1,434,000		1.1616		1,665,734
2002		1,460,495		1.1881		1,735,214
2001		1,102,683		1.2069		1,330,828
2000		1,005,000		1.2412		1,247,406
Total					$	31,023,557
Ten Year Average					$	3,102,356

(a) 2009 expense is for 12 months ended October 31, 2009.
All other years expenses are for calendar year.

(b) 2008 and 2009 expenses do not include 2008 Wind Storm and 2009 Winter Storm expenses that were recorded as regulatory assets.

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

APPLICATION OF KENTUCKY UTILITIES COMPANY FOR AN ADJUSTMENT OF BASE RATES	)))	CASE NO. 2009-00548

TESTIMONY OF SHANNON L. CHARNAS DIRECTOR OF UTILITY ACCOUNTING & REPORTING KENTUCKY UTILITIES COMPANY

Filed: January 29, 2010

Q. Please state your name, position and business address.

A. My name is Shannon L. Charnas. I am the Director of Utility Accounting and Reporting for E.ON U.S. Services Inc., which provides services to Kentucky Utilities Company ("KU" or the "Company") and Louisville Gas and Electric Company ("LG&E"). My business address is 220 West Main Street, Louisville, Kentucky 40202. A statement of my qualifications is attached hereto in Appendix A.

Q. Have you previously testified before the Commission?

A. Yes, I testified in KU's rate application in Case No. 2008-00251, *In re Application of Kentucky Utilities Company for an Adjustment of Base Rates* and LG&E's rate application in Case No. 2008-00252, *In re Application of Louisville Gas and Electric Company for an Adjustment of Base Rates*. I have also testified in or supported data responses in numerous environmental surcharge proceedings, including Case No. 2009-00197, *In the Matter Of: The Application of Kentucky Utilities Company for Certificates of Public Convenience and Necessity and Approval of Its 2009 Compliance Plan for Recovery by Environmental Surcharge*, as well as in the Companies' depreciation study proceedings in Case Nos. 2007-00564 and 2007-00565.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to support certain pro forma adjustments to KU's operating income and rate base for the twelve months ended October 31, 2009. The pro forma adjustments are described on the Reference Schedules attached to Rives Exhibit 1. My testimony demonstrates that these adjustments are known and measurable and therefore, reasonable. Additionally, my testimony also addresses certain Schedules supporting KU's application.

Q. Are you supporting the information required by Commission regulation 807 KAR 5:001, Section 10(6)(a)-(v)—The Historical Test Period?

A. Yes. I am sponsoring the Schedules for the corresponding Filing Requirements:

- Current Chart of Accounts — Section 10(6)(j) — Tab 29
- Depreciation Study — Section 10(6)(n) — Tab 33

Q. Please describe the information you are supporting that is required by Commission regulation 807 KAR 5:001, Section 10(6)(a)-(v)—The Historical Test Period.

A. I am sponsoring the Current Chart of Accounts, as required by 807 KAR 5:001, 10(6)(j), as well as the Depreciation Study required by 807 KAR 5:001, Section 10(6)(n). The Company's latest depreciation study, prepared by John Spanos of Gannett Fleming, Inc., is filed in Case No. 2007-00565. The study recommended the use of Equal Life Group methodology, but the Settlement Agreement in the Company's last rate case, Case No. 2008-00251, instead continued the use of Average Service Life methodology. The Company continues to use the Average Service Life rates, which can be found in the Settlement Agreement at Exhibit 7 in Case No. 2008-00251. In addition, the Company proposed rates for Trimble County Unit 2 ("TC2") in Case No. 2009-00329 which the Commission approved on an interim basis in its Order dated December 23, 2009.

Q. Are you supporting the information required by Commission regulation 807 KAR 5:001, Section 10(7)(a) – (d) – Pro Forma Adjustments?

A. Yes. I am sponsoring the following Schedules for the corresponding Filing Requirements:

- Capital Construction Budget Section 10(7)(b) Tab 43
- Pro Forma Adjustments – Plant Additions Section 10(7)(c) Tab 44

<u>Pro Forma Adjustments</u>

Q. Please explain the adjustment to operating revenues shown in Reference Schedule 1.09 of Rives Exhibit 1.

A. This adjustment has been made to remove the effects of accrued Environmental Cost Recovery ("ECR"), Merger Surcredit ("MSR"), Fuel Adjustment Clause ("FAC") and Demand-Side Management ("DSM") revenues in FERC Accounts 440-445. The adjustment removes the effects of the accruals recorded at both the beginning and end of the test year. KU proposed a similar adjustment in its most recent base rate case, Case No. 2008-00251 and a similar adjustment was also approved by the Commission in Case No. 2003-00434.

Q. Please explain the adjustment to operating expenses shown in Reference Schedule 1.15 of Rives Exhibit 1.

A. This adjustment has been made to reflect annualized depreciation expenses. The purpose of this adjustment is to reflect a full year's depreciation expense on net plant in service and TC2 assets, excluding depreciation on assets set up for asset retirement obligations and depreciation on assets remaining in the ECR, as of October, 31, 2009. Mr. Bellar's testimony will support the annualized depreciation expenses of TC2 generation and transmission assets as of October 31, 2009. The depreciation rates used in calculating the adjustment are those to which the parties agreed in the settlement of KU's last base rate case, Case No. 2008-00251, utilizing the Average Service Life methodology, which was found reasonable by the Commission, and for TC2 are the rates that were approved by the Commission's December 23, 2009 Order in Case No. 2009-00329 on an interim basis.

Q. Please explain the adjustment to operating expenses shown in Reference Schedule 1.22 of Rives Exhibit 1.

A. This adjustment is made to normalize the expenses in Account 925 "Injuries and Damages" based on a ten-year average adjusted for inflation. Because a full year of data is not available for 2009, the 2009 expense is for twelve months ending October 31, 2009; all other expense years are calendar years. KU proposed a similar adjustment in its most recent base rate case, Case No. 2008-00251 and a similar adjustment was also approved by the Commission in Case No. 2003-00434.

Q. Please explain the adjustment to operating expenses shown in Reference Schedule 1.23 of Rives Exhibit 1.

A. This adjustment eliminates advertising expenses that are primarily institutional and promotional in nature. Commission regulation 807 KAR 5:016, Section 2(1) provides that a utility will be allowed to recover, for ratemaking purposes, only those advertising expenses which produce a "material benefit" to its ratepayers. KU proposed a similar adjustment in its most recent base rate case, Case No. 2008-00251 and a similar adjustment was also approved by the Commission in Case No. 2003-00434.

Q. Please explain the adjustment to operating expenses shown in Reference Schedule 1.24 of Rives Exhibit 1.

A. This adjustment to operating income is necessary to exclude the expenses incurred in the test year associated with the Company's mainframe computer, which was retired in November 2009. The mainframe has been retired because the Customer Care Solution system is now fully implemented and this mainframe, which housed the previous system, is no longer needed.

Q. Please explain the adjustment to operating expenses shown in Reference Schedule 1.31 of Rives Exhibit 1.

A. This adjustment to operating expenses is necessary to include the expenses incurred in conjunction with this base rate case and annualized amortization for expenses incurred in the most recent base rate case, Case No. 2008-00251. KU estimates the total rate case expense to be $1,325,000. The adjustment has been amortized over 3 years at a rate of $441,667 per year. This estimate was used only for the purpose of calculating the revenue requirement at the time of filing KU's Application. KU requests recovery of its actual rate case expenses in this case in accordance with Commission policy and requests that it be allowed to provide the Commission monthly updates to reflect its actual rate case expenses through Commission requests for information. The adjustment thus will be trued-up as actual expenditures are incurred. This adjustment is consistent with a similar adjustment in the revenue requirements analysis performed and found reasonable by the Commission in the Company's most recent base rate case, Case No. 2008-00251, and in Case No. 2003-00434 and Case No. 2000-00080. The adjustment also includes the annualization of the amortization of rate case expenses from the last rate case, as the Commission approved a three-year amortization for those expenses in Case No. 2008-00251.

Capitalization

Q. Please explain the adjustment made in Rives Exhibit 2, Page 1 Column 3, "TC2 Joint Use Assets."

A. As described in the Companies' July 30, 2009 letter to the Commission's Executive Director, in December 2009, LG&E transferred to KU an interest in certain assets at the Trimble County Generating Station. These assets are necessary for the operation of TC2 ("TC2 Joint Use Assets"), in which unit KU owns 81% of the Companies' collective 75% ownership share pursuant to the Commission's Order in Case No. 2004-00507. KU previously held license and easement rights to, but no ownership interest in, the TC2 Joint Use Assets at the Trimble County Generating Station. The net book value of the assets transferred was $48.4 million. The transfer of the Joint Use Assets conforms the overall ownership interests to the allocation the Commission has already approved in Case No. 2004-00507. The addition to capitalization associated with KU's ownership interest in the TC2 Joint Use Assets is shown in Rives Exhibit 2, Page 1, Column 3.

Q. Does this conclude your testimony?

A. Yes, it does.

VERIFICATION

COMMONWEALTH OF KENTUCKY)
) SS:
COUNTY OF JEFFERSON)

The undersigned, **Shannon L. Charnas**, being duly sworn, deposes and says that she is Director – Utility Accounting and Reporting for E.ON U.S. Services, Inc., and that she has personal knowledge of the matters set forth in the foregoing testimony, and that the answers contained therein are true and correct to the best of her information, knowledge and belief.

Shannon L. Charnas

Shannon L. Charnas

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 22nd day of January 2010.

Tammy J. Elzy (SEAL)

Notary Public

My Commission Expires:

November 9, 2010

APPENDIX A

Shannon L. Charnas

Director, Utility Accounting & Reporting
E.ON U.S. Services Inc.
220 West Main Street
Louisville, KY 40202
(502) 627-4978

Professional Memberships

American Institute of Certified Public Accountants
Kentucky Society of Certified Public Accountants

Education

University of Louisville, Masters of Business Administration, 2000
University of Wisconsin Oshkosh, Bachelor of Business Administration with Majors in Accounting and Management Information Systems, 1993
Certified Public Accountant, Kentucky, 1995

Previous Positions

E.ON U.S.

2001 (Mar) - 2005 (Feb) - Manager, Finance & Budgeting - Energy Services
1999 (Sept) - 2001 (Apr) - Senior Budget Analyst
1995 (Aug) - 1999 (Sept) - Accounting Analyst, various positions

Arthur Andersen LLP

1995 – Senior Auditor
1993 – 1994 – Audit Staff

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

APPLICATION OF KENTUCKY UTILITIES COMPANY FOR AN ADJUSTMENT OF BASE RATES	)))	CASE NO. 2009-00548

TESTIMONY OF
RONALD L. MILLER
DIRECTOR, CORPORATE TAX
KENTUCKY UTILITIES COMPANY

Filed: January 29, 2010

Q. Please state your name, position and business address.

A. My name is Ronald L. Miller. I am the Director of Corporate Tax for Kentucky Utilities Company ("KU" or the "Company") and an employee of E.ON U.S. Services, Inc., which provides services to KU and Louisville Gas and Electric Company ("LG&E"). My business address is 220 West Main Street, Louisville, Kentucky. A statement of my education and work experience is attached to this testimony as Appendix A.

Q. Have you previously testified before the regulatory commissions?

A. Yes. I filed direct testimony on behalf of KU and LG&E in Case Nos. 2007-00178 (KU) and 2007-00179 (LG&E) concerning an advanced coal project investment tax credit. I have also sponsored numerous data responses in previous rate cases and other regulatory proceedings on tax issues. I have also submitted testimony before the Virginia State Corporation Commission in KU's most recent rate case.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to support certain pro forma adjustments to KU's operating income and capital structure for the twelve months ended October 31, 2009. The pro forma adjustments are described on the Reference Schedules attached to Rives Exhibit 1. My testimony demonstrates that these adjustments are known and measurable and, therefore, reasonable.

Pro Forma Adjustments

Q. Please explain the three adjustments to operating expenses shown in Reference Schedule 1.38 of Rives Exhibit 1.

A. Reference Schedule 1.38 contains three adjustments: the first removes the Kentucky coal credit received by the Company during the test year and applied to property tax expense; the second reduces property tax expense due to the resolution of a disputed property value assessment; and the third increases property tax expense associated with assets KU purchased from LG&E related to their respective ownership shares in Trimble County Unit No. 2 ("TC2").

Q. Please explain the first adjustment contained in Reference Schedule 1.38 of Rives Exhibit 1.

A. The coal credit was established by Kentucky Revised Statute 141.0405 and is contingent on the Company's annual level of Kentucky coal purchases versus its 1999 level of purchases. The Company must apply for the credit annually and, if approved, the coal tax credit must be applied first to income taxes, then any remaining credit may be applied to property taxes.

In addition to its contingent nature, this statutory credit is expiring, ending with Kentucky coal purchases made in calendar-year 2009 and therefore will not be a credit to tax expense on an ongoing forward basis. Calendar year 2000 was the first period wherein Kentucky coal purchases in excess of 1999 levels were eligible for the $2 per ton credit under KRS 141.0405. Under KRS 141.0406, Kentucky coal purchases in calendar year 2009 will be the last such purchases eligible for the credit. After that, the Companies will cease to be eligible for the credit. For that reason alone, the credit is not the kind of reoccurring reduction of tax expense appropriate to include in formulating base rates in this proceeding. Reference Schedule 1.38 contains the adjustment to remove this nonrecurring tax credit.

Q. Do you have a reasonable basis to believe the Kentucky Coal Tax Credit will be extended or replaced upon its expiration?

A. No. The Company is not aware of any potential tax credit statutes or mechanisms that would replace or extend the current coal tax credit statute. I wish to note that in 2005 the Kentucky General Assembly enacted a statute for new clean coal facilities (KRS 141.428) that provides a $2 per ton credit for eligible Kentucky coal purchases. Facilities eligible for this "Kentucky Clean Coal Incentive" must be certified by the Environmental and Public Protection Cabinet. Because this new credit applies only to facilities beginning commercial operation after January 1, 2005, none of our present facilities qualify for this credit. While the Company is planning to pursue this new credit in connection with TC2 if and when the credit can be obtained is not known and or measurable. It is therefore not appropriate to adjust rates in any amount on the basis of an unknown and only speculative tax credit.

Q. Please explain the second adjustment contained in Reference Schedule 1.38 of Rives Exhibit 1.

A. KU received its 2009 Kentucky Property Tax assessment dated September 23, 2009. The Company believed that the assessment was excessive and on October 28, 2009 filed a formal protest with the Kentucky Department of Revenue. Following the submission of the protest, the Company and the state reached a settlement in late December 2009. This pro-forma adjustment reduces test year property tax expense to the amount estimated for 2009 as a result of this settlement.

Q. Please explain the third adjustment contained in Reference Schedule 1.38 of Rives Exhibit 1.

A. In December 2009, KU purchased from LG&E a portion of certain assets at the Trimble County Generating Station previously used only by Trimble County Unit No. 1 ("TC1"), but which will be used by both TC1 and TC2 when TC2 becomes commercially operational ("Joint Use Assets"). The property tax expense related to Joint Use Assets sold by LG&E has been added to KU's test year expense and correspondingly removed from LG&E's test year expense.

Q. Please explain the adjustment to operating expenses shown in Reference Schedule 1.41 of Rives Exhibit 1.

A. Reference Schedule 1.41 shows the calculation of a composite federal and state income tax rate using a federal corporate income tax rate of 35%, and a Kentucky corporate income tax rate of 6%. The calculation includes a reduction of pre-tax income related to the domestic production activities deduction, enacted by the American Jobs Creation Act of 2004, and allowed by the Internal Revenue Code Section 199 (which was adopted by the state in Kentucky Revised Statutes 141.010), for both federal and state taxes. The current production activities deduction rate is 6%; however, the rate used in this adjustment is 9%, which is the rate effective beginning in January 2010. As shown on Reference Schedule 1.41 of Rives Exhibit 1, the composite federal and state income tax rate is 36.9264%. The method for calculating the composite tax rate KU uses in this schedule is similar to the method KU used its most recent base rate case, Case No. 2008-00251, and to the method the Commission approved in Case No. 2003-00434.

Q. **Please explain the adjustment to operating expenses shown in Reference Schedule 1.42 of Rives Exhibit 1.**

A. This adjustment is for federal and state income taxes corresponding to the annualization and adjustment of year-end interest expense. The Commission has traditionally recognized the income tax effects of adjustments to interest expense through an "interest synchronization" adjustment. KU proposed a similar adjustment in its most recent base rate case, Case No. 2008-00251 and a similar adjustment was also approved by the Commission in Case No. 2003-00434. The total capitalization amount for KU is taken from Rives Exhibit 2 and is multiplied by KU's weighted cost of debt, and that amount is then compared to KU's interest per books (excluding other interest) to arrive at the interest synchronization amount. The composite federal and state income tax rate from Reference Schedule 1.41 of Rives Exhibit 1 has been applied to the interest synchronization amount. The adjustment will be trued-up as the weighted cost of debt is updated.

Q. **Please explain the adjustment to operating expenses shown in Reference Schedule 1.43 of Rives Exhibit 1.**

A. This adjustment is for income tax true-ups related to the 2008 federal and state income tax returns and prior period adjustments booked to income tax expense during the test year. This adjustment also removes the Kentucky coal tax credit from the test year income tax expense, as I explained above concerning Reference Schedule 1.38 of Rives Exhibit 1. KU proposed a similar adjustment in its most recent base rate case, Case No. 2008-00251 and a similar adjustment was also approved by the Commission in Case No. 2003-00434.

Q. Please explain the adjustment to operating expenses shown in Reference Schedule 1.44 of Rives Exhibit 1.

A. This adjustment restates the test year income tax expenses for the production activities deduction. As mentioned above, the production activities deduction statutory rate in effect for the test year was 6%, the rate, however, will increase to 9% in calendar year 2010. This adjustment calculates the deduction based on the test year taxable income at the new 9% rate.

Q. Please explain the adjustment to operating expenses shown in Reference Schedule 1.45 of Rives Exhibit 1.

A. This adjustment relates to the annual amount of the permanent reduction in depreciable tax basis required by Internal Revenue Code 50(c) and attributable to the Advanced Coal Investment Tax Credit ("ACITC") awarded to KU and LG&E for TC2.[1] The annual amount of the lost tax basis was determined based on the total amount of ACITC claimed and recorded as of October 31, 2009, then amortized over the financial statement lives for the TC2 assets. These are the same lives used to record book depreciation expense. Amortization of this permanent depreciation basis difference is then multiplied by the statutory combined federal and state tax rate of 38.9%.

Q. Please explain Reference Schedule 1.47 of Rives Exhibit 1.

A. This Reference Schedule illustrates the calculation of the net after-tax factor needed to gross up the net operating income deficiency on Rives Exhibit 8 to determine the

[1] I discussed this requirement on page 9 of my May 4, 2007 direct testimony in Case No. 2007-00178, and the book and tax treatment of KU's portion of the credit in pages 7-9 of the same testimony. . In 1972, KU elected a rate treatment under the tax code' wherein KU would reduce its rate base by the amount of investment tax credit it received. This rate treatment is referred to as the "ratable restoration" method."

overall revenue deficiency. The calculation begins with an assumed $100 pre-tax income and is adjusted by the following to determine the equivalent state taxable income: a factor for bad debt expense that is equal to the percent of net charged-off accounts to revenue during the test year; the Kentucky Public Service Commission assessment factor based on the assessment from the Commonwealth of Kentucky Finance and Administrative Cabinet; and the Section 199 deduction related to domestic production activities from Reference Schedule 1.41 of Rives Exhibit 1. State income tax on the equivalent state taxable income is calculated using the statutory 6% rate. Equivalent federal taxable income is determined by deducting the state income tax from state taxable income.

Federal income tax on the equivalent federal taxable income is calculated using the statutory 35% rate. The difference between the assumed $100 pre-tax income and the total of the bad debt, Kentucky Public Service Commission assessment, and state and federal income tax factors is the gross up revenue factor.

This calculation is similar to the calculations presented in Case No. 2008-00251 and approved by the Commission in Case No. 2003-00434.

Q. Does this conclude your testimony?

A. Yes, it does.

VERIFICATION

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

The undersigned, **Ronald L. Miller**, being duly sworn, deposes and says that he is Director – Corporate Tax for E.ON U.S. Services, Inc., and that he has personal knowledge of the matters set forth in the foregoing testimony, and that the answers contained therein are true and correct to the best of his information, knowledge and belief.

Ronald L. Miller

Ronald L. Miller

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 22nd day of January 2010.

Tammy J. Elzy (SEAL)

Notary Public

My Commission Expires:

November 9, 2010

APPENDIX A

Ronald L. Miller
Director, Corporate Tax
E.ON U.S. Services Inc.
220 West Main Street
Louisville, Kentucky 40202
Telephone: (502) 627-2687

Education

Eastern Kentucky University, BBA, Major in Accounting, 1979
Certified Public Accountant, Kentucky, 1981
University of Louisville – The Effective Executive, 1996
Licensed Kentucky Real Estate Agent, 1978
Accredited Investment Fiduciary, 2009
Continuing Professional Education – (over 40 hours annually)

Positions Held

E.ON U.S. Services Inc. (LG&E Energy Corp.), Louisville, Kentucky

Director, Corporate Tax	June 2001 – present
Director, Corporate Accounting and Tax	June 1998 – June 2001
Director, Corporate Tax	July 1994 -- June 1998
Corporate Tax Administrator	January 1994 – July 1994
Corporate Tax Coordinator	February 1992 – December 1993

National City Bank, Louisville, Kentucky

Vice President, Corporate Treasury Officer and Manager-Tax and General Accounting	1984-1992

Ernst and Young CPA's, Louisville, Kentucky

Audit Supervisor	1983 – 1984
Audit Staff/Senior	1979 -- 1983

Professional Memberships

Tax Executives Institute, (past local President and past National Board Member)
Edison Electric Institute, Tax Committee
Greater Louisville Inc., Tax Committee
Kentucky Association of Manufacturers, Tax Committee
Kentucky Chamber of Commerce, Tax Committee
Kentucky Society of Certified Public Accountants
American Institute of Certified Public Accountants

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

APPLICATION OF KENTUCKY UTILITIES COMPANY FOR AN ADJUSTMENT OF BASE RATES	)))	**CASE NO. 2009-00548**

TESTIMONY OF
DANIEL K. ARBOUGH
TREASURER
KENTUCKY UTILITIES COMPANY

Filed: January 29, 2010

Q. Please state your name, position and business address.

A. My name is Daniel K. Arbough. I am the Treasurer for Kentucky Utilities Company ("KU" or the "Company") and an employee of E.ON U.S. Services Inc., which provides services to KU and Louisville Gas and Electric Company ("LG&E"). My business address is 220 West Main Street, Louisville, Kentucky. A statement of my education and work experience is attached to this testimony as Appendix A.

Q. Have you previously testified before the Commission?

A. Since 2000, I have attested to the factual representations in each of KU's financing applications filed with the Kentucky Public Service Commission ("Commission") and have appeared before the Commission Staff on behalf of the Company on a regular basis. I have not, however, testified before the Commission previously.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to discuss KU's cost of debt, as well as its current and target capital structures. I am also sponsoring Reference Schedules 1.18 and 1.19 of Rives Exhibit 1 of the testimony of S. Bradford Rives, which schedules describe pro-forma adjustments related to insurance costs of the Company.

Q. Please explain the capital structure of KU.

A. As KU's witnesses have stated in previous testimony before the Commission in Case Nos. 2003-00434 and 2008-00251, KU is firmly committed to maintaining the financial strength of the Company. The Company has a target capital structure of the midpoint of the range for "A" rated utilities published by Standard and Poor's ("S&P").

Q. What is the current target capital structure?

A. KU's current capital structure is established in accordance with the criteria set by S&P, an independent credit rating agency, to achieve an A rating. S&P issued guidelines for utility capital structures in an article entitled "*Utility Financial Targets Are Revised*" dated June 18, 1999. The debt to total capital range S&P established was 43 percent to 49.5 percent for A-rated utilities with a business position of 4. Prior to S&P's discontinuance of the business position ranking measure, KU was ranked with a business position of 4. This indicates an acceptable range for the equity component of capital of 50.5 percent to 57 percent.

More recently, S&P adopted a business and financial risk matrix structure in an article entitled, "*U.S. Utilities Ratings Analysis Now Portrayed in the S&P Corporate Ratings Matrix*," dated November 30, 2007. This article is attached as Arbough Exhibit 1. A copy of a November 26, 2008 article explaining the S&P methodology, "*Key Credit Factors: Business and Financial Risks in the Investor-Owned Utilities Industry*," is attached as Arbough Exhibit 2. The 2008 article explains that a utility's rating is a function of its "business risk profile" and its "financial risk profile." Table 1 from that article shows the relationship of S&P's assessments of the business and the financial risks for purposes of determining the credit rating of an investor-owned utility. KU's financial risk profile, according to S&P's assessment, fits the category between "Intermediate" and "Highly Leveraged" known as the "Aggressive" category for which S&P suggested (in the November 2007 article) a debt-to-total-capital range of 45-60 percent. As the table in the same 2007 article shows, given KU's "Excellent" business risk profile, the utility must achieve an "Intermediate" financial risk profile to move from its current BBB+ rating to its desired A rating. To reach the Intermediate financial risk profile, KU must maintain a debt-to-total-capital ratio of 35-50 percent as measured by S&P. KU targets the upper end of this leverage range with debt-to-total-capital, as measured by S&P, of approximately 48 percent.

This translates into a targeted adjusted equity-to-total-capital ratio (including imputed debt for purchased power, leases, pensions, and other adjustments) of 52 percent. As shown on Rives Exhibit 2, column 2, the overall equity component of capital per books is 53.93 percent as of October 31, 2009. Including the debt adjustments set forth in S&P's April 3, 2009 report for leases, pensions, and other adjustments, the equity ratio decreases to 51.44 percent. The power purchase agreements adjustment listed in the S&P report was not included because it relates to KU's long-term power purchase contract with Owensboro Municipal Utilities that will terminate in May 2010, as described in more detail in Mr. Bellar's testimony. The S&P report reflects an adjustment to debt for other power purchase agreements under "other adjustments." Consistent with past practice, the Asset Retirement Obligation adjustment has not been included. The debt ratio is somewhat higher than normal due to the magnitude of the pension adjustment ($120.9 million at year-end 2008 versus $54 million at year-end 2007) resulting from a weak investment environment in the second half of 2008.

Q. Why does the Company include adjustments to its debt balances in determining the target capital structure?

A. The Company treats power purchase agreements, operating leases, and pension obligations as debt in determining the target capital structure because the rating agencies require such obligations to be treated as fixed obligations equivalent to debt. S&P's April 3, 2009 review of KU noted that it has imputed $173.5 million of debt equivalent to KU for 2008 for leases, pensions, and other adjustments. If this adjustment is made to the capital structure shown in Rives Exhibit 2, KU's debt-to–total-capital ratio increases to 48.56 percent, just above the targeted ratio. This indicates an equity component of capital of 51.44 percent, at the low end of the S&P guideline range. Disregarding the impact of the power purchase agreements, leases, and pension obligations could impact the Company's debt rating and limit its future access to attractively priced debt capital.

Q. Has KU prepared an exhibit showing its capitalization as of October 31, 2009?

A. Yes. Rives Exhibit 2 to the testimony of S. Bradford Rives shows KU's capitalization at October 31, 2009.

Q. Can you explain what is contained in Rives Exhibit 2?

A. Yes. Rives Exhibit 2 shows the calculation of KU's adjusted capitalization for operations as of October 31, 2009, as well as the weighted average cost of capital to apply to the adjusted capitalization. Mr. Rives provides a fuller description of Rives Exhibit 2 in his testimony.

Q. Please explain how the cost of debt was calculated in Rives Exhibit 2.

A. The cost of debt shown in Rives Exhibit 2 is a weighted-average cost of debt as of the end of October 2009. It includes all components of interest expense for each bond including the interest paid to the bondholders, amortization of bond issuance costs, amortization of the losses associated with reacquiring bonds that were refinanced by the existing bonds, and the credit enhancements that support each series, if applicable. The credit enhancement costs include ongoing bond insurance fees and letter of credit fees paid to banks.

<u>Pro Forma Adjustments</u>

Q. Please describe the adjustment shown on Reference Schedule 1.18 of Rives Exhibit 1 relating to Property Insurance costs.

A. The Company renews its property insurance policy on November 1 each year. The adjustment reflected on the schedule shows the change in the insurance premium from the test year to the period of November 1, 2009, to October 31, 2010. The property insurance premium is determined by multiplying the premium rate times the estimated replacement cost of the insured facilities. The premium rate was unchanged for the new policy, but the estimated replacement cost was higher, based on the application of the Handy-Whitman Index to the original asset cost, which resulted in the higher insurance cost. The adjustment shown in Reference Schedule 1.18 of Rives Exhibit 1 adds the Kentucky-jurisdictional portion of the premium increase to KU's operating expenses.

Q. Please describe the adjustment shown on Reference Schedule 1.19 of Rives Exhibit 1 relating to liability insurance costs.

A. The adjustment in the liability insurance costs is related to a new pollution liability policy the Company purchased effective November 2009. The policy is designed to protect against all types of pollution risks, including the risk of ash pond failures similar to that experienced by the Tennessee Valley Authority ("TVA") in December 2008 at its Kingston Fossil Plant. The Company believed its general liability policy with AEGIS would cover such an incident; however, AEGIS has denied coverage to TVA concerning the Kingston incident under a policy that mirrors the Company's. Although the Company is confident in the safety of its ash ponds, it was prudent to purchase a separate policy that would cover a situation similar to TVA's Kingston incident to avoid any issue of coverage. There was a prolonged due-diligence process to put the coverage in place, which culminated in binding coverage on November 24, 2009. Additional insurance capacity was bound in December 2009, bringing the total amount of the insurance to $170 million. The $170 million limit is available to the Company and LG&E, and the premium has been allocated equally between the two companies. The requested adjustment includes only the Kentucky-jurisdictional portion of the premium paid for this new policy.

Q. Does this conclude your testimony?

A. Yes, it does.

VERIFICATION

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

The undersigned, **Daniel K. Arbough**, being duly sworn, deposes and says that he is Treasurer for Kentucky Utilities Company and an employee of E.ON U.S. Services, Inc., and that he has personal knowledge of the matters set forth in the foregoing testimony, and that the answers contained therein are true and correct to the best of his information, knowledge and belief.

Daniel K. Arbough

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 22nd day of January 2010.

Tammy J. Elzy (SEAL)
Notary Public

My Commission Expires:

November 9, 2010

APPENDIX A

Daniel K. Arbough

Treasurer
E.ON U.S. Services Inc.
220 West Main Street
Louisville, Kentucky 40202
(502) 627-4956

Previous Positions

E.ON U.S.
Director, Corporate Finance and Treasurer — January 2001 – September 2007

LG&E Energy Corp.
Director, Corporate Finance — May 1998 – January 2001

LG&E Energy Corp.
Manager, Corporate Finance — August 1996 – May 1998

LG&E Power Inc.
Manager, Project Finance — June 1994 - August 1996

Conoco Inc., Houston, Texas
Corporate Finance, Project Finance, and Credit Management — June 1988 - May 1994

Boise Cascade Office Products, Denver, Colorado
Inventory Management — November 1983 - September 1987

Professional/Trade Memberships

National Association of Corporate Treasurers
Association for Financial Professionals

Education

Master of Business Administration – Finance - May 1988 – GPA 3.8
University of Denver

Bachelor of Science Business Administration – General Business
June 1983 – GPA 3.9 – Graduated Summa Cum Laude
Honors Program scholarship recipient
University of Denver

Civic Activities

Louisville Central Community Centers – President, Board of Directors
National Center for Family Literacy – Endowment Oversight Committee

Arbough Exhibit 1

STANDARD
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Global Credit Portal
RatingsDirect®

November 30, 2007

U.S. Utilities Ratings Analysis Now Portrayed In The S&P Corporate Ratings Matrix

Primary Credit Analysts:
Todd A Shipman, CFA, New York (1) 212-438-7676; todd_shipman@standardandpoors.com
William Ferara, New York (1 212-438-1776; bill_ferara@standardandpoors.com
John W Whitlock, New York (1) 212-438-7678; john_whitlock@standardandpoors.com

Secondary Credit Analyst:
Michael Messer, New York (1) 212- 438-1618; michael_messer@standardandpoors.com

U.S. Utilities Ratings Analysis Now Portrayed In The S&P Corporate Ratings Matrix

The electric, gas, and water utility ratings ranking lists published today by Standard & Poor's U.S. Utilities & Infrastructure Ratings practice are categorized under the business risk/financial risk matrix used by the Corporate Ratings group. This is designed to present our rating conclusions in a clear and standardized manner across all corporate sectors. Incorporating utility ratings into a shared framework to communicate the fundamental credit analysis of a company furthers the goals of transparency and comparability in the ratings process. Table 1 shows the matrix.

Table 1

Business Risk/Financial Risk

	Financial Risk Profile				
Business Risk Profile	**Minimal**	**Modest**	**Intermediate**	**Aggressive**	**Highly leveraged**
Excellent	AAA	AA	A	BBB	BB
Strong	AA	A	A-	BBB-	BB-
Satisfactory	A	BBB+	BBB	BB+	B+
Weak	BBB	BBB-	BB+	BB-	B
Vulnerable	BB	B+	B+	B	B-

The utilities rating methodology remains unchanged, and the use of the corporate risk matrix has not resulted in any changes to ratings or outlooks. The same five factors that we analyzed to produce a business risk score in the familiar 10-point scale are used in determining whether a utility possesses an "Excellent," "Strong," "Satisfactory," "Weak," or "Vulnerable" business risk profile:

- Regulation,
- Markets,
- Operations,
- Competitiveness, and
- Management.

Regulated utilities and holding companies that are utility-focused virtually always fall in the upper range ("Excellent" or "Strong") of business risk profiles. The defining characteristics of most utilities--a legally defined service territory generally free of significant competition, the provision of an essential or near-essential service, and the presence of regulators that have an abiding interest in supporting a healthy utility financial profile--underpin the business risk profiles of the electric, gas, and water utilities.

As the matrix concisely illustrates, the business risk profile loosely determines the level of financial risk appropriate for any given rating. Financial risk is analyzed both qualitatively and quantitatively, mainly with financial ratios and other metrics that are calculated after various analytical adjustments are performed on financial statements prepared under GAAP. Financial risk is assessed for utilities using, in part, the indicative ratio ranges in table 2.

Table 2

Financial Risk Indicative Ratios - U.S. Utilities

(Fully adjusted, historically demonstrated, and expected to consistently continue)

	Cash flow		Debt leverage
	(FFO/debt) (%)	**(FFO/interest) (x)**	**(Total debt/capital) (%)**
Modest	40 - 60	4.0 - 6.0	25 - 40
Intermediate	25 - 45	3.0 - 4.5	35 - 50
Aggressive	10 - 30	2.0 - 3.5	45 - 60
Highly leveraged	Below 15	2.5 or less	Over 50

The indicative ranges for utilities differ somewhat from the guidelines used for their unregulated counterparts because of several factors that distinguish the financial policy and profile of regulated entities. Utilities tend to finance with long-maturity capital and fixed rates. Financial performance is typically more uniform over time, avoiding the volatility of unregulated industrial entities. Also, utilities fare comparatively well in many of the less-quantitative aspects of financial risk. Financial flexibility is generally quite robust, given good access to capital, ample short-term liquidity, and the like. Utilities that exhibit such favorable credit characteristics will often see ratings based on the more accommodative end of the indicative ratio ranges, especially when the company's business risk profile is solidly within its category. Conversely, a utility that follows an atypical financial policy or manages its balance sheet less conservatively, or falls along the lower end of its business risk designation, would have to demonstrate an ability to achieve financial metrics along the more stringent end of the ratio ranges to reach a given rating.

Note that even after we assign a company a business risk and financial risk, the committee does not arrive by rote at a rating based on the matrix. The matrix is a guide--it is not intended to convey precision in the ratings process or reduce the decision to plotting intersections on a graph. Many small positives and negatives that affect credit quality can lead a committee to a different conclusion than what is indicated in the matrix. Most outcomes will fall within one notch on either side of the indicated rating. Larger exceptions for utilities would typically involve the influence of related unregulated entities or extraordinary disruptions in the regulatory environment.

We will use the matrix, the ranking list, and individual company reports to communicate the relative position of a company within its business risk peer group and the other factors that produce the ratings.

Arbough Exhibit 2

STANDARD & POOR'S

Global Credit Portal
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November 26, 2008

Criteria | Corporates | Utilities:

Key Credit Factors: Business And Financial Risks In The Investor-Owned Utilities Industry

Primary Credit Analyst:
Todd A Shipman, CFA, New York (1) 212-438-7676; todd_shipman@standardandpoors.com

Table Of Contents

Criteria | Corporates | Utilities:

Key Credit Factors: Business And Financial Risks In The Investor-Owned Utilities Industry

(Editor's Note: Table 1 in this article is no longer current. It has been superseded by the table found in "Criteria Methodology: Business Risk/Financial Risk Matrix Expanded," published May 27, 2009, on RatingsDirect.)

Standard & Poor's Ratings Services' analytic framework for companies in all sectors, including investor-owned utilities, is divided into two major segments: The first part is the fundamental business risk analysis. This step forms the basis and provides the industry and business contexts for the second segment of the analysis, an in-depth financial risk analysis of the company.

An integrated utility is often a part of a larger holding company structure that also owns other businesses, including unregulated power generation. This fact does not alter how we analyze the regulated utility, but it may affect the ultimate rating outcome because of any higher risk credit drag that the unregulated activities may have on the utility. Such considerations include the freedom and practice of management with respect to shifting cash resources among subsidiaries and the presence of ring-fencing mechanisms that may protect the utility.

Relationship Between Business And Financial Risks

Prior to discussing the specific risk factors we analyze within our framework, it is important to understand how we view the relationship between business and financial risks. Table 1 displays this relationship and its implications for a company's rating.

Table 1

Business And Financial Risk Profile Matrix

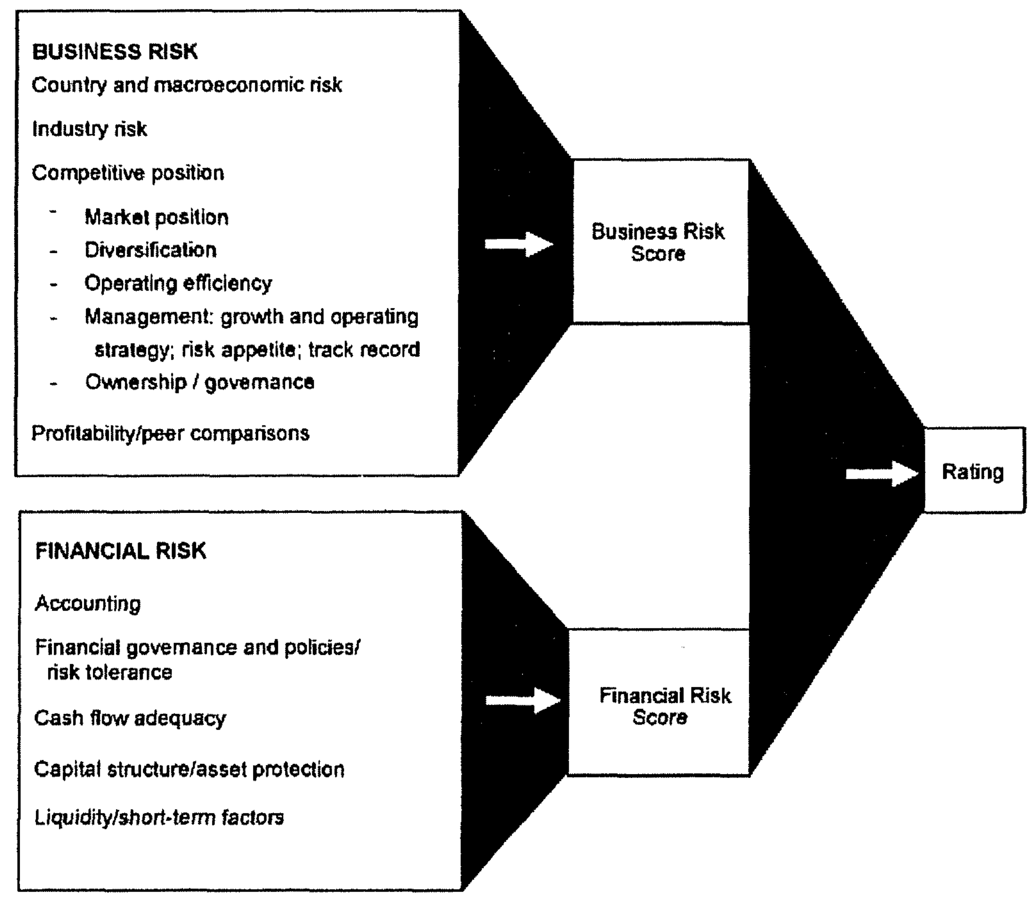
Business Risk Profile		Financial Risk Profile: Minimal	Modest	Intermediate	Aggressive	Highly leveraged
		(AAA/AA)	(A)	(BBB)	(BB)	(B)
Excellent	(AAA/AA)	AAA	AA	A	BBB	BB
Strong	(A)	AA	A	A-	BBB-	BB-
Satisfactory	(BBB)	A	BBB+	BBB	BB+	B+
Weak	(BB)	BBB	BBB-	BB+	BB-	B
Vulnerable	(B)	BB	B+	B+	B	B-

These rating outcomes are shown for guidance purposes only. Other qualitative and quantitative rating factors may override these measures.

Chart 1 summarizes the ratings process.

Chart 1

Scoring And Rating Determination Process



Part 1--Business Risk Analysis

Business risk is analyzed in four categories: country risk, industry risk, competitive position, and profitability. We determine a score for the overall business risk based on the scale shown in table 2.

Table 2

Business Risk Measures

Description	Rating equivalent
Excellent	AAA/AA
Strong	A
Satisfactory	BBB
Weak	BB
Vulnerable	B/CCC

Analysis of business risk factors is supported by factual data, including statistics, but ultimately involves a fair amount of subjective judgment. Understanding business risk provides a context in which to judge financial risk, which covers analysis of cash flow generation, capitalization, and liquidity. In all cases, the analysis uses historical experience to make estimates of future performance and risk.

In the U.S., regulated utilities and holding companies that are utility-focused virtually always fall in the upper range (Excellent or Strong) of business risk profiles. The defining characteristics of most utilities--a legally defined service territory generally free of significant competition, the provision of an essential or near-essential service, and the presence of regulators that have an abiding interest in supporting a healthy utility financial profile--underpin the business risk profiles of the electric, gas, and water utilities.

1. Country risk and macroeconomic factors (economic, political, and social environments)

Country risk plays a critical role in determining all ratings on companies in a given national domicile. Sovereign-related stress can have an overwhelming effect on company creditworthiness, both directly and indirectly.

Sovereign credit ratings suggest the general risk local entities face, but the ratings may not fully capture the risk applicable to the private sector. As a result, when rating a corporation, we look beyond the sovereign rating to evaluate the specific economic or country risks that may affect the entity's creditworthiness. Such risks pertain to the effect of government policies and other country risk factors on the obligor's business and financial environments, and an entity's ability to insulate itself from these risks.

2. Industry business and credit risk characteristics

In establishing a view of the degree of credit risk in a given industry for rating purposes, it is useful to consider how its risk profile compares to that of other industries. Although the industry risk characteristic categories are broadly similar across industries, the effect of these factors on credit risk can vary markedly among industries. Chart 2 illustrates how the effects of these credit-risk factors vary among some major industries. The key industry factors are scored as follows: High risk (H), medium/high risk (M/H), medium risk (M), low/medium risk (L/M), and low risk (L).

Chart 2

Key Industry Characteristics And Drivers Of Credit Risk

	Utilities regulated	Competitive power	Oil & gas downstream	Autos	Airlines
Industry dynamics and competitive environment					
Industry cyclicality	M	H	H	H	H
Ease of entry	L	M/H	H	M/H	M/H
Product cycle/obsolescence	L	L	L	H	L
Level of product quality	L	L	M	H	M
Disintermediation/substitution	L	L	L	L/M	L
Competition/commoditization	L/M	H	M	H	H
Pricing inflexibility	M	H	M	H	H
Business model stability	M	M/H	L	L/M	M
Demographic trends	L	L	M	H	L
Growth and profitability					
Growth outlook	L	M	L	M/H	L/M
Profit margin pressure/outlook	M	M/H	M	M/H	H
Earnings volatility	M	M/H	H	H	H
Operating considerations and costs					
Technological risk/change	L	L	L/M	L/M	L/M
Cost efficiency/pressures	M	H	M	H	H
Operating leverage	M/H	H	H	H	H
R&D costs	L	L	L	H	L
Energy cost sensitivity	H	H	H	H	H
Raw material cost sensitivity	H	H	H	H	L
Labor costs	M	M	M	H	H
Labor inflexibility/unrest	L	L	M	H	H
Pension costs/contingents	M	L	L/M	H	M/H
Environmental impact/costs	H	L	H	H	M/H
Marketing costs	L	L	M	H	L/M
Customer concentration	L	M	L	L	L
Supplier concentration	H	H	H	M	M
Risk management	M	H	M	M	M
Asset/plant quality and age/upkeep	M	H	H	M	M/H
Event risk sensitivity	M/H	H	H	M/H	H
Financial market volatility/sensitivity	M	M/H	L	M	M
Fashion/fad/design sensitivity	L	L	L	H	L/M
Capital and financing characteristics					
Capital intensity	H	H	H	H	H
Borrowing requirement	H	H	L/M	H	H
Interest rate sensitivity	L/M	L/M	L/M	H	L/M
Government, regulatory, and legal environments					
Regulation/deregulation	H	H	M	M/H	H
Government microeconomic and social policies	H	H	H	H	M/H
Litigiousness/legal risk	L	H	M	M	M

Industry strengths:

- Material barriers to entry because of government-granted franchises, despite deregulatory trends;
- Strategically important to national and regional economies; key pillar of the consumer and commercial economy;
- Improving management focus industry-wide on operating efficiency in recent years; and
- Cross-border growth opportunities in Europe and industrializing emerging markets.

Industry challenges/risks:

- Maturity, with a weak growth outlook in developed countries;
- Highly politicized and burdensome regulatory (i.e., rate setting and investment recovery) process; and
- Risks of "legacy cost drag" as wholesale and retail markets move toward greater deregulation.

Major global risk issues facing the utilities industry:

- Increased volatility in the regulatory environment and competitive landscape leading to greater uncertainty regarding adequacy of pricing and return on capital;
- Longer-term impact of, and ability to absorb, significant secular upturn in fuel costs, which is the industry's major operating expense;
- Ability to recover massive investment costs that will likely be necessary to replace aging industry infrastructure in a harsher cost and regulatory environment; and
- The debate over global warming will continue far beyond 2008. What the ultimate outcome will be is unclear, but growing legislation addressing carbon emissions and other greenhouse gases is probable in the near future. Utilities' ability to recover environmentally mandated costs in authorized rates and consumers' willingness to pay them could impact the industry's future credit strength.

Industry business model and risk profile in transition

Regulated utilities are in many developed countries transitioning away from quasi-monopolies toward more open competitive environments.

The level of business and credit risk associated with the investor-owned regulated utilities has historically proven in most countries to be lower (risk) than for many other industries. This has been because of the existence of government policy and related regulation that created significant barriers to entry limiting competition, and regulatory rate setting designed to provide an opportunity to achieve a specific level of profitability. The credit quality of most vertically integrated utilities in developed countries has historically been, and remains, solidly investment grade. This, to reiterate, is primarily a function of the existence of protective regulation.

The risks of, and rationale for, deregulation

The traditional protected and privileged utilities industry business model with its marked monopolistic characteristics is in many countries undergoing transition to a more competitive and open framework. This transition process, known as deregulation or liberalization, is weakening the business and credit risk profile of the industry. While the impact of these changes may prove positive in the longer term for more efficient industry players, it is important to bear in mind that economic history is littered with the vestiges of industries and enterprises that once flourished under the protection of government-created barriers and other protections. The shift is being driven by introduction in many countries of policies to encourage the entrance of new competitors and to reduce the traditional regulatory protections and privileges enjoyed by incumbents. Historically, the regulated investor-owned utilities were usually granted exclusive franchises. Because of the significant risks associated with the capital-intense nature of the utility investment, including massive sunk/fixed costs and long-term break-even horizons, governments in many countries created legal and regulatory frameworks that granted exclusivity to one operator in a given geographic area. To offset the monopolistic pricing power this exclusivity created, a system of heavy regulation was typically developed, which included the setting of pricing. The model often set pricing on a "cost-plus-basis", i.e., the margin over cost allowing for a perceived fair return to shareholders of investor-owned utilities. One major weakness of this system is that it created little incentive for utilities to efficiently manage costs. In recent years as many governments have adopted more liberal open market economic philosophies and related policies focused on the creation of greater competition—in an effort to foster improved economic growth and pricing efficiency throughout the economy—the traditional utility models in many countries have come under increasing political scrutiny and pressure.

A major public policy and political risk, as well as a credit risk, associated with deregulation of protected industries, is that existing incumbents often experience significant challenges in readjusting their management strategies, cultures, and expense basis to be able to compete effectively in the new environment.

The turmoil and bankruptcies in the U.S. in the nonregulated power marketing and trading arena between 2000 and 2002 arose subsequent to a major government initiative to deregulate the wholesale market. These failures, as well as other high-profile problems arising from deregulation elsewhere in the world, have given governments pause as to the desirability of a headlong rush into deregulation. In the U.S., for example, there is currently little impetus to carry deregulation any further.

Regulation and deregulation in the U.S.

While considerable attention has been focused on companies in states that deregulated in the late 1990s and the early part of this decade, and the related consequences of disaggregation and nonregulated generation, 27 states (plus four that formally reversed, suspended, or delayed restructuring) have retained the traditional regulated model. For utilities operating in those states, the quality of regulation and management loom considerably larger than markets, operations, and competitiveness in shaping overall financial performance. Policies and practices among state and federal regulatory bodies will be key credit determinants. Likewise, the quality of management, defined by its posture towards creditworthiness, strategic decisions, execution and consistency, and its ability to sustain a good working relationship with regulators, will be key. Importantly, however, it is virtually impossible to completely segregate each of these characteristics from the others; to some extent they are all interrelated.

Fragmentation of original model emerges in the U.S.

- Traditional regulated, vertically integrated utilities (generation, transmission, and distribution);
- Transmission and distribution;
- Diversified;
- Transmission; and
- Merchant generation.

We view a company that owns regulated generation, transmission, and distribution operations as positioned between companies with relatively low-risk transmission and distribution operations and companies with higher-risk diversified activities on the business profile spectrum. What typically distinguishes one vertically integrated utility's business profile score from another is the quality of regulation and management, which are the two leading drivers of credit quality.

Deregulation in the U.S. creates a new volatile industry subsector

The birth of large-scale, nonregulated power generators created the opportunity--and the need--for companies to market and broker power. Power marketers, independent power producers, and unregulated subsidiaries of utility companies offer power-supply alternatives to other utilities in the wholesale market as well as to large industrial customers. Power marketing operations have been formed by energy companies (many with experience in marketing natural gas), utility subsidiaries, and independents. As with the gas industry, electric power marketers expected to develop an efficient market by straddling the gulf between electricity generators and their customers, who have become "free agents" in the newly competitive environment.

Deregulation creates tiering of industry, business and credit risk profiles in Europe

The regional differences in market liberalization across Western Europe result in material variations in industry and business risk profiles for the utilities industry at the national level. The U.K. and Nordic markets, in particular, are substantially deregulated and open, and consequently present higher risks than other markets that are less open, including France and the Iberian market. Ratings therefore generally are lower in these more deregulated markets. The less-liberalized markets may face more regulatory risk going forward, particularly if efforts by the EU to advance the internal market by increasing the extent of market liberalization across the EU continue.

Legal action against companies that infringe on competition laws should be expected--particularly against those that move to prevent new entry and limit customer choice (for example, through the tying of markets and capacity hoarding) or collude with other incumbents to do so. The European Commission (EC) can fine companies that have violated antitrust laws up to 10% of their global annual turnover and, under certain conditions, impose structural remedies. Particular emphasis would be placed on increasing the effective unbundling of network and supply activities and on diminishing market concentration and barriers to entry.

The EC has publicly stated is intention to pursue, as a priority, abuses of the dominant position of vertically integrated companies (called vertical foreclosure). Behavioral remedies, such as energy release programs, are expected to be imposed by the EC for which such abuses, or collusion, are proved. The commission could also enforce structural measures when behavioral remedies are deemed insufficient.

3. Company competitive position and keys to competitive success

In analyzing a company's competitive position, we consider the following:

- Regulation;
- Markets;
- Diversification;
- Operations;
- Management, including growth strategy;
- Governance; and
- Profitability.

We are most concerned about how these elements contribute individually and in aggregate to the predictability and sustainability of financial performance, particularly cash flow generation relative to fixed obligations.

Regulation.

Critical success factors include:

- Consistency and predictability of decisions;
- Support for recovery of fuel and investment costs;
- History of timely and consistent rate treatment, permitting satisfactory profit margins and timely return on investment; and
- Support for a reasonable cash return on investment.

Regulation is the most critical aspect that underlies regulated integrated utilities' creditworthiness. Regulatory decisions can profoundly affect financial performance. Our assessment of the regulatory environments in which a utility operates is guided by certain principles, most prominently consistency and predictability, as well as efficiency and timeliness. For a regulatory process to be considered supportive of credit quality, it must limit uncertainty in the recovery of a utility's investment. They must also eliminate, or at least greatly reduce, the issue of rate-case lag, especially when a utility engages in a sizable capital expenditure program.

Our evaluation encompasses the administrative, judicial, and legislative processes involved in state and national government regulation, and includes the political environment in which commissions render decisions. Regulation is assessed in terms of its ability to satisfy the particular needs of individual utilities. Rate-setting actions are reviewed case by case with regard to the potential effect on credit quality.

Evaluation of regulation focuses on the ability of regulation to provide utilities with the opportunity to generate cash flow and earnings quality and stability adequate to:

- Meet investment needs;
- Service debt and maintain a satisfactory rating profile; and
- Generate a competitive rate of return to investors.

To achieve this, regulation must allow for:

- Timely recognition of volatile cost components such as fuel and satisfactory returns on invested capital and equity;
- Ability to enter into long-term arrangements at negotiated rates without having to seek regulatory approval for each contract; and
- Ability to recover costs in new investment over a reasonable time frame.

Because the bulk of a utility's operating expenses relate to fuel and purchased power, of primary importance to rating stability is the level of support that state regulators provide to utilities for fuel cost recovery, particularly as gas and coal costs have risen. Utilities that are operating under rate moratoriums, or without access to fuel and purchased-power adjustment clauses, or face significant regulatory lag, also are subject to reduced operating margins, increased cash flow volatility, and greater demand for working capital. Companies that are granted fuel true-ups may be required to spread recovery over many years to ease the pain for the consumer. In addition to fuel cost recovery filings, regulators will have to address significant rate increase requests related to new generating capacity additions, environmental modifications, and reliability upgrades. Current cash recovery and/or return by means of construction work in progress support what would otherwise sometimes be a significant cash flow drain and reduces the utility's need to issue debt during construction.

Markets/market position.
Critical success factors include:

- A healthy and growing economy;
- Growth in population and residential and commercial customer base;
- An attractive business environment;
- An above-average residential base; and
- Limited bypass risk.

The importance of diversification and size.
Critical success factors include:

- Regional and cross-border market diversification (mitigates economic, demographic, and political risk concentration);

- Industrial customer diversification;
- Fuel supplier diversification;
- Retail, compared with wholesale;
- Regulatory regime diversification; and
- Generating facility diversification.

Operations (operating strategy, capability, and performance efficiency).
Critical success factors include:

- Low cost structure;
- Well-maintained assets;
- Solid plant performance;
- Adequate generating reserves, and compliance with environmental standards; and
- Limited environmental exposures.

Management evaluation.
Utilities are complex specialized businesses requiring experienced and successful management teams to have a strong mix of the aforementioned disciplines. Critical elements of management success include:

- Commitment to credit quality;
- Operating efficiency and cost control;
- Maintaining a competitive asset base, i.e., power plant construction project management, and plant upkeep and renovation;
- Regulatory track record, process, and relationship management;
- M&A experience in successfully identifying, executing, and integrating acquisitions;
- Credibility and strong corporate governance;
- Conservative financial policies, especially regarding non-regulated activities; and
- Ability and track record in repositioning and transforming business to not just survive, but prosper in a more open market environment.

Management is assessed for its ability to run and expand the business efficiently, while mitigating inherent business and financial risks. The evaluation also focuses on the credibility of management's strategy and projections, its operating and financial track record, and its appetite for assuming business and financial risk.

The management assessment is based on tenure, turnover, industry experience, financial track record, corporate governance, a grasp of industry issues, and knowledge of regulation, the impact of deregulation, of customers, and their needs. Management's ability and willingness to develop workable strategies to address system needs, and to execute reasonable and effective long-term plans are assessed. Management quality is also indicated by thoughtful balancing of multiple priorities; a record of credibility; and effective communication with the public, regulatory bodies, and the financial community.

We also focus on management's ability to achieve cost-effective operations and commitment to maintaining credit quality. This can be assessed by evaluating accounting and financial practices, capitalization and common dividend objectives, and the company's philosophy regarding growth and risk-taking.

4. Profitability/peer comparison

Regulated.

Traditionally, the lower levels of risk in utilities because of the highly regulated environment has resulted in lower profitability and return on capital than in many other industrial sectors. In the regulated marketplace the level and margin of profitability has often primarily been a function of regulatory leeway, with the contribution of operating efficiency and revenue growth taking more of a back seat.

Deregulated/liberalized environments.

In deregulated markets, cost efficiency and flexibility, and internal growth, are the major profitability drivers. The development of a robust risk management culture and infrastructure are also keys to creating stability of earnings, because the company no longer has recourse to the regulator to cover costs or losses—a recourse that usually protects from downside earnings surprises in the regulated sector.

Whether generated by the regulated or deregulated side of the business, profitability is critical for utilities because of the need to fund investment-generating capacity, maintain access to external debt and equity capital, and make acquisitions. Profit potential and stability is a critical determinant of credit protection. A company that generates higher operating margins and returns on capital also has a greater ability to fund growth internally, attract capital externally, and withstand business adversity. Earnings power ultimately attests to the value of the company's assets, as well. In fact, a company's profit performance offers a litmus test of its fundamental health and competitive position. Accordingly, the conclusions about profitability should confirm the assessment of business risk, including the degree of advantage provided by the regulatory environment.

Part 2—Financial Risk Analysis

Having evaluated a company's competitive position, operating environment, and earnings quality, our analysis proceeds to several financial categories. Financial risk is portrayed largely through quantitative means, particularly by using financial ratios.

We analyze five risk categories: accounting characteristics; financial governance/policies and risk tolerance; cash flow adequacy; capital structure and leverage; and liquidity/short-term factors. We then determine a score for overall financial risk using the following scale:

Table 3

Financial Risk Measures

Description	Rating equivalent
Minimal	AAA/AA
Modest	A
Intermediate	BBB
Aggressive	BB
Highly leveraged	B

The major goal of financial risk analysis is to determine the quality of cash resources from operations and other major sources available to service the debt and other financial liabilities, including any new debt. An integral part of this analysis is to form an understanding of the debt structure, including the mix of senior versus subordinated, fixed versus floating debt, as well as its maturity structure. It is also important to analyze and form an opinion of management's financial policy, accounting elections, and risk appetite. Using cash flow analysis as a building block, it is further necessary to establish the company's liquidity profile and flexibility. While closely interrelated, the analysis of a company's liquidity differs from that of its cash flow as it also incorporates the evaluation of other sources and uses of funds, such as committed undrawn bank facilities, as well as contingent liabilities (e.g., guarantees, triggers, regulatory issues, and legal settlements).

1. Accounting characteristics

Financial statements and related footnotes are the primary source of information about a company's financial condition and performance. The analysis begins with a review of accounting characteristics to determine whether ratios and statistics derived from the statements adequately measure a company's performance and position relative to those of both its direct peer group and the universe of industrial companies. This assessment is important in providing a common frame of reference and in helping the analyst determine the quality of disclosure and the reliability of the reported numbers. We focus on the following areas:

- Analytical adjustments and areas of potential concern;
- Significant transactions and notable events that have accounting implications.
- Significant accounting and financial reporting policies and the underlying assumptions.
- History of nonoperating results and extraordinary charges or adjustments and underlying accounting treatment, disclosure, and explanation.

2. Financial governance/policies and risk tolerance

The robustness of management's financial and accounting strategies and related implementation processes is a key element in credit risk evaluation. We attach great importance to management's philosophies and policies involving financial risk.

Financial policies are also important because companies with more conservative balance sheets and the credit capacity to pursue the necessary investments or acquisitions gain an advantage. Overly aggressive capital structures can leave very little capacity to absorb unexpected negative developments and will certainly leave little capacity to make future strategic investments. Companies with the credit capacity to support strategic investments will be better positioned to both evolve with industry change and to withstand inevitable downturns.

Understanding management's strategy for raising its share price, including its financial performance objectives, e.g., return on equity, can provide invaluable insight about the financial and business risk appetite.

3. Cash flow adequacy

Cash-flow analysis is one of the most critical elements of all credit rating decisions. Although there usually is a strong relationship between cash flow and profitability, many transactions and accounting entries affect one and not the other. Analysis of cash-flow patterns can reveal a level of debt-servicing capability that is either stronger or weaker than might be apparent from earnings. Focusing on the source and quality/volatility of cash flow is also important (e.g., regulated/deregulated; generation/transmission/trading).

A review of cash flow historically, as well as needs on a forward-looking basis, should take into account levels of capital expenditures for new generation plants. In periods where elevated new construction occurs in anticipation of a rise in power demand, cash outflows will be high.

It is particularly important to evaluate capital-intensive businesses, such as utility companies, on the basis of how much cash they generate and absorb. Debt service is an especially important use of cash flow.

Cash-flow ratios.
Ratios show the relationship of cash flow to debt and debt service, and also to the company's needs. Because there are calls on cash flow other than repaying debt, it is important to know the extent to which those requirements will allow cash to be used for debt service or, alternatively, lead to greater need for borrowing. The most important cash flow ratios we look at for the investor-owned utilities are:

- Funds from operations (FFO)/Total debt;
- FFO/Income;
- Funds from operations/Total debt (adjusted for off-balance-sheet liabilities);
- EBITDA/Interest; and
- Net cash flow/Capital spending requirements.

4. Capital structure and leverage
For utilities, the long-term nature of capital commitments and extended breakeven periods on investment, make the type of financing required by these companies to finance these needs to be similar in many ways to the financing needs of other long-term asset-intensive businesses. Our analysts review projections of future CAPEX, debt, and FFO levels to make a determination of the likely level of leverage and debt over the medium term, and the companies' ability to sustain them. The valuation of the debt amortization scheduled is tied into projections of profitability breakeven, and the underlying assets becoming cash-flow-positive, are key components of the combined cash flow and leverage analysis.

Capitalization ratios.
When analyzing a utility's balance sheet, a key element is analysis of capitalization ratios. The main factors influencing the level of debt are the level of capital expenditures, particularly construction expenditures, and the cost of debt. Companies with strong balance sheets will have more flexibility to further reduce their debt, and/or increase their dividends. The following are useful indicators of leverage:

- Total debt*/total debt + equity; and
- Total debt* + off-balance-sheet liabilities/total debt + off-balance-sheet liabilities + equity.

*Power purchase agreement-adjusted total debt. Fully adjusted, historically demonstrated, and expected to consistently continue.

Debt leverage, and interest and amortization coverage ratios are the key drivers of the financial risk score.

5. Liquidity/working capital/short-term factors:
Our liquidity analysis starts with operating cash flow and cash on hand, and then looks forward at other actual and contingent sources and uses of funds in the short term that could either provide or drain cash under given circumstances.

A key source of liquidity is bank lines. Key factors reviewed are total amount of facilities; whether they are contractually committed; facility expiration date(s); current and expected usage and estimated availability; bank group quality; evidence of support/lack of support of bank group; and covenant and trigger analysis. Financial covenant analysis is critical for speculative-grade credits. We request copies of all bank loan agreements and bond terms and conditions for rated entities, and review supplemental information provided by issuers for listing of financial covenants and stipulated compliance levels. We review covenant compliance as indicated in compliance certificates, as well as expected future compliance and covenant headroom levels. Entities that have already tripped or are expected to trip financial covenants need to be subject to special scrutiny and are reviewed for their ability to obtain waivers or modifications need to be subject to special scrutiny and are reviewed for their ability to obtain waivers or modifications to covenants. Tripping covenants can have a double negative effect on a company's liquidity. It may preclude it from borrowing further under its credit line, and may also lead to a contractual acceleration of repayment and increased interest rates.

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

APPLICATION OF KENTUCKY UTILITIES COMPANY FOR AN ADJUSTMENT OF BASE RATES	)))))	**CASE NO. 2009-00548**

DIRECT TESTIMONY

OF

WILLIAM E. AVERA

on behalf of

KENTUCKY UTILITIES COMPANY

Filed: January 29, 2010

DIRECT TESTIMONY OF WILLIAM E. AVERA

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I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. William E. Avera, 3907 Red River, Austin, Texas, 78751.

Q. IN WHAT CAPACITY ARE YOU EMPLOYED?

A. I am the President of FINCAP, Inc., a firm providing financial, economic, and policy consulting services to business and government.

A. Qualifications

Q. PLEASE DESCRIBE YOUR QUALIFICATIONS AND EXPERIENCE.

A. I received a B.A. degree with a major in economics from Emory University. After serving in the U.S. Navy, I entered the doctoral program in economics at the University of North Carolina at Chapel Hill. Upon receiving my Ph.D., I joined the faculty at the University of North Carolina and taught finance in the Graduate School of Business. I subsequently accepted a position at the University of Texas at Austin where I taught courses in financial management and investment analysis. I then went to work for International Paper Company in New York City as Manager of Financial Education, a position in which I had responsibility for all corporate education programs in finance, accounting, and economics.

In 1977, I joined the staff of the Public Utility Commission of Texas ("PUCT") as Director of the Economic Research Division. During my tenure at the PUCT, I managed a division responsible for financial analysis, cost allocation and rate design, economic and financial research, and data processing systems, and I testified in cases on a variety of financial and economic issues. Since leaving the PUCT, I have been engaged as a consultant. I have participated in a wide range of assignments involving utility-related matters on behalf of utilities, industrial customers, municipalities, and regulatory commissions. I have previously testified before the Federal Energy Regulatory Commission ("FERC"), as well as the Federal Communications Commission, the Surface Transportation Board (and its predecessor, the Interstate Commerce Commission), the Canadian Radio-Television and Telecommunications Commission, and regulatory agencies, courts, and legislative committees in over 40 states, including the Public Service Commission of the Commonwealth of Kentucky ("KPSC" or "the Commission").

In 1995, I was appointed by the PUCT to the Synchronous Interconnection Committee to advise the Texas legislature on the costs and benefits of connecting Texas to the national electric transmission grid. In addition, I served as an outside director of Georgia System Operations Corporation, the system operator for electric cooperatives in Georgia.

I have served as Lecturer in the Finance Department at the University of Texas at Austin and taught in the evening graduate program at St. Edward's University for twenty years. In addition, I have lectured on economic and regulatory topics in programs sponsored by universities and industry groups. I have taught in hundreds of educational programs for financial analysts in programs sponsored by the Association for Investment Management and Research, the Financial Analysts Review, and local financial analysts societies. These programs have been presented in Asia, Europe, and North America, including the Financial Analysts Seminar at Northwestern University. I hold the Chartered Financial Analyst (CFA®) designation and have served as Vice President for Membership of the Financial Management Association. I have also served on the Board of Directors of the North Carolina Society of Financial Analysts. I was elected Vice Chairman of the National Association of Regulatory Commissioners ("NARUC") Subcommittee on Economics and appointed to NARUC's Technical Subcommittee on the National

Energy Act. I have also served as an officer of various other professional organizations and societies. A resume containing the details of my experience and qualifications is attached as Exhibit WEA-1.

B. Overview

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is to present to the KPSC my independent assessment of the fair rate of return on equity ("ROE") that Kentucky Utilities Company ("KU" or "the Company") should be authorized to earn on its investment in providing electric utility service. In addition, I also examined the reasonableness of KU's capital structure, considering both the specific risks faced by the Company, as well as other industry guidelines.

Q. PLEASE SUMMARIZE THE BASIS OF YOUR KNOWLEDGE AND CONCLUSIONS CONCERNING THE ISSUES TO WHICH YOU ARE TESTIFYING IN THIS CASE.

A. To prepare my testimony, I used information from a variety of sources that would normally be relied upon by a person in my capacity. In connection with the present filing, I considered and relied upon corporate disclosures, publicly available financial reports and filings, and other published information relating to KU. I also reviewed information relating generally to capital market conditions and specifically to investor perceptions, requirements, and expectations for electric utilities. These sources, coupled with my experience in the fields of finance and utility regulation, have given me a working knowledge of the issues relevant to investors' required return for KU, and they form the basis of my analyses and conclusions.

Q. WHAT IS THE ROLE OF THE ROE IN SETTING UTILITY RATES?

A. The ROE compensates common equity investors for the use of their capital to finance the plant and equipment necessary to provide utility service. Investors commit capital only if they expect to earn a return on their investment commensurate with returns available from alternative investments with comparable risks. To be consistent with sound regulatory economics and the standards set forth by the Supreme Court in the *Bluefield*[1] and *Hope*[2] cases, a utility's allowed ROE should be sufficient to: (1) fairly compensate investors for capital invested in the utility, (2) enable the utility to offer a return adequate to attract new capital on reasonable terms, and (3) maintain the utility's financial integrity.

Q. HOW IS YOUR TESTIMONY ORGANIZED?

A. I first reviewed the operations and finances of KU and the current conditions in the electric utility industry and the capital markets. With this as a background, I conducted various well-accepted quantitative analyses to estimate the current cost of equity, including alternative applications of the discounted cash flow ("DCF") model and the Capital Asset Pricing Model ("CAPM"), as well as reference to expected earned rates of return for utilities. Based on the cost of equity estimates indicated by my analyses, KU's ROE was evaluated taking into account the specific risks and potential challenges for its jurisdictional electric utility operations in Kentucky, as well as other factors (*e.g.*, flotation costs) that are properly considered in setting a fair rate of return on equity.

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[1] *Bluefield Water Works & Improvement Co. v. Pub. Serv. Comm'n*, 262 U.S. 679 (1923).
[2] *Fed. Power Comm'n v. Hope Natural Gas Co.*, 320 U.S. 591 (1944).

C. Summary of Conclusions

Q. WHAT ARE YOUR FINDINGS REGARDING THE FAIR RATE OF RETURN ON EQUITY FOR KU?

A. Based on the results of my analyses and the economic requirements necessary to support continuous access to capital, I recommend an ROE for KU from the middle of my 10.5 percent to 12.5 percent reasonable range, or 11.5 percent. The bases for my conclusion are summarized below:

- In order to reflect the risks and prospects associated with KU's jurisdictional utility operations, my analyses focused on a proxy group of fourteen other utilities with comparable investment risks. Consistent with the fact that utilities must compete for capital with firms outside their own industry, I also referenced a proxy group of comparable risk companies in the non-utility sector of the economy;
- Because investors' required return on equity is unobservable and no single method should be viewed in isolation, I applied both the DCF and CAPM methods, as well as the expected earnings approach, to estimate a fair ROE for KU;
- Based on my evaluation of the strength of the various methods, I concluded that the cost of equity for the proxy groups of utilities and non-utility companies is in the 10.5 percent to 12.5 percent range;
- Investors view existing cost recovery mechanisms as supportive of KU's financial integrity, but there is no evidence that these provisions will result in a measurable change in the Company's investment risk or ROE relative to the proxy companies;
- The reasonableness of an 11.5 percent ROE for KU is also supported by the need to consider flotation costs and support access to capital.

Q. WHAT OTHER EVIDENCE DID YOU CONSIDER IN EVALUATING YOUR ROE RECOMMENDATION IN THIS CASE?

A. My recommendation is reinforced by the following findings:

- Sensitivity to financial market and regulatory uncertainties has increased dramatically and investors recognize that constructive regulation is a key ingredient in supporting utility credit standing and financial integrity; and,

- Providing KU with the opportunity to earn a return that reflects these realities is an essential ingredient to support the Company's financial position, which ultimately benefits customers by ensuring reliable service at lower long-run costs.

Q. WHAT IS YOUR CONCLUSION AS TO THE REASONABLENESS OF THE COMPANY'S CAPITAL STRUCTURE?

A. Based on my evaluation, I concluded that a common equity ratio of 53.85 percent represents a reasonable basis from which to calculate KU's overall rate of return. This conclusion was based on the following findings:

- KU's common equity ratio is consistent with the range of capitalizations maintained by the firms in the proxy group of utilities and electric utility operating companies based on data at year-end 2008 and near-term expectations;
- The additional leverage implied by KU's purchased power commitments, leases, and pension obligations warrant a more conservative financial posture; and,
- The requested capitalization reflects the need to support the credit standing and financial flexibility of KU as the Company seeks to fund system investments and meet the requirements of customers.

II. FUNDAMENTAL ANALYSES

Q. WHAT IS THE PURPOSE OF THIS SECTION?

A. As a predicate to subsequent quantitative analyses, this section briefly reviews the operations and finances of KU. In addition, it examines the risks and prospects for the electric utility industry and conditions in the capital markets and the general economy. An understanding of the fundamental factors driving the risks and prospects of electric utilities is essential in developing an informed opinion of investors' expectations and requirements that are the basis of a fair rate of return.

A. Kentucky Utilities Company

Q. BRIEFLY DESCRIBE KU.

A. Along with Louisville Gas and Electric Company ("LGE"), KU is a wholly owned subsidiary of E.ON U.S. LLC ("E.ON U.S."), which in turn is an indirect subsidiary of E.ON AG ("E.ON"). Headquartered in Lexington, Kentucky, KU is principally engaged in providing regulated electric utility service. In addition to serving over 513,000 retail customers in central, southeastern, and western Kentucky, KU also provides service to nearly 30,000 customers in Virginia.[3]

Although KU and LGE are separate operating subsidiaries, they are operated as a single, fully integrated system. The Company's utility facilities include over 4,500 megawatts ("MW") of generating capacity. Coal-fired generating stations account for approximately 63 percent of KU's total generating capacity and produced 99 percent of the electricity generated by the Company in 2008. In addition to company-owned generation, the Company purchases power under long-term contracts with various suppliers and meets a portion of its energy needs by purchases of additional supplies in the wholesale electricity markets. KU's transmission and distribution system includes over 20,000 miles of lines. At October 31, 2009, the Company had total assets of $4.6 billion, with total revenues of approximately $1.4 billion. KU's retail electric operations are subject to the jurisdiction of the KPSC and the Virginia State Corporation Commission. The FERC regulates the Company's interstate transmission and wholesale operations.

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[3] KU also serves a limited number of customers in Tennessee.

Q. HOW ARE FLUCTUATIONS IN THE COMPANY'S OPERATING EXPENSES CAUSED BY VARYING FUEL AND POWER MARKET CONDITIONS ACCOMMODATED IN ITS RATES?

A. KU's retail electric rates in Kentucky contain a fuel adjustment clause ("FAC"), whereby increases and decreases in the cost of fuel for electric generation are reflected in the rates charged to retail electric customers. The KPSC requires public hearings at six-month intervals to examine past fuel adjustments, and at two-year intervals to review past operations of the fuel clause and transfer of the then current fuel adjustment charge or credit to the base charges. The Commission also requires that electric utilities, including KU, file documents relating to fuel procurement and the purchase of power and energy from other utilities.

Q. ARE THERE OTHER MECHANISMS THAT AFFECT KU'S RATES FOR UTILITY SERVICE?

A. Yes. The KPSC has approved an environmental cost recovery mechanism ("ECR") for the Company that allows for recovery of related costs required to comply with federal and state environmental statutes.

Q. WHERE DOES KU OBTAIN THE CAPITAL USED TO FINANCE ITS INVESTMENT IN ELECTRIC UTILITY PLANT?

A. As a wholly-owned subsidiary of E.ON U.S., KU ultimately obtains equity capital and most of its debt capital solely from the parent corporation, E.ON, whose common stock is included as one of the 30 members of the DAX stock index of major German companies. Although not presently listed on a major U.S. stock exchange, E.ON shares also trade in the U.S. through the American Depository Receipt system. In addition to capital supplied by E.ON, KU also issues tax-exempt debt securities in its own name.

Q. WHAT CREDIT RATINGS ARE ASSIGNED TO KU?

A. Currently, KU is assigned a corporate credit rating of "BBB+" by Standard & Poor's Corporation ("S&P"), while Moody's Investors Service ("Moody's") has assigned the Company an issuer rating of "A2".

B. Risks for KU

Q. HOW HAVE INVESTORS' RISK PERCEPTIONS FOR THE UTILITY INDUSTRY EVOLVED?

A. Implementation of structural change and related events caused investors to rethink their assessment of the relative risks associated with the utility industry. The past decade witnessed steady erosion in credit quality throughout the utility industry, both as a result of revised perceptions of the risks in the industry and the weakened finances of the utilities themselves. S&P recently reported that the majority of the companies in the utility sector now fall in the triple-B rating category.[4] Going forward, S&P observed that:

> Looming costs associated with environmental compliance, slack demand caused by economic weakness, the potential for permanent demand destruction caused by changes in consumer behavior and closing of manufacturing facilities, and numerous regulatory filings seeking recovery of costs are some of the significant challenges the industry has to deal with.[5]

Q. DOES KU ANTICIPATE THE NEED FOR ADDITIONAL CAPITAL GOING FORWARD?

A. Yes. KU will require capital investment to provide for necessary maintenance and replacements of its utility infrastructure, as well as to fund new investment in

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[4] Standard & Poor's Corporation, "Industry Report Card: U.S. Electric Utility Sector's Liquidity Remains Adequate In Third Quarter 2009," (Sep. 21, 2009).

[5] Standard & Poor's Corporation, "U.S. Regulated Electric Utilities Head Into 2010 With Familiar Concerns," *RatingsDirect* (Dec. 28, 2009).

electric generation, transmission and distribution facilities. Total capital expenditures for the Company are expected to be approximately $1.2 billion over the 2010-2012 period, with Moody's noting the challenges associated with "supporting the level of demand in its service territory and maintaining an adequate reserve margin."[6] Similarly, S&P noted that the "[h]eavy construction program to meet environmental requirements and new generating capacity" places pressure on KU's credit profile,[7] and concluded that external financing will be required to meet these obligations.[8] Support for KU's financial integrity and flexibility will be instrumental in attracting the capital necessary to fund its share of these projects in an effective manner.

Q. IS THE POTENTIAL FOR ENERGY MARKET VOLATILITY AN ONGOING CONCERN FOR INVESTORS?

A. Yes. In recent years utilities and their customers have had to contend with dramatic fluctuations in energy costs due to ongoing price volatility in the spot markets, and investors recognize the prospect of further turmoil in energy markets. Moody's has warned investors of ongoing exposure to "extremely volatile" energy commodity costs, including purchased power prices, which are heavily influenced by fuel costs,[9] and Fitch noted that rapidly rising energy costs created vulnerability in the utility industry.[10]

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6 Moody's Investors Service, "Credit Opinion: Kentucky Utilities Co.," *Global Credit Research* (May 1, 2009).

7 Standard & Poor's Corporation, "Kentucky Utilities Co.," *RatingsDirect* (Apr. 3, 2009).

8 Standard & Poor's Corporation, "Kentucky Utilities Co.," *RatingsDirect* (Aug. 18, 2009).

9 Moody's Investors Service, "Storm Clouds Gathering on the Horizon for the North American Electric Utility Sector," *Special Comment* at 6 (Aug. 2007).

10 Fitch Ratings Ltd., "Staying Afloat: Downstream Liquidity in the Energy and Power Sectors," *Oil & Gas / Global Power Special Report* (June 16, 2008).

For example, while coal has historically provided relative stability with respect to fuel costs, the Energy Information Administration ("EIA"), a statistical agency of the U.S. Department of Energy ("DOE"), reported that prices for Central and Northern Appalachia coal spiked from approximately $45 per ton in June 2007 to over $140 per ton in September 2008, before falling back into the $40 to $50 range in September 2009.[11] The power industry and its customers have also had to contend with dramatic fluctuations in gas costs due to ongoing price volatility in the spot markets. Moody's concluded that natural gas "remains highly volatile," and warned that such price fluctuations "could have a significant impact on a utility's liquidity profile."[12]

While expectations for significantly lower power prices reflect weaker fundamentals affecting current load and fuel prices, investors recognize the potential that such trends could quickly reverse. Indeed, Fitch highlighted the challenges that such dramatic fluctuations in commodity prices can have for utilities and their investors and recently noted that "uncertainty regarding fuel prices, in particular natural gas costs, has made planning for the future even more problematic."[13] The rapid rise in electricity costs that can result from higher wholesale energy prices has heightened investor concerns over the implications for regulatory uncertainty. S&P noted that, while timely cost recovery was paramount to maintaining credit quality in the electric power sector, an "environment of rising customer tariffs, coupled with a sluggish economy, portend a difficult regulatory environment in coming years."[14]

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[11] Energy Information Administration, *Coal News and Markets* (Jun. 20 & Sep. 26, 2008, Oct. 13, 2009).

[12] Moody's Investors Service, "Carbon Risks Becoming More Imminent for U.S. Electric Utility Sector," *Special Comment* (March 2009).

[13] Fitch Ratings, Ltd., "Electric Utility Capital Spending: The Show Will Go On," *Global Power U.S. and Canada Special Report* (Oct. 14, 2009).

[14] Standard & Poor's Corporation, "Top 10 U.S. Electric Utility Credit Issues For 2008 And Beyond," *RatingsDirect* (Jan. 28, 2008).

Q. DO THE KPSC'S ADJUSTMENT MECHANISMS PROTECT KU FROM EXPOSURE TO FLUCTUATIONS IN POWER SUPPLY COSTS?

A. To a limited extent, yes. The investment community views KU's ability to periodically adjust retail rates to accommodate fluctuations in fuel and purchased power as an important source of support for KU's financial integrity. Nevertheless, they also recognize that there can be a lag between the time KU actually incurs the expenditure and when it is recovered from ratepayers. As a result, KU is not insulated from the need to finance deferred power production and supply costs. Indeed, despite the significant investment of resources to manage fuel procurement, investors are aware that the best that KU can do is to recover its actual costs. In other words, KU earns no return on fuel costs and is exposed to disallowances for imprudence in its fuel procurement.

Q. WHAT OTHER FINANCIAL PRESSURES IMPACT INVESTORS' RISK ASSESSMENT OF KU?

A. Investors are aware of the financial and regulatory pressures faced by utilities associated with rising costs and the need to undertake significant capital investments. As Moody's observed:

> [P]ressures are building. Utilities are facing rising operating costs and infrastructure investment needs that are prompting them to seek more-frequent requests for rate relief. Meanwhile, as energy (and other commodity) costs rise, so does the risk of a consumer backlash over electric rates that could prompt legislative intervention or a more contentious atmosphere between utilities and their regulators.[15]

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[15] Moody's Investors Service, "U.S. Investor-Owned Electric Utilities: Six-Month Industry Update," *Industry Outlook* (July 2008).

Similarly, S&P noted that "heavy construction programs," along with rising operating and maintenance costs and volatile fuel costs, were a significant challenge to the utility industry.[16] Fitch echoed this assessment, concluding:

> Continued access to capital at reasonable rates in 2009 remains uncertain at a time when many utility holding groups have historically high capital investment programs and will require ongoing access to reasonably priced capital in order to fund new investment and refinance maturing debt.[17]

As noted earlier, investors anticipate that KU will undertake significant electric utility capital expenditures. While providing the infrastructure necessary to meet the energy needs of customers is certainly desirable, it imposes additional financial responsibilities on the Company.

Q. ARE ENVIRONMENTAL CONSIDERATIONS ALSO AFFECTING INVESTORS' EVALUATION OF ELECTRIC UTILITIES, INCLUDING KU?

A. Yes. Although KU's exposure is moderated through the ECR mechanism in Kentucky, utilities are confronting increased environmental pressures that could impose significant uncertainties and costs. In early 2007 S&P cited environmental mandates, including emissions, conservation, and renewable resources, as one of the top ten credit issues facing U.S. utilities.[18] Similarly, Moody's noted that "the prospect for new environmental emission legislation – particularly concerning carbon dioxide – represents the biggest emerging issue for electric utilities,"[19] while Fitch observed that the response to greenhouse gas limits "is going to present

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[16] Standard & Poor's Corporation, "Ratings Roundup: Utility Sector Experienced Equal Number Of Upgrades And Downgrades During Second Quarter Of 2008," *RatingsDirect* (Jul. 22, 2008).

[17] Fitch Ratings Ltd., "U.S. Utilities, Power and Gas 2009 Outlook," *Global Power North America Special Report* (Dec. 22, 2008).

[18] Standard & Poor's Corporation, "Top Ten Credit Issues Facing U.S. Utilities," *RatingsDirect* (Jan. 29, 2007).

[19] Moody's Investors Service, "U.S. Investor-Owned Electric Utilities," *Industry Outlook* (Jan. 2009).

enormous challenges to the industry over the immediate to longer term."[20] Given the significance of KU's exposure, Moody's went on to conclude that it would consider a downgrade to the Company's credit ratings if significant changes were made to the ECR.[21]

At the national level, the Obama administration has taken a far more active stance towards energy and environmental policy. It has endorsed the American Clean Energy and Security Act of 2009 ("ACES"), passed by the House of Representatives on June 26, 2009. In addition to creating a comprehensive, economy-wide cap-and-trade regulatory framework, ACES would reduce carbon emissions 17 percent by 2020 compared to 2005 levels and require electric utilities to meet 20 percent of their electricity needs from renewable sources by 2020. Compliance with these evolving standards will undoubtedly require significant capital expenditures, especially for utilities like KU that depend significantly on coal-fired generation. S&P concluded, "Although we expect the cap-and-trade program to be economywide and affect a variety of sectors, it will disproportionately affect the power sector."[22] S&P recently emphasized that because of uncertainty over the details and timing of future limits on CO_2 emissions, existing ratings do not fully reflect the impact of carbon risks.[23]

[20] Fitch Ratings Ltd., "U.S. Utilities, Power, and Gas 2010 Outlook," *Global Power North America Special Report* (Dec. 4, 2009).
[21] Moody's Investors Service, "Credit Opinion: Kentucky Utilities Company," *Global Credit Research* (May 1, 2009).
[22] Standard & Poor's Corporation, "The Potential Credit Impact Of Carbon Cap-And-Trade Legislation On U.S. Companies," *RatingsDirect* (Sep. 14, 2009).
[23] *Id.*

D. Impact of Capital Market Conditions

Q. WHAT ARE THE IMPLICATIONS OF RECENT CAPITAL MARKET CONDITIONS?

A. The financial and real estate crisis that accelerated during the third quarter of 2008 led to unprecedented price fluctuations in the capital markets as investors dramatically revised their risk perceptions and required returns. As a result of investors' trepidation to commit capital, stock prices declined sharply while the yields on corporate bonds experienced a dramatic increase.

With respect to utilities specifically, as of December 2009, the Dow Jones Utility Average stock index remained almost 30 percent below the level in June 2008. This sell-off in common stocks and sharp fluctuations in utility bond yields reflect the fact that the utility industry was not immune to the impact of financial market turmoil and the ongoing economic downturn. As the Edison Electric Institute ("EEI") noted in a letter to congressional representatives as the financial crisis intensified, capital market uncertainties have serious implications for utilities and their customers:

> In the wake of the continuing upheaval on Wall Street, capital markets are all but immobilized, and short-term borrowing costs to utilities have already increased substantially. If the financial crisis is not resolved quickly, financial pressures on utilities will intensify sharply, resulting in higher costs to our customers and, ultimately, could compromise service reliability.[24]

Similarly, an October 1, 2008, *Wall Street Journal* report confirmed that utilities had been forced to delay borrowing or pursue more costly alternatives to raise funds.[25]

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[24] *Letter to House of Representatives*, Thomas R. Kuhn, President, Edison Electric Institute (Sep. 24, 2008).

[25] Smith, Rebecca, "Corporate News: Utilities' Plans Hit by Credit Markets," *Wall Street Journal* at B4 (Oct. 1, 2008).

An October 2008 report on the implications of credit market upheaval for utilities noted that even high-quality companies "now have to pay an unusually high risk premium over Treasuries."[26] Meanwhile, a Managing Director with Fitch Ratings, Ltd. ("Fitch") observed that, "significantly higher regulated returns will be required to attract equity capital."[27] In December 2008, Fitch confirmed "sharp repricing of and aversion to risk in the investment community," and noted that the disruptions in financial markets and the fundamental shift in investors' risk perceptions has increased the cost of capital for utilities:

> While credit is available to investment-grade issuers in the utilities, power and gas sectors, it is more expensive, particularly when viewed against the easy money environment which prevailed for most of this decade.[28]

Fitch recently concluded, "While utilities maintained relatively good market access during the credit crisis, the cost of capital is higher than prior to the credit crisis, and bank credit remains relatively tight."[29]

Q. HAS THE ECONOMY IN KU'S SERVICE TERRITORY FELT THE IMPACT OF THE GLOBAL RECESSION?

A. Yes. Investors recognize that electric utilities such as KU are not immune to the declining sales and cash flow that accompanies an economic downturn. The economy in Kentucky has been hard-hit during the ongoing recession, with unemployment in the state remaining above 10.5 percent in November 2009. The Kentucky State Budget Director noted that:

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[26] *Rudden's Energy Strategy Report* (Oct. 1, 2008).

[27] Fitch Ratings Ltd., "EEI 2008 Wrap-Up: Cost of Capital Rising," *Global Power North America Special Report* (Nov. 17, 2008).

[28] Fitch Ratings Ltd., "U.S. Utilities, Power and Gas 2009 Outlook," *Global Power North America Special Report* (Dec. 22. 2008).

[29] Fitch Ratings Ltd., "Electric Utility Capital Spending: The Show Will Go On," *Global Power U.S. and Canada Special Report* (Oct. 14, 2009).

> Kentucky manufacturing employment suffered the largest absolute employment loss as well as the largest percentage loss, with a loss of 26,900 jobs, or 10.6 percent. Kentucky is over-represented in the manufacturing sector, so recessions typically negatively affect the Kentucky manufacturing sector more profoundly than the U.S.[30]

This decline in manufacturing has been mirrored in KU's service territory, with commercial and industrial demand falling 5 percent in 2009 from a year earlier.

Q. HOW DO CURRENT INTEREST RATES ON LONG-TERM BONDS COMPARE WITH THOSE PROJECTED FOR THE NEXT FEW OF YEARS?

A. Table WEA-1 below compares current interest rates on 30-year Treasury bonds, double-A rated utility bonds, and triple-A rated corporate bonds with those projected for 2010 through 2013 by the Value Line Investment Survey ("Value Line"),[31] GlobalInsight,[32] and the EIA:[33]

TABLE WEA-1
INTEREST RATE TRENDS

	2010	**2011**	**2012**	**2013**	**Dec. 2009**
30-Yr. Treasury					
Value Line	4.5%	5.0%	5.1%	5.3%	4.5%
GlobalInsight	3.8%	4.9%	5.0%	5.2%	4.5%
AA Utility					
GlobalInsight	6.2%	6.5%	6.4%	6.7%	5.5%
EIA	6.7%	6.4%	6.5%	6.8%	5.5%
AAA Corporate					
Value Line	5.8%	6.3%	6.4%	6.5%	5.3%
GlobalInsight	5.4%	6.0%	6.0%	6.2%	5.3%

[30] Office of the State Budget Director, "Quarterly Economic and Revenue Report," *Governor's Office for Economic Analysis* (July 30, 2009).
[31] The Value Line Investment Survey, *Forecast for the U.S. Economy* (Nov. 27, 2009).
[32] GlobalInsight, *The U.S. Economy: The 30-Year Focus* (First Quarter 2009).
[33] Energy Information Administration, *Annual Energy Outlook 2010, Early Release* (Dec. 5, 2009).

As evidenced above, there is a clear consensus that the cost of permanent capital will be higher in the 2010-2013 timeframe than it is currently. As a result, current cost of capital estimates are likely to understate investors' requirements at the time the outcome of this proceeding becomes effective and beyond.

Q. WHAT DO THESE EVENTS IMPLY WITH RESPECT TO THE ROE FOR KU?

A. No one knows the future of our complex global economy. We know that the financial crisis had been building for a long time and few predicted that the economy would fall as rapidly as it has, or that corporate bond yields would fluctuate as dramatically as they did. While conditions in the economy and capital markets appear to have stabilized, investors are apt to react swiftly and negatively to any future signs of trouble in the financial system or economy. Given the importance of reliable electric power for customers and the economy, it would be unwise to ignore investors' increased sensitivity to risk in evaluating KU's ROE.

III. CAPITAL MARKET ESTIMATES

Q. WHAT IS THE PURPOSE OF THIS SECTION?

A. This section presents capital market estimates of the cost of equity. First, I address the concept of the cost of common equity, along with the risk-return tradeoff principle fundamental to capital markets. Next, I describe DCF and CAPM analyses conducted to estimate the cost of common equity for benchmark groups of comparable risk firms and evaluate expected earned rates of return for utilities. Finally, I examine flotation costs, which are properly considered in evaluating a fair rate of return on equity.

A. Economic Standards

Q. WHAT ROLE DOES THE RATE OF RETURN ON COMMON EQUITY PLAY IN A UTILITY'S RATES?

A. The return on common equity is the cost of inducing and retaining investment in the utility's physical plant and assets. This investment is necessary to finance the asset base needed to provide utility service. Investors will commit money to a particular investment only if they expect it to produce a return commensurate with those from other investments with comparable risks. Moreover, the return on common equity is integral in achieving the sound regulatory objectives of rates that are sufficient to: 1) fairly compensate capital investment in the utility, 2) enable the utility to offer a return adequate to attract new capital on reasonable terms, and 3) maintain the utility's financial integrity. Meeting these objectives allows the utility to fulfill its obligation to provide reliable service while meeting the needs of customers through necessary system expansion.

Q. WHAT FUNDAMENTAL ECONOMIC PRINCIPLE UNDERLIES THE COST OF EQUITY CONCEPT?

A. The fundamental economic principle underlying the cost of equity concept is the notion that investors are risk averse. In capital markets where relatively risk-free assets are available (*e.g.*, U.S. Treasury securities), investors can be induced to hold riskier assets only if they are offered a premium, or additional return, above the rate of return on a risk-free asset. Because all assets compete with each other for investor funds, riskier assets must yield a higher expected rate of return than safer assets to induce investors to invest and hold them.

Given this risk-return tradeoff, the required rate of return (k) from an asset (i) can generally be expressed as:

$$k_i = R_f + RP_i$$

where: R_f = Risk-free rate of return, and
RP_i = Risk premium required to hold riskier asset i.

Thus, the required rate of return for a particular asset at any time is a function of: (1) the yield on risk-free assets, and (2) the asset's relative risk, with investors demanding correspondingly larger risk premiums for bearing greater risk.

Q. IS THERE EVIDENCE THAT THE RISK-RETURN TRADEOFF PRINCIPLE ACTUALLY OPERATES IN THE CAPITAL MARKETS?

A. Yes. The risk-return tradeoff can be readily documented in segments of the capital markets where required rates of return can be directly inferred from market data and where generally accepted measures of risk exist. Bond yields, for example, reflect investors' expected rates of return, and bond ratings measure the risk of individual bond issues. The observed yields on government securities, which are considered free of default risk, and bonds of various rating categories demonstrate that the risk-return tradeoff does, in fact, exist in the capital markets.

Q. DOES THE RISK-RETURN TRADEOFF OBSERVED WITH FIXED INCOME SECURITIES EXTEND TO COMMON STOCKS AND OTHER ASSETS?

A. It is generally accepted that the risk-return tradeoff evidenced with long-term debt extends to all assets. Documenting the risk-return tradeoff for assets other than fixed income securities, however, is complicated by two factors. First, there is no standard measure of risk applicable to all assets. Second, for most assets – including common stock – required rates of return cannot be directly observed. Yet there is every reason to believe that investors exhibit risk aversion in deciding whether or not to hold common stocks and other assets, just as when choosing among fixed-income securities.

Q. **IS THIS RISK-RETURN TRADEOFF LIMITED TO DIFFERENCES BETWEEN FIRMS?**

A. No. The risk-return tradeoff principle applies not only to investments in different firms, but also to different securities issued by the same firm. The securities issued by a utility vary considerably in risk because they have different characteristics and priorities. Long-term debt is senior among all capital in its claim on a utility's net revenues and is, therefore, the least risky. The last investors in line are common shareholders. They receive only the net revenues, if any, remaining after all other claimants have been paid. As a result, the rate of return that investors require from a utility's common stock, the most junior and riskiest of its securities, must be considerably higher than the yield offered by the utility's senior, long-term debt.

Q. **WHAT DOES THE ABOVE DISCUSSION IMPLY WITH RESPECT TO ESTIMATING THE COST OF COMMON EQUITY FOR A UTILITY?**

A. Although the cost of common equity cannot be observed directly, it is a function of the returns available from other investment alternatives and the risks to which the equity capital is exposed. Because it is not readily observable, the cost of common equity for a particular utility must be estimated by analyzing information about capital market conditions generally, assessing the relative risks of the company specifically, and employing various quantitative methods that focus on investors' required rates of return. These various quantitative methods typically attempt to infer investors' required rates of return from stock prices, interest rates, or other capital market data.

Q. **DID YOU RELY ON A SINGLE METHOD TO ESTIMATE THE COST OF COMMON EQUITY FOR KU?**

A. No. In my opinion, no single method or model should be relied on by itself to determine a utility's cost of common equity because no single approach can be regarded as definitive. For example, a publication of the Society of Utility and Financial Analysts (formerly the National Society of Rate of Return Analysts), concluded that:

> Each model requires the exercise of judgment as to the reasonableness of the underlying assumptions of the methodology and on the reasonableness of the proxies used to validate the theory. Each model has its own way of examining investor behavior, its own premises, and its own set of simplifications of reality. Each method proceeds from different fundamental premises, most of which cannot be validated empirically. Investors clearly do not subscribe to any singular method, nor does the stock price reflect the application of any one single method by investors.[34]

Therefore, I applied both the DCF and CAPM methods to estimate the cost of common equity. In addition, I also evaluated a fair ROE using an earnings approach based on investors' current expectations in the capital markets. In my opinion, comparing estimates produced by one method with those produced by other approaches ensures that the estimates of the cost of common equity pass fundamental tests of reasonableness and economic logic.

Q. DOES THE FACT THAT THERE ARE DIFFERENT ACCEPTED METHODS TO ESTIMATE THE COST OF COMMON EQUITY, EACH BASED ON CERTAIN ASSUMPTIONS, IMPLY THAT DETERMINING THE ROE IS SUBJECTIVE?

A. Absolutely not. The alternative approaches that I have applied to estimate the cost of common equity have considerable theoretical and practical support, and the body of knowledge on the topic of cost of capital attests to the significance of developing cost of capital estimates that work in the real world of financial markets. For example, the reality that investors require compensation for bearing the risk of

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[34] Parcell, David C., "The Cost of Capital – A Practitioner's Guide," *Society of Utility and Regulatory Financial Analysts* at Part 2, p. 4 (1997).

putting their money in common stock is a fundamental tenet of the theory and practice of finance. While assumptions and judgment underlie these methods to estimate the cost of common equity, this does not imply that they are subjective or that the cost of common equity is unknowable.

Each method of estimating the cost of common equity is based on empirical evidence and accepted applications. While experts may disagree on particular nuances and details of their application, the reliability of these methods is confirmed by their use throughout the regulatory arena as well as in the worlds of investment management and corporate finance. The fact that alternative methods may give somewhat different results, or that different experts may come to different estimates using these methods, does not mean the methods are subjective or unreliable. It means simply that interpreting the results of these methods requires care and practical judgment.

B. Comparable Risk Proxy Groups

Q. HOW DID YOU IMPLEMENT THESE QUANTITATIVE METHODS TO ESTIMATE THE COST OF COMMON EQUITY FOR KU?

A. Application of the DCF model and other quantitative methods to estimate the cost of common equity requires observable capital market data, such as stock prices. Moreover, even for a firm with publicly traded stock, the cost of common equity can only be estimated. As a result, applying quantitative models using observable market data only produces an estimate that inherently includes some degree of observation error. Thus, the accepted approach to increase confidence in the results is to apply the DCF model and other quantitative methods to a proxy group of publicly traded companies that investors regard as risk-comparable.

Q. WHAT SPECIFIC PROXY GROUP OF UTILITIES DID YOU RELY ON FOR YOUR ANALYSIS?

A. In order to reflect the risks and prospects associated with KU's jurisdictional utility operations, my DCF analyses focused on a reference group of other utilities composed of those companies classified by Value Line as electric utilities with: (1) both electric and gas utility operations, (2) S&P corporate credit ratings of "BBB", "BBB+", "A-", or "A," (3) a Value Line Safety Rank of "1" or "2", (4) a Value Line Financial Strength Rating of "B++" or higher, and (5) published earnings per share ("EPS") growth projections from at least two of the following sources: Value Line, Thomson I/B/E/S ("IBES"), First Call Corporation ("First Call"), and Zacks Investment Research ("Zacks").[35] These criteria resulted in a proxy group composed of fourteen companies, which I will refer to as the "Utility Proxy Group."

Q. WHAT OTHER PROXY GROUP DID YOU CONSIDER IN EVALUATING A FAIR ROE FOR KU?

A. Under the regulatory standards established by *Hope* and *Bluefield*, the salient criterion in establishing a meaningful benchmark to evaluate a fair rate of return is relative risk, not the particular business activity or degree of regulation. As noted in *Regulatory Finance: Utilities' Cost of Capital,* "It should be emphasized that the definition of a comparable risk class of companies does not entail similarity of operation, product lines, or environmental conditions, but rather similarity of experienced business risk and financial risk."[36] Utilities must compete for capital, not just against firms in their own industry, but with other investment opportunities of comparable risk. With regulation taking the place of competitive market forces,

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[35] Thomson Reuters separately compiles and publishes consensus securities analyst growth rates under the IBES (formerly I/B/E/S International, Inc.) and First Call brands.

[36] Morin, Roger A., "Regulatory Finance: Utilities' Cost of Capital," *Public Utilities Reports, Inc.* at 58 (1994).

required returns for utilities should be in line with those of non-utility firms of comparable risk operating under the constraints of free competition. Consistent with this accepted regulatory standard, I also applied the DCF model to a reference group of comparable risk companies in the non-utility sectors of the economy. I refer to this group as the "Non-Utility Proxy Group".

Q. WHAT CRITERIA DID YOU APPLY TO DEVELOP THE NON-UTILITY PROXY GROUP?

A. My comparable risk proxy group was composed of those U.S. companies followed by Value Line that: (1) pay common dividends; (2) have a Safety Rank of "1"; (3) have investment grade credit ratings from S&P, and (4) have a Value Line Financial Strength Rating of "B++" or higher. In addition, consistent with the criteria used to define the Utility Proxy Group, I included only those firms with published EPS growth projections from at least two of Value Line, IBES, First Call, or Zacks.

Q. DO THESE CRITERIA PROVIDE OBJECTIVE EVIDENCE TO EVALUATE INVESTORS' RISK PERCEPTIONS?

A. Yes. Credit ratings are assigned by independent rating agencies for the purpose of providing investors with a broad assessment of the creditworthiness of a firm. Ratings generally extend from triple-A (the highest) to D (in default). Other symbols (*e.g.*, "A+") are used to show relative standing within a category. Because the rating agencies' evaluation includes virtually all of the factors normally considered important in assessing a firm's relative credit standing, corporate credit ratings provide a broad, objective measure of overall investment risk that is readily available to investors. Widely cited in the investment community and referenced by investors, credit ratings are also frequently used as a primary risk indicator in establishing proxy groups to estimate the cost of common equity.

While credit ratings provide the most widely referenced benchmark for investment risks, other quality rankings published by investment advisory services also provide relative assessments of risks that are considered by investors in forming their expectations for common stocks. Value Line's primary risk indicator is its Safety Rank, which ranges from "1" (Safest) to "5" (Riskiest). This overall risk measure is intended to capture the total risk of a stock, and incorporates elements of stock price stability and financial strength. Given that Value Line is perhaps the most widely available source of investment advisory information, its Safety Rank provides useful guidance regarding the risk perceptions of investors.

The Financial Strength Rating is designed as a guide to overall financial strength and creditworthiness, with the key inputs including financial leverage, business volatility measures, and company size. Value Line's Financial Strength Ratings range from "A++" (strongest) down to "C" (weakest) in nine steps. These objective, published indicators incorporate consideration of a broad spectrum of risks, including financial and business position, relative size, and exposure to firm-specific factors.

Q. HOW DO THE OVERALL RISKS OF YOUR PROXY GROUPS COMPARE WITH KU?

A. As shown below, Table WEA-2 compares the utility proxy group with the non-utility proxy group and KU across four key indicators of investment risk:[37]

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[37] KU has no publicly traded common stock and Value Line does not publish risk measures for its parent, E.ON.

TABLE WEA-2
COMPARISON OF RISK INDICATORS

	S&P Credit Rating	Value Line Safety Rank	Value Line Financial Strength	Beta
Utility Group	BBB+	2	A	0.69
Non-Utility Proxy Group	A	1	A+	0.79
KU	BBB+	--	--	--

Q. DOES THIS COMPARISON INDICATE THAT INVESTORS WOULD VIEW THE FIRMS IN YOUR PROXY GROUPS AS RISK-COMPARABLE TO KU?

A. Yes. As discussed earlier, the Company is rated "BBB+" by S&P, which is identical to the average corporate credit rating for the Utility Proxy Group. Meanwhile, the average Value Line Safety Rank and Financial Strength Rating for the Utility Proxy Group is "2" and "A", respectively. These two benchmarks indicate that the risks associated with an equity investment in the Utility Proxy Group are conservative and in-line with those generally associated with a "BBB+" credit.[38] Based on my screening criteria, which reflect objective, published indicators that incorporate consideration of a broad spectrum of risks, including financial and business position, relative size, and exposure to company specific factors, investors are likely to regard the Utility Proxy Group as having risks and prospects comparable to those of KU.

With respect to the Non-Utility Proxy Group, its average credit ratings, Quality Ranking, and Safety Rank suggest less risk than for the Utility Proxy Group, with its 0.79 average beta indicating greater risk. While any differences in

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[38] Because KU has no publicly traded common stock and Value Line does not publish risk indicators for its parent, E.ON, it is not possible to make a direct comparison between the proxy group and the Company. The fact that the average Value Line Safety Rank and Financial Strength Rating are indicative of a conservative risk profile supports my conclusion that the Utility Proxy Group provides a sound basis to estimate the cost of equity for KU.

investment risk attributable to regulation should already be reflected in these objective measures, my analyses nevertheless conservatively focus on a lower-risk group of non-utility firms.

C. Discounted Cash Flow Analyses

Q. HOW IS THE DCF MODEL USED TO ESTIMATE THE COST OF COMMON EQUITY?

A. DCF models attempt to replicate the market valuation process that sets the price investors are willing to pay for a share of a company's stock. The model rests on the assumption that investors evaluate the risks and expected rates of return from all securities in the capital markets. Given these expectations, the price of each stock is adjusted by the market until investors are adequately compensated for the risks they bear. Therefore, we can look to the market to determine what investors believe a share of common stock is worth. By estimating the cash flows investors expect to receive from the stock in the way of future dividends and capital gains, we can calculate their required rate of return. That is, the cost of equity is the discount rate that equates the current price of a share of stock with the present value of all expected cash flows from the stock. The general form of the DCF model is expressed as follows:

$$P_0 = \frac{D_1}{(1+k_e)^1} + \frac{D_2}{(1+k_e)^2} + \cdots + \frac{D_t}{(1+k_e)^t} + \frac{P_t}{(1+k_e)^t}$$

where: P_0 = Current price per share;
P_t = Expected future price per share in period t;
D_t = Expected dividend per share in period t;
k_e = Cost of common equity.

Q. WHAT FORM OF THE DCF MODEL IS CUSTOMARILY USED TO ESTIMATE THE COST OF COMMON EQUITY IN RATE CASES?

A. Rather than developing annual estimates of cash flows into perpetuity, the DCF model can be simplified to a "constant growth" form:[39]

$$P_0 = \frac{D_1}{k_e - g}$$

where: g = Investors' long-term growth expectations.

The cost of common equity (k_e) can be isolated by rearranging terms within the equation:

$$k_e = \frac{D_1}{P_0} + g$$

This constant growth form of the DCF model recognizes that the rate of return to stockholders consists of two parts: 1) dividend yield (D_1/P_0); and, 2) growth (g). In other words, investors expect to receive a portion of their total return in the form of current dividends and the remainder through price appreciation.

Q. WHAT FORM OF THE DCF MODEL DID YOU USE?

A. I applied the constant growth DCF model to estimate the cost of common equity for KU, which is the form of the model most commonly relied on to establish the cost of common equity for traditional regulated utilities and the method most often referenced by regulators.

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[39] The constant growth DCF model is dependent on a number of strict assumptions, which in practice are never met. These include a constant growth rate for both dividends and earnings; a stable dividend payout ratio; the discount rate exceeds the growth rate; a constant growth rate for book value and price; a constant earned rate of return on book value; no sales of stock at a price above or below book value; a constant price-earnings ratio; a constant discount rate (*i.e.*, no changes in risk or interest rate levels and a flat yield curve); and all of the above extend to infinity.

Q. HOW IS THE CONSTANT GROWTH FORM OF THE DCF MODEL TYPICALLY USED TO ESTIMATE THE COST OF COMMON EQUITY?

A. The first step in implementing the constant growth DCF model is to determine the expected dividend yield (D_1/P_0) for the firm in question. This is usually calculated based on an estimate of dividends to be paid in the coming year divided by the current price of the stock. The second, and more controversial, step is to estimate investors' long-term growth expectations (*g*) for the firm. The final step is to sum the firm's dividend yield and estimated growth rate to arrive at an estimate of its cost of common equity.

Q. HOW WAS THE DIVIDEND YIELD FOR THE UTILITY PROXY GROUP DETERMINED?

A. Estimates of dividends to be paid by each of these utilities over the next twelve months, obtained from Value Line, served as D_1. This annual dividend was then divided by the corresponding stock price for each utility to arrive at the expected dividend yield. The expected dividends, stock prices, and resulting dividend yields for the firms in the utility proxy group are presented on Exhibit WEA-2. As shown there, dividend yields for the firms in the Utility Proxy Group ranged from 3.0 percent to 6.0 percent.

Q. WHAT IS THE NEXT STEP IN APPLYING THE CONSTANT GROWTH DCF MODEL?

A. The next step is to evaluate long-term growth expectations, or "*g*", for the firm in question. In constant growth DCF theory, earnings, dividends, book value, and market price are all assumed to grow in lockstep, and the growth horizon of the DCF model is infinite. But implementation of the DCF model is more than just a theoretical exercise; it is an attempt to replicate the mechanism investors used to arrive at observable stock prices. A wide variety of techniques can be used to derive growth rates, but the only "*g*" that matters in applying the DCF model is the value that investors expect.

Q. ARE HISTORICAL GROWTH RATES LIKELY TO BE REPRESENTATIVE OF INVESTORS' EXPECTATIONS FOR UTILITIES?

A. No. If past trends in earnings, dividends, and book value are to be representative of investors' expectations for the future, then the historical conditions giving rise to these growth rates should be expected to continue. That is clearly not the case for utilities, where structural and industry changes have led to declining dividends, earnings pressure, and, in many cases, significant write-offs. While these conditions serve to depress historical growth measures, they are not representative of long-term expectations for the utility industry.

Q. WHAT ARE INVESTORS MOST LIKELY TO CONSIDER IN DEVELOPING THEIR LONG-TERM GROWTH EXPECTATIONS?

A. While the DCF model is technically concerned with growth in dividend cash flows, implementation of this DCF model is solely concerned with replicating the forward-looking evaluation of real-world investors. In the case of utilities, dividend growth rates are not likely to provide a meaningful guide to investors' current growth expectations. This is because utilities have significantly altered their dividend policies in response to more accentuated business risks in the industry, with the payout ratio for electric utilities falling from approximately 80 percent historically to on the order of 60 percent.[40] As a result of this trend towards a more conservative payout ratio, dividend growth in the utility industry has remained largely stagnant as utilities conserve financial resources to provide a hedge against heightened uncertainties.

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[40] The Value Line Investment Survey (Sep. 15, 1995 at 161, Dec. 26, 2008 at 687).

As payout ratios for firms in the utility industry trended downward, investors' focus has increasingly shifted from dividends to earnings as a measure of long-term growth. Future trends in earnings, which provide the source for future dividends and ultimately support share prices, play a pivotal role in determining investors' long-term growth expectations. The importance of earnings in evaluating investors' expectations and requirements is well accepted in the investment community. As noted in *Finding Reality in Reported Earnings* published by the Association for Investment Management and Research:

> [E]arnings, presumably, are the basis for the investment benefits that we all seek. "Healthy earnings equal healthy investment benefits" seems a logical equation, but earnings are also a scorecard by which we compare companies, a filter through which we assess management, and a crystal ball in which we try to foretell future performance.[41]

Value Line's near-term projections and its Timeliness Rank, which is the principal investment rating assigned to each individual stock, are also based primarily on various quantitative analyses of earnings. As Value Line explained:

> The future earnings rank accounts for 65% in the determination of relative price change in the future; the other two variables (current earnings rank and current price rank) explain 35%.[42]

The fact that investment advisory services focus primarily on growth in earnings indicates that the investment community regards this as a superior indicator of future long-term growth. Indeed, "A Study of Financial Analysts: Practice and Theory," published in the *Financial Analysts Journal*, reported the results of a survey conducted to determine what analytical techniques investment analysts

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[41] Association for Investment Management and Research, "Finding Reality in Reported Earnings: An Overview" at 1 (Dec. 4, 1996).

[42] The Value Line Investment Survey, *Subscriber's Guide* at 53.

actually use.[43] Respondents were asked to rank the relative importance of earnings, dividends, cash flow, and book value in analyzing securities. Of the 297 analysts that responded, only 3 ranked dividends first while 276 ranked them last. The article concluded:

> Earnings and cash flow are considered far more important than book value and dividends.[44]

In 2007, the *Financial Analysts Journal* reported the results of a study of the relationship between valuations based on alternative multiples and actual market prices, which concluded, "In all cases studied, earnings dominated operating cash flows and dividends."[45]

Q. DO THE GROWTH RATE PROJECTIONS OF SECURITY ANALYSTS CONSIDER HISTORICAL TRENDS?

A. Yes. Professional security analysts study historical trends extensively in developing their projections of future earnings. Hence, to the extent there is any useful information in historical patterns, that information is incorporated into analysts' growth forecasts.

Q. WHAT ARE SECURITY ANALYSTS CURRENTLY PROJECTING IN THE WAY OF GROWTH FOR THE FIRMS IN THE UTILITY PROXY GROUP?

A. The earnings growth projections for each of the firms in the Utility Proxy Group reported by Value Line, IBES, First Call, and Zacks are displayed on Exhibit WEA-2.

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[43] Block, Stanley B., "A Study of Financial Analysts: Practice and Theory", *Financial Analysts Journal* (July/August 1999).
[44] *Id.* at 88.
[45] Liu, Jing, Nissim, Doron, & Thomas, Jacob, "Is Cash Flow King in Valuations?," *Financial Analysts Journal*, Vol. 63, No. 2 at 56 (March/April 2007).

Q. SOME ARGUE THAT ANALYSTS' ASSESSMENTS OF GROWTH RATES ARE BIASED. DO YOU BELIEVE THESE PROJECTIONS ARE INAPPROPRIATE FOR ESTIMATING INVESTORS' REQUIRED RETURN USING THE DCF MODEL?

A. No. In applying the DCF model to estimate the cost of common equity, the only relevant growth rate is the forward-looking expectations of investors that are captured in current stock prices. Investors, just like securities analysts and others in the investment community, do not know how the future will actually turn out. They can only make investment decisions based on their best estimate of what the future holds in the way of long-term growth for a particular stock, and securities prices are constantly adjusting to reflect their assessment of available information.

Any claims that analysts' estimates are not relied upon by investors are illogical given the reality of a competitive market for investment advice. If financial analysts' forecasts do not add value to investors' decision making, then it is irrational for investors to pay for these estimates. Similarly, those financial analysts who fail to provide reliable forecasts will lose out in competitive markets relative to those analysts whose forecasts investors find more credible. The reality that analyst estimates are routinely referenced in the financial media and in investment advisory publications (e.g., Value Line) implies that investors use them as a basis for their expectations.

The continued success of investment services such as Thompson Reuters and Value Line, and the fact that projected growth rates from such sources are widely referenced, provides strong evidence that investors give considerable weight to analysts' earnings projections in forming their expectations for future growth. While the projections of securities analysts may be proven optimistic or pessimistic in hindsight, this is irrelevant in assessing the expected growth that investors have incorporated into current stock prices, and any bias in analysts' forecasts – whether pessimistic or optimistic – is irrelevant if investors share analysts' views. Earnings growth projections of security analysts provide the most frequently referenced guide to investors' views and are widely accepted in applying the DCF model. As explained in *Regulatory Finance: Utilities' Cost of Capital*:

> Because of the dominance of institutional investors and their influence on individual investors, analysts' forecasts of long-run growth rates provide a sound basis for estimating required returns. Financial analysts also exert a strong influence on the expectations of many investors who do not possess the resources to make their own forecasts, that is, they are a cause of *g* [growth].[46]

Q. HOW ELSE ARE INVESTORS' EXPECTATIONS OF FUTURE LONG-TERM GROWTH PROSPECTS OFTEN ESTIMATED WHEN APPLYING THE CONSTANT GROWTH DCF MODEL?

A. In constant growth theory, growth in book equity will be equal to the product of the earnings retention ratio (one minus the dividend payout ratio) and the earned rate of return on book equity. Furthermore, if the earned rate of return and the payout ratio are constant over time, growth in earnings and dividends will be equal to growth in book value. Despite the fact that these conditions are seldom, if ever, met in practice, this "sustainable growth" approach may provide a rough guide for evaluating a firm's growth prospects and is frequently proposed in regulatory proceedings.

Accordingly, while I believe that analysts' forecasts provide a superior and more direct guide to investors' growth expectations, I have included the "sustainable growth" approach for completeness. The sustainable growth rate is calculated by the formula, g = br+sv, where "b" is the expected retention ratio, "r" is the expected

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[46] Morin, Roger A., "Regulatory Finance: Utilities' Cost of Capital," *Public Utilities Reports, Inc.* at 154 (1994).

earned return on equity, "s" is the percent of common equity expected to be issued annually as new common stock, and "v" is the equity accretion rate.

Q. WHAT IS THE PURPOSE OF THE "SV" TERM?

A. Under DCF theory, the "sv" factor is a component of the growth rate designed to capture the impact of issuing new common stock at a price above, or below, book value. When a company's stock price is greater than its book value per share, the per-share contribution in excess of book value associated with new stock issues will accrue to the current shareholders. This increase to the book value of existing shareholders leads to higher expected earnings and dividends, with the "sv" factor incorporating this additional growth component.

Q. WHAT GROWTH RATE DOES THE EARNINGS RETENTION METHOD SUGGEST FOR THE UTILITY PROXY GROUP?

A. The sustainable, "br+sv" growth rates for each firm in the Utility Proxy Group are summarized on Exhibit WEA-2, with the underlying details being presented on Exhibit WEA-3. For each firm, the expected retention ratio (b) was calculated based on Value Line's projected dividends and earnings per share. Likewise, each firm's expected earned rate of return (r) was computed by dividing projected earnings per share by projected net book value. Because Value Line reports end-of-year book values, an adjustment factor was incorporated to compute an average rate of return over the year, consistent with the theory underlying this approach to estimating investors' growth expectations. Meanwhile, the percent of common equity expected to be issued annually as new common stock (s) was equal to the product of the projected market-to-book ratio and growth in common shares outstanding, while the equity accretion rate (v) was computed as 1 minus the inverse of the projected market-to-book ratio.

Q. WHAT OTHER GROWTH RATE DID YOU CONSIDER?

A. As noted earlier, the DCF model assumes that investors expect to receive a portion of their total return in the form of current dividends and the remainder through price appreciation. Consistent with this paradigm, I also examined expected growth in each utility's stock price based on Value Line's 2011-2014 projections.

Q. WHAT COST OF COMMON EQUITY ESTIMATES WERE IMPLIED FOR THE UTILITY PROXY GROUP USING THE DCF MODEL?

A. After combining the dividend yields and respective growth projections for each utility, the resulting cost of common equity estimates are shown on Exhibit WEA-2.

Q. IN EVALUATING THE RESULTS OF THE CONSTANT GROWTH DCF MODEL, IS IT APPROPRIATE TO ELIMINATE ESTIMATES THAT ARE EXTREME LOW OR HIGH OUTLIERS?

A. Yes. In applying quantitative methods to estimate the cost of equity, it is essential that the resulting values pass fundamental tests of reasonableness and economic logic. Accordingly, DCF estimates that are implausibly low or high should be eliminated when evaluating the results of this method.

Q. HOW DID YOU EVALUATE DCF ESTIMATES AT THE LOW END OF THE RANGE?

A. It is a basic economic principle that investors can be induced to hold more risky assets only if they expect to earn a return to compensate them for their risk bearing. As a result, the rate of return that investors require from a utility's common stock, the most junior and riskiest of its securities, must be considerably higher than the yield offered by senior, long-term debt. As noted earlier, the average corporate credit rating associated with the firms in the Utility Proxy Group is "BBB+". Companies rated "BBB-", "BBB", and "BBB+" are all considered part of the triple-B rating category, with Moody's monthly yields on triple-B bonds averaging approximately 6.3 percent in December 2009.[47] It is inconceivable that investors are not requiring a substantially higher rate of return for holding common stock. Consistent with this principle, the DCF results for the Utility Proxy Group must be adjusted to eliminate estimates that are determined to be extreme low outliers when compared against the yields available to investors from less risky utility bonds.

Q. HAVE SIMILAR TESTS BEEN APPLIED BY REGULATORS?

A. Yes. FERC has noted that adjustments are justified where applications of the DCF approach produce illogical results. FERC evaluates DCF results against observable yields on long-term public utility debt and has recognized that it is appropriate to eliminate estimates that do not sufficiently exceed this threshold. In a 2000 opinion establishing its current precedent for determining ROEs for electric utilities, for example, FERC noted:

> An adjustment to this data is appropriate in the case of PG&E's low-end return of 8.42 percent, which is comparable to the average Moody's "A" grade public utility bond yield of 8.06 percent, for October 1999. Because investors cannot be expected to purchase stock if debt, which has less risk than stock, yields essentially the same return, this low-end return cannot be considered reliable in this case.[48]

More recently, in its March 27, 2009 decision in *Pioneer*, FERC concluded that it would exclude low-end ROEs "within about 100 basis points above the cost of debt."[49]

Q. WHAT ELSE SHOULD BE CONSIDERED IN EVALUATING DCF ESTIMATES AT THE LOW END OF THE RANGE?

A. As indicated earlier, while corporate bond yields have declined substantially as the worst of the financial crisis has abated, it is generally expected that long-term

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[47] Moody's Investors Service, www.credittrends.com.

[48] *Southern California Edison Company*, 92 FERC ¶ 61,070 (2000) at p. 22.

[49] *Pioneer Transmission, LLC*, 126 FERC ¶ 61,281 at P 94 (2009) ("*Pioneer*").

interest rates will rise as the recession ends and the economy returns to a more normal pattern of growth. The most recent forecast of GlobalInsight calling for double-A public utility bond yields to average 6.16 percent in 2010.[50] Meanwhile, the EIA anticipates that double-A public utility bond yields will average 6.66 percent in 2010.[51]

As shown in Table WEA-3 below, with the average yield spread between double-A and triple-B utility bonds during December 2009 being approximately 75 basis points,[52] these forecasts imply an average triple-B bond yield of 7.26 percent for 2010, or 7.39 percent over the 5-year period 2010-2014:

TABLE WEA-3
IMPLIED BBB BOND YIELD

Line No.		2010	2010-14
1	Projected AA Utility Yield		
2	GlobalInsight (a)	6.16%	6.57%
3	EIA (b)	6.66%	6.71%
4	Average	6.41%	6.64%
5	BBB – AA Yield Spread (c)	0.75%	0.75%
6	**Implied BBB Utility Yield**	**7.26%**	**7.39%**

(a) GlobalInsight, *The U.S. Economy: The 30-Year Focus*" (First-Quarter 2009) at Table 34.

(b) Energy Information Administration, *Annual Energy Outlook 2010, Early Release* (Dec. 5, 2009) at Table 20.

(c) Based on monthly average bond yields for December 2009 reported in Moody's *Credit Perspectives*.

The increase in debt yields anticipated by GlobalInsight and EIA is also supported by the widely-referenced Blue Chip forecast, which projects that yields on corporate

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[50] GlobalInsight, *The U.S. Economy: The 30-Year Focus* (First Quarter 2009) at Table 34.

[51] Energy Information Administration, *Updated Annual Energy Outlook 2009* (Mar. 2009) at Table 20.

[52] This is also consistent with the average yield spread between triple-B and double-A rated utility bonds over the past five years.

bonds will climb on the order of at least 50 basis points through the first quarter of 2011.[53] Consistent with these forecasts, Fitch recently concluded, "Interest rates are expected to rise over the course of the year from very low levels."[54]

Q. WHAT DOES THIS TEST OF LOGIC IMPLY WITH RESPECT TO THE DCF RESULTS FOR THE UTILITY PROXY GROUP?

A. As shown on Exhibit WEA-2, nine of the highlighted cost equity estimates for the firms in the Utility Proxy Group fell below 8.0 percent, with six of these values being equal to or less than the yield currently available on triple-B utility bonds.[55] In light of the risk-return tradeoff principle and the test applied in *Pioneer*, it is inconceivable that investors are not requiring a substantially higher rate of return for holding common stock, which is the riskiest of a utility's securities. As a result, consistent with the test of economic logic applied by FERC and the upward trend expected for utility bond yields, these values provide little guidance as to the returns investors require from utility common stocks and should be excluded.

Q. WHAT COST OF COMMON EQUITY ESTIMATES ARE IMPLIED BY YOUR DCF RESULTS FOR THE UTILITY PROXY GROUP?

A. As shown on Exhibit WEA-2 and summarized in Table WEA-4, below, after eliminating illogical low-end values, application of the constant growth DCF model resulted in cost of common equity estimates ranging from 10.1 percent to 11.4 percent, and generally trending toward 10.5 percent:

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[53] Blue Chip Financial Forecasts (Dec. 1, 2009) at 2.

[54] Fitch Ratings Ltd., "U.S. Utilities, Power, and Gas 2010 Outlook," *Global Power North America Special Report* (Dec. 4, 2009).

[55] As highlighted on Exhibit WEA-2, these DCF estimates ranged from 4.2 percent to 7.9 percent.

TABLE WEA-4
DCF RESULTS – UTILITY PROXY GROUP

Growth Rate	Average Cost of Equity
Value Line	10.2%
IBES	10.5%
First Call	10.3%
Zacks	10.1%
br+sv	10.5%
Stock Price	11.4%

Q. WHAT WERE THE RESULTS OF YOUR DCF ANALYSIS FOR THE NON-UTILITY PROXY GROUP?

A. I applied the DCF model to the Non-Utility Proxy Group in exactly the same manner described earlier for the Utility Proxy Group. The results of my DCF analysis for the Non-Utility Proxy Group are presented in Exhibit WEA-4, with the sustainable, "br+sv" growth rates being developed on Exhibit WEA-5.

I noted earlier that values that are implausibly low or high should be eliminated when evaluating the results of any quantitative method used to estimate the cost of equity. As highlighted on Exhibit WEA-4, in addition to illogical low-end values, various DCF estimates for the firms in the Non-Utility Proxy Group exceeded 17.0 percent. I determined that, when compared with the balance of the remaining estimates, these values could be considered implausible and should be excluded. This is also consistent with the precedent adopted by FERC, which has established that estimates found to be "extreme outliers" should be disregarded in interpreting the results of quantitative methods used to estimate the cost of equity.[56]

As shown on Exhibit WEA-4 and summarized in Table WEA-5, below, after eliminating illogical low- and high-end values, application of the constant growth DCF model resulted in cost of common equity estimates generally in the 12 percent

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[56] See, *e.g.*, *ISO New England, Inc.*, 109 FERC ¶ 61,147 at P 205 (2004).

to 13 percent range:

TABLE WEA-5
DCF RESULTS – NON-UTILITY GROUP

Growth Rate	Average Cost of Equity
Value Line	12.0%
IBES	12.6%
First Call	12.8%
Zacks	12.7%
br+sv	12.2%
Stock Price	13.7%

As discussed earlier, reference to the Non-Utility Proxy Group is consistent with established regulatory principles. Required returns for utilities should be in line with those of non-utility firms of comparable risk operating under the constraints of free competition.

D. Capital Asset Pricing Model

Q. PLEASE DESCRIBE THE CAPM.

A. The CAPM is a theory of market equilibrium that measures risk using the beta coefficient. Assuming investors are fully diversified, the relevant risk of an individual asset (*e.g.*, common stock) is its volatility relative to the market as a whole, with beta reflecting the tendency of a stock's price to follow changes in the market. The CAPM is mathematically expressed as:

$$R_j = R_f + \beta_j(R_m - R_f)$$

where:
R_j = required rate of return for stock j;
R_f = risk-free rate;
R_m = expected return on the market portfolio; and,
β_j = beta, or systematic risk, for stock j.

Like the DCF model, the CAPM is an *ex-ante,* or forward-looking model based on expectations of the future. As a result, in order to produce a meaningful estimate of investors' required rate of return, the CAPM must be applied using estimates that reflect the expectations of actual investors in the market, not with backward-looking, historical data.

Q. HOW DID YOU APPLY THE CAPM TO ESTIMATE THE COST OF COMMON EQUITY?

A. Application of the CAPM to the Utility Proxy Group based on a forward-looking estimate for investors' required rate of return from common stocks is presented on Exhibit WEA-6. In order to capture the expectations of today's investors in current capital markets, the expected market rate of return was estimated by conducting a DCF analysis on the dividend paying firms in the S&P 500.

The dividend yield for each firm was calculated based on the annual indicated dividend payment obtained from Value Line, increased by one-half of the growth rate discussed subsequently $(1 + g)$ to convert them to year-ahead dividend yields presumed by the constant growth DCF model. The growth rate was equal to the earnings growth projections for each firm published by IBES, with each firm's dividend yield and growth rate being weighted by its proportionate share of total market value. Based on the weighted average of the projections for the 348 individual firms, current estimates imply an average growth rate over the next five years of 9.2 percent. Combining this average growth rate with an adjusted dividend yield of 2.7 percent results in a current cost of common equity estimate for the market as a whole of approximately 11.9 percent. Subtracting a 4.4 percent risk-free rate based on the average yield on 20-year Treasury bonds produced a market equity risk premium of 7.5 percent.

Q. WHAT WAS THE SOURCE OF THE BETA VALUES YOU USED TO APPLY THE CAPM?

A. I relied on the beta values reported by Value Line, which in my experience is the most widely referenced source for beta in regulatory proceedings. As noted in *Regulatory Finance: Utilities' Cost of Capital*:

> Value Line betas are computed on a theoretically sound basis using a broadly-based market index, and they are adjusted for the regression tendency of betas to converge to 1.00. . . . Value Line is the largest and most widely circulated independent investment advisory service, and exerts influence on a large number of institutional and individual investors and on the expectations of these investors.[57]

As shown on Exhibit WEA-6, multiplying the 7.5 percent market risk premium by the average Value Line beta for the firms in the Utility Proxy Group, and then adding the resulting risk premium to the average long-term Treasury bond yield, results in an average indicated cost of common equity of 9.6 percent.

Q. WHAT COST OF COMMON EQUITY WAS INDICATED FOR THE NON-UTILITY PROXY GROUP BASED ON THIS FORWARD-LOOKING APPLICATION OF THE CAPM?

A. As shown on Exhibit WEA-7, applying the forward-looking CAPM approach to the firms in the Non-Utility Proxy Group results in an average implied cost of common equity of 10.3 percent.

Q. DO YOU HAVE ANY OBSERVATIONS REGARDING THESE CAPM RESULTS?

A. Yes. Applying the CAPM is complicated by the impact of the recent capital market turmoil and recession on investors' risk perceptions and required returns. The CAPM cost of common equity estimate is calibrated from investors' required risk

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[57] Morin, Roger A., "Regulatory Finance: Utilities' Cost of Capital," *Public Utilities Reports* at 65 (1994).

premium between Treasury bonds and common stocks. In response to heightened uncertainties, investors have sought a safe haven in U.S. government bonds and this "flight to safety" has pushed Treasury yields significantly lower while yield spreads for corporate debt have widened. This distortion not only impacts the absolute level of the CAPM cost of equity estimate, but it affects estimated risk premiums. Economic logic would suggest that investors' required risk premium for common stocks over Treasury bonds has also increased. Thus, recent capital market conditions may cause CAPM cost of common equity estimates to understate investors' required returns for common stocks, particularly when historical data are used to calculate the market risk premium. As the Staff of the Florida Public Service Commission recently concluded:

> [R]ecognizing the impact the Federal Government's unprecedented intervention in the capital markets has had on the yields on long-term Treasury bonds, staff believes models that relate the investor-required return on equity to the yield on government securities, such as the CAPM approach, produce less reliable estimates of the ROE at this time.[58]

While my application of the CAPM makes every effort to incorporate investors' forward-looking expectations, the full effect of the "flight to safety" may not be captured in my market risk premium estimate.

Second, the beta in CAPM theory is a measure of the investors' expected relationship of a firm's stock price to the market as a whole. Because investors' expected beta for a firm is not known, reported betas are estimated based on historical relationships. The precipitous drop and subsequent partial recovery in stock prices over the last year or so have caused many firms' historical betas to

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[58] *Staff Recommendation for Docket No. 080677-EI - Petition for increase in rates by Florida Power & Light Company*, at p. 280 (Dec. 23, 2009).

become unstable, so that reported betas may or may not reflect investors' expected beta. Because of this inherent mismatch between the historical circumstances underlying reported beta values and the current perceptions of investors, the CAPM may not accurately reflect investor's forward-looking rate of return requirements.

Meanwhile, forward-looking estimates of the market required rate of return may be distorted by the recent run-up in stock prices. It is not clear whether reported security analysts' dividend and growth projections have kept pace with the economic recovery expectations presumably pushing up stock prices; if not, there is a mismatch that under-estimates the market required rate of return. This incongruity between current measures of the market risk premium and historical beta values is particularly relevant during periods of heightened uncertainty and rapidly changing capital market conditions, such as those experienced recently. As a result, there is every indication that CAPM approaches fail to fully reflect the risk perceptions of real-world investors in today's capital markets, which would violate the standards underlying a fair rate of return by failing to provide an opportunity to earn a return commensurate with other investments of comparable risk.

E. Expected Earnings Approach

Q. WHAT OTHER ANALYSES DID YOU CONDUCT TO ESTIMATE THE COST OF COMMON EQUITY?

A. As I noted earlier, I also evaluated the cost of common equity using the expected earnings method. Reference to rates of return available from alternative investments of comparable risk can provide an important benchmark in assessing the return necessary to assure confidence in the financial integrity of a firm and its ability to attract capital. This expected earnings approach is consistent with the economic underpinnings for a fair rate of return established by the U.S. Supreme Court in

Bluefield and *Hope*. Moreover, it avoids the complexities and limitations of capital market methods and instead focuses on the returns earned on book equity, which are readily available to investors.

Q. WHAT RATES OF RETURN ON EQUITY ARE INDICATED FOR UTILITIES BASED ON THE EXPECTED EARNINGS APPROACH?

A. Value Line reports that its analysts anticipate an average rate of return on common equity for the electric utility industry of 10.5 percent in 2009, 11.0 percent in 2010, and 11.5 percent over its 2012-2014 forecast horizon.[59] Meanwhile, for the firms in the Utility Proxy Group specifically, the returns on common equity projected by Value Line over its three-to-five year forecast horizon are shown on Exhibit WEA-8. Consistent with the rationale underlying the development of the br+sv growth rates, these year-end values were converted to average returns using the same adjustment factor discussed earlier and developed on Exhibit WEA-3. As shown on Exhibit WEA-8, Value Line's projections for the utility proxy group suggested an average ROE of 11.4 percent.

F. Flotation Costs

Q. WHAT OTHER CONSIDERATIONS ARE RELEVANT IN SETTING THE RETURN ON EQUITY FOR A UTILITY?

A. The common equity used to finance the investment in utility assets is provided from either the sale of stock in the capital markets or from retained earnings not paid out as dividends. When equity is raised through the sale of common stock, there are costs associated with "floating" the new equity securities. These flotation costs include services such as legal, accounting, and printing, as well as the fees and

[59] The Value Line Investment Survey at 687 (Dec. 25, 2009).

discounts paid to compensate brokers for selling the stock to the public. Also, some argue that the "market pressure" from the additional supply of common stock and other market factors may further reduce the amount of funds a utility nets when it issues common equity.

Q. IS THERE AN ESTABLISHED MECHANISM FOR A UTILITY TO RECOGNIZE EQUITY ISSUANCE COSTS?

A. No. While debt flotation costs are recorded on the books of the utility, amortized over the life of the issue, and thus increase the effective cost of debt capital, there is no similar accounting treatment to ensure that equity flotation costs are recorded and ultimately recognized. No rate of return is authorized on flotation costs necessarily incurred to obtain a portion of the equity capital used to finance plant. In other words, equity flotation costs are not included in a utility's rate base because neither that portion of the gross proceeds from the sale of common stock used to pay flotation costs is available to invest in plant and equipment, nor are flotation costs capitalized as an intangible asset. Unless some provision is made to recognize these issuance costs, a utility's revenue requirements will not fully reflect all of the costs incurred for the use of investors' funds. Because there is no accounting convention to accumulate the flotation costs associated with equity issues, they must be accounted for indirectly, with an upward adjustment to the cost of equity being the most appropriate mechanism.

Q. WILL ADDITIONAL EQUITY CAPITAL BE REQUIRED TO SUPPORT KU?

A. Yes. Additional equity will be instrumental in financing the sizeable investment in utility infrastructure contemplated for the Company. S&P noted that capital expenditures are expected to exceed KU's cash flow from operations and will require reliance on external funding to meet these obligations.[60] Similarly, Moody's noted that since the Company's capital spending requirements began to ramp up in 2005, "KU received $220M of equity contributions during this timeframe in order to maintain an approximate 53% equity capitalization."[61]

Q. WHAT IS THE MAGNITUDE OF THE ADJUSTMENT TO THE "BARE BONES" COST OF EQUITY TO ACCOUNT FOR ISSUANCE COSTS?

A. There are any number of ways in which a flotation cost adjustment can be calculated, and the adjustment can range from just a few basis points to more than a full percent. One of the most common methods used to account for flotation costs in regulatory proceedings is to apply an average flotation-cost percentage to a utility's dividend yield. Based on a review of the finance literature, *Regulatory Finance: Utilities' Cost of Capital* concluded:

> The flotation cost allowance requires an estimated adjustment to the return on equity of approximately 5% to 10%, depending on the size and risk of the issue.[62]

Alternatively, a study of data from Morgan Stanley regarding issuance costs associated with utility common stock issuances suggests an average flotation cost percentage of 3.6%.[63]

Issuance costs are a legitimate consideration in setting the return on equity for a utility, and applying these expense percentages to a representative dividend yield for the Utility Proxy Group of 5.0 percent implies a flotation cost adjustment on the order of 18 to 50 basis points. A specific adjustment for flotation costs was

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[60] Standard & Poor's Corporation, "Summary: Kentucky Utilities Co.," *RatingsDirect* (Aug. 18, 2009).

[61] Moody's Investors Service, "Credit Opinion: Kentucky Utilities Co.," (May 1, 2009).

[62] Roger A. Morin, *Regulatory Finance: Utilities' Cost of Capital*, 1994, at 166.

[63] *Application of Yankee Gas Services Company for a Rate Increase*, DPUC Docket No. 04-06-01, Direct Testimony of George J. Eckenroth (Jul. 2, 2004) at Exhibit GJE-11.1. Updating the results presented by Mr. Eckenroth through April 2005 also resulted in an average flotation cost percentage of 3.6%.

not included in defining my recommended ROE range. While issuance costs are a legitimate consideration in setting the return on equity for a utility, it is my recommendation that they be considered in selecting a reasonable point estimate from within the range of reasonableness for KU.

G. Summary of Quantitative Results

Q. PLEASE SUMMARIZE THE RESULTS OF YOUR QUANTITATIVE ANALYSES.

A. The cost of common equity estimates produced by the various capital market oriented analyses described in my testimony are summarized in Table WEA-6, below:

TABLE WEA-6
SUMMARY OF QUANTITATIVE RESULTS

DCF	**Utility**	**Non-Utility**
Value Line	10.2%	12.0%
IBES	10.5%	12.6%
First Call	10.3%	12.8%
Zacks	10.1%	12.7%
br+sv	10.5%	12.2%
Stock Price	11.4%	13.7%
CAPM	9.6%	10.3%
Expected Earnings		
Electric Utilities - 2009	10.5%	
Electric Utilities - 2010	11.0%	
Electric Utilities - 2012-14	11.5%	
Utility Proxy Group	11.4%	

As noted earlier, because the capital market crisis and ensuing recovery have created a number of problems in applying the CAPM, I largely disregarded the resulting cost of equity estimates. Based on my assessment of the relative strengths and weaknesses inherent in each method, and conservatively giving less emphasis to the upper- and lower-most boundaries of the range of results, I concluded that the cost of common equity indicated by my analyses is in the 10.5 percent to 12.5 percent range. The reasonableness of my recommended ROE range is reinforced by the need to consider flotation costs and the fact that current cost of capital estimates are likely to understate investors' requirements at the time the outcome of this proceeding becomes effective and beyond.

IV. RETURN ON EQUITY FOR KENTUCKY UTILITIES COMPANY

Q. WHAT IS THE PURPOSE OF THIS SECTION?

A. In addition to presenting my conclusions regarding a fair ROE for KU, this section also discusses the relationship between ROE and preservation of a utility's financial integrity and the ability to attract capital. In addition, I evaluate the reasonableness of KU's requested capital structure and examine the implications of cost adjustment mechanisms for the Company's ROE.

A. Implications for Financial Integrity

Q. WHY IS IT IMPORTANT TO ALLOW KU AN ADEQUATE ROE?

A. Given the importance of the utility industry to the economy and society, it is essential to maintain reliable and economical service to all consumers. While the Company remains committed to providing reliable electric service, a utility's ability to fulfill its mandate can be compromised if it lacks the necessary financial wherewithal or is unable to earn a return sufficient to attract capital.

As documented earlier, the major rating agencies have warned of exposure to uncertainties associated with political and regulatory developments, especially in view of the pressures associated with ongoing capital expenditure requirements, uncertain environmental compliance costs, and the potential for continued energy price volatility. Investors understand just how swiftly unforeseen circumstances can lead to deterioration in a utility's financial condition, and stakeholders have discovered first hand how difficult and complex it can be to remedy the situation after the fact.

While providing the infrastructure necessary to enhance the power system and meet the energy needs of customers is certainly desirable, it imposes additional financial responsibilities on KU. For a utility with an obligation to provide reliable service, investors' increased reticence to supply additional capital during times of crisis highlights the necessity of preserving the flexibility necessary to overcome periods of adverse capital market conditions. These considerations heighten the importance of allowing KU an adequate ROE.

Q. WHAT ROLE DOES REGULATION PLAY IN ENSURING THAT KU HAS ACCESS TO CAPITAL UNDER REASONABLE TERMS AND ON A SUSTAINABLE BASIS?

A. Considering investors' heightened awareness of the risks associated with the utility industry and the damage that results when a utility's financial flexibility is compromised, the continuation of supportive regulation remains crucial to the Company's access to capital. Investors recognize that regulation has its own risks, and that constructive regulation is a key ingredient in supporting utility credit ratings and financial integrity, particularly during times of adverse conditions.

Fitch concluded, "[G]iven the lingering rate of unemployment and voter concerns about the economy, there could well be pockets of adverse rate decisions, and those companies with little financial cushion could suffer adverse effects." [64] Moody's has also emphasized the need for regulatory support, concluding:

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[64] Fitch Ratings Ltd., "U.S. Utilities, Power and Gas 2010 Outlook," *Global Power North America Special Report* (Dec. 4, 2009).

> For the longer term, however, we are becoming increasingly concerned about possible changes to our fundamental assumptions about regulatory risk, particularly the prospect of a more adversarial political (and therefore regulatory) environment. A prolonged recessionary climate with high unemployment, or an intense period of inflation, could make cost recovery more uncertain.[65]

Similarly, S&P concluded, "the quality of regulation is at the forefront of our analysis of utility creditworthiness."[66]

Q. DO CUSTOMERS BENEFIT BY ENHANCING THE UTILITY'S FINANCIAL FLEXIBILITY?

A. Yes. Providing a return on fair value that is both commensurate with those available from investments of corresponding risk and sufficient to maintain KU's ability to attract capital, even under duress, is consistent with the economic requirements embodied in the U.S. Supreme Court's *Bluefield* and *Hope* decisions; but it is also in customers' best interests. Ultimately, it is customers and the service area economy that enjoy the benefits that come from ensuring that the utility has the financial wherewithal to take whatever actions are required to ensure a reliable energy supply. By the same token, customers also bear a significant burden when the ability of the utility to attract capital is impaired and service quality is compromised.

B. Capital Structure

Q. IS AN EVALUATION OF THE CAPITAL STRUCTURE MAINTAINED BY A UTILITY RELEVANT IN ASSESSING ITS RETURN ON EQUITY?

A. Yes. Other things equal, a higher debt ratio, or lower common equity ratio, translates into increased financial risk for all investors. A greater amount of debt

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[65] Moody's Investors Service, "U.S. Regulated Electric Utilities, Six-Month Update," *Industry Outlook* (July 2009).

[66] Standard & Poor's Corporation, "Assessing U.S. Utility Regulatory Environments," *RatingsDirect* (Nov. 7, 2008).

means more investors have a senior claim on available cash flow, thereby reducing the certainty that each will receive his contractual payments. This increases the risks to which lenders are exposed, and they require correspondingly higher rates of interest. From common shareholders' standpoint, a higher debt ratio means that there are proportionately more investors ahead of them, thereby increasing the uncertainty as to the amount of cash flow, if any, that will remain.

Q. WHAT COMMON EQUITY RATIO IS IMPLICIT IN KU'S REQUESTED CAPITAL STRUCTURE?

A. The Company's capital structure is discussed in the testimony of Daniel K. Arbough. As summarized there and shown in Exhibit 2 to the testimony S. Bradford Rives, common equity as a percent of the capital sources used to compute the overall rate of return for KU was 53.85 percent.

Q. HOW CAN THE COMPANY'S REQUESTED CAPITAL STRUCTURES BE EVALUATED?

A. It is generally accepted that the norms established by comparable firms provide one valid benchmark against which to evaluate the reasonableness of a utility's capital structure. The capital structure maintained by other electric utilities should reflect their collective efforts to finance themselves so as to minimize capital costs while preserving their financial integrity and ability to attract capital. Moreover, these industry capital structures should also incorporate the requirements of investors (both debt and equity), as well as the influence of regulators.

Q. WHAT WAS THE AVERAGE CAPITALIZATION MAINTAINED BY THE UTILITY PROXY GROUP?

A. As shown on Exhibit WEA-9, for the firms in the Utility Proxy Group, common equity ratios at December 31, 2008 ranged between 39.2 percent and 60.4 percent and averaged 48.6 percent of long-term capital.

Q. WHAT CAPITALIZATION IS REPRESENTATIVE FOR THE UTILITY PROXY GROUP GOING FORWARD?

A. As shown on Exhibit WEA-9, Value Line expects an average common equity ratio for the Utility Proxy Group of 50.3 percent for its three-to-five year forecast horizon, with the individual common equity ratios ranging from 42.0 percent to 58.5 percent.

Q. WHAT CAPITALIZATION RATIOS ARE MAINTAINED BY OTHER ELECTRIC UTILITY OPERATING COMPANIES?

A. Exhibit WEA-10 displays capital structure data at year-end 2008 for the group of electric utility operating companies owned by the firms in the Utility Proxy Group used to estimate the cost of equity. As shown there, common equity ratios for these electric utilities averaged 51.7 percent.

Q. WHAT IMPLICATION DOES THE INCREASING RISK OF THE UTILITY INDUSTRY HAVE FOR THE CAPITAL STRUCTURE MAINTAINED BY KU?

A. As discussed earlier, utilities are facing energy market volatility, rising cost structures, the need to finance significant capital investment plans, uncertainties over accommodating future environmental mandates, and ongoing regulatory risks. Coupled with the ongoing turmoil in capital markets, these considerations warrant a stronger balance sheet to deal with an increasingly uncertain environment. A more conservative financial profile, in the form of a higher common equity ratio, is consistent with increasing uncertainties and the need to maintain the continuous access to capital that is required to fund operations and necessary system investment, even during times of adverse capital market conditions.

Moody's has warned investors of the risks associated with debt leverage and fixed obligations and advised utilities not to squander the opportunity to strengthen the balance sheet as a buffer against future uncertainties.[67] Moody's noted that, "maintaining unfettered access to capital markets will be crucial," and cited the importance of forestalling future downgrades by bolstering utility balance sheets.[68] As Moody's concluded:

> Our concerns are clearly growing, but we believe utilities have adequate time to adjust and revise their corporate finance polices and strengthen balance sheets, thereby improving their ability to manage volatility and address uncertainty.[69]

Similarly, in a review of the analytical methodology underlying its ratings assessment, S&P characterized a debt-to-total capital ratio in the range of 50 percent to 60 percent as "Aggressive",[70] and noted, "A total debt to capitalization level of 50% or greater is generally considered to be aggressive to highly leveraged for utilities."[71] Fitch affirmed that it expects regulated utilities "to extend their conservative balance sheet stance in 2010," and employ "a judicious mix of debt and equity to finance high levels of planned investments."[72]

Q. WHAT OTHER FACTORS DO INVESTORS CONSIDER IN THEIR ASSESSMENT OF A COMPANY'S CAPITAL STRUCTURE?

A. Depending on their specific attributes, contractual agreements or other obligations that require the utility to make specified payments may be treated as debt in evaluating a utility's financial risk. For example, because power purchase

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[67] Moody's Investors Service, "Storm Clouds Gathering on the Horizon for the North American Electric Utility Sector," *Special Comment* (Aug. 2007); "U.S. Electric Utility Sector," *Industry Outlook* (Jan. 2008).
[68] Moody's Investors Service, "U.S. Investor-Owned Electric Utilities," *Industry Outlook* (Jan. 2009).
[69] *Id.*
[70] Standard & Poor's Corporation, "Criteria Methodology: Business Risk/Financial Risk Matrix Expanded," *RatingsDirect* (May 27, 2009).
[71] Standard & Poor's Corporation, "Ratings Trend Turns Negative During First Quarter Of 2009 For U.S. Electric Utilities," *RatingsDirect* (Apr. 14, 2009).
[72] Fitch Ratings Ltd., "U.S. Utilities, Power, and Gas 2010 Outlook," *Global Power North America Special Report* (Dec. 4, 2009).

agreements ("PPAs") and leases typically obligate the utility to make specified minimum contractual payments akin to those associated with traditional debt financing, investors consider a portion of these commitments as debt in evaluating total financial risks. Because investors consider the debt impact of such fixed obligations in assessing a utility's financial position, they imply greater risk and reduced financial flexibility. In order to offset the debt equivalent associated with off-balance sheet obligations, the utility must rebalance its capital structure by increasing its common equity in order to restore its effective capitalization ratios to previous levels.[73]

These commitments have been repeatedly cited by major bond rating agencies in connection with assessments of utility financial risks. For example, in explaining its evaluation of the credit implications of PPAs, S&P affirmed its position that such agreements give rise to "debt equivalents" and that the increased financial risk must be considered in evaluating a utility's credit risks.[74] S&P also noted that it has refined its methodology to include imputed debt associated with shorter-term PPAs and operating leases.[75]

As discussed earlier, a portion of the Company's power requirements are currently obtained through purchased power contracts. These contractual payment obligations, along with operating leases and obligations associated with postretirement benefits, are fixed commitments with debt-like characteristics and are properly considered when evaluating the financial risks implied by KU's capital structure. As discussed by witness Arbough, S&P's calculations result in a $173.5

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[73] The capital structure ratios presented earlier do not include imputed debt associated with power purchase agreements or the impact of other off-balance sheet obligations.

[74] Standard & Poor's Corporation, "Standard & Poor's Methodology For Imputing Debt For U.S. Utilities' Power Purchase Agreements," *RatingsDirect* (May 7, 2007).

[75] Standard & Poor's Corporation, "Implications Of Operating Leases On Analysis Of U.S. Electric Utilities," *RatingsDirect* (Jan. 15, 2008).

million adjustment to the Company's capitalization for the imputed debt associated with PPAs, leases, and postretirement benefit obligations. Unless KU takes action to offset this additional financial risk by maintaining a higher equity ratio, the resulting leverage will weaken the Company's creditworthiness, implying a higher required rate of return to compensate investors for the greater risks.[76]

Q. WHAT DID YOU CONCLUDE REGARDING THE REASONABLENESS OF KU'S REQUESTED CAPITAL STRUCTURE?

A. Based on my evaluation, I concluded that the 53.85 percent common equity ratio requested by KU represents a reasonable mix of capital sources from which to calculate the Company's overall rate of return. Although this common equity ratio is somewhat higher than the historical and projected averages maintained by the Utility Proxy Group, it is well within the range of individual results, consistent with the capitalization maintained by other utility operating companies, and reflects the trend towards lower financial leverage necessary to accommodate higher expected capital expenditures in the industry.

While industry averages provide one benchmark for comparison, each firm must select its capitalization based on the risks and prospects it faces, as well as its specific needs to access the capital markets. A public utility with an obligation to serve must maintain ready access to capital under reasonable terms so that it can meet the service requirements of its customers. The need for access becomes even more important when the company has capital requirements over a period of years, and financing must be continuously available, even during unfavorable capital market conditions.

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[76] Apart from the immediate impact that the fixed obligation of purchased power costs has on the utility's financial risk, higher fixed charges also reduce ongoing financial flexibility, and the utility may face other uncertainties, such as potential replacement power costs in the event of supply disruption.

Financial flexibility plays a crucial role in ensuring the wherewithal to meet the needs of customers, and utilities with higher leverage may be foreclosed from additional borrowing, especially during times of stress. KU's capital structure reflects the Company's ongoing efforts to maintain its credit standing and support access to capital on reasonable terms. The reasonableness of the Company's capital structure is reinforced by the ongoing uncertainties associated with the electric power industry and the importance of supporting continued system investment, even during times of adverse industry or market conditions.

C. Impact of Trackers

Q. DOES THE FACT THAT KU OPERATES UNDER CERTAIN RATE ADJUSTMENT MECHANISMS WARRANT ANY ADJUSTMENT IN YOUR EVALUATION OF A FAIR ROE?

A. No. Investors recognize that KU is exposed to significant risks associated with energy price volatility and rising costs and concerns over these risks have become increasingly pronounced in the industry. The KPSC's rate adjustment mechanisms are a valuable means of mitigating those risks, but they do not eliminate them. While the adjustment mechanisms approved for KU partially attenuate exposure to attrition in an era of rising costs, this leveling of the playing field only serves to address factors that could otherwise impair KU's opportunity to earn its authorized return, as required by established regulatory standards.

Reflective of this industry trend, the companies in the Utility Proxy Group operate under a wide variety of cost adjustment mechanisms, which range from riders to recover bad debt expense and post-retirement employee benefit costs to revenue decoupling and adjustment clauses designed to address the rising costs of environmental compliance measures. Similarly, the firms in the Non-Utility Proxy

Group also have the ability to alter prices in response to rising production costs, with the added flexibility to withdraw from the market altogether. As a result, the mitigation in risks associated with utilities' ability to attenuate the risk of cost recovery is already reflected in the cost of equity range determined earlier, and no separate adjustment to KU's ROE is necessary or warranted.

D. Return on Equity Range Recommendation

Q. PLEASE SUMMARIZE THE RESULTS OF YOUR ANALYSES.

A. In order to reflect the risks and prospects associated with KU's jurisdictional utility operations, my analyses focused on a proxy group of fourteen other utilities with comparable investment risks. Consistent with the fact that utilities must compete for capital with firms outside their own industry, I also referenced a proxy group of comparable risk companies in the non-utility sectors of the economy. The cost of common equity estimates produced by the various capital market oriented analyses described in my testimony were summarized earlier in Table WEA-6, which is reproduced as Table WEA-7, below:

TABLE WEA-7
SUMMARY OF QUANTITATIVE RESULTS

DCF	**Utility**	**Non-Utility**
Value Line	10.2%	12.0%
IBES	10.5%	12.6%
First Call	10.3%	12.8%
Zacks	10.1%	12.7%
br+sv	10.5%	12.2%
Stock Price	11.4%	13.7%
CAPM	9.6%	10.3%
Expected Earnings		
Electric Utilities - 2009	10.5%	
Electric Utilities - 2010	11.0%	
Electric Utilities - 2012-14	11.5%	
Utility Proxy Group	11.4%	

As noted earlier, based on my assessment of the relative strengths and weaknesses inherent in each method, I concluded that the cost of common equity indicated by my analyses is in the 10.5 percent to 12.5 percent range. The reasonableness of my recommended ROE range is reinforced by the need to consider flotation costs and the fact that current cost of capital estimates are likely to understate investors' requirements at the time the outcome of this proceeding becomes effective and beyond.

Q. WHAT THEN IS YOUR CONCLUSION AS TO A FAIR ROE FOR KU?

A. Considering capital market expectations, the potential exposures faced by KU, and the economic requirements necessary to maintain financial integrity and support additional capital investment even under adverse circumstances, it is my opinion that the midpoint of this range, or 11.5 percent represents a fair and reasonable ROE for KU. My conclusion is supported by the need to consider the potential exposures faced by KU and the economic requirements necessary to maintain financial integrity and support access to capital even under adverse circumstances. In addition, KU faces ongoing uncertainties related to future emissions legislation. Coupled with the need to provide an ROE that supports KU's credit standing while funding necessary system investments, these considerations indicate that an ROE from the middle of my recommended range is reasonable. The cost of providing the Company an adequate return is small relative to the potential benefits that a strong utility can have in providing reliable service. Considering investors' heightened awareness of the risks associated with the utility industry and the damage that results when a utility's financial flexibility is compromised, supportive regulation is crucial.

Q. DOES THIS CONCLUDE YOUR PRE-FILED DIRECT TESTIMONY?

A. Yes.

VERIFICATION

STATE OF TEXAS)
) **SS:**
COUNTY OF TRAVIS)

The undersigned, **William E. Avera**, being duly sworn, deposes and says that he is President of FINCAP, Inc., that he has personal knowledge of the matters set forth in the foregoing testimony and exhibits, and the answers contained therein are true and correct to the best of his information, knowledge and belief.

WILLIAM E. AVERA

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 14th day of January, 2010.

__________________(SEAL)
Notary Public

My Commission Expires:

1/10/2011

ADRIEN MCKENZIE
Notary Public
STATE OF TEXAS
My Comm Exp Jan 10, 2011

Exhibit WEA-1

WILLIAM E. AVERA

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Economic and Financial Counsel

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Summary of Qualifications

Ph.D. in economics and finance; Chartered Financial Analyst (CFA®) designation; extensive expert witness testimony before courts, alternative dispute resolution panels, regulatory agencies and legislative committees; lectured in executive education programs around the world on ethics, investment analysis, and regulation; undergraduate and graduate teaching in business and economics; appointed to leadership positions in government, industry, academia, and the military.

Employment

Principal, FINCAP, Inc. (Sep. 1979 to present)	Financial, economic and policy consulting to business and government. Perform business and public policy research, cost/benefit analyses and financial modeling, valuation of businesses (almost 200 entities valued), estimation of damages, statistical and industry studies. Provide strategy advice and educational services in public and private sectors, and serve as expert witness before regulatory agencies, legislative committees, arbitration panels, and courts.
Director, Economic Research Division, Public Utility Commission of Texas (Dec. 1977 to Aug. 1979)	Responsible for research and testimony preparation on rate of return, rate structure, and econometric analysis dealing with energy, telecommunications, water and sewer utilities. Testified in major rate cases and appeared before legislative committees and served as Chief Economist for agency. Administered state and federal grant funds. Communicated frequently with political leaders and representatives from consumer groups, media, and investment community.
Manager, Financial Education, International Paper Company New York City (Feb. 1977 to Nov. 1977)	Directed corporate education programs in accounting, finance, and economics. Developed course materials, recruited and trained instructors, liaison within the company and with academic institutions. Prepared operating budget and designed financial controls for corporate professional development program.

Lecturer in Finance,
The University of Texas at Austin
(Sep. 1979 to May 1981)
Assistant Professor of Finance,
(Sep. 1975 to May 1977)

Taught graduate and undergraduate courses in financial management and investment theory. Conducted research in business and public policy. Named Outstanding Graduate Business Professor and received various administrative appointments.

Assistant Professor of Business,
University of North Carolina at Chapel Hill
(Sep. 1972 to Jul. 1975)

Taught in BBA, MBA, and Ph.D. programs. Created project course in finance, Financial Management for Women, and participated in developing Small Business Management sequence. Organized the North Carolina Institute for Investment Research, a group of financial institutions that supported academic research. Faculty advisor to the Media Board, which funds student publications and broadcast stations.

Education

Ph.D., Economics and Finance,
University of North Carolina at Chapel Hill
(Jan. 1969 to Aug. 1972)

Elective courses included financial management, public finance, monetary theory, and econometrics. Awarded the Stonier Fellowship by the American Bankers' Association and University Teaching Fellowship. Taught statistics, macroeconomics, and microeconomics.

Dissertation: *The Geometric Mean Strategy as a Theory of Multiperiod Portfolio Choice*

B.A., Economics,
Emory University, Atlanta, Georgia
(Sep. 1961 to Jun. 1965)

Active in extracurricular activities, president of the Barkley Forum (debate team), Emory Religious Association, and Delta Tau Delta chapter. Individual awards and team championships at national collegiate debate tournaments.

Professional Associations

Received Chartered Financial Analyst (CFA) designation in 1977; Vice President for Membership, Financial Management Association; President, Austin Chapter of Planning Executives Institute; Board of Directors, North Carolina Society of Financial Analysts; Candidate Curriculum Committee, Association for Investment Management and Research; Executive Committee of Southern Finance Association; Vice Chair, Staff Subcommittee on Economics and National Association of Regulatory Utility Commissioners (NARUC); Appointed to NARUC Technical Subcommittee on the National Energy Act.

Teaching in Executive Education Programs

University-Sponsored Programs: Central Michigan University, Duke University, Louisiana State University, National Defense University, National University of Singapore, Texas A&M University, University of Kansas, University of North Carolina, University of Texas.

Business and Government-Sponsored Programs: Advanced Seminar on Earnings Regulation, American Public Welfare Association, Association for Investment Management and Research, Congressional Fellows Program, Cost of Capital Workshop, Electricity Consumers Resource Council, Financial Analysts Association of Indonesia, Financial Analysts Review, Financial Analysts Seminar at Northwestern University, Governor's Executive Development Program of Texas, Louisiana Association of Business and Industry, National Association of Purchasing Management, National Association of Tire Dealers, Planning Executives Institute, School of Banking of the South, State of Wisconsin Investment Board, Stock Exchange of Thailand, Texas Association of State Sponsored Computer Centers, Texas Bankers' Association, Texas Bar Association, Texas Savings and Loan League, Texas Society of CPAs, Tokyo Association of Foreign Banks, Union Bank of Switzerland, U.S. Department of State, U.S. Navy, U.S. Veterans Administration, in addition to Texas state agencies and major corporations.

Presented papers for Mills B. Lane Lecture Series at the University of Georgia and Heubner Lectures at the University of Pennsylvania. Taught graduate courses in finance and economics for evening program at St. Edward's University in Austin from January 1979 through 1998.

Expert Witness Testimony

Testified in over 300 cases before regulatory agencies addressing cost of capital, regulatory policy, rate design, and other economic and financial issues.

Federal Agencies: Federal Communications Commission, Federal Energy Regulatory Commission, Surface Transportation Board, Interstate Commerce Commission, and the Canadian Radio-Television and Telecommunications Commission.

State Regulatory Agencies: Alaska, Arizona, Arkansas, California, Colorado, Connecticut, Delaware, Florida, Georgia, Hawaii, Idaho, Illinois, Indiana, Iowa, Kansas, Kentucky, Maryland, Michigan, Missouri, Nevada, New Mexico, Montana, North Carolina, Ohio, Oklahoma, Oregon, Pennsylvania, South Carolina, South Dakota, Texas, Utah, Virginia, Washington, West Virginia, Wisconsin, and Wyoming.

Testified in 42 cases before federal and state courts, arbitration panels, and alternative dispute tribunals (88 depositions given) regarding damages, valuation, antitrust liability, fiduciary duties, and other economic and financial issues.

Board Positions and Other Professional Activities

Audit Committee and Outside Director, Georgia System Operations Corporation (electric system operator for member-owned electric cooperatives in Georgia); Chairman, Board of Print Depot, Inc. and FINCAP, Inc.; Co-chair, Synchronous Interconnection Committee, appointed by Public Utility Commission of Texas and approved by governor; Appointed by Hays County Commission to Citizens Advisory Committee of Habitat Conservation Plan, Operator of AAA Ranch, a certified organic producer of agricultural products; Appointed to Organic Livestock Advisory Committee by

Texas Agricultural Commissioner Susan Combs; Appointed by Texas Railroad Commissioners to study group for *The UP/SP Merger: An Assessment of the Impacts on the State of Texas;* Appointed by Hawaii Public Utilities Commission to team reviewing affiliate relationships of Hawaiian Electric Industries; Chairman, Energy Task Force, Greater Austin-San Antonio Corridor Council; Consultant to Public Utility Commission of Texas on cogeneration policy and other matters; Consultant to Public Service Commission of New Mexico on cogeneration policy; Evaluator of Energy Research Grant Proposals for Texas Higher Education Coordinating Board.

Community Activities

Board of Directors, Sustainable Food Center; Chair, Board of Deacons, Finance Committee, and Elder, Central Presbyterian Church of Austin; Founding Member, Orange-Chatham County (N.C.) Legal Aid Screening Committee.

Military

Captain, U.S. Naval Reserve (retired after 28 years service); Commanding Officer, Naval Special Warfare Engineering (SEAL) Support Unit; Officer-in-Charge of SWIFT patrol boat in Vietnam; Enlisted service as weather analyst (advanced to second class petty officer).

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Monographs

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"Definition of Industry Ethics and Development of a Code" and "Applying Ethics in the Real World," in *Good Ethics: The Essential Element of a Firm's Success*, Association for Investment Management and Research (1994)

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"The Energy Crisis and the Homeowner: The Grief Process," *Texas Business Review* (Jan.–Feb. 1980); reprinted in *The Energy Picture: Problems and Prospects*, J. E. Pluta, ed., Bureau of Business Research (1980)

"Use of IFPS at the Public Utility Commission of Texas," *Proceedings of the IFPS Users Group Annual Meeting* (1979)

"Production Capacity Allocation: Conversion, CWIP, and One-Armed Economics," *Proceedings of the NARUC Biennial Regulatory Information Conference* (1978)

"Some Thoughts on the Rate of Return to Public Utility Companies," with Bruce H. Fairchild in *Proceedings of the NARUC Biennial Regulatory Information Conference* (1978)

"A New Capital Budgeting Measure: The Integration of Time, Liquidity, and Uncertainty," with David Cordell in *Proceedings of the Southwestern Finance Association* (1977)

"Usefulness of Current Values to Investors and Creditors," in *Inflation Accounting/Indexing and Stock Behavior* (1977)

"Consumer Expectations and the Economy," *Texas Business Review* (Nov. 1976)

"Portfolio Performance Evaluation and Long-run Capital Growth," with Henry A. Latané in *Proceedings of the Eastern Finance Association* (1973)

Book reviews in *Journal of Finance* and *Financial Review*. Abstracts for *CFA Digest*. Articles in *Carolina Financial Times*.

Selected Papers and Presentations

"Economic Perspective on Water Marketing in Texas," 2009 Water Law Institute, The University of Texas School of Law, Austin, TX (Dec. 2009).

"Estimating Utility Cost of Equity in Financial Turmoil," SNL EXNET 15th Annual FERC Briefing, Washington, D.C. (Mar. 2009)

"The Who, What, When, How, and Why of Ethics," San Antonio Financial Analysts Society (Jan. 16, 2002). Similar presentation given to the Austin Society of Financial Analysts (Jan. 17, 2002)

"Ethics for Financial Analysts," Sponsored by Canadian Council of Financial Analysts: delivered in Calgary, Edmonton, Regina, and Winnipeg, June 1997. Similar presentations given to Austin Society of Financial Analysts (Mar. 1994), San Antonio Society of Financial Analysts (Nov. 1985), and St. Louis Society of Financial Analysts (Feb. 1986)

"Cost of Capital for Multi-Divisional Corporations," Financial Management Association, New Orleans, Louisiana (Oct. 1996)

"Ethics and the Treasury Function," Government Treasurers Organization of Texas, Corpus Christi, Texas (Jun. 1996)

"A Cooperative Future," Iowa Association of Electric Cooperatives, Des Moines (December 1995). Similar presentations given to National G & T Conference, Irving, Texas (June 1995), Kentucky Association of Electric Cooperatives Annual Meeting, Louisville (Nov. 1994), Virginia, Maryland, and Delaware Association of Electric Cooperatives Annual Meeting, Richmond (July 1994), and Carolina Electric Cooperatives Annual Meeting, Raleigh (Mar. 1994)

"Information Superhighway Warnings: Speed Bumps on Wall Street and Detours from the Economy," Texas Society of Certified Public Accountants Natural Gas, Telecommunications and Electric Industries Conference, Austin (Apr. 1995)

"Economic/Wall Street Outlook," Carolinas Council of the Institute of Management Accountants, Myrtle Beach, South Carolina (May 1994). Similar presentation given to Bell Operating Company Accounting Witness Conference, Santa Fe, New Mexico (Apr. 1993)

"Regulatory Developments in Telecommunications," Regional Holding Company Financial and Accounting Conference, San Antonio (Sep. 1993)

"Estimating the Cost of Capital During the 1990s: Issues and Directions," The National Society of Rate of Return Analysts, Washington, D.C. (May 1992)

"Making Utility Regulation Work at the Public Utility Commission of Texas," Center for Legal and Regulatory Studies, University of Texas, Austin (June 1991)

"Can Regulation Compete for the Hearts and Minds of Industrial Customers," Emerging Issues of Competition in the Electric Utility Industry Conference, Austin (May 1988)

"The Role of Utilities in Fostering New Energy Technologies," Emerging Energy Technologies in Texas Conference, Austin (Mar. 1988)

"The Regulators' Perspective," Bellcore Economic Analysis Conference, San Antonio (Nov. 1987)

"Public Utility Commissions and the Nuclear Plant Contractor," Construction Litigation Superconference, Laguna Beach, California (Dec. 1986)

"Development of Cogeneration Policies in Texas," University of Georgia Fifth Annual Public Utilities Conference, Atlanta (Sep. 1985)

"Wheeling for Power Sales," Energy Bureau Cogeneration Conference, Houston (Nov. 1985).

"Asymmetric Discounting of Information and Relative Liquidity: Some Empirical Evidence for Common Stocks" (with John Groth and Kerry Cooper), Southern Finance Association, New Orleans (Nov. 1982)

"Used and Useful Planning Models," Planning Executive Institute, 27th Corporate Planning Conference, Los Angeles (Nov. 1979)

"Staff Input to Commission Rate of Return Decisions," The National Society of Rate of Return Analysts, New York (Oct. 1979)

""Discounted Cash Life: A New Measure of the Time Dimension in Capital Budgeting," with David Cordell, Southern Finance Association, New Orleans (Nov. 1978)

"The Relative Value of Statistics of Ex Post Common Stock Distributions to Explain Variance," with Charles G. Martin, Southern Finance Association, Atlanta (Nov. 1977)

"An ANOVA Representation of Common Stock Returns as a Framework for the Allocation of Portfolio Management Effort," with Charles G. Martin, Financial Management Association, Montreal (Oct. 1976)

"A Growth-Optimal Portfolio Selection Model with Finite Horizon," with Henry A. Latané, American Finance Association, San Francisco (Dec. 1974)

"An Optimal Approach to the Finance Decision," with Henry A. Latané, Southern Finance Association, Atlanta (Nov. 1974)

"A Pragmatic Approach to the Capital Structure Decision Based on Long-Run Growth," with Henry A. Latané, Financial Management Association, San Diego (Oct. 1974)

"Growth Rates, Expected Returns, and Variance in Portfolio Selection and Performance Evaluation," with Henry A. Latané, Econometric Society, Oslo, Norway (Aug. 1973)

DCF MODEL

Exhibit WEA-2
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UTILITY PROXY GROUP

		(a)	(a)		(b)	(c)	(d)	(e)	(f)	(b)	(g)	(g)	(g)	(g)	(g)	(g)
		Dividend Yield			Growth Rates						Cost of Equity Estimates					
	Company	Price	Dividends	Yield	V Line	IBES	First Call	Zacks	br+sv	Price	V Line	IBES	First Call	Zacks	br+sv	Price
1	ALLETE	$ 34.01	$ 1.78	5.2%	-1.0%	4.0%	4.0%	4.0%	5.3%	4.1%	4.2%	9.2%	9.2%	9.2%	10.5%	9.4%
2	Alliant Energy	$ 30.49	$ 1.60	5.2%	4.0%	4.3%	4.0%	3.0%	4.2%	7.0%	9.2%	9.5%	9.2%	8.2%	9.4%	12.3%
3	Consolidated Edison	$ 45.03	$ 2.36	5.2%	3.0%	3.4%	4.0%	3.6%	3.7%	2.7%	8.2%	8.6%	9.2%	8.8%	8.9%	7.9%
4	Dominion Resources	$ 39.25	$ 1.87	4.8%	8.0%	5.2%	4.0%	5.0%	8.7%	8.8%	12.8%	10.0%	8.8%	9.8%	13.5%	13.6%
5	Duke Energy Corp.	$ 17.65	$ 0.98	5.6%	5.0%	3.6%	4.0%	4.3%	1.9%	5.1%	10.6%	9.2%	9.6%	9.9%	7.5%	10.6%
6	Entergy Corp.	$ 83.00	$ 3.00	3.6%	6.0%	6.8%	5.0%	4.7%	6.9%	7.3%	9.6%	10.4%	8.6%	8.3%	10.5%	10.9%
7	Exelon Corp.	$ 51.05	$ 2.10	4.1%	4.5%	2.2%	1.0%	2.0%	9.2%	7.2%	8.6%	6.3%	5.1%	6.1%	13.3%	11.3%
8	PG&E Corp.	$ 45.14	$ 1.77	3.9%	6.5%	7.3%	7.6%	7.7%	6.7%	1.3%	10.4%	11.2%	11.5%	11.6%	10.6%	5.2%
9	Progress Energy	$ 41.51	$ 2.48	6.0%	6.0%	4.5%	4.5%	4.5%	3.2%	0.6%	12.0%	10.5%	10.5%	10.5%	9.1%	6.6%
10	SCANA Corp.	$ 37.49	$ 1.92	5.1%	4.0%	5.8%	5.5%	5.0%	5.9%	6.1%	9.1%	10.9%	10.6%	10.1%	11.1%	11.2%
11	Sempra Energy	$ 55.47	$ 1.68	3.0%	5.5%	7.0%	7.0%	7.0%	8.3%	10.4%	8.5%	10.0%	10.0%	10.0%	11.3%	13.5%
12	Vectren Corp.	$ 24.81	$ 1.36	5.5%	5.0%	6.3%	6.0%	7.5%	3.7%	4.9%	10.5%	11.8%	11.5%	13.0%	9.2%	10.3%
13	Wisconsin Energy	$ 47.87	$ 1.55	3.2%	8.0%	9.9%	10.0%	8.3%	6.4%	7.9%	11.2%	13.1%	13.2%	11.5%	9.6%	11.2%
14	Xcel Energy, Inc.	$ 21.48	$ 1.00	4.7%	6.5%	7.3%	7.1%	5.7%	4.9%	0.6%	11.2%	12.0%	11.8%	10.4%	9.6%	5.3%
	Average (h)										**10.2%**	**10.5%**	**10.3%**	**10.1%**	**10.5%**	**11.4%**

(a) Recent price and estimated dividend for next 12 mos. from The Value Line Investment Survey, *Summary and Index* (Nov. 6, 2009).
(b) The Value Line Investment Survey (Nov. 6, Nov. 27, & Dec. 25, 2009).
(c) *Thomson ReutersCompany Report* (Dec. 21, 2009).
(d) *First Call Earnings Valuation Report* (Dec. 22, 2009).
(e) www.zacks.com (retrieved Dec. 22, 2009).
(f) See Exhibit WEA-3.
(g) Sum of dividend yield and respective growth rate.
(h) Excludes highlighted figures.

UTILITY PROXY GROUP

		(a)	(a)	(b)	(a)	(a)	(a)	(c)	(d)
		2012-14 Market Price			2012-14 Projections				
	Company	High	Low	Avg.	EPS	DPS	BVPS	b	r
1	ALLETE	45.00	35.00	$40.00	$2.75	$1.90	$28.25	30.9%	9.7%
2	Alliant Energy	45.00	35.00	$40.00	$3.10	$1.92	$31.05	38.1%	10.0%
3	Consolidated Edison	55.00	45.00	$50.00	$3.85	$2.44	$41.05	36.6%	9.4%
4	Dominion Resources	65.00	45.00	$55.00	$4.00	$2.20	$26.00	45.0%	15.4%
5	Duke Energy Corp.	25.00	18.00	$21.50	$1.40	$1.10	$17.25	21.4%	8.1%
6	Entergy Corp.	125.00	95.00	$110.00	$8.00	$3.60	$57.50	55.0%	13.9%
7	Exelon Corp.	75.00	60.00	$67.50	$5.00	$2.40	$26.25	52.0%	19.0%
8	PG&E Corp.	55.00	40.00	$47.50	$4.25	$2.20	$35.75	48.2%	11.9%
9	Progress Energy	50.00	35.00	$42.50	$3.60	$2.56	$36.80	28.9%	9.8%
10	SCANA Corp.	55.00	40.00	$47.50	$3.50	$2.10	$33.25	40.0%	10.5%
11	Sempra Energy	95.00	70.00	$82.50	$6.00	$2.10	$51.25	65.0%	11.7%
12	Vectren Corp.	35.00	25.00	$30.00	$2.20	$1.50	$20.50	31.8%	10.7%
13	Wisconsin Energy	75.00	55.00	$65.00	$4.50	$2.15	$38.00	52.2%	11.8%
14	Xcel Energy, Inc.	25.00	19.00	$22.00	$2.00	$1.10	$19.00	45.0%	10.5%

UTILITY PROXY GROUP

		(a)	(a)	(e)	(a)	(a)	(e)	(f)	(g)	(h)
		2008			2012-14			Adjusted "r"		
	Company	BVPS	No. Shares	Common Equity	BVPS	No. Shares	Common Equity	Chg in Equity	Adj. Factor	Adj. r
1	ALLETE	$25.37	32.60	$827	$28.25	42.00	$1,187	7.5%	1.0361	10.1%
2	Alliant Energy	$25.56	110.45	$2,823	$31.05	116.00	$3,602	5.0%	1.0244	10.2%
3	Consolidated Edison	$35.43	273.72	$9,698	$41.05	285.00	$11,699	3.8%	1.0188	9.6%
4	Dominion Resources	$17.28	583.20	$10,078	$26.00	623.00	$16,198	10.0%	1.0474	16.1%
5	Duke Energy Corp.	$16.50	1,272.00	$20,988	$17.25	1315.00	$22,684	1.6%	1.0078	8.2%
6	Entergy Corp.	$42.07	189.36	$7,966	$57.50	180.00	$10,350	5.4%	1.0262	14.3%
7	Exelon Corp.	$16.79	658.00	$11,048	$26.25	635.00	$16,669	8.6%	1.0411	19.8%
8	PG&E Corp.	$25.97	361.06	$9,377	$35.75	400.00	$14,300	8.8%	1.0422	12.4%
9	Progress Energy	$32.55	264.00	$8,593	$36.80	288.00	$10,598	4.3%	1.0210	10.0%
10	SCANA Corp.	$25.81	118.00	$3,046	$33.25	141.00	$4,688	9.0%	1.0431	11.0%
11	Sempra Energy	$32.75	243.32	$7,969	$51.25	250.00	$12,813	10.0%	1.0475	12.3%
12	Vectren Corp.	$16.68	81.03	$1,352	$20.50	83.00	$1,702	4.7%	1.0230	11.0%
13	Wisconsin Energy	$28.54	116.92	$3,337	$38.00	117.00	$4,446	5.9%	1.0287	12.2%
14	Xcel Energy, Inc.	$15.35	453.79	$6,966	$19.00	464.00	$8,816	4.8%	1.0236	10.8%

UTILITY PROXY GROUP

		(a)	(a)	(f)	(i)	(j)	(k)	(l)	(m)
		Common Shares Outstanding			M/B	"sv" Factor			
	Company	2008	2012-14	Change	Ratio	s	v	sv	br + sv
1	ALLETE	32.6	42.0	5.20%	1.42	0.0736	0.2938	2.16%	5.3%
2	Alliant Energy	110.5	116.0	0.99%	1.29	0.0127	0.2238	0.28%	4.2%
3	Consolidated Edison	273.7	285.0	0.81%	1.22	0.0099	0.1790	0.18%	3.7%
4	Dominion Resources	583.2	623.0	1.33%	2.12	0.0281	0.5273	1.48%	8.7%
5	Duke Energy Corp.	1,272.0	1,315.0	0.67%	1.25	0.0083	0.1977	0.16%	1.9%
6	Entergy Corp.	189.4	180.0	-1.01%	1.91	(0.0193)	0.4773	-0.92%	6.9%
7	Exelon Corp.	658.0	635.0	-0.71%	2.57	(0.0182)	0.6111	-1.11%	9.2%
8	PG&E Corp.	361.1	400.0	2.07%	1.33	0.0275	0.2474	0.68%	6.7%
9	Progress Energy	264.0	288.0	1.76%	1.15	0.0203	0.1341	0.27%	3.2%
10	SCANA Corp.	118.0	141.0	3.63%	1.43	0.0518	0.3000	1.55%	5.9%
11	Sempra Energy	243.3	250.0	0.54%	1.61	0.0087	0.3788	0.33%	8.3%
12	Vectren Corp.	81.0	83.0	0.48%	1.46	0.0070	0.3167	0.22%	3.7%
13	Wisconsin Energy	116.9	117.0	0.01%	1.71	0.0002	0.4154	0.01%	6.4%
14	Xcel Energy, Inc.	453.8	464.0	0.45%	1.16	0.0052	0.1364	0.07%	4.9%

(a) The Value Line Investment Survey (Nov. 6, Nov. 27, & Dec. 25, 2009).
(b) Average of High and Low expected market prices.
(c) Computed at (EPS - DPS) / EPS.
(d) Computed as EPS / BVPS.
(e) Product of BVPS and No. Shares Outstanding.
(f) Five-year rate of change.
(g) Computed using the formula 2*(1+5-Yr. Change in Equity)/(2+5 Yr. Change in Equity).
(h) Product of year-end "r" for 2012-14 and Adjustment Factor.
(i) Average of High and Low expected market prices divided by 2012-14 BVPS.
(j) Product of change in common shares outstanding and M/B Ratio.
(k) Computed as 1 - B/M Ratio.
(l) Product of "s" and "v".
(m) Product of average "b" and adjusted "r", plus "sv".

DCF MODEL

NON-UTILITY PROXY GROUP

		(a)	(b)	(c)	(d)	(e)	(a)	(f)	(f)	(f)	(f)	(f)	(f)
		Growth Rates						Cost of Equity Estimates					
	Company	V Line	IBES	First Call	Zacks	br+sv	Price	V Line	IBES	First Call	Zacks	br+sv	Price
1	3M Company	5.0%	12.1%	12.5%	11.6%	15.8%	10.4%	7.5%	14.6%	15.0%	14.1%	18.4%	12.9%
2	Abbott Labs.	10.0%	11.5%	12.0%	10.8%	13.6%	15.7%	13.0%	14.5%	15.0%	13.8%	16.6%	18.7%
3	Alberto-Culver	14.5%	11.7%	12.5%	12.5%	8.0%	7.6%	15.7%	12.9%	13.7%	13.7%	9.2%	8.8%
4	Allergan, Inc.	14.0%	13.0%	13.3%	15.2%	19.2%	15.6%	14.3%	13.3%	13.6%	15.5%	19.5%	16.0%
5	AT&T Inc.	5.0%	5.9%	5.0%	5.9%	5.9%	13.0%	11.2%	12.1%	11.2%	12.1%	12.0%	19.2%
6	Automatic Data Proc.	10.0%	11.8%	12.0%	11.4%	9.8%	15.8%	13.2%	15.0%	15.2%	14.6%	13.1%	19.0%
7	Bard (C.R.)	12.5%	13.6%	13.9%	13.4%	13.4%	14.4%	13.3%	14.4%	14.7%	14.2%	14.3%	15.2%
8	Baxter Int'l Inc.	14.0%	11.5%	11.5%	11.5%	15.1%	15.4%	16.0%	13.5%	13.5%	13.5%	17.1%	17.4%
9	Becton, Dickinson	11.5%	11.3%	11.0%	11.4%	12.1%	12.3%	13.5%	13.3%	13.0%	13.4%	14.0%	14.3%
10	Bemis Co.	4.5%	7.0%	7.0%	8.0%	9.3%	8.9%	7.5%	10.0%	10.0%	11.0%	12.3%	11.9%
11	Bristol-Myers Squibb	9.0%	2.5%	3.0%	7.1%	5.5%	11.7%	13.8%	7.3%	7.8%	11.9%	10.3%	16.5%
12	Brown-Forman 'B'	7.0%	13.0%	13.0%	NA	12.2%	9.2%	9.3%	15.3%	15.3%	NA	14.5%	11.4%
13	Cardinal Health	-2.5%	6.6%	10.0%	10.1%	7.6%	10.8%	-0.2%	8.9%	12.3%	12.4%	9.8%	13.1%
14	Chevron Corp.	5.0%	NA	NA	9.0%	17.5%	12.1%	8.5%	NA	NA	12.5%	21.0%	15.7%
15	Chubb Corp.	3.0%	8.0%	8.5%	7.7%	9.1%	12.4%	5.9%	10.9%	11.4%	10.6%	12.0%	15.3%
16	Coca-Cola	6.5%	9.0%	9.0%	8.9%	11.1%	11.1%	9.6%	12.1%	12.1%	12.0%	14.2%	14.2%
17	Colgate-Palmolive	11.5%	9.0%	10.0%	9.8%	19.5%	13.9%	13.7%	11.2%	12.2%	12.0%	21.7%	16.2%
18	Commerce Bancshs.	5.0%	6.5%	6.5%	6.5%	8.2%	3.5%	7.4%	8.9%	8.9%	8.9%	10.5%	5.9%
19	ConAgra Foods	11.5%	8.6%	9.0%	9.0%	5.9%	12.2%	15.1%	12.2%	12.6%	12.6%	9.5%	15.8%
20	ConocoPhillips	3.0%	-8.8%	-5.6%	3.1%	17.4%	21.1%	7.0%	-4.8%	-1.6%	7.1%	21.3%	25.1%
21	Costco Wholesale	6.0%	13.2%	13.0%	13.5%	8.8%	6.1%	7.3%	14.5%	14.3%	14.8%	10.1%	7.4%
22	CVS Caremark Corp.	10.5%	11.8%	14.0%	13.1%	7.7%	19.6%	11.5%	12.8%	15.0%	14.1%	8.7%	20.6%
23	Disney (Walt)	12.0%	6.3%	6.5%	9.0%	9.6%	20.1%	13.2%	7.5%	7.7%	10.2%	10.8%	21.3%
24	Du Pont	0.0%	5.5%	5.5%	9.3%	4.7%	14.6%	5.2%	10.7%	10.7%	14.5%	9.9%	19.8%
25	Eaton Corp.	-1.5%	10.1%	11.3%	9.7%	7.6%	11.1%	1.6%	13.2%	14.4%	12.8%	10.7%	14.2%
26	Ecolab Inc.	11.5%	13.2%	13.0%	13.3%	22.9%	7.2%	12.9%	14.6%	14.4%	14.7%	24.2%	8.6%
27	Emerson Electric	4.5%	11.5%	10.0%	10.8%	7.8%	10.6%	7.8%	14.8%	13.3%	14.1%	11.1%	13.9%
28	Everest Re Group Ltd.	5.0%	7.5%	7.5%	10.0%	10.7%	13.1%	7.3%	9.8%	9.8%	12.3%	13.0%	15.4%
29	Exxon Mobil Corp.	3.5%	2.8%	3.5%	6.7%	14.6%	10.3%	6.0%	5.3%	6.0%	9.2%	17.1%	12.8%
30	Gen'l Dynamics	11.0%	7.8%	8.0%	10.1%	12.9%	18.2%	13.4%	10.2%	10.4%	12.5%	15.2%	20.6%
31	Gen'l Mills	9.0%	9.1%	8.5%	7.7%	6.2%	9.4%	11.8%	11.9%	11.3%	10.5%	9.0%	12.2%
32	Grainger (W.W.)	6.5%	11.0%	12.0%	11.0%	6.9%	9.2%	8.5%	13.0%	14.0%	13.0%	8.9%	11.2%
33	Heinz (H.J.)	6.5%	6.9%	8.0%	8.0%	15.9%	12.2%	10.6%	11.0%	12.1%	12.1%	20.0%	16.3%
34	Hewlett-Packard	9.0%	10.0%	10.0%	15.5%	10.6%	11.2%	9.6%	10.6%	10.6%	16.1%	11.2%	11.8%
35	Home Depot	1.5%	9.6%	9.5%	11.2%	9.9%	9.7%	4.6%	12.7%	12.6%	14.3%	13.0%	12.8%
36	Honeywell Int'l	4.0%	8.9%	10.0%	9.2%	11.6%	13.0%	7.1%	12.0%	13.1%	12.3%	14.7%	16.0%
37	Hormel Foods	10.5%	10.0%	10.0%	9.3%	10.1%	16.5%	12.7%	12.2%	12.2%	11.5%	12.4%	18.8%
38	Illinois Tool Works	3.0%	3.3%	2.6%	9.0%	9.9%	7.1%	5.6%	5.9%	5.2%	11.6%	12.5%	9.7%
39	Int'l Business Mach.	10.5%	9.4%	10.0%	13.6%	10.6%	13.9%	12.3%	11.2%	11.8%	15.4%	12.4%	15.7%
40	Intel Corp.	10.0%	11.1%	10.0%	11.2%	15.1%	15.8%	13.3%	14.4%	13.3%	14.5%	18.4%	19.1%

DCF MODEL

Exhibit WEA-4
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NON-UTILITY PROXY GROUP

		(a)	(b)	(c)	(d)	(e)	(a)	(f)	(f)	(f)	(f)	(f)	(f)
		Growth Rates						Cost of Equity Estimates					
	Company	V Line	IBES	First Call	Zacks	br+sv	Price	V Line	IBES	First Call	Zacks	br+sv	Price
41	ITT Corp.	7.5%	6.8%	5.0%	10.0%	13.4%	12.5%	9.2%	8.5%	6.7%	11.7%	15.1%	14.2%
42	Johnson & Johnson	7.5%	7.4%	7.0%	7.4%	10.8%	12.6%	10.6%	10.5%	10.1%	10.5%	13.9%	15.7%
43	Kellogg	9.0%	10.4%	9.0%	9.1%	21.3%	11.2%	11.9%	13.3%	11.9%	12.0%	24.2%	14.1%
44	Kimberly-Clark	6.0%	11.0%	11.0%	9.5%	23.2%	11.0%	9.8%	14.8%	14.8%	13.3%	26.9%	14.8%
45	Kraft Foods	6.5%	9.1%	9.1%	14.1%	4.7%	13.4%	10.8%	13.4%	13.4%	18.4%	9.0%	17.7%
46	Lilly (Eli)	5.0%	1.3%	2.2%	3.8%	17.6%	19.6%	10.7%	7.0%	7.9%	9.5%	23.3%	25.3%
47	Lockheed Martin	11.5%	9.1%	9.5%	9.1%	19.8%	25.9%	14.8%	12.4%	12.8%	12.4%	23.1%	29.2%
48	McCormick & Co.	8.5%	10.0%	20.0%	10.0%	13.2%	11.9%	11.4%	12.9%	22.9%	12.9%	16.1%	14.8%
49	McDonald's Corp.	10.0%	9.4%	9.0%	9.1%	6.2%	8.9%	13.6%	13.0%	12.6%	12.7%	9.8%	12.5%
50	McKesson Corp.	9.0%	11.3%	13.0%	12.0%	12.2%	5.8%	9.8%	12.1%	13.8%	12.8%	12.9%	6.6%
51	Medtronic, Inc.	10.5%	11.0%	11.0%	11.2%	11.7%	22.3%	12.4%	12.9%	12.9%	13.1%	13.7%	24.3%
52	Microsoft Corp.	10.0%	11.0%	11.0%	11.2%	5.0%	13.1%	12.0%	13.0%	13.0%	13.2%	6.9%	15.1%
53	NIKE, Inc. 'B'	9.5%	12.6%	15.0%	11.9%	11.8%	9.6%	11.2%	14.3%	16.7%	13.6%	13.6%	11.3%
54	Northrop Grumman	9.5%	9.2%	10.0%	9.2%	9.6%	21.5%	12.8%	12.5%	13.3%	12.5%	12.9%	24.8%
55	Oracle Corp.	11.5%	12.8%	12.5%	13.1%	8.8%	18.2%	12.4%	13.7%	13.4%	14.0%	9.7%	19.0%
56	PepsiCo, Inc.	8.5%	10.8%	10.8%	10.0%	14.0%	14.3%	11.5%	13.8%	13.8%	13.0%	17.0%	17.3%
57	Pfizer, Inc.	-4.0%	1.5%	1.9%	-0.7%	5.9%	1.8%	-0.1%	5.5%	5.9%	3.3%	9.8%	5.7%
58	Procter & Gamble	7.0%	9.3%	10.0%	8.0%	8.5%	13.5%	9.9%	12.2%	12.9%	10.9%	11.4%	16.4%
59	Raytheon Co.	13.0%	9.0%	9.0%	9.3%	9.3%	17.6%	15.5%	11.5%	11.5%	11.8%	11.8%	20.1%
60	Sigma-Aldrich	10.0%	9.0%	9.0%	8.0%	18.1%	8.7%	11.1%	10.1%	10.1%	9.1%	19.2%	9.8%
61	Stryker Corp.	12.0%	10.7%	10.4%	11.7%	13.7%	20.8%	13.2%	11.9%	11.6%	12.9%	14.9%	22.0%
62	Sysco Corp.	7.0%	15.0%	15.0%	15.0%	9.4%	9.9%	10.8%	18.8%	18.8%	18.8%	13.1%	13.7%
63	TJX Companies	13.5%	12.4%	12.0%	12.5%	14.3%	11.4%	14.8%	13.7%	13.3%	13.8%	15.6%	12.7%
64	United Parcel Serv.	1.5%	7.9%	12.0%	11.7%	16.2%	12.3%	4.6%	11.0%	15.1%	14.8%	19.3%	15.4%
65	United Technologies	8.0%	10.2%	10.0%	8.7%	14.5%	14.8%	10.2%	12.4%	12.2%	10.9%	16.7%	17.0%
66	Verizon Communic.	4.0%	4.6%	4.0%	5.3%	5.9%	13.6%	9.8%	10.4%	9.8%	11.1%	11.7%	19.4%
67	Wal-Mart Stores	9.5%	11.8%	11.0%	11.5%	8.6%	14.3%	11.7%	14.0%	13.2%	13.7%	10.8%	16.4%
68	Walgreen Co.	10.0%	14.2%	15.0%	14.3%	10.9%	12.2%	11.5%	15.7%	16.5%	15.8%	12.3%	13.7%
69	Waste Management	5.5%	9.8%	10.1%	11.0%	6.4%	6.3%	9.2%	13.5%	13.8%	14.7%	10.1%	10.0%
	Average (g)							**12.0%**	**12.6%**	**12.8%**	**12.7%**	**12.2%**	**13.7%**

(a) www.valueline.com (retrieved Dec. 24, 2009).
(b) Thomson Reuters, *Company in Context Report* (Dec. 23, 2009).
(c) *First Call Earnings Valuation Report* (Dec. 24, 2009).
(d) www.zacks.com (retrieved Dec. 24, 2009).
(e) See Exhibit WEA-5.
(f) Sum of dividend yield and respective growth rate.
(g) Excludes highlighted figures.

SUSTAINABLE GROWTH RATE

NON-UTILITY PROXY GROUP

		(a)	(a)	(b)	(a)	(a)	(a)	(c)	(d)
		2012-14 Market Price			2012-14 Projections				
	Company	High	Low	Avg.	EPS	DPS	BVPS	b	r
1	3M Company	$120.00	$100.00	$110.00	$6.90	$2.26	$29.35	67.2%	23.5%
2	Abbott Labs	$100.00	$80.00	$90.00	$5.00	$2.18	$21.95	56.4%	22.8%
3	Alberto-Culver	$45.00	$35.00	$40.00	$2.00	$0.45	$16.30	77.5%	12.3%
4	Allergan, Inc	$110.00	$90.00	$100.00	$4.35	$0.25	$24.20	94.3%	18.0%
5	AT&T Inc	$50.00	$40.00	$45.00	$3.25	$2.00	$22.05	38.5%	14.7%
6	Automatic Data Proc.	$85.00	$70.00	$77.50	$3.30	$1.60	$20.75	51.5%	15.9%
7	Bard (C.R.)	$155.00	$125.00	$140.00	$7.80	$0.94	$39.25	87.9%	19.9%
8	Baxter Int'l Inc.	$105.00	$90.00	$97.50	$6.10	$1.60	$20.00	73.8%	30.5%
9	Becton, Dickinson	$130.00	$105.00	$117.50	$7.35	$1.90	$38.85	74.1%	18.9%
10	Bemis Co.	$40.00	$35.00	$37.50	$2.25	$1.04	$16.90	53.8%	13.3%
11	*Bristol-Myers Squibb*	$40.00	$30.00	$35.00	$1.95	$1.40	$10.25	28.2%	19.0%
12	Brown-Forman 'B'	$75.00	$65.00	$70.00	$4.10	$1.24	$22.05	69.8%	18.6%
13	Cardinal Health	$50.00	$45.00	$47.50	$2.80	$1.00	$23.65	64.3%	11.8%
14	Chevron Corp	$140.00	$110.00	$125.00	$12.50	$3.00	$53.15	76.0%	23.5%
15	Chubb Corp.	$85.00	$70.00	$77.50	$7.00	$1.60	$57.85	77.1%	12.1%
16	Coca-Cola	$90.00	$75.00	$82.50	$3.85	$2.12	$16.40	44.9%	23.5%
17	Colgate-Palmolive	$140.00	$115.00	$127.50	$6.30	$2.50	$17.70	60.3%	35.6%
18	Commerce Bancshs.	$50.00	$40.00	$45.00	$3.40	$1.10	$31.75	67.6%	10.7%
19	ConAgra Foods	$40.00	$30.00	$35.00	$2.25	$0.88	$14.95	60.9%	15.1%
20	ConocoPhillips	$125.00	$100.00	$112.50	$11.85	$2.20	$59.05	81.4%	20.1%
21	Costco Wholesale	$80.00	$65.00	$72.50	$3.75	$0.80	$29.00	78.7%	12.9%
22	*CVS Caremark Corp*	*$70.00*	*$60.00*	*$65.00*	$3.60	$0.48	$35.45	86.7%	10.2%
23	Disney (Walt)	$65.00	$50.00	$57.50	$3.85	$0.60	$27.05	84.4%	14.2%
24	Du Pont	$60.00	$50.00	$55.00	$3.00	$1.92	$13.55	36.0%	22.1%
25	Eaton Corp.	$110.00	$90.00	$100.00	$6.15	$2.50	$53.55	59.3%	11.5%
26	Ecolab Inc.	$65.00	$55.00	$60.00	$3.15	$0.85	$12.25	73.0%	25.7%
27	Emerson Electric	$65.00	$55.00	$60.00	$3.50	$1.55	$13.65	55.7%	25.6%
28	Everest Re Group Ltd.	$165.00	$135.00	$150.00	$15.00	$2.35	$116.65	84.3%	12.9%
29	Exxon Mobil Corp.	$125.00	$100.00	$112.50	$9.35	$1.85	$38.70	80.2%	24.2%
30	Gen'l Dynamics	$145.00	$120.00	$132.50	$9.50	$2.50	$50.25	73.7%	18.9%
31	Gen'l Mills	$105.00	$85.00	$95.00	$5.50	$2.45	$22.60	55.5%	24.3%
32	Grainger (W.W.)	$140.00	$115.00	$127.50	$7.40	$2.26	$42.30	69.5%	17.5%
33	Heinz (*H.J.*)	*$70.00*	*$60.00*	*$65.00*	*$3.90*	$2.20	*$10.65*	*43.6%*	*36.6%*
34	Hewlett-Packard	$80.00	$65.00	$72.50	$4.50	$0.45	$28.55	90.0%	15.8%
35	Home Depot	$45.00	$35.00	$40.00	$2.50	$1.05	$14.85	58.0%	16.8%
36	Honeywell Int'l	$65.00	$55.00	$60.00	$3.95	$1.75	$18.15	55.7%	21.8%
37	Hormel Foods	$75.00	$60.00	$67.50	$3.80	$1.20	$23.85	68.4%	15.9%
38	Illinois Tool Works	$70.00	$55.00	$62.50	$3.80	$1.36	$21.30	64.2%	17.8%
39	Int'l Business Mach.	$220.00	$180.00	$200.00	$13.25	$3.00	$23.90	77.4%	55.4%
40	Intel Corp.	$40.00	$30.00	$35.00	$1.75	$0.80	$9.15	54.3%	19.1%
41	ITT Corp.	$95.00	$75.00	$85.00	$5.30	$1.24	$33.80	76.6%	15.7%
42	Johnson & Johnson	$110.00	$90.00	$100.00	$6.50	$2.50	$25.85	61.5%	25.1%
43	Kellogg	$85.00	$70.00	$77.50	$4.60	$1.80	$13.70	60.9%	33.6%
44	Kimberly-Clark	*$95.00*	*$80.00*	*$87.50*	*$5.85*	*$2.55*	*$15.15*	56.4%	38.6%
45	Kraft Foods	$50.00	$40.00	$45.00	$2.75	$1.40	$26.20	49.1%	10.5%
46	Lilly (Eli)	$75.00	$60.00	$67.50	$4.75	$2.30	$16.05	51.6%	29.6%
47	Lockheed Martin	$215.00	$175.00	$195.00	$13.00	$3.50	$22.75	73.1%	57.1%
48	McCormick & Co.	$60.00	$50.00	$55.00	$3.15	$1.28	$17.40	59.4%	18.1%
49	McDonald's Corp.	$100.00	$80.00	$90.00	$5.25	$2.85	$18.25	45.7%	28.8%
50	McKesson Corp.	$90.00	$70.00	$80.00	$5.90	$0.48	$43.25	91.9%	13.6%
51	Medtronic, Inc.	$100.00	$80.00	$90.00	$4.80	$0.98	$20.15	79.6%	23.8%
52	Microsoft Corp.	$50.00	$45.00	$47.50	$2.65	$0.80	$7.70	69.8%	34.4%
53	NIKE, Inc. 'B'	$100.00	$85.00	$92.50	$5.10	$1.50	$23.90	70.6%	21.3%
54	Northrop Grumman	$130.00	$110.00	$120.00	$8.60	$2.25	$57.35	73.8%	15.0%
55	Oracle Corp.	$45.00	$40.00	$42.50	*$2.15*	*$0.30*	*$7.90*	*86.0%*	*27.2%*
56	PepsiCo, Inc.	$115.00	$95.00	$105.00	$5.15	$2.10	$19.45	59.2%	26.5%
57	Pfizer, Inc.	$20.00	$16.00	$18.00	$1.40	$0.64	$13.45	54.3%	10.4%
58	Procter & Gamble	$105.00	$85.00	$95.00	$4.75	$1.95	$26.00	58.9%	18.3%
59	Raytheon Co.	$110.00	$90.00	$100.00	$6.80	$1.75	$39.60	74.3%	17.2%
60	Sigma-Aldrich	$85.00	$65.00	$75.00	$4.15	$0.70	$18.95	83.1%	21.9%
61	Stryker Corp.	$115.00	$95.00	$105.00	$4.75	$0.72	$27.10	84.8%	17.5%
62	Sysco Corp.	$45.00	$35.00	$40.00	$2.40	$1.20	$8.50	50.0%	28.2%
63	TJX Companies	$65.00	$55.00	$60.00	$4.00	$0.75	$10.90	81.3%	36.7%
64	United Parcel Serv.	$100.00	$85.00	$92.50	$4.20	$2.30	$11.85	45.2%	35.4%
65	United Technologies	$120.00	$95.00	$107.50	$6.75	$2.20	$27.75	67.4%	24.3%
66	Verizon Communic.	$60.00	$50.00	$55.00	$3.10	$1.96	$18.85	36.8%	16.4%
67	Wal-Mart Stores	$95.00	$75.00	$85.00	$5.45	$1.55	$31.90	71.6%	17.1%
68	Walgreen Co.	$65.00	$55.00	$60.00	$3.35	$0.76	$22.20	77.3%	15.1%
69	Waste Management	$45.00	$40.00	$42.50	$2.80	$1.50	$16.55	46.4%	16.9%

NON-UTILITY PROXY GROUP

		(a)	(a)	(e)	(a)	(a)	(e)	(f)	(g)	(h)
			2008			2012-14			Adjusted "r"	
			No.	Common		No.	Common	Chg in	Adj.	Adj.
	Company	BVPS	Shares	Equity	BVPS	Shares	Equity	Equity	Factor	r
1	3M Company	$14.24	693.54	$9,876	$29.35	680.00	$19,958	15.1%	1.0702	25.2%
2	Abbott Labs.	$11.48	1522.40	$17,477	$21.95	1520.00	$33,364	13.8%	1.0646	24.2%
3	Alberto-Culver	$11.35	97.86	$1,111	$16.30	92.00	$1,500	6.2%	1.0300	12.6%
4	Allergan, Inc.	$13.19	304.09	$4,011	$24.20	310.00	$7,502	13.3%	1.0625	19.1%
5	AT&T Inc.	$16.35	5893.00	$96,351	$22.05	5900.00	$130,095	6.2%	1.0300	15.2%
6	Automatic Data Proc.	$9.97	510.30	$5,088	$20.75	520.00	$10,790	16.2%	1.0750	17.1%
7	Bard (C.R.)	$19.89	99.39	$1,977	$39.25	90.00	$3,533	12.3%	1.0580	21.0%
8	Baxter Int'l Inc.	$10.11	615.99	$6,228	$20.00	550.00	$11,000	12.1%	1.0568	32.2%
9	Becton, Dickinson	$20.30	243.08	$4,935	$38.85	227.00	$8,819	12.3%	1.0580	20.0%
10	Bemis Co.	$13.50	99.71	$1,346	$16.90	108.00	$1,825	6.3%	1.0304	13.7%
11	*Bristol-Myers Squibb*	*$6.20*	*1974.30*	*$12,241*	$10.25	1970.00	$20,193	10.5%	1.0500	20.0%
12	Brown-Forman 'B'	$12.10	150.13	$1,817	$22.05	145.00	$3,197	12.0%	1.0565	19.6%
13	Cardinal Health	$21.70	357.10	$7,749	$23.65	355.00	$8,396	1.6%	1.0080	11.9%
14	Chevron Corp.	$43.23	2004.20	$86,642	$53.15	1950.00	$103,643	3.6%	1.0179	23.9%
15	Chubb Corp.	$38.13	352.30	$13,433	$57.85	325.00	$18,801	7.0%	1.0336	12.5%
16	Coca-Cola	$8.85	2312.00	$20,461	$16.40	2310.00	$37,884	13.1%	1.0615	24.9%
17	Colgate-Palmolive	$3.47	501.41	$1,740	$17.70	480.00	$8,496	37.3%	1.1573	41.2%
18	Commerce Bancshs.	$19.79	79.68	$1,577	$31.75	85.00	$2,699	11.3%	1.0537	11.3%
19	ConAgra Foods	$11.02	484.37	$5,338	$14.95	425.00	$6,354	3.5%	1.0174	15.3%
20	ConocoPhillips	$37.27	1480.20	$55,167	$59.05	1500.00	$88,575	9.9%	1.0473	21.0%
21	Costco Wholesale	$21.25	432.51	$9,191	$29.00	410.00	$11,890	5.3%	1.0257	13.3%
22	*CVS Caremark Corp.*	$23.90	*1438.80*	*$34,387*	*$35.45*	*1325.00*	*$46,971*	*6.4%*	*1.0312*	*10.5%*
23	Disney (Walt)	$17.73	1822.90	$32,320	$27.05	1610.00	$43,551	6.1%	1.0298	14.7%
24	Du Pont	$7.63	902.37	$6,885	$13.55	850.00	$11,518	10.8%	1.0514	23.3%
25	Eaton Corp.	$38.28	165.00	$6,316	$53.55	170.00	$9,104	7.6%	1.0365	11.9%
26	Ecolab Inc.	$6.65	236.20	$1,571	$12.25	245.00	$3,001	13.8%	1.0647	27.4%
27	Emerson Electric	$11.82	771.22	$9,116	$13.65	700.00	$9,555	0.9%	1.0047	25.8%
28	Everest Re Group Ltd.	$75.62	65.60	$4,961	$116.65	60.00	$6,999	7.1%	1.0344	13.3%
29	Exxon Mobil Corp.	$22.70	4976.00	$112,955	$38.70	4300.00	$166,410	8.1%	1.0387	25.1%
30	Gen'l Dynamics	$26.00	386.71	$10,054	$50.25	365.00	$18,341	12.8%	1.0600	20.0%
31	Gen'l Mills	$18.42	337.50	$6,217	$22.60	300.00	$6,780	1.7%	1.0087	24.5%
32	Grainger (W.W.)	$27.20	74.78	$2,034	$42.30	65.00	$2,750	6.2%	1.0301	18.0%
33	Heinz (H.J.)	*$3.87*	*315.04*	*$1,219*	*$10.65*	*310.00*	*$3,302*	*22.0%*	*1.0993*	*40.3%*
34	Hewlett-Packard	$16.13	2415.00	$38,954	$28.55	2100.00	$59,955	9.0%	1.0431	16.4%
35	Home Depot	$10.48	1696.00	$17,774	$14.85	1685.00	$25,022	7.1%	1.0342	17.4%
36	Honeywell Int'l	$9.78	734.59	$7,184	$18.15	715.00	$12,977	12.6%	1.0591	23.0%
37	Hormel Foods	$14.92	134.52	$2,007	$23.85	130.00	$3,101	9.1%	1.0435	16.6%
38	Illinois Tool Works	$14.41	499.12	$7,192	$21.30	475.00	$10,118	7.1%	1.0341	18.4%
39	Int'l Business Mach.	$10.06	1339.10	$13,471	$23.90	1050.00	$25,095	13.2%	1.0621	58.9%
40	Intel Corp	$7.03	5562.00	$39,101	$9.15	6000.00	$54,900	7.0%	1.0339	19.8%
41	ITT Corp.	$16.83	181.80	$3,060	$33.80	185.00	$6,253	15.4%	1.0714	16.8%
42	Johnson & Johnson	$15.35	2769.20	$42,507	$25.85	2520.00	$65,142	8.9%	1.0427	26.2%
43	Kellogg	$3.79	381.86	$1,447	$13.70	375.00	$5,138	28.8%	1.1260	37.8%
44	Kimberly-Clark	*$9.38*	*413.60*	*$3,880*	*$15.15*	*415.00*	*$6,287*	*10.1%*	*1.0482*	*40.5%*
45	Kraft Foods	$15.11	1469.30	$22,201	$26.20	1400.00	$36,680	10.6%	1.0502	11.0%
46	Lilly (Eli)	$5.93	1136.10	$6,737	$16.05	1150.00	$18,458	22.3%	1.1004	32.6%
47	Lockheed Martin	$7.29	393.00	$2,865	$22.75	330.00	$7,508	21.2%	1.0960	62.6%
48	McCormick & Co.	$8.11	130.10	$1,055	$17.40	135.00	$2,349	17.4%	1.0799	19.5%
49	McDonald's Corp.	$12.00	1115.30	$13,384	$18.25	1015.00	$18,524	6.7%	1.0325	29.7%
50	McKesson Corp.	$22.85	271.00	$6,192	$43.25	254.00	$10,986	12.1%	1.0573	14.4%
51	Medtronic, Inc.	$11.42	1124.90	$12,846	$20.15	1000.00	$20,150	9.4%	1.0450	24.9%
52	Microsoft Corp.	$3.97	9151.00	$36,329	$7.70	7500.00	$57,750	9.7%	1.0463	36.0%
53	NIKE, Inc. 'B'	$15.93	491.10	$7,823	$23.90	460.00	$10,994	7.0%	1.0340	22.1%
54	Northrop Grumman	$36.45	327.01	$11,920	$57.35	300.00	$17,205	7.6%	1.0367	15.5%
55	Oracle Corp.	$4.47	5150.00	$23,021	$7.90	4300.00	$33,970	8.1%	1.0389	28.3%
56	PepsiCo, Inc.	$7.77	1553.00	$12,067	$19.45	1500.00	$29,175	19.3%	1.0881	28.8%
57	Pfizer, Inc.	$8.52	6746.00	$57,476	$13.45	6700.00	$90,115	9.4%	1.0449	10.9%
58	Procter & Gamble	$22.46	3032.70	$68,114	$26.00	2900.00	$75,400	2.1%	1.0102	18.5%
59	Raytheon Co.	$22.71	400.10	$9,086	$39.60	350.00	$13,860	8.8%	1.0422	17.9%
60	Sigma-Aldrich	$11.29	122.13	$1,379	$18.95	120.00	$2,274	10.5%	1.0500	23.0%
61	Stryker Corp.	$13.64	396.40	$5,407	$27.10	382.00	$10,352	13.9%	1.0649	18.7%
62	Sysco Corp.	$5.67	601.23	$3,409	$8.50	560.00	$4,760	6.9%	1.0334	29.2%
63	TJX Companies	$5.17	412.82	$2,134	$10.90	340.00	$3,706	11.7%	1.0551	38.7%
64	United Parcel Serv.	$6.81	995.44	$6,779	$11.85	990.00	$11,732	11.6%	1.0548	37.4%
65	United Technologies	$16.89	942.29	$15,915	$27.75	900.00	$24,975	9.4%	1.0450	25.4%
66	Verizon Communic.	$14.68	2840.60	$41,700	$18.85	2820.00	$53,157	5.0%	1.0243	16.8%
67	Wal-Mart Stores	$16.63	3925.00	$65,273	$31.90	3450.00	$110,055	11.0%	1.0522	18.0%
68	Walgreen Co.	$13.01	989.18	$12,869	$22.20	950.00	$21,090	10.4%	1.0494	15.8%
69	Waste Management	$12.03	490.74	$5,904	$16.55	465.00	$7,696	5.4%	1.0265	17.4%

NON-UTILITY PROXY GROUP

		(a)	(a)	(f)	(i)	(j)	(k)	(l)	(m)
		Common Shares Outstanding			M/B	"sv" Factor			
	Company	2008	2012-14	Change	Ratio	s	v	sv	br + sv
1	3M Company	693.54	680.00	-0.39%	3.75	(0.0147)	0.7332	-1.08%	15.8%
2	Abbott Labs	1522.40	1520.00	-0.03%	4.10	(0.0013)	0.7561	-0.10%	13.6%
3	Alberto-Culver	97.86	92.00	-1.23%	2.45	(0.0301)	0.5925	-1.78%	8.0%
4	Allergan, Inc.	304.09	310.00	0.39%	4.13	0.0159	0.7580	1.21%	19.2%
5	AT&T Inc.	5893.00	5900.00	0.02%	2.04	0.0005	0.5100	0.02%	5.9%
6	Automatic Data Proc.	510.30	520.00	0.38%	3.73	0.0141	0.7323	1.03%	9.8%
7	Bard (C.R.)	99.39	90.00	-1.97%	3.57	(0.0701)	0.7196	-5.04%	13.4%
8	Baxter Int'l Inc.	615.99	550.00	-2.24%	4.88	(0.1092)	0.7949	-8.68%	15.1%
9	Becton, Dickinson	243.08	227.00	-1.36%	3.02	(0.0411)	0.6694	-2.75%	12.1%
10	Bemis Co.	99.71	108.00	1.61%	2.22	0.0357	0.5493	1.96%	9.3%
11	Bristol-Myers Squibb	1974.30	1970.00	-0.04%	3.41	(0.0015)	0.7071	-0.11%	5.5%
12	Brown-Forman 'B'	150.13	145.00	-0.69%	3.17	(0.0220)	0.6850	-1.51%	12.2%
13	Cardinal Health	357.10	355.00	-0.12%	2.01	(0.0024)	0.5021	-0.12%	7.6%
14	Chevron Corp.	2004.20	1950.00	-0.55%	2.35	(0.0129)	0.5748	-0.74%	17.5%
15	Chubb Corp.	352.30	325.00	-1.60%	1.34	(0.0214)	0.2535	-0.54%	9.1%
16	Coca-Cola	2312.00	2310.00	-0.02%	5.03	(0.0009)	0.8012	-0.07%	11.1%
17	Colgate-Palmolive	501.41	480.00	-0.87%	7.20	(0.0626)	0.8612	-5.39%	19.5%
18	Commerce Bancshs.	79.68	85.00	1.30%	1.42	0.0184	0.2944	0.54%	8.2%
19	ConAgra Foods	484.37	425.00	-2.58%	2.34	(0.0604)	0.5729	-3.46%	5.9%
20	ConocoPhillips	1480.20	1500.00	0.27%	1.91	0.0051	0.4751	0.24%	17.4%
21	Costco Wholesale	432.51	410.00	-1.06%	2.50	(0.0266)	0.6000	-1.59%	8.8%
22	CVS Caremark Corp	1438.80	1325.00	-1.63%	1.83	(0.0300)	0.4546	-1.36%	7.7%
23	Disney (Walt)	1822.90	1610.00	-2.45%	2.13	(0.0521)	0.5296	-2.76%	9.6%
24	Du Pont	902.37	850.00	-1.19%	4.06	(0.0482)	0.7536	-3.64%	4.7%
25	Eaton Corp.	165.00	170.00	0.60%	1.87	0.0112	0.4645	0.52%	7.6%
26	Ecolab Inc.	236.20	245.00	0.73%	4.90	0.0360	0.7958	2.86%	22.9%
27	Emerson Electric	771.22	700.00	-1.92%	4.40	(0.0844)	0.7725	-6.52%	7.8%
28	Everest Re Group Ltd.	65.60	60.00	-1.77%	1.29	(0.0227)	0.2223	-0.51%	10.7%
29	Exxon Mobil Corp.	4976.00	4300.00	-2.88%	2.91	(0.0837)	0.6560	-5.49%	14.6%
30	Gen'l Dynamics	386.71	365.00	-1.15%	2.64	(0.0303)	0.6208	-1.88%	12.9%
31	Gen'l Mills	337.50	300.00	-2.33%	4.20	(0.0979)	0.7621	-7.46%	6.2%
32	Grainger (W.W.)	74.78	65.00	-2.76%	3.01	(0.0833)	0.6682	-5.57%	6.9%
33	Heinz (H.J.)	315.04	310.00	-0.32%	6.10	(0.0197)	0.8362	-1.64%	15.9%
34	Hewlett-Packard	2415.00	2100.00	-2.76%	2.54	(0.0700)	0.6062	-4.24%	10.6%
35	Home Depot	1696.00	1685.00	-0.13%	2.69	(0.0035)	0.6288	-0.22%	9.9%
36	Honeywell Int'l	734.59	715.00	-0.54%	3.31	(0.0178)	0.6975	-1.24%	11.6%
37	Hormel Foods	134.52	130.00	-0.68%	2.83	(0.0193)	0.6467	-1.25%	10.1%
38	Illinois Tool Works	499.12	475.00	-0.99%	2.93	(0.0289)	0.6592	-1.91%	9.9%
39	Int'l Business Mach.	1339.10	1050.00	-4.75%	8.37	(0.3973)	0.8805	-34.98%	10.6%
40	Intel Corp.	5562.00	6000.00	1.53%	3.83	0.0584	0.7386	4.32%	15.1%
41	ITT Corp.	181.80	185.00	0.35%	2.51	0.0088	0.6024	0.53%	13.4%
42	Johnson & Johnson	2769.20	2520.00	-1.87%	3.87	(0.0723)	0.7415	-5.36%	10.8%
43	Kellogg	381.86	375.00	-0.36%	5.66	(0.0205)	0.8232	-1.69%	21.3%
44	Kimberly-Clark	413.60	415.00	0.07%	5.78	0.0039	0.8269	0.32%	23.2%
45	Kraft Foods	1469.30	1400.00	-0.96%	1.72	(0.0165)	0.4178	-0.69%	4.7%
46	Lilly (Eli)	1136.10	1150.00	0.24%	4.21	0.0102	0.7622	0.78%	17.6%
47	Lockheed Martin	393.00	330.00	-3.43%	8.57	(0.2943)	0.8833	-26.00%	19.8%
48	McCormick & Co.	130.10	135.00	0.74%	3.16	0.0235	0.6836	1.60%	13.2%
49	McDonald's Corp.	1115.30	1015.00	-1.87%	4.93	(0.0921)	0.7972	-7.34%	6.2%
50	McKesson Corp.	271.00	254.00	-1.29%	1.85	(0.0238)	0.4594	-1.09%	12.2%
51	Medtronic, Inc.	1124.90	1000.00	-2.33%	4.47	(0.1039)	0.7761	-8.06%	11.7%
52	Microsoft Corp.	9151.00	7500.00	-3.90%	6.17	(0.2407)	0.8379	-20.16%	5.0%
53	NIKE, Inc. 'B'	491.10	460.00	-1.30%	3.87	(0.0503)	0.7416	-3.73%	11.8%
54	Northrop Grumman	327.01	300.00	-1.71%	2.09	(0.0358)	0.5221	-1.87%	9.6%
55	Oracle Corp.	5150.00	4300.00	-3.54%	5.38	(0.1906)	0.8141	-15.52%	8.8%
56	PepsiCo, Inc.	1553.00	1500.00	-0.69%	5.40	(0.0374)	0.8148	-3.04%	14.0%
57	Pfizer, Inc.	6746.00	6700.00	-0.14%	1.34	(0.0018)	0.2528	-0.05%	5.9%
58	Procter & Gamble	3032.70	2900.00	-0.89%	3.65	(0.0326)	0.7263	-2.36%	8.5%
59	Raytheon Co.	400.10	350.00	-2.64%	2.53	(0.0667)	0.6040	-4.03%	9.3%
60	Sigma-Aldrich	122.13	120.00	-0.35%	3.96	(0.0139)	0.7473	-1.04%	18.1%
61	Stryker Corp.	396.40	382.00	-0.74%	3.87	(0.0286)	0.7419	-2.12%	13.7%
62	Sysco Corp.	601.23	560.00	-1.41%	4.71	(0.0664)	0.7875	-5.23%	9.4%
63	TJX Companies	412.82	340.00	-3.81%	5.50	(0.2096)	0.8183	-17.15%	14.3%
64	United Parcel Serv.	995.44	990.00	-0.11%	7.81	(0.0086)	0.8719	-0.75%	16.2%
65	United Technologies	942.29	900.00	-0.91%	3.87	(0.0354)	0.7419	-2.63%	14.5%
66	Verizon Communic.	2840.60	2820.00	-0.15%	2.92	(0.0042)	0.6573	-0.28%	5.9%
67	Wal-Mart Stores	3925.00	3450.00	-2.55%	2.66	(0.0679)	0.6247	-4.24%	8.6%
68	Walgreen Co.	989.18	950.00	-0.81%	2.70	(0.0218)	0.6300	-1.37%	10.9%
69	Waste Management	490.74	465.00	-1.07%	2.57	(0.0275)	0.6106	-1.68%	6.4%

(a) www.valueline.com (retrieved Dec 24, 2009).
(b) Average of High and Low expected market prices.
(c) Computed at (EPS - DPS) / EPS.
(d) Computed as EPS / BVPS.
(e) *Product of BVPS and No. Shares Outstanding.*
(f) Five-year rate of change.
(g) Computed using the formula 2*(1+5-Yr. Change in Equity)/(2+5 Yr. Change in Equity).
(h) Product of year-end "r" for 2012-14 and Adjustment Factor.
(i) Average of High and Low expected market prices divided by 2012-14 BVPS.
(j) Product of change in common shares outstanding and M/B Ratio.
(k) Computed as 1 - B/M Ratio.
(l) Product of "s" and "v".
(m) Product of average "b" and adjusted "r", plus "sv".

CAPITAL ASSET PRICING MODEL

UTILITY PROXY GROUP

Market Rate of Return		
Dividend Yield (a)	2.7%	
Growth Rate (b)	9.2%	
Market Return (c)		11.9%
Less: Risk-Free Rate (d)		
Long-term Treasury Bond Yield		4.4%
Market Risk Premium (e)		7.5%
Utility Proxy Group Beta (f)		0.69
Utility Proxy Group Risk Premium (g)		5.2%
Plus: Risk-free Rate (d)		
Long-term Treasury Bond Yield		4.4%
Implied Cost of Equity (h)		**9.6%**

(a) Weighted average dividend yield for the dividend paying firms in the S&P 500 from www.valueline.com (retrieved Oct. 1, 2009).
(b) Weighted average of IBES earnings growth rates for the dividend paying firms in the S&P 500 based on data from *Thomson Reuters Company Report* (Oct. 1, 2009).
(c) (a) + (b)
(d) Average yield on 20-year Treasury bonds for December 2009 from the Federal Reserve Board at http://www.federalreserve.gov/releases/h15/data/Monthly/H15_TCMNOM_Y20.txt.
(e) (c) - (d).
(f) The Value Line Investment Survey (Nov. 6, Nov. 27, & Dec. 25, 2009).
(g) (e) x (f).
(h) (d) + (g).

CAPITAL ASSET PRICING MODEL

NON-UTILITY PROXY GROUP

Market Rate of Return		
Dividend Yield (a)	2.7%	
Growth Rate (b)	9.2%	
Market Return (c)		11.9%
Less: Risk-Free Rate (d)		
Long-term Treasury Bond Yield		4.4%
Market Risk Premium (e)		7.5%
Non-Utility Proxy Group Beta (f)		0.79
Utility Proxy Group Risk Premium (g)		5.9%
Plus: Risk-free Rate (d)		
Long-term Treasury Bond Yield		4.4%
Implied Cost of Equity (h)		**10.3%**

(a) Weighted average dividend yield for the dividend paying firms in the S&P 500 from www.valueline.com (retrieved Oct. 1, 2009).
(b) Weighted average of IBES earnings growth rates for the dividend paying firms in the S&P 500 based on data from *Thomson Reuters Company Report* (Oct. 1, 2009).
(c) (a) + (b)
(d) Average yield on 20-year Treasury bonds for December 2009 from the Federal Reserve Board at http://www.federalreserve.gov/releases/h15/data/Monthly/H15_TCMNOM_Y20.txt.
(e) (c) - (d).
(f) www.valueline.com (retrieved Sep. 9, 2009).
(g) (e) x (f).
(h) (d) + (g).

EXPECTED EARNINGS APPROACH

UTILITY PROXY GROUP

	Company	(a) Expected Return on Common Equity	(b) Adjustment Factor	(c) Adjusted Return on Common Equity
1	ALLETE	9.0%	1.0361	9.3%
2	Alliant Energy	10.0%	1.0244	10.2%
3	Consolidated Edison	9.5%	1.0188	9.7%
4	Dominion Resources	15.5%	1.0474	16.2%
5	Duke Energy Corp.	8.0%	1.0078	8.1%
6	Entergy Corp.	14.5%	1.0262	14.9%
7	Exelon Corp.	19.0%	1.0411	$\boxed{19.8\%}$
8	PG&E Corp.	12.0%	1.0422	12.5%
9	Progress Energy	9.5%	1.0210	9.7%
10	SCANA Corp.	10.5%	1.0431	11.0%
11	Sempra Energy	12.0%	1.0475	12.6%
12	Vectren Corp.	11.0%	1.0230	11.3%
13	Wisconsin Energy	11.5%	1.0287	11.8%
14	Xcel Energy, Inc.	10.5%	1.0236	10.7%
	Average (d)			**11.4%**

(a) 3-5 year projections from The Value Line Investment Survey (Nov. 6, Nov. 27, & Dec. 25, 2009).

(b) Adjustment to convert year-end "r" to an average rate of return from Exhibit WEA-3.

(c) (a) x (b).

(d) Excludes highlighted figures.

CAPITAL STRUCTURE

UTILITY PROXY GROUP

		At Fiscal Year-End 2008 (a)			Value Line Projected (b)		
	Company	Long-term Debt	Preferred	Common Equity	Long-term Debt	Other	Common Equity
1	ALLETE	41.7%	0.0%	58.3%	49.0%	0.0%	51.0%
2	Alliant Energy	38.0%	4.9%	57.0%	37.5%	4.0%	58.5%
3	Consolidated Edison	49.5%	1.1%	49.4%	48.5%	0.0%	51.5%
4	Dominion Resources	59.8%	1.0%	39.2%	53.5%	0.5%	46.0%
5	Duke Energy Corp.	39.6%	0.0%	60.4%	48.5%	0.0%	51.5%
6	Entergy Corp.	58.6%	1.6%	39.8%	57.0%	1.0%	42.0%
7	Exelon Corp.	49.8%	2.1%	48.1%	42.5%	0.5%	57.0%
8	PG&E Corp.	50.7%	1.3%	48.0%	45.0%	1.0%	54.0%
9	Progress Energy	54.8%	0.5%	44.7%	52.5%	0.0%	47.5%
10	SCANA Corp.	58.8%	1.5%	39.7%	55.5%	1.0%	43.5%
11	Sempra Energy	45.3%	1.2%	53.5%	42.0%	1.0%	57.0%
12	Vectren Corp.	48.0%	0.0%	52.0%	50.0%	0.0%	50.0%
13	Wisconsin Energy	55.1%	0.4%	44.5%	54.5%	0.0%	45.5%
14	Xcel Energy, Inc.	54.0%	0.7%	45.3%	51.0%	0.5%	48.5%
	Average	**50.3%**	**1.2%**	**48.6%**	**49.1%**	**0.7%**	**50.3%**

(a) Company Form 10-K and Annual Reports.
(b) The Value Line Investment Survey (Nov. 6, Nov. 27, & Dec. 25, 2009).

CAPITAL STRUCTURE

UTILITY OPERATING COS.

	Company	At Fiscal Year-End 2008 (a) Long-term Debt	Preferred Stock	Common Equity
1	Carolina Power & Light Co.	44.6%	0.7%	54.7%
2	Commonweath Edison Co.	41.2%	0.0%	58.8%
3	Consolidated Edison of NY	49.4%	1.2%	49.5%
4	Duke Energy Carolinas	49.9%	0.0%	50.1%
5	Duke Energy Indiana	52.5%	0.0%	47.5%
6	Duke Energy Kentucky	45.2%	0.0%	54.8%
7	Duke Energy Ohio	22.0%	0.0%	78.0%
8	Entergy Arkansas Inc.	51.6%	3.7%	44.7%
9	Entergy Gulf States Louisiana LLC	60.6%	0.3%	39.1%
10	Entergy Louisiana LLC	44.8%	3.2%	51.9%
11	Entergy Mississippi Inc.	49.3%	3.6%	47.1%
12	Entergy New Orleans Inc.	52.1%	3.8%	44.1%
13	Entergy Texas Inc.	56.8%	0.0%	43.2%
14	Florida Power Corp.	54.9%	0.4%	44.6%
15	Interstate Power & Light	42.8%	7.9%	49.3%
16	Northern States Power Co. (MN)	49.1%	0.0%	50.9%
17	Northern States Power Co. (WI)	48.7%	0.0%	51.3%
18	Orange & Rockland	45.4%	0.0%	54.6%
19	Pacific Gas & Electric Co.	49.6%	1.3%	49.0%
20	PECO Energy Co.	44.6%	6.1%	49.3%
21	Public Service Co. of Colorado	41.0%	0.0%	59.0%
22	San Diego Gas & Electric	45.0%	1.7%	53.3%
23	South Carolina Electric & Gas	53.0%	1.9%	45.1%
24	Southwestern Public Service Co.	52.4%	0.0%	47.6%
25	Superior Water, Light & Power Co.	44.5%	0.0%	55.5%
26	Vectren Utility Holdings	40.1%	0.0%	59.9%
27	Virginia Electric Power	48.4%	2.0%	49.6%
28	Wisconsin Electric Power Co.	42.0%	0.7%	57.3%
29	Wisconsin Power & Light	39.1%	3.0%	57.9%
	Average	**46.9%**	**1.4%**	**51.7%**

(a) Company Form 10-K Reports and FERC Form-1 Reports.

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

APPLICATION OF KENTUCKY UTILITIES COMPANY FOR AN ADJUSTMENT OF BASE RATES	)))	CASE NO. 2009-00548

TESTIMONY OF
LONNIE E. BELLAR
VICE PRESIDENT OF STATE REGULATION AND RATES
KENTUCKY UTILITIES COMPANY

Filed: January 29, 2010

Q. **Please state your name, position and business address.**

A. My name is Lonnie E. Bellar. I am the Vice President of State Regulation and Rates for Kentucky Utilities Company ("KU" or "Company") and an employee of E.ON U.S. Services, Inc., which provides services to KU and Louisville Gas and Electric Company ("LG&E") (collectively, "Companies"). My business address is 220 West Main Street, Louisville, Kentucky. A statement of my qualifications is attached as Appendix A.

Q. **Have you previously testified before the Kentucky Public Service Commission?**

A. Yes. I have testified before the Commission multiple times, including Case Nos. 2007-00562 (LG&E) and 2007-00563 (KU) concerning the disposition of KU's and LG&E's merger surcredit mechanisms; the Companies' most recent base rate cases, Case Nos. 2008-00251 (KU) and 2008-00252 (LG&E); and most recently in the Companies' 2009 Environmental Surcharge Compliance Plan proceedings, Case Nos. 2009-00197 (KU) and 2009-00198 (LG&E).

Q. **What are the purposes of your testimony?**

A. The purposes of my testimony are: (1) to support certain exhibits required by the Commission's regulations; (2) to present the revenue effect and the bill impact to the average residential customer; (3) to present KU's recommendation for the allocation of the proposed increase in revenues among the customer classes based on the results of the Company's cost-of-service study prepared by The Prime Group and sponsored by W. Steven Seelye in this case; (4) to explain the relationship of KU's various cost-recovery mechanisms to its base rates; and (5) to explain certain pro forma adjustments to which the testimony of S. Bradford Rives refers.

Q. Are you supporting the schedules that are required by Commission regulations 807 KAR 5:001?

A. Yes, the table of contents to KU's filing requirements states which schedules I am sponsoring. Please note that, though I am sponsoring KU's proposed electric tariffs and proposed tariff changes, the testimonies of Robert M. Conroy and Mr. Seelye will address issues of electric rate design, and the testimony of John Wolfram will address changes to the terms and conditions of KU's electric services.

<u>Revenue Effect</u>

Q. What is the revenue effect of the proposed rates?

A. As shown in Tab 23 of the Company's Filing Requirements, attached to the Application in this case, the total increase in revenues to KU that would result from the proposed rate adjustment is $135.3 million.

Q. If the Commission approves the proposed base rates, what will be the percentage increase in monthly residential electric bills?

A. The average monthly residential electric bill increase due to the proposed electric base rates will be 13.5%, or approximately $11.70, for a residential customer using an average of 1,230 kWh of electricity.

<u>Revenue Allocation</u>

Q. Has KU analyzed how the proposed increase in revenue should be allocated among its customers?

A. Yes. KU engaged The Prime Group to analyze the existing class rates of return to determine whether in existing rates any significant cross-subsidization existed between customer classes. The Prime Group conducted a fully allocated, embedded cost-of-service study, which was also time-differentiated.

Q. What methodology did KU use in its electric cost-of-service study?

A. KU used the Base-Intermediate-Peak methodology that the Commission has followed for years. The details of that study are presented in the testimony of Mr. Seelye. The summary of the results of that study, reflecting the pro forma rate of return for the principal rate schedules, is set forth below:

Bellar Table I – Pro Forma Electric Rates of Return

Customer Class	**KU Electric Actual**
Residential – Rate RS	2.33%
General Service Rate – Rate GS	9.24%
All Electric Schools – Rate AES	2.19%
Power Service – Rate PS	
- Primary	7.87%
- Secondary	8.30%
Time-of-Day Secondary – Rate TODS	5.66%
Time-of-Day Primary – Rate TODP	6.44%
Retail Transmission Service – Rate RTS	9.73%
Fluctuating Load Service – Rate FLS	13.11%
Lighting	9.34%
Total Kentucky Jurisdiction	5.34%

The results of the study demonstrate that the individual class rates-of-return are above and below the total system class rate-of-return average of 5.34%. Based on this information, I directed The Prime Group to prepare a revenue allocation that would address the disparity among the customer class returns. The details of the KU electric revenue allocation are contained in Mr. Seeyle's testimony. The overall results are shown below:

Bellar Table II –

Pro Forma Electric Rates of Return as Adjusted for Proposed Increase

Customer Class	KU Electric Proposed
Residential – Rate RS	4.73%
General Service Rate – Rate GS	12.11%
All Electric Schools – Rate AES	4.57%
Power Service – Rate PS	
- Primary	10.81%
- Secondary	11.45%
Time-of-Day Secondary – Rate TODS	8.63%
Time-of-Day Primary – Rate TODP	9.67%
Retail Transmission Service – Rate RTS	13.26%
Fluctuating Load Service – Rate FLS	13.31%
Lighting	11.13%
Total Kentucky Jurisdiction	8.03%

The proposed residential increase strikes a balance between the cost-of-service principles of gradualism and reducing interclass subsidies. It also recognizes other cost-of-service principles such as customer acceptance, gradualism, and the need to maintain price stability by avoiding overly disruptive changes.

Q. Following the results of the cost of service study, did KU provide any guidance to The Prime Group in developing the electric rates for this proceeding?

A. Yes. First, we advised The Prime Group that, with regard to the rate design, unit charges should reflect the cost-of-service study as nearly as practicable so that customer charges were more reflective of customer-related costs, demand charges were more reflective of demand-related costs, and energy/commodities charges were more reflective of energy/commodity-related costs. Secondly, we advised The Prime Group to take into account the ratemaking principle of gradualism concerning residential rate increases. Finally, we advised The Prime Group to simplify rate design whenever feasible.

Relationship of Other Ratemaking Mechanisms to Base Rates

Q. Please give an overview of the composition of KU's current retail rates.

A. In addition to the base rates, certain cost items, such as fuel costs, demand-side management plan costs, and environmental compliance costs are included in our retail rates but are assessed separately from base rates.

Q. Do ratemaking mechanisms such as the fuel adjustment clause, environmental cost recovery/environmental surcharge, or demand-side management cost recovery have any effect on the base rate increase that KU is requesting?

A. No. As presented in the testimony of Mr. Rives and discussed in detail in Mr. Conroy's testimony, the impact of those mechanisms has been removed from the calculation of KU's operating revenues and expenses for the test year ended October 31, 2009. The mechanisms, and the costs and revenues associated with them, therefore have no effect on the calculation of the revenue deficiency and corresponding base rate increase that KU is requesting in this case. In addition, by removing these items from the calculation of net operating income in the Application, there is no double recovery of these costs.

Pro-Forma Adjustments

Q. Was an adjustment made to eliminate unbilled revenues for electric operations?

A. Yes. Consistent with prior rate cases, unbilled revenues were removed from test-year operating revenues. This adjustment is included in Reference Schedule 1.00 of Rives Exhibit 1. The Commission approved a similar adjustment in Case No. 2003-00434, and KU proposed such an adjustment in Case No. 2008-00251.

Q. Has an adjustment been made to eliminate the effect of KU's already-terminated merger surcredit mechanism?

A. Yes. The Commission's February 5, 2009 Order in Case No. 2008-00251 recognized that KU's merger surcredit mechanism would terminate when the rates that Order approved went into effect on February 6, 2009, subject to a final balancing adjustment. Since then, KU's customers have enjoyed the full benefit of all merger savings, which have been fully embedded in base rates, and which will continue to be embedded in base rates going forward. This adjustment, however, removes the effect of the merger surcredit from the test year, and is included in Reference Schedule 1.01 of Rives Exhibit 1.

Q. Has an adjustment been made to eliminate the effect of KU's already-terminated Value Delivery Team surcredit ("VDT")?

A. Yes. On its own terms, the VDT surcredit terminated concurrently with the filing of KU's application in its most recent base rate proceeding, Case No. 2008-00251, which application KU filed on July 29, 2008. While the VDT terminated prior to the beginning of the test year, there remained a small amount of credits on the books during the test year due to billing adjustments. This adjustment is included in Reference Schedule 1.02 of Rives Exhibit 1.

Q. Please explain the adjustment to annualize late payment charge revenues.

A. In KU's most recent base rate case, Case No. 2008-00251, the Commission approved the implementation of a late payment charge for KU (LG&E has had such a charge for years). Since the late payment charges were not implemented until April 2009, this adjustment annualizes the revenue impact of the late payment charge, increasing operating revenues to reflect the full test year, November 2008 through October 2009. This adjustment is included in Reference Schedule 1.14 of Rives Exhibit 1.

Q. Please explain the adjustment for the expiration of the Owensboro Municipal Utility ("OMU") contract.

A. This is a post-test year adjustment to expenses to reflect the expiration of the purchase power contract with OMU in May 2010. The demand charges for that contract are costs incurred during the twelve-month period ending October 31, 2009. The contract expires seven months later. The capacity available to KU, and its sister company LG&E through inter-company sales, through this contract will be replaced by Trimble County Unit No. 2 ("TC2") when it begins commercial operation in June 2010. The adjustment is shown on Reference Schedule 1.34 of Rives Exhibit 1.

Q. Please explain the adjustment to include the pro rata amount of depreciation expense associated with TC2 Construction Work in Progress.

A. The purpose of this adjustment is to reflect the depreciation expense of KU's portion of the TC2 Construction Work in Progress ("CWIP") balance at the end of the test period. The depreciation rates used in this adjustment are those the Companies proposed in Case No. 2009-00329 (supported in that case by the expert testimony of John Spanos and approved by the Commission on an interim basis through its Order dated December 23, 2009). The adjustment reflects the application of those rates to the CWIP balance as of the end of the test year associated with KU's portion of the TC2 assets. Although the commercial operation of TC2 and its some of its related transmission facilities will begin outside of the test year, it constitutes a known and measurable change of significant proportion. As described in the testimony of Paul

W. Thompson, commissioning operations and check out of the unit began in November 2009, and there have been no material mishaps or delays associated with unit testing to date. That testing success, coupled with the significant daily liquidated damages under the contract that would accrue if the Companies' contractor failed to meet its June 2010 commercial operation deadline, provide a high degree of assurance that TC2 will be in full commercial operation before KU's new base rates go into effect on August 1, 2010 after the expected suspension period.

By the date the base rates authorized in this case take effect, TC2 and its related transmission facilities will be in commercial operation and all CWIP expenditures through the end of the test period will be reclassified from CWIP to plant-in-service. TC2 and its related transmission facilities represent a significant addition to KU's plant in service. The adjustment recognizes the known and measurable fixed cost associated with the commercialization of TC2 before the rates authorized in this case take effect.

Shannon L. Charnas and I sponsor this adjustment, which is included in Reference Schedule 1.15 of Rives Exhibit 1.

Q. Does the Commission's practice favor post-test year adjustments?

A. No, the Commission generally has not looked favorably on post-test year adjustments; however, as I discuss later in my testimony, the Commission has recognized exceptions to this general position. More importantly, the relationship between the expiration of the power contract with OMU and the addition of the TC2 facility necessitates both events be considered together.

LG&E and KU are proposing two related post-test-period adjustments: (1) an increase in their depreciation expenses related to test-year-end CWIP for TC2 and its related transmission facilities which will become commercial in June 2010; and (2) a decrease in KU's operating expenses due to OMU's May 2010 termination of its purchased power contract with KU. Both of these proposed adjustments concern expenditures in the test year, but relate to events after the test year.

Q. In the light of the Commission's traditional practice, please explain why the Commission should accept KU's and LG&E's proposed post-test-year adjustments.

A. First, the demand for power by LG&E's and KU's native load customers will not diminish with the termination of the OMU contract. A resource of power must replace the OMU power. LG&E customers benefited from the OMU power contract through its replacement of other KU generation resources, which in turn, were used to serve LG&E customers through inter-company sales. A portion of the TC2 facility scheduled to become commercial in June 2010 will replace the OMU power contract. It is therefore appropriate to match the loss of the OMU power contract with the generation resource that will replace it, TC2. The addition of the pro rata amount of depreciation associated with LG&E's and KU's portion of test-year-end CWIP for TC2 presents the related cost of the TC2 facility based on the test year-end amount of CWIP.

Second, these two adjustments, together, create an appropriate balance in the cost of providing service and are based on the known and measureable changes in objective data to reflect the going forward cost of providing service.

Third, establishing the revenue requirements based on these two adjustments mitigates the immediate need for another rate case by KU and LG&E once TC2 has begun commercial operation.

Q. Has the Commission approved post-test year adjustments in previous cases?

A. Yes. In certain cases the Commission has accepted post-test year adjustments as the exception to its traditional position when the proposed changes are known and measurable. For example, there is a very strong correlation between the conditions under which the Commission allowed such a depreciation adjustment for test-year-end Trimble County Unit No. 1 ("TC1") CWIP and those giving rise to the proposed TC2-related adjustment. The amount of TC2 CWIP at the end of the test year is fully known and measurable; the rates KU proposes to use are those it has proposed in Case No. 2009-00329, which are known and measurable and approved by the Commission on an interim basis through its Order dated December 23, 2009 in Case No. 2009-00329; and TC2 will be in commercial operation before KU's proposed rates go into effect, just as was true when the Commission granted LG&E its requested TC1 CWIP depreciation adjustment in Case No. 90-158.

Second, the adjustments together represent a clear certainty in events that will occur after the test period, but before the rates established in this proceeding take effect. It is similar to The Union Light, Heat and Power Company's adjustment the Commission approved in Case No. 2001-00092, except that it is an expense that will end, not a revenue.[1]

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[1] *In the Matter of: Adjustment of Gas Rates of The Union Light, Heat and Power Company*, Case No. 2001-00092, Order at 31 (Jan. 31, 2002) ("ULH&P recognized reductions in revenue due to reduced gas usage by two large customers, Johns Manville and Newport Steel. These reductions, which occurred in April 2000 for Johns Manville and March 2001 for Newport Steel, were known and measurable when ULH&P filed its application

Concerning other kinds of post-test-period adjustments, in Case Nos. 1998-00426 (LG&E) and 1998-00474 (KU), which had test years ending December 31, 1998, the Commission accepted adjustments based on LG&E's and KU's actual margins from off-system sales and purchase power expenses for the twelve months ended August 1999 (i.e., actual sales and purchases until the September 1999 hearing in those proceedings). In doing so, the Commission accepted adjustments using actual data eight months beyond the end of the test year period.[2]

All of these Commission decisions demonstrate that the Commission has accepted known and measurable changes to operating revenues and expenses, even when the events that give rise to them, or the data that support them, occur outside of the test year. It would therefore be in accordance with the Commission Orders discussed above to approve this post-test-period adjustment.

Q. **Please explain the adjustment concerning KU's Hazard Tree Program.**

A. Following the 2008 Wind Storm and the 2009 Winter Storm, both of which caused significant damage to the Companies' facilities, the Companies engaged Davies Consulting, Inc. to provide options for further improving the survivability of their electrical system. The report by Davies Consulting, Inc. was previously provided to the Commission in connection with its investigation of utilities' responses to the 2009 Winter Storm ("Davies Report"). One option the Davies Report recommends for any overall system hardening program relates to "hazard tree" removal. This is as an

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[May 4, 2001], and result in a revenue decrease of $583,000. [ULH&P's test period ended September 30, 2000.]

... Based on both the magnitude of the revenue adjustments and when the changes in the customers' gas usage occurred, the Commission will accept ULH&P's adjustment to decrease revenues by $583,000.").

[2] *In the Matter of: The Application of Kentucky Utilities Company for Approval of an Alternative Method of Regulation of Its Rates and Services*, Case No. 1998-00474, Order at 68, 77-78 (Jan. 7, 2000).

extension of KU's and LG&E's typical tree trimming programs because the removal of these "hazardous trees" occurs outside of the Company's easements and rights-of-way. Approval of this adjustment is necessary to reflect the going forward cost of providing service. The cost of this additional vegetation management, which the Companies plan to implement with approval of new rates, will be $3,791,496 per year for KU. This adjustment is included in Reference Schedule 1.20 of Rives Exhibit 1.

Q. Please explain the adjustment concerning the Kentucky Consortium for Carbon Storage.

A. This adjustment is necessary to recover the costs of KU's investment in the Kentucky Consortium for Carbon Storage ("KCCS"). The Commission approved the establishment of a regulatory asset with regard to this investment in Case No. 2008-00308. The Companies allocate their contribution to KCCS between the two utilities on the basis of each utility's revenue, total assets, and payroll as of December 2007, resulting in a 51.22% allocation to KU and a 48.78% allocation to LG&E. KU proposes to amortize this regulatory asset over a period of four years, which corresponds to the duration of the project. This adjustment is included in Reference Schedule 1.29 of Rives Exhibit 1.

Q. Please explain the adjustment concerning the Carbon Management Resource Group.

A. This adjustment is necessary to recover the costs of KU's investment in the Carbon Management Resource Group ("CMRG"). The Commission approved the establishment of a regulatory asset with regard to this investment in Case No. 2008-00308. In a similar manner as discussed above for KCCS, the Companies agreement to provide CMRG up to $200,000 per year over 10 years is allocated 51.22% to KU and 48.78% to LG&E. KU proposes to amortize this regulatory asset over a period of ten years, which corresponds to the duration of the project. This adjustment is included in Reference Schedule 1.30 of Rives Exhibit 1.

Q. Please explain the adjustment to remove the expense associated with the Companies' settlement with the Southwest Power Pool ("SPP").

A. The Companies recently made a $2.27 million one-time payment to SPP under a recent settlement agreement concerning SPP's provision of Independent Transmission Operator ("ITO") services to the Companies. KU's portion of the settlement expense was $1,452,873. Because the settlement amount related to the cost of the entire 3.5-year (42-month) ITO contract with SPP, the portion of the settlement amount relating to time periods outside of the test year should be removed from test-year operating expenses. To achieve this exclusion, KU is removing 30/42 of its Kentucky-jurisdictional settlement amount from test-year operating expenses ($1,037,767), though 12/42 of the Kentucky-jurisdictional settlement amount, representing the test-year portion of the settlement amount ($415,107), should remain in test-year operating expenses. This adjustment is included in Reference Schedule 1.32 of Rives Exhibit 1.

Q. Please explain the adjustment removing reserve margin demand purchases.

A. As I noted in my direct testimony in KU's most recent rate case, Case No. 2008-00251, KU had entered into an agreement with Dynegy Power Marketing, Inc., to purchase unit firm capacity and an exclusive call option for the energy from Unit 1 (165 MW) at the Bluegrass Generating Station in Oldham County, Kentucky. KU had entered into the contract to maintain an adequate planning reserve margin for the summer periods (June through September) in 2008 and 2009. Because KU anticipated (and currently anticipates) that TC2 would be commercially operable in June 2010, it did not seek to renew its contract with Dynegy, which expired in September 2009. This adjustment therefore removes from the test year the expense associated with the Dynegy contract. This adjustment is included in Reference Schedule 1.36 of Rives Exhibit 1.

Q. Does this conclude your testimony?

A. Yes.

VERIFICATION

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

The undersigned, **Lonnie E. Bellar**, being duly sworn, deposes and says that he is Vice President, State Regulation and Rates for Kentucky Utilities Company and an employee of E.ON U.S. Services, Inc., and that he has personal knowledge of the matters set forth in the foregoing testimony, and that the answers contained therein are true and correct to the best of his information, knowledge and belief.

Lonnie E. Bellar

Lonnie E. Bellar

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 22nd day of January 2010.

Tammy J. Elzy (SEAL)
Notary Public

My Commission Expires:

November 9, 2010

APPENDIX A

Lonnie E. Bellar
E.ON U.S. Services Inc.
220 West Main Street
Louisville, Kentucky 40202

Education

Bachelors in Electrical Engineering;
University of Kentucky, May 1987
Bachelors in Engineering Arts;
Georgetown College, May 1987
E.ON Academy, Intercultural Effectiveness Program: 2002-2003
E.ON Finance, Harvard Business School: 2003
E.ON Executive Pool: 2003-2007
E.ON Executive Program, Harvard Business School: 2006
E.ON Academy, Personal Awareness and Impact: 2006

Professional Experience

E.ON U.S. LLC

Vice President, State Regulation and Rates	Aug. 2007 – Present
Director, Transmission	Sept. 2006 – Aug. 2007
Director, Financial Planning and Controlling	April 2005 – Sept. 2006
General Manager, Cane Run, Ohio Falls and Combustion Turbines	Feb. 2003 – April 2005
Director, Generation Services	Feb. 2000 – Feb. 2003
Manager, Generation Systems Planning	Sept. 1998 – Feb. 2000
Group Leader, Generation Planning and Sales Support	May 1998 – Sept. 1998

Kentucky Utilities Company

Manager, Generation Planning	Sept. 1995 – May 1998
Supervisor, Generation Planning	Jan. 1993 – Sept. 1995
Technical Engineer I, II and Senior, Generation System Planning	May 1987 – Jan. 1993

Professional Memberships

IEEE

Civic Activities

E.ON U.S. Power of One Co-Chair – 2007
Louisville Science Center – Board of Directors – 2008
Metro United Way Campaign – 2008
UK College of Engineering Advisory Board -- 2009

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

APPLICATION OF KENTUCKY UTILITIES COMPANY FOR AN ADJUSTMENT OF BASE RATES	)))	CASE NO. 2009-00548

TESTIMONY OF
ROBERT M. CONROY
DIRECTOR, RATES
KENTUCKY UTILITIES COMPANY

Filed: January 29, 2010

Q. Please state your name, position and business address.

A. My name is Robert M. Conroy. I am the Director of Rates for E.ON U.S. Services Inc., which provides services to Louisville Gas and Electric Company ("LG&E") and Kentucky Utilities Company ("KU") (collectively, "the Companies"). My business address is 220 West Main Street, Louisville, Kentucky. A statement of my professional history and education is attached to this testimony as Appendix A.

Q. Have you previously testified before this Commission?

A. Yes, I have testified before the Commission on a number of occasions, including the Companies' most recent base rate cases, Case Nos. 2008-00251 & 2008-00252, the Companies' fuel adjustment clause ("FAC") review cases, Case Nos. 2009-00287 & 2009-00288, and environmental cost recovery ("ECR") proceedings, most recently in the Companies' 2009 ECR Plan proceedings, Case Nos. 2009-00197 & 2009-00198.

Q. What are the purposes of your testimony?

A. The purposes of my testimony are: (1) to support certain exhibits identified below which are required by the Commission's regulations; (2) to explain certain proposed pro forma adjustments; and (3) to discuss and explain the various rate and tariff changes KU proposes.

Q. Are you supporting certain information required by Commission regulation 807 KAR 5:001, Section 10(6)(a)-(v) and Section 10(7)(e)?

A. Yes, I am sponsoring the following schedules for the corresponding Filing Requirements:

• New Rates Effect – Overall Revenues	Section 10(6)(d)	Tab 23
• Average Customer Class Bill Impact	Section 10(6)(e)	Tab 24
• Analysis of Customer Bills	Section 10(6)(g)	Tab 26

Pro Forma Adjustments

Q. Has an adjustment been made to eliminate the mismatch in fuel cost recovery?

A. Yes. Consistent with past Commission practice, the mismatch between fuel costs and fuel cost recovery through KU's FAC has been eliminated. These over- and under-recoveries were taken directly from KU's monthly FAC filings. The Commission approved a similar adjustment in Case No. 2003-00434, and KU proposed such an adjustment in Case No. 2008-00251. This adjustment is included in Reference Schedule 1.03 of Rives Exhibit 1.

Q. Has an adjustment been made to annualize the level of revenues associated with the base rates for KU the Commission approved in Case No. 2008-00251?

A. Yes. The Commission's February 5, 2009 Order in Case No. 2008-00251 approved a reduction in annual revenues for KU of nearly $9 million (achieved through the reduction of certain rates), which rates were to become effective for service rendered on and after February 6, 2009. Because the test year at issue in this application is from November 1, 2008, to October 31, 2009, an adjustment is necessary to reflect the revenue impact of current rates for the entire test year. This adjustment is included in Reference Schedule 1.04 of Rives Exhibit 1. Conroy Exhibit 1 shows the determination of the necessary adjustment to revenues to reflect a full year of rates approved in Case No. 2008-00251.

Q. Have adjustments been made to reflect the roll-in of the FAC and ECR for a full year?

A. Yes. The Commission's June 3, 2009 Order in Case No. 2008-00520 authorized the roll-in of the FAC into base rates effective with the July 2009 billing cycle. In addition, the Commission's December 2, 2009 Order in Case No. 2009-00310 authorized the roll-in of the ECR into base rates to be effective with the February 2010 billing cycle. Test-year revenues have been adjusted to reflect the rolled-in level of base rates and FAC and ECR billings for a full year. Conroy Exhibit 1 shows the impact on base rate revenues of the FAC and ECR roll-ins for a full year. Conroy Exhibit 2 shows the impact on FAC billings of reflecting the new base fuel cost (Fb/Sb) for a full year. The adjustment to reflect the FAC roll-in is included in Reference Schedule 1.04, and the adjustment to reflect the ECR roll-in is included in Reference Schedule 1.06 of Rives Exhibit 1. These adjustments are consistent with the methodology utilized in Case Nos. 2003-00434 and 2008-00251.

Q. Please explain the adjustment made to eliminate ECR revenues and expenses.

A. Consistent with the Commission's practice of eliminating the revenues and expenses associated with full-recovery cost trackers, an adjustment was made to eliminate ECR revenues during the test year and ECR expenses that will continue to be recovered through the ECR mechanism after the implementation of new base rates as shown in Reference Schedule 1.05 of Rives Exhibit 1. The ECR surcharge provides for full recovery of approved environmental costs that qualify for the surcharge.

In Case No. 2003-00434, KU proposed, and the Commission approved, the elimination of the original 1994 ECR Plan from the ECR mechanism. In a similar manner, KU is proposing in this proceeding to eliminate its 2001 and 2003 ECR Plans from its monthly ECR filings on a going-forward basis because the projects in those plans are now complete and have been in service for over five years, the costs of the projects in those plans are already included in base rates through a series of "roll-ins," and eliminating the two plans will simplify the oversight and administration of the ECR mechanism. As a result of eliminating the 2001 and 2003 ECR Plans, only the operating expenses associated with KU's 2005, 2006, 2009, and subsequent Plans that will continue to be recovered in the separate ECR mechanism are eliminated in this adjustment; however, all ECR revenues collected in the test year are eliminated because failure to do so would overstate KU's adjusted operating revenues by the portion of ECR revenues not received through the ECR mechanism going forward. KU proposes to recover the revenue requirements for the environmental compliance rate base associated with the 2001 and 2003 Plans through base rates, and proposes to continue to recover the revenue requirements of the remaining environmental compliance rate base through its monthly ECR filings. Upon approval of new base rates, KU will continue to use the approved ES Forms in the monthly ECR filings but exclude the cost associated with the 2001 and 2003 Plan projects in the expense month associated with the change in base rates until the next 2-year review at which time the ES Forms will be modified to reflect the elimination of the 2001 and 2003 Plans. Conroy Exhibit 3 shows the supporting data and calculations for the expenses associated with the 2001 and 2003 ECR Plans that are included in Reference Schedule 1.05 of Rives Exhibit 1.

Q. **Are there other adjustments necessary for the elimination of the 2001 and 2003 ECR Plans previously discussed?**

A. Yes. As discussed in the testimony of Mr. Rives, KU's capitalization as of October 31, 2009, is adjusted to remove the environmental compliance rate base. This adjustment, shown in Column 12 of Rives Exhibit 2, includes only the environmental compliance rate base associated with the ECR Plans that will continue to be included in the ECR monthly filings. It does not include the environmental rate base associated with the 2001 and 2003 ECR Plans or the remaining amount associated with the roll-in recently approved in Case No. 2009-00310.

Q. Please explain the adjustment made concerning off-system sales revenues related to the ECR mechanism.

A. In the determination of the monthly ECR surcharge, a portion of KU's environmental compliance costs are allocated to off-system sales, including intercompany sales, through the jurisdictional allocation ratio. But by including off-system and intercompany sales revenues in test-year operating results, these revenues are credited to jurisdictional customers. Moreover, because total ECR expenses are removed through the adjustment in Reference Schedule 1.05, the expenses associated with off-system and intercompany sales are understated. This results in an overstatement of margins from off-system and intercompany sales and a mismatch of the revenues and expenses related to the off-system and intercompany sales portion of the allocated environmental surcharge monthly revenue requirement. KU has included in this adjustment a reduction to revenues associated with ECR-related off-system and intercompany sales revenues. KU performed the adjustment in a manner generally consistent with the methodology prescribed in the Commission's Order on rehearing in Case No. 98-474 dated June 1, 2000, and in the manner used in Case Nos. 2003-00434 and 2008-00251; however, total off-system sales revenues, inclusive of intercompany sales, are used in the calculation.

This adjustment is included in Reference Schedule 1.07 of Rives Exhibit 1.

Q. Please explain the adjustment to eliminate DSM revenues and expenses.

A. Consistent with the Commission's practice of eliminating the revenues and expenses associated with full-recovery cost trackers, an adjustment was made to eliminate revenue recovered through the Demand-Side Management Cost Recovery Mechanism ("DSMRM") and the corresponding demand-side management expenses recorded during the test year. The DSMRM includes a balance adjustment that automatically adjusts unit charges under the mechanism to account for differences between revenues collected and demand-side management program costs incurred during the applicable period. KU proposed a similar adjustment in its most recent base rate case, Case No. 2008-00251, and a similar adjustment was also approved by the Commission in Case No. 2003-00434. This adjustment is included in Reference Schedule 1.10 of Rives Exhibit 1.

Q. Please explain the adjustment concerning customer billing corrections and rate switching.

A. KU must adjust its operating revenues to account for a billing correction to one major account during the test year. Specifically, for several months beginning February 2007 through February 2009, the customer's demand was billed incorrectly at the metered level when the contract minimum demands were not met. In February 2009, a billing adjustment was made that included corrected billings for all months. Four of the impacted months are not in the test period; therefore, KU is making an adjustment to test year revenues to remove the impact of the corrected billings for those four months.

In addition, subsequent to the implementation of new rates and rate structures on February 6, 2009, as approved by the Commission in Case No. 2008-00251, 25 KU customers switched from mainly power service rate schedules to time-of-day rate schedules. An adjustment to revenue (supported by Conroy Exhibit 4) is necessary to reflect a full year of customer revenue on the time-of-day rate schedules. KU's sister utility, LG&E, proposed such an adjustment in Case No. 2008-00252. These adjustments are included in Reference Schedule 1.13 of Rives Exhibit 1.

Rate Design

Q. What efforts have LG&E and KU made towards harmonizing the service schedules offered by each company?

A. The Companies continue to take strides towards harmonizing their rate schedules by consolidating, renaming, adding, and revising them to be as consistent as possible between the two Companies. The table below summarizes the changes being made to the current KU rate schedule designations to transition towards a uniform set of rate schedules between the two Companies.

Current Rate Schedule	Proposed Rate Schedule	Availability kW or kVA
RS	RS	All
GS	GS	0 - 50
AES	AES	All
PS Secondary	PS Secondary	50 - 250
PS Primary	PS Primary	0 - 250
TOD Secondary	TODS (Secondary)	250 - 5,000
TOD Primary	TODP (Primary)	250 - 75,000 kVA
LTOD Primary		
RTS	RTS	0 - 75,,000 kVA
IS	FLS	20,000 - 200,000 kVA

Although the Companies are not yet able to completely harmonize their rate schedules, the transition that began in the last two rate cases has continued through this proceeding. Conroy Exhibit 5 is a visual comparison of LG&E's and KU's rate schedules.

Q. What is the basic objective of the rate design being proposed?

A. It is the Companies' intent to continue the principles followed in the previous two rate cases of gradually eliminating cross-subsidization and bringing both the structure and the charges of the rate design in line with the results of the cost of service study. My testimony addresses changes the Company is proposing to the structure of the various rate schedules. These rate design principles and all charges are supported by the testimony and exhibits of W. Steven Seelye.

Q. Is KU proposing any general changes to its tariff?

A. Yes. The term "Customer Charge" is being changed to "Basic Service Charge" throughout the tariff to better reflect the reason for the charge and the costs it is designed to recover. Also, the winter and summer billing periods associated with the power rates are being redefined to include May in the summer billing period.

Q. Does KU propose to change all of its rate structures?

A. No. Though KU proposes to change most charges, it proposes structural changes only to its Power Service and time-of-day rate schedules. I will address only those rate schedules the Company proposes to change structurally or with significant text changes. Mr. Seelye supports all KU's proposed structural changes and charges in his testimony and exhibits.

Q. Does KU propose to change its All Electric School Tariff, Rate AES?

A. Yes. KU proposes to keep a flat energy charge for Rate AES, but to add a basic service charge, one fixed amount for single-phase customers and another fixed amount for three-phase customers. The proposed fixed-amount basic service charge will be the minimum charge under the revised Rate AES, replacing the current Rate AES minimum charge, which is calculated based on a customer's demand. The basic service charge is necessary to ensure recovery of costs associated with providing service.

In addition, KU is clarifying the language approved in its 2008 rate case limiting the future availability of the tariff to those customers taking service under the tariff on February 6, 2009.

Q. What rate design is being proposed for Power Service Rate PS.

A. KU is proposing to retain a basic service charge and a flat energy charge, but to replace the current "Maximum Load Charge" with a seasonally (Winter and Summer) differentiated demand charge to harmonize KU's design with that of LG&E.

Additionally, the Rate PS minimum bill has been redesigned to more accurately reflect the purpose of a minimum billing provision. The current minimum design has an annual value satisfied by the addition of customer, energy, and demand charges. The purpose of a minimum bill is to ensure recovery of fixed costs associated with demand charges only. To that end, KU proposes a minimum tied only to a customer's demand. Though similar to the existing minimum, the proposed minimum is based only on demand and is the greatest of: (a) the monthly maximum load; (b) fifty percent (50%) of the monthly maximum load during the preceding eleven billing periods; and (c) sixty percent (60%) of the contract capacity based on the expected maximum load on the system or the kW capacity of facilities specified by the customer. The charges and the minimum design are supported by the testimony and exhibits of Mr. Seelye.

Q. Is KU proposing to modify the Time-of-Day Rate TOD and Large Time-of-Day Rate LTOD?

A. Yes. Currently Rate TOD is available for secondary and primary service while Rate LTOD is only available for primary service. KU is proposing to leave customers under the current Rate TOD receiving service at the secondary level on that rate schedule but rename it Time-of-Day Secondary (Rate TODS). Rate TODS will remain available for secondary customers with loads between 250 kW and 5,000 kW. Primary service under the current Rate TOD will migrate to the current Rate LTOD and it will be renamed Time-of-Day Primary (Rate TODP). Rate TODP will be available for primary customers with minimum average loads of 250 kVA and maximum loads of 75,000 kVA. The move to kVA billing and the potential increase to 75,000 kVA are further discussed below.

Q. Please describe other changes proposed for Rate TODS.

A. The current rate for service under the existing Rate TOD employs two time periods. The length of the on-peak period makes it difficult for customers to shift load. To encourage load shifting away from the system peak hours, the on-peak period is being reduced and an additional intermediate time period is being introduced. KU is proposing a three-part rate structure consisting of a basic service charge, a flat energy charge, and a three-time-period (Peak, Intermediate, and Base) demand charge, harmonizing KU's design with that of LG&E.

Additionally, the minimum bill has been redesigned to more accurately reflect the purpose of a minimum billing provision. The current minimum design under Rate TOD is an annual value satisfied by the addition of customer, energy, and demand charges. The purpose of a minimum bill is to ensure recovery of fixed costs associated with demand charges only. To that end, KU proposes a minimum tied only to the customer's demand. Though similar to the existing minimum, the proposed minimum is based only on demand and is applied for each demand time period. For the Peak and Intermediate periods, the proposed minimum for a given month is the greatest of: (a) that month's maximum load; and (b) fifty percent (50%) of the monthly maximum load during the preceding eleven billing periods. For the Base period, the proposed minimum for a given month is based only on demand and is the greatest of: (a) that month's maximum load but not less than 250 kW; (b) seventy-five percent (75%) of the monthly maximum load during the preceding eleven billing periods; and (c) seventy-five percent (75%) of the contract capacity based on either the expected maximum load on the system or the kW capacity of facilities specified by the customer.

These charges and the minimum design are supported by the testimony and exhibits of Mr. Seelye.

Q. **Please describe other changes proposed for Rate TODP.**

A. The current rates for service under existing Rate LTOD employ two time periods with the demand billing based on kW. Continuing the move in the last rate case where kVA billing was introduced for transmission deliveries, KU is proposing kVA billing for Rate TODP. The length of the current on-peak periods makes it difficult for customers to shift load. To encourage load shifting away from the system peak hours, the on-peak period is being reduced and an additional intermediate time period is being introduced. KU is proposing a three-part rate structure consisting of a basic service charge, a flat energy charge, and a three-time-period (Peak, Intermediate, and Base) demand charge, harmonizing KU's design with that of LG&E.

Additionally, the minimum bill has been redesigned to more accurately reflect the purpose of a minimum billing provision. The current minimum design under Rate LTOD is an annual value satisfied by the addition of customer, energy, and demand charges. The purpose of a minimum bill is to ensure recovery of fixed costs associated with demand charges only. To that end, KU proposes a minimum tied only to a customer's demand. Though similar to the existing minimum, the proposed minimum is based only on demand and is applied for each demand time period. For the Peak and Intermediate periods, the proposed minimum for a given month is the greatest of: (a) that month's maximum load; and (b) fifty percent (50%) of the monthly maximum load during the preceding eleven billing periods. For the Base period the proposed minimum for a given month is based only on demand and is the greatest of: (a) that month's maximum load but not less than 250 kVA; (b) seventy-five percent (75%) of the monthly maximum load during the preceding eleven billing periods; and (c) seventy-five percent (75%) of the contract capacity based on either the expected maximum load on the system or the kW capacity of facilities specified by the customer.

One other difference between Rate TODP and Rate LTOD it is replacing should be noted. The maximum load permitted on Rate TODP is 75,000 kVA as compared to 50,000 kW for Rate LTOD. Existing customers can increase their loads up to 75,000 kVA with annual increases not exceeding 2,000 kVA unless approved by the Company's transmission operator. New loads coming onto the system cannot exceed 50,000 kVA; however, once they are an existing customer they have the ability to increase their load as previously mentioned. This change is made to allow for growth of customers' loads while taking into consideration system constraints.

These charges and minimum design are supported by the testimony and exhibits of Mr. Seelye.

Q. Is KU proposing to modify Retail Transmission Service, Rate RTS?

A. Yes. Consistent with the changes to Rate TOD and Rate LTOD with the introduction of Rate TODS and Rate TODP discussed above, KU proposes to introduce three demand time periods, alter the minimum billing, and increase the availability cap for Rate RTS.

The length of the on-peak periods makes it difficult for customers to shift load. To encourage load shifting away from the system peak hours, the on-peak period is being reduced and an additional intermediate time period is being introduced. KU is proposing a three-part rate structure consisting of a basic service charge, a flat energy charge, and a three-time-period (Peak, Intermediate, and Base) demand charge, harmonizing KU's design with that of LG&E.

Additionally, the minimum bill has been redesigned to more accurately reflect the purpose of a minimum billing provision. The current minimum design is an annual value satisfied by the addition of customer, energy, and demand charges. The purpose of a minimum bill is to ensure recovery of fixed costs associated with demand charges only. To that end, we are proposing a minimum tied only to a customer's demand. Though similar to the existing minimum, the proposed minimum is based only on demand and is applied for each demand time period. For the Peak and Intermediate periods, the proposed minimum for a given month is the greatest of: (a) that month's maximum load; and (b) fifty percent (50%) of the monthly maximum load during the preceding eleven billing periods. For the Base period, the proposed minimum for a given month is based only on demand and is the greatest of: (a) that month's maximum load but not less than 250 kVA; (b) seventy-five percent (75%) of the monthly maximum load during the preceding eleven billing periods; and (c) seventy-five percent (75%) of the contract capacity based on either the expected maximum load on the system or the kW capacity of facilities specified by the customer.

In addition, as discussed above for Rate TODP, the maximum load permitted on Rate RTS is 75,000 kVA as compared to the current 50,000 kVA. Existing customers can increase their loads up to 75,000 kVA with annual increases not exceeding 2,000 kVA unless approved by the Company's transmission operator. New loads coming onto the system cannot exceed 50,000 kVA; however, once they are an existing customer they have the ability to increase their load as previously mentioned. This change is made to allow for growth of customers' loads while taking into consideration system constraints.

These charges and minimum design are supported by the testimony and exhibits of Mr. Seelye.

Q. Is KU proposing to modify the Industrial Service, Rate IS?

A. Yes, KU proposes to rename "Industrial Service" to be "Fluctuating Load Service (Rate FLS)" because it more accurately describes the rate. In addition, KU proposes to modify Rate FLS to match the changes made to the proposed Rate TODS, TODP, and RTS, with the notable exception that Rate FLS will be based on a 5-minute demand billing interval. Rate FLS will continue to be available for primary and transmission service.

KU proposes to introduce three demand time periods, eliminate the 15-minute demand charges, and base the demand charges only on 5-minute demand intervals. The length of the on-peak periods makes it difficult for customers to shift load. To encourage load shifting away from the system peak hours, the on-peak period is being reduced and an additional intermediate time period is being introduced. KU is proposing a three-part rate structure consisting of a basic service charge, a flat energy charge, and a three-time-period (Peak, Intermediate, and Base) demand charge, harmonizing KU's design that of LG&E.

Additionally, the minimum has been redesigned to match the 5-minute demand intervals and the three-time-period design. The proposed minimum is based only on demand and is applied for each demand time period. For the Peak and Intermediate periods, the proposed minimum for a given month is the greatest of: (a) that month's maximum load; and (b) sixty percent (60%) of the monthly maximum load during the preceding eleven billing periods. For the Base period, the proposed minimum for a given month is based only on demand and is the greatest of: (a) that month's maximum load but not less than 20,000 kVA; (b) seventy-five percent (75%) of the monthly maximum load during the preceding eleven billing periods; and (c) seventy-five percent (75%) of the contract capacity based on either the expected maximum load on the system or the kW capacity of facilities specified by the customer.

These charges and the minimum design are supported by the testimony and exhibits of Mr. Seelye.

Q. What changes are KU proposing to its lighting rates Street Lighting ST, LT, and Public Outdoor Lighting P.O. LT.?

A. The changes are primarily associated with formatting for clarity and harmonizing the language with that of LG&E. An effort has also been made to more clearly define what facilities are provided with each type light and service. All charges are supported by the testimony and exhibits of Mr. Seelye.

Q. Is KU proposing any additions to its lighting service?

A. Yes. KU added a Contemporary "fixture only" option to its current underground selections for P.O. LT. Although not a new fixture type, this new option will allow for the installation of multiple fixtures on a single pole. Such change was in response to numerous customer requests.

Q. Does KU propose to modify its Cable Television Attachment Charges (Rate CTAC)?

A. Yes. KU's proposed Rate CTAC tariff is the same as its current Rate CTAC tariff, except for a change in the amount of the attachment charge, an extension of the bill due date, and the elimination of several redundant paragraphs in the Terms and Conditions section. Mr. Seelye's testimony explains and supports the attachment charge.

Q. Is KU proposing to modify the Curtailable Service Riders?

A. Yes. KU currently has three Curtailable Service Riders, CSR1, CSR2, and CSR3. CSR1 and CSR3 are restricted to the customers currently on the rate. All three vary by the number of hours of curtailment that may be requested, the credit charge that is given, and whether buy-through is available. To replace CSR1, CSR2, and CSR3, KU proposes a single CSR to allow 500 hours of curtailment in any 12-month period. Physical curtailment would be required for 100 hours, and the other 400 hours of curtailment would be met by either physical curtailment or an automatic buy-through at a formulaic price. These charges are supported by the testimony and exhibits of Mr. Seelye.

Q. What changes does KU propose to make to its Excess Facilities Rider, Rider EF?

A. The rider currently allows a customer to use facilities beyond those normally provided for service by paying either: (1) a monthly charge reflecting a return on the installed cost of the facilities plus maintenance costs; or (2) the installed cost of the facilities in advance, plus a monthly charge based on maintenance costs. Under the current Rider EF, a customer who paid upfront for the installed cost of any excess facilities must pay for them again if the facilities fail. KU proposes to modify the Rider EF to make KU responsible for replacing excess facilities that fail. Mr. Seelye's testimony and exhibits support Rider EF and KU's proposed changes thereto.

Q. Is KU proposing to rename any other tariffs or add any new tariffs?

A. Yes, KU proposes to rename the "Intermittent/Fluctuating Load Rider" to be the "Intermittent Load Rider" to avoid confusion with the Fluctuating Load Service, though it proposes no other changes to the rider. Also, KU proposes to add a Low Emissions Vehicle Rate, which John Wolfram addresses in his testimony.

Q. How will this proceeding affect the Company's proposed changes to the Small Green Energy Rider ("SGE") and Large Green Energy Rider ("LGE") submitted in Case No. 2009-00467?

A. The Company does not propose to make any substantive changes to the Riders SGE and LGE as a result of this proceeding, though the Company will make basic formatting and other generally applicable changes to the draft rider proposed in Case No. 2009-00467 pending the outcome of that proceeding before filing the final tariff in this proceeding.

Q. What changes does KU propose to make to its Environmental Cost Recovery Surcharge rider?

A. KU proposes to make only minor change to the listing of the specific rate schedules to which the ECR applies under the section for "Availability of Service" to reflect the appropriate name changes proposed above.

Q. Does KU propose any changes to the Demand-Side Management Cost Recovery schedule, Adjustment Clause DSM?

A. Yes, though the changes KU proposes are minor. The only substantive change KU proposes is to add a definition of "industrial customer." If the Commission approves KU's proposed tariff changes, there will no longer be any "industrial" rates. It is therefore necessary to add a definition of "industrial customer" to the DSM tariff sheets to determine which customers could qualify for industrial DSM programs.

The only other changes KU proposes are those necessary to track the renaming of rate schedules KU is proposing in this proceeding.

Q. **Does this conclude your testimony?**

A. Yes, it does.

VERIFICATION

COMMONWEALTH OF KENTUCKY)
) SS:
COUNTY OF JEFFERSON)

The undersigned, **Robert M. Conroy**, being duly sworn, deposes and says that he is Director - Rates for E.ON U.S. Services, Inc., and that he has personal knowledge of the matters set forth in the foregoing testimony, and that the answers contained therein are true and correct to the best of his information, knowledge and belief.

Robert M. Conroy

Robert M. Conroy

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 22nd day of January 2010.

Tammy J. Elzy (SEAL)
Notary Public

My Commission Expires:

November 9, 2010

APPENDIX A

Robert M. Conroy
Director, Rates
E.ON U.S. Services Inc.
220 West Main Street
Louisville, Kentucky 40202
Telephone: (502) 627-3324

Education

Masters of Business Administration
Indiana University (Southeast campus), December 1998. GPA: 3.9

Bachelor of Science in Electrical Engineering
Rose Hulman Institute of Technology, May 1987. GPA: 3.3

Essentials of Leadership, London Business School, 2004

Center for Creative Leadership, Foundations in Leadership program, 1998

Registered Professional Engineer in Kentucky, 1995

Previous Positions

Manager, Rates	April 2004 – Feb 2008
Manager, Generation Systems Planning	Feb. 2001 – April 2004
Group Leader, Generation Systems Planning	Feb. 2000 – Feb. 2001
Lead Planning Engineer	Oct. 1999 – Feb. 2000
Consulting System Planning Analyst	April 1996 – Oct. 1999
System Planning Analyst III & IV	Oct. 1992 - April 1996
System Planning Analyst II	Jan. 1991 - Oct. 1992
Electrical Engineer II	Jun. 1990 - Jan. 1991
Electrical Engineer I	Jun. 1987 - Jun. 1990

Professional/Trade Memberships

Registered Professional Engineer in Kentucky, 1995

KENTUCKY UTILITIES COMPANY

Calculations Showing the Effect on Base Rate Revenue of PSC 14, the Fuel Adjustment Clause Roll-in and the Environmental Cost Recovery Roll-in for a Full Year
Based on Sales for the 12 months ended October 31, 2009

		PSC 14 For a Full Year		FAC Roll-in Rates For a Full Year		ECR Roll-in Rates For a Full Year	
	As Billed Base Rates Revenues	Calculated Base Rates Revenue	Increased Revenue	Calculated Base Rates Revenue	Increased Revenue	Calculated Base Rates Revenue	Increased Revenue
Residential Service							
Residential Rate - RS	$ 298,152,617	380,774,534	82,621,918	387,813,062	7,038,528	421,450,169	33,637,107
Full Electric Residential Rate - FERS (rate eliminated with PSC 14)	83,967,346	-	(83,967,346)	-	-	-	-
	382,119,963	380,774,534	(1,345,428)	387,813,062	7,038,528	421,450,169	33,637,107
General Service							
General Service Rate GS	132,425,053	132,031,674	(393,379)	134,001,152	1,969,477	145,668,593	11,667,441
All Electric School Service Rate - AES	7,283,439	7,259,429	(24,011)	7,407,610	148,182	8,047,810	640,200
Power Service					-		-
Power Service Rate PSS - Secondary	128,717,248	190,599,497	61,882,249	194,563,122	3,963,625	210,905,683	16,342,561
Power Service Rate PSP - Primary	52,741,533	79,291,811	26,550,278	80,944,657	1,652,846	87,747,710	6,803,052
General Service Primary Rate GS - P (moved to rate PSP with PSC 14)	369,565	-	(369,565)	-	-	-	-
Large Power Rate LPS - Secondary (moved to rate PSS with PSC 14)	62,536,250	-	(62,536,250)	-	-	-	-
Large Power Rate LPP - Primary (moved to rate PSP with PSC 14	23,823,942	-	(23,823,942)	-	-	-	-
Coal Mining Power Service Rate MP-Primary (moved to rate PSP with PSC 14)	2,620,962	-	(2,620,962)	-	-	-	-
	270,809,501	269,891,308	(918,193)	275,507,779	5,616,471	298,653,393	23,145,614
Time of Day Service							
Time-of-Day Service - TODS Secondary	7,656,759	9,765,155	2,108,396	9,950,002	184,847	10,691,663	741,661
Time-of-Day Service - TODP Primary	3,359,051	3,550,360	191,308	3,601,463	51,103	4,046,807	445,345
Small Time-of-Day - STODS Secondary (moved to rate TODS with PSC 14)	2,117,087	-	(2,117,087)	-	-	-	-
Small Time-of-Day - STODP Primary (moved to rate TODP with PSC 14)	193,542	-	(193,542)	-	-	-	-
	13,326,439	13,315,515	(10,924)	13,551,465	235,950	14,738,470	1,187,006
Large Power Time of Day Service							
Large Time-of-Day Primary Service - LTOD Primary	80,860,980	113,869,107	33,008,127	116,389,138	2,520,031	126,120,077	9,730,939
Large Comm./Industrial Time-of-Day - LCI-TOD Primary (moved to rate LTOD with PSC 14)	31,959,221	-	(31,959,221)	-	-	-	-
Large Mine Power Time-of-Day Rate - LMP-TPD Primary (moved to rate LTOD with PSC 14)	1,467,528	-	(1,467,528)	-	-	-	-
	114,287,730	113,869,107	(418,623)	116,389,138	2,520,031	126,120,077	9,730,939
Retail Transmission Service -- RTS	44,765,786	59,690,397	14,924,611	60,939,067	1,248,670	65,823,782	4,884,714
Large Power Rate LPT - Transmission (moved to rate RTS with PSC 14)	480,648	-	(480,648)	-	-	-	-
Coal Mining Power Service Rate - MP Transmission (moved to rate RTS with PSC 14)	1,446,809	-	(1,446,809)	-	-	-	-
Large Comm./Industrial Time-of-Day - LCI-TOD Transmission (moved to rate RTS with PSC 14)	10,247,081	-	(10,247,081)	-	-	-	-
Large Mine Power Time-of-Day Rate - LMP-TPD Transmission (moved to rate RTS with PSC 14)	3,491,868	-	(3,491,868)	-	-	-	-
	60,432,192	59,690,397	(741,795)	60,939,067	1,248,670	65,823,782	4,884,714
Industrial Service -- IS (including PSC 13 rate LI-TOD)	16,875,133	16,487,327	(387,806)	16,766,111	278,784	18,074,837	1,308,726
Lighting Rates							
Outdoor Lighting Service -- LE	-	-	-	-	-	-	-
Traffic Lighting Energy -- TE	15	15	(0)	15	-	16	1
Street Lighting - SL	8,058,263	8,033,243	(25,020)	8,079,266	46,023	8,690,534	611,268
Decorative Street Lighting - SLDEC (moved to rate SL with PSC 14)	-	-	-	-	-	-	-
Private Outdoor Lighting - POL	10,072,526	10,046,730	(25,796)	10,127,280	80,550	10,898,368	771,088
Customer Outdoor Lighting - OL (moved to rate POL with PSC 14)	-	-	-	-	-	-	-
	18,130,804	18,079,988	(50,816)	18,206,561	126,573	19,588,918	1,382,357
Curtailable Service Rider Credits - Primary	(126,145)	(126,145)	-	(126,145)	-	(126,145)	-
Curtailable Service Rider Credits - Transmission	(5,515,286)	(5,515,286)	-	(5,515,286)	-	(5,515,286)	-
	(5,641,432)	(5,641,432)	-	(5,641,432)	-	(5,641,432)	-
TOTAL	$ 1,010,048,821	1,005,757,847	(4,290,974)	1,024,940,513	19,182,666	1,112,524,616	87,584,103

KENTUCKY UTILITIES COMPANY

Calculations Showing the Effect on Base Rate Revenue of PSC 14, the Fuel Adjustment Clause Roll-in and the Environmental Cost Recovery Roll-in for a Full Year
Based on Sales for the 12 months ended October 31, 2009

					"As Billed Rates" During 12 Month Period		P.S.C. 14 for Full Year		FAC Roll-in Rates for Full Year		"Current Rates" ECR Roll-in Rates for Full Year	
	Customers 12 Mo End Oct 2009	Basic Demand	Peak Demand	kWh's	Unit Charges	Calculated Revenue	Unit Charges	Calculated Revenue	Unit Charges	Calculated Revenue	Unit Charges	Calculated Revenue
RESIDENTIAL RATE RS												
Customers For the 12 Month Period (Rate RS)	4,300,354				$ 5.00	$ 21,501,770	$ 5.00	$ 21,501,770	$ 5.00	$ 21,501,770	$ 5.00	$ 21,501,770
Customers For the Period Through Jan 2009 (Rate FERS)	718,887				$ 5.00	$ 3,594,435	$ 5.00	$ 3,594,435	$ 5.00	$ 3,594,435	$ 5.00	$ 3,594,435
kWh Nov08-Jan09 Rates: (Rate RS)				927,321,464	$ 0.05774	$ 53,543,541	$ 0.05716	$ 53,005,695	$ 0.05879	$ 54,517,229	$ 0.06424	$ 59,571,131
kWh Nov08-Jan09 Rates: (Rate FERS)				1,392,425,364	$ 0.05774	$ 80,398,641	$ 0.05716	$ 79,591,034	$ 0.05879	$ 81,860,687	$ 0.06424	$ 89,449,405
kWh Feb09-Jun09 Rates:				1,998,368,949	$ 0.05716	$ 114,226,769	$ 0.05716	$ 114,226,769	$ 0.05879	$ 117,484,111	$ 0.06424	$ 128,375,221
kWh Jul09-Oct09 Rates:				1,853,833,843	$ 0.05879	$ 108,986,892	$ 0.05879	$ 108,986,892	$ 0.05879	$ 108,986,892	$ 0.06424	$ 119,090,286
Minimum billings (Rate RS)						$ (106,328)		$ (106,340)		$ (106,340)		$ (106,340)
Minimum billings (Rate FERS)						$ (25,757)		$ (25,720)		$ (25,721)		$ (25,740)
TOTAL	5,019,241			6,171,949,620		$ 382,119,963		$ 380,774,534		$ 387,813,062		$ 421,450,169

KENTUCKY UTILITIES COMPANY

Calculations Showing the Effect on Base Rate Revenue of PSC 14, the Fuel Adjustment Clause Roll-in and the Environmental Cost Recovery Roll-in for a Full Year

Based on Sales for the 12 months ended October 31, 2009

	Customers 12 Mo End Oct 2009	Basic Demand	Peak Demand	kWh's	"As Billed Rates" During 12 Month Period Unit Charges	"As Billed Rates" During 12 Month Period Calculated Revenue	P.S.C. 14 for Full Year Unit Charges	P.S.C. 14 for Full Year Calculated Revenue	FAC Roll-in Rates for Full Year Unit Charges	FAC Roll-in Rates for Full Year Calculated Revenue	"Current Rates" ECR Roll-in Rates for Full Year Unit Charges	"Current Rates" ECR Roll-in Rates for Full Year Calculated Revenue
GENERAL SERVICE RATE GS												
Single Phase Customers For the 12 Month Period	950,552				$ 10.00	$ 9,505,520	$ 10.00	$ 9,505,520	$ 10.00	$ 9,505,520	$ 10.00	$ 9,505,520
kWh Nov08-Jan09 Rates:				614,596,344	$ 0.06745	$ 41,454,523	$ 0.06681	$ 41,061,182	$ 0.06844	$ 42,062,974	$ 0.07486	$ 46,008,682
kWh Feb09-Jun09 Rates:				593,671,807	$ 0.06681	$ 39,663,213	$ 0.06681	$ 39,663,213	$ 0.06844	$ 40,630,898	$ 0.07486	$ 44,442,271
kWh Jul09-Oct09 Rates:				609,090,260	$ 0.06844	$ 41,686,137	$ 0.06844	$ 41,686,137	$ 0.06844	$ 41,686,137	$ 0.07486	$ 45,596,497
Minimum Billings						$ 115,659		$ 115,622		$ 115,622		$ 115,622
TOTAL	950,552			1,817,358,411		$ 132,425,053		$ 132,031,674		$ 134,001,152		$ 145,668,593

KENTUCKY UTILITIES COMPANY

Calculations Showing the Effect on Base Rate Revenue of PSC 14, the Fuel Adjustment Clause Roll-in and the Environmental Cost Recovery Roll-in for a Full Year
Based on Sales for the 12 months ended October 31, 2009

	Customers 12 Mo End Oct 2009	Basic Demand	Peak Demand	kWh's	"As Billed Rates" During 12 Month Period Unit Charges	Calculated Revenue	P.S.C. 14 for Full Year Unit Charges	Calculated Revenue	FAC Roll-in Rates for Full Year Unit Charges	Calculated Revenue	"Current Rates" ECR Roll-in Rates for Full Year Unit Charges	Calculated Revenue
ALL ELECTRIC SCHOOLS RATE AES												
Single Phase Customers For the 12 Month Period	3,539				$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
kWh Nov08-Jan09 Rates:				46,174,396	$ 0.05571	$ 2,572,376	$ 0.05519	$ 2,548,365	$ 0.05682	$ 2,623,629	$ 0.06173	$ 2,850,345
kWh Feb09-Jun09 Rates:				44,734,624	$ 0.05519	$ 2,468,904	$ 0.05519	$ 2,468,904	$ 0.05682	$ 2,541,821	$ 0.06173	$ 2,761,468
kWh Jul09-Oct09 Rates:				39,477,973	$ 0.05682	$ 2,243,138	$ 0.05682	$ 2,243,138	$ 0.05682	$ 2,243,138	$ 0.06173	$ 2,436,975
Minimum Billings						$ (979)		$ (979)		$ (979)		$ (979)
TOTAL	3,539			130,386,993		$ 7,283,439		$ 7,259,429		$ 7,407,610		$ 8,047,810

KENTUCKY UTILITIES COMPANY

Calculations Showing the Effect on Base Rate Revenue of PSC 14, the Fuel Adjustment Clause Roll-in and the Environmental Cost Recovery Roll-in for a Full Year

Based on Sales for the 12 months ended October 31, 2009

	Customers 12 Mo End Oct 2009	Basic Demand	Peak Demand	kWh's	"As Billed Rates" During 12 Month Period: Unit Charges	"As Billed Rates" During 12 Month Period: Calculated Revenue	P.S.C. 14 for Full Year: Unit Charges	P.S.C. 14 for Full Year: Calculated Revenue	FAC Roll-in Rates for Full Year: Unit Charges	FAC Roll-in Rates for Full Year: Calculated Revenue	"Current Rates" ECR Roll-in Rates for Full Year: Unit Charges	"Current Rates" ECR Roll-in Rates for Full Year: Calculated Revenue
POWER SERVICE RATE PS-Primary (consists of former rates GS-Primary, LP-Primary and MP-Primary)												
Customers For the 12 Month Period (LP customers)	4,771				$ 75.00	$ 357,825	$ 75.00	$ 357,825	$ 75.00	$ 357,825	$ 75.00	$ 357,825
Customers For the Period Through Jan 2009 (MP customers)	118				$ 75.00	$ 8,850	$ 75.00	$ 8,850	$ 75.00	$ 8,850	$ 75.00	$ 8,850
Customers For the Period Through Jan 2009 (GS-P customers; eliminated from Rate GS with P.S.C. 14)	232				$ 10.00	$ 2,320	$ 75.00	$ 17,400	$ 75 00	$ 17,400	$ 75.00	$ 17,400
kW Demand Nov08-Jan09 Rates: (LP customers)		1,149,455			$ 7.26	$ 8,345,042	$ 7.26	$ 8,345,042	$ 7.26	$ 8,345,042	$ 9.03	$ 10,379,577
kW Demand Nov08-Jan09 Rates: (MP customers)		159,188			$ 5.45	$ 867,572	$ 7.26	$ 1,155,701	$ 7.26	$ 1,155,701	$ 9.03	$ 1,437,463
kW Demand Feb09-Jun09 Rates:		1,242,705			$ 7.26	$ 9,022,040	$ 7.26	$ 9,022,040	$ 7.26	$ 9,022,040	$ 9.03	$ 11,221,628
kW Demand Jul09-Oct09 Rates:		1,292,185			$ 7.26	$ 9,381,263	$ 7.26	$ 9,381,263	$ 7.26	$ 9,381,263	$ 9.03	$ 11,668,431
kWh Nov08-Jan09 Rates: (LP customers)				469,632,791	$ 0.03282	$ 15,413,348	$ 0.03223	$ 15,136,265	$ 0.03386	$ 15,901,766	$ 0.03386	$ 15,901,766
kWh Nov08-Jan09 Rates: (MP customers)				44,804,760	$ 0.03479	$ 1,558,758	$ 0.03223	$ 1,444,057	$ 0.03386	$ 1,517,089	$ 0.03386	$ 1,517,089
kWh Nov08-Jan09 Rates: (GS primary customers)				4,983,030	$ 0.06745	$ 336,105	$ 0.03223	$ 160,603	$ 0.03386	$ 168,725	$ 0.03386	$ 168,725
kWh Feb09-Jun09 Rates:				494,595,476	$ 0.03223	$ 15,940,812	$ 0.03223	$ 15,940,812	$ 0.03386	$ 16,747,003	$ 0.03386	$ 16,747,003
kWh Jul09-Oct09 Rates:				522,765,025	$ 0.03386	$ 17,700,824	$ 0.03386	$ 17,700,824	$ 0.03386	$ 17,700,824	$ 0.03386	$ 17,700,824
Minimum Billings						$ 621,244		$ 621,129		$ 621,129		$ 621,129
TOTAL - Primary	5,121	3,843,533		1,536,781,082		$ 79,556,003		$ 79,291,811		$ 80,944,657		$ 87,747,710
POWER SERVICE RATE PS-Secondary (consists of former rate LP-Secondary)												
Customers For the 12 Month Period	99,144				$ 75.00	$ 7,435,800	$ 75.00	$ 7,435,800	$ 75.00	$ 7,435,800	$ 75.00	$ 7,435,800
kW Demand Nov08-Jan09 Rates:		3,062,320			$ 7.65	$ 23,426,746	$ 7.65	$ 23,426,746	$ 7.65	$ 23,426,746	$ 9.42	$ 28,847,053
kW Demand Feb09-Jun09 Rates:		3,030,011			$ 7.65	$ 23,179,584	$ 7.65	$ 23,179,584	$ 7.65	$ 23,179,584	$ 9.42	$ 28,542,704
kW Demand Jul09-Oct09 Rates:		3,140,755			$ 7.65	$ 24,026,776	$ 7.65	$ 24,026,776	$ 7.65	$ 24,026,776	$ 9.42	$ 29,585,912
kWh Nov08-Jan09 Rates:				1,108,142,118	$ 0.03282	$ 36,369,224	$ 0.03223	$ 35,715,420	$ 0.03386	$ 37,521,692	$ 0.03386	$ 37,521,692
kWh Feb09-Jun09 Rates:				1,323,528,959	$ 0.03223	$ 42,657,338	$ 0.03223	$ 42,657,338	$ 0.03386	$ 44,814,691	$ 0.03386	$ 44,814,691
kWh Jul09-Oct09 Rates:				957,867,411	$ 0.03386	$ 32,433,391	$ 0.03386	$ 32,433,391	$ 0.03386	$ 32,433,391	$ 0.03386	$ 32,433,391
Minimum Billings						$ 1,724,639		$ 1,724,442		$ 1,724,442		$ 1,724,442
TOTAL - Secondary	99,144	9,233,086		3,389,538,488		$ 191,253,498		$ 190,599,497		$ 194,563,122		$ 210,905,683
TOTAL POWER SERVICE RATE PS	104,265	13,076,618		4,926,319,570		$ 270,809,501		$ 269,891,308		$ 275,507,779		$ 298,653,393

KENTUCKY UTILITIES COMPANY

Calculations Showing the Effect on Base Rate Revenue of PSC 14, the Fuel Adjustment Clause Roll-in and the Environmental Cost Recovery Roll-in for a Full Year

Based on Sales for the 12 months ended October 31, 2009

	Customers 12 Mo End Oct 2009	Basic Demand	Peak Demand	kWh's	"As Billed Rates" During 12 Month Period Unit Charges	"As Billed Rates" During 12 Month Period Calculated Revenue	P.S.C. 14 for Full Year Unit Charges	P.S.C. 14 for Full Year Calculated Revenue	FAC Roll-in Rates for Full Year Unit Charges	FAC Roll-in Rates for Full Year Calculated Revenue	"Current Rates" ECR Roll-in Rates for Full Year Unit Charges	"Current Rates" ECR Roll-in Rates for Full Year Calculated Revenue
POWER SERVICE TIME OF DAY RATE TOD-Primary (includes former rate STOD Primary)												
Customers For the 12 Month Period	180				$ 120.00	$ 21,600	$ 120.00	$ 21,600	$ 120.00	$ 21,600	$ 120.00	$ 21,600
Customers For the 12 Month Period former STOD customers	7				$ 90.00	$ 630	$ 120.00	$ 840	$ 120.00	$ 840	$ 120.00	$ 840
kW Basic Demand Nov08-Jan09 Rates: former STOD customers		5,852			$ -	$ -	$ 1.27	$ 7,432	$ 1.27	$ 7,432	$ 2.25	$ 13,167
kW Basic Demand Feb09-Jun09 Rates:		115,859			$ 1.27	$ 147,141	$ 1.27	$ 147,141	$ 1.27	$ 147,141	$ 2.25	$ 260,684
kW Basic Demand Jul09-Oct09 Rates:		114,562			$ 1.27	$ 145,494	$ 1.27	$ 145,494	$ 1.27	$ 145,494	$ 2.25	$ 257,765
kW Peak Demand Nov08-Jan09 Rates: former STOD customers			7,622		$ 7.26	$ 55,332	$ 6.00	$ 45,729	$ 6.00	$ 45,729	$ 6.98	$ 53,198
kW Peak Demand Feb09-Jun09 Rates:			101,078		$ 6.00	$ 606,468	$ 6.00	$ 606,468	$ 6.00	$ 606,468	$ 6.98	$ 705,524
kW Peak Demand Jul09-Oct09 Rates:			109,461		$ 6.00	$ 656,766	$ 6.00	$ 656,766	$ 6.00	$ 656,766	$ 6.98	$ 764,038
kWh Nov08-Jan09 Rates: former STOD-P customers, Peak Energy				2,155,598	$ 0.03879	$ 83,616	$ 0.03223	$ 69,475	$ 0.03386	$ 72,989	$ 0.03386	$ 72,989
kWh Nov08-Jan09 Rates: former STOD-P customers, Off-Peak Energy				2,209,602	$ 0.02596	$ 57,361	$ 0.03223	$ 71,215	$ 0.03386	$ 74,817	$ 0.03386	$ 74,817
kWh Feb09-Jun09 Rates:				26,985,860	$ 0.03223	$ 869,754	$ 0.03223	$ 869,754	$ 0.03386	$ 913,741	$ 0.03386	$ 913,741
kWh Jul09-Oct09 Rates:				32,348,780	$ 0.03386	$ 1,095,330	$ 0.03386	$ 1,095,330	$ 0.03386	$ 1,095,330	$ 0.03386	$ 1,095,330
Minimum billings						$ (186,899)		$ (186,884)		$ (186,884)		$ (186,884)
TOTAL - TOD Primary	187	230,421	218,160	63,699,840		$ 3,552,593		$ 3,550,360		$ 3,601,463		$ 4,046,807
POWER SERVICE TIME OF DAY RATE TOD-Secondary (includes former rate STOD Secondary)												
Customers For the 12 Month Period	494				$ 90.00	$ 44,460	$ 90.00	$ 44,460	$ 90.00	$ 44,460	$ 90.00	$ 44,460
Customers For the 12 Month Period former STOD customers	163				$ 90.00	$ 14,670	$ 90.00	$ 14,670	$ 90.00	$ 14,670	$ 90.00	$ 14,670
kW Basic Demand Nov08-Jan09 Rates: former STOD customers		62,911			$ -	$ -	$ 1.27	$ 79,897	$ 1.27	$ 79,897	$ 2.25	$ 141,550
kW Basic Demand Feb09-Jun09 Rates:		131,301			$ 1.27	$ 166,752	$ 1.27	$ 166,752	$ 1.27	$ 166,752	$ 2.25	$ 295,426
kW Basic Demand Jul09-Oct09 Rates:		170,356			$ 1.27	$ 216,352	$ 1.27	$ 216,352	$ 1.27	$ 216,352	$ 2.25	$ 383,301
kW Peak Demand Nov08-Jan09 Rates: former STOD customers			84,907		$ 7.65	$ 649,541	$ 6.39	$ 542,558	$ 6.39	$ 542,558	$ 7.37	$ 625,767
kW Peak Demand Feb09-Jun09 Rates:			130,987		$ 6.39	$ 837,009	$ 6.39	$ 837,009	$ 6.39	$ 837,009	$ 7.37	$ 965,377
kW Peak Demand Jul09-Oct09 Rates:			176,335		$ 6.39	$ 1,126,781	$ 6.39	$ 1,126,781	$ 6.39	$ 1,126,781	$ 7.37	$ 1,299,589
kWh Nov08-Jan09 Rates: former STOD-S customers, Peak Energy				21,064,040	$ 0.03879	$ 817,074	$ 0.03223	$ 678,894	$ 0.03386	$ 713,228	$ 0.03386	$ 713,228
kWh Nov08-Jan09 Rates: former STOD-S customers, Off-Peak Energy				24,964,908	$ 0.02596	$ 648,089	$ 0.03223	$ 804,619	$ 0.03386	$ 845,312	$ 0.03386	$ 845,312
kWh Feb09-Jun09 Rates:				67,374,034	$ 0.03223	$ 2,171,465	$ 0.03223	$ 2,171,465	$ 0.03386	$ 2,281,285	$ 0.03386	$ 2,281,285
kWh Jul09-Oct09 Rates:				84,255,730	$ 0.03386	$ 2,852,899	$ 0.03386	$ 2,852,899	$ 0.03386	$ 2,852,899	$ 0.03386	$ 2,852,899
Minimum billings						$ 228,754		$ 228,799		$ 228,799		$ 228,799
TOTAL - TOD Secondary	657	301,657	392,230	197,658,712		$ 9,773,846		$ 9,765,155		$ 9,950,002		$ 10,691,663
TOTAL RATE TOD	657	301,657	568,565	-		$ 13,326,439		$ 13,315,515		$ 13,551,465		$ 14,738,470

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	Customers 12 Mo End Oct 2009	Basic Demand	Peak Demand	kWh's	"As Billed Rates" During 12 Month Period: Unit Charges	"As Billed Rates" During 12 Month Period: Calculated Revenue	P.S.C. 14 for Full Year: Unit Charges	P.S.C. 14 for Full Year: Calculated Revenue	FAC Roll-in Rates for Full Year: Unit Charges	FAC Roll-in Rates for Full Year: Calculated Revenue	"Current Rates" ECR Roll-in Rates for Full Year: Unit Charges	"Current Rates" ECR Roll-in Rates for Full Year: Calculated Revenue
LARGE TIME OF DAY SERVICE – PRIMARY DELIVERY (Includes former rates LCI-TOD-P and LMP-TOD-P)												
Customers For the Period Through Jan 2009 former LCI-TOD billing	143				$ 120.00	$ 17,160	$ 120.00	$ 17,160	$ 120.00	$ 17,160	$ 120.00	$ 17,160
Customers For the Period Through Jan 2009 former LMPT	11				$ 120.00	$ 1,320	$ 120.00	$ 1,320	$ 120.00	$ 1,320	$ 120.00	$ 1,320
Customers For the 12 Month Period current RTS billing	340				$ 120.00	$ 40,800	$ 120.00	$ 40,800	$ 120.00	$ 40,800	$ 120.00	$ 40,800
kW Basic Demand Nov08-Jan09 Rates: (former LCI-TOD billing)		1,414,233			$ 1.27	$ 1,796,075	$ 1.27	$ 1,796,075	$ 1.27	$ 1,796,075	$ 2.22	$ 3,139,596
kW Basic Demand Nov08-Jan09 Rates: (former LMP-TOD billing)		86,376			$ 1.13	$ 97,605	$ 1.27	$ 109,697	$ 1.27	$ 109,697	$ 2.22	$ 191,754
kVa Basic Demand Nov08-Jan09 Rates: (current LTOD billing)		-			$ -	$ -	$ 1.27	$ -	$ 1.27	$ -	$ 2.22	$ -
kVa Basic Demand Feb09-Jun09 Rates:		1,728,077			$ 1.27	$ 2,194,658	$ 1.27	$ 2,194,658	$ 1.27	$ 2,194,658	$ 2.22	$ 3,836,331
kVa Basic Demand Jul09-Oct09 Rates:		1,877,719			$ 1.27	$ 2,384,703	$ 1.27	$ 2,384,703	$ 1.27	$ 2,384,703	$ 2.22	$ 4,168,536
kW Peak Demand Nov08-Jan09 Rates: (former LCI-TOD billing)			1,446,449		$ 5.12	$ 7,405,820	$ 5.12	$ 7,405,820	$ 5.12	$ 7,405,820	$ 6.07	$ 8,779,946
kW Peak Demand Nov08-Jan09 Rates: (former LMP-TOD billing)			91,315		$ 5.79	$ 528,713	$ 5.12	$ 467,532	$ 5.12	$ 467,532	$ 6.07	$ 554,281
kVa Peak Demand Nov08-Jan09 Rates: (current LTOD billing)			-		$ -	$ -	$ 5.12	$ -	$ 5.12	$ -	$ 6.07	$ -
kVa Peak Demand Feb09-Jun09 Rates:			1,721,090		$ 5.12	$ 8,811,979	$ 5.12	$ 8,811,979	$ 5.12	$ 8,811,979	$ 6.07	$ 10,447,014
kVa Peak Demand Jul09-Oct09 Rates:			1,877,836		$ 5.12	$ 9,614,520	$ 5.12	$ 9,614,520	$ 5.12	$ 9,614,520	$ 6.07	$ 11,398,465
kWh Nov08-Jan09 Rates: (former LCI-TOD billing)				692,875,277	$ 0.03282	$ 22,740,167	$ 0.03223	$ 22,331,370	$ 0.03386	$ 23,460,757	$ 0.03386	$ 23,460,757
kWh Nov08-Jan09 Rates: (former LMP-TOD billing)				27,846,000	$ 0.03082	$ 858,214	$ 0.03223	$ 897,477	$ 0.03386	$ 942,866	$ 0.03386	$ 942,866
kWh Nov08-Jan09 Rates: (current LTOD billing)				-	$ -	$ -	$ 0.03223	$ -	$ 0.03386	$ -	$ 0.03386	$ -
kWh Feb09-Jun09 Rates:				825,309,684	$ 0.03223	$ 26,599,731	$ 0.03223	$ 26,599,731	$ 0.03386	$ 27,944,986	$ 0.03386	$ 27,944,986
kWh Jul09-Oct09 Rates:				922,030,472	$ 0.03386	$ 31,219,952	$ 0.03386	$ 31,219,952	$ 0.03386	$ 31,219,952	$ 0.03386	$ 31,219,952
Minimum billings						$ (23,687)		$ (23,687)		$ (23,687)		$ (23,687)
TOTAL - Large Primary Time of Day	494	5,106,405	5,136,690	2,468,061,433		$ 114,287,730		$ 113,869,107		$ 116,389,138		$ 126,120,077
Interruptible Credits						$ (126,145)		$ (126,145)		$ (126,145)		$ (126,145)

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Based on Sales for the 12 months ended October 31, 2009

					"As Billed Rates" During 12 Month Period		P.S.C. 14 for Full Year		FAC Roll-in Rates for Full Year		"Current Rates" ECR Roll-in Rates for Full Year	
	Customers 12 Mo End Oct 2009	Basic Demand	Peak Demand	kWh's	Unit Charges	Calculated Revenue	Unit Charges	Calculated Revenue	Unit Charges	Calculated Revenue	Unit Charges	Calculated Revenue
RETAIL TRANSMISSION SERVICE TIME OF DAY (Includes former rates LP-T, LCI-TOD, MPT, and LMPT)												
Customers For the Period Through Jan 2009 former LPT billing	8				$ 75.00	$ 600	$ 120.00	$ 960	$ 120.00	$ 960	$ 120.00	$ 960
Customers For the Period Through Jan 2009 former LCI-TOD billing	24				$ 120.00	$ 2,880	$ 120.00	$ 2,880	$ 120.00	$ 2,880	$ 120.00	$ 2,880
Customers For the 12 Month Period former MPT billing	41				$ 75.00	$ 3,075	$ 120.00	$ 4,920	$ 120.00	$ 4,920	$ 120.00	$ 4,920
Customers For the Period Through Jan 2009 former LMPT	19				$ 120.00	$ 2,280	$ 120.00	$ 2,280	$ 120.00	$ 2,280	$ 120.00	$ 2,280
Customers For the 12 Month Period current RTS billing	272				$ 120.00	$ 32,640	$ 120.00	$ 32,640	$ 120.00	$ 32,640	$ 120.00	$ 32,640
kW Basic Demand Nov08-Jan09 Rates: (former LPT billing)		-			$ -	$ -	$ 1.13	$ -	$ 1.13	$ -	$ 1.92	$ -
kW Basic Demand Nov08-Jan09 Rates: (former LCI-TOD billing)		463,643			$ 1.27	$ 588,827	$ 1.13	$ 523,917	$ 1.13	$ 523,917	$ 1.92	$ 890,195
kW Basic Demand Nov08-Jan09 Rates: (former MPT billing)		-			$ -	$ -	$ 1.13	$ -	$ 1.13	$ -	$ 1.92	$ -
kW Basic Demand Nov08-Jan09 Rates: (former LMP-TOD billing)		183,205			$ 1.13	$ 207,022	$ 1.13	$ 207,022	$ 1.13	$ 207,022	$ 1.92	$ 351,753
kVa Basic Demand Nov08-Jan09 Rates: (current RTS billing)		-			$ -	$ -	$ 1.13	$ -	$ 1.13	$ -	$ 1.92	$ -
kVa Basic Demand Feb09-Jun09 Rates:		1,127,476			$ 1.13	$ 1,274,048	$ 1.13	$ 1,274,048	$ 1.13	$ 1,274,048	$ 1.92	$ 2,164,754
kVa Basic Demand Jul09-Oct09 Rates:		1,231,654			$ 1.13	$ 1,391,769	$ 1.13	$ 1,391,769	$ 1.13	$ 1,391,769	$ 1.92	$ 2,364,776
kW Peak Demand Nov08-Jan09 Rates: (former LPT billing)			22,639		$ 6.92	$ 156,660	$ 4.39	$ 99,384	$ 4.39	$ 99,384	$ 5.18	$ 117,268
kW Peak Demand Nov08-Jan09 Rates: (former LCI-TOD billing)			513,963		$ 4.93	$ 2,533,840	$ 4.39	$ 2,256,300	$ 4.39	$ 2,256,300	$ 5.18	$ 2,662,331
kW Peak Demand Nov08-Jan09 Rates: (former MPT billing)			84,369		$ 5.33	$ 449,685	$ 4.39	$ 370,378	$ 4.39	$ 370,378	$ 5.18	$ 437,029
kW Peak Demand Nov08-Jan09 Rates: (former LMP-TOD billing)			188,354		$ 5.25	$ 988,858	$ 4.39	$ 826,874	$ 4.39	$ 826,874	$ 5.18	$ 975,673
kVa Peak Demand Nov08-Jan09 Rates: (current RTS billing)			-		$ -	$ -	$ 4.39	$ -	$ 4.39	$ -	$ 5.18	$ -
kVa Peak Demand Feb09-Jun09 Rates:			1,128,955		$ 4.39	$ 4,956,114	$ 4.39	$ 4,956,114	$ 4.39	$ 4,956,114	$ 5.18	$ 5,847,989
kVa Peak Demand Jul09-Oct09 Rates:			1,238,924		$ 4.39	$ 5,438,876	$ 4.39	$ 5,438,876	$ 4.39	$ 5,438,876	$ 5.18	$ 6,417,626
kWh Nov08-Jan09 Rates: (former LPT billing)				9,851,150	$ 0.03282	$ 323,315	$ 0.03223	$ 317,503	$ 0.03386	$ 333,560	$ 0.03386	$ 333,560
kWh Nov08-Jan09 Rates: (former LCI-TOD billing)				219,340,464	$ 0.03282	$ 7,198,754	$ 0.03223	$ 7,069,343	$ 0.03386	$ 7,426,868	$ 0.03386	$ 7,426,868
kWh Nov08-Jan09 Rates: (former MPT billing)				28,312,000	$ 0.03479	$ 984,974	$ 0.03223	$ 912,496	$ 0.03386	$ 958,644	$ 0.03386	$ 958,644
kWh Nov08-Jan09 Rates: (former LMP-TOD billing)				74,364,000	$ 0.03082	$ 2,291,898	$ 0.03223	$ 2,396,752	$ 0.03386	$ 2,517,965	$ 0.03386	$ 2,517,965
kWh Nov08-Jan09 Rates: (current RTS billing)				-	$ -	$ -	$ 0.03223	$ -	$ 0.03386	$ -	$ 0.03386	$ -
kWh Feb09-Jun09 Rates:				434,188,756	$ 0.03223	$ 13,993,904	$ 0.03223	$ 13,993,904	$ 0.03386	$ 14,701,631	$ 0.03386	$ 14,701,631
kWh Jul09-Oct09 Rates:				521,660,642	$ 0.03386	$ 17,663,429	$ 0.03386	$ 17,663,429	$ 0.03386	$ 17,663,429	$ 0.03386	$ 17,663,429
Minimum billings						$ (51,256)		$ (51,392)		$ (51,392)		$ (51,392)
TOTAL - Retail Transmission Service	364	3,005,978	3,177,204	1,287,717,012		$ 60,432,192		$ 59,690,397		$ 60,939,067		$ 65,823,782

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Based on Sales for the 12 months ended October 31, 2009

	Customers 12 Mo End Oct 2009	Basic Demand	Peak Demand	kWh's	"As Billed Rates" During 12 Month Period: Unit Charges	"As Billed Rates" During 12 Month Period: Calculated Revenue	P.S.C. 14 for Full Year: Unit Charges	P.S.C. 14 for Full Year: Calculated Revenue	FAC Roll-in Rates for Full Year: Unit Charges	FAC Roll-in Rates for Full Year: Calculated Revenue	"Current Rates" ECR Roll-in Rates for Full Year: Unit Charges	"Current Rates" ECR Roll-in Rates for Full Year: Calculated Revenue
INDUSTRIAL SERVICE TIME OF DAY Rate IS (Former Rate LI-TOD)												
Customers For the 12 Month Period former LITOD billing	4				$ 120.00	$ 480	$ 120.00	$ 480	$ 120.00	$ 480	$ 120.00	$ 480
Customers For the 12 Month Period	8				$ 120.00	$ 960	$ 120.00	$ 960	$ 120.00	$ 960	$ 120.00	$ 960
kVa Basic Demand Nov08-Jan09 Rates: (former LITOD billing)		576,090			$ 0.93	$ 535,764	$ 0.93	$ 535,764	$ 0.93	$ 535,764	$ 1.37	$ 789,244
kVa Basic Demand Feb09-Jun09 Rates:		651,925			$ 0.93	$ 606,290	$ 0.93	$ 606,290	$ 0.93	$ 606,290	$ 1.37	$ 893,138
kVa Basic Demand Jul09-Oct09 Rates:		598,636			$ 0.93	$ 556,731	$ 0.93	$ 556,731	$ 0.93	$ 556,731	$ 1.37	$ 820,131
Minimum basic demand charges						$ 21,289		$ 21,289		$ 21,289		$ 21,289
kVa Basic Fluctuating Demand Nov08-Jan09 Rates: (former LITOD billing)		-			$ 0.37	$ -	$ 0.37	$ -	$ 0.37	$ -	$ 0.81	$ -
kVa Basic Fluctuating Demand Feb09-Jun09 Rates:		16,735			$ 0.37	$ 6,192	$ 0.37	$ 6,192	$ 0.37	$ 6,192	$ 0.81	$ 13,556
kVa Basic Fluctuating Demand Jul09-Oct09 Rates:		40,705			$ 0.37	$ 15,061	$ 0.37	$ 15,061	$ 0.37	$ 15,061	$ 0.81	$ 32,971
						$ 9,590		$ 9,590		$ 9,590		$ 9,590
kVa Peak Demand Nov08-Jan09 Rates: (former LITOD billing)			327,809		$ 4.58	$ 1,501,365	$ 4.58	$ 1,501,365	$ 4.58	$ 1,501,365	$ 5.02	$ 1,645,601
kVa Peak Demand Feb09-Jun09 Rates:			337,834		$ 4.58	$ 1,547,278	$ 4.58	$ 1,547,278	$ 4.58	$ 1,547,278	$ 5.02	$ 1,695,925
kVa Peak Demand Jul09-Oct09 Rates:			336,101		$ 4.58	$ 1,539,343	$ 4.58	$ 1,539,343	$ 4.58	$ 1,539,343	$ 5.02	$ 1,687,227
Minimum Peak Demand Charges						$ 462,263		$ 462,263		$ 462,263		$ 462,263
kVa Peak Fluctuating Demand Nov08-Jan09 Rates: (former LITOD billing)			-		$ 2.20	$ -	$ 2.20	$ -	$ 2.20	$ -	$ 2.64	$ -
kVa Peak Fluctuating Demand Feb09-Jun09 Rates:			30,621		$ 2.20	$ 67,366	$ 2.20	$ 67,366	$ 2.20	$ 67,366	$ 2.64	$ 80,839
kVa Peak Fluctuating Demand Jul09-Oct09 Rates:			57,921		$ 2.20	$ 127,427	$ 2.20	$ 127,427	$ 2.20	$ 127,427	$ 2.64	$ 152,912
Minimum Peak Fluctuating Demand Charges						$ 17,037		$ 17,037		$ 17,037		$ 17,037
kWh Nov08-Jan09 Rates: (former LITOD billing)				75,297,600	$ 0.03280	$ 2,469,761	$ 0.02767	$ 2,083,485	$ 0.02930	$ 2,206,220	$ 0.02930	$ 2,206,220
kWh Feb09-Jun09 Rates:				95,735,520	$ 0.02767	$ 2,649,002	$ 0.02767	$ 2,649,002	$ 0.02930	$ 2,805,051	$ 0.02930	$ 2,805,051
kWh Jul09-Oct09 Rates:				161,136,000	$ 0.02930	$ 4,721,285	$ 0.02930	$ 4,721,285	$ 0.02930	$ 4,721,285	$ 0.02930	$ 4,721,285
Minimum energy billings						$ 20,649		$ 19,119		$ 19,119		$ 19,119
TOTAL - Industrial Service	12	1,826,652	1,001,744	332,169,120		$ 16,875,133		$ 16,487,327		$ 16,766,111		$ 18,074,837
Interruptible Credits						$ (5,515,286)		$ (5,515,286)		$ (5,515,286)		$ (5,515,286)

KENTUCKY UTILITIES COMPANY

Calculations Showing the Effect on Base Rate Revenue of PSC 14, the Fuel Adjustment Clause Roll-in and the Environmental Cost Recovery Roll-in for a Full Year
Based on Sales for the 12 months ended October 31, 2009

	Customers 12 Mo End Oct 2009	Basic Demand	Peak Demand	kWh's	"As Billed Rates" During 12 Month Period Unit Charges	Calculated Revenue	P.S.C. 14 for Full Year Unit Charges	Calculated Revenue	FAC Roll-in Rates for Full Year Unit Charges	Calculated Revenue	"Current Rates" ECR Roll-in Rates for Full Year Unit Charges	Calculated Revenue
LIGHTING ENERGY RATE LE												
Customers	-				$ -	$ -						
kWh Nov08-Jan09 Rates:				-	$ -	$ -	$ 0.04739	$ -	$ 0.04902	$ -	$ 0.05474	$ -
kWh Feb09-Jun09 Rates:				-	$ 0.04739	$ -	$ 0.04739	$ -	$ 0.04902	$ -	$ 0.05474	$ -
kWh Jul09-Oct09 Rates:				-	$ 0.04902	$ -	$ 0.04902	$ -	$ 0.04902	$ -	$ 0.05474	$ -
Minimum billings						$ -		$ -		$ -		$ -
TOTAL RATE LE	-			-		$ -		$ -		$ -		$ -
TRAFFIC LIGHTING ENERGY RATE TE												
Customers	4				$ 2.80	$ 11	$ 2.80	$ 11	$ 2.80	$ 11	$ 2.80	$ 11
kWh Nov08-Jan09 Rates:				-	$ -	$ -	$ 0.05795	$ -	$ 0.05958	$ -	$ 0.06530	$ -
kWh Feb09-Jun09 Rates:				-	$ 0.05795	$ -	$ 0.05795	$ -	$ 0.05958	$ -	$ 0.06530	$ -
kWh Jul09-Oct09 Rates:				8	$ 0.05958	$ -	$ 0.05958	$ -	$ 0.05958	$ -	$ 0.06530	$ 1
						$ 4		$ 4		$ 4		$ 4
TOTAL RATE TE	4			8		$ 15		$ 15		$ 15		$ 16

	Lights at Nov08-Jan09 Rates: rates	Lights at Feb09-Jun09 Rates: rates	Lights at Jul09-Oct09 Rates: rates	Nov08-Jan09 Rates:	Feb09-Jun09 Rates:	Jul09-Oct09 Rates:	Rates Reflecting ECR Roll-in (Case No. 2009-00310)	Revenue for 12 Months Ending October 31, 2009	Revenue Reflecting P.S.C. 14 Rates for a Full Year	Revenue Reflecting FAC Roll-in Rates for a Full Year	Revenue Reflecting ECR Roll-in Rates for a Full Year
STREET LIGHTING SERVICE – RATE St.Lt.											
INCANDESCENT:											
1000 Inc Std StLt	167	219	195	$ 2.76	$ 2.74	$ 2.80	$ 3.04	$ 1,607	$ 1,604	$ 1,627	$ 1,766
2500 Inc Std StLt	3,590	5,683	4,162	$ 3.63	$ 3.61	$ 3.72	$ 4.05	$ 49,030	$ 48,958	$ 49,978	$ 54,412
4000 Inc Std StLt	987	1,440	965	$ 5.35	$ 5.32	$ 5.50	$ 6.15	$ 18,249	$ 18,219	$ 18,656	$ 20,861
6000 Inc Std StLt	9	14	11	$ 7.17	$ 7.13	$ 7.37	$ 8.06	$ 245	$ 245	$ 251	$ 274
1000 Inc Orn StLt	-	-	-	$ 3.42	$ 3.39	$ 3.45	$ 3.69	$ -	$ -	$ -	$ -
2500 Inc Orn StLt	29	35	24	$ 4.47	$ 4.44	$ 4.55	$ 4.84	$ 394	$ 393	$ 400	$ 426
4000 Inc Orn StLt	126	148	132	$ 6.34	$ 6.29	$ 6.47	$ 7.07	$ 2,584	$ 2,578	$ 2,627	$ 2,870
6000 Inc Orn StLt	-	-	-	$ 8.27	$ 8.21	$ 8.45	$ 9.08	$ -	$ -	$ -	$ -
MERCURY VAPOR:											
7000 MV Std StLt	3,932	6,474	5,120	$ 7.74	$ 7.66	$ 7.77	$ 8.55	$ 119,807	$ 119,492	$ 120,637	$ 132,747
10000 MV Std StLt	2,807	3,502	3,510	$ 9.13	$ 9.04	$ 9.20	$ 10.09	$ 89,578	$ 89,325	$ 90,335	$ 99,074
20000 MV Std StLt	4,938	7,323	6,357	$ 11.12	$ 11.03	$ 11.28	$ 12.35	$ 207,390	$ 206,946	$ 210,011	$ 229,932
7000 MV Orn StLt	374	624	537	$ 10.11	$ 10.00	$ 10.11	$ 10.77	$ 15,450	$ 15,409	$ 15,519	$ 16,532
10000 MV Orn StLt	1,656	2,003	2,073	$ 11.24	$ 11.12	$ 11.28	$ 12.06	$ 64,270	$ 64,072	$ 64,657	$ 69,128
20000 MV Orn StLt	4,259	5,834	5,680	$ 12.82	$ 12.69	$ 12.94	$ 13.92	$ 202,133	$ 201,579	$ 204,103	$ 219,560
HIGH PRESSURE SODIUM:											
4000 HPS Std StLt	20,899	33,171	27,808	$ 5.48	$ 5.41	$ 5.44	$ 6.05	$ 445,257	$ 443,794	$ 445,416	$ 495,362
5800 HPS Std StLt	25,580	38,855	35,964	$ 6.02	$ 5.95	$ 6.00	$ 6.84	$ 600,963	$ 599,172	$ 602,394	$ 686,729
9500 HPS Std StLt	59,700	96,813	79,764	$ 6.86	$ 6.78	$ 6.84	$ 7.40	$ 1,611,520	$ 1,606,744	$ 1,616,135	$ 1,748,450
22000 HPS Std StLt	16,905	26,915	22,784	$ 10.38	$ 10.27	$ 10.40	$ 11.42	$ 688,845	$ 686,985	$ 692,682	$ 760,618
50000 HPS Std StLt	2,543	4,085	3,373	$ 17.09	$ 16.92	$ 17.18	$ 17.29	$ 170,526	$ 170,094	$ 171,817	$ 172,917
4000 HPS Orn StLt	11,614	15,312	15,363	$ 8.24	$ 8.13	$ 8.16	$ 8.62	$ 345,548	$ 344,270	$ 345,078	$ 364,531
5800 HPS Orn StLt	25,312	33,810	33,840	$ 8.77	$ 8.66	$ 8.71	$ 9.41	$ 809,527	$ 806,743	$ 809,699	$ 874,772
9500 HPS Orn StLt	8,671	12,601	11,722	$ 9.81	$ 9.68	$ 9.74	$ 10.15	$ 321,212	$ 320,085	$ 321,362	$ 334,889
22000 HPS Orn StLt	13,619	20,542	18,985	$ 13.32	$ 13.17	$ 13.30	$ 14.17	$ 704,444	$ 702,401	$ 706,842	$ 753,079
50000 HPS Orn StLt	1,393	1,939	1,780	$ 20.03	$ 19.81	$ 20.07	$ 20.02	$ 102,038	$ 101,732	$ 102,598	$ 102,342
DECORATIVE UNDERGROUND SERVICE											
HIGH PRESSURE SODIUM:											
4000 HPS Dec Acorn StLt	-	-	-	$ 10.82	$ 10.72	$ 10.75	$ 11.14	$ -	$ -	$ -	$ -
4000 HPS His Acorn StLt	446	744	596	$ 17.38	$ 17.13	$ 17.16	$ 17.15	$ 30,724	$ 30,612	$ 30,648	$ 30,630
5800 HPS Dec Acorn StLt	17	23	24	$ 11.82	$ 11.66	$ 11.71	$ 12.02	$ 750	$ 747	$ 749	$ 769
5800 HPS His Acorn StLt	215	359	288	$ 18.03	$ 17.78	$ 17.83	$ 18.05	$ 15,395	$ 15,341	$ 15,369	$ 15,559
9500 HSP Acorn Dec StLt	434	691	588	$ 12.64	$ 12.48	$ 12.54	$ 12.81	$ 21,483	$ 21,414	$ 21,481	$ 21,944
9500 HPS Historic Acorn StLt	1,256	2,064	1,667	$ 18.86	$ 18.61	$ 18.67	$ 18.62	$ 93,222	$ 92,908	$ 93,107	$ 92,858
4000 HPS Colonial StLt	2,193	3,537	2,875	$ 7.43	$ 7.33	$ 7.36	$ 7.87	$ 63,380	$ 63,161	$ 63,333	$ 67,721
5800 HPS Colonial StLt	2,927	4,639	3,975	$ 7.99	$ 7.89	$ 7.94	$ 8.68	$ 91,550	$ 91,257	$ 91,636	$ 100,176
9500 HPS Colonial StLt	4,731	7,899	6,333	$ 8.74	$ 8.63	$ 8.69	$ 9.16	$ 164,551	$ 164,031	$ 164,788	$ 173,701
5800 HPS Coach Dec StLt	62	83	83	$ 26.74	$ 26.39	$ 26.44	$ 26.22	$ 6,043	$ 6,021	$ 6,028	$ 5,978
9500 HSP Coach Dec StLt	29	39	39	$ 27.49	$ 27.11	$ 27.17	$ 26.67	$ 2,914	$ 2,903	$ 2,907	$ 2,854
5800 HPS Contemporary StLt	12,281	16,445	16,538	$ 13.56	$ 13.38	$ 13.43	$ 13.88	$ 608,670	$ 606,459	$ 607,896	$ 628,264
9500 HPS Contemporary StLt	1,522	2,138	2,080	$ 16.22	$ 16.00	$ 16.06	$ 16.27	$ 92,300	$ 91,965	$ 92,184	$ 93,390
22000 HPS Contemporary StLt	1,416	2,031	1,874	$ 19.20	$ 18.96	$ 19.09	$ 19.65	$ 101,470	$ 101,130	$ 101,578	$ 104,558
50000 HPS Contemporary StLT	164	221	236	$ 25.49	$ 25.19	$ 25.45	$ 25.12	$ 15,754	$ 15,704	$ 15,804	$ 15,600
HPS-16000 Gran Ville	1,001	1,303	1,316	$ 40.81	$ 40.19	$ 40.27	$ 44.78	$ 146,214	$ 145,593	$ 145,777	$ 162,104
Gran Ville Accessories:											
Single Crossarm Bracket	-	-	-	16.28	16.13	16.13	16.13	$ -	$ -	$ -	$ -
Twin Crossarm Bracket	157	210	212	18.12	17.96	17.96	17.96	$ 10,424	$ 10,399	$ 10,399	$ 10,399
24 Inch Banner Arm	66	100	104	2.82	2.80	2.80	2.80	$ 757	$ 756	$ 756	$ 756
24 Inch Clamp Banner Arm	306	406	408	3.90	3.87	3.87	3.87	$ 4,344	$ 4,334	$ 4,334	$ 4,334
18 Inch Banner Arm	160	214	216	2.60	2.58	2.58	2.58	$ 1,525	$ 1,522	$ 1,522	$ 1,522
18 Inch Clamp On Banner Arm	-	-	-	-	3.19	3.19	3.19	$ -	$ -	$ -	$ -
Flagpole Holder	175	240	244	1.20	1.19	1.19	1.19	$ 786	$ 784	$ 784	$ 784
Post-Mounted Receptacle	169	230	236	16.90	16.75	16.75	16.75	$ 10,662	$ 10,636	$ 10,636	$ 10,636
Base-Mounted Receptacle	-	-	-	16.31	16.16	16.16	16.16	$ -	$ -	$ -	$ -
Additional Receptacles	-	-	-	2.31	2.29	2.29	2.29	$ -	$ -	$ -	$ -
Planter	162	217	220	3.91	3.88	3.88	3.88	$ 2,329	$ 2,324	$ 2,324	$ 2,324
Clamp On Planter	-	-	-	-	4.31	4.31	4.31	$ -	$ -	$ -	$ -
Partial Month Charges								$ 2,401	$ 2,401	$ 2,401	$ 2,401
Total Rate StLt								$ 8,058,263	$ 8,033,243	$ 8,079,266	$ 8,690,534

	Lights at Nov08-Jan09 Rates: rates	Lights at Feb09-Jun09 Rates: rates	Lights at Jul09-Oct09 Rates: rates	Nov08-Jan09 Rates:	Feb09-Jun09 Rates:	Jul09-Oct09 Rates:	Rates Reflecting ECR Roll-in (Case No. 2009-00310)	Revenue for 12 Months Ending October 31, 2009	Revenue Reflecting P.S.C. 14 Rates for a Full Year	Revenue Reflecting FAC Roll-in Rates for a Full Year	Revenue Reflecting ECR Roll-in Rates for a Full Year
PRIVATE OUTDOOR LIGHTING Rate POL											
Standard (Served Overhead)											
7000 Open Bottom Mercury Vapor POL	29,619	48,408	38,414	$ 8.77	$ 8.68	$ 8.79	$ 9.52	$ 1,017,599	$ 1,014,933	$ 1,023,516	$ 1,108,518
20000 Cobra Mercury Vapor POL*	1,571	2,569	2,132	$ 11.12	$ 11.03	$ 11.28	$ 12.35	$ 69,855	$ 69,713	$ 70,748	$ 77,459
5800 Open Bottom HPS POL	580	1,054	825	$ 4.87	$ 4.82	$ 4.87	$ 5.77	$ 11,923	$ 11,894	$ 11,975	$ 14,188
9500 Open Bottom HPS POL	102,610	172,346	138,285	$ 5.63	$ 5.57	$ 5.63	$ 6.26	$ 2,316,206	$ 2,310,049	$ 2,326,547	$ 2,586,889
22000 Cobra HPS POL	4,480	7,476	6,128	$ 10.38	$ 10.27	$ 10.40	$ 11.42	$ 187,012	$ 186,519	$ 188,074	$ 206,519
50000 Cobra HPS POL	6,442	10,776	8,588	$ 17.09	$ 16.92	$ 17.18	$ 18.60	$ 439,966	$ 438,870	$ 443,347	$ 479,992
Directional (Served Overhead)											
9500 HPS Directional POL	31,690	52,904	42,488	$ 6.72	$ 6.64	$ 6.70	$ 7.27	$ 848,909	$ 846,374	$ 851,449	$ 923,886
22000 HPS Directional POL	18,579	31,001	24,959	$ 9.81	$ 9.79	$ 9.83	$ 10.88	$ 731,107	$ 730,735	$ 732,718	$ 810,984
50000 HSP Directional POL	23,146	38,150	30,942	$ 15.36	$ 15.20	$ 15.46	$ 15.65	$ 1,413,766	$ 1,410,063	$ 1,425,999	$ 1,443,525
Metal Halide Commercial and Industrial Lighting											
12000 MH Directional Fixture	1,540	2,551	2,063	$ 10.05	$ 9.94	$ 10.05	$ 11.23	$ 61,567	$ 61,398	$ 61,848	$ 69,109
12000 MH Directional Wood Pole	392	666	554	$ 12.12	$ 11.97	$ 12.08	$ 13.15	$ 19,415	$ 19,357	$ 19,473	$ 21,198
12000 MH Directiona Metal Pole	65	97	83	$ 18.85	$ 18.68	$ 18.72	$ 19.45	$ 4,591	$ 4,580	$ 4,586	$ 4,765
32000 MH Directional Fixture	12,605	21,190	17,097	$ 14.54	$ 14.39	$ 14.63	$ 16.11	$ 738,330	$ 736,439	$ 744,550	$ 819,870
32000 MH Directional Wood Pole	2,711	4,604	3,720	$ 16.60	$ 16.43	$ 16.67	$ 18.05	$ 182,659	$ 182,198	$ 183,953	$ 199,182
32000 MH Directional Metal Pole	768	1,254	1,040	$ 23.33	$ 23.06	$ 23.30	$ 24.33	$ 71,067	$ 70,859	$ 71,345	$ 74,498
107800 MH Directional Fixture	3,329	5,507	4,370	$ 30.59	$ 30.30	$ 30.89	$ 33.81	$ 403,686	$ 402,720	$ 407,933	$ 446,495
107800 MH Directional Wood Pole	900	1,354	1,096	$ 33.46	$ 33.13	$ 33.72	$ 36.92	$ 111,929	$ 111,632	$ 112,962	$ 123,682
107800 MH Directional Metal Pole	262	413	314	$ 39.38	$ 38.97	$ 39.56	$ 42.46	$ 38,834	$ 38,727	$ 39,125	$ 41,993
12000 MH Contemporary Fixture	173	283	235	$ 11.20	$ 11.07	$ 11.18	$ 12.30	$ 7,698	$ 7,675	$ 7,725	$ 8,499
12000 MH Contemporary Metal Pole	548	865	740	$ 20.01	$ 19.76	$ 19.87	$ 20.54	$ 42,762	$ 42,625	$ 42,780	$ 44,223
32000 MH Contemporary Fixture	919	1,540	1,223	$ 16.15	$ 15.98	$ 16.22	$ 17.62	$ 59,288	$ 59,132	$ 59,722	$ 64,877
32000 MH Contemporary Metal Pole	1,829	2,997	2,460	$ 24.94	$ 24.65	$ 24.89	$ 25.84	$ 180,721	$ 180,190	$ 181,349	$ 188,270
107800 MH Contemporary Fixture	132	223	185	$ 33.26	$ 32.93	$ 33.52	$ 36.73	$ 17,935	$ 17,891	$ 18,101	$ 19,834
107800 MH Contemporary Metal Pole	443	732	589	$ 42.06	$ 41.61	$ 42.20	$ 44.96	$ 73,947	$ 73,748	$ 74,441	$ 79,309
Decorative High Pressure Sodium (Served Underground)											
4000 HPS Decorative Acorn	5	8	8	$ 11.16	$ 11.01	$ 11.04	$ 11.35	$ 232	$ 231	$ 232	$ 238
4000 HPS Historic Acorn	185	309	248	$ 17.38	$ 17.13	$ 17.16	$ 17.15	$ 12,764	$ 12,718	$ 12,733	$ 12,725
5800 HPS Decorative Acorn	104	140	176	$ 11.82	$ 11.66	$ 11.71	$ 12.25	$ 4,923	$ 4,906	$ 4,918	$ 5,145
5800 HPS Historic Acorn	221	368	296	$ 18.03	$ 17.78	$ 17.73	$ 17.95	$ 15,776	$ 15,721	$ 15,691	$ 15,886
9500 HPS Decorative Acorn	787	1,090	978	$ 12.66	$ 12.48	$ 12.56	$ 12.82	$ 35,850	$ 35,709	$ 35,859	$ 36,601
9500 HPS Historic Acorn	1,996	2,722	2,364	$ 18.86	$ 18.61	$ 18.67	$ 18.62	$ 132,437	$ 131,938	$ 132,221	$ 131,867
4000 HPS Colonial Decorative	191	319	285	$ 7.43	$ 7.33	$ 7.36	$ 7.87	$ 5,855	$ 5,836	$ 5,851	$ 6,257
5800 HPS Colonial Decorative	530	857	682	$ 7.99	$ 7.89	$ 7.94	$ 8.68	$ 16,412	$ 16,359	$ 16,428	$ 17,959
9500 HPS Colonial Decorative	5,185	8,585	6,799	$ 8.74	$ 8.63	$ 8.69	$ 9.16	$ 178,489	$ 177,918	$ 178,745	$ 188,412
5800 HPS Coach Dec POL	71	119	108	$ 26.74	$ 26.38	$ 26.43	$ 26.21	$ 7,892	$ 7,867	$ 7,876	$ 7,811
9500 HPS Coach Dec POL	859	1,414	1,067	$ 27.49	$ 27.11	$ 27.17	$ 26.67	$ 90,938	$ 90,611	$ 90,748	$ 89,078
5800 HPS Contemporary Decorative	152	184	175	$ 13.56	$ 13.38	$ 13.43	$ 13.88	$ 6,873	$ 6,846	$ 6,863	$ 7,093
9500 HPS Contemporary Decorative	941	1,500	1,326	$ 16.22	$ 16.00	$ 16.06	$ 16.14	$ 60,559	$ 60,352	$ 60,498	$ 60,799
22000 HPS Contemporary Decorative	2,091	3,331	2,854	$ 19.20	$ 18.96	$ 19.09	$ 19.65	$ 157,786	$ 157,284	$ 157,989	$ 162,623
50000 HPS Contemporary Decorative	2,565	4,228	3,445	$ 25.49	$ 25.19	$ 25.45	$ 25.12	$ 259,560	$ 258,791	$ 260,557	$ 257,179
HPS-16000 Gran Ville POL	26	44	36	$ 40.81	$ 40.19	$ 40.27	$ 44.77	$ 4,279	$ 4,263	$ 4,269	$ 4,746
Special Contract Lighting											
20000 MV Special Lighting	1,356	2,065	1,742	$ 6.88	$ 6.85	$ 6.95	$ 7.63	$ 35,581	$ 35,541	$ 35,883	$ 39,394
50000 HPS Special Lighting	631	706	659	$ 9.18	$ 9.13	$ 9.23	$ 9.80	$ 18,321	$ 18,289	$ 18,423	$ 19,561
Partial Month Billings								$ (22,770)	$ (22,770)	$ (22,770)	$ (22,770)
Total Rate POL								$ 10,072,526	$ 10,046,730	$ 10,127,280	$ 10,898,368

KENTUCKY UTILITIES COMPANY
Adjustment to Reflect FAC Billings for a Full Year of the Roll-in
12 Months Ended October 31, 2009

BASE RATE ACTUAL FUEL ADJUSTMENT CLAUSE BILLINGS

	January-09	February-09	March-09	April-09	May-09	June-09	July-09	August-09	September-09	October-09	November-08	December-08	TOTAL 12 Mos. Ended
FAC RATE CHARGED:	0.00244	0.00409	0.00317	0.00584	0.00385	0.00225	(0.00087)	0.00363	0.00113	0.00180	0.00559	0.00163	
Residential Rate													
Residential Rate RS	728,583	1,583,686	1,641,608	2,827,582	1,339,781	998,745	(451,501)	1,777,367	532,072	675,536	1,009,533	430,039	13,093,031
Residential Rate FERS	1,129,180	1,277,586	-	-	-	-	-	-	-	-	1,232,392	646,054	4,285,211
	1,857,763	2,861,271	1,641,608	2,827,582	1,339,781	998,745	(451,501)	1,777,367	532,072	675,536	2,241,925	1,076,093	17,378,242
General Service													
General Service Secondary	426,243	691,335	441,563	878,806	493,186	341,595	(137,056)	551,111	179,824	242,851	722,456	268,587	5,100,500
All Electric School Rate AES	32,966	53,750	35,137	59,878	38,804	24,883	(496)	27,452	15,119	17,438	57,081	21,550	383,563
Power Service Rate													
Power Service Rate PSS - Secondary	-	-	752,645	1,637,594	1,026,043	1,253,850	(767,861)	1,030,509	391,786	491,906	-	-	5,816,471
Power Service Rate PSP - Primary	-	2,025	357,159	768,739	455,009	318,406	(88,751)	453,651	167,197	218,081	-	-	2,651,515
General Service Primary (moved to rate PSP)	8,027	5,567	-	-	-	-	-	-	-	-	21,603	(36,490)	(1,293)
Large Power Rate LPS - Secondary (moved to rate PSS with PSC 14)	700,050	1,100,111	-	-	-	-	-	-	-	-	1,485,075	465,210	3,750,446
Large Power Rate LPP - Primary (moved to rate PSP with PSC 14	253,021	492,459	-	-	-	-	-	-	-	-	637,396	238,245	1,621,122
Mining Power Service Rate MP-Primary (moved to rate PSP with PSC 14)	28,909	40,935	-	-	-	-	-	-	-	-	57,717	20,474	148,035
	990,007	1,641,097	1,109,804	2,406,333	1,481,052	1,572,256	(856,613)	1,484,160	558,982	709,987	2,201,792	687,439	13,986,297
Time of Day Power Rate													
Time-of-Day Service - TODS Secondary	-	9,549	15,188	37,272	19,376	20,626	(7,249)	25,717	12,189	16,437	-	-	149,104
Time-of-Day Service - TODP Primary	-	30,821	35,244	89,899	51,615	45,366	(20,248)	74,881	25,369	38,225	-	-	371,173
Small Time-of-Day - STODS Secondary (moved to rate TODS with PSC 14)	32,606	22,042	-	-	-	-	-	-	-	-	73,582	22,220	150,450
Small Time-of-Day - STODP Primary (moved to rate TODP with PSC 14)	2,763	3,364	-	-	-	-	-	-	-	-	6,167	2,131	14,424
	35,369	65,775	50,432	127,171	70,990	65,992	(27,497)	100,598	37,558	54,662	79,749	24,351	685,150
Large Power Time of Day Rate													
Large Time-of-Day Primary Service - LTOD Primary	-	230,703	552,202	1,056,338	788,204	523,228	(110,149)	618,470	374,790	406,242	-	-	4,440,029
Large Comm./Industrial Time-of-Day - LCI-TOD Primary (moved to rate LTOD with PSC 14)	422,731	441,941	-	-	-	-	-	-	-	-	1,115,294	363,127	2,343,093
Large Mining Power Service Time of Day RateL LMP TOD-Primary (moved to rate LTOD with PSC 14)	16,477	26,511	-	-	-	-	-	-	-	-	39,822	12,090	94,900
	439,209	699,154	552,202	1,056,338	788,204	523,228	(110,149)	618,470	374,790	406,242	1,155,116	375,217	6,878,022
Retail Transmission Service	-	146,024	289,288	626,954	386,563	229,263	(83,313)	420,803	140,265	261,555	-	-	2,417,403
Large Power Rate LPT - Transmission (moved to rate RTS with PSC 14)	6,019	12,406	-	-	-	-	-	-	-	-	10,459	4,014	32,899
Mining Power Service Rate - MP Transmission (moved to rate RTS with PSC 14)	23,444	7,133	-	-	-	-	-	-	-	-	44,278	14,734	89,588
Large Comm./Industrial Time-of-Day - LCI-TOD Transmission	151,385	187,870	-	-	-	-	-	-	-	-	335,679	85,056	759,990
Large Mining Power Service Time of Day Rate - LMP TOD Transmission (moved to rate RTS with PSC 14)	49,044	24,648	-	-	-	-	-	-	-	-	125,674	38,778	238,145
	229,892	378,081	289,288	626,954	386,563	229,263	(83,313)	420,803	140,265	261,555	516,091	142,581	3,538,024
Industrial Service Rate	-	-	81,632	127,405	80,665	61,236	(27,624)	147,407	48,084	83,203	-	-	602,009
	38,932	83,149	-	-	-	-	-	-	-	-	119,935	28,617	270,634
	38,932	83,149	81,632	127,405	80,665	61,236	(27,624)	147,407	48,084	83,203	119,935	28,617	872,643
Lighting Rates													
Outdoor Lighting Service -- LE	-	-	-	-	-	-	-	-	-	-	-	-	-
Traffic Lighting Energy -- TE	-	-	-	-	-	-	-	0	-	-	-	-	0
Street Lighting - SL	11,160	15,835	12,366	13,114	16,062	9,285	1,546	5,273	6,936	5,781	24,237	7,603	129,197
Decorative Street Lighting - SLDEC (moved to rate SL with PSC 14)	-	-	-	-	-	-	-	-	-	-	-	-	-
Private Outdoor Lighting - POL	20,247	28,349	22,211	38,415	22,869	13,252	(4,390)	19,324	7,267	12,084	43,421	13,645	236,694
Customer Outdoor Lighting - OL (moved to rate POL with PSC 14)	-	-	-	-	-	-	-	-	-	-	-	-	-
	31,407	44,184	34,578	51,529	38,931	22,536	(2,843)	24,597	14,203	17,865	67,657	21,248	365,891
Curtailable Service Rider Credits - Primary	-	-	-	-	-	-	-	-	-	-	-	-	-
Curtailable Service Rider Credits - Transmission	-	-	-	-	-	-	-	-	-	-	-	-	-
Total	4,081,788	6,517,796	4,236,244	8,161,996	4,718,175	3,839,736	(1,697,091)	5,151,965	1,900,897	2,469,340	7,161,803	2,645,683	49,188,332

KENTUCKY UTILITIES COMPANY
Adjustment to Reflect FAC Billings for a Full Year of the Roll-in
12 Months Ended October 31, 2009

	January-09	February-09	March-09	April-09	May-09	June-09	July-09	August-09	September-09	October-09	November-08	December-08	TOTAL 12 Mos. Ended
FUEL ADJUSTMENT CLAUSE BILLINGS REFLECTING BASE RATE ROLL-IN FOR A FULL YEAR													
FAC RATE CHARGED:	*0.00244*	*0.00409*	*0.00317*	*0.00584*	*0.00385*	*0.00225*	*(0.00087)*	*0.00363*	*0.00113*	*0.00180*	*0.00559*	*0.00163*	
FAC Rate Rolled in:	*(0.00163)*	*(0.00163)*	*(0.00163)*	*(0.00163)*	*(0.00163)*	*(0.00163)*	-	-	-	-	*(0.00163)*	*(0.00163)*	
FAC Rate After Roll-in:	*0.00081*	*0.00246*	*0.00154*	*0.00421*	*0.00222*	*0.00062*	*(0.00087)*	*0.00363*	*0.00113*	*0.00180*	*0.00396*	-	
Residential Rate													
Residential Rate RS	616,665	1,719,642	799,072	2,039,567	772,975	275,343	(450,495)	1,775,951	532,840	675,434	1,588,223	0	10,345,217
Residential Rate FERS	-	-	-	-	-	-	-	-	-	-	-	-	-
	616,665	1,719,642	799,072	2,039,567	772,975	275,343	(450,495)	1,775,951	532,840	675,434	1,588,223	0	10,345,217
General Service													
General Service Secondary	142,315	419,519	214,864	633,944	280,643	93,784	(141,678)	562,801	175,241	245,015	511,720	0	3,138,168
All Electric School Rate AES	10,944	32,579	17,073	43,167	20,862	6,183	(8,305)	32,076	12,276	18,417	40,437	0	225,708
Power Service Rate													
Power Service Rate PSS - Secondary	231,592	669,647	365,596	1,180,587	575,922	338,694	(59,407)	1,089,917	351,050	501,601	1,052,067	0	6,297,266
Power Service Rate PSP - Primary	96,553	337,417	173,530	554,176	254,894	83,690	(117,331)	468,625	152,962	222,191	507,701	0	2,734,408
General Service Primary (moved to rate PSP)	-	-	-	-	-	-	-	-	-	-	-	-	-
Large Power Rate LPS - Secondary (moved to rate PSS with PSC 14)	-	-	-	-	-	-	-	-	-	-	-	-	-
Large Power Rate LPP - Primary (moved to rate PSP with PSC 14	-	-	-	-	-	-	-	-	-	-	-	-	-
Mining Power Service Rate MP-Primary (moved to rate PSP with PSC 14)	-	-	-	-	-	-	-	-	-	-	-	-	-
	328,144	1,007,064	539,126	1,734,763	830,816	422,383	(176,738)	1,558,542	504,012	723,792	1,559,769	0	9,031,674
Time of Day Power Rate													
Time-of-Day Service - TODS Secondary	917	7,766	7,348	26,869	11,172	5,248	(6,430)	25,742	9,858	16,458	4,369	0	109,318
Time-of-Day Service - TODP Primary	10,824	33,307	17,122	64,807	29,762	12,268	(17,013)	78,299	24,732	38,240	52,126	0	344,474
Small Time-of-Day - STODS Secondary (moved to rate TODS with PSC 14)	-	-	-	-	-	-	-	-	-	-	-	-	-
Small Time-of-Day - STODP Primary (moved to rate TODP with PSC 14)	-	-	-	-	-	-	-	-	-	-	-	-	-
	11,741	41,074	24,469	91,677	40,935	17,517	(23,442)	104,040	34,590	54,697	56,495	0	453,792
Large Power Time of Day Rate													
Large Time-of-Day Primary Service - LTOD Primary	145,803	437,481	267,033	761,504	428,412	136,598	(194,841)	704,091	285,376	452,819	818,293	0	4,242,570
Large Comm./Industrial Time-of-Day - LCI-TOD Primary (moved to rate LTOD with PSC 14)	-	-	-	-	-	-	-	-	-	-	-	-	-
Large Mining Power Service Time of Day RateL LMP TOD-Primary (moved to rate LTOD with PSC 14)	-	-	-	-	-	-	-	-	-	-	-	-	-
	145,803	437,481	267,033	761,504	428,412	136,598	(194,841)	704,091	285,376	452,819	818,293	0	4,242,570
Retail Transmission Service	75,614	232,283	140,538	451,965	217,509	63,175	(94,058)	433,227	132,380	318,692	365,603	0	2,336,927
Large Power Rate LPT - Transmission (moved to rate RTS with PSC 14)	-	-	-	-	-	-	-	-	-	-	-	-	-
Mining Power Service Rate - MP Transmission (moved to rate RTS with PSC 14)	-	-	-	-	-	-	-	-	-	-	-	-	-
Large Comm./Industrial Time-of-Day - LCI-TOD Transmission	-	-	-	-	-	-	-	-	-	-	-	-	-
Large Mining Power Service Time of Day Rate - LMP TOD Transmission (moved to rate RTS with PSC 14)	-	-	-	-	-	-	-	-	-	-	-	-	-
	75,614	232,283	140,538	451,965	217,509	63,175	(94,058)	433,227	132,380	318,692	365,603	0	2,336,927
Industrial Service Rate	12,924	50,012	39,657	91,845	46,513	16,874	(27,624)	147,407	48,084	83,203	84,963	0	593,859
	-	-	-	-	-	-	-	-	-	-	-	-	-
	12,924	50,012	39,657	91,845	46,513	16,874	(27,624)	147,407	48,084	83,203	84,963	0	593,859
Lighting Rates													
Outdoor Lighting Service – LE	-	-	-	-	-	-	-	-	-	-	-	-	-
Traffic Lighting Energy – TE	-	-	-	-	-	-	(0)	0	0	0	-	-	0
Street Lighting - SL	3,705	9,524	6,008	9,454	7,488	1,968	(2,735)	10,817	3,691	6,842	17,169	0	73,931
Decorative Street Lighting - SLDEC (moved to rate SL with PSC 14)	-	-	-	-	-	-	-	-	-	-	-	-	-
Private Outdoor Lighting - POL	6,705	17,130	10,792	27,739	13,028	3,564	(4,760)	19,999	6,932	12,194	30,770	0	144,094
Customer Outdoor Lighting - OL (moved to rate POL with PSC 14)	-	-	-	-	-	-	-	-	-	-	-	-	-
	10,410	26,654	16,800	37,193	20,516	5,532	(7,495)	30,816	10,624	19,036	47,939	0	218,025
Curtailable Service Rider Credits - Primary	-	-	-	-	-	-	-	-	-	-	-	-	-
Curtailable Service Rider Credits - Transmission	-	-	-	-	-	-	-	-	-	-	-	-	-
	-	-	-	-	-	-	-	-	-	-	-	-	-
Total	1,354,560	3,966,307	2,058,632	5,885,626	2,659,180	1,037,389	(1,124,676)	5,348,951	1,735,424	2,591,105	5,073,441	0	30,585,939

Conroy Exhibit 2

KENTUCKY UTILITIES COMPANY
Adjustment to Reflect FAC Billings for a Full Year of the Roll-in
12 Months Ended October 31, 2009

REDUCED FUEL ADJUSTMENT CLAUSE BILLINGS REFLECTING BASE RATE ROLL-IN FOR A FULL YEAR

	January-09	February-09	March-09	April-09	May-09	June-09	July-09	August-09	September-09	October-09	November-08	December-08	TOTAL 12 Mos. Ended
Residential Rate													
Residential Rate RS	(111,918)	135,956	(842,536)	(788,015)	(566,806)	(723,402)	1,006	(1,416)	768	(102)	578,689	(430,039)	(2,747,814)
Residential Rate FERS	(1,129,180)	(1,277,586)	-	-	-	-	-	-	-	-	(1,232,392)	(646,054)	(4,285,211)
	(1,241,098)	(1,141,630)	(842,536)	(788,015)	(566,806)	(723,402)	1,006	(1,416)	768	(102)	(653,703)	(1,076,093)	(7,033,025)
General Service													
General Service Secondary	(283,927)	(271,817)	(226,699)	(244,862)	(212,543)	(247,811)	(4,622)	11,691	(4,583)	2,163	(210,736)	(268,587)	(1,962,332)
All Electric School Rate AES	(22,022)	(21,170)	(18,064)	(16,711)	(17,942)	(18,700)	(7,810)	4,624	(2,843)	978	(16,644)	(21,550)	(157,855)
Power Service Rate													
Power Service Rate PSS - Secondary	231,592	669,647	(387,049)	(457,007)	(450,121)	(915,157)	708,455	59,408	(40,735)	9,695	1,052,067	0	480,795
Power Service Rate PSP - Primary	96,553	335,392	(183,629)	(214,562)	(200,115)	(234,716)	(28,580)	14,974	(14,234)	4,110	507,701	0	82,893
General Service Primary (moved to rate PSP)	(8,027)	(5,567)	-	-	-	-	-	-	-	-	(21,603)	36,490	1,293
Large Power Rate LPS - Secondary (moved to rate PSS with PSC 14)	(700,050)	(1,100,111)	-	-	-	-	-	-	-	-	(1,485,075)	(465,210)	(3,750,446)
Large Power Rate LPP - Primary (moved to rate PSP with PSC 14	(253,021)	(492,459)	-	-	-	-	-	-	-	-	(637,396)	(238,245)	(1,621,122)
Mining Power Service Rate MP-Primary (moved to rate PSP with PSC 14)	(28,909)	(40,935)	-	-	-	-	-	-	-	-	(57,717)	(20,474)	(148,035)
	(661,863)	(634,033)	(570,678)	(671,569)	(650,236)	(1,149,873)	679,875	74,382	(54,970)	13,805	(642,023)	(687,439)	(4,954,623)
Time of Day Power Rate													
Time-of-Day Service - TODS Secondary	917	(1,782)	(7,840)	(10,403)	(8,203)	(15,378)	820	24	(2,331)	21	4,369	0	(39,786)
Time-of-Day Service - TODP Primary	10,824	2,486	(18,122)	(25,092)	(21,853)	(33,098)	3,235	3,418	(637)	14	52,126	0	(26,698)
Small Time-of-Day - STODS Secondary (moved to rate TODS with PSC 14)	(32,606)	(22,042)	-	-	-	-	-	-	-	-	(73,582)	(22,220)	(150,450)
Small Time-of-Day - STODP Primary (moved to rate TODP with PSC 14)	(2,763)	(3,364)	-	-	-	-	-	-	-	-	(6,167)	(2,131)	(14,424)
	(23,627)	(24,702)	(25,962)	(35,495)	(30,056)	(48,475)	4,055	3,442	(2,968)	35	(23,254)	(24,351)	(231,358)
Large Power Time of Day Rate													
Large Time-of-Day Primary Service - LTOD Primary	145,803	206,779	(285,169)	(294,834)	(359,792)	(386,630)	(84,692)	85,621	(89,414)	46,577	818,293	0	(197,459)
Large Comm./Industrial Time-of-Day - LCI-TOD Primary (moved to rate LTOD with PSC 14)	(422,731)	(441,941)	-	-	-	-	-	-	-	-	(1,115,294)	(363,127)	(2,343,093)
Large Mining Power Service Time of Day RateL LMP TOD-Primary (moved to rate LTOD with PSC 14)	(16,477)	(26,511)	-	-	-	-	-	-	-	-	(39,822)	(12,090)	(94,900)
	(293,406)	(261,673)	(285,169)	(294,834)	(359,792)	(386,630)	(84,692)	85,621	(89,414)	46,577	(336,823)	(375,217)	(2,635,452)
Retail Transmission Service	75,614	86,260	(148,751)	(174,989)	(169,054)	(166,089)	(10,745)	12,424	(7,885)	57,137	365,603	0	(80,476)
Large Power Rate LPT - Transmission (moved to rate RTS with PSC 14)	(6,019)	(12,406)	-	-	-	-	-	-	-	-	(10,459)	(4,014)	(32,899)
Mining Power Service Rate - MP Transmission (moved to rate RTS with PSC 14)	(23,444)	(7,133)	-	-	-	-	-	-	-	-	(44,278)	(14,734)	(89,588)
Large Comm./Industrial Time-of-Day - LCI-TOD Transmission	(151,385)	(187,870)	-	-	-	-	-	-	-	-	(335,679)	(85,056)	(759,990)
Large Mining Power Service Time of Day Rate - LMP TOD Transmission (moved to rate RTS with PSC 14)	(49,044)	(24,648)	-	-	-	-	-	-	-	-	(125,674)	(38,778)	(238,145)
	(154,279)	(145,798)	(148,751)	(174,989)	(169,054)	(166,089)	(10,745)	12,424	(7,885)	57,137	(150,488)	(142,581)	(1,201,098)
Industrial Service Rate	12,924	50,012	(41,975)	(35,560)	(34,152)	(44,362)	-	-	-	-	84,963	0	(8,150)
	(38,932)	(83,149)	-	-	-	-	-	-	-	-	(119,935)	(28,617)	(270,634)
	(26,008)	(33,138)	(41,975)	(35,560)	(34,152)	(44,362)	-	-	-	-	(34,972)	(28,617)	(278,784)
Lighting Rates													
Outdoor Lighting Service -- LE	-	-	-	-	-	-	-	-	-	-	-	-	-
Traffic Lighting Energy -- TE	-	-	-	-	-	-	(0)	(0)	0	0	-	-	(0)
Street Lighting - SL	(7,455)	(6,310)	(6,358)	(3,660)	(8,574)	(7,317)	(4,281)	5,544	(3,244)	1,061	(7,068)	(7,603)	(55,266)
Decorative Street Lighting - SLDEC (moved to rate SL with PSC 14)	-	-	-	-	-	-	-	-	-	-	-	-	-
Private Outdoor Lighting - POL	(13,543)	(11,219)	(11,420)	(10,676)	(9,841)	(9,687)	(370)	675	(335)	110	(12,650)	(13,645)	(92,600)
Customer Outdoor Lighting - OL (moved to rate POL with PSC 14)	-	-	-	-	-	-	-	-	-	-	-	-	-
	(20,998)	(17,529)	(17,778)	(14,336)	(18,414)	(17,004)	(4,651)	6,219	(3,579)	1,172	(19,718)	(21,248)	(147,866)
Curtailable Service Rider Credits - Primary	-	-	-	-	-	-	-	-	-	-	-	-	-
Curtailable Service Rider Credits - Transmission	-	-	-	-	-	-	-	-	-	-	-	-	-
Total	(2,727,228)	(2,551,489)	(2,177,612)	(2,276,370)	(2,058,995)	(2,802,347)	572,416	196,986	(165,473)	121,765	(2,088,362)	(2,645,683)	(18,602,393)

Kentucky Utilities Company

Calculation of ECR Revenue Requirement at October 31, 2009

	TOTAL	Eliminated Plans (2001 & 2003)	Post Rate Case ECR Plans (05 & 06)
Calculation of Revenue Requirement	Environmental Compliance Plans at Oct 31, 2009	Environmental Compliance Plans at Oct 31, 2009	Environmental Compliance Plans at Oct 31, 2009
Environmental Compliance Rate Base			
Pollution Control Plant in Service	858,123,898	240,167,567	617,956,331
Pollution Control CWIP Excluding AFUDC	589,332,587	1,142,172	588,190,415
Subtotal	1,447,456,485	241,309,739	1,206,146,746
Additions:			
Limestone, net of amount in base rates	463,655	-	463,655
Emission Allowances, net of amount in base rates	1,214,889	-	1,214,889
Cash Working Capital Allowance	1,610,137	307,049	1,303,088
Subtotal	3,288,681	307,049	2,981,632
Deductions:			
Accumulated Depreciation on Pollution Control Plant	70,658,298	33,946,555	36,711,743
Pollution Control Deferred Income Taxes	55,590,379	34,843,377	20,747,002
Pollution Control Deferred Investment Tax Credit	27,300,334	-	27,300,334
Subtotal	153,549,011	68,789,932	84,759,079
Environmental Compliance Rate Base	$ 1,297,196,155	$ 172,826,856	$ 1,124,369,299
Rate of Return -- Environmental Compliance Rate Base		11.12%	11.12%
Return on Environmental Compliance Rate Base	$ 144,248,212	$ 19,218,346	$ 125,029,866
Pollution Control Operating Expenses			
12 Month Depreciation and Amortization Expense	29,431,778	6,976,795	22,454,982
12 Month Taxes Other than Income Taxes	1,725,833	321,349	1,404,484
12 Month Operating and Maintenance Expense	12,881,091	2,456,390	10,424,701
12 Month Emission Allowance Expense, net of amounts in base rates	966,382	-	966,382
Total Pollution Control Operating Expenses	$ 45,005,084	$ 9,754,534	$ 35,250,550
Gross Proceeds from By-Product & Allowance Sales	(273,091)	-	(273,091)
Total Company Environmental Surcharge Gross Revenue Requirement			
Return on Environmental Compliance Rate Base	144,248,212	19,218,346	125,029,866
Pollution Control Operating Expenses	45,005,084	9,754,534	35,250,550
Less Gross Proceeds from By-Product & Allowance Sales	273,091	-	273,091
Total Company Environmental Surcharge Gross Revenue Requirement	$ 189,526,387	$ 28,972,880	$ 160,553,507

Balances for Selected Operating Expense Accounts for 12-months ended October 31, 2009

All Plans	Depreciation & Amortization Steam Plant	Taxes Other than Income Taxes	Operating and Maintenance Expense FERC 502	FERC 506	FERC 512	Emission Allowance Expense FERC 509	Total
Nov-08	2,546,527	106,610	184,043	102,573	64,072	249,574	3,253,400
Dec-08	2,546,527	106,606	215,838	813,882	81,149	9,418	3,773,420
Jan-09	2,546,528	151,270	229,022	640,633	76,168	28	3,643,649
Feb-09	2,000,060	151,261	176,509	302,793	153,109	23	2,783,755
Mar-09	2,214,349	151,261	202,422	721,911	67,998	15	3,357,956
Apr-09	2,429,770	151,261	189,551	765,878	63,396	9	3,599,866
May-09	2,481,998	151,261	158,935	873,522	47,679	76,175	3,789,571
Jun-09	2,532,586	151,261	173,440	832,319	46,216	156,006	3,891,827
Jul-09	2,532,586	151,261	137,982	720,871	75,243	160,833	3,778,776
Aug-09	2,532,586	151,261	725,587	800,513	619,936	169,269	4,999,153
Sep-09	2,533,615	151,261	204,210	811,465	270,388	97,426	4,068,365
Oct-09	2,534,645	151,259	203,259	687,107	441,471	105,950	4,123,690
less amount in Base Rates						(58,344)	(58,344)
Totals	29,431,778	1,725,833	2,800,799	8,073,468	2,006,824	966,382	45,005,084

Balances for Allowance Sales and By-Product Sales for 12-months ended October 31, 2009

	Total Proceeds from Allowance Sales ES Form 2.00	Proceeds from By-Product Sales ES Form 2.00	Total All Sale Proceeds	
Nov-08	3,600	-	3,600	
Dec-08	-	-	-	
Jan-09	-	-	-	
Feb-09	-	-	-	
Mar-09	-	-	-	
Apr-09	(201,458)	-	(201,458)	
May-09	-	-	-	
Jun-09	-	-	-	
Jul-09	-	-	-	
Aug-09	-	(69,038)	(69,038)	*Aug09 includes prior period adj for Mar09-Jul09
Sep-09	-	(8,830)	(8,830)	
Oct-09	-	2,635	2,635	
Totals	(197,858)	(75,233)	(273,091)	

Balances for Selected Operating Expense Accounts for 12-months ended October 31, 2009
Eliminated Plans (2001 & 2003)

2001 Plan	Depreciation & Amortization Steam Plant	Taxes Other than Income Taxes	Operating and Maintenance Expense FERC 502	FERC 506	FERC 512	Emission Allowance Expense FERC 509	Total
Nov-08	465,764	25,449	-	75,892	42,490	-	609,595
Dec-08	465,764	25,444	-	346,686	52,958	-	890,852
Jan-09	465,764	24,878	-	188,748	32,440	-	711,830
Feb-09	572,711	24,878	-	103,814	97,493	-	798,895
Mar-09	572,711	24,878	-	169,649	40,684	-	807,922
Apr-09	572,711	24,878	-	180,660	15,410	-	793,658
May-09	572,711	24,878	-	259,216	10,641	-	867,446
Jun-09	572,711	24,878	-	109,641	20,762	-	727,992
Jul-09	572,711	24,878	-	143,222	28,687	-	769,498
Aug-09	572,711	24,878	-	117,312	24,834	-	739,735
Sep-09	572,711	24,878	-	144,643	65,896	-	808,128
Oct-09	572,711	24,878	-	156,924	27,691	-	782,203
less Base Rate amount						-	-
Totals	6,551,690	299,674	-	1,996,405	459,985	-	9,307,754

2003 Plan	Depreciation & Amortization Steam Plant	Taxes Other than Income Taxes	Operating and Maintenance Expense FERC 502	FERC 506	FERC 512	Emission Allowance Expense FERC 509	Total
Nov-08	29,067	1,842	-	-	-	-	30,909
Dec-08	29,067	1,842	-	-	-	-	30,909
Jan-09	29,067	1,799	-	-	-	-	30,866
Feb-09	37,545	1,799	-	-	-	-	39,344
Mar-09	37,545	1,799	-	-	-	-	39,344
Apr-09	37,545	1,799	-	-	-	-	39,344
May-09	37,545	1,799	-	-	-	-	39,344
Jun-09	37,545	1,799	-	-	-	-	39,344
Jul-09	37,545	1,799	-	-	-	-	39,344
Aug-09	37,545	1,799	-	-	-	-	39,344
Sep-09	37,545	1,799	-	-	-	-	39,344
Oct-09	37,545	1,799	-	-	-	-	39,344
less Base Rate amount						-	-
Totals	425,105	21,674	-	-	-	-	446,780

2001 & 2003 Plans	Depreciation & Amortization Steam Plant	Taxes Other than Income Taxes	Operating and Maintenance Expense FERC 502	FERC 506	FERC 512	Emission Allowance Expense FERC 509	Total
Nov-08	494,831	27,291	-	75,892	42,490	-	640,504
Dec-08	494,830	27,287	-	346,686	52,958	-	921,761
Jan-09	494,831	26,677	-	188,748	32,440	-	742,696
Feb-09	610,256	26,677	-	103,814	97,493	-	838,239
Mar-09	610,256	26,677	-	169,649	40,684	-	847,266
Apr-09	610,256	26,677	-	180,660	15,410	-	833,002
May-09	610,256	26,677	-	259,216	10,641	-	906,790
Jun-09	610,256	26,677	-	109,641	20,762	-	767,336
Jul-09	610,256	26,677	-	143,222	28,687	-	808,842
Aug-09	610,256	26,677	-	117,312	24,834	-	779,079
Sep-09	610,256	26,677	-	144,643	65,896	-	847,472
Oct-09	610,256	26,677	-	156,924	27,691	-	821,547
less Base Rate amount						-	-
Totals	6,976,795	321,349	-	1,996,405	459,985	-	9,754,534

Balances for Selected Operating Expense Accounts for 12-months ended October 31, 2009
Post Rate Case ECR Plans (2005 & 2006)

2005 Plan	Depreciation & Amortization Steam Plant	Taxes Other than Income Taxes	Operating and Maintenance Expense FERC 502	FERC 506	FERC 512	Emission Allowance Expense FERC 509	Total
Nov-08	2,035,833	71,385	184,043	-	16,455	249,574	2,557,289
Dec-08	2,035,833	71,385	215,838	-	17,202	9,418	2,349,675
Jan-09	2,035,833	104,300	229,022	-	18,588	28	2,387,771
Feb-09	1,371,759	104,291	176,509	-	25,972	23	1,678,554
Mar-09	1,586,048	104,291	202,422	-	14,303	15	1,907,080
Apr-09	1,799,830	104,291	189,551	-	36,823	9	2,130,504
May-09	1,850,418	104,291	158,935	-	29,021	76,175	2,218,840
Jun-09	1,901,005	104,291	173,440	-	9,085	156,006	2,343,827
Jul-09	1,901,005	104,291	137,982	-	42,643	160,833	2,346,754
Aug-09	1,901,005	104,291	725,587	-	592,849	169,269	3,493,002
Sep-09	1,901,005	104,291	204,210	-	202,952	97,426	2,509,884
Oct-09	1,901,005	104,289	203,259	-	402,920	105,950	2,717,423
less Base Rate amount						(58,344)	(58,344)
Totals	22,220,577	1,185,687	2,800,799	-	1,408,814	966,382	28,582,259

*August 2009 includes prior period adjustment for March through July as shown on ES Form 1.10 and Attachment 1 and Attachment 2 in the August 2009 monthly filing.

2006 Plan	Depreciation & Amortization Steam Plant	Taxes Other than Income Taxes	Operating and Maintenance Expense FERC 502	FERC 506	FERC 512	Emission Allowance Expense FERC 509	Total
Nov-08	15,864	7,934	-	26,681	5,127	-	55,606
Dec-08	15,864	7,934	-	467,196	10,989	-	501,983
Jan-09	15,864	20,293	-	451,885	25,140	-	513,182
Feb-09	18,045	20,293	-	198,980	29,644	-	266,962
Mar-09	18,045	20,293	-	552,262	13,010	-	603,611
Apr-09	19,685	20,293	-	585,219	11,163	-	636,359
May-09	21,325	20,293	-	614,306	8,017	-	663,941
Jun-09	21,325	20,293	-	722,678	16,368	-	780,664
Jul-09	21,325	20,293	-	577,649	3,913	-	623,180
Aug-09	21,325	20,293	-	683,202	2,252	-	727,072
Sep-09	22,354	20,293	-	666,822	1,541	-	711,010
Oct-09	23,384	20,293	-	530,183	10,860	-	584,720
less Base Rate amount						-	-
Totals	234,405	218,798	-	6,077,063	138,025	-	6,668,291

2005 & 2006 Plans	Depreciation & Amortization Steam Plant	Taxes Other than Income Taxes	Operating and Maintenance Expense FERC 502	FERC 506	FERC 512	Emission Allowance Expense FERC 509	Total
Nov-08	2,051,697	79,319	184,043	26,681	21,582	249,574	2,612,895
Dec-08	2,051,697	79,319	215,838	467,196	28,191	9,418	2,851,658
Jan-09	2,051,697	124,593	229,022	451,885	43,728	28	2,900,953
Feb-09	1,389,804	124,584	176,509	198,980	55,616	23	1,945,516
Mar-09	1,604,093	124,584	202,422	552,262	27,314	15	2,510,690
Apr-09	1,819,515	124,584	189,551	585,219	47,986	9	2,766,864
May-09	1,871,743	124,584	158,935	614,306	37,038	76,175	2,882,782
Jun-09	1,922,330	124,584	173,440	722,678	25,454	156,006	3,124,492
Jul-09	1,922,330	124,584	137,982	577,649	46,556	160,833	2,969,934
Aug-09	1,922,330	124,584	725,587	683,202	595,102	169,269	4,220,074
Sep-09	1,923,359	124,584	204,210	666,822	204,493	97,426	3,220,894
Oct-09	1,924,389	124,582	203,259	530,183	413,780	105,950	3,302,143
less Base Rate amount						(58,344)	(58,344)
Totals	22,454,982	1,404,484	2,800,799	6,077,063	1,546,839	966,382	35,250,550

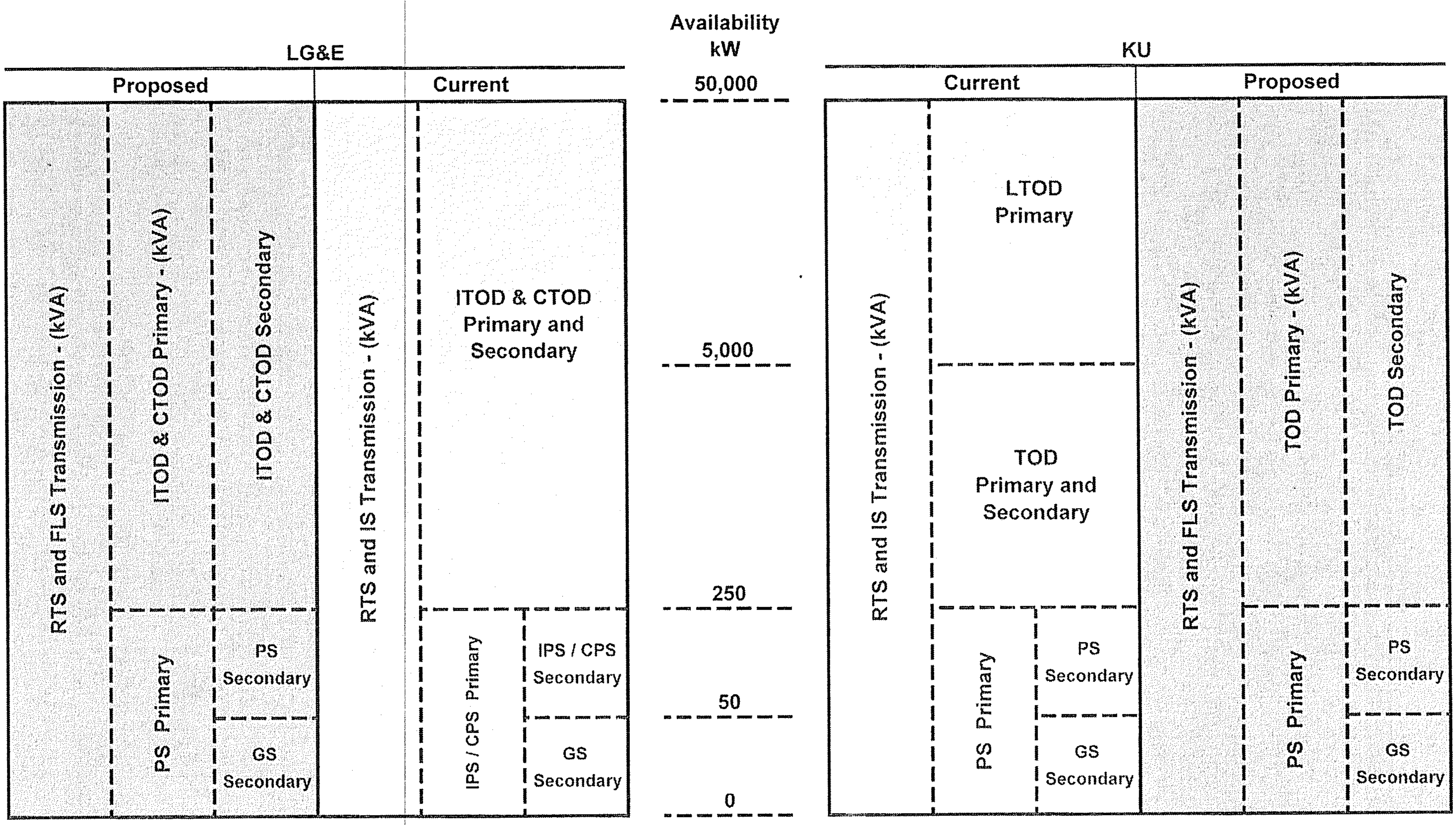
Kentucky Utilities Company
Adjustment to Test Year Revenues Due to Electric Rate Switching

					Test Year "As Billed" Revenues						Test Year Revenues Using New Rate					
	KWH	KW On Peak	KW Off Peak	Previous Rate	Peak Demand Revenue	Off-Peak Demand Revenue	Customer Charge	Energy Rate	Energy Revenue	Total Revenue	Peak Demand Revenue	Off-Peak Demand Revenue	Customer Charge	Energy Revenue	Total Revenue	Change In Revenue Due To Rate Switch
Customer 1	2,136,400	3,974	2,463	LPS/PSS	27,251.06	3,128.01	1,005.00		70,405.18	101,789.25	25,390.67	4,982.21	1,080.00	69,561.13	101,014.01	(775.24)
Customer 2	1,791,120	4,116	2,073	LPS/PSS	28,792.26	2,632.71	1,005.00		59,038.33	91,468.30	26,301.24	5,068.57	1,080.00	58,762.92	91,212.73	(255.57)
Customer 3	6,210,062	11,983	6,244	LPP/PSP	79,185.36	7,929.88	1,170.00		204,599.27	292,884.51	71,895.00	15,331.44	1,440.00	203,808.71	292,475.15	(409.36)
Customer 4	2,289,600	5,622	2,610	LPS/PSS	39,471.48	3,314.70	990.00		75,375.10	119,151.28	35,924.58	6,645.91	1,080.00	75,048.16	118,698.65	(452.63)
Customer 5	15,516,000	32,603	19,098	LPS/PSS	224,427.15	24,254.46	1,005.00		512,082.65	761,769.26	208,333.17	39,879.27	1,080.00	509,771.03	759,063.47	(2,705.79)
Customer 6	9,258,000	18,927	8,485	LPS/PSS	133,994.57	10,775.95	975.00		305,297.03	451,042.55	120,940.34	23,807.42	1,080.00	304,090.78	449,918.54	(1,124.01)
Customer 7	3,254,400	9,701	1,654	LPS/PSS	72,141.17	2,100.58	930.00		107,502.48	182,674.23	61,986.20	12,414.25	1,080.00	107,095.69	182,576.14	(98.09)
Customer 8	11,502,600	28,810	8,925	LPS/PSS	211,184.64	9,136.38	960.00		377,920.23	599,201.25	184,095.90	35,808.92	1,080.00	375,753.75	596,738.57	(2,462.68)
Customer 9	3,318,912	8,450	1,492	LPS/PSS	62,713.44	1,894.84	930.00		109,608.98	175,147.26	53,995.50	10,457.18	1,080.00	109,213.41	174,746.09	(401.17)
Customer 10	12,340,800	26,956	2,228	LPP/PSP	192,638.76	2,829.56	945.00		407,082.63	603,495.95	161,736.00	31,389.32	1,440.00	405,293.16	599,858.48	(3,637.47)
Customer 11	2,021,400	5,797	1,290	LPS/PSS	42,692.67	1,638.30	945.00		66,508.95	111,784.92	37,042.83	7,233.92	1,080.00	66,103.27	111,460.02	(324.90)
Customer 12	2,763,600	5,477	3,541	LPS/PSS	37,449.99	4,497.07	1,005.00		91,085.30	134,037.36	34,998.03	6,981.19	1,080.00	90,755.60	133,814.82	(222.54)
Customer 13	10,298,880	19,923	9,827	LPS/PSS	139,511.07	12,480.29	990.00		339,159.28	492,140.64	127,307.97	24,283.67	1,080.00	337,588.09	490,259.73	(1,880.91)
Customer 14	6,234,300	14,970	7,493	LPP/PSP	99,081.00	9,516.11	1,170.00		204,915.09	314,682.20	89,820.00	18,694.40	1,440.00	203,997.51	313,951.91	(730.29)
Customer 15	5,522,400	27,664	11,941	LPP/PSP	192,515.82	15,165.07	1,125.00		181,792.45	390,598.34	85,232.70	32,258.00	1,440.00	180,830.97	299,761.67	(90,836.67)
Customer 16	2,478,300	4,532	2,085	LPS/PSS	32,154.17	2,647.95	975.00		81,698.22	117,475.34	28,956.29	6,018.53	1,080.00	81,340.15	117,394.97	(80.37)
Customer 17	2,904,000	4,046	1,284	LPS/PSS	29,229.48	1,630.68	770.00		120,886.87	152,517.03	27,652.72	5,165.09	990.00	96,264.88	130,072.69	(22,444.34)
Customer 18	763,209	2,871	1,042	LPS/PSS	20,524.82	1,323.34	945.00		25,435.36	48,228.52	18,342.50	3,361.69	1,080.00	25,407.51	48,191.70	(36.82)
Customer 19	4,617,200	13,792	4,683		24,009.57	3,481.07	430.00		187,709.01	215,629.65	53,267.04	10,327.64	990.00	112,127.03	176,711.71	(38,917.94)
Customer 20	3,813,000	6,890	3,807	LPS/PSS	47,820.96	4,834.89	975.00		126,024.42	179,655.27	44,027.10	8,585.20	1,080.00	125,793.26	179,485.56	(169.71)
Customer 21	1,161,120	4,555	1,828	LPS/PSS	32,500.85	2,321.56	975.00		38,427.37	74,224.78	29,103.26	5,697.22	1,080.00	38,214.55	74,095.03	(129.75)
Customer 22	1,370,000	3,442	1,653	LPS/PSS	24,137.60	2,099.31	975.00		45,311.86	72,523.77	21,991.19	4,161.79	1,080.00	45,170.26	72,403.24	(120.53)
Customer 23	14,763,500	39,661	10,987	LPS/PSS	288,905.31	13,953.49	960.00		484,814.69	788,633.49	253,433.79	48,080.93	1,080.00	481,875.75	784,470.47	(4,163.02)
Customer 24	2,494,200	8,081	3,263	LPS/PSS	57,821.67	4,144.01	975.00		82,241.90	145,182.58	51,637.59	10,596.88	1,080.00	81,813.32	145,127.79	(54.79)
Customer 25	7,702,983	19,596	13,272	PSP	57,643.14	9,363.71	750.00		143,715.33	211,472.18	57,311.91	14,229.08	630.00	139,697.70	211,868.69	396.51

Total Revenue Adjustment Due to Customers Switching Rates During the Test Year **(172,038.08)**

Conroy Exhibit 4

Visual Comparison of Louisville Gas and Electric and Kentucky Utilities Company Rate Schedules



COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

APPLICATION OF KENTUCKY UTILITIES COMPANY FOR AN ADJUSTMENT OF ITS ELECTRIC BASE RATES	))))	**CASE NO. 2009-00548**

TESTIMONY OF JOHN WOLFRAM DIRECTOR, CUSTOMER SERVICE & MARKETING KENTUCKY UTILITIES COMPANY

Filed: January 29, 2010

Q. Please state your name, position and business address.

A. My name is John Wolfram. I am the Director, Customer Service & Marketing for E.ON U.S. Services Inc., which provides services to Louisville Gas and Electric Company ("LG&E") and Kentucky Utilities Company ("KU") (collectively, "the Companies"). My business address is 220 West Main Street, Louisville, Kentucky. A statement of my professional history and education is attached to this testimony as Appendix A.

Q. Have you testified previously before the Commission?

A. Yes. I have testified several times before the Commission, including in Case No. 2002-00029, wherein the Companies sought a certificate of public convenience and necessity ("CPCN") to construct two combustion turbines, and in Case Nos. 2005-00467 and 2005-00472, concerning the Companies' application for a CPCN to construct alternative transmission facilities. I testified most recently in the Companies' Green Energy Rider proceeding, Case No. 2007-00067, and in the Companies' most recent Demand-Side Management and Energy Efficiency Plan proceeding, Case No. 2007-00319.

Q. What are the purposes of your testimony?

A. The purposes of my testimony are: (1) to present and discuss KU's new service offering for Low Emission Vehicles; (2) to describe the proposed revisions to KU's terms and conditions for furnishing electric service, including Special Charges; and (3) to discuss Company offerings, initiatives and programs aimed at assisting customers or enhancing customer service.

Low Emission Vehicle Service

Q. Please describe KU's proposed Low Emission Vehicle ("LEV") service.

A. The LEV rate is a tariff offering for customers operating Low Emission Vehicles, including Plug-in Electric Hybrid Vehicles ("PHEVs"), All-Electric Vehicles, and natural gas vehicles. The tariff provides an incentive for these customers to charge or fuel their vehicles in off-peak periods when the costs to provide energy are lower.

The tariff is proposed as an experimental rate, effective for three years or until the rate is modified or terminated by order of the Commission. This tariff is similar to the Rate RRP tariff approved in Case No. 2007-00117 for LG&E's Responsive Pricing and Smart Metering Pilot Program in that both pilots are aimed at evaluating emerging technologies and their impact on the electric system.

There are significant uncertainties surrounding the impact of LEVs on the electric system if these vehicles become popular in the near future. The typical start time for charging, the average duration of charging, the ultimate charging load, and the number of vehicles being charged are just some of the unknowns that could create a broad range of operational challenges for the utility.

KU expects that as smart metering and associated Time-of-Use ("TOU") rates become more prevalent in the future, the need for a tariff specifically aimed at LEVs will become moot. Nonetheless, KU proposes this rate now to position the utility to assess these issues as they emerge.

The Company's intention is to avoid erecting barriers to participation in this pilot, in order to facilitate the assessment of this emerging segment. For this reason, the Basic Service Charge is proposed to be the same as that of the standard Residential Rate RS. No demand charge is proposed. The energy rates are determined based upon various times of day by season; support for the proposed energy rates is provided in the testimony of Mr. Steve Seelye. The Company will install metering equipment for the premise that can accommodate the proposed rate structure; any incremental costs associated with such equipment or its installation shall be borne by the Company for the purposes of this pilot. In a full deployment, it is possible that either a higher Basic Service Charge, or a Demand Charge, or both may be warranted; one aspect of the pilot is to assess this need and quantify it if applicable.

For customers who qualify for this schedule, the Company shall apply this rate not only to consumption for LEV charging but also to all consumption at a participating customer's premise; a special metering installation to isolate the LEV charging is not required. The Company will provide to Rate LEV customers the necessary metering for the entire premise, but will not provide the other devices associated with LG&E's RRP pilot program (e.g., in-home displays and programmable thermostats). The Company further reserves the right to limit participation on this rate to the first 100 applicants for service under this rate schedule.

Proposed Revisions to Special Charges

Q. Is KU proposing to make any changes to the Special Charges stated in its electric tariff?

A. Yes. KU is adding language to the Meter Data Processing Charge to clarify the policy already in place. A customer who requests meter data reports must have a recorder meter to receive them. If a customer does not have such a meter, the customer must pay to install one because meter installation costs are not included in the data processing charge.

Proposed Revisions to Terms and Conditions of Service

Q. Does KU propose any changes to the Customer Responsibilities, Rate Sheet No. 97?

A. Yes. KU proposes to clarify policies already in place by adding language concerning the establishment of a customer's contract demand for rates that use such demand to determine billing demand minimums. KU is also adding language to make clear that if a customer undergoes a material and permanent change to its operations that results in a significant reduction of the customer's maximum load, KU may reduce that customer's contract demand.

Q. What changes does KU propose to Billing, Rate Sheet No. 101?

A. KU proposes three changes to Rate Sheet No. 101. First, KU proposes to add the same language that was added to the DSM rate sheet defining industrial customers, as well as a minor clarification of the existing text.

Second, KU proposes to add language to the "Monitoring of Customer Usage" section making clear the Company's authority to investigate usage deviations brought ~~to its attention as a result of its ongoing meter reading or of a customer inquiry.~~

Third, a "Minimum Charge" section has been added to clarify that a customer must pay the demand charge due to the Company for each billing period regardless of any event or circumstance that might prevent the customer's facility from actually taking service or the Company from actually providing such service.

Q. What changes does KU propose to Deposits, Rate Sheet No. 102?

A. KU proposes to restrict the option to pay deposits by installments to customers whom KU has not required to make a deposit as a condition of reconnection following disconnection for non-payment. This restriction is a commonsense loss prevention measure; because a deposit is a protection against non-payment, it is rational to require that such protection be fully in place before reconnecting a customer previously disconnected for non-payment.

KU does not propose any other changes to its deposit policies, though it does propose to change the amounts of its gas and electric deposits, as Mr. Seelye describes in his testimony.

Company Offerings, Initiatives and Programs

Q. Does KU have offerings, initiatives or programs aimed at assisting customers or enhancing customer service?

A. Yes. KU has numerous offerings for helping customers, including assistance for customers who have billing and payment challenges, energy consumption management tools and programs, and self-service options. Also, KU's customer service team works diligently to address and resolve individual customer situations and concerns.

Q. Please describe how KU helps customers with billing and payment.

A. KU has a number of programs aimed at helping customers with billing and payments, including the Budget Payment Plan, Automatic Bank Club, E-Bill (electronic billing and payment), installment plans, and Home Energy Assistance Program. Furthermore, KU collaborates with community action agencies and local ministries to assist their clients with their energy bills.

Q. What is the status of KU's Home Energy Assistance Program?

A. KU's application to extend the Home Energy Assistance ("HEA") Program for five years was granted by the Commission on September 14, 2007, in Case No. 2007-00337. HEA provides hardship assistance to low-income customers through the collection of 15 cents per residential meter per month. In order to participate, customers must (among other things) be enrolled in the federal Low Income Home Energy Assistance Program.

Q. Please describe how KU helps customers manage their energy consumption.

A. KU has crafted its Demand Side Management and Energy Efficiency ("DSM/EE") programs to help customers manage their energy consumption. These include DSM Programs (e.g., the Demand Conservation load control program and energy audits), and the Real-Time Pricing Program. Also, KU provides a suite of online energy calculators on its company Web site for commercial customers.

Additionally, several of KU's standard tariffs enable large customers to manage their consumption more efficiently. These include a Curtailable Service Rider and Load Reduction Incentive that reward customers who contract to reduce load during peak times. KU is also proposing enhanced Time-of-Day and Transmission Service Rates, incorporating more time intervals and a shorter peak period, allowing the customers additional flexibility in controlling costs through judicious consideration of their load patterns.

Q. What is the status of KU's Demand-Side Management/Energy Efficiency programs?

A. The Companies have had significant DSM/EE programs in place in for a number of years. In 2007, the Companies applied to the Commission for approval of a suite of twelve DSM/EE programs, some of which were continuations of existing programs and some of which were new. The Commission approved the proposed programs on March 31, 2008 in Case No. 2007-00319. All of these programs are now available in both Companies' service territories.

Q. What is KU's Real-Time Pricing Pilot Program, and what is its status?

A. In Case No. 2007-00161, the Companies proposed and the Commission approved a Real-Time Pricing Pilot program for large commercial and industrial customers. Pilot participants receive day-ahead hourly pricing to allow them to plan the usage schedule for the next day and thus optimize hourly consumption costs. At present no customers have elected to participate in this pilot.

Q. Please describe the Company initiatives or offerings to improve customer self-service.

A. Company initiatives undertaken to provide customers with "self-service" alternatives include the deployment of the Customer Care Solution system and the associated Customer Self-Service Web site. We also provide information on the Web related to energy saving tips, fuel cost comparisons, safety around power lines, net metering, payment options, and other reference material for residential and commercial customers.

Q. Please describe the Customer Care Solution system ("CCS").

A. CCS is a comprehensive customer information system that is used for front office and back office customer information management for LG&E and KU. The CCS project was a 24-month effort comprising blueprint, design, build, test, and deployment phases. The Companies implemented CCS on April 1, 2009.

Q. Why did the Companies implement the CCS?

A. The broad objectives of the CCS project were to mitigate the risk associated with an aging information technology infrastructure, to maintain a high level of customer satisfaction, to create a platform for emerging business needs, and to harmonize the business practices of LG&E and KU to the greatest practicable extent.

Q. How does CCS assist customers and enhance customer service?

A. CCS reduces the risk of extended information system outages associated with aging mainframe-based systems. (The previous CIS systems for KU and LG&E were implemented in 1987 and 1994, respectively.) CCS provides one fully integrated data system with enhanced Customer Self-Serve functionality, including improved online account management and customized online portals for particular customer segments (e.g. low-income assistance agencies and property managers). CCS also provides near-real-time reflection of customer payments.

Furthermore, CCS provides a single system for customer service representatives or agents to use for both LG&E and KU. Agents no longer have to learn to use two separate systems in order to assist customers, streamlining the training process and improving consistency in customer interactions.

Finally, CCS provides a platform to support emerging business needs like smart grid, smart metering, and flexible pricing strategies to enhance customers' consumption management and energy efficiency programs. These are functions that the old mainframe-based systems simply did not provide.

Q. What functions are now available to customers via the Customer Self-Service Web site?

A. The Customer Self-Service Web site allows customers to perform a myriad of functions. More specifically, the site allows customers to:

- View billing history, pay bills, and view payment history;
- View meter and usage history;
- Revise billing and payment options (e.g., enroll in E-bill or paperless billing, enroll in Automatic Bank Club or Budget Payment Plan, add Winterhelp/Wintercare pledges, and establish payment arrangements);
- Access details on energy efficiency programs;
- Report outages;
- Request street light installation, tree trimming, and other services;
- Request changes to service related to moves, whether moving in, moving out, or transferring service to a new address;
- Enter meter data (for customers who read their own meters); and
- Manage account information and profiles, including bank account information and self-service account passwords.

Q. Does KU work with individual customers on matters unique to their particular situations?

A. Yes. It is our aim to work in good faith to resolve matters with individual customers who contact any of our customer service staff about issues pertaining to their particular utility service.

Q. Does this conclude your testimony?

A. Yes, it does.

VERIFICATION

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

The undersigned, **John Wolfram**, being duly sworn, deposes and says that he is Director – Customer Service and Marketing for E.ON U.S. Services, Inc., and that he has personal knowledge of the matters set forth in the foregoing testimony, and that the answers contained therein are true and correct to the best of his information, knowledge and belief.

John Wolfram

John Wolfram

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 22nd day of January 2010.

Tammy J. Elzy (SEAL)

Notary Public

My Commission Expires:

November 9, 2010

APPENDIX A

John Wolfram

Director, Customer Service & Marketing
E.ON U.S. Services, Inc.
820 West Broadway
P.O. Box 32020
Louisville, Kentucky 40232

Education

University of Notre Dame, B.S. in Electrical Engineering - 1990
Drexel University, M.S. in Electrical Engineering - 1997
Leadership Louisville 2006

Previous Positions

LG&E Energy LLC, Louisville, Kentucky

2004 – 2005	Manager, Regulatory Affairs
2001 – 2004	Manager, Regulatory Policy & Strategy
1998 – 2001	Lead Planning Engineer, Generation Planning
1997 – 1998	Trader, Energy Marketing

PJM Interconnection, Norristown Pennsylvania

1994 – 1997	Senior Engineer, Operations Planning
1990 – 1993	Engineer, Operations Planning

Cincinnati Gas & Electric Company

1993 – 1994	Project Consultant, Energy Management System

Other Associations

~~Greater Louisville Regional Board for Commonwealth Fund for KET~~
Edison Electric Institute, Economic Regulation & Competition Committee
Institute of Electrical & Electronics Engineers and IEEE Power Engineering Society