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: 2008-00251**

VOLUME 4 OF 5

DIRECT TESTIMONY AND EXHIBITS

Filed: July 29, 2008

Kentucky Utilities Company
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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. 2008-00251

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

Filed: July 29, 2008

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 Kentucky Utilities Company ("KU" or "Company"), 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 have testified before this Commission several times in connection with KU's and LG&E's base rate filings and the transactions involving the change of control over their ownership. I testified before this Commission in 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.* I also testified before this Commission in 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.* Prior to that, I testified in 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. I also testified in Case Nos. 98-426 and 98-474, concerning the Applications of KU and LG&E, respectively, for approval of an alternative method of regulation. Finally, I testified in Case No. 97-300 concerning the merger of KU Energy Corporation into LG&E Energy, and the resulting change in the ownership and control of LG&E and KU.

Q. Please identify the other witnesses offering direct testimony on behalf of the Company in this case, and generally describe the subject matter of each such testimony.

A. KU is offering direct testimony from the following witnesses:

- Paul Thompson, Senior Vice President – Energy Services – Mr. Thompson will describe, from a generation and transmission function perspective, certain efficiency initiatives the Company has undertaken over the last several years to manage the increasing costs of doing business, and explain the investments in and construction of generation and transmission facilities which support the need for the proposed adjustment in base rates at this time;
- Chris Hermann, Senior Vice President – Energy Delivery – Mr. Hermann will describe how KU has been able to effectively manage costs while providing reliable, safe service for our retail operations and electric distribution businesses, and will explain the investments in and construction of distribution electric facilities 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 Company requires the requested increase in base rates, present the financial exhibits to KU's application, discuss the Company's accounting records, describe the calculation of KU's adjusted net operating income for the twelve month period ended April 30, 2008, support the different valuations of the Company's property, and support certain reference schedules supporting the Company's application;
- Valerie L. Scott, Controller – Ms. Scott will support certain pro forma adjustments to the Company's operating income for the twelve months ended April 30, 2008, demonstrate that those adjustments are known and measurable and, therefore, reasonable, and support certain reference schedules supporting the Company's application;
- Shannon Charnas, Director of Utility Accounting and Reporting – Ms. Charnas will support certain pro forma adjustments to the Company's operating income for the twelve months ended April 30, 2008, demonstrate that those adjustments are known and measurable and, therefore, reasonable, and support certain reference schedules supporting the Company's application;
- William E. Avera, President, FINCAP, Inc. – Mr. Avera will present the results of his analysis which shows that the equity for the proxy groups of utilities and non-utility companies is on the order of 10.9 percent to 12.7 percent and his recommendation that the Commission adopt an 11.25% allowed return on equity ("ROE") for KU's electric operations;

- Lonnie Bellar, Vice President – State Regulation and Rates – Mr. Bellar will support certain exhibits required by the Commission's regulations, including the tariffs with the propose changes in rates, terms and conditions, identify the revenue effect of the proposed rates, present the Company's recommendation for the allocation of the proposed increase in revenues among the customer classes, and will support certain pro forma adjustments to the Company's operating income for the twelve months ended April 30, 2008;
- W. Steven Seelye, Principal and Senior Consultant, The Prime Group, LLC – Mr. Seelye will support certain pro forma adjustments to the Company's operating income for the twelve months ended April 30, 2008, demonstrate that those adjustments are known, measurable and reasonable, support certain reference schedules supporting the Company's application, and present the results of his cost-of-service study;
- Robert M. Conroy, Director – Rates – Mr. Conroy will describe and support certain exhibits which are required by the Commission's regulations, explain certain proposed pro forma adjustments, and discuss and explain various electric rate and tariff changes the Company proposes; and
- Butch Cockerill, Director – Revenue Collections – Mr. Cockerill will describe and support the proposed revisions to the Company's terms and conditions for furnishing electric services, discuss the proposed changes to some of the Company's non-recurring charges, and review several of the Company's successful programs, including its Demand-Side Management and energy

efficiency programs, real-time pricing pilot programs, and its efforts to assist its low income customers.

Q. What is the purpose of your testimony?

A. I will provide an overview in general terms of the reasons why KU is proposing to adjust its base rates at this time. In doing so, I will describe some of the significant changes that have occurred since KU last requested an increase in base rates, and will describe why the Company's investments in facilities to provide service to customers require an increase in base rates. Finally, I will discuss KU's ongoing commitment to the environment, the community and low income customers.

Q. What steps has KU taken to control its costs since its last request for a base rate increase?

A. KU has made every effort to offset or absorb increased costs since seeking its last electric base rate increases in 2004. As discussed in the testimonies of Mr. Thompson and Mr. Hermann, KU continuously seeks ways to create efficiencies and, in turn, optimize savings in the face of additional capital expenditures and other rising costs. KU has a long track record of operating very efficiently and avoiding price increases as the first method of managing the Company's business. In addition, as described in Mr. Rives's testimony, we are providing all of the actual savings associated with the merger between KU and LG&E and our Value Delivery Team initiative. We are very proud of the fact that our rates are among the lowest in the nation.

Q. Please describe KU's proposed increase in base rates.

A. KU is requesting a 2%, or $22.2 million a year, increase in its electric base rates. The impact of the proposed change in base rates on a typical monthly residential electric bill is an increase of 5.3%, or approximately $3.70, for a customer using 1,000 kWh of electricity. Eliminating the VDT and merger surcredit mechanisms, along with the proposed changes in base rates, together, will result in a typical monthly residential electric bill increasing by 6.5%, or approximately $4.50, using the same amount of electricity.

The testimonies of Mr. Rives, Ms. Scott, Ms. Charnas, Mr. Seelye, Mr. Conroy and Mr. Bellar provide a detailed explanation of the calculation of KU's revenue requirement. The testimony of Mr. Avera supports KU's proposed rate of return on equity through an extensive cost of capital analysis. The testimonies of these witnesses demonstrate that KU is not presently earning a fair and reasonable return and present a fair, just and reasonable recommendation for the increase in base rates.

Q. Has KU made significant investments in facilities to serve its customers since its last rate case?

A. Yes. To ensure reliability of service to native load, KU has, among other things, made substantial investments in its utility infrastructure during the last several years, including transmission and distribution systems and electric generation. For example, as discussed in detail in the testimony of Mr. Thompson, the Company is spending approximately $670 million constructing a coal-fired power plant in Trimble County, Kentucky. As a result of these types of investments, since September 30, 2003, the end of the test year used in Case No. 2003-00434, KU has increased its net investment in plant for electric operations by over $1.251 billion.

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

A. Absolutely. We do not take lightly the effect of any increase on our customers, but this needed increase will ensure that our customers continue receiving a high level of service while still enjoying among the lowest rates in the nation. Moreover, it will allow our customers to enjoy 100% of the savings generated from the merger between LG&E and KU.

Consistent with KU's long-standing focus on outstanding customer service, in 2007, J.D. Power & Associates, an international marketing firm, ranked KU, and its sister utility LG&E, first in the Midwest among investor-owned utilities in overall satisfaction among residential electric customers. Those rankings are not arbitrarily assigned – they are based on thousands of interviews with customers throughout the country in several categories. To win, a company has to earn high rankings in such key areas as price/value, power quality and reliability, billing and payment, customer service and overall company image.

For 2008, KU and LG&E remain the highest ranking investor-owned utilities in the nation and continued to be ranked in the top-five for Midsize Midwest utilities.

Q. Please describe KU's commitment to the environment and its efforts in that regard.

A. KU is committed to preserving and protecting the environment. Over the years, the Company has spent hundreds of millions of dollars to reduce pollution by implementing emission control measures and other environmental-friendly practices.

More than two years ago, as Chairman and Chief Executive Officer of E.ON U.S. LLC, I said what few in this industry had publicly said at that time: "There is credible science suggesting that greenhouse gases resulting from human activities are influencing changes in the Earth's climate." At that same time, E.ON U.S. LLC, which is of course the parent company of KU, contributed $1.5 million to the University of Kentucky for the purpose of funding research on how to reduce carbon dioxide emissions from power plants, and announced a three-year partnership with the University of Kentucky's Center for Applied Energy Research to examine technology that separates and captures carbon dioxide from power plants.

KU and LG&E have also jointly agreed to provide $200,000 per year for ten years to the Carbon Management Research Group, a partnership between academia, state government and the private sector, and will jointly provide up to $1.8 million in funding over two years to the Kentucky Consortium of Carbon Storage, which will study the feasibility of geologic storage in the Commonwealth of carbon dioxide from Kentucky coal-fired generation.

Further, and as discussed in more detail in the testimony of Mr. Thompson, KU and LG&E have made a significant pledge of $25 million to the FutureGen project, which is a public-private partnership to design, build, and operate the world's first coal-fueled, near-zero emissions power plant.

Q. Please describe KU's commitment to the community.

A. We are proud of our employees, who give freely of their time and talents by actively volunteering on nonprofit boards, in classrooms, on Little League fields, and in soup kitchens throughout our service territory, to improve the quality of life in the communities where they work and live. KU and LG&E maintain a firm commitment to the community by contributing resources, talent and ideas that support community heritage and economic growth.

In addition, the LG&E Energy Foundation was established in 1994 as a self-sufficient, non-profit business entity with the goal of contributing to the communities we serve by supporting education, diversity initiatives, the environment, and health & safety programs. Since its inception, the LG&E Energy Foundation has awarded more than $20 million in grants in order to proactively support philanthropic initiatives to strengthen communities across the Commonwealth. Not one dollar of these donations is paid by our customers. Instead, the gifts are funded solely by our shareholders.

Q. What steps has KU taken to assist low-income customers with their energy bills?

A. Caring about people and being a good neighbor are much more than corporate obligations to E.ON U.S. LLC. Over the years, KU has developed a number of programs to assist our low-income customers. Several of these programs are administered by way of long standing partnerships between the Company and independent non-profit organizations throughout our service territory. In the testimony of Mr. Hermann, he describes the WinterCare Energy Assistance Fund, the Winter Blitz initiative and our partnering efforts with the Community Action Kentucky. Additionally, Mr. Hermann describes our Home Energy Assistance program and our WeCare energy efficiency program.

Q. Do you have any final comments?

A. In closing, let me reiterate that KU's commitment to provide low-cost, reliable service to its customers is as strong as ever. Although no utility enjoys implementing rate increases, we take great pride in how long we were able to go before asking for this increase. The rate adjustments KU has proposed in this case *are* necessary, and will allow KU to continue to live up to the standard of excellence the Company and its customers 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 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., that he has personal knowledge of the matters set forth in the foregoing testimony, and 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 24th day of July, 2008.

Tammy J. Elzy (SEAL)
Notary Public

My Commission Expires:
November 9, 2010

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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. E.ON U.S. LLC's parent company, E.ON AG, is the world's largest investor-owned electricity and gas company. Mr. Staffieri is also one of the nine members of E.ON AG's Top Executive Council.

Civic Activities

Boards

Metro United Way - Board of Directors – 1998 – 2001; Chairman Metro Campaign 2002
Leadership Louisville – Board of Directors – June 2006 – Present
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

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. 2008-00251**

In the Matter of:

APPLICATION OF LOUISVILLE GAS AND ELECTRIC COMPANY FOR AN ADJUSTMENT OF ITS ELECTRIC AND GAS BASE RATES	))))	**CASE NO. 2008-00252**

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

Filed: July 29, 2008

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 acquired eleven years of experience 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 both regulated and unregulated power generation functions, regulated electric transmission, and regulated and unregulated fuels and energy marketing activities. For purposes of this testimony, I will refer to the above regulated functions collectively as "Energy Services."

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

A. Yes. 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.* 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.* In addition, I 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.

Q. Please provide an overview of your testimony, and comment on the Companies' request for a base rate increase in their cases.

A. In this testimony, I will describe certain notable efficiency initiatives that Energy Services has undertaken over the last several years to manage the increasing costs of doing business, while at the same time preserving service reliability and workforce safety. LG&E and KU have always strived to offer their customers an exceptional value in electric service by striking a balance between two key attributes: low price and high reliability. The Companies' success in achieving this balance to date is a credit to their innovation and initiative.

The innovative steps taken to this point, however, are no longer sufficient to offset the increasing cost of meeting the Companies' service obligations and commitments, particularly now that the Companies are engaged in the process of constructing a new generation unit, Trimble County Unit No. 2. As demonstrated in my testimony and the testimonies of S. Bradford Rives and Lonnie Bellar, LG&E and KU are at a point where they must implement a base rate increase to reflect fully the costs of providing reliable service to their customers, thereby allowing them to maintain the optimum balance between price and reliability.

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

A. Energy Services has three 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; and (iii) to continue to provide high value electric service to LG&E and KU customers.

Q. Please describe LG&E's generation and transmission systems.

A. LG&E's generation system consists primarily of three coal-fired generating stations – Cane Run, Mill Creek, and Trimble County. All of these stations are equipped with 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.

LG&E owns and operates approximately 3,100 MW of generating capacity with a net book value of approximately $1.2 billion. The Company serves approximately 401,000 electricity customers over a transmission and distribution network extending approximately 700 square miles in 8 surrounding counties.

LG&E's transmission plant covers approximately 900 circuit miles, and has a net book value of approximately $120 million.

Q. Please describe KU's generation and transmission systems.

A. KU's power generating 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. By the end of 2010, scrubbers will be in place on all KU coal-fired units with the exception of the much smaller Green River 3 and 4 and Tyrone 3 units. 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.

KU owns and operates approximately 4,400 MW of generating capacity with a net book value of approximately $1.1 billion. The Company serves approximately 505,000 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 $200 million.

The Companies provide their customers with some of the lowest-cost energy in the nation.

Q. Are the generation and transmission systems of LG&E and KU jointly operated since the LG&E and KU merger?

A. Yes. Since 1998, the generation and transmission systems of LG&E and KU have been jointly operated as one system. The joint dispatch of the generation units on both systems allows the companies to achieve operating efficiencies. And, as a result of the merger, we have been able to implement joint integrated resource planning and forecasting for new generation and transmission facilities.

Q. Please describe any additions the Companies are currently making or are planning to make to their generation fleet and transmission systems.

A. On December 17, 2004, LG&E and KU applied for, and by Order dated November 1, 2005, in Case No. 2004-00507, the Commission granted, a certificate of public convenience and necessity to construct Trimble County Unit No. 2 ("TC2"). TC2 will be a state-of-the-art, super-critical, pulverized coal-fired generating unit that will employ the latest technology to achieve extraordinary efficiency and low environmental impact. It is currently scheduled for completion in 2010, and once completed, TC2 will have a nameplate generation capacity of 750 MW, of which the Companies will own 75%, or approximately 563 MW. LG&E will be entitled to 19% or approximately 107 MW, and KU will be entitled to 81% or approximately 456 MW.

The Companies are building significant additional transmission facilities in conjunction with the TC2 project. The Companies have begun construction on 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 proposed line from the east boundary of the Fort Knox Military Reservation to the Hardin County Substation.

The Companies will also construct upgrades and replacements of transmission facilities in Franklin, Anderson and Woodford Counties (owned by KU), as well as a new 345 kV transmission line approximately 2.6 miles long, of which approximately 1.0 mile will be located in Kentucky and 1.6 miles will be located in Indiana (owned by LG&E). The line will run from TC2 and will interconnect with an existing 345 kV transmission line near Marble Hill, Indiana.

Q. What is the status of the Companies' Power Supply Agreement with Electric Energy, Inc.?

A. As LG&E and KU notified the Commission by letter dated December 22, 2005,[1] the Companies' long-standing Power Supply Agreement ("PSA") with Electric Energy, Inc. ("EEI") ended as of January 1, 2006. Until that time, EEI had provided the Companies with approximately 200 MW of relatively low cost-based capacity and energy. EEI elected to pursue market-based pricing beginning in 2006, however, which caused it to no longer be a cost-effective source of capacity or energy for the Companies. The loss of EEI as a source of low-cost supply has increased the Companies' need for TC2 and other cost-effective means of meeting the demand and energy needs of our customers.

Q. Has anything occurred to change the need for TC2?

A. No. The original TC2 certificate of convenience and necessity was based on the same forecast used in the 2005 Integrated Resource Plan ("IRP"). Compared to the 2005 IRP, the current combined Companies' sales forecast for the 2008 – 2012 period has been reduced by an average of 202 GWh per year, or 0.5 percent. Comparing the

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[1] *In the Matter of: The 2005 Integrated Resource Plan of Louisville Gas and Electric Company and Kentucky Utilities Company*, Case No. 2005-00162, Letter from Kent W. Blake to Elizabeth O'Donnell (Dec. 22, 2005).

same time periods, the current combined Companies' peak demand forecast has been reduced by an average of 104 MW per year, or 1.4 percent. The anticipated growth in sales during this period is lower by only 0.4 percent, while the anticipated growth in peak demand during this period is also lower by only 0.4 percent. Through 2022, the average annual reduction in sales is greater (1,630 GWh), as is the average annual reduction in peak demand (345 MW). The differences are primarily driven by the disparity in growth rates throughout the forecast period. With respect to both energy sales and current peak demand, the downward revisions in the 2008 IRP forecast are driven primarily by projected slower growth in large commercial/industrial sales and residential use per customer, which, at least with respect to energy sales, stems from projected efficiency gains resulting from the Energy Independence and Security Act of 2007. The 2008 IRP incorporates the impact of the new lighting and appliance efficiency standards on electricity energy sales and peak demand. Thus, while there has been a nominal decrease in projected demand and energy, the need for TC2 certainly still exists.

Q. Are there any other noteworthy trends or events impacting the Companies' generation or transmission systems?

A. Yes. Tightening environmental constraints could require both LG&E and KU to retire generation units sooner than expected. Retiring such units creates the need for LG&E and KU to find additional generation more rapidly than would otherwise be the case, and provides additional impetus to introduce innovative energy efficiency programs to help reduce demand growth and energy consumption, as I discuss at greater length herein.

Q. What efforts has Energy Services undertaken since the Companies' last base rate case to create efficiencies and manage costs?

A. Energy Services has undertaken a number of initiatives over the last several years aimed at managing costs. One such effort has been to reduce the risk of gas transportation cost shocks for the Companies' Trimble County combustion turbines. The Companies have mitigated this risk by purchasing longer-term firm interstate pipeline transportation capacity.

Energy Services has also taken steps to enhance efficiencies and productivity. These initiatives, which focus largely on asset management, employ improved system analysis techniques, best practices, and technological advances designed to optimize the performance of the Companies' assets and eliminate costly duplication and improve efficiencies in operations and administration.

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

A. As used by Energy Services, the term "asset management" refers broadly to a business discipline for managing the lifecycle of long-term generation and transmission assets, and to maximize the performance of these assets, from both an efficiency and reliability perspective, in the most cost-effective manner possible.

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

A. Yes. On the generation side, Energy Services has implemented a system-wide initiative to enhance long-term boiler circuit availability and, in turn, generating unit performance. Among other things, this initiative is designed to promote more rapid detection of, and more accurate analysis of, boiler circuit failures and failure trends, with the aim of significantly reducing boiler-related availability losses. In addition, LG&E and KU have expanded the use of digital control technology (Distributed Control Systems or DCS) across parts of its generation fleet, allowing the Companies to more accurately control the interrelated operation of various generating unit components and the coordination of various processes integral to power production. This technology not only improves operational efficiencies, but also enhances the real-time diagnostic capabilities of the Companies' operating and maintenance staff.

LG&E and KU also continue to transition from a more rigid, time-based preventive maintenance approach to a predictive, reliability-centered maintenance process for their generation assets, allowing the Companies to efficiently prioritize and allocate maintenance activities and resources consistent with the actual needs of their equipment. Under the Companies' reliability-based maintenance model, equipment within a generating unit (motors, pumps, etc.) is routinely tested to measure equipment performance. If such tests (*e.g.*, vibration and lubricating analyses on rotating equipment) show performance degradation warranting repair, repairs can be made timely and efficiently, as both the equipment and the problem are effectively isolated through the testing process. Should testing reveal more minor performance variations, tests can be undertaken on a more frequent basis, facilitating the timely discovery of equipment problems warranting repair and, in turn, mitigating the risk of major repair or outage-related costs.

It should be noted, however, that even using this more reasonable maintenance approach does not guarantee that maintenance costs will not rise over time. For example, LG&E and KU moved from using a purely time-based maintenance regime for its CTs to using a wear-based maintenance schedule, the main determinants of which are start and run times. Even using this approach, though, O&M and capital maintenance costs rose in 2007 to maintain these CTs. Such costs are likely to continue to rise over time as the Companies increasingly rely on CTs to meet demand.

Enhancements to purchasing and procurement practices have been undertaken to better leverage the types of work being performed during planned outages, and the amount of work that can be packaged into one uniform contract across the fleet, whether it be for outage contract labor or materials. Despite this effort and others, however, costs are rising at a rate greater than general inflation, for both labor and materials, driven by large increases in energy prices, international demand for materials such as steel, aluminum, and copper, and a national spike in the cost of utility construction labor. For example, between January 1, 2004, and January 1, 2007, the cost of constructing steam generating units increased by 25 percent, which is more than triple the rate of inflation over the same time period. Similarly, the cost of transmission plant investments increased by almost 30 percent between 2004 and 2007, or nearly four times the annual inflation rate over that time period.

It also bears mentioning that both LG&E and KU continue to optimize their generation assets through off-system sales. To that end, when market conditions permit, the Companies sell their surplus energy to other utilities. Thus, while the Companies continue to utilize best practices with respect to their operations, they are also able to implement prudent economic strategies to manage their assets with a high degree of efficacy.

Q. Can you offer some specific examples of the Companies' asset management initiatives for their transmission systems?

A. In terms of transmission operational improvements, LG&E and KU have been using thermal-based transmission line ratings, as opposed to seasonal (static) ratings, to measure line capability. The use of thermal-based line ratings has, in my judgment, resulted in a measurable increase in the productivity of the Companies' assets. One indication of the enhanced productivity is the significant decrease in the number of Transmission Line Loading Relief ("TLR") directives called on the Companies' systems by their regional transmission grid operator since the Companies' adoption of a thermal-based rating approach.

Further, Energy Services has increased its use of telemetry equipment, which allows dispatch centers to operate and monitor substation equipment remotely and on a real-time basis. Not only has this initiative created workforce efficiencies, it likewise has enhanced the system's reliability by affording dispatch centers additional continuous monitoring capabilities.

Q. In addition to the asset management initiatives you just described, have the Companies undertaken other operational or work process-related initiatives aimed at achieving efficiencies and managing costs?

A. Yes. In addition to the benefits of joint system dispatch and planning (commencing with the LG&E and KU merger), the Companies increased their employee training and capabilities with respect to both their generation and transmission functions, thereby improving productivity. This has allowed the use of practices such as "multi-skilling" (*e.g.*, training employees to undertake a combination of power plant and scrubber operations), and the sharing of special services or expertise among plants across the fleet (*e.g.*, turbine overhaul specialists and continuous emission monitor testing services). LG&E and KU have increased the attention and resources directed to new training, particularly with respect to transmission employees, as an aging workforce has required a steady stream of new employees to take the places of those retiring.

In addition, similar to other utilities, Energy Services has continued to use independent contractors, or a variable workforce, to perform maintenance and repairs on both its transmission and generation systems. The nature of a variable workforce (specialized and working only when needed) is particularly well-suited to the various needs of Energy Services.

LG&E and KU also place a strong emphasis on promoting a safe working environment for its employees and contractors as they implement the work processes aimed at generating efficiencies. In this regard, the Companies work diligently to develop policies and practices focusing on safety in the workplace.

Q. How has the reliability of LG&E's and KU's generation systems fared over the last several years?

A. LG&E's and KU's generation systems as a whole have been highly reliable historically, as evidenced both by capacity factor trends and actual system reliability performance, measured through systematic benchmarking. In the latter regard, Energy Services' weighted average Equivalent Forced Outage Rate ("EFOR"), a measure commonly used in the industry to gauge the reliability of coal-fired generating units, has historically remained quite low. LG&E's and KU's EFOR between 2004 and 2007 averaged 5.2% and 5.0%, respectively, compared to a national average of 6.5% during the same period. The Companies' EFORs can be attributed to the capital investments made in areas such as boiler circuitry and boiler and turbine controls, as well as continually improving maintenance practices.

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

A. LG&E's and KU's internal analyses show a relatively consistent upward trend in the steam capacity factor of the Companies' coal-fired baseload generating units since 1991. LG&E's capacity factor averaged 71% over the period 1999 through 2003, and that average increased to 78% over the period 2004 through 2007. KU's capacity factor averaged 65% over the period 1999 through 2003, and increased to 66% over the period 2004 through 2007. KU's capacity factor will grow further once the remainder of the scrubbers (to reduce sulfur dioxide) are in place, as its units will be better positioned to be dispatched in closer proximity to the LG&E units, which are already fully scrubbed for sulfur dioxide.

Q. Would you explain in more detail how LG&E and KU benchmark the reliability of their generation assets to others in the industry?

A. LG&E and KU perform reliability (as measured by EFOR) benchmarking on an individual unit basis, and then capacity-weight the unit benchmarks to construct a combined system metric. The benchmarking exercise is essentially a two-step process. First, LG&E and KU establish a "target" performance quartile for each unit, based on an appropriate balance of reliability and cost. For example, LG&E and KU have historically targeted second quartile performance for their older and relatively less efficient units such as KU's Tyrone and Green River facilities and LG&E's Cane

Run facility. It does not make economic sense to target top quartile performance for these units, given the incremental costs necessary to achieve such status.

Once LG&E and KU establish target performance quartiles, they 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. The Companies use three-year EFORs because they minimize the impact of multi-year unit overhauls on cycle performance. It is reasonable to use NERC's RFC region as a basis for comparison because the units in that region are similar to LG&E's and KU's units with respect to design, fuel, installation, vintage and environmental controls. LG&E and KU rely on EFOR data reported by other utilities to NERC.

Q. How does the EFOR of Energy Services' combined system generally compare to those of the benchmark groups described above?

A. The combined system EFOR compares favorably. In fact, based on a comparison to all coal-fired baseload units nationwide, the Companies' overall system EFOR (the capacity weighted average EFOR of all coal-fired generating units) consistently achieves top quartile and second quartile performance. A comparison of the combined system EFOR to the more limited group of comparable units (the second benchmark group described above) shows that the overall system EFOR consistently achieves at least second quartile performance, and is trending towards top quartile performance levels.

Q. Have the Companies invested any capital in their generation systems for reliability purposes over the last several years?

A. Yes. The most significant of the Companies' ongoing generation investments is TC2. The Companies currently project KU will have spent approximately $670 million, and LG&E approximately $160 million, when TC2 is complete and ready for commercial operation. When completed, TC2 will have been constructed at cost of $1,500 per kW, making TC2 a leader in terms of dollars per kW installed among other plants currently under construction in the United States.

Investments in existing power plants have helped with the improvement in reliability and capacity factor. Over the period 2004 through 2007, capital spending for generation projects, excluding TC2 and Environmental Cost Recovery, averaged $36 million and $37 million for LG&E and KU, respectively. In addition, over the past four years, LG&E has spent approximately $17 million on boiler tube projects, with KU spending approximately $3 million on such projects. On system controls projects, LG&E has spent approximately $6 million, while KU has spent approximately $22 million.

Looking to the future, the Companies are planning to meet additional anticipated demand with an additional base load unit, which the Companies included in their 2008 Integrated Resource Plan.

The Companies do not plan to rely solely on securing additional generating capacity to meet future demand. As the Commission is aware, the Commission approved the new and comprehensive suite of demand-side management and energy efficiency programs for which the Companies sought approval in Case No. 2007-00319, the implementation of which should reduce demand and energy usage. Also, the Companies have begun putting in place responsive pricing pilot programs for residential and commercial customers that may help reduce peak demand by using energy pricing to encourage customers to shift energy usage to lower-demand periods whenever possible. The Companies will report to the Commission regularly concerning these pilot programs.

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

A. Concerning clean coal, LG&E and KU have made a significant pledge to the FutureGen project. FutureGen is a public-private partnership to design, build, and operate the world's first coal-fueled, near-zero emissions power plant, at an estimated net project cost of $1.5 billion. The commercial-scale plant will prove the technical and economic feasibility of producing low-cost electricity and hydrogen from coal while nearly eliminating emissions. It will also support testing and commercialization of technologies focused on generating clean power, capturing and permanently storing carbon dioxide, and producing hydrogen. In the process, FutureGen will create unique opportunities for scientific exploration, education, and stakeholder engagement. All investments by LG&E and KU in FutureGen are treated as below-the-line costs.

In addition to clean coal, the Companies plan on refurbishing KU's Dix Dam facility at an estimated cost of $21 million, and are renovating LG&E's Ohio Falls hydroelectric units at a total estimated cost of $130 million. We have completed renovating two of the Ohio Falls units and will renovate the remaining six units as well. The Ohio Falls project is the largest hydroelectric rehabilitation and renovation project currently underway in the Federal Electric Regulatory Commission's ("FERC") jurisdiction.

With respect to renewable energy, and as part of their 2008 IRP, the Companies are undertaking a comprehensive review of generation technology options. To that end, in July of 2007, LG&E and KU announced a Request for Proposal for long-term supply of capacity and energy powered by renewable fuel resources. The Companies have completed an initial screening of the offers received based primarily on the standing of the respondent and the stage of development of project(s) providing the renewable resource, and have entered into more detailed discussions of cost and reliability terms with the short-listed developers.

Q. What have LG&E and KU done to ensure the effective and efficient use and disposal of generation byproducts?

A. The Companies have made provision for adequate ash storage facilities at their generating stations, and have also arranged for the beneficial reuse of gypsum and ash whenever economically feasible. Trimble County, Mill Creek and Ghent all have agreements to off-load gypsum, and Mill Creek has completed a three year plan to move ash from the generating site to a beneficial reuse location. The Companies will continue to examine new and economically reasonable means of beneficially reusing generation byproducts.

Q. Turning to transmission, how has the reliability of the Companies' transmission systems fared over the last several years?

A. The Companies' transmission systems remain highly reliable, though much has changed on the transmission landscape since the Companies' last base rate case.

Most notably, the Companies fully ended their membership in the Midwest Independent Transmission System Operator, Inc. ("MISO") on September 1, 2006. Until then, MISO had acted as the Companies' NERC-certified reliability coordinator. Since then, the Tennessee Valley Authority ("TVA") has filled that role, and the Southwest Power Pool, Inc. ("SPP") has administered the Companies' Open Access Transmission Tariff in accord with relevant federal regulations, including, most recently, FERC Order No. 890-A. Under the stewardship of TVA, SPP, and the Companies, the Companies' transmission systems have remained highly reliable and compliant with all relevant open-access requirements. Moreover, the Companies have substantially lowered their transmission-related costs under TVA and SPP. In that regard, for the last 18 months prior to ending their relationship with MISO, LG&E and KU incurred MISO-related costs of $92.9 million. For the first 18 months after the termination of the MISO relationship, the two utilities incurred costs of $9.7 million for comparable services.

In addition to those more proximate changes, the federal Energy Policy Act of 2005 ("EPAct 2005") brought about significant regional and national transmission reliability management and oversight changes. For example, as part of restructuring the former NERC reliability councils, the reliability council to which the Companies belonged, the East Central Area Reliability Council ("ECAR"), ceased to exist at the end of 2005, when ECAR merged with two other reliability councils to become the aforementioned Reliability First Corporation ("RFC"), effective as of January 1, 2006. RFC is a Regional Entity under the new EPAct 2005 regime, which falls under the purview of the NERC successor, the North American Electric Reliability Corp.

("New NERC"). New NERC is the Electric Reliability Organization under EPAct 2005 and is subject to federal and Canadian government audits. New NERC is responsible for setting transmission reliability criteria in the U.S. and requires mandatory compliance with the Reliability Standards as approved and established for electric utilities by FERC effective June 18, 2007. Thus far, FERC has approved over 90 Mandatory Reliability Standards established by NERC. Compliance with these standards includes plans for each region and utility that assures reliability of electricity across the national grid. LG&E and KU continue to evaluate and assess their internal processes and practices in order achieve a high level of consistency with the newly established Reliability Standards. One understandable byproduct of the Companies' compliance efforts has been an increase in spend directed at transmission reliability practices.

Q. Do the Companies utilize any internal measures to evaluate reliability?

A. Yes. Apart from its commitment to meet the reliability criteria established by New NERC, Energy Services tracks the average duration of service interruptions related to transmission. Because LG&E's and KU's transmission systems are integrated, the Companies track performance on a combined company basis. The Companies use this measure to gauge and trend their performance over time.

Q. Have the Companies made any capital or other investments in their transmission systems over the last several years?

A. Yes. Over the past four years, LG&E and KU have invested more than $32 million and $52 million, respectively, to preserve the reliability of their transmission systems. Once TC2 is in service, KU will have invested approximately $78 million in the transmission at that unit, with LG&E investing approximately $14 million. In addition, KU, which has a much larger transmission system than LG&E, spent approximately $10 million on vegetation management from 2004 – 2007, while LG&E spent almost $2 million over that period.

The Companies have spent approximately $26 million to put in place the Simpsonville Transmission Control and Data Center, a joint transmission dispatch center which will aid in the more efficient coordination of the Companies' combined transmission systems and will also serve as a back-up IT data site for the Companies.

Q. You indicated earlier that LG&E and KU have a strong interest in promoting a safe working environment for their workforces. Please discuss the Companies' safety performance in the areas of generation and transmission.

A. The Companies have worked extremely hard to develop a higher level of trust and partnering among our employees and contractors to reduce injuries in the workplace. We have also performed better and more consistent hazard assessments to prevent the occurrence of injuries. The combined recordable injury incident rate ("RIIR") per 200,000 work hours for LG&E and KU employees (combined to include the impact of employees who support both companies) was 3.72 in the year 2003, 1.93 in 2006, 1.86 in 2007, and 1.54 for 2008 to date. For contractors, the RIIR was 5.48 in 2003, 1.88 in 2006, 1.95 in 2007, and 2.18 for 2008 to date.

Q. Does Energy Services use of independent contractors compromise the Companies' commitment to safety in any way?

A. Absolutely not. Based upon data available from 2006 regarding current contractor injury trends, our contractors have a safety rating that beats the national benchmark by nearly 68%. Although we are pleased with that performance, there is always room for improvement and we will continue to focus on safety for our entire workforce.

One of the ways the Companies are helping to ensure the safety of its workforce is through their drug testing program. While approximately 10% of the employee population is randomly tested for drugs and alcohol on an annual basis, an average of 50% of the regular contractors stationed at each plant are randomly tested each year, and an average of 10% of the contractors on the TC2, Ghent Scrubber and Brown Scrubber sites are randomly tested each month.

Regrettably, and despite our best efforts to prevent against the occurrence of such events, the Companies suffered three contractor fatalities in 2007 from work related to the construction of generation and transmission systems. Though LG&E and KU recognize the dangerous nature of constructing these systems and that all hazards cannot be totally eliminated, it is imperative that we take any and all measures to prevent against these occurrences. To that end, and as discussed by Chris Hermann from the distribution side of the Companies, we have implemented a new Safety Governance Council that will improve on our existing safety measures and help to mitigate against injuries and accidents in the workforce.

Q. Do you have any closing thoughts?

A. Yes. As I stated at the outset of this testimony, Energy Services' mission is predicated on three 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; and

(iii) providing high-value electric service to the Companies' customers. Through the various initiatives described above and the commitment and dedication of its employees, Energy Services has achieved these objectives in the face of mounting cost pressures. Nonetheless, in my professional judgment the Companies cannot continue to meet these goals without the ability to adequately recover their costs. A base rate increase now will allow LG&E and KU to continue to provide the reliable service its customers have grown to expect, at rates that will continue to rank among the lowest in the nation.

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 he is Senior Vice President, Energy Services for E.ON U.S. LLC, that he has personal knowledge of the matters set forth in the foregoing testimony, and the answers contained therein are true and correct to the best of his information, knowledge and belief.

Paul Thompson

PAUL W. THOMPSON

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 24th day of July, 2008.

Kimberly Walters (SEAL)
Notary Public

My Commission Expires:
9/11/2008

APPENDIX

Paul W. Thompson
Senior Vice President - Energy Services
E.ON U.S. LLC

Industry Affiliations

FutureGen Industrial Alliance, Chairman of the Board
Center for Applied Energy Research, Advisory Board Member
Center for Energy and Economic Development, 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
Louisville Downtown Development Corporation Board, Finance Committee Chair
Louisville Free Public Library Foundation Board, Vice Chairman
Chair, Annual Appeal 2002
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 - 1999 – 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
Manager, Financial Planning

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. 2008-00251

TESTIMONY OF
CHRIS HERMANN
SENIOR VICE PRESIDENT – ENERGY DELIVERY
KENTUCKY UTILITIES COMPANY

Filed: July 29, 2008

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

A. My name is Chris Hermann. I am Senior Vice President – Energy Delivery for Kentucky Utilities Company ("KU" or "the Company"), 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 Louisville Gas and Electric Company ("LG&E") that same year. 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 retail operations as well as the gas and electric distribution functions for KU and LG&E (collectively the "Companies"), also known as "Energy Delivery." Our mission is simple. 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 KU and LG&E 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 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*, and 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.*

I. <u>Description of Energy Delivery Operations and Purpose of Testimony</u>

Q. Please describe KU's electric distribution business.

A. KU's distribution business serves approximately 505,000 electric customers in 77 counties in Kentucky. The electric distribution assets we manage include over 460 substations and over 15,000 miles of electric lines, with approximately 2,050 miles of such line being underground. KU's service area covers approximately 6,600 noncontiguous square miles. Our electricity is primarily produced by our coal-fired generating stations which are discussed in greater detail in the testimony of Mr. Paul Thompson.

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

A. In general, we oversee the delivery of electricity to our customers by constructing, operating and maintaining the distribution infrastructure. We take appropriate actions to ensure safety and to restore service to our customers in the event of outages, emergencies, or damage to our distribution system. We also provide retail and customer service functions to our residential, commercial, and industrial customers.

The cornerstone of our retail and distribution operations continues to be our commitment to the safe and reliable provision of service to our customers in a cost-effective manner. We continue to strive to achieve high levels of customer service through both traditional and innovative programs and methods.

Q. What is the purpose of your testimony?

A. My testimony will describe how KU has been able to accomplish its goals related to providing safe, reliable and cost-effective energy services for our retail operations and electric distribution business, while continuing to provide high levels of customer service. I will also briefly explain some of the reasons we need rate relief as it relates to my areas of responsibilities.

Q. Why is KU now seeking a base rate increase?

A. From an energy delivery standpoint, KU's aging infrastructure, coupled with the rise in energy and equipment costs, challenges KU's ability to both reinforce existing infrastructure and extend new systems that will benefit KU's customers without also compromising KU's ability to earn an adequate return on our investment. For example, since the last rate case, KU has invested over $264 million in distribution facilities to serve the needs of its customers.

II. Safety and Reliability

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

A. Energy Delivery is committed to the health and safety of its employees, business partners and the public. Over the last several years, Energy Delivery employees and contractors have continued to reduce the already low number of recordable injuries and lost-time incidents. We believe these achievements and reductions are attributable to KU's demonstrable commitment to safety through its "No Compromise" plan. The "No Compromise" plan was initiated in 2001 for employees and business partners. It clearly states that safety is KU's business priority and core value and that absolutely no other operating priority should come before it. The plan begins with a top-down commitment and is based on modifying behaviors and attitudes in order to create an ownership and safety culture within our workforce. In order to ensure that the plan is operating as it should, we utilize such programs as random field audits, safety tailgates, and quarterly safety meetings. These efforts have resulted in Energy Delivery's employees achieving a 0.63 year-to-date recordable injury rate, which is well below the utility employee industry average of 4.0, and even below the Edison Electric Institute Top Performer designation of 1.67.

In addition, KU holds its contractors to the same high standard as its employees. By making safety a focus of its relationships with its contractors through the Contractor Performance Management program, Energy Delivery's contractors have achieved a 1.79 year-to-date recordable injury rate, which compares well against the industry average of 6.30 for utility contractors. Moreover, Energy Delivery's management team has heightened its presence in the field by increasing formal field safety and quality audits. These policies and practices are supplemented with safety summits to promote the sharing of best practices with respect to safety.

Q. Can you identify some of the measurable improvements that KU has achieved with respect to safety, and any awards evidencing such improvements?

A. In 2007, Energy Delivery had an employee recordable injury rate of 0.81, which is 82% lower than our rate in 2004. Similarly, our 2007 contractor recordable injury rate was 1.63, which is an improvement of 94% compared to our 2004 rate. In 2007, E.ON U.S., comprised of KU and LG&E, was ranked first in the Edison Electric Institute Safety Survey for lost-work-day cases and days away, restricted or transferred rates, amongst combined utilities of similar size. As a result of our efforts, Energy Delivery has received a number of safety awards over the past few years, which are listed in Appendix B.

Q. What is KU doing to build on these successes?

A. In 2007, E.ON U.S., and in turn KU and LG&E, implemented a Corporate Safety Governance Council. The Council is a standing advisory team comprised of five executive-level officers, including myself, that is dedicated to continuing the Companies' top-down commitment to safety by utilizing a companywide collaborative approach to promote and provide leadership support for the adoption of best practice initiatives throughout the Companies.

The Council meets on a quarterly basis, or more often as needed, to actively address safety issues and discuss strategies for addressing such issues. In addition to providing leadership, the Council's objectives include: providing a formal mechanism for the thorough exchange of safety information and ideas at the highest level of the organization; ensuring optimum application of safety processes and elimination of process redundancies; and, ensuring contractors and business partners have processes in place to promote adherence to safety practices and procedures that meet or exceed our own standards. The Council is supported by a Council Working Group, which consists of safety managers and leaders from the Companies' various operations. The Council Working Group meets on a quarterly basis, or more frequently as needed, to conduct and provide evaluations, research and recommendations for Council leadership review, and to assist with the adoption of best safety practices within the Companies. One of the many initiatives of the working group is to hold cross-functional sessions outlining current high level safety issues and to recommend how, when and where to implement appropriate safety improvements company-wide.

Energy Delivery also has a Contractor Safety Council, which is comprised of some of our larger contractors, as well as Energy Delivery personnel. The Contractor Council meets quarterly to discuss safety issues and helps set the agenda for quarterly meetings attended by all of Energy Delivery's contractors, wherein performance from the prior quarter is discussed along with the strategies for addressing safety issues.

Q. In your testimony in KU's last rate case, you mentioned that KU and LG&E were about to implement a new Outage Management System. Has that taken place yet?

A. Yes. In 2004, we implemented a new Outage Management System in order to improve crew management and dispatch functions during outages by tracking incoming calls to assist in quickly identifying system protective devices (e.g., fuses) that have operated, thus improving dispatch efficiency.

Q. How has KU performed in the area of electric reliability?

A. KU measures distribution reliability by utilizing performance metrics such as the Customer Average Interruption Duration Index ("CAIDI"). CAIDI is the product of two measurements known as SAIDI (System Average Interruption Duration Index) and SAIFI (System Average Interruption Frequency Index). SAIDI is defined as the average electric service interruption duration in minutes per customer for the specified period and system. SAIFI is defined as the average electric service interruption frequency per customer for the specified period and system. CAIDI, which combines these two measurements, is defined as the average electric service interruption duration per interrupted customer for the specified period and system. KU's measures in 2003 indicated an upward trend in duration and frequency of interruptions. In response, we increased our investment in reliability, including our new outage management system, and are now beginning to see improvements.

Q. Are there any other actions KU takes to ensure reliability?

A. Yes. On December 12, 2006, the Commission initiated an investigation of, among other things, the vegetation management practices related to electric utility distribution systems in Kentucky. Consistent with KU's existing vegetation management program, KU prepared and filed its vegetation management plan on December 19, 2007. KU's Distribution Vegetation Management Program encompasses 13,600 miles of right of way maintenance. The program is centralized and managed by a Forestry Manager and six Company Utility Arborists. All arborists are certified by the International Society of Arboriculture. In addition, the Company employs four professional tree contractor companies. Utility line clearing is undertaken to maintain an acceptable level of safety, reliability of service, and access to KU's facilities for maintenance and repair.

KU's plan, as submitted to the Commission on behalf of both KU and LG&E, includes the application of a flexible multi-cycle strategy to address growth and tree density which will vary across the service area. One of the objectives of the plan is to maintain a proactive trim cycle while balancing the reactive needs of high maintenance circuits.

III. Efforts to Achieve Efficiencies

Q. In your testimony in KU's last rate case, you discussed a technology called GEMINI, which KU and LG&E were about to implement as part of its asset management initiatives. Has GEMINI been successful?

A. Yes. Since the last rate case, KU and LG&E completed the implementation of the Geospatial Enterprise Management Integration Network Initiative ("GEMINI") in December 2004. GEMINI consists of a Work Management System, Graphical Design Tool, Geospatial Information System, and the aforementioned Outage Management System. The work management system tracks the workflow of all customer-driven and planned work activities starting with project initiation, estimation, approvals, scheduling, and ending with field completion. The graphical design tool provides a framework for consistent design which is then automatically inserted in the Geospatial Information System as the distribution infrastructure changes.

Each Operation and Crew Center now utilizes the same suite of applications which allows Energy Delivery to use a more centralized approach in the management of work and resources.

Q. Please generally describe KU's initiatives and technologies aimed at cost management.

A. Over the past several years, KU has continued to undertake a number of initiatives, such as our Scheduling and Planning strategy and our Contractor Performance Management initiative, designed to manage costs by increasing efficiencies and achieving synergies, without compromising safety, reliability and customer service.

The Scheduling and Planning strategy is made possible by this GEMINI system, and is a simple yet effective way KU and LG&E manage their work force. The Scheduling and Planning organization was established in late 2004 and consists of six individuals who have varied backgrounds in the distribution business. For planned work initiatives greater than $25,000, the Scheduling and Planning organization maintains an overall construction schedule and assigns work crews between 11 operation centers based on scheduled in-service dates established by customers and our Asset Management organization. The Scheduling and Planning group also measures operational performance, all within a monthly reporting structure to Energy Delivery management. In effect, our Scheduling and Planning strategy allows us to look across the expanse of our territory and efficiently deploy our expenditures in the right places.

The previously mentioned Contractor Performance Management Program allows us to more efficiently manage our contractors through improved oversight. As part of this program, KU establishes measurements and controls designed to improve the productivity, safety, and quality of the work performed by our contractors, establishes targets for unit measure of the work to be performed, and provides contractors with reviews and feedback on their performance. Many of KU's Contractor Performance Management processes incorporate the use of incentive mechanisms to increase productivity without diminishing reliability or safety.

IV. <u>Customer Service and Focus</u>

Q. Describe KU's customer satisfaction levels.

A. In recent years, KU has continued to be nationally recognized for its strong customer focus and outstanding customer service. In 2004, 2005, 2006 and 2007, J.D. Power and Associates ranked LG&E Energy (both KU and LG&E), which became known as E.ON US in 2006, first in the Midwest in its residential survey of the nation's largest electric utilities. E.ON U.S. also ranked first in the Midwest in customer satisfaction in J.D. Power's 2007 survey of midsize business electric customers.

The J.D. Power electric studies focus on customer service, power quality and reliability, company image, price/value and billing. Although the methodology employed by J.D. Power in conducting and reporting its surveys changed in 2008, KU and LG&E were still ranked number three and two, respectively, among mid-sized utilities in the Midwest, and were the highest ranking investor-owned utilities in the nation.

Q. Please describe some of the customer service-oriented programs and initiatives.

A. Since its last rate case, KU has initiated a number of programs and efforts aimed at providing a high level of service to our customers. Chief among these are our Energy Efficiency Programs, the Green Energy Program and Carbon on the Bill. The Companies have also launched the Customer Commitment Advisory Forum to encourage on-going dialogue between the Companies and the entities that provide assistance to our customers most in need. The Companies have also renewed the Home Energy Assistance Program that was established at the time of the last rate case and have a community partnership program that distributes Low Income Heating Assistance Program funds to families who qualify for assistance. Overlaying those specific initiatives, the Companies are in the process of implementing a new Customer Care Solution system ("CCS"), a comprehensive business system that will operate as the foundation for all wide-ranging interactions with customers.

Q. Please describe CCS and the benefits KU and its customers can expect from the new system.

A. CCS is a hardware and software solution that essentially serves as the central source and warehouse for all customer-related information. As such, CCS will support the wide array of KU's customer-interfacing processes. These include customer interaction in the call centers and business offices, customer self-service over the web, service orders, billing and revenue related finance activities, as well as the reporting associated with these activities. Each of these categories includes numerous functions and processes that will allow KU to provide improved interactions with the customers. The system was described to an extent in 2007 in Case No. 2007-00410. The CCS project addresses hundreds of business processes collectively in the areas mentioned above, allowing for efficient operation under a common solution. The implementation of this system will require approximately 100 interfaces to existing internal and external systems used by the Companies. Replacing a core CIS system which dates to the late 1980's at KU, this system will provide more capability for contemporary rate design and enhanced customer self-services functions. This project is a multi-year initiative and is expected to be implemented in 2009. The comprehensive system will provide the foundation for the continued provision of high-quality customer service to KU's customers for 2009 and beyond.

Q. Please describe the Energy Efficiency Programs.

A. Since the last rate case, the Companies have operated several energy efficiency programs under the Demand-Side Management Program Plan for 2000 through 2007. The plan included programs for Demand Conservation Load Control, Residential and

Commercial Energy Audits, and WeCare Low Income Weatherization. On July 19, 2007, the Companies filed an Application seeking approval to establish a new Energy Efficiency Program Plan (also known as a Demand-Side Management or "DSM" filing) for 2008 through 2014. The Commission approved the Application in March 2008. The application included enhancement of the existing programs and implementation of several new programs. Many of the programs help to reduce peak demand, enabling us to use our power plants more efficiently and delay the addition of new ones, which, in turn, benefits all of our electric customers. The Demand Conservation Load Control program alone has already allowed the Companies to reduce peak demand by 110 MW and perpetually avoid the construction of a combustion turbine of that size. Appendix C provides a description of each program. The total annual budget of the new set of programs is approximately $26 million - a significant increase over the previous annual budgets of almost $10 million. These programs, which are currently under development, are expected to reduce the need for additional generation capacity in the future, with implementation occurring over the balance of 2008.

Q. Please describe the program known as "Carbon on the Bill."

A. Since July 2007, customer bills began containing a notation of the estimated amount of carbon dioxide emissions associated with each customer's consumption. This information is coupled with monthly tips on what actions customers can take to reduce their carbon footprint. This helps give customers greater awareness of and control over the impact of their energy usage on the environment. To our knowledge, KU and LG&E are the first utilities in the nation to provide this information to customers on their bills.

Q. Please describe the Customer Commitment Advisory Forum.

A. The Companies, in an effort to improve customer satisfaction within a particular customer segment, launched the E.ON U.S. Customer Commitment Advisory Forum to provide a forum for discussion for the Companies and the low-income advocate stakeholders. This forum is intended to promote open, meaningful dialogue and to ultimately provide input and guidance to the Companies regarding strategies, policies and practices that relate to the provision of electric and gas service to customers in need and their families. Three meetings have been held since September of 2007, and a fourth meeting is scheduled for later this year. Topics discussed to date include Customer Identification, Heating Season assistance, low-income customer weatherization programs, budget billing, expectations regarding winter gas prices, and other topics.

Q. Please describe the Green Energy Program.

A. In February of 2007, the Companies submitted an application to the Commission to establish a Green Energy Program. The program, which allows customers to contribute funds to be used for the purchase of Renewable Energy Certificates, or Green Tags, was approved by the Commission on May 31, 2007. The program allows customers to voluntarily contribute funds in $5 blocks (residential/commercial) or $13 blocks (industrial) for the Companies to purchase Green Tags from qualified renewable resources. The Green Tags are sourced first from the Mother Ann Lee Hydroelectric power station at Lock & Dam Number 7 on the Kentucky River, then from other qualified hydroelectric, landfill gas, or wind resources in Kentucky and surrounding states. The Green-E certified program is designed to be revenue neutral, with 75% of all revenues received being expended to purchase Green Tags and 25% of all revenues being expended on promotion aimed at increasing participation in the program.

Q. Please describe the Home Energy Assistance Program aimed at assisting low-income customers.

A. The Home Energy Assistance ("HEA") program that was established following the last rate case expired in September 2007. In order to continue the provision of assistance to low-income customers, the Companies filed an Application to renew the HEA program. The Commission approved the Application on July 30, 2007 in Case No. 2007-00338. In this program, KU collects 10 cents per residential meter per month to support the provision of hardship assistance to low income customers. In addition, KU participates in the WinterCare Energy Assistance Fund, a statewide energy assistance fund supported privately by utilities and community action agencies, which also provides assistance to low income individuals during the winter heating season.

Q. Please describe Winter Blitz and Community Action Kentucky.

Beginning in 2005, KU undertook an effort, in conjunction with the Lexington Community Action Council, to "weatherize" the homes of low-income, elderly and disabled persons in our service area. In 2007, over 30 KU employees and their family members participated in the Winter Blitz. We are working to expand the program in the coming years to also include free workshops where customers are taught how to weatherize their own homes and receive free weatherization kits.

The Community Action Kentucky ("CAK") agencies distribute Low Income Heating Assistance Program ("LIHEAP") funds to families who qualify for such assistance. For several years, we have partnered with CAK to ensure that our business processes are streamlined and do not impede our low income customers' efforts to apply any LIHEAP funds they receive to their outstanding utility bills.

Conclusion

Q. Can you briefly summarize your testimony?

A. Yes. KU and LG&E have implemented a number of programs and initiatives designed to provide safe and reliable service and to ensure that our customers continue to receive service they have come to expect and deserve. However, as explained by Mr. S. Bradford Rives, KU's current rates do not provide sufficient revenue to recover the costs incurred to allow for a reasonable return on investment. As a result, we are seeking an increase in our base rates.

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 he is Senior Vice President – Energy Delivery for Kentucky Utilities Company, that he has personal knowledge of the matters set forth in the foregoing testimony, and 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 23rd day of July, 2008.

Kathy L Wilson (SEAL)
Notary Public

My Commission Expires:
Jan. 22, 2009

KATHY L WILSON
Notary Public, State at Large, KY
My Commission Expires: January 22, 2009

APPENDIX A

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

Current Major Accountabilities
Effectively leads organizations and individuals that manage:

- Business strategies, plans, and budgets that are consistent with the company's philosophy and financial targets, as well as with E.ON requirements.
- Core operating processes designed to achieve financial and best practice targets.
- Natural gas and electric distribution operations functions focused on new customer connections, network enhancement, and network operation and maintenance.
- Service restoration and emergency operations that minimize adverse customer impact.
- Customer Service functions including metering, customer call centers, marketing, revenue collection, economic development, and business offices.
- Assets so as to maximize investment.
- Service provision that exceeds customer expectations and results in excellent customer satisfaction.
- Uniform material and construction standards to achieve maximum cost and process efficiencies.
- The Operating Services organization, including real estate, right of way, and facilities management, in addition to offices services and critical security operations.
- Assets and the operation of interests in the Argentine gas businesses.
- International Electric Distribution and Gas Transmission Best Practice for E.ON worldwide.

Previous Accountabilities
In previous positions, Chris has been responsible for these key areas:

- Generation
- Transmission
- Fuel Procurement
- Off-System Sales
- Plant Construction
- Load Dispatch
- Engineering Services
- Business Integration

Key Strengths

- Comprehensive knowledge of energy industry operations and issues.
- Strategic planning expertise.
- Strong commercial orientation and associated skills.
- Powerful leadership and change agent capabilities.
- Sound financial and management skills.
- Analytical and judgmental expertise.
- Extraordinary interpersonal skills demonstrated by positive working relationships with employees, peers and international audiences.

Previous Company Positions

E.ON US, Louisville, KY

December 2000 – February 2003: Senior Vice President, Distribution Operations

Louisville Gas and Electric, Louisville, KY

January 2000 – December 2000: Vice President, Supply and Logistics
May 1999 – December 1999: Vice President, Business Integration
June 1998 – April 1999: Vice President, Power Generation and General Services
May 1997 – May 1998: Vice President, Business Integration
1993 – May 1997: Vice President and General Manager, Wholesale Electric Business
1992 – 1993: General Manager, Wholesale Electric
1990 – 1991: General Manager, Power Production
1984 – 1990: Manager of Administration, Power Production
1978 – 1984: Plant Manager, Cane Run

Present Civic Activities

University of Louisville Speed Scientific School
Board of Industrial Advisors: 1992
Chairing Board Sub-Committee
Lutheran Family Services
Board of Directors: current
Kentucky State Park Foundation
Board of Directors: current
Metro United Way
Campaign Cabinet: current

Previous Civic Activities

Louisville Orchestra Development Committee: 2001, 2002, 2003
Technology Network of Louisville
Executive Committee Member: 2002, 2003
Founding Member: *2001*
Board Member: 2001, 2002

Fund for the Arts Corporate Campaign: 2002
Advanced Technology Council
Board Member: 1999
President: 2000
Leadership Louisville Class of 1994
Bingham Fellows Class of 2000
LG&E Employees Credit Union, Chairman of the Board: 1984 - 1992
University of Louisville Speed Scientific School, Elected Chairman of the Board of Advisors: 1993 - 1994, 2002
Friends of Scouting Campaign, Vice Chair
Lincoln Heritage Council of Boy Scouts, Explorer Post Sponsor: 1997 – 1998
United Way, Variety of positions
Volunteers of America, Major Gifts Vice Chair: 1999, 2000, 2001
Junior Achievement, Variety of positions

Professional/Trade Memberships

Southern Gas Association Board Member
American Gas Association Board Member
American Gas Association Safety Task Force Board Member
American Management Association
American Gas Association Executive Committee (January—December 2008)
American Society of Mechanical Engineers
Association for Quality Participation

Previous Professional/Trade Memberships

OVEC [Ohio Valley Electric Corporation], Board of Directors and Executive Committee
EEI [Edison Electric Institute] Generation Subject Area Committee, National Chair
EEI Prime Movers Committee
EEI Power Supply Technical Task Force
EEI Engineering, Operating, and Standards Executive Advisory Committee
ECAR [East Central Area Reliability Group] Executive Board and Executive Board Working Group

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: 2003

APPENDIX B

<u>2007 Energy Delivery Safety Awards</u>

- Royal Society for the Prevention of Accidents Awards
- Distribution Operations, Retail Business and Retail Metering
- American Gas Association DART Award
- American Gas Association top performer in employee safety
- Edison Electric Institute Safety Achievement Award
- Danville/Lexington Substation Construction and Maintenance
- Edison Electric Institute Safety Achievement Award
- Central Substation Construction and Maintenance
- Southern Gas Association Safety Achievement Award
- Center storage area
- Southern Gas Association Safety Achievement Award
- Gas Distribution and Maintenance
- Kentucky Governor's Health and Safety Award
- Pineville Substation Construction and Maintenance
- Kentucky Gas Association Accident Prevention Award

APPENDIX C

E.ON U.S. Energy Efficiency Programs	
Program	Comment
"Demand Conservation" Load Control Program	This program provides for the installation of a switch on air conditioning units or water heaters that permits LG&E/KU to cycle that load to manage demand at peak times. For participating, the customer receives either a $20 credit per year or a programmable thermostat. Program enrollment exceeds 115,000 at present and provides ~110 MW of peak demand savings.
Residential Energy Audits	This program provides energy audits for residential customers to identify areas for reduction of wasted energy.
Commercial Energy Audits	This program provides energy audits for commercial customers to identify areas for reduction of wasted energy.
"WeCare" Low Income Weatherization	This program provides for energy improvements at the homes of qualified low income customers.
Efficient Lighting Program	Working with manufacturers or retailers, this program will provide incentives to put Compact Fluorescent Light ("CFL") bulbs into the residential market. Promotion of other forms of efficient lighting is included. Several million CFLs are contemplated over the first few years.
HVAC Diagnostics/ Tune-Up	The program will offer central air conditioning or heat pump diagnostics at a subsidized cost. Customers needing remediation could choose to have an "approved" dealer make repairs at a reduced cost. The program would focus on over- or under- refrigerant charge and air flow restrictions.
Residential New Construction	The Company will encourage builders to develop homes that meet the Energy Star standards. Homes must pass plan reviews and on-site inspections to ensure compliance.
Dealer Referral Network	This program will provide customers with a list of energy efficiency dealers who agree to meet certain minimum standards, such as insurance and bonding, but would also agree to perform services according to manufacturer and industry standards and requirements.
Public Information and Education	This program will educate the public, including school students, about energy efficiency.
Program Development and Administration	This program will allow LG&E/KU to invest in energy efficiency program design that is not easily assigned to an individual program noted above, including research—e.g. new technologies for metering, control systems, etc.

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. 2008-00251**

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

Filed: July 29, 2008

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") 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 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.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to describe why the financial condition of KU requires the requested increase in base rates, present the Financial Exhibits to KU's application, review KU's accounting records, describe the calculation of KU's adjusted net operating income for the twelve month period ended April 30, 2008, and support the different valuations of KU's property.

<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, but, as my testimony will demonstrate, its financial condition has declined due to its continuous investment in facilities to serve customers. Even with ongoing initiatives to control costs and improve efficient operations described by Messrs. Thompson and Hermann, KU's financial results for the twelve-month period ending April 30, 2008, are below a reasonable level.

It is essential that KU achieve and maintain a strong financial condition to allow it to 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 September 30, 2003, the test period used by the Commission in Case No. 2003-00434?

A. Yes. The following chart shows KU's investment in net utility plant has increased by approximately $1.25 billion since September 30, 2003:

Net Utility Plant

	September 30, 2003	April 30, 2008	Increase
Utility plant	$3,527,901,229	$5,151,234,451	$1,623,333,222
Accumulated depreciation	$1,600,258,255	$1,927,362,645	$372,104,390
Net utility plant	$1,927,642,974	$3,178,871,806	$1,251,228,832

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 10.9 percent to 12.7 percent. He has recommended the Commission adopt an 11.25 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 Mr. Avera's recommendation. For the twelve months ended April 30, 2008, KU's electric operations earned an adjusted return on equity of 9.96 percent, below the recommended 11.25 percent ROE, and an adjusted return on capital of 7.64 percent.

It is important to keep in mind that these test-year adjusted *earned* return figures are overstated because they include pro forma adjustments to eliminate the LG&E/KU Merger Surcredit Rider ("MSR") and Value Delivery Team ("VDT") surcredit mechanisms. These mechanisms in fact were in effect during the test year, but are now or will be terminated going forward. If these surcredits continued (which they would if KU did not seek new base rates in this proceeding), the adjusted earned return on equity for KU's electric operations would be only 9.08 percent, far below Mr. Avera's recommended ROE. Therefore, although the VDT surcredit will expire upon the filing of KU's application in this proceeding[1] and the merger surcredit will expire when KU's new base rates go into effect,[2] the fully "pro formed" *earned* ROE for KU's electric operations do not completely portray the full extent of KU's current need to seek and obtain new base rates for its electric operations.

PSC Financial Exhibits

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

[1] Pursuant to the settlement agreement approved by the Commission in Case No. 2005-00351.
[2] Pursuant to the settlement agreement approved by the Commission in Case No. 2007-00563.

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 April 30, 2008.

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 audits KU's financial statements annually. The most recent opinion of our external auditor is provided in Filing Requirements Tab 30.

<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 April 30, 2008. Because the historical test year is used instead of a forecasted test year, it is necessary that the historical test year be adjusted to reflect 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 1.41 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 April 30, 2008, shown on Rives Exhibit 1.

A. For the electric operations as reflected in the twelve month period ended April 30, 2008, 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, 1.02, 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, 1.15, 1.16, 1.21, 1.27, 1.30, 1.31, 1.32, and 1.35),

d) Adjust for other excludable unusual, non-recurring or out-of-period items in the test year (Reference Schedules 1.08, 1.11, 1.17, 1.18, 1.19, 1.20, 1.22, 1.23, 1.24, 1.25, 1.26, 1.28, 1.29, 1.33, and 1.34), and

e) Adjust for federal and state income tax expenses for these pro-forma adjustments (Reference Schedules 1.39 - 1.41).

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

A. This adjustment has been made to eliminate the effect of unbilled revenues. It is consistent with a similar adjustment in the revenue requirements analysis performed and found reasonable by the Commission in its June 30, 2004 Order in the

Company's most recent base rate case, Case No. 2003-00434. 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 Exhibit 1.

A. The adjustment has been made to eliminate the merger surcredit mechanism as directed by the Commission's June 26, 2008 Order in Case No. 2007-00563. 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 1.02 of Exhibit 1.

A. The adjustment has been made to eliminate the VDT surcredit mechanism as directed by the Commission's March 24, 2006 Order in Case No. 2005-00351. 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 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 April 30, 2008. It is consistent with a similar adjustment in the revenue requirements analysis performed and found reasonable by the Commission in its June 30, 2004 Order in the Company's most recent base rate case, Case No. 2003-00434. 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 Exhibit 1.

A. Reference Schedule 1.04 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 October 31, 2007 Order in Case No. 2006-00509. It is consistent with a similar adjustment in the revenue requirements analysis performed and found reasonable by the Commission in its June 30, 2004 Order in the Company's most recent base rate case, Case No. 2003-00434. 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 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. It is consistent with a similar adjustment in the revenue requirements analysis performed and found reasonable by the Commission in its June 30, 2004 Order in the Company's most recent base rate case, Case No. 2003-00434. 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 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 March 28, 2008 Order in Case No. 2007-00379. It is consistent with a similar adjustment in the revenue requirements analysis performed and found reasonable by the Commission in its June

30, 2004 Order in the Company's most recent base rate case, Case No. 2003-00434. This adjustment was prepared by Mr. Conroy and is discussed in his testimony.

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

A. This adjustment includes the environmental compliance costs associated with off-system sales revenues. This adjustment is made in accordance with the methodology approved by the Commission in its June 1, 2000 Order in Case No. 98-474. It is also consistent with the Commission's determination in Case No. 94-332 that LG&E should assign eligible environmental compliance costs attributable to off-system sales that are otherwise eligible for environmental surcharge recovery. Furthermore, it is consistent with a similar adjustment in the revenue requirements analysis performed and found reasonable by the Commission in its June 30, 2004 Order in the Company's most recent base rate case, Case No. 2003-00434. 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 Exhibit 1.

A. This adjustment has been made to eliminate electric brokered sales revenues and expenses as directed by the Commission in Case No. 98-474. It is consistent with a similar adjustment in the revenue requirements analysis performed and found reasonable by the Commission in its June 30, 2004 Order in the Company's most recent base rate case, Case No. 2003-00434. This adjustment was prepared by Shannon L. Charnas and is discussed in her testimony.

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

A. This adjustment is necessary to eliminate accrued revenues associated with the ECR, MSR, VDT, and FAC rate mechanisms. It is consistent with a similar adjustment in the revenue requirements analysis performed and found reasonable by the Commission in its June 30, 2004 Order in the Company's most recent base rate case, Case No. 2003-00434. This adjustment was prepared by Ms. Charnas and is discussed in her testimony.

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

A. This adjustment has been made to remove the impact of the revenues and expenses associated with KU's demand-side management mechanism from the test year revenues and expenses. It is consistent with a similar adjustment in the revenue requirements analysis performed and found reasonable by the Commission in its June 30, 2004 Order in the Company's most recent base rate case, Case No. 2003-00434. 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. This adjustment was prepared by Ms. Charnas and is discussed in her testimony.

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

A. This adjustment has been made to reflect weather normalized electric sales margins. 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 Exhibit 1.

A. This adjustment has been made to annualize revenues based on actual customers at April 30, 2008. It is consistent with a similar adjustment in the revenue requirements analysis performed and found reasonable by the Commission in its June 30, 2004 Order in the Company's most recent base rate case, Case No. 2003-00434. This adjustment was prepared by Mr. Seelye and is discussed in his testimony.

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

A. This adjustment has been made to reflect annualized depreciation expenses under the new rates proposed in this case as applied to plant-in-service as of April 30, 2008. The calculation of the adjustment was prepared by Ms. Charnas and is discussed in her testimony. The proposed new rates are based on a depreciation study conducted by Gannett Fleming, Inc., in Case No. 2007-00565, *In the Matter of: Application of Kentucky Utilities Company to File Depreciation Study*. The justification for these new rates is set forth in John Spanos's testimony in Case No. 2007-00565. On July 9, 2008, KU filed a motion with the Commission requesting an order consolidating the record in *In the Matter of: An Adjustment of the Electric Rates, Terms and Conditions of Kentucky Utilities Company*, Case No. 2008-00251, with the record in *In the Matter of: Application of Kentucky Utilities Company to File Depreciation Study*, Case No. 2007-00565.

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

A. This adjustment has been made to reflect increases in labor and labor-related costs as applied to the twelve months ended April 30, 2008 and includes specific adjustments for labor, payroll taxes, and KU's 401(k) match. It is consistent with a similar adjustment in the revenue requirements analysis performed and found reasonable by the Commission in its June 30, 2004 Order in the Company's most recent base rate case, Case No. 2003-00434, and in Case No. 2000-00080. 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 1.16 of Exhibit 1.

A. This adjustment is necessary to annualize pension and post-retirement medical benefit expenses. It is consistent with a similar adjustment in the revenue requirements analysis performed and found reasonable by the Commission in its June 30, 2004 Order in the Company's most recent base rate case, Case No. 2003-00434, and in Case No. 2000-00080. 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 Exhibit 1.

A. This adjustment has been made to reflect the appropriate amount of post-employment benefits in the test year. 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 Exhibit 1.

A. This adjustment has been made to reflect a normalized level of storm damage expenses. It is consistent with a similar adjustment in the revenue requirements analysis performed and found reasonable by the Commission in its June 30, 2004 Order in the Company's most recent base rate case, Case No. 2003-00434. 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 1.19 of Exhibit 1.

A. This adjustment is made to normalize the expense levels in Account 925 "Injuries and Damages." It is consistent with a similar adjustment in the revenue requirements analysis performed and found reasonable by the Commission in its June 30, 2004 Order in the Company's most recent base rate case, Case No. 2003-00434. 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 1.20 of Exhibit 1.

A. This adjustment eliminates advertising expenses pursuant to 807 KAR 5:016 that are primarily institutional and promotional in nature. It is consistent with a similar adjustment in the revenue requirements analysis performed and found reasonable by the Commission in its June 30, 2004 Order in the Company's most recent base rate case, Case No. 2003-00434. 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 1.21 of Exhibit 1.

A. This adjustment removes amortization of Earnings Sharing Mechanism ("ESM") and management audit expenses, which is consistent with a similar adjustment in the revenue requirements analysis performed and found reasonable by the Commission in its June 30, 2004 Order in the Company's most recent base rate case, Case No. 2003-00434. 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 1.22 of Exhibit 1.

A. The adjustment removes out-of-period operation and maintenance expenses associated with the FERC assessment fee, which is necessary to reflect properly the annual FERC assessment fee operation and maintenance expenses. 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 Exhibit 1.

A. This adjustment is made for the Midwest Independent Transmission System Operator, Inc. ("MISO") exit regulatory asset and Schedule 10 regulatory liability. In its May 31, 2006 Order in Case No. 2003-00266, the Commission authorized LG&E and KU to establish for accounting purposes both a regulatory asset for the MISO exit fee and a regulatory liability upon exiting MISO for the revenues associated with Schedule 10 charges included in existing rates. 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 1.24 of Exhibit 1.

A. This adjustment is to amortize East Kentucky Power Cooperative, Inc. ("EKPC") transmission settlement charges consistently with the treatment of other MISO exit costs. The adjustment was prepared by Mr. Bellar and Ms. Scott and is discussed in their testimonies. Ms. Scott notes that KU has requested in this proceeding that the Commission authorize the Company to establish a regulatory asset for the costs of the EKPC transmission depancaking settlement agreement.

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

A. This adjustment is to reflect the reallocation of Ohio Valley Electric Corporation ("OVEC") demand charges between LG&E and KU. This adjustment was prepared by Ms. Scott and is discussed in her testimony.

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

A. This adjustment is for reserve margin demand purchases. This adjustment was prepared by Mr. Bellar and is discussed in his testimony.

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

A. This adjustment is necessary to include amortization of the expenses incurred in conjunction with this base rate case. It is consistent with a similar adjustment in the revenue requirements analysis performed and found reasonable by the Commission in its June 30, 2004 Order in the Company's most recent base rate case, Case No. 2003-00434, and in Case No. 2000-00080. 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 1.28 of Exhibit 1.

A. This adjustment is to operating and maintenance expenses for retirement of Tyrone Units 1 and 2. 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 1.29 of Exhibit 1.

A. This adjustment is to reflect properly expenses for Information Technology ("IT") prepaid maintenance contracts in the test year. 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 1.30 of Exhibit 1.

A. This adjustment is necessary to reflect a postage rate increase. 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 1.31 of Exhibit 1.

A. This adjustment is necessary to reflect the annualized cost of vehicle fuel, which continues to rise dramatically. 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 Exhibit 1.

A. This adjustment is necessary to reflect the cost of the letter of credit bank fees associated with the new credit facilities the Company will require. The new facilities are necessary because certain of the Company's debt that is currently in the auction rate mode is facing higher interest rates as the result of the financial difficulties of bond insurance companies. The Commission has approved the refinancing of the tax-exempt bonds in Case No. 2008-00132.

The adjustment assumes bonds totaling $200,000,000 will be backed by letters of credit. These fees are based on a proposal from a bank willing to provide a portion of these facilities under current market conditions. These fees will be on-going expenses paid quarterly for as long as the letters of credit remain outstanding. The current expectation is that letters of credit will remain outstanding for the duration of the pollution control bonds once they are reissued. The Company anticipates updating these costs as the facilities are put in place during this proceeding.

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

A. This adjustment is made to adjust property tax expenses for non-recurring credits during the test year. 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 1.34 of Exhibit 1.

A. This adjustment is to remove out-of-period use tax expenses. 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 1.39 of Exhibit 1.

A. This adjustment is for federal and state income taxes corresponding to the base revenue and expense adjustments discussed above. It is consistent with a similar adjustment in the revenue requirements analysis performed and found reasonable by the Commission in its June 30, 2004 Order in the Company's most recent base rate case, Case No. 2003-00434. 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 1.40 of 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. It is consistent with a similar adjustment in the revenue requirements analysis performed and found reasonable by the Commission in its June 30, 2004 Order in the Company's most recent base rate case, Case No. 2003-00434, and in Case No. 2000-00080. 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 1.41 of Exhibit 1.

A. This adjustment is for income tax true-ups and adjustments made during the test year that relate to prior periods and is in accordance with the Commission's approval of this type of adjustment in the Company's most recent base rate case, Case No. 2003-00434. This adjustment was prepared by Ms. Scott and is discussed in her testimony.

Capitalization and Weighted Average Cost of Capital

Q. Please explain the capital structure of KU.

A. As I have expressed in previous testimony before the Commission in Case No. 2003-00434, 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.

Q. What is the current target capital structure?

A. KU's current capital structure is established in accordance with the criteria set by Standard and Poor's, an independent credit rating agency. Standard and Poor's 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 established by Standard and Poor's is 43 percent to 49.5 percent for A rated utilities with a business position of 4. Prior to Standard and Poor'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, Standard and Poor's has adopted a business risk/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. The Company's financial risk profile is Intermediate for which Standard and Poor's suggests a maximum debt to total capital of 50 percent to remain in this category. Based on these criteria, the Company is targeting an adjusted equity to total capital ratio (including imputed debt for purchased power) of 52 percent. As shown on Rives Exhibit 2, the overall jurisdictional adjusted equity component of capital (not including the purchased power adjustment) is 52.63 percent, as of April 30, 2008.

Including the imputed debt from long-term purchased power agreements of $86.1 million, the equity component of capital is 51.06 percent, as of April 30, 2008.

Q. What impact do long-term purchased power agreements have in determining the Company's target capital structure?

A. The Company treats the purchased power agreements as debt in determining the target capital structure because the rating agencies require such obligations to be treated as fixed obligations equivalent to debt. KU has significant purchased power contracts with Owensboro Municipal Utilities and Ohio Valley Electric Corporation. Although these contracts are attractively priced, the rating agencies consider payments under these contracts to be debt equivalents in establishing the ratings. Standard and Poor's recently released review of KU noted that it has imputed $86.1 million of debt equivalent to KU for 2006. If this adjustment is made to the capital structure shown in Rives Exhibit 2, KU's debt to total capitalization ratio increases to 48.94 percent - just below the maximum debt in the range published by Standard and Poor's. This indicates an equity component of capital of 51.06 percent, at the low end of the Standard and Poor's guideline range. Disregarding the impact of the purchased power agreements could limit the Company's future access to attractively priced debt capital.

Q. Have you prepared an exhibit showing KU's capitalization as of April 30, 2008?

A. Yes. Exhibit 2, shows KU's capitalization at April 30, 2008, for electric operations.

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 April 30, 2008, as well as the weighted average cost of capital to apply to the adjusted capitalization. As indicated on Exhibit 2, the requested rate of return on electric capitalization as of April 30, 2008, is 8.31 percent, based on the proposed 11.25 percent return on common equity.

Q. Please explain the calculation of the adjusted 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, April 30, 2008. 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). Column 3 adjusts the short- and long-term capital amounts by the amounts of bonds the Company reacquired but did not retire. The Company expects to have issued these bonds into the market before the end of calendar year 2008. Columns 4 through 6 are adjustments to capitalization that are totaled (with column 3) in column 7 of Rives Exhibit 2. These three adjustments are to remove undistributed subsidiary earnings, KU's equity investment in Electric Energy Inc., and KU's investment in Ohio Valley Electric Corporation consistent with the adjustments approved in the Commission's Order in Case No. 2003-00434. 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). Each row of column 13, the Cost of Capital, is the product of the corresponding rows of columns 11, the Adjusted Jurisdictional Capital Structure, and column 12, the Annual Cost Rate of each source of capital.

Q. **Will you please explain the adjustments to capitalization contained in column 3 of Rives Exhibit 2?**

A. Yes. In order to obtain lower interest rates on selected variable rate pollution control debt, KU used bond insurance and an auction mechanism periodically to reset the debt's variable interest rates. Recently, the bond insurance companies insuring selected KU variable interest rate pollution control bonds have experienced credit downgrades. The credit downgrades have resulted from the bond insurers' diversification into insuring riskier types of debt, such as securities backed by sub-prime home mortgages. In some cases, the downgrades have resulted in failed auctions, which result in the interest rate being set at a higher rate pursuant to the terms of the indenture. Due to the state of the auction bond market, KU is converting from auction mode interest rates to fixed rates or another variable mode utilizing additional liquidity or credit support facilities. The Commission has approved the refinancing of the tax-exempt bonds in Case No. 2008-00132.

This adjustment is necessary to reflect the reacquired but not retired bonds that are presently recorded as short term debt, but which will become long term debt later this year when they are reissued.

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

A. Yes. Column 10 reflects the removal of ECR investment from capitalization through the use of the Jurisdictional Rate Base Percentage (which includes an ECR rate base adjustment) in column 9 applied to the Adjusted Total Company Capitalization in column 8. Through this adjustment, the appropriate amount of environmental surcharge assets is removed from the Company's capitalization through the balanced and well-established rate-base allocation method shown on Rives Exhibit 3. This approach is explained on pages 25 through 29 of my testimony.

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

A. Column 11 (Adjusted Jurisdictional Capital Structure) of Rives Exhibit 2 calculates the respective capitalization percentages for the components of adjusted capitalization from column 10 (e.g., line 1, column 10 divided by line 4, column 10 equals line 1, column 11). Column 12 (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 April 30, 2008. The annual cost rate for Long Term Debt is the embedded cost of the outstanding pollution control bonds, including reacquired but not retired bonds, and inter-company loans outstanding as of April 30, 2008. 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 Mr. Avera and supported in his testimony. Column 13 then calculates the weighted average cost of capital by multiplying column 11 by column 12, resulting in 8.31 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 April 30, 2008?

A. Yes. Page 1 of Rives Exhibit 3 shows KU's net original cost rate base at April 30, 2008, using a similar format to the one KU has used in prior rate cases. 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. Page 3 of Rives Exhibit 3 shows the calculation of the Kentucky jurisdictional ECR Rate Base at April 30, 2008.

Q. Please explain rows 8 through 12 of Rives Exhibit 3 concerning asset retirement obligation assets, liabilities, and accumulated depreciation.

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 the following:

> 1) Approves the regulatory assets and liabilities associated with adopting SFAS No. 143 and going forward;
>
> 2) Eliminates 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, such amounts will be reclassified to accumulated depreciation for rate-making purposes of calculating rate base; and
>
> 4) 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 will be excluded from rate base.[3]

In KU's most recent base rate case, Case No. 2003-00434, KU excluded ARO assets from rate base.[4] The Commission approved the exclusion in its June 30, 2004 Order in that proceeding.[5]

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 assets, liabilities, and accumulated depreciation from rate base, as shown in rows 8 through 12 of Rives Exhibit 3.

Q. Please explain the adjustment made in row 13 of Rives Exhibit 3, "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.[6] The deduction from rate base associated with the investment tax credits KU has received is shown in row 13 of Rives Exhibit 3.

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[3] *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).

[4] *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).

[5] *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).

[6] *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).

Q. Please explain the adjustments made to the original cost rate bases in columns 3 and 4 on page 1 of Rives Exhibit 3.

A. Column 3 of Exhibit 3 is the entirety of KU's Kentucky jurisdictional ECR rate base as of April 30, 2008. In order to remove KU's Kentucky jurisdictional ECR rate base from its overall Kentucky jurisdictional electric rate base shown in column 2, the difference between the amount shown in column 3 (total Kentucky jurisdictional ECR rate base) and the amount in column 4 (Kentucky jurisdictional ECR roll-in) is calculated to arrive at the amount in column 5 (Kentucky jurisdictional net ECR rate base). Because some of the ECR rate base amounts are incorporated or "rolled into" base rates per the Commission's March 28, 2008 Order in Case No. 2007-00379, those amounts in column 4, "Kentucky Jurisdictional ECR Roll-In Rate Base" are subtracted from KU's Kentucky jurisdictional ECR rate base amount in column 3 to yield the amount in column 5, KU's Kentucky jurisdictional net ECR rate base. The amount in column 5 (Kentucky Jurisdictional Net ECR Rate Base) is then subtracted from the amount in column 2 (Kentucky Jurisdictional Rate Base as of April 30, 2008) to arrive at the amount in column 6 (Kentucky Jurisdictional Base Rate Base at April 30, 2008). The total net Original Cost Rate Base percentages are shown on line 23 under column 5 (13.86 percent for Kentucky Jurisdictional Net ECR Rate Base), column 7 (12.20 percent for Other Jurisdictional Rate Base), and column 6 (73.94 percent for Kentucky Jurisdictional Base Rate Base) at April 30, 2008. The Kentucky Jurisdictional Base Rate Base at April 30, 2008 percentage (73.94 percent) appears in column 9 on Exhibit 2 and is applied to Adjusted Total Company Capitalization in column 8 on Exhibit 2 to produce the amounts in column 10 on Exhibit 2, Adjusted Kentucky Jurisdictional Capitalization.

Q. Is this allocation consistent with the adjustment to capitalization to reflect the exclusion of the environmental surcharge in Case Nos. 1998-474 and 2003-00434?

A. While the methodology is different, the allocation is consistent with the purpose and goal of the Commission adjustment in those cases, which was "to remove the effects of a stand-alone cost recovery mechanism from the determination of KU's base rate revenue requirements."[7] KU is addressing this issue in this proceeding in accord with the Commission's final order in Case No. 2007-00178.[8] In that order, the Commission denied KU's request to establish rate base allocation of capitalization as the correct method of allocating capitalization between ECR and non-ECR rate base, stating (1) that it was not reasonable in that proceeding (a non-base-rate proceeding) to establish base rate methodologies and (2) that KU had not shown that the Commission's historical method of allocating capitalization was unreasonable. As I discuss below, KU's proposed methodology is reasonable, and the Commission's historical methodology is not; the Commission should, therefore, adopt and establish KU's proposed rate base allocation of capitalization as the appropriate methodology for allocating capitalization in KU's current and future base rate cases.

Q. Is the allocation of the capitalization based on the rate base allocation methodology to reflect the exclusion of the environmental surcharge assets a

[7] Case No. 1998-474, Order at 3 (June 1, 2000).
[8] *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 Ratemaking Methods for Base Rates*, Case No. 2007-00178, Order at 9 (Sept. 7, 2007).

more reasonable method than the adjustment to capitalization in Case Nos. 1998-474 and 2003-00434?

A. Yes. First, using the rate base allocation methodology to remove the ECR capitalization from total capitalization rather than the Case No. 1998-474 method avoids understating the capitalization supporting the appropriate amount of electric rate base. Deferred income taxes are well-established reductions in the calculation of rate base and are always included in the calculation of the ECR rate base. The recovery of deferred taxes from customers effectively reduces KU's capitalization to fund ECR projects from the level it would be without them. The Case No. 1998-474 approach, however, overlooks the impact of deferred taxes on reducing the overall amount of ECR capitalization in the adjustment used to remove ECR capitalization in the determination of base revenue requirements.

Tab 28 to KU's Application contains the Reconciliation of Capitalization And Rate Base, Kentucky Jurisdiction ("Reconciliation"). Lines 1 through 13 of the Reconciliation calculate capitalization as filed in this case and indicate the allocation of such capitalization among ECR, Base Electric, and Other Jurisdictional. Lines 15 through 41 list the adjustments necessary to reconcile from Capitalization to Rate Base in total and for each of the components shown. Finally, Line 43 lists total Rate Base and each of its components.

As shown in the Reconciliation, KU's accumulated deferred income taxes and KU's investment tax credits are not reconciling items between capitalization and rate base. This is so because both reduce capitalization and rate base. Thus, excluding these items, as was done using the Case No. 98-474 approach, creates an inflated

ECR capitalization that does not exist and that is not considered in determining ECR revenues, and in effect establishes a lower than actual cost of doing business.

Second, the allocation of capitalization using the rate base methodology is simple, straightforward, and accurate, and produces a reasonable result. The Commission has used this methodology to allocate the capital supporting retail base rates in LG&E's and KU's rate cases for years. KU has used this same methodology for many years to allocate the appropriate amount of capital to Kentucky and Virginia retail jurisdictions and wholesale jurisdictions. KU's sister company, LG&E, has used this methodology to allocate the appropriate amount of capital between electric and gas operations for years. Allocating the capitalization supporting ECR rate base from the Company's overall capitalization using the rate base allocation methodology is consistent with the use of this allocation methodology to allocate the appropriate amount of capitalization supporting electric and gas operations for base rate purposes, and is consistent with the method for allocating capitalization to the Kentucky jurisdiction for base rate making purposes. Not including the ECR rate base as part of the determination of the rate base allocation percentages is inconsistent with this well-established ratemaking method.

In sum, it is appropriate to deduct accumulated deferred income taxes and investment tax credits when calculating ECR rate base, as is done in ECR filings (see Exhibit 3). The calculation of relative rate base percentages on Exhibit 3 correctly deducts accumulated deferred income tax and investment tax credits. By using the rate base percentages shown at the bottom of page 1 of Exhibit 3 to allocate capitalization, KU has allocated the correct amount of the ECR capitalization from total capitalization and reflected accurately the amount of capitalization supporting the rate base associated with electric retail base rates.

Q. Have you prepared a schedule showing an adjustment to KU's capitalization reflecting the methodology in Case No. 1998-00474 to remove the effects of the ECR?

A. Yes. Appendix B of my testimony contains this information. KU has provided the calculation as an informational matter, but does not believe it is reasonable because it does not accurately allocate the capitalization between base rates and the ECR rate base. It treats deferred taxes and investment tax credits inconsistently for rate base purposes and capitalization purposes. As I previously stated, deferred taxes and investment tax credit ("ITC") impact rate base and capitalization in the same manner and, therefore, must be treated consistently.

Q. Have you prepared an exhibit showing KU's pro forma rate base as of April 30, 2008?

A. Yes. Exhibit 4 shows KU's pro forma rate base as of April 30, 2008. This exhibit also contains the adjustments I previously described in connection with 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 April 30, 2008?

A. Yes. The estimated net reproduction cost rate base at April 30, 2008, 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 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 as of April 30, 2008. The net estimated reproduction cost at April 30, 2008, is approximately $1.5 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 April 30, 2008?

A. Yes. Rives Exhibit 7 shows the actual electric rate of return earned for the twelve months ended April 30, 2008, was 7.85 percent on jurisdictional net original cost rate base, 7.86 percent on jurisdictional pro forma rate base, and 4.22 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 7.77 percent on jurisdictional net original cost rate base, 7.77 percent on jurisdictional pro forma rate base, and 4.18 percent on jurisdictional reproduction cost rate base.

Q. Have you prepared an exhibit showing the calculation of the overall revenue deficiency at April 30, 2008 for KU?

A. Yes. Rives Exhibit 8 shows the calculation of the revenue deficiency at April 30, 2008, for KU to be $22,199,996.

Q. Have you prepared an exhibit showing the calculation of Kentucky jurisdictional rate of return on common equity for the twelve months ended April 30, 2008?

A. Yes. Exhibit 9 shows the return on KU's Kentucky retail jurisdictional electric operations for the twelve months ended April 30, 2008 is 7.64 percent, including a 9.96 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 $22,199,996 through the proposed changes in electric base rates.

Q. Does this conclude your testimony?

A. Yes.

KENTUCKY UTILITIES

Adjustments to Operating Revenues, Operating Expenses and Net Operating Income
For the Twelve Months Ended April 30, 2008

	Reference Schedule (1)	Operating Revenues (2)	Operating Expenses (3)	Net Operating Income (4)
1. Jurisdictional amount per books		1,154,156,041	980,014,414	$ 174,141,627
2. Adjustments for known changes and to eliminate unrepresentative conditions:				
3. Adjustment to eliminate unbilled revenues	1.00	(6,878,000)	-	(6,878,000)
4. Adjustment to eliminate Merger Surcredit	1.01	18,568,431	-	18,568,431
5. Adjustment to eliminate Value Delivery Surcredit	1.02	3,405,550	-	3,405,550
6. To adjust mismatch in fuel cost recovery	1.03	(116,253,633)	(96,155,056)	(20,098,577)
7. To adjust base rates and FAC to reflect a full year of the FAC roll-in	1.04	98,267	-	98,267
8. Adjustment to eliminate Environmental Surcharge revenues and expenses	1.05	(54,342,557)	(16,467,656)	(37,874,901)
9. To adjust base rate revenues and expenses to reflect a full year of the ECR roll-in	1.06	21,935,653	8,506,554	13,429,099
10. Off-system sales revenue adjustment for the ECR calculation	1.07	(371,295)	-	(371,295)
11. To eliminate electric brokered/swap sales revenues and expenses	1.08	90,748	(8,127)	98,875
12. To eliminate ECR, MSR, VDT, and FAC accruals	1.09	17,682,129	-	17,682,129
13. To eliminate DSM revenue and expenses	1.10	(4,429,150)	(4,437,148)	7,998
14. To reflect weather normalized electric sales margins	1.11	(8,721,229)	(4,355,146)	(4,366,083)
15. Adjustment to annualize year-end customers	1.12	(4,243,045)	(2,747,550)	(1,495,495)
16. This adjustment left intentionally blank	1.13			
17. Adjustment to reflect annualized depreciation expenses under proposed rates	1.14	-	236,248	(236,248)
18. Adjustment to reflect increases in labor and labor related costs	1.15	-	1,549,969	(1,549,969)
19. Adjustment for pension and post retirement costs	1.16	-	(152,671)	152,671
20. Adjustment for post-employment benefits	1.17	-	1,114,405	(1,114,405)
21. Adjustment to reflect normalized storm damage expense	1.18	-	(2,731,370)	2,731,370
22. Adjustment for injuries and damages FERC account 925	1.19	-	664,233	(664,233)

KENTUCKY UTILITIES

Adjustments to Operating Revenues, Operating Expenses and Net Operating Income
For the Twelve Months Ended April 30, 2008

		Reference Schedule (1)	Operating Revenues (2)	Operating Expenses (3)	Net Operating Income (4)
23. Adjustment to eliminate advertising expenses pursuant to Commission Rule 807 KAR 5:016		1.20	-	(436,901)	436,901
24. Adjustment to remove amortization of ESM and Management audit expenses		1.21	-	(37,986)	37,986
25. Adjustment to remove out-of-period FERC assessment fee		1.22	-	(497,965)	497,965
26. Adjustment for MISO Exit and Schedule 10		1.23	-	1,961,979	(1,961,979)
27. Adjustment for EKPC settlement charges		1.24	-	(1,338,790)	1,338,790
28. Adjustment to reflect reallocation of OVEC demand charges		1.25	-	2,721,857	(2,721,857)
29. Adjustment for reserve margin demand purchases		1.26	-	1,199,403	(1,199,403)
30. Adjustment to reflect amortization of rate case expenses		1.27	-	324,904	(324,904)
31. Adjustment to expenses for Retirement of Tyrone Units 1 and 2		1.28	-	(9,585)	9,585
32. Adjustment to O&M expenses for IT prepaid contracts		1.29	-	978,329	(978,329)
33. Adjustment for postage rate increase		1.30	-	65,522	(65,522)
34. Adjustment to reflect annualized vehicle fuel costs		1.31	-	198,608	(198,608)
35. Adjustment for cost of new bank credit facilities		1.32	-	2,005,628	(2,005,628)
36. To adjust property tax expense		1.33	-	447,054	(447,054)
37. To adjust use tax expense		1.34	-	(208,516)	208,516
38. These adjustments left intentionally blank		1.35 - 1.38			
39. Total of above adjustments			(133,458,131)	(107,609,774)	(25,848,357)
40. Federal and state income taxes corresponding to above adjustments	37.602802 %	1.39		(9,719,707)	9,719,707
41. Federal and state income taxes corresponding to annualization and adjustment of year-end interest expense		1.40		(1,198,199)	1,198,199
42. Prior income tax true-ups and adjustments		1.41		709,277	(709,277)
43. Total adjustments			(133,458,131)	(117,818,403)	$ (15,639,728)
44. Adjusted Net Operating Income			1,020,697,910	862,196,011	$ 158,501,899

Exhibit 1
Reference Schedule 1.00
Sponsoring Witness: Bellar

KENTUCKY UTILITIES

Adjustment to Eliminate Unbilled Revenues

1. Unbilled revenues at April 30, 2007	$	32,325,000
2. Unbilled revenues at April 30, 2008		(39,203,000)
3. Decrease in book revenues due to unbilled revenues	$	(6,878,000)

Exhibit 1
Reference Schedule 1.01
Sponsoring Witness: Bellar

KENTUCKY UTILITIES

Adjustment to Eliminate Merger Surcredit
For the Twelve Months Ended April 30, 2008

1. Revenue returned to customers through the merger surcredit and amortization of amounts previously returned to customers for the 12 months ended April 30, 2008	$(18,568,431)
2. Merger Surcredit revenue adjustment	$ 18,568,431

Exhibit 1
Reference Schedule 1.02
Sponsoring Witness: Bellar

KENTUCKY UTILITIES

Adjustment to Eliminate Value Delivery Surcredit
For the Twelve Months Ended April 30, 2008

1. Actual Value Delivery Surcredit refunded	$ (3,405,550)
2. Value Delivery Surcredit revenue adjustment	$ 3,405,550

Exhibit 1
Reference Schedule 1.03
Sponsoring Witness: Conroy

KENTUCKY UTILITIES

To Adjust Mismatch in Fuel Cost Recovery
For the Twelve Months Ended April 30, 2008

Expense Month	Revenue Form A Page 5 of 6 Line 3	Expense Form A* Page 5 of 6 Line 8
May-07	8,716,887	14,323,725
Jun-07	17,054,396	7,862,564
Jul-07	14,102,349	11,867,445
Aug-07	8,427,673	24,141,033
Sep-07	12,857,244	11,116,718
Oct-07	18,470,295	3,641,713
Nov-07	9,752,453	11,294,739
Dec-07	3,874,557	1,975,449
Jan-08	14,078,486	(182,250)
Feb-08	2,143,207	7,962,301
Mar-08	(160,217)	966,474
Apr-08	6,936,303	1,185,145
Total	$ 116,253,633	$ 96,155,056
Adjustment	$ (116,253,633)	$ (96,155,056)

* NOTE : Expenses are recovered in the second succeeding month. For example, January 2008 would be reflected in March 2008.

Exhibit 1
Reference Schedule 1.04
Sponsoring Witness: Conroy

KENTUCKY UTILITIES

To Adjust Base Rates and FAC to Reflect a Full Year of the FAC Roll-in
For the Twelve Months Ended April 30, 2008

1. Adjustment to base rate revenues to reflect a full year of the FAC roll-in	$	84,205,087
2. Adjustment to FAC revenues to reflect a full year of the FAC roll-in		(84,106,820)
3. Net adjustment	$	98,267

Exhibit 1
Reference Schedule 1.05
Sponsoring Witness: Conroy

KENTUCKY UTILITIES

Adjustment to Eliminate Environmental Surcharge Revenues and Expenses
For the Twelve Months Ended April 30, 2008

Expense Month	Revenues All Plans (1)	Expenses Post '94 Plan (2)	Net
May-07	$ 2,339,019	$ 1,000,328	
Jun-07	3,973,879	1,759,415	
Jul-07	4,095,263	2,144,308	
Aug-07	4,367,489	2,028,724	
Sep-07	5,094,711	1,499,893	
Oct-07	4,696,399	1,617,797	
Nov-07	3,486,782	1,554,607	
Dec-07	5,482,500	1,627,390	
Jan-08	8,085,888	1,424,993	
Feb-08	5,168,528	1,449,628	
Mar-08	2,964,623	1,178,399	
Apr-08	4,587,476	1,580,406	
	$ 54,342,557	$ 18,865,888	
Kentucky Jurisdiction (Reference Schedule Allocators)		87.288%	
Total	$ 54,342,557	$ 16,467,656	$ 37,874,901
Adjustment	$ (54,342,557)	$ (16,467,656)	$ (37,874,901)

(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.

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 April 30, 2008

		Electric
1. Adjustment to base rate revenues to reflect a full year of the ECR roll-in	$	21,935,653
2. Adjustment to expenses to reflect a full year of the ECR roll-in	$	8,506,554

NOTE: ECR Roll-in pursuant to Commission's Order dated March 28, 2008 in Case No. 2007-00379.

Determination of Expenses Roll-In (Attachment to Response to Question No. 11 (a)(c)):

a. Total Pollution Control Operating Expenses	$	10,743,151
b. Less Gross Proceeds from By-Product & Allowance Sales		(997,763)
c. Total Expenses Roll-In	$	9,745,388
d. Kentucky Jurisdiction (Reference Schedule Allocators)		87.288%
e. Adjustment	$	8,506,554

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 April 30, 2008

	(1)	(2)	(3)	(4)	(5)	(6)
	KU Off-System Sales Revenue	KU Off-System Sales Intercompany Revenue	KU Off-System Sales Revenue Less Intercompany (Col. 1 - 2)	Monthly Environmental Surcharge Factor (1)	Average Environmental Surcharge Factor	Off-System Sales Environmental Cost (Col. 3 * 5)
May-07	2,893,472	2,874,230	19,242	4.47%	5.06%	974
Jun-07	3,421,235	2,893,920	527,315	4.86%	5.06%	26,682
Jul-07	3,762,428	3,573,739	188,689	5.27%	5.06%	9,548
Aug-07	1,832,015	1,717,673	114,342	5.31%	5.06%	5,786
Sep-07	2,907,154	1,965,421	941,733	4.67%	5.06%	47,652
Oct-07	5,250,562	4,431,541	819,021	6.11%	5.06%	41,442
Nov-07	3,827,419	3,201,175	626,244	7.14%	5.06%	31,688
Dec-07	6,100,090	5,444,225	655,865	5.27%	5.06%	33,187
Jan-08	6,669,148	6,174,146	495,002	3.29%	5.06%	25,047
Feb-08	2,841,790	2,780,773	61,017	5.31%	5.06%	3,087
Mar-08	7,301,946	5,383,972	1,917,974	3.73%	5.06%	97,049
Apr-08	5,316,025	3,232,717	2,083,308	5.33%	5.06%	105,415
Total	$ 52,123,284	$ 43,673,532	$ 8,449,752			$ 427,557
Average				5.06%		
Kentucky Jurisdiction (Reference Schedule Allocators)						86.841%
Total						$ 371,295
Adjustment						$ (371,295)

(1) ES Form 1.00

KENTUCKY UTILITIES

To Eliminate Electric Brokered Sales Revenues and Expenses
For the Twelve Months Ended April 30, 2008

1. Brokered Sales	$	506,097
2. Brokered Expense recorded in revenues		610,596
3. Net Brokered Sales revenue adjustment		(104,499)
4. Kentucky Jurisdiction (Reference Schedule Allocators)		86.841%
5. Kentucky Jurisdiction Net Brokered Sales Revenue	$	(90,748)
6. Kentucky Jurisdiction Net Brokered Sales Revenue adjustment	$	90,748
7. Operating Expense related to Brokered Sales		9,359 *
8. Kentucky Jurisdiction (Reference Schedule Allocators)		86.841%
9. Kentucky Jurisdiction Brokered Sales Operating Expense	$	8,127
10. Kentucky Jurisdiction Brokered Sales Operating Expense adjustment	$	(8,127)
11. Net Kentucky Jurisdictional adjustment (Line 6 - Line 10)	$	98,875

*NOTE: Reflects 2.71% 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, VDT and FAC Accruals
For the Twelve Months Ended April 30, 2008

1. ECR Accrued Revenue in Accounts 440-445	$ 6,711,871
2. MSR Accrued Revenue in Accounts 440-445	489,000
3. VDT Accrued Revenue in Accounts 440-445	132,000
4. FAC Accrued Revenue in Accounts 440-445	(25,015,000)
5. Total Kentucky Jurisdictional Accrued Revenues	$ (17,682,129)
6. Adjustment	$ 17,682,129

Exhibit 1
Reference Schedule 1.10
Sponsoring Witness: Charnas

KENTUCKY UTILITIES

To Eliminate DSM Revenues and Expenses
For the Twelve Months Ended April 30, 2008

1. DSM Revenue adjustment	$	(4,429,150)
2. DSM Expense adjustment		(4,437,148)
3. Total	$	7,998

Exhibit 1
Reference Schedule 1.11
Sponsoring Witness: Seelye

KENTUCKY UTILITIES

Adjustment to Reflect Weather Normalized Electric Sales Margins
For the Twelve Months Ended April 30, 2008

1. Revenue adjustment	$	(8,721,229)
2. Expense adjustment		(4,355,146)
3. Net adjustment	$	(4,366,083)

Exhibit 1
Reference Schedule 1.12
Sponsoring Witness: Seelye

KENTUCKY UTILITIES

Adjustment to Annualize Year-End Customers
At April 30, 2008

1. Revenue adjustment	$ (4,243,045)
2. Expense adjustment	(2,747,550)
3. Net adjustment	$ (1,495,495)

Exhibit 1
Reference Schedule 1.13
Sponsoring Witness:

KENTUCKY UTILITIES

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Exhibit 1
Reference Schedule 1.14
Sponsoring Witness: Charnas

KENTUCKY UTILITIES

Adjustment To Reflect Annualized Depreciation Expenses Under Proposed Rates At April 30, 2008

1. Annualized depreciation expense under proposed rates (1)	$111,536,507
2. Depreciation expense per books for test year	$124,356,219
3. Depreciation expense for asset retirement costs (ARO)	335,141
4. Depreciation for post-1995 environmental cost recovery (ECR)	12,754,702
5. Depreciation expense per books excluding ARO and post-1995 ECR	$111,266,376
6. Total Adjustment to reflect annualized depreciation expense (Line 1 - Line 5)	270,131
7. Kentucky Jurisdiction (Reference Schedule Allocators)	87.457%
8. Kentucky Jurisdictional adjustment	$ 236,248

(1) Reflects proposed rates per Case No. 2007-00565.

KENTUCKY UTILITIES

Adjustment to Reflect Increases in Labor and Labor-Related Costs
As Applied to the Twelve Months Ended April 30, 2008

1.	Labor (Page 2)	$ 1,389,036
2.	Payroll Taxes (Page 3)	105,228
3.	401(k) (Page 4)	244,558
4.	Total	1,738,822
5.	Kentucky Jurisdiction (Reference Schedule Allocators)	89.139%
6.	Kentucky Jurisdictional adjustment	$ 1,549,969

KENTUCKY UTILITIES

Adjustment to Reflect Increases in Labor and Labor-Related Costs
As Applied to the Twelve Months Ended April 30, 2008

				Construction/	
1	Labor for 12 months ended April 30, 2008:		Operating	Other	Total
2.	Base		$ 64,595,765	$ 27,317,163	$ 91,912,928
3.	Overtime and Premium		8,588,366	2,206,534	10,794,900
4.	TIA		7,040,236	2,717,525	9,757,761
5.	Total Labor		$ 80,224,367	$ 32,241,222	$ 112,465,589
6	Total Operating and Construction/Other %		71 3%	28 7%	100 0%
7.	Total labor Excluding TIA		$ 73,184,131	$ 29,523,697	$ 102,707,828
8.	Total Operating and Construction/Other %		71 3%	28 7%	100 0%
9.	Annualized base labor at April 30, 2008:			Employees	
10.	Union			144	$ 9,036,805
11.	Exempt KU			133	10,636,390
12.	Non-Exempt/Hourly			684	38,194,236
13.	Exempt SERVCO (allocated to KU)	(45 4% of total)		357	31,190,524
14	Non-Exempt SERVCO (allocated to KU)	(45 4% of total)		110	4,473,183
15.	Total Annualized Labor			1,428	93,531,138
16.	Union Overtime/Premiums (a)				2,513,431
17.	Union labor increase applied to union overtime (5/07-7/07 OT labor x 3.5%)				18,169
18.	Non-Exempt/Hourly/Servco Overtime/Premium (a)				8,281,469
19.	Labor Increase applied to Non-Exempt/Hourly/Servco Overtime/Premium (5/07 - 2/08 OT labor) x 3.5%				246,490
20	Total Annualized Labor				$ 104,590,697
21.	Operating Labor for 12 months ended April 30, 2008				$ 73,184,131
22.	Operating Labor based on annualized labor				
	$ 104,590,697	x	71 3%		74,573,167
23.	Labor Adjustment Total				$ 1,389,036

(a) Represents actual numbers taken from the Company's financial records for the 12 months ended April 30, 2008

KENTUCKY UTILITIES

Adjustments to Reflect Increases in Payroll Taxes
As Applied to the Twelve Months Ended April 30, 2008

1	Operating Labor increase (Page 2 Line 23)	$ 1,389,036
2	Percentage of labor that does not exceed Social Security (OASDI) limit	98.80%
3	Operating Labor increase subject to Social Security tax	$ 1,372,368
4	Medicare Tax (Line 1 x 1.45%)	$ 20,141
5	Social Security Tax (Line 3 x 6.2%)	85,087
6	Payroll Tax adjustment	$ 105,228

KENTUCKY UTILITIES

Adjustment to Reflect Increases in Company Match of 401(k)
As Applied to the Twelve Months Ended April 30, 2008

1	Direct total payroll for 12 months ended 04/30/08 (Page 2 Line 5)	$ 112,465,589
2	Total 401(k) Company Match for 12 months ended 04/30/08	3,622,085
3	401(k) Company Match as a percent of payroll	3.22%
4	Operating Labor increase (Page 2 Line 23)	1,389,036
5	401(k) Company Match operating increase (Line 3 x Line 4)	$ 44,727
6	401(k) Company Match increase from 60% to 70% (May 2007 - October 2007)	199,831
7	Total 401(k) Company Match operating increase	$ 244,558

Exhibit 1
Reference Schedule 1.16
Sponsoring Witness: Scott

KENTUCKY UTILITIES

To Adjust for Pension and Post Retirement
For the Twelve Months Ended April 30, 2008

	Pension	Post Retirement	Total
1. Pension and Post Retirement expenses in test year	$ 7,167,400	$ 4,627,481	$ 11,794,881
2. Pension and Post Retirement expenses annualized for 2008 Mercer study	6,731,237	4,892,371	11,623,608
3. Total adjustment (Line 2 - Line 1)	$ (436,163)	$ 264,890	$ (171,273)
4. Kentucky Jurisdiction (Reference Schedule Allocators)			89.139%
5. Kentucky Jurisdictional adjustment			$ (152,671)

Exhibit 1
Reference Schedule 1.17
Sponsoring Witness: Scott

KENTUCKY UTILITIES

Adjustment for Post-Employment Benefits
For the Twelve Months Ended April 30, 2008

		Total
1. Post-Employment Benefits expenses in test year	$	(1,048,511)
2. Post-Employment expenses per 2008 Mercer Study		201,677
3. Total adjustment (Line 2 - Line 1)	$	1,250,188
4. Kentucky Jurisdiction (Reference Schedule Allocators)		89.139%
5. Kentucky Jurisdictional adjustment	$	1,114,405

Exhibit 1
Reference Schedule 1.18
Sponsoring Witness: Charnas

KENTUCKY UTILITIES

Adjustment to Reflect Normalized Storm Damage Expense
For the Twelve Months Ended April 30, 2008

1. Storm damage provision based upon nine year average	$	2,805,384
2. Storm damage expenses incurred during the 12 months ended April 30, 2008		5,708,101
3. Adjustment		(2,902,717)
4. Kentucky Jurisdiction (Reference Schedule Allocators)		94.097%
5. Kentucky Jurisdictional adjustment	$	(2,731,370)

Year	Expense *	CPI-All Urban Consumers	Amount
2008	$ 5,708,101	1.0000	$ 5,708,101
2007	2,035,000	1.0133	2,062,066
2006	4,114,000	1.0422	4,287,611
2005	2,538,000	1.0758	2,730,380
2004	4,120,000	1.1123	4,582,676
2003	1,434,000	1.1419	1,637,485
2002	1,460,495	1.1679	1,705,712
2001	1,102,683	1.1864	1,308,223
2000	1,005,000	1.2201	1,226,201
Total			$ 25,248,455
Nine Year Average			$ 2,805,384

* NOTE: 2008 expense is for 12 months ended April 30, 2008.
All other years expenses are for calendar year.

KENTUCKY UTILITIES

Adjustment for Injuries and Damages FERC Account 925
For the Twelve Months Ended April 30, 2008

1. Injury/Damage provision based upon ten year average	$ 1,933,531
2. Injury/Damage expenses incurred during the 12 months ended April 30, 2008	1,188,366
3. Adjustment	745,165
4. Kentucky Jurisdiction (Reference Schedule Allocators)	89.139%
5. Kentucky Jurisdictional adjustment	$ 664,233

Year	Amount *	CPI-All Urban Consumers	Adjusted Amount
2008	$ 1,188,366	1.0000	$ 1,188,366
2007	1,178,212	1.0133	1,193,882
2006	1,690,654	1.0422	1,762,000
2005	2,268,036	1.0758	2,439,953
2004	1,080,732	1.1123	1,202,098
2003	1,776,006	1.1419	2,028,021
2002	2,510,515	1.1679	2,932,030
2001	1,609,827	1.1864	1,909,899
2000	1,637,520	1.2201	1,997,938
1999	2,126,017	1.2611	2,681,120
Total			$19,335,307
Ten Year Average			$ 1,933,531

* NOTE: 2008 expense is for 12 months ended April 30, 2008.
All other years expenses are for calendar year.

Exhibit 1
Reference Schedule 1.20
Sponsoring Witness: Charnas

KENTUCKY UTILITIES

Adjustment to Eliminate Advertising Expenses
Pursuant to Commission Rule 807 KAR 5:016
For the Twelve Months Ended April 30, 2008

1. Uniform System of Accounts - Account No. 930.1 General Advertising Expenses	$	387,987
2. Account No. 913 Advertising Expenses		70,495
3. Total		458,482
4. Kentucky Jurisdiction (Reference Schedule Allocators)		95.293%
5. Kentucky Jurisdictional amount	$	436,901
6. Kentucky Jurisdictional adjustment	$	(436,901)

Exhibit 1
Reference Schedule 1.21
Sponsoring Witness: Charnas

KENTUCKY UTILITIES

Adjustment to Remove Earnings Sharing Mechanism (ESM) and Management Audit Expenses
For the Twelve Months Ended April 30, 2008

1. ESM and Management Audit amortization in test year	$	(37,986)
2. Kentucky Jurisdiction (Reference Schedule Allocators)		100.000%
3. Kentucky Jurisdictional adjustment	$	(37,986)

Exhibit 1
Reference Schedule 1.22
Sponsoring Witness: Charnas

KENTUCKY UTILITIES

Adjustment to Remove Out-of-Period FERC Assessment Fee
For the Twelve Months Ended April 30, 2008

1. Electric Sales (MWH) in test year		6,132,982
2. FERC Assessment Charge Factor per MWH		0.0489072120
3. FERC Assessment Fee test year expense (Line 1 x Line 2)	$	299,947
4. FERC Assessment Fee per books for test year		873,368
5. Total Adjustment (Line 3 - Line 4)	$	(573,421)
6. Kentucky Jurisdiction (Reference Schedule Allocators)		86.841%
7. Kentucky Jurisdictional adjustment	$	(497,965)

Exhibit 1
Reference Schedule 1.23
Sponsoring Witness: Scott

KENTUCKY UTILITIES

Adjustment for MISO Exit and Schedule 10
For the Twelve Months Ended April 30, 2008

1. MISO Exit Fee Regulatory Asset	$	18,907,345
2. Kentucky Jurisdiction (Reference Schedule Allocators)		86.537%
3. Kentucky Jurisdictional MISO Exit Fee Regulatory Asset	$	16,361,849
4. Less Cumulative Schedule 10 Regulatory Liability (Sep 2006 - Apr 2008)		(6,551,955)
5. Net Exit Fee (Line 3 - Line 4)	$	9,809,894
6. Amortization period in years		5
7. Amortization per year	$	1,961,979

Exhibit 1
Reference Schedule 1.24
Sponsoring Witness: Scott / Bellar

KENTUCKY UTILITIES

Adjustment for EKPC Transmission Settlement
For the Twelve Months Ended April 30, 2008

1. EKPC Depancaking Settlement	$	1,911,800
2. Forgive Imbalance Charge		22,038
3. Total expenses charged in test year	$	1,933,838
4. Amortization period in years		5
5. Annual amortization	$	386,768
6. Remove 4 years from test year		4
7. Net reduction to operating expenses	$	1,547,072
8. Adjustment	$	(1,547,072)
9. Kentucky Jurisdiction (Reference Schedule Allocators)		86.537%
10. Kentucky Jurisdictional adjustment	$	(1,338,790)

Exhibit 1
Reference Schedule 1.25
Sponsoring Witness: Scott

KENTUCKY UTILITIES

Adjustment to reflect reallocation of OVEC Demand Charges
For the Twelve Months Ended April 30, 2008

1. Reallocation of OVEC Demand Charges	$	3,460,535
2. OVEC Demand Charges in test year		315,225
3. Adjustment	$	3,145,310
4. Kentucky Jurisdiction (Reference Schedule Allocators)		86.537%
5. Kentucky Jurisdictional adjustment	$	2,721,857

Exhibit 1
Reference Schedule 1.26
Sponsoring Witness: Bellar

KENTUCKY UTILITIES

Adjustment for Reserve Margin Demand Purchases
For the Twelve Months Ended April 30, 2008

1. Reserve Margin Demand Purchases (June - September 2008)	$ 1,386,000
2. Kentucky Jurisdiction (Reference Schedule Allocators)	86.537%
3. Kentucky Jurisdictional amount	$ 1,199,403

Exhibit 1
Reference Schedule 1.27
Sponsoring Witness: Charnas

KENTUCKY UTILITIES

Adjustment to Reflect Amortization of Rate Case Expenses

1. Total estimated cost of rate case	$ 1,170,000
2. Amortization period in years	3
3. Annual amortization	$ 390,000
4. Amortization included in test year	65,096
5. Net adjustment	$ 324,904

Exhibit 1
Reference Schedule 1.28
Sponsoring Witness: Charnas

KENTUCKY UTILITIES

Adjustment to Expenses for Retirement of Tyrone Units 1 and 2
For the Twelve Months Ended April 30, 2008

1. Tyrone units 1 and 2 operation and maintenance expenses included in test year			$	4,362
2. Tyrone units 1 & 2 Net Book value at 1/1/07	$	6,714,006		
3. Property tax rate	$	0.0015		
4. Property tax expense for 2007 (Line 2 x Line 3)	$	10,071		
5. Amount in test year (May-Dec 2007) (Line 4/12 x 8)			$	6,714
6. Total Tyrone expense adjustments (Line 1 + Line 5)			$	11,076
7. Kentucky Jurisdiction (Reference Schedule Allocators)				86.537%
8. Kentucky Jurisdictional amount			$	9,585
9. Kentucky Jurisdictional adjustment			$	(9,585)

Exhibit 1
Reference Schedule 1.29
Sponsoring Witness: Charnas

<u>KENTUCKY UTILITIES</u>

Adjustment to O&M Expenses for IT Prepaid Contracts
<u>For the Twelve Months Ended April 30, 2008</u>

1. Remove adjustment to IT Prepaid Amortization from operation and maintenance expenses included in test year	$(1,097,532)
2. Kentucky Jurisdiction (Reference Schedule Allocators)	89.139%
3. Kentucky Jurisdictional amount	$ (978,329)
4. Kentucky Jurisdictional adjustment	$ 978,329

Exhibit 1
Reference Schedule 1.30
Sponsoring Witness: Charnas

KENTUCKY UTILITIES

Adjustment for Postage Rate Incease
For the Twelve Months Ended April 30, 2008

1. Total Bill Volume for Twelve Months Ended April 30, 2008		6,965,261
2. One-cent increase in postage effective May 2008	$	0.01
3. Increase to postage expense (Line 1 x Line 2)	$	69,653
4. Kentucky Jurisdiction (Reference Schedule Allocators)		94.069%
5. Kentucky Jurisdictional adjustment	$	65,522

Exhibit 1
Reference Schedule 1.31
Sponsoring Witness: Charnas

KENTUCKY UTILITIES

Adjustment to Reflect Annualized Vehicle Fuel Costs
For the Twelve Months Ended April 30, 2008

	Amount	Total
1. Total Fuel Consumed for Twelve Months Ended April 30, 2008 (gallons)	866,280	
2. Average Per Gallon Cost of Fuel for April 2008 (1)	$ 3.67	
3. Annualized Vehicle Fuel Cost (Line 1 x Line 2)		$ 3,179,248
4. Vehicle Fuel Cost Twelve Months Ended April 30, 2008		$ 2,616,525
5. Increase Vehicle Fuel Cost (Line 3 - Line 4)		$ 562,723
6. Increase Vehicle Fuel Cost Applicable to O&M (Line 5 x 40.46%)		$ 227,678
7. Kentucky Jurisdiction (Reference Schedule Allocators)		87.232%
8. Kentucky Jurisdictional adjustment		$ 198,608

(1) Average per gallon book cost of fuel (diesel and gasoline) for calendar month April 2008.

Exhibit 1
Reference Schedule 1.32
Sponsoring Witness: Rives

KENTUCKY UTILITIES

Adjustment for Cost of New Bank Credit Facilities
For the Twelve Months Ended April 30, 2008

1. Cost of New Bank Credit Facilities	$	2,288,510
2. Bank Credit Facilities Cost in Test Year		38,510
3. Adjustment	$	2,250,000
4. Kentucky Jurisdiction (Reference Schedule Allocators)		89.139%
5. Kentucky Jurisdictional adjustment	$	2,005,628

Exhibit 1
Reference Schedule 1.33
Sponsoring Witness: Scott

KENTUCKY UTILITIES

Adjustment for Property Taxes
For the Twelve Months Ended April 30, 2008

1.	Property tax expense adjustment due to coal tax credit received	$ 507,797
2.	Kentucky Jurisdiction (Reference Schedule Allocators)	88.038%
3.	Kentucky Jurisdictional adjustment	$ 447,054

Exhibit 1
Reference Schedule 1.34
Sponsoring Witness: Scott

KENTUCKY UTILITIES

Adjustment for Use Tax Expense
For the Twelve Months Ended April 30, 2008

1. Use tax expense relating to period outside of test year	$ (236,848)
2. Kentucky Jurisdiction (Reference Schedule Allocators)	88.038%
3. Kentucky Jurisdictional adjustment	$ (208,516)

Exhibit 1
Reference Schedule 1.35-1.38
Sponsoring Witness:

KENTUCKY UTILITIES

THESE ADJUSTMENTS LEFT INTENTIONALLY BLANK

Exhibit 1
Reference Schedule 1.39
Sponsoring Witness: Scott

KENTUCKY UTILITIES

Calculation of Composite Federal and Kentucky Income Tax Rate (Based on Law in Effect January 1, 2008)

1. Assume pre-tax income of		$100.000000
2. State income tax at 6.00%		$ 5.799918
3. Taxable income for Federal income tax before production credit		$ 94.200082
Production Rate		6.00%
Allocation to Production Inc.		0.59
Allocated Production Rate		3.54%
4. Less: Production tax credit (3.54% of Line 3)		3.334700
5. Taxable income for Federal income tax (Line 3 - Line 4)		90.865382
6. Federal income tax at 35% (Line 5 x 35%)		31.802884
7. Total State and Federal income taxes (Line 2 + Line 6)		37.602802
8. Therefore, the composite rate is:		
9. Federal	31.802884%	
10. State	5.799918%	
11. Total	37.602802%	

State Income Tax Calculation

1. Assume pre-tax income of	$100.000000
2. Less: Production tax credit	$ 3.334700
3. Taxable income for State income tax	$ 96.665300
4. State Tax Rate	$ 0.060000
5. State Income Tax	$ 5.799918

Exhibit 1
Reference Schedule 1.40
Sponsoring Witness: Scott

KENTUCKY UTILITIES

Calculation of Current Tax Adjustment Resulting From "Interest Synchronization"

1. Adjusted Jurisdictional Capitalization - Exhibit 2	$	2,073,463,254
2. Weighted Cost of Debt - Exhibit 2		2.39%
3. "Interest Synchronization"	$	49,555,772
4. Kentucky Jurisdictional Interest per books (excluding other interest)		46,369,311
5. "Interest Synchronization" adjustment (Line 4 - 3)	$	(3,186,461)
6. Composite Federal and State tax rate		37.602802%
7. Current tax adjustment from "Interest Synchronization"	$	(1,198,199)

Exhibit 1
Reference Schedule 1.41
Sponsoring Witness: Scott

KENTUCKY UTILITIES

Adjustment for Prior Period Income Tax True-Ups and Adjustments
For the Twelve Months Ended April 30, 2008

1. 2006 Income Tax True-up:		
2. Federal Tax (benefit)	$	(497,646)
3. State Tax (benefit)		333,891
4. Total 2006 Income Tax True-up	$	(163,755)
5. Other Tax adjustments:		
6. Kentucky Coal Credit		(598,704)
7. Total Other Tax adjustments:	$	(598,704)
8. Total adjustments (Line 4 + Line 7)	$	(762,459)
9. Kentucky Jurisdiction (Reference Schedule Allocators)		93.025%
10. Kentucky Jurisdiction amount (Line 8 x Line 9)	$	(709,277)
11. Kentucky Jurisdiction adjustment	$	709,277

Exhibit 1
Reference Schedule 1.42
Sponsoring Witness: Scott

KENTUCKY UTILITIES

Calculation of Revenue Gross Up Factor
(Based on Law in Effect January 1, 2008)

1. Assume pre-tax income of	$ 100.000000
2. Bad Debt at .2030%	0.203000
3. PSC Assessment at .1603%	0.160300
4. Production Tax Credit (Reference Schedule 1.39)	3.334700
5. Taxable income for State income tax	96.302000
6. State income tax at 6.00%	5.778120
7. Taxable income for Federal income tax	90.523880
8. Federal income tax at 35%	31.683358
9. Total Bad Debt, PSC Assessment, State and Federal income taxes (Line 2 + Line 3 + Line 6 + Line 8)	37.824778
10. Assume pre-tax income of	$ 100.000000
11. Gross Up Revenue Factor	62.175222

KENTUCKY UTILITIES

Kentucky Jurisdictional Allocators
At April 30, 2008

Title	Reference Schedule	Factor	Allocation Based On
ECR Operating Expense	1.05, 1.06	87.288%	Composite rate developed from steam depreciation allocator (86.537%) and net plant allocator for property tax (88.038%)
Brokered and Off-System Energy	1.07, 1.08	86.841%	Ratio of Kentucky retail kilowatt-hour sales to Total Company kilowatt-hour sales
Depreciation	1.14	87.457%	Composite rate developed by dividing Kentucky retail depreciation by Total Company depreciation
Labor	1.15	89.139%	Direct labor
Pension and Post Retirement and Benefits	1.16, 1.17	89.139%	Direct labor
Distribution O&M (Storm Damages)	1.18	94.097%	Distribution plant
Injuries/Damages	1.19	89.139%	Direct labor
Advertising Expense	1.20	95.293%	Retail energy
FERC Assessment	1.22	86.841%	Ratio of Kentucky retail kilowatt-hour sales to Total Company kilowatt-hour sales
MISO, EKPC, OVEC, Reserve Margin, Tyron	1.23, 1.24, 1.25, 1.26, 1.28	86.537%	Demand (12 CP)
IT Prepaid	1.29	89.139%	Direct labor
Postage	1.30	94.069%	Exp9025
Vehicle Fuel Costs	1.31	87.232%	Allocated Operating Expense
Bank Fees	1.32	89.139%	Direct labor
Property Taxes, Sales and Use Tax	1.33, 1.34	88.038%	Net Plant
Prior Period Tax True-up	1.41	93.025%	Income tax expense

KENTUCKY UTILITIES

Capitalization at April 30, 2008

		Per Books 04-30-08 (1)	Capital Structure (2)	Reacquired Bonds (not retired) (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 Company Capitalization (Sum of Col 3 - Col 6) (7)	Adjusted Total Company Capitalization (Col 1 + Col 7) (8)
1.	Short Term Debt	$ 93,302,454	3.27%	$ (16,693,620)	$ -	$ (813,592)	$ (21,619)	$ (17,528,831)	$ 75,773,623
2.	Long Term Debt	1,247,059,520	43.70%	16,693,620	-	(10,872,769)	(288,918)	5,531,933	1,252,591,453
3.	Common Equity	1,513,015,410	53.03%	-	(23,584,679)	(13,194,117)	(350,603)	(37,129,399)	1,475,886,011
4.	Total Capitalization	$2,853,377,384	100.00%	$ -	$ (23,584,679)	$ (24,880,478)	$ (661,140)	$ (49,126,297)	$2,804,251,087

		Adjusted Total Company Capitalization (8)	Jurisdictional Rate Base Percentage (Exhibit 3 Line 23) (9)	Adjusted Kentucky Jurisdictional Capitalization (Col 8 x Col 9) (10)	Adjusted Jurisdictional Capital Structure (11)	Annual Cost Rate (12)	Cost of Capital (Col 11 x Col 12) (13)
1.	Short Term Debt	$ 75,773,623	73.94%	$ 56,027,017	2.70%	2.63%	0.07%
2.	Long Term Debt	1,252,591,453	73.94%	926,166,120	44.67%	5.21%	2.32%
3.	Common Equity	1,475,886,011	73.94%	1,091,270,117	52.63%	11.25%	5.92%
4.	Total Capitalization	$2,804,251,087		$2,073,463,254	100.00%		8.31%

KENTUCKY UTILITIES

Net Original Cost Kentucky Jurisdictional Rate Base
At April 30, 2008

Title of Account (1)	Kentucky Jurisdictional Rate Base at April 30, 2008 (2)	Kentucky Jurisdictional ECR Rate Base at April 30, 2008 (3)	Kentucky Jurisdictional ECR Roll-In Rate Base (4)	Kentucky Jurisdictional Net ECR Rate Base (5)	Kentucky Jurisdictional Base Rate Base at April 30, 2008 (6)	Other Jurisdictional Rate Base at April 30, 2008 (7)	Total Company Rate Base at April 30, 2008 (8)
		(Page 3)	(Page 3)	(3 - 4)	(2 - 5)		(5 + 6 + 7)
1. Utility Plant at Original Cost	$ 4,495,693,653	$ 869,467,204	$ 428,970,572	$ 440,496,632	$ 4,055,197,021	$ 655,540,798	$ 5,151,234,451
2. Deduct:							
3. Reserve for Depreciation	1,707,655,598	24,789,649	14,514,584	10,275,065	1,697,380,533	264,707,047	1,972,362,645
4. Net Utility Plant	2,788,038,055	844,677,555	414,455,988	430,221,567	2,357,816,488	390,833,751	3,178,871,806
5. Deduct:							
6. Customer Advances for Construction	2,405,862	-	-	-	2,405,862	14,190	2,420,052
7. Accumulated Deferred Income Taxes	256,897,609	30,399,982	26,480,871	3,919,111	252,978,498	36,747,188	293,644,797
8. Asset Retirement Obligation-Net Assets	4,232,200	-	-	-	4,232,200	658,430	4,890,630
9. Asset Retirement Obligation-Liabilities	(26,805,403)	-	-	-	(26,805,403)	(4,170,288)	(30,975,691)
10. Asset Retirement Obligation-Regulatory Assets	21,526,237	-	-	-	21,526,237	3,348,974	24,875,211
11. Asset Retirement Obligation-Regulatory Liabilities	(1,951,342)	-	-	-	(1,951,342)	(303,583)	(2,254,925)
12. Reclassification of Accumulated Depreciation associated		-	-	-			
with Cost of Removal for underlying ARO Assets	2,066,847	-	-	-	2,066,847	321,553	2,388,400
13. Investment Tax Credit (a)	49,714,508	11,690,219	1,754,214	9,936,005	39,778,503	8,379,841	58,094,349
14. Total Deductions	308,086,518	42,090,201	28,235,085	13,855,116	294,231,402	44,996,305	353,082,823
15. Net Plant Deductions	2,479,951,537	802,587,354	386,220,903	416,366,451	2,063,585,086	345,837,446	2,825,788,983
16. Add:							
17. Materials and Supplies (b)	74,430,157	267,997	-	267,997	74,162,160	11,532,922	85,963,079
18. Prepayments (b)(c)	1,461,220	-	-	-	1,461,220	203,059	1,664,279
19. Emission Allowances	193,051	132,567	1,113,313	(980,746)	1,173,797	30,034	223,085
20. Cash Working Capital (page 2)	78,937,746	366,055	133,271	232,784	78,704,962	8,603,686	87,541,432
21. Total Additions	155,022,174	766,619	1,246,584	(479,965)	155,502,139	20,369,701	175,391,875
22. Total Net Original Cost Rate Base	$ 2,634,973,711	$ 803,353,973	$ 387,467,487	$ 415,886,486	$ 2,219,087,225	$ 366,207,147	$ 3,001,180,858
23. Percentage of Rate Base to Total Company Rate Base				13.86%	73.94%	12.20%	100.00%

(a) Reflects investment tax credit treatment per Case No. 2007-00178.
(b) Average for 13 months.
(c) Includes prepayments for property insurance only.

KENTUCKY UTILITIES

Calculation of Cash Working Capital
At April 30, 2008

Title of Account (1)	Kentucky Jurisdictional Rate Base at April 30, 2008 (2)	Kentucky Jurisdictional ECR Rate Base at April 30, 2008 (3)	Kentucky Jurisdictional ECR Roll-In Rate Base (4)	Kentucky Jurisdictional Net ECR Rate Base (5) (3 - 4)	Kentucky Jurisdictional Base Rate Base at April 30, 2008 (6) (2 - 5)	Other Jurisdictional Rate Base at April 30, 2008 (7)	Total Company Rate Base at April 30, 2008 (8) (5 + 6 + 7)
1. Operating and maintenance expense for the 12 months ended April 30, 2008	$ 788,744,613	$ 2,928,440	$ 1,066,168	$ 1,862,272	$ 786,882,341	$ 114,603,502	$ 903,348,115
2. Deduct:							
3. Electric Power Purchased	157,242,642	-	-	-	157,242,642	23,887,144	181,129,786
4. Total Deductions	$ 157,242,642	$ -	$ -	$ -	$ 157,242,642	$ 23,887,144	$ 181,129,786
5. Remainder (Line 1 - Line 4)	$ 631,501,971	$ 2,928,440	$ 1,066,168	$ 1,862,272	$ 629,639,699	$ 90,716,358	$ 722,218,329
6. Cash Working Capital	$ 78,937,746	$ 366,055	$ 133,271	$ 232,784	$ 78,704,962	$ 8,603,686	$ 87,541,432

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

KENTUCKY UTILITIES

Net Original Cost Kentucky Jurisdictional Rate Base
At April 30, 2008

Title of Account (1)	Kentucky Jurisdictional ECR Rate Base at April 30, 2008 (2)	Other Jurisdictional ECR Rate Base at April 30, 2008 (3)	Total Company ECR Rate Base at April 30, 2008 (1) (4)	Kentucky Jurisdictional ECR Roll-In Rate Base (2) (5)
1. Utility Plant at Original Cost	$ 869,467,204	$ 135,267,423	$ 1,004,734,627	$ 428,970,572
2. Deduct:				
3. Reserve for Depreciation	24,789,649	3,856,652	28,646,301	14,514,584
4. Net Utility Plant	844,677,555	131,410,771	976,088,326	414,455,988
5. Deduct:				
6. Customer Advances for Construction	-	-	-	-
7. Accumulated Deferred Income Taxes	30,399,982	4,729,479	35,129,461	26,480,871
8. Asset Retirement Obligation-Net Assets	-	-	-	-
9. Asset Retirement Obligation-Liabilities	-	-	-	-
10. Asset Retirement Obligation-Regulatory Assets	-	-	-	-
11. Asset Retirement Obligation-Regulatory Liabilities	-	-	-	-
12. Reclassification of Accumulated Depreciation associated with Cost of Removal for underlying ARO Assets	-	-	-	-
13. Investment Tax Credit (a)	11,690,219	1,969,451	13,659,670	1,754,214
14. Total Deductions	42,090,201	6,698,930	48,789,131	28,235,085
15. Net Plant Deductions	802,587,354	124,711,841	927,299,195	386,220,903
16. Add:				
17. Materials and Supplies	267,997	43,002	310,999	-
18. Prepayments	-	-	-	-
19. Emission Allowances	132,567	20,624	153,191	1,113,313
20. Cash Working Capital	366,055	55,881	421,936	133,271
21. Total Additions	766,619	119,507	886,126	1,246,584
22. Total Net Original Cost Rate Base	$ 803,353,973	$ 124,831,348	$ 928,185,321	$ 387,467,487

(1) ES Form 2.00 Determination of Environmental Compliance Rate Base for the Expense Month of April 2008.
(2) ECR Roll-in pursuant to Commission's Order dated March 28, 2008 in Case No. 2007-00379.

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

KENTUCKY UTILITIES

Pro Forma Kentucky Jurisdictional Rate Base
At April 30, 2008

	Title of Account (1)	Kentucky Jurisdictional Base Rate Base at April 30, 2008 (2) (Exhibit 3 Col 6)	Kentucky Jurisdictional Pro Forma Adjustments (3)	Kentucky Jurisdictional Pro Forma Base Rate Base (4) (2 + 3)
1.	Utility Plant at Original Cost	$ 4,055,197,021		$ 4,055,197,021
2.	Deduct:			
3.	Reserve for Depreciation	1,697,380,533	236,248 (a)	1,697,616,781
4.	Net Utility Plant	2,357,816,488		2,357,580,240
5.	Deduct:			
6.	Customer Advances for Construction	2,405,862		2,405,862
7.	Accumulated Deferred Income Taxes	252,978,498		252,978,498
8.	Asset Retirement Obligation-Net Assets	4,232,200		4,232,200
9.	Asset Retirement Obligation-Liabilities	(26,805,403)		(26,805,403)
10	Asset Retirement Obligation-Regulatory Assets	21,526,237		21,526,237
11	Asset Retirement Obligation-Regulatory Liabilities	(1,951,342)		(1,951,342)
12.	Reclassification of Accumulated Depreciation associated with Cost of Removal for underlying ARO Assets	2,066,847		2,066,847
13	Investment Tax Credit	39,778,503		39,778,503
14.	Total Deductions	294,231,402		294,231,402
15	Net Plant Deductions	2,063,585,086		2,063,348,838
16.	Add:			
17.	Materials and Supplies	74,162,160		74,162,160
18.	Prepayments	1,461,220		1,461,220
19.	Emission Allowances	1,173,797		1,173,797
20.	Cash Working Capital	78,704,962	(1,942,732) (b)	76,762,230
21.	Total Additions	155,502,139		153,559,407
22.	Total Net Original Cost Rate Base	$ 2,219,087,225		$ 2,216,908,245

(a) Adjustment to reflect annualized depreciation expenses under proposed rates (Reference Schedule 1.14)
(b) Using the 1/8th formula and change in Operation and Maintenance Expenses adjusted for FAC roll-in and less ECR expense adjustments ((Exhibit 1 Col 3, Line 39 - Line 8 - Line 9 - Ref Sch 1.04 Line 2) / 8).

KENTUCKY UTILITIES

Estimated Net Reproduction Cost Kentucky Jurisdictional Rate Base
At April 30, 2008

Title of Account (1)	Kentucky Jurisdictional Rate Base at April 30, 2008 (2)	Kentucky Jurisdictional ECR Rate Base at April 30, 2008 (3)	Kentucky Jurisdictional ECR Roll-In Rate Base (4)	Kentucky Jurisdictional Net ECR Rate Base (5) (3 - 4)	Kentucky Jurisdictional Base Rate Base at April 30, 2008 (6) (2 - 5)	Other Jurisdictional Rate Base at April 30, 2008 (7)	Total Company Rate Base at April 30, 2008 (8) (5 + 6 + 7)
1. Utility Plant at Original Cost	$ 9,377,831,324	$ 869,467,204	$ 428,970,572	$ 440,496,632	$ 8,937,334,692	$ 1,353,933,478	$ 10,731,764,802
2. Deduct:							
3. Reserve for Depreciation	4,681,722,278	24,789,649	14,514,584	10,275,065	4,671,447,213	703,325,794	5,385,048,072
4. Net Utility Plant	4,696,109,046	844,677,555	414,455,988	430,221,567	4,265,887,479	650,607,684	5,346,716,730
5. Deduct:							
6. Customer Advances for Construction	2,405,862	-	-	-	2,405,862	14,190	2,420,052
7. Accumulated Deferred Income Taxes	256,897,609	30,399,982	26,480,871	3,919,111	252,978,498	36,747,188	293,644,797
8. Asset Retirement Obligation-Net Assets	4,232,200	-	-	-	4,232,200	658,430	4,890,630
9. Asset Retirement Obligation-Liabilities	(26,805,403)	-	-	-	(26,805,403)	(4,170,288)	(30,975,691)
10. Asset Retirement Obligation-Regulatory Assets	21,526,237	-	-	-	21,526,237	3,348,974	24,875,211
11. Asset Retirement Obligation-Regulatory Liabilities	(1,951,342)	-	-	-	(1,951,342)	(303,583)	(2,254,925)
12. Reclassification of Accumulated Depreciation associated with Cost of Removal for underlying ARO Assets	2,066,847	-	-	-	2,066,847	321,553	2,388,400
13. Investment Tax Credit (a)	49,714,508	11,690,219	1,754,214	9,936,005	39,778,503	8,379,841	58,094,349
14. Total Deductions	308,086,518	42,090,201	28,235,085	13,855,116	294,231,402	44,996,305	353,082,823
15. Net Plant Deductions	4,388,022,528	802,587,354	386,220,903	416,366,451	3,971,656,077	605,611,379	4,993,633,907
16. Add:							
17. Materials and Supplies (b)	74,430,157	267,997	-	267,997	74,162,160	11,532,922	85,963,079
18. Prepayments (b)(c)	1,461,220	-	-	-	1,461,220	203,059	1,664,279
19. Emission Allowances	193,051	132,567	1,113,313	(980,746)	1,173,797	30,034	223,085
20. Cash Working Capital	78,937,746	366,055	133,271	232,784	78,704,962	8,603,686	87,541,432
21. Total Additions	155,022,174	766,619	1,246,584	(479,965)	155,502,139	20,369,701	175,391,875
22. Total Net Original Cost Rate Base	$ 4,543,044,702	$ 803,353,973	$ 387,467,487	$ 415,886,486	$ 4,127,158,216	$ 625,981,080	$ 5,169,025,782

(a) Reflects investment tax credit treatment per Case No. 2007-00178.
(b) Average for 13 months.
(c) Includes prepayments for property insurance only.

KENTUCKY UTILITY COMPANY

Estimated Reproduction (or Current) Cost of Utility Plant And Applicable Reserve for Depreciation at April 30, 2008

	Original Cost 4/30/2008 (1)	Effect of Changing Prices (a) (2)	At 4/30/2008 (3)	Jurisdictional Factor (4)	Kentucky Jurisdictional Plant at 4/30/2008 (5)	Other Jurisdictional Plant at 4/30/2008 (6)
1. Plant in Service						
2. Electric Plant :						
3. Steam Production	$ 1,680,088,593	$ 2,289,283,568	$ 3,969,372,161	86.537%	$ 3,434,975,587	$ 534,396,574
4. Hydraulic Production	11,033,232	164,996,268	176,029,500	86.537%	152,330,648	23,698,852
5. Other Production	497,590,725	172,178,245	669,768,970	86.537%	579,597,974	90,170,996
6. Transmission	521,778,335	1,336,906,581	1,858,684,916	80.089%	1,488,602,162	370,082,754
7. Distribution	1,081,564,173	1,538,445,404	2,620,009,577	94.097%	2,465,350,412	154,659,165
8. General	99,461,628	72,135,901	171,597,529	89.139%	152,960,321	18,637,208
9. Intangible	25,664,252	6,584,384	32,248,636	87.303%	28,154,027	4,094,609
10. Total Plant in Service	3,917,180,938	5,580,530,351	9,497,711,289		8,301,971,131	1,195,740,158
11. Construction Work In Progress	1,234,053,513	-	1,234,053,513	87.181%	1,075,860,193	158,193,320
12. Total Utility Plant	$ 5,151,234,451	$ 5,580,530,351	$10,731,764,802		$ 9,377,831,324	$ 1,353,933,478
13. Less Reserve for Depreciation:						
14. Steam Production	$ 943,974,736	$ 1,574,689,517	$ 2,518,664,253	86.537%	$ 2,179,576,485	$ 339,087,768
15. Hydraulic Production	8,291,935	126,760,601	135,052,536	86.537%	116,870,413	18,182,123
16. Other Production	122,156,871	58,505,572	180,662,443	86.537%	156,339,858	24,322,585
17. Transmission	322,982,906	859,770,000	1,182,752,906	80.089%	947,254,975	235,497,931
18. Distribution	510,728,393	754,790,958	1,265,519,351	94.097%	1,190,815,744	74,703,607
19. General	50,166,959	29,871,966	80,038,925	89.139%	71,345,897	8,693,028
20. Intangible	18,438,658	3,919,000	22,357,658	87.303%	19,518,906	2,838,752
21. Total Reserve for Depreciation	$ 1,976,740,458	$ 3,408,307,614	$ 5,385,048,072		$ 4,681,722,278	$ 703,325,794
22. Total Utility Plant less Reserve for Depreciation	$ 3,174,493,993	$ 2,172,222,737	$ 5,346,716,730		$ 4,696,109,046	$ 650,607,684

(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 April 30, 2008

		Total (1)
1. Kentucky Jurisdictional Net Original Cost Rate Base - Exhibit 3		$ 2,219,087,225
2. Kentucky Jurisdictional Pro Forma Rate Base - Exhibit 4		$ 2,216,908,245
3. Kentucky Jurisdictional Reproduction Cost Rate Base - Exhibit 5		$ 4,127,158,216
4. Kentucky Jurisdictional Net Operating Income - Actual - Exhibit 1		$ 174,141,627
5. Rate of Return (Actual):		
6. On Kentucky Jurisdictional Net Original Cost Rate Base		7.85%
7. On Kentucky Jurisdictional Pro Forma Rate Base		7.86%
8. On Kentucky Jurisdictional Reproduction Cost Rate Base		4.22%
9. Kentucky Jurisdictional Adjusted Net Operating Income - Exhibit 1		$ 158,501,899
10. Revenue Increase Applied for - Exhibit 8		22,199,996
11. Income Taxes - Exhibit 1, Reference Schedule 1.39	37.602802 %	(8,347,821)
12. Adjusted Kentucky Jurisdictional Net Operating Income Pro-formed for Rate Increase		$ 172,354,074
13. Rate of Return (Pro-forma):		
14. On Kentucky Jurisdictional Net Original Cost Rate Base		7.77%
15. On Kentucky Jurisdictional Pro Forma Rate Base		7.77%
16. On Kentucky Jurisdictional Reproduction Cost Rate Base		4.18%

KENTUCKY UTILITIES

Calculation of Overall Revenue Deficiency/(Sufficiency) at April 30, 2008

1. Adjusted Kentucky Jurisdictional Capitalization (Exhibit 2, Col 10)	$ 2,073,463,254
2. Total Cost of Capital (Exhibit 2, Col 13)	8.31%
3. Net Operating Income Found Reasonable (Line 1 x Line 2)	$ 172,304,796
4. Pro-forma Net Operating Income	158,501,899
5. Net Operating Income Deficiency/(Sufficiency)	$ 13,802,897
6. Gross Up Revenue Factor - Exhibit 1, Reference Schedule 1.42	0.62175222
7. Overall Revenue Deficiency/(Sufficiency)	$ 22,199,996

KENTUCKY UTILITIES

Kentucky Jurisdictional Rate of Return on Common Equity
For the Twelve Months Ended April 30, 2008

	Adjusted Kentucky Jurisdictional Capitalization (Exhibit 2 Col 10) (1)	Percent of Total (2)	Annual Cost Rate (Exhibit 2 Col 12) (3)		Weighted Cost of Capital (Col 2 x Col 3) (4)	
1. Short Term Debt	$56,027,017	2.70%	2.63%		0.07%	
2. Long Term Debt	$926,166,120	44.67%	5.21%		2.33%	
3. Common Equity	$1,091,270,117	52.63%	9.96%	(a)	5.24%	(b)
4. Total Capitalization	$2,073,463,254	100.00%			7.64%	
5. Pro-forma Net Operating Income					$158,501,899	(c)
6. Net Operating Income / Total Capitalization					7.64%	(d)

Notes: (a) - Column 4, Line 3 / Column 2, Line 3
(b) - Column 4, Line 4 - Line 1 - Line 2
(c) - Exhibit 1, Line 44, Column 4
(d) - Column 4, Line 5 divided by Column 1, Line 4

VERIFICATION

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

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

SBRives

S. BRADFORD RIVES

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 24th day of July, 2008.

Kimberly Walters (SEAL)
Notary Public

My Commission Expires:
9/11/2008

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

Capitalization at April 30, 2008

Case No. 1998-00474 - ECR Capitalization Adjustment

		Per Books 04-30-08 (1)	Capital Structure (2)	Reacquired Bonds (not retired) (3)	Undistributed Subsidiary Earnings [illegible] (4)	Investment in EEI [illegible] (5)	Investments in OVEC and Other [illegible] (6)	Adjustments to Total Co. Capitalization [illegible] (7)	Adjusted Total Company Capitalization (Col 1 - Col 7) (8)	Jurisdictional Rate Base Percentage (Appendix B-Exhibit 3 Line 23) (9)	Kentucky Jurisdictional Capitalization (Col 8 x Col 9) (10)
1.	Short Term Debt	$ 93,302,454	3.27%	$ (16,693,620)	$	$ (813,592)	$ (21,619)	$ (17,528,831)	$ 75,773,623	87.80%	$ 66,529,241
2.	Long Term Debt	1,247,059,520	43.70%	16,693,620		(10,872,769)	(288,918)	5,531,933	1,252,591,453	87.80%	1,099,775,296
3.	Common Equity	1,513,015,410	53.03%	-	(23,584,679)	(13,194,117)	(350,603)	(37,129,399)	1,475,886,011	87.80%	1,295,827,918
4.	Total Capitalization	$ 2,853,377,384	100.00%	$ -	$ (23,584,679)	$ (24,880,478)	$ (661,140)	$ (49,126,297)	$ 2,804,251,087		$ 2,462,132,455

		Kentucky Jurisdictional Capitalization (10)	Capital Structure (11)	Environmental Surcharge Post '94 Plan (1) (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	$ 66,529,241	2.70%	$ (11,603,023)	$ 54,926,218	2.70%	2.63%	0.07%
2.	Long Term Debt	1,099,775,296	44.67%	(191,965,574)	907,809,722	44.67%	5.21%	2.32%
3.	Common Equity	1,295,827,918	52.63%	(226,173,005)	1,069,654,913	52.63%	11.25%	5.92%
4.	Total Capitalization	$ 2,462,132,455	100.00%	$ (429,741,602)	$ 2,032,390,853	100.00%		8.31%

(1) Kentucky Jurisdictional Net ECR Rate Base excluding the balance for Accumulated Deferred Income Taxes and Investment Tax Credit.

KENTUCKY UTILITIES

Net Original Cost Kentucky Jurisdictional Rate Base as of April 30, 2008

Case No. 1998-00474 - ECR Capitalization Adjustment

	Title of Account (1)	Kentucky Jurisdictional Rate Base at April 30, 2008 (2)	Other Jurisdictional Rate Base at April 30, 2008 (3)	Total Company Rate Base at April 30, 2008 (4)
1	Utility Plant at Original Cost	$ 4,495,693,653	$ 655,540,798	$ 5,151,234,451
2	Deduct:			
3	Reserve for Depreciation	1,707,655,598	264,707,047	1,972,362,645
4	Net Utility Plant	2,788,038,055	390,833,751	3,178,871,806
5	Deduct:			
6	Customer Advances for Construction	2,405,862	14,190	2,420,052
7	Accumulated Deferred Income Taxes	256,897,609	36,747,188	293,644,797
8	Asset Retirement Obligation-Net Assets	4,232,200	658,430	4,890,630
9	Asset Retirement Obligation-Liabilities	(26,805,403)	(4,170,288)	(30,975,691)
10	Asset Retirement Obligation-Regulatory Assets	21,526,237	3,348,974	24,875,211
11	Asset Retirement Obligation-Regulatory Liabilities	(1,951,342)	(303,583)	(2,254,925)
12	Reclassification of Accumulated Depreciation associated with Cost of Removal for underlying ARO Assets	2,066,847	321,553	2,388,400
13	Investment Tax Credit (a)	49,714,508	8,379,841	58,094,349
14	Total Deductions	308,086,518	44,996,305	353,082,823
15	Net Plant Deductions	2,479,951,537	345,837,446	2,825,788,983
16	Add:			
17	Materials and Supplies (b)	74,430,157	11,532,922	85,963,079
18	Prepayments (b)(c)	1,461,220	203,059	1,664,279
19	Emission Allowances	193,051	30,034	223,085
20	Cash Working Capital (page 2)	78,937,746	8,603,686	87,541,432
21	Total Additions	155,022,174	20,369,701	175,391,875
22	Total Net Original Cost Rate Base	$ 2,634,973,711	$ 366,207,147	$ 3,001,180,858
23	Percentage of Rate Base to Total Company Rate Base	87.80%	12.20%	100.00%

(a) Reflects investment tax credit treatment per Case No. 2007-00178.
(b) Average for 13 months.
(c) Includes prepayments for property insurance only

KENTUCKY UTILITIES

Calculation of Cash Working Capital as of April 30, 2008

Case No. 1998-00474 - ECR Capitalization Adjustment

	Title of Account (1)	Kentucky Jurisdictional Rate Base at April 30, 2008 (2)	Other Jurisdictional Rate Base at April 30, 2008 (3)	Total Company Rate Base at April 30, 2008 (4)
1	Operating and maintenance expense for the 12 months ended April 30, 2008	$ 788,744,613	$ 114,603,502	$ 903,348,115
2	Deduct:			
3	Electric Power Purchased	157,242,642	23,887,144	181,129,786
4	Total Deductions	$ 157,242,642	$ 23,887,144	$ 181,129,786
5	Remainder (Line 1 - Line 4)	$ 631,501,971	$ 90,716,358	$ 722,218,329
6	Cash Working Capital	$ 78,937,746	$ 8,603,686	$ 87,541,432

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

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

APPLICATION OF KENTUCKY	)	
UTILITIES COMPANY FOR AN	)	**CASE NO: 2008-00251**
ADJUSTMENT OF BASE RATES	)	

DIRECT TESTIMONY

OF

WILLIAM E. AVERA

on behalf of

KENTUCKY UTILITIES COMPANY

Filed: July 29, 2008

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

DIRECT TESTIMONY OF WILLIAM E. AVERA

Table of Contents

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

CASE NO. 2008-00251

DIRECT TESTIMONY OF WILLIAM E. AVERA

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.

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 41 states.

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 Appendix A.

A. Overview

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. The purpose of my testimony is to present to the Public Service Commission of the Commonwealth of Kentucky ("KPSC" or "the Commission") my independent evaluation of the fair rate of return on equity ("ROE") for the jurisdictional electric utility operations of Kentucky Utilities Company ("KU" or "the Company"). In addition, I also examined the reasonableness of KU's requested capital structure, considering both the specific risks faced by the Company and other industry guidelines.

Q. PLEASE SUMMARIZE THE INFORMATION AND MATERIALS YOU RELIED ON TO SUPPORT THE OPINIONS AND CONCLUSIONS CONTAINED IN YOUR TESTIMONY.

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 current capital market conditions and specifically to current investor perceptions, requirements, and expectations for KU's utility operations. 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 rate of return for KU, and they form the basis of my analyses and conclusions.

Q. WHAT IS THE ROLE OF THE RATE OF RETURN ON COMMON EQUITY IN SETTING A UTILITY'S RATES?

A. The ROE serves to compensate 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 the utility's investors, 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 DID YOU GO ABOUT DEVELOPING YOUR CONCLUSIONS REGARDING A FAIR RATE OF RETURN FOR KU?

A. I first reviewed the operations and finances of KU and the general conditions in the utility industry. 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, the Company's ROE

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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).

was evaluated taking into account the specific risks and potential challenges for KU's utility operations and the balanced regulatory environment in Kentucky.

B. 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 under reasonable terms, I recommend that KU be authorized an ROE of 11.25 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 seventeen 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;
- I applied both the DCF and CAPM methods, as well as the expected earnings approach, to estimate a fair ROE for KU:
    - My application of the constant growth DCF model considered four alternative growth measures based on projected earnings growth, as well as the sustainable, "br+sv" growth rate for each firm in the respective proxy groups;
    - After eliminating extreme low- and high-end outliers, my DCF analyses implied a cost of equity of 10.9 percent for the proxy group of comparable-risk utilities and 12.7 percent for the group of non-utility companies;
    - Application of the CAPM approach using forward-looking data that best reflects the underlying assumptions of this approach implied a cost of equity of 11.9 percent for the comparable utilities and 11.4 percent for the firms in the non-utility proxy group;
    - My evaluation of earned rates of return expected for utilities suggested a cost of equity on the order of 11.5 percent;
    - Considering these results, I concluded that the cost of equity for the proxy groups of utilities and non-utility companies is on the order of 10.9 percent to 12.7 percent. Based on my evaluation of the strength of the various methods as they apply to KU, and conservatively giving less weight to the upper end of the range, my recommended reasonable ROE for KU is 11.25 percent.

- My conclusion that an 11.25 percent represents a fair ROE for KU is reinforced by the fact that my recommended ROE range does not consider flotation 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 approximately 52.6 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 entirely consistent with average equity ratios for the firms in the proxy group of utilities at year-end 2007 and based on investors' near-term expectations;
- My conclusion is reinforced by the investment community's focus on the need for a greater equity cushion to accommodate higher operating risks and the pressures of financing capital investments. Financial flexibility plays a crucial role in ensuring the wherewithal to meet the needs of customers, and KU's capital structure reflects the Company's ongoing efforts to strengthen its credit standing and support access to capital on reasonable terms.

Q. WHAT OTHER EVIDENCE DID YOU CONSIDER IN EVALUATING YOUR RECOMMENDATION IN THIS CASE?

A. My recommendation was reinforced by the following findings:

- Sensitivity to regulatory uncertainties has increased dramatically and investors recognize that constructive regulation is a key ingredient in supporting utility credit standing and financial integrity;
- KU must compete for investors' capital with other utilities and businesses of comparable risk. If the Company is not provided an opportunity to earn a return that is sufficient to compensate for the underlying risks, investors will be unwilling to supply capital;
- Providing KU with the opportunity to earn a return that reflects these realities is an essential ingredient to strengthen the Company's financial position, which ultimately benefits customers by ensuring reliable service at lower long-run costs.

II. FUNDAMENTAL ANALYSES

Q. WHAT IS THE PURPOSE OF THIS SECTION?

A. As a predicate to my analyses, this section briefly reviews the operations and finances of KU, along with the risks and prospects for the utility industry. An understanding of these fundamental factors is essential in developing an informed opinion about investor expectations and requirements that form the basis of a fair rate of return.

A. Kentucky Utilities Company

Q. BRIEFLY DESCRIBE KU AND ITS ELECTRIC UTILITY OPERATIONS.

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 to over 500,000 retail customers in central, southeastern, and western Kentucky.[3]

Although KU and LGE are separate operating subsidiaries, they are operated as a single, fully integrated system. KU's utility facilities include over 4,400 megawatts ("MW") of generating capacity, with coal-fired generating stations accounting for approximately 66 percent of this total. In addition to company-owned generation, KU 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. The Company's transmission and distribution system includes over 20,000 miles of lines. At year-end 2007, KU had total assets of $3.8 billion, with total revenues of approximately $1.3 billion. KU is a member of the

[3] KU also provides retail electric service in five counties in southwestern Virginia and serves a limited number of customers in Tennessee.

Southwest Power Pool, Inc. ("SPP") and transmission service is available on the KU system under the SPP regional Open Access Transmission Tariff.[4] 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.

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 statutes.

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[4] Formerly transmission-owning members of the Midwest Independent Transmission System Operator, Inc. ("MISO"), KU and LGE withdrew from MISO on September 1, 2006. The KPSC approved the Tennessee Valley Authority to be their Reliability Coordinator and the SPP to be their independent transmission organization.

Q. DOES KU ANTICIPATE THE NEED FOR ADDITIONAL CAPITAL IN THE FUTURE?

A. Yes. KU will require capital in order to fund new investment in electric utility facilities, including transmission, to meet customer growth, provide for necessary maintenance and replace its utility infrastructure. Total capital expenditures are expected to be approximately $1.5 billion over the 2008-2010 period.

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. Utility Industry

Q. HOW HAVE INVESTORS' RISK PERCEPTIONS FOR THE UTILITY INDUSTRY EVOLVED?

A. Since the 1990s, the electric utility industry has experienced significant structural change resulting from market forces and legislative and regulatory initiatives.

Structural changes within the utility industry have forced electric utilities to confront new complexities and risks entailed in actively contracting for economical and secure energy supplies. 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,[5] with Fitch Ratings Ltd. ("Fitch") recently concluding that "the long-term outlook is negative" for investor-owned electric utilities.[6] Similarly, Moody's observed, "[m]aterial negative bias appears to be developing over the intermediate and longer term due to rapidly rising business and operating risks."[7]

Q. IS THE POTENTIAL FOR ENERGY MARKET VOLATILITY AN ONGOING CONCERN FOR INVESTORS?

A. Yes. In recent years utilities and their customers have also had to contend with dramatic fluctuations in energy costs due to ongoing price volatility in the spot markets. Investors recognize that the prospect of further turmoil in energy markets is an ongoing concern. S&P has reported continued spikes in wholesale energy market prices,[8] with average day-ahead prices within SPP, MISO, and PJM Interconnection,

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5 Standard & Poor's Corporation, "U.S. Electric utility Sector Continues To Benefit From Strong Liquidity Amid Current Credit Crunch," *RatingsDirect* (Mar. 27, 2008).

6 Fitch Ratings, Ltd., "U.S. Utilities, Power and Gas 2008 Outlook," *Global Power North America Special Report* (Dec. 11, 2007).

7 Moody's Investors Service, "U.S. Electric Utility Sector," *Industry Outlook* (Jan. 2008).

8 Standard & Poor's Corporation, "Fuel and Purchased Power Cost Recovery in the Wake of Volatile Gas and Power Markets – U.S. Electric Utilities to Watch" *RatingsDirect* (Mar. 22, 2006).

LLC ("PJM") also experiencing significant fluctuation.[9] Moody's warned investors of ongoing exposure to "extremely volatile" energy commodity costs, including purchased power prices, which are heavily influenced by fuel costs.[10] Similarly, the FERC Commission's Staff has continued to recognize the ongoing potential for market disruption. A 2008 market assessment report recognized ongoing concerns regarding tight supply and congestion and observed that wholesale power prices across the nation are likely to be significantly higher than the previous year.[11] FERC continues to warn of load pockets vulnerable to periods of high peak demand and unplanned outages of generation or transmission capacity and ongoing reliability concerns led FERC to establish mandatory standards for the bulk power system.[12]

Additionally, utilities and customers have also been confronted with significant volatility in natural gas costs. For example, the Energy Information Agency ("EIA") reported that the average price of gas used by electricity generators (regulated utilities and non-regulated power producers) spiked from an average price of $7.18 per thousand cubic feet ("Mcf") for the first eight months of 2005 to over $11.00 per Mcf in September and October 2005.[13] S&P observed that "natural gas prices have proven to be very volatile," warning of a "turbulent journey" due to the

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[9] For example, FERC reported that the average real-time prices in certain SPP zones spiked from approximately $50 per MWh to upwards of $350 per MWh in June and July 2007. FERC, "Southwest Power Pool Electric Market: RTO Prices; Daily Average of SPP Real Time Prices – All Hours," (Nov. 2, 2007), http://www.ferc.gov/market-oversight/mkt-electric/spp/2007/elec-spp-rto-pr.pdf. With respect to MISO, recent day-ahead prices more than tripled to approximately $150 per MWh in June 2008, while in PJM certain prices rose from approximately $50 per MWh to upwards of $225 per MWh between June and August 2007. http://www.ferc.gov/market-oversight/mkt-electric/midwest/elec-mw-rto-pr.pdf and http://www.ferc.gov/market-oversight/mkt-electric/pjm.asp.

[10] Moody's Investors Service, "Storm Clouds Gathering on the Horizon for the North American Electric Utility Sector," *Special Comment* at 6 (Aug. 2007).

[11] FERC, Office of Market Oversight and Investigations, "2008 Summer Market and Reliability Assessment," (May 15, 2008).

[12] *See Open Commission Meeting Statement of Chairman Joseph T. Kelliher,* Item E-13: Mandatory Reliability Standards for the Bulk-Power System (Docket No. RM06-16-000) (Mar. 15, 2007).

[13] Energy Information Administration, http://tonto.eia.doe.gov/dnav/ng/hist/n3045us3m.htm.

uncertainty associated with future fluctuations in energy costs,[14] and concluding; "Cost pressures from natural gas are not likely to recede in the near future."[15] Fitch also highlighted the challenges that fluctuations in commodity prices can have for utilities and their investors, concluding that gas prices are subject to near-term and longer-term fluctuations that contribute to an "adverse environment" for electric utilities.[16]

Further, while coal-fired generation has historically provided relative stability with respect to fuel costs, price hikes over the last few years have raised investors' concerns. In a 2004 article entitled "Rising Coal Prices May Threaten U.S. Utility Credit Profiles," S&P noted that:

> [S]everal current and structural developments for the coal mining industry have resulted in a dramatic increase in spot coal prices.[17]

More recently, the Energy Information Administration ("EIA"), a statistical agency of the U.S. Department of Energy, reported that average delivered coal prices for electric utilities increased 9.7 percent in 2006, the sixth consecutive annual rise,[18] while Reuters reported in May 2008 that benchmark coal prices exceeded $100 per ton, or over twice the levels of the previous fall.[19]

The rapid rise in electricity costs prompted by higher wholesale energy prices has heightened investor concerns over the implications for regulatory uncertainty. The

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[14] Standard & Poor's Corporation, "Top Ten Credit Issues Facing U.S. Utilities," *RatingsDirect* (Jan. 29, 2007).

[15] *Id.*

[16] Fitch Ratings, Ltd., "U.S. Power and Gas 2008 Outlook," *Global Power North American Special Report*, at 3 (Dec. 11, 2007).

[17] Standard & Poor's Corporation, "Rising Coal Prices May Threaten U.S. Utility Credit Profiles," *RatingsDirect* (Aug. 12, 2004).

[18] Energy Information Administration, *Annual Coal Report 2006* at 9 (Nov. 2007).

[19] Nichols, Bruce, "US coal prices pass $100 a ton, twice last fall's," *Reuters* (May 9, 2008).

Wall Street Journal reported in May 2008 that escalating fuel costs were leading to soaring electricity rates across the nation, raising the specter that social pressures could impact the outcome of regulatory proceedings.[20] S&P noted that, while timely cost recovery was paramount to maintaining credit quality in the electric utility sector, an "environment of rising customer tariffs, coupled with a sluggish economy, portend a difficult regulatory environment in coming years."[21]

Q. DOES THE FAC COMPLETELY ELIMINATE THE COMPANY'S EXPOSURE TO FLUCTUATIONS IN POWER SUPPLY COSTS?

A. No. While the opportunity to periodically adjust retail rates to accommodate fluctuations in fuel and purchased power costs is generally supportive of KU's financial integrity, there can be a lag between the time KU actually incurs the expenditure and when it is recovered from ratepayers. As a result, the Company is not insulated from the need to finance deferred power production and supply costs.

Q. WHAT OTHER KEY FACTORS ARE OF CONCERN TO INVESTORS?

A. Investors are also 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:

> [T]here are concerns arising from the sector's sizeable infrastructure investment plans in the face of an environment of steadily rising operating costs. Combined, these costs and investments can create a continuous need for regulatory rate relief, which in turn can increase the likelihood for political and/or regulatory intervention.[22]

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20 Smith, Rebecca, "Expect a Jolt When Opening The Electric Bill," Wall Street Journal at D1 (May 7, 2008).

21 Standard & Poor's Corporation, "Top 10 U.S. Electric Utility Credit Issues For 2008 And Beyond," *RatingsDirect* (Jan. 28, 2008).

22 Moody's Investors Service, "Storm Clouds Gathering on the Horizon for the North American Electric Utility Sector," *Special Comment* (Aug. 2007).

Moody's recently reaffirmed that ambitious investment needs are a material credit issue and will require significant access to new capital.[23] Similarly, S&P noted that "onerous construction programs", along with rising operating and maintenance costs and volatile fuel costs, were a significant challenge to the utility industry.[24] As noted earlier, the Company's plans include capital expenditures of approximately $1.5 billion for enhancements to its electric and gas utility systems. While providing the infrastructure necessary to meet the energy needs of customers is certainly desirable, investors are aware that it imposes additional financial responsibilities on KU.

Q. HAVE INVESTORS RECOGNIZED THAT ELECTRIC UTILITIES FACE ADDITIONAL RISKS BECAUSE OF THE IMPACT OF INDUSTRY RESTRUCTURING ON TRANSMISSION OPERATIONS?

A. Yes. As S&P affirmed, "The U.S. electric power industry is embarking on a period of rapid change."[25] S&P recently confirmed a "continued lack of clarity from lawmakers and regulators on the regulatory framework surrounding transmission projects."[26] Transmission operations have become increasingly complex and investors have recognized that difficulties in obtaining permits and uncertainty over the adequacy of allowed rates of return have contributed to heightened risk and fueled concerns regarding the need for additional investment in the transmission sector of the electric power industry.

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23 Moody's Investors Service, "U.S. Investor-Owned Electric Utilities: Six-Month Industry Update," *Industry Outlook* (July 2008).

24 Standard & Poor's Corporation, "U.S. Electric Utilities Continued Their Long Shift To Stability In Third Quarter," *RatingsDirect* (Oct. 23, 2007).

25 Standard & Poor's Corporation, "Top Ten Credit Issues Facing U.S. Utilities," *RatingsDirect* (Jan. 29, 2007).

26 Standard & Poor's Corporation, "Capital Spending on Electric Transmission Is on the Upswing Around the World," *RatingsDirect* (Aug. 7, 2006).

At the same time, the development of competitive wholesale power markets has resulted in increased demand for transmission resources. The perceived need to encourage further investment in the transmission sector was exemplified by FERC's Order Nos. 679 and 679-A, which established incentive-based rate treatments to promote investment in electric utility infrastructure. While there is little debate that increased investment in the transmission system will be required to fully realize the benefits of effective competition in wholesale power markets, the challenges posed by an increasingly complex marketplace heighten the uncertainties associated with transmission operations while requiring the commitment of significant new capital investment to maintain and enhance service capabilities.

Q. WHAT OTHER CONSIDERATIONS AFFECT INVESTORS' EVALUATION OF KU?

A. Utilities such as KU are confronting increased environmental pressures that are imposing significant uncertainties and costs. In early 2007, S&P cited environmental mandates as one of the top ten credit issues facing U.S. utilities.[27] More recently, S&P observed that:

> What the ultimate outcome will be is cloudy right now, but legislation addressing carbon emissions and other greenhouse gases is extremely probable in the near future. The credit implications of any policy will be vast due to the compliance costs involved.[28]

Similarly, Moody's noted that "increasingly stringent environmental compliance mandates will elevate cash outflow recovery risk",[29] while Fitch noted that the electric

[27] Standard & Poor's Corporation, "Top Ten Credit Issues Facing U.S. Utilities," *RatingsDirect* (Jan. 29, 2007).

[28] Standard & Poor's Corporation, "Upgrades Lead In U.S. Electric Utility Industry In 2007," *RatingsDirect* (Jan. 17, 2008).

[29] Moody's Investors Service, "U.S. Electric Utility Sector," *Industry Outlook* (Jan. 2008).

utility industry would be "a primary target" of new environmental legislation, and concluded: "The murkiness of the future policies and regulations on carbon emissions is another factor clouding Fitch's long-term view of electric utilities."[30] While proposed legislation that would have imposed significant limits on carbon emissions recently failed to receive sufficient support in the Senate, there is widespread expectation that binding emissions caps will be adopted following the inauguration of a new administration.

Compliance with these evolving standards will mean significant capital expenditures for those utilities, such as KU, that rely significantly on coal-fired generation. As noted earlier, the Company benefits from an ECR mechanism that allows for recovery of related costs required to meet federal and state statutes. As Moody's noted:

> This is important given that KU and LG&E environmental capital spending will exceed $1 billion in aggregate.[31]

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.[32]

III. CAPITAL MARKET ESTIMATES

Q. WHAT IS THE PURPOSE OF THIS SECTION?

A. In this section, I develop capital market estimates of the cost of equity. First, I address the concept of the cost of equity, along with the risk-return tradeoff principle

[30] Fitch Ratings, Ltd., "U.S. Utilities, Power and Gas 2008 Outlook," *Global Power North America Special Report* (Dec. 11, 2007).

[31] Moody's Investors Service, "Credit Opinion: Kentucky Utilities Co.," *Global Credit Research* (May 16, 2008).

[32] *Id.*

fundamental to capital markets. Next, I describe DCF and CAPM analyses conducted to estimate the cost of equity for benchmark groups of comparable risk firms and evaluate expected earned rates of return for utilities. Finally, I examine other factors (*e.g.*, flotation costs) that are properly considered in evaluating a fair rate of return on equity.

A. Economic Standards

Q. WHAT ROLE DOES THE 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. Competition for investor funds is intense and investors are free to invest their funds wherever they choose. 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.

A. 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 EQUITY FOR A UTILITY?

A. Although the cost of 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 unobservable, the cost of 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 EQUITY FOR KU?

A. No. I used both the DCF and CAPM methods to estimate the cost of equity, as well as referencing expected earned rates of return for utilities. In my opinion, comparing estimates produced by one method with those produced by other approaches ensures that estimates of the cost of equity pass fundamental tests of reasonableness and economic logic. In addition, I applied the DCF and CAPM to alternative proxy groups of comparable risk firms.

B. Discounted Cash Flow Analyses

Q. HOW IS THE DCF MODEL USED TO ESTIMATE THE COST OF 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. In other words, the cash flows that investors expect from a stock are estimated, and given its current market price, we can "back-into" the discount rate, or cost of equity, that investors implicitly used in bidding the stock to that price.

Q. WHAT MARKET VALUATION PROCESS UNDERLIES DCF MODELS?

A. DCF models assume that the price of a share of common stock is equal to the present value of the expected cash flows (i.e., future dividends and stock price) that will be received while holding the stock, discounted at investors' required rate of return. Thus, 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. Notationally, the general form of the DCF model is 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 equity.

That is, the cost of equity is the discount rate that will equate the current price of a share of stock with the present value of all expected cash flows from the stock.

Q. WHAT FORM OF THE DCF MODEL IS CUSTOMARILY USED TO ESTIMATE THE COST OF 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:[33]

[33] The constant growth DCF model is dependent on a number of strict assumptions, which in practice are never strictly 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.

$$P_0 = \frac{D_1}{k_e - g}$$

where: g = Investors' long-term growth expectations.

The cost of 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 equity for KU, which is the form of the model most commonly relied on to establish the cost of equity for traditional regulated utilities and the method most often referenced by regulators.

Q. HOW DID YOU IMPLEMENT THE DCF MODEL TO ESTIMATE THE COST OF EQUITY FOR KU?

A. Application of the DCF model to estimate the cost of equity requires an observable stock price. Because KU is a wholly owned subsidiary of E.ON and has no publicly traded stock, its cost of common equity cannot be estimated directly using the DCF model. In such circumstances, the cost of equity is generally estimated by applying the DCF model to a proxy group of publicly traded companies engaged in similar business activities and the results of that analysis are relied upon to determine the cost of equity for the specific company at issue.

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 included by *The Value Line Investment Survey* ("Value Line") in its Electric Utilities Industry groups with: (1) both electric and gas utility operations, (2) S&P corporate credit ratings between "BBB" and "A"; (2) a Value Line Safety Rank of "3" or better; and (3) a Value Line Financial Strength Rating of "B++" or better. I excluded three firms that otherwise would have been in the proxy group, but are not appropriate for inclusion because they either are in the process of being acquired (Energy East Corporation), have announced the intention to sell their gas utility operations (PPL Corporation), or lack sufficient information to apply the DCF model (CH Energy Group Inc.). These criteria resulted in a proxy group composed of seventeen comparable risk utilities. I refer to this group as the "Utility Proxy Group."

Q. DO THESE CRITERIA PROVIDE OBJECTIVE EVIDENCE THAT INVESTORS WOULD VIEW THE FIRMS IN THE UTILITY PROXY GROUP AS RISK-COMPARABLE?

A. Yes. Credit ratings are assigned by independent rating agencies to provide investors with a broad assessment of the creditworthiness of a firm. 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 measure of overall investment risk that is readily available to investors. Widely cited in the investment community and referenced by investors as an objective measure of risk, credit ratings are also frequently used as a primary risk indicator in establishing proxy groups to estimate the cost of equity.

Apart from the broad assessment of investment risk provided by credit ratings, other quality rankings published by investment advisory services also provide relative assessments of risk that are considered by investors in forming their expectations. Given that Value Line is perhaps the most widely available source of investment advisory information, its Safety Rank and Financial Strength Rating provide useful guidance regarding the risk perceptions of investors.

The Safety Rank is Value Line's primary risk indicator and 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. 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.

As discussed earlier, KU is rated "BBB+" by S&P, which is identical to the average for the utilities in 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 "B++" credit.[34] Based on my screening criteria, which

[34] 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 KU. 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.

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 this group as having risks and prospects comparable to those of KU.

Q. HOW IS THE CONSTANT GROWTH FORM OF THE DCF MODEL TYPICALLY USED TO ESTIMATE THE COST OF 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 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 Schedule WEA-1, based on Value Line data as of May 9, 2008. As shown there, dividend yields for the firms in the Utility Proxy Group ranged from 2.1 percent to 6.5 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. Moreover, to the extent historical trends for utilities are meaningful, they are also captured in projected growth rates, since securities analysts also routinely examine and assess the impact and continued relevance (if any) of historical trends.

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.[35] 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.

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.[36]

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:

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[35] For example, the payout ratio for electric utilities fell from approximately 80% historically to on the order of 60%. The Value Line Investment Survey (Sep. 15, 1995 at 161, Dec. 28, 2007 at 695).

[36] Association for Investment Management and Research, "Finding Reality in Reported Earnings: An Overview", p. 1 (Dec. 4, 1996).

> 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%.[37]

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 actually use.[38] 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 it last. The article concluded:

> Earnings and cash flow are considered far more important than book value and dividends.[39]

More recently, 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."[40]

Q. WHAT ARE SECURITY ANALYSTS CURRENTLY PROJECTING IN THE WAY OF GROWTH FOR THE FIRMS IN THE UTILITY PROXY GROUP?

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[37] The Value Line Investment Survey, *Subscriber's Guide*, p. 53.

[38] Block, Stanley B., "A Study of Financial Analysts: Practice and Theory", *Financial Analysts Journal* (July/August 1999).

[39] *Id.* at 88.

[40] Liu, Jing, Nissim, Doron, & Thomas, Jacob, "Is Cash Flow King in Valuations?," *Financial Analysts Journal*, Vol. 63, No. 2 (March/April 2007) at 56.

A. The earnings growth projections for each of the firms in the Utility Proxy Group reported by Value Line, Thomson Financial ("Thomson"),[41] Reuters, Inc. ("Reuters"), and Zacks Investment Research ("Zacks") are displayed on Schedule WEA-1.

Q. HOW ELSE ARE INVESTORS' EXPECTATIONS OF FUTURE LONG-TERM GROWTH PROSPECTS OFTEN ESTIMATED WHEN APPLYING THE CONSTANT GROWTH DCF MODEL?

A. Based on the assumptions underlying constant growth theory, conventional applications of the constant growth DCF model often examine the relationship between retained earnings and earned rates of return as an indication of the sustainable growth investors might expect from the reinvestment of earnings within a firm. The sustainable growth rate is calculated by the formula, $g = br+sv$, where "b" is the expected retention ratio, "r" is the expected 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.

[41] Thomson Financial, an arm of The Thomson Corporation, compiles and publishes consensus securities analyst growth rates under the IBES and First Call brands.

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 Schedule WEA-1, with the underlying details being presented on Schedule WEA-2. 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 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 COST OF 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 equity estimates are shown on Schedule WEA-1.

Q. IN EVALUATING THE RESULTS OF THE CONSTANT GROWTH DCF MODEL, IS IT APPROPRIATE TO ELIMINATE COST OF EQUITY ESTIMATES THAT ARE EXTREME OUTLIERS?

A. Yes. 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. Consistent with this principle, the DCF range for the Utility Proxy Group must be adjusted to eliminate cost of equity estimates that are determined to be extreme outliers.

Q. HAVE SIMILAR TESTS BEEN APPLIED BY REGULATORS?

A. Yes. The 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 cost of equity estimates that do not sufficiently exceed this threshold. In a 2002 opinion establishing its current precedent for determining ROEs for electric utilities, for example, FERC concluded:

> 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.[42]

More recently, in its October 2006 decision in *Kern River Gas Transmission Company*, FERC noted that:

> [T]he 7.31 and 7.32 percent costs of equity for El Paso and Williams found by the ALJ are only 110 and 122 basis points above that average yield for public utility debt.[43]

FERC upheld the opinion of Staff and the Administrative Law Judge that cost of equity estimates for these two proxy group companies "were too low to be credible."[44]

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[42] *Southern California Edison Company*, 92 FERC ¶ 61,070 (2000) at p. 22.

[43] *Kern River Gas Transmission Company*, Opinion No. 486, 117 FERC ¶ 61,077 at P 140 & n. 227 (2006).

[44] *Id.*

Q. WHAT DOES THIS TEST OF LOGIC IMPLY WITH RESPECT TO THE DCF RESULTS FOR THE UTILITY PROXY GROUP?

A. 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 6.8 percent in April 2008.[45] As highlighted on Schedule WEA-1, three of the individual equity estimates for the firms in the Utility Proxy Group exceeded this threshold by 120 basis points or less.[46] In light of the risk-return tradeoff principle and the test applied in *Kern River Gas Transmission Company*, 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, these values provide little guidance as to the returns investors require from utility common stocks.

Q. DO YOU ALSO RECOMMEND EXCLUDING COST OF EQUITY ESTIMATES AT THE HIGH END OF THE RANGE OF DCF RESULTS?

A. Yes. The upper end of the cost of equity range produced by the DCF analysis presented in Schedule WEA-1 was set by a cost of equity estimate of 20.3 percent for Constellation Energy, with four other DCF estimates ranging from 17.2 percent to 18.8 percent. Compared with the balance of the remaining estimates, these results are extreme outliers and should also be excluded in evaluating the results of the DCF model for the Utility Proxy Group. This is also consistent with the threshold adopted

[45] Moody's *Investors* Service, *www.CreditTrends.com*.

[46] As *highlighted* on Schedule WEA-1, these DCF estimates ranged from 6.7 percent to 7.7percent

by FERC, which established that a 17.7 percent DCF estimate for was "an extreme outlier" and should be disregarded.[47]

Q. WHAT COST OF EQUITY IS IMPLIED BY YOUR DCF RESULTS FOR THE UTILITY PROXY GROUP?

A. As shown on Schedule WEA-1 and summarized in Table 1, below, after eliminating illogical low- and high-end values, application of the constant growth DCF model resulted in the following cost of equity estimates:

TABLE 1
DCF RESULTS –UTILITY PROXY GROUP

Growth Rate	Average Cost of Equity
Value Line	10.7%
IBES	10.9%
Reuters	11.5%
Zacks	11.2%
br+sv	10.5%

Q. WHAT DID YOU CONCLUDE BASED ON THE RESULTS OF THE DCF ANALYSES FOR THE UTILITY PROXY GROUP?

A. Taken together, and considering the relative strengths and weaknesses associated with the alternative growth measures, I concluded that the constant growth DCF results for the Utility Proxy Group implied a cost of equity of 10.9 percent.

Q. HOW ELSE CAN THE DCF MODEL BE APPLIED TO ESTIMATE THE ROE FOR KU?

A. Under the regulatory standards established by *Bluefield*, the salient criteria in establishing a meaningful benchmark to evaluate a fair rate of return is relative risk, not the particular business activity or degree of regulation. Utilities must compete for

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47 *ISO New England, Inc.*, 109 FERC ¶ 61,147 at P 205 (2004).

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, 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. To reflect investors' risk perceptions in developing the Non-Utility Proxy Group, my assessment of comparable risk relied on three objective benchmarks for the risks associated with common stocks – Value Line's Safety Rank, Financial Strength rating, and beta. Given that Value Line is perhaps the most widely available source of investment advisory information, its Safety Rank and Financial Strength Rating provide useful guidance regarding the risk perceptions of investors. These objective, published indicators incorporate consideration of a broad spectrum of risks, including financial and business position, relative size, and exposure to company specific factors.

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 a Financial Strength Rating of "A" or above, and 4) have beta values of 0.90 or less.[48] Consistent with the development of my utility proxy group, I also eliminated firms with below-investment grade credit ratings. Table 2 compares the Non-Utility

[48] This threshold is corresponds to the average betas for the Utility Proxy Group of 0.84.

Proxy Group with the Utility Proxy Group and KU across four key indicators of investment risk:[49]

TABLE 2
COMPARISON OF RISK INDICATORS

	S&P	Value Line		
Proxy Group	**Credit Rating**	**Safety Rank**	**Financial Strength**	**Beta**
Non-Utility	A+	1	A+	0.79
Utility	BBB+	2	A	0.84
KU	BBB+	--	--	--

Considered along with S&P's corporate credit ratings, a comparison of these Value Line indicators suggests that the investment risks associated with the Non-Utility Proxy Group are below those of the proxy group of utilities and KU. While any differences in 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.

Q. WHAT WERE THE RESULTS OF YOUR DCF ANALYSIS FOR THE NON-UTILITY PROXY GROUP?

A. Once again, I applied the DCF model to the Non-Utility Proxy Group in exactly the same manner described earlier for the Utility Proxy Group.[50] As shown on Schedule WEA-3 and summarized in Table 3, below, after eliminating illogical low- and high-end values, application of the constant growth DCF model resulted in the following cost of equity estimates:

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[49] KU has no publicly traded common stock and Value Line does not publish risk measures for its parent, E.ON.

[50] Schedule WEA-4 contains the details underlying the calculation of the br+sv growth rates for the Non-Utility Proxy Group.

TABLE 3
DCF RESULTS – NON-UTILITY PROXY GROUP

Growth Rate	Average Cost of Equity
Value Line	12.7%
IBES	12.4%
Reuters	12.9%
Zacks	12.8%
br+sv	12.9%

Q. WHAT DID YOU CONCLUDE BASED ON THE RESULTS OF THE DCF ANALYSES FOR THE NON-UTILITY PROXY GROUP?

A. Taken together, I concluded that the constant growth DCF results for the Non-Utility Proxy Group implied a cost of equity of 12.7 percent. As discussed earlier, reference to the Non-Utility Proxy Group is consistent with established regulatory principles and required returns for utilities should be in line with those of non-utility firms of comparable risk operating under the constraints of free competition.

Q. DO YOU BELIEVE THE DCF MODEL SHOULD BE RELIED ON EXCLUSIVELY TO EVALUATE A REASONABLE ROE FOR THE PROXY GROUPS OR KU?

A. No. Because the cost of equity is unobservable, no single method should be viewed in isolation. While the DCF model has been routinely relied on in regulatory proceedings as one guide to investors' required return, it is widely recognized that no single method 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.[51]

Moreover, evidence suggests that reliance on the DCF model as a tool for estimating investors' required rate of return has declined outside the regulatory sphere, with the CAPM being "the dominant model for estimating the cost of equity."[52]

C. Capital Asset Pricing Model

Q. PLEASE DESCRIBE THE CAPM.

A. The CAPM is generally considered to be the most widely referenced method for estimating the cost of equity both among academicians and professional practitioners, with the pioneering researchers of this method receiving the Nobel Prize in 1990. The CAPM is a theory of market equilibrium that measures risk using the beta coefficient. Because investors are assumed to be 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

[51] Parcell, David C., "The Cost of Capital – A Practitioner's Guide," *Society of Utility and Regulatory Financial Analysts* (1997) at Part 2, p. 4.

[52] *See e.g.*, Bruner, R.F., Eades, K.M., Harris, R.S., and Higgins, R.C., "Best Practices in Estimating Cost of Capital: Survey and Synthesis," Financial Practice and Education (1998).

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 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 Schedule WEA-5. 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 Composite Index (S&P 500).

The dividend yield for each firm was obtained from Value Line, with the growth rate being equal to the average of the earnings growth projections for each firm published by IBES and Value Line, 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 338 individual firms, current estimates imply an average growth rate over the next five years of 10.9 percent. Combining this average growth rate with a dividend yield of 2.4 percent results in a current cost of equity estimate for the market as a whole of approximately 13.3 percent. Subtracting a 4.4 percent risk-free rate based on the average yield on 20-year Treasury bonds for April 2008 produced a market equity risk premium of 8.9 percent. As shown on Schedule WEA-5, multiplying this risk premium by the average Value Line beta of 0.84 for the Utility Proxy Group, and then adding the resulting 7.5 percent risk premium to the average long-term Treasury bond yield, indicated an ROE of approximately 11.9 percent.

Q. WHAT COST OF EQUITY WAS INDICATED FOR THE NON-UTILITY PROXY GROUP BASED ON THIS FORWARD-LOOKING APPLICATION OF THE CAPM?

A. As shown on Schedule WEA-6, applying the forward-looking CAPM approach to the firms in the Non-Utility Proxy Group implied a cost of equity estimate of 11.4 percent.

Q. DID YOUR CAPM ANALYSIS RELY ON GEOMETRIC OR ARITHMETIC MEANS IN ARRIVING AT AN EQUITY RISK PREMIUM?

A. No. Reference to arithmetic or geometric mean risk premiums is associated with applications of the CAPM that depend on historical data. In order to derive an estimate of the market equity risk premium under this approach, historical average returns on Treasury bonds are typically subtracted from those for common stocks. These average rates of return based on backward-looking data for historical time periods can be derived using both arithmetic and geometric means.

As discussed above, however, my application of the CAPM was a purely forward-looking approach, which is consistent with the underlying assumptions of this method and the standards underlying a determinative of a fair rate of return. Because I looked directly at investors' current expectations in the capital markets – and not at historical rates of return – my CAPM analysis made no reference to arithmetic or geometric mean of historical rates of return.

D. Expected Earnings Approach

Q. WHAT OTHER ANALYSES DID YOU CONDUCT TO ESTIMATE THE COST OF EQUITY?

A. As I noted earlier, I also evaluated the cost of 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 Supreme Court. 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 11.5 percent in 2008 and 2009, with projected returns expected to average 11.0 percent over its 2011-2013 forecast horizon.[53]

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 Schedule WEA-7. 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. As shown on Schedule WEA-7, Value Line's projections for the Utility Proxy Group suggested an average ROE of 11.8 percent after eliminating potential outliers.[54]

Q. WHAT RETURN ON EQUITY IS INDICATED BY THE RESULTS OF THE EXPECTED EARNINGS APPROACH?

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[53] The Value Line Investment Survey at 1779 (May 9, 2008).

[54] As highlighted on Schedule WEA-7, I eliminated a high-end estimate of 26.1 percent. While this Value Line projection may accurately reflect expectations for actual earned rates of return on common equity over the forecast horizon, it is unlikely to be representative of investors' required rate of return.

A. Based on the results discussed above, I concluded that the comparable earnings approach implies a fair rate of return on equity of 11.5 percent.

E. Summary of Results

Q. PLEASE SUMMARIZE THE RESULTS OF YOUR QUANTITATIVE ANALYSES.

A. The cost of equity estimates implied by my quantitative analyses are summarized in Table 4 below:

TABLE 4
SUMMARY OF QUANTITATIVE RESULTS

Method	Utility	Non-Utility
DCF	10.9%	12.7%
CAPM	11.9%	11.4%
Expected Earnings	11.5%	

Considering the results produced by my alternative analyses, I concluded that the cost of equity for the proxy groups of utilities and non-utility companies is in the 10.9 percent to 12.7 percent range.

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 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. Alternatively, 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 logical mechanism.

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.[55]

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%.[56]

Applying these expense percentages to a representative dividend yield for a utility of 4 percent implies a flotation cost adjustment on the order of 14 to 40 basis points. A specific adjustment for flotation costs was not included in defining my recommended ROE range. While issuance costs are a legitimate consideration in

[55] Roger A. Morin, Regulatory Finance: Utilities' Cost of Capital, 1994, at 166.

[56] 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%.

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.

IV. RETURN ON EQUITY FOR KU

Q. WHAT IS THE PURPOSE OF THIS SECTION?

A. In addition to presenting the conclusions of my evaluation of a fair rate of return on equity for KU, this section also discusses the relationship between ROE and preservation of a utility's financial integrity and the ability to attract capital, and evaluates the reasonableness of KU's capital structure.

A. Implications for Financial Integrity

Q. WHY IS IT IMPORTANT TO ALLOW KU AN ADEQUATE RETURN ON EQUITY?

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 KU remains committed to providing reliable utility 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. 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.

Coupled with the ongoing potential for energy market volatility, KU's plans for infrastructure investment and ongoing regulatory uncertainty pose a number of potential challenges that might require the relatively swift commitment of significant capital resources in order to maintain the high level of service that customers expect. 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 ACCESS TO CAPITAL FOR KU?

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, supportive regulation remains crucial to KU'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. S&P recently concluded, "The political atmosphere will remain highly charged, fostering uncertainty."[57] Moody's echoed these sentiments, noting that "regulatory relationships are becoming more important" in an era of broadly rising costs and uncertainties,[58] and recently concluded:

> If the regulatory framework begins to take on a more contentious tone, we would consider that to be a material credit negative.[59]

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[57] Standard & Poor's Corporation, "Top Ten Credit Issues Facing U.S. Utilities," *RatingsDirect* (Jan. 29, 2007).

[58] Moody's Investors Service, "Regulatory Pressures Increase for U.S. Electric Utilities," *Special Comment* (March 2007).

[59] Moody's Investors Service, "U.S. Investor-Owned Electric Utilities: Six-Month Industry Update," *Industry Outlook* (July 2008).

Q. WHAT DANGER DOES AN INADEQUATE RATE OF RETURN POSE TO KU?

A. Considering the magnitude of the events that have transpired since the third quarter of 2000, investors' sensitivity to market and regulatory uncertainties has increased dramatically. At the same time, KU's plans include significant plant investment to ensure that the customers' energy needs are met in a reliable and cost-effective manner. While providing the infrastructure necessary to further the goals of enhancing the utility system and meeting the energy needs of customers is certainly desirable, it imposes additional financial responsibilities on KU. While acknowledging that the regulatory environment for KU has generally been supportive, the investment community recognizes that regulation has its own risks.

Investors have many alternatives and competition for capital is intense. Lingering uncertainties from a prior era, as well as new challenges in the utility industry, breed reluctance to make the long-term commitment of capital that is required to ensure the reliable and economic supply of electricity that customers both demand and deserve. Moreover, the utility industry is not immune to upheaval in credit markets. According to Fitch, "the sector is sensitive to systemic market dislocations,"[60] with S&P observing, "[t]he significant dislocations in the credit markets, spurred in part from credit concerns of the monoline insurance companies, caused many companies to experience difficulties in performing successful auctions for auction rate securities."[61] Thus, while customers might realize short-term

60 Fitch Ratings Ltd., "U.S. Utilities, Power and Gas 2008 Outlook," *Global Power North America Special Report* (Dec. 11, 2007).

61 Standard & Poor's Corporation, "U.S. Utility Sector Continues To Benefit From Strong Liquidity Amid Current Credit Crunch," *RatingsDirect* (Mar.27, 2008).

"savings" through a downward-biased ROE, these will prove illusory if the utility lacks the financial integrity to make investments that are consistent with providing sustained, high quality service at the lowest possible price in the long run.

Q. DO CUSTOMERS BENEFIT BY ENHANCING THE UTILITY'S FINANCIAL FLEXIBILITY?

A. Yes. While providing an ROE that is sufficient to maintain KU's ability to attract capital, even in times of financial and market stress, is consistent with the economic requirements embodied in the Supreme Court's *Hope* and *Bluefield* decisions, 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 reliable service. By the same token, customers also bear a significant burden when the ability of the utility to attract necessary 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 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. KU's capital structure is presented in the testimony of S. Bradford Rives. As summarized there, the common equity ratio used to compute KU's overall rate of return was approximately 52.6 percent in this filing.

Q. WHAT WAS THE AVERAGE CAPITALIZATION MAINTAINED BY THE UTILITY PROXY GROUP?

A. As shown on Schedule WEA-8, for the nineteen firms in the Utility Proxy Group, common equity ratios at year-end 2007 ranged between 38.7 percent and 66.0 percent and averaged 51.3 percent. Value Line expects that the average common equity ratio for the proxy group of utilities will average 53.4 percent over the next three to five years, with the individual common equity ratios ranging from 44.5 percent to 70.0 percent.

Q. HOW DOES KU'S COMMON EQUITY RATIO COMPARE WITH THOSE MAINTAINED BY THE REFERENCE GROUP OF UTILITIES?

A. KU's 52.6 percent common equity ratio is entirely consistent with average equity ratios for the firms in the Utility Proxy Group at year-end 2007 and based on Value Line's near-term expectations.

Q. WHAT IMPLICATION DO THE UNCERTAINTIES FACING THE UTILITY INDUSTRY HAVE FOR THE CAPITAL STRUCTURES MAINTAINED BY UTILITIES?

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 a decline in credit quality, these considerations warrant a stronger balance sheet to deal with an increasingly uncertain and competitive market. 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.[62] Moody's recently noted that, absent a stronger equity cushion, utilities would be faced with lower credit ratings in the face of rising business and operating risks:

> There are significant negative trends developing over the longer-term horizon. This developing negative concern primarily relates to our view that the sector's overall business and operating risks are rising – at an increasingly fast pace – but that the overall financial profile remains relatively steady. A rising risk profile accompanied by a relatively stable balance sheet profile would ultimately result in credit quality deterioration.[63]

Moody's affirmed that, because of its significant investment plans, the utility industry "will need to attract a significant amount of new equity capital in order to maintain existing ratings."[64]

Q. WHAT OTHER FACTORS DO INVESTORS CONSIDER IN THEIR ASSESSMENT OF A COMPANY'S CAPITAL STRUCTURE?

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[62] Moody's Investors Service, "Storm Clouds Gathering on the Horizon for the North American Electric Utility Sector," *Special Comment* (Aug. 2007).

[63] Moody's Investors Service, "U.S. Electric Utility Sector," *Industry Outlook* (Jan. 2008).

[64] Moody's Investors Service, "U.S. Investor-Owned Electric Utilities: Six-Month Industry Update," *Industry Outlook* (July 2008).

A. Depending on their specific attributes, contracts or other obligations that require the utility to make specified payments akin to those associated with traditional debt financing may be treated as debt in evaluating financial risk. 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.[65]

Reflecting the longstanding perception of investors that the fixed obligations associated with off-balance sheet obligations diminish a utility's creditworthiness and financial flexibility, the implications of 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 off-balance sheet obligations, 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.[66]

Q. WHAT DID YOU CONCLUDE WITH RESPECT TO THE COMPANY'S CAPITAL STRUCTURE?

A. Based on my evaluation, I concluded that KU's capital structure represents a reasonable mix of capital sources from which to calculate the Company's overall rate of return. KU's common equity ratio is entirely consistent with the average capital

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65 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.

66 Standard & Poor's Corporation, "Standard & Poor's Methodology For Imputing Debt For U.S. Utilities' Power Purchase Agreements," *RatingsDirect* (May 7, 2007).

structures for the proxy group of utilities based on year-end 2007 data and Value Line's near-term projections.

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.

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 strengthen its credit standing and support access to capital on reasonable terms. The reasonableness of KU's capital structure is reinforced by the ongoing uncertainties associated with the electric power industry, the need to accommodate ongoing regulatory risks, and the importance of supporting continued system investment, even during times of adverse industry or market conditions.

C. Return on Equity Recommendation

Q. PLEASE SUMMARIZE THE RESULTS OF YOUR ANALYSES.

A. Reflecting the fact that investors' required return on equity is unobservable and no single method should be viewed in isolation, I considered the results of both the DCF and CAPM methods and evaluated expected earned rates of return for utilities. In order to reflect the risks and prospects associated with KU's jurisdictional electric utility operations, my analyses focused on a proxy group of seventeen comparable risk utilities. 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.

My application of the constant growth DCF model considered four alternative growth measures based on projected earnings growth, as well as the sustainable, "br+sv" for each firm in the respective proxy groups. In addition, I evaluated the reasonableness of the resulting DCF estimates and eliminated low- and high-end outliers that failed to meet threshold tests of economic logic. My CAPM analyses were based on forward-looking data that best reflects the underlying assumptions of this approach. The results of my alternative analyses were summarized earlier in Table 4, which is reproduced below:

TABLE 4
SUMMARY OF QUANTITATIVE RESULTS

Method	**Utility**	**Non-Utility**
DCF	10.9%	12.7%
CAPM	11.9%	11.4%
Expected Earnings	11.5%	

Q. WHAT THEN IS YOUR CONCLUSION AS TO A FAIR RATE OF RETURN ON EQUITY FOR KU?

A. As explained above, I concluded that the fair rate of return on equity range was 10.9 percent to 12.7 percent. Based on my assessment of the relative strengths and weaknesses inherent in each method, and conservatively giving less emphasis to the upper end of the range of results, it is my opinion that 11.25 percent, represents a fair and reasonable ROE for KU. My conclusion recognizes the balanced regulatory environment in Kentucky and is supported by the need to consider the potential exposures faced by KU, the economic requirements necessary to maintain financial integrity and support access to capital even under adverse circumstances, and the fact that my recommendation does not expressly include an adjustment for flotation costs.

Q. DOES THIS COMPLETE YOUR PRE-FILED DIRECT TESTIMONY?

A. Yes, it does.

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 (over 150 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 in evening program at St. Edward's University in Austin from January 1979 through 1998.

Expert Witness Testimony

Testified in over 250 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, Kansas, Maryland, Michigan, Missouri, Nevada, New Mexico, North Carolina, Ohio, Oklahoma, Oregon, Pennsylvania, South Carolina, South Dakota, Texas, Utah, Virginia, Washington, West Virginia, Wisconsin, and Wyoming.

Testified in 41 cases before federal and state courts, arbitration panels, and alternative dispute tribunals (86 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 Member, 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 Support Unit; Officer-in-charge of SWIFT patrol boat in Vietnam; Enlisted service as weather analyst (advanced to second class petty officer).

Bibliography

Monographs

Ethics and the Investment Professional (video, workbook, and instructor's guide) and *Ethics Challenge Today* (video), Association for Investment Management and Research (1995)

"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)

"On the Use of Security Analysts' Growth Projections in the DCF Model," with Bruce H. Fairchild in *Earnings Regulation Under Inflation*, J. R. Foster and S. R. Holmberg, eds. Institute for Study of Regulation (1982)

An Examination of the Concept of Using Relative Customer Class Risk to Set Target Rates of Return in Electric Cost-of-Service Studies, with Bruce H. Fairchild, Electricity Consumers Resource Council (ELCON) (1981); portions reprinted in *Public Utilities Fortnightly* (Nov. 11, 1982)

"Usefulness of Current Values to Investors and Creditors," *Research Study on Current-Value Accounting Measurements and Utility*, George M. Scott, ed., Touche Ross Foundation (1978)

"The Geometric Mean Strategy and Common Stock Investment Management," with Henry A. Latané in *Life Insurance Investment Policies*, David Cummins, ed. (1977)

Investment Companies: Analysis of Current Operations and Future Prospects, with J. Finley Lee and Glenn L. Wood, American College of Life Underwriters (1975)

Articles

"Should Analysts Own the Stocks they Cover?" *The Financial Journalist*, (March 2002)

"Liquidity, Exchange Listing, and Common Stock Performance," with John C. Groth and Kerry Cooper, *Journal of Economics and Business* (Spring 1985); reprinted by National Association of Security Dealers

"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

"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)

"Electric Rate Design in Texas," Southwestern Economics Association, Fort Worth (Mar. 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)

"Multi-period Wealth Distributions and Portfolio Theory," Southern Finance Association, Houston (Nov. 1973)

"Growth Rates, Expected Returns, and Variance in Portfolio Selection and Performance Evaluation," with Henry A. Latané, Econometric Society, Oslo, Norway (Aug. 1973)

CONSTANT GROWTH DCF MODEL

UTILITY PROXY GROUP

		(a)	(a)		(b)	(c)	(d)	(e)	(f)	(g)	(g)	(g)	(g)	(g)
		Dividend Yield			Growth Rates					Cost of Equity Estimates				
	Company	Price	Dividends	Yield	V Line	IBES	Reuters	Zacks	br+sv	V Line	IBES	Reuters	Zacks	br+sv
1	ALLETE	$ 41.68	$ 1.74	4.2%	2.5%	5.0%	8.8%	5.0%	7.3%	$\boxed{6.7\%}$	9.2%	12.9%	9.2%	11.5%
2	Alliant Energy	$ 37.49	$ 1.40	3.7%	6.0%	5.7%	7.0%	7.0%	4.8%	9.7%	9.4%	10.7%	10.7%	8.6%
3	Consolidated Edison	$ 41.58	$ 2.34	5.6%	4.5%	3.0%	3.8%	3.2%	3.3%	10.1%	8.6%	9.4%	8.8%	8.9%
4	Constellation Energy	$ 86.31	$ 1.96	2.3%	13.5%	16.0%	12.5%	18.0%	11.6%	15.8%	$\boxed{18.3\%}$	14.8%	$\boxed{20.3\%}$	13.9%
5	Dominion Resources	$ 43.44	$ 1.67	3.8%	9.5%	8.3%	8.7%	10.3%	7.8%	13.3%	12.1%	12.5%	14.1%	11.7%
6	Duke Energy	$ 18.20	$ 0.91	5.0%	NA	4.8%	6.6%	5.8%	2.4%	NA	9.8%	11.6%	10.8%	$\boxed{7.4\%}$
7	Entergy Corp.	$ 112.02	$ 3.00	2.7%	8.0%	12.6%	9.9%	13.3%	7.2%	10.7%	15.3%	12.5%	16.0%	9.9%
8	Exelon Corp.	$ 84.33	$ 2.02	2.4%	9.0%	8.0%	9.8%	11.5%	11.4%	11.4%	10.4%	12.2%	13.9%	13.8%
9	Integrys Energy Group	$ 48.37	$ 2.68	5.5%	2.5%	12.1%	7.0%	5.5%	2.2%	8.0%	$\boxed{17.6\%}$	12.5%	11.0%	$\boxed{7.7\%}$
10	MDU Resources Group	$ 28.69	$ 0.61	2.1%	7.0%	9.9%	7.9%	7.7%	9.3%	9.1%	12.0%	10.0%	9.8%	11.5%
11	PG&E Corp.	$ 39.62	$ 1.59	4.0%	5.0%	7.7%	7.9%	7.8%	5.5%	9.0%	11.7%	11.9%	11.8%	9.5%
12	P S Enterprise Group	$ 43.82	$ 1.29	2.9%	10.5%	15.9%	9.5%	14.3%	7.8%	13.4%	$\boxed{18.8\%}$	12.4%	$\boxed{17.2\%}$	10.7%
13	SCANA Corp.	$ 39.71	$ 1.86	4.7%	4.0%	5.4%	5.9%	4.8%	4.7%	8.7%	10.1%	10.5%	9.5%	9.4%
14	Sempra Energy	$ 56.67	$ 1.50	2.6%	6.0%	8.1%	7.0%	6.7%	7.4%	8.6%	10.7%	9.6%	9.3%	10.1%
15	Vectren Corp.	$ 28.19	$ 1.31	4.6%	4.0%	5.3%	5.0%	6.3%	3.6%	8.6%	9.9%	9.6%	10.9%	8.3%
16	Wisconsin Energy	$ 46.31	$ 1.12	2.4%	9.0%	9.7%	10.7%	9.4%	7.6%	11.4%	12.1%	13.2%	11.8%	10.0%
17	Xcel Energy, Inc.	$ 20.77	$ 0.96	4.6%	7.5%	6.7%	5.2%	5.4%	4.9%	12.1%	11.3%	9.8%	10.0%	9.5%
	Average (h)									**10.7%**	**10.9%**	**11.5%**	**11.2%**	**10.5%**

(a) Recent price and estimated dividend for next 12 mos. from The Value Line Investment Survey, *Summary and Index* (May 9, 2008).
(b) The Value Line Investment Survey (Feb. 29, Mar. 28 & May 9, 2008).
(c) Thompson Financial, *Company in Context Report* (May 16, 2008).
(d) http://stocks.us.reuters.com (retrieved May 18, 2008).
(e) http://www.zacks.com/research (retrieved May 18, 2008).
(f) See Schedule WEA-2.
(g) Sum of dividend yield and respective growth rate.
(h) Excludes highlighted figures.

SUSTAINABLE GROWTH RATE

UTILITY PROXY GROUP

		(a)	(a)	(a)	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
		Projections			2007		Mid-Year					
	Company	EPS	DPS	Net Book Value	Net Book Value	Annual Change	Adjustment Factor	"b"	Adjusted "r"	"b x r" growth	"sv" Factor	Sustainable Growth
1	ALLETE	$3.25	$2.00	$32.00	$24.11	5.8%	1.0283	38.5%	10.4%	4.0%	3.29%	7.3%
2	Alliant Energy	$3.30	$1.92	$31.95	$24.30	5.6%	1.0274	41.8%	10.6%	4.4%	0.38%	4.8%
3	Consolidated Edison	$3.80	$2.42	$43.65	$34.90	4.6%	1.0224	36.3%	8.9%	3.2%	0.04%	3.3%
4	Constellation Energy	$8.25	$2.70	$52.00	$30.00	11.6%	1.0549	67.3%	16.7%	11.3%	0.39%	11.6%
5	Dominion Resources	$3.75	$2.20	$26.50	$16.15	10.4%	1.0495	41.3%	14.9%	6.1%	1.68%	7.8%
6	Duke Energy	$1.50	$1.06	$19.00	$16.83	2.5%	1.0121	29.3%	8.0%	2.3%	0.06%	2.4%
7	Entergy Corp.	$8.20	$4.20	$62.25	$40.71	8.9%	1.0424	48.8%	13.7%	6.7%	0.53%	7.2%
8	Exelon Corp.	$5.75	$2.40	$24.00	$15.35	9.4%	1.0447	58.3%	25.0%	14.6%	-3.16%	11.4%
9	Integrys Energy Group	$3.95	$2.84	$50.05	$42.34	3.4%	1.0167	28.1%	8.0%	2.3%	-0.05%	2.2%
10	MDU Resources Group	$2.50	$0.76	$20.75	$13.75	8.6%	1.0411	69.6%	12.5%	8.7%	0.61%	9.3%
11	PG&E Corp.	$3.50	$2.04	$28.95	$22.60	5.1%	1.0248	41.7%	12.4%	5.2%	0.36%	5.5%
12	P S Enterprise Group	$3.25	$1.65	$22.85	$14.35	9.8%	1.0465	49.2%	14.9%	7.3%	0.44%	7.8%
13	SCANA Corp.	$3.50	$2.10	$32.25	$25.30	5.0%	1.0243	40.0%	11.1%	4.4%	0.24%	4.7%
14	Sempra Energy	$5.75	$2.00	$44.00	$31.87	6.7%	1.0322	65.2%	13.5%	8.8%	-1.37%	7.4%
15	Vectren Corp.	$2.15	$1.47	$19.70	$16.16	4.0%	1.0198	31.6%	11.1%	3.5%	0.10%	3.6%
16	Wisconsin Energy	$4.25	$1.60	$36.00	$26.50	6.3%	1.0306	62.4%	12.2%	7.6%	0.00%	7.6%
17	Xcel Energy, Inc.	$2.00	$1.15	$18.25	$14.70	4.4%	1.0216	42.5%	11.2%	4.8%	0.16%	4.9%

(a) Values for 2011-2013 forecast horizon from The Value Line Investment Survey (Feb. 29, Mar. 28 & May 9, 2008).
(b) Annual growth in book value per share from historical to projected period.
(c) Equal to 2(1+b)/(2+b), where b = annual change in net book value.
(d) (EPS-DPS)/EPS.
(e) (Projected EPS/Projected Net Book Value) x Mid-Year Adjustment Factor.
(f) (d) x (e).
(g) "s" equals projected market-to-book ratio x growth in common shares. "v" equals (1- 1/projected market-to-book ratio).
(h) (f) + (g).

CONSTANT GROWTH DCF MODEL

NON-UTILITY PROXY GROUP

		(a)	(b)	(a)	(c)	(d)	(e)	(f)	(f)	(f)	(f)	(f)
			Growth Rates					Cost of Equity Estimates				
		Dividend		VL					VL			
	Company	Yield	IBES	EPS	Reuters	Zacks	br+sv	IBES	EPS	Reuters	Zacks	br+sv
1	3M Company	2.49%	11.3%	6.0%	11.2%	10.7%	16.3%	13.8%	8.5%	13.7%	13.2%	$\boxed{18.8\%}$
2	Abbott Labs.	2.67%	11.8%	10.0%	11.2%	9.9%	12.4%	14.5%	12.7%	13.8%	12.6%	15.0%
3	Aflac Inc.	1.45%	14.9%	14.5%	13.9%	14.5%	10.9%	16.4%	16.0%	15.4%	16.0%	12.3%
4	Allergan, Inc.	0.35%	17.0%	14.5%	17.3%	17.5%	15.0%	$\boxed{17.4\%}$	14.9%	$\boxed{17.6\%}$	$\boxed{17.9\%}$	15.3%
5	Allstate Corp.	3.38%	7.2%	9.0%	8.1%	8.1%	10.6%	10.6%	12.4%	11.5%	11.5%	14.0%
6	Anheuser-Busch	2.72%	8.2%	7.5%	8.4%	8.6%	25.3%	10.9%	10.2%	11.1%	11.3%	$\boxed{28.0\%}$
7	Automatic Data Proc.	2.71%	14.2%	10.0%	13.7%	13.0%	12.8%	16.9%	12.7%	16.4%	15.7%	15.5%
8	Bank of America	6.79%	8.9%	7.0%	8.7%	8.8%	7.1%	15.7%	13.8%	15.5%	15.6%	13.9%
9	Bard (C.R.)	0.62%	14.3%	13.5%	14.5%	14.1%	12.0%	14.9%	14.1%	15.1%	14.7%	12.6%
10	Becton, Dickinson	1.33%	13.1%	12.0%	12.8%	13.3%	13.7%	14.4%	13.3%	14.1%	14.6%	15.1%
11	Brown-Forman 'B'	1.90%	10.2%	11.5%	10.7%	NA	15.0%	12.1%	13.4%	12.6%	NA	16.9%
12	Coca-Cola	2.48%	9.6%	9.0%	9.8%	8.9%	11.9%	12.1%	11.5%	12.3%	11.4%	14.4%
13	Colgate-Palmolive	2.03%	11.1%	12.0%	11.0%	10.9%	19.1%	13.1%	14.0%	13.1%	12.9%	$\boxed{21.1\%}$
14	Commerce Bancshs.	2.42%	6.3%	4.5%	6.3%	6.5%	7.8%	8.7%	$\boxed{6.9\%}$	8.7%	8.9%	10.2%
15	Fortune Brands	2.34%	9.3%	7.0%	8.9%	10.2%	10.5%	11.6%	9.3%	11.2%	12.5%	12.9%
16	Gannett Co.	5.60%	2.5%	3.5%	3.5%	4.3%	8.1%	8.1%	9.1%	9.1%	9.9%	13.7%
17	Gen'l Electric	3.37%	11.0%	10.5%	10.8%	10.5%	11.7%	14.4%	13.9%	14.2%	13.9%	15.1%
18	Gen'l Mills	2.68%	8.7%	8.5%	8.6%	8.7%	7.1%	11.4%	11.2%	11.3%	11.4%	9.8%
19	Genuine Parts	3.77%	9.3%	8.0%	8.8%	8.6%	8.3%	13.1%	11.8%	12.5%	12.4%	12.0%
20	Heinz (H.J.)	3.25%	8.7%	8.0%	8.0%	8.5%	11.7%	12.0%	11.3%	11.2%	11.8%	15.0%
21	Hormel Foods	1.77%	8.9%	12.0%	9.0%	8.5%	11.2%	10.7%	13.8%	10.8%	10.3%	13.0%
22	Johnson & Johnson	2.50%	8.0%	8.0%	8.7%	8.9%	10.7%	10.5%	10.5%	11.2%	11.4%	13.2%
23	Kimberly-Clark	3.66%	7.6%	7.0%	7.6%	8.1%	12.4%	11.3%	10.7%	11.2%	11.8%	16.1%
24	Kraft Foods	3.49%	6.9%	5.5%	7.3%	7.4%	3.8%	10.4%	9.0%	10.8%	10.9%	$\boxed{7.2\%}$
25	Lilly (Eli)	3.59%	7.7%	7.0%	8.4%	9.2%	7.8%	11.3%	10.6%	12.0%	12.8%	11.4%
26	Lockheed Martin	1.63%	11.5%	12.5%	11.2%	8.6%	15.1%	13.1%	14.1%	12.8%	10.2%	16.7%
27	Medtronic, Inc.	1.00%	13.7%	12.0%	14.3%	13.6%	11.7%	14.7%	13.0%	15.3%	14.6%	12.7%
28	Meredith Corp.	2.30%	11.8%	13.0%	11.8%	12.7%	9.7%	14.1%	15.3%	14.1%	15.0%	12.0%
29	NIKE, Inc. 'B'	1.37%	13.4%	13.0%	13.9%	13.9%	8.5%	14.8%	14.4%	15.3%	15.3%	9.9%
30	Northrop Grumman	1.90%	15.6%	11.5%	13.6%	9.4%	8.1%	$\boxed{17.5\%}$	13.4%	15.5%	11.3%	10.0%
31	PepsiCo, Inc.	2.09%	10.9%	10.5%	11.1%	10.8%	9.4%	13.0%	12.6%	13.2%	12.9%	11.5%
32	Pfizer, Inc.	6.12%	4.4%	1.5%	6.6%	5.5%	3.7%	10.5%	$\boxed{7.6\%}$	12.8%	11.6%	9.8%
33	Procter & Gamble	2.28%	12.1%	9.5%	13.2%	11.6%	6.4%	14.4%	11.8%	15.5%	13.9%	8.6%

CONSTANT GROWTH DCF MODEL

NON-UTILITY PROXY GROUP

		(a)	(b)	(a)	(c)	(d)	(e)	(f)	(f)	(f)	(f)	(f)
			Growth Rates					Cost of Equity Estimates				
		Dividend		VL					VL			
	Company	Yield	IBES	EPS	Reuters	Zacks	br+sv	IBES	EPS	Reuters	Zacks	br+sv
34	Sigma-Aldrich	0.85%	9.9%	10.0%	10.3%	10.5%	14.0%	10.8%	10.9%	11.1%	11.4%	14.8%

CONSTANT GROWTH DCF MODEL

NON-UTILITY PROXY GROUP

		(a)	(b)	(a)	(c)	(d)	(e)	(f)	(f)	(f)	(f)	(f)
			Growth Rates					Cost of Equity Estimates				
		Dividend		VL					VL			
	Company	Yield	IBES	EPS	Reuters	Zacks	br+sv	IBES	EPS	Reuters	Zacks	br+sv
35	Sysco Corp.	3.13%	13.1%	13.0%	12.8%	12.6%	10.1%	16.2%	16.1%	16.0%	15.7%	13.3%
36	Tootsie Roll Ind.	1.25%	NA	2.0%	NA	NA	5.6%	NA	$\boxed{3.3\%}$	NA	NA	$\boxed{6.9\%}$
37	Torchmark Corp.	0.90%	8.2%	8.0%	8.6%	NA	10.3%	9.1%	8.9%	9.5%	NA	11.2%
38	United Parcel Serv.	2.52%	13.0%	10.0%	13.0%	12.6%	13.4%	15.5%	12.5%	15.5%	15.1%	15.9%
39	Wal-Mart Stores	1.74%	11.7%	10.0%	11.9%	11.4%	8.8%	13.4%	11.7%	13.6%	13.1%	10.5%
40	Walgreen Co.	1.04%	13.6%	13.0%	13.4%	13.5%	13.1%	14.6%	14.0%	14.5%	14.5%	14.2%
41	Washington Federal	3.89%	8.0%	10.5%	8.0%	6.5%	10.2%	11.9%	14.4%	11.9%	10.4%	14.1%
42	Washington Post	1.27%	10.0%	4.5%	10.0%	NA	7.6%	11.3%	$\boxed{5.8\%}$	11.3%	NA	8.9%
43	Weis Markets	3.36%	NA	4.5%	NA	NA	5.2%	NA	$\boxed{7.9\%}$	NA	NA	8.5%
44	Wrigley (Wm.) Jr.	2.15%	10.4%	9.5%	10.3%	10.1%	10.9%	12.6%	11.7%	12.4%	12.3%	13.0%
	Average (g)							**12.7%**	**12.4%**	**12.9%**	**12.8%**	**12.9%**

(a) www.valueline.com (retrieved Apr. 17, 2008).
(b) Thompson Financial, *Company in Context Report* (Apr. 16, 2008).
(c) http://stocks.us.reuters.com (retrieved Apr. 17, 2008).
(d) http://www.zacks.com/research (retrieved Apr. 17, 2008).
(e) See Schedule WEA-4.
(f) Sum of dividend yield and respective growth rate.
(g) Excludes highlighted figures.

SUSTAINABLE GROWTH RATE

NON-UTILITY PROXY GROUP

		(a)	(a)	(a)	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
		Projections			Historical		Mid-Year					
				Net Book	Net Book	Annual	Adjustment		Adjusted	"b x r"	"sv"	Sustainable
	Company	EPS	DPS	Value	Value	Change	Factor	"b"	"r"	growth	Factor	Growth
1	3M Company	$6.10	$2.28	$22.65	$16.56	8.1%	1.0391	62.6%	28.0%	17.5%	-1.25%	16.3%
2	Abbott Labs.	$4.80	$2.10	$20.10	$10.35	14.2%	1.0663	56.3%	25.5%	14.3%	-1.96%	12.4%
3	Aflac Inc.	$6.50	$1.88	$30.70	$18.08	11.2%	1.0529	71.1%	22.3%	15.8%	-4.98%	10.9%
4	Allergan, Inc.	$3.85	$0.30	$28.55	$12.22	18.5%	1.0847	92.2%	14.6%	13.5%	1.47%	15.0%
5	Allstate Corp.	$8.75	$2.25	$61.90	$38.81	9.8%	1.0467	74.3%	14.8%	11.0%	-0.35%	10.6%
6	Anheuser-Busch	$3.95	$1.46	$6.90	$5.11	6.2%	1.0300	63.0%	59.0%	37.2%	-11.84%	25.3%
7	Automatic Data Proc.	$3.00	$1.25	$17.20	$9.61	15.7%	1.0726	58.3%	18.7%	10.9%	1.92%	12.8%
8	Bank of America	$5.75	$3.00	$40.15	$32.09	5.8%	1.0280	47.8%	14.7%	7.0%	0.05%	7.1%
9	Bard (C.R.)	$7.15	$0.95	$31.65	$18.05	11.9%	1.0561	86.7%	23.9%	20.7%	-8.66%	12.0%
10	Becton, Dickinson	$6.60	$1.90	$34.95	$17.89	14.3%	1.0669	71.2%	20.1%	14.3%	-0.62%	13.7%
11	Brown-Forman 'B'	$5.50	$1.40	$24.05	$12.76	13.5%	1.0633	74.5%	24.3%	18.1%	-3.09%	15.0%
12	Coca-Cola	$3.65	$1.84	$15.00	$7.30	15.5%	1.0719	49.6%	26.1%	12.9%	-1.01%	11.9%
13	Colgate-Palmolive	$5.80	$2.30	$13.55	$4.10	27.0%	1.1190	60.3%	47.9%	28.9%	-9.82%	19.1%
14	Commerce Bancshs.	$3.70	$1.20	$32.15	$21.25	8.6%	1.0414	67.6%	12.0%	8.1%	-0.30%	7.8%
15	Fortune Brands	$7.15	$1.76	$54.05	$31.08	11.7%	1.0553	75.4%	14.0%	10.5%	0.01%	10.5%
16	Gannett Co.	$6.00	$1.96	$49.35	$39.55	5.7%	1.0277	67.3%	12.5%	8.4%	-0.36%	8.1%
17	Gen'l Electric	$3.60	$1.45	$18.95	$11.57	10.4%	1.0493	59.7%	19.9%	11.9%	-0.19%	11.7%
18	Gen'l Mills	$4.40	$2.00	$18.95	$15.64	4.9%	1.0240	54.5%	23.8%	13.0%	-5.90%	7.1%
19	Genuine Parts	$4.35	$1.95	$25.65	$16.36	9.4%	1.0449	55.2%	17.7%	9.8%	-1.52%	8.3%
20	Heinz (H.J.)	$3.70	$1.90	$10.30	$5.72	12.5%	1.0587	48.6%	38.0%	18.5%	-6.79%	11.7%
21	Hormel Foods	$3.50	$1.00	$21.80	$13.89	11.9%	1.0563	71.4%	17.0%	12.1%	-0.93%	11.2%
22	Johnson & Johnson	$5.95	$2.18	$26.25	$15.30	11.4%	1.0539	63.4%	23.9%	15.1%	-4.47%	10.7%
23	Kimberly-Clark	$6.00	$2.95	$19.00	$12.41	8.9%	1.0426	50.8%	32.9%	16.7%	-4.32%	12.4%
24	Kraft Foods	$2.60	$1.20	$24.65	$17.45	7.2%	1.0345	53.8%	10.9%	5.9%	-2.12%	3.8%
25	Lilly (Eli)	$4.15	$2.16	$20.45	$12.05	11.2%	1.0528	48.0%	21.4%	10.2%	-2.48%	7.8%
26	Lockheed Martin	$11.00	$2.50	$37.65	$23.97	9.5%	1.0451	77.3%	30.5%	23.6%	-8.52%	15.1%
27	Medtronic, Inc.	$4.80	$0.89	$19.65	$10.20	14.0%	1.0655	81.5%	26.0%	21.2%	-9.52%	11.7%
28	Meredith Corp.	$4.80	$0.90	$29.45	$17.28	14.3%	1.0665	81.3%	17.4%	14.1%	-4.41%	9.7%
29	NIKE, Inc. 'B'	$4.70	$1.50	$23.30	$13.94	13.7%	1.0641	68.1%	21.5%	14.6%	-6.10%	8.5%

SUSTAINABLE GROWTH RATE

NON-UTILITY PROXY GROUP

		(a)	(a)	(a)	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
		Projections			Historical		Mid-Year					
				Net Book	Net Book	Annual	Adjustment		Adjusted	"b x r"	"sv"	Sustainable
	Company	EPS	DPS	Value	Value	Change	Factor	"b"	"r"	growth	Factor	Growth
30	Northrop Grumman	$8.35	$2.10	$72.50	$52.35	6.7%	1.0326	74.9%	11.9%	8.9%	-0.82%	8.1%
31	PepsiCo, Inc.	$4.85	$1.96	$13.15	$9.36	7.0%	1.0340	59.6%	38.1%	22.7%	-13.33%	9.4%
32	Pfizer, Inc.	$2.30	$1.40	$11.40	$9.60	3.5%	1.0172	39.1%	20.5%	8.0%	-4.37%	3.7%
33	Procter & Gamble	$4.75	$1.95	$32.30	$20.87	9.1%	1.0436	58.9%	15.3%	9.0%	-2.68%	6.4%
34	Sigma-Aldrich	$3.60	$0.70	$17.65	$12.24	7.6%	1.0366	80.6%	21.1%	17.0%	-3.07%	14.0%
35	Sysco Corp.	$2.70	$1.25	$7.80	$5.36	9.8%	1.0469	53.7%	36.2%	19.5%	-9.32%	10.1%
36	Tootsie Roll Ind.	$1.30	$0.38	$14.75	$11.39	5.3%	1.0258	70.8%	9.0%	6.4%	-0.75%	5.6%
37	Torchmark Corp.	$8.00	$0.75	$62.35	$36.07	11.6%	1.0547	90.6%	13.5%	12.3%	-1.95%	10.3%
38	United Parcel Serv.	$5.85	$2.20	$24.80	$15.65	9.6%	1.0460	62.4%	24.7%	15.4%	-1.97%	13.4%
39	Wal-Mart Stores	$4.65	$1.20	$22.30	$14.91	8.4%	1.0402	74.2%	21.7%	16.1%	-7.34%	8.8%
40	Walgreen Co.	$3.45	$0.54	$22.30	$11.20	14.8%	1.0688	84.3%	16.5%	13.9%	-0.81%	13.1%
41	Washington Federal	$2.90	$1.04	$19.10	$15.07	4.9%	1.0237	64.1%	15.5%	10.0%	0.20%	10.2%
42	Washington Post	$44.65	$9.80	$463.55	$330.20	7.0%	1.0339	78.1%	10.0%	7.8%	-0.18%	7.6%
43	Weis Markets	$2.80	$1.35	$28.65	$23.31	4.2%	1.0206	51.8%	10.0%	5.2%	0.00%	5.2%
44	Wrigley (Wm.) Jr.	$3.25	$1.38	$15.05	$8.65	11.7%	1.0553	57.5%	22.8%	13.1%	-2.23%	10.9%

(a) www.valueline.com (retrieved Apr. 17, 2008).
(b) Annual growth in book value per share from historical to projected period.
(c) Equal to 2(1+b)/(2+b), where b = annual change in net book value.
(d) (EPS-DPS)/EPS.
(e) (Projected EPS/Projected Net Book Value) x Mid-Year Adjustment Factor.
(f) (d) x (e).
(g) "s" equals projected market-to-book ratio x growth in common shares. "v" equals (1- 1/projected market-to-book ratio).
(h) (f) + (g).

UTILITY PROXY GROUP

Market Rate of Return		
Dividend Yield (a)	2.4%	
Growth Rate (b)	10.9%	
Market Return (c)		13.3%
Less: Risk-Free Rate (d)		
Long-term Treasury Bond Yield		4.4%
Market Risk Premium (e)		8.9%
Proxy Group Beta (f)		0.84
Proxy Group Risk Premium (g)		7.5%
Plus: Risk-free Rate (d)		
Long-term Treasury Bond Yield		4.4%
Implied Cost of Equity (h)		**11.9%**

(a) Weighted average dividend yield for the dividend paying firms in the S&P 500 from www.valueline.com (Retreived Mar. 27, 2008).
(b) Weighted average of IBES and Value Line growth rates for the dividend paying firms in the S&P 500 based on data from Thomson Financial *Company in Context Report* (retrieved Mar. 27, 2008) and www.valueline.com (retrieved Mar. 27, 2008).
(c) (a) + (b)
(d) Average yield on 20-year Treasury bonds for April 2008 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 (Feb. 29, Mar. 28 & May 9, 2008).
(g) (e) x (f).
(h) (d) + (g).

FORWARD-LOOKING CAPM

NON-UTILITY PROXY GROUP

Market Rate of Return		
Dividend Yield (a)	2.4%	
Growth Rate (b)	10.9%	
Market Return (c)		13.3%
Less: Risk-Free Rate (d)		
Long-term Treasury Bond Yield		4.4%
Market Risk Premium (e)		8.9%
Proxy Group Beta (f)		0.79
Proxy Group Risk Premium (g)		7.0%
Plus: Risk-free Rate (d)		
Long-term Treasury Bond Yield		4.4%
Implied Cost of Equity (h)		11.4%

(a) Weighted average dividend yield for the dividend paying firms in the S&P 500 from www.valueline.com (Retreived Mar. 27, 2008).
(b) Weighted average of IBES and Value Line growth rates for the dividend paying firms in the S&P 500 based on data from Thomson Financial *Company in Context Report* (retrieved Mar. 27, 2008) and www.valueline.com (retrieved Mar. 27, 2008).
(c) (a) + (b)
(d) Average yield on 20-year Treasury bonds for April 2008 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 Apr. 17, 2008).
(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%	1.0283	9.3%
2	Alliant Energy	10.0%	1.0274	10.3%
3	Consolidated Edison	8.5%	1.0224	8.7%
4	Constellation Energy	16.0%	1.0549	16.9%
5	Dominion Resources	14.5%	1.0495	15.2%
6	Duke Energy	8.0%	1.0121	8.1%
7	Entergy Corp.	14.0%	1.0424	14.6%
8	Exelon Corp.	25.0%	1.0447	$\boxed{26.1\%}$
9	Integrys Energy Group	8.0%	1.0167	8.1%
10	MDU Resources Group	11.5%	1.0411	12.0%
11	PG&E Corp.	11.5%	1.0248	11.8%
12	P S Enterprise Group	14.0%	1.0465	14.7%
13	SCANA Corp.	10.5%	1.0243	10.8%
14	Sempra Energy	13.5%	1.0322	13.9%
15	Vectren Corp.	11.0%	1.0198	11.2%
16	Wisconsin Energy	12.0%	1.0306	12.4%
17	Xcel Energy, Inc.	11.0%	1.0216	11.2%
	Average (d)			**11.8%**

(a) 3-5 year projections from The Value Line Investment Survey (Feb. 29, Mar. 28 & May 9, 2008).

(b) Adjustment to convert year-end "r" to an average rate of return from Schedule WEA-2.

(c) (a) x (b).

(d) Excludes highlighted figures.

CAPITAL STRUCTURE

UTILITY PROXY GROUP

		At Fiscal Year-End 2007 (a)			Value Line Projected (b)		
	Company	Long-term Debt	Preferred	Common Equity	Long-term Debt	Other	Common Equity
1	ALLETE	59.7%	0.2%	40.1%	46.5%	0.0%	53.5%
2	Alliant Energy	34.5%	5.4%	60.0%	41.0%	3.5%	55.5%
3	Consolidated Edison	47.4%	1.2%	51.4%	48.5%	1.0%	50.5%
4	Constellation Energy	47.6%	1.8%	50.6%	39.5%	1.0%	59.5%
5	Dominion Resources	59.2%	2.2%	38.7%	49.0%	1.0%	50.0%
6	Duke Energy	34.0%	0.0%	66.0%	44.5%	0.0%	55.5%
7	Entergy Corp.	56.7%	1.6%	41.6%	49.0%	1.0%	50.0%
8	Exelon Corp.	49.4%	3.0%	47.6%	46.0%	0.5%	53.5%
9	Integrys Energy Group	41.4%	0.9%	57.7%	44.5%	0.5%	55.0%
10	MDU Resources Group	34.1%	0.4%	65.5%	30.0%	0.0%	70.0%
11	PG&E Corp.	48.1%	1.5%	50.4%	48.0%	1.0%	51.0%
12	P S Enterprise Group	52.8%	0.5%	46.7%	48.0%	0.5%	51.5%
13	SCANA Corp.	50.3%	1.8%	47.9%	54.0%	1.5%	44.5%
14	Sempra Energy	34.5%	1.4%	64.2%	40.0%	1.0%	59.0%
15	Vectren Corp.	50.2%	0.0%	49.8%	49.5%	0.0%	50.5%
16	Wisconsin Energy	53.0%	0.5%	46.6%	48.5%	0.5%	51.0%
17	Xcel Energy, Inc.	52.1%	0.8%	47.1%	51.5%	0.5%	48.0%
	Average	**47.4%**	**1.4%**	**51.3%**	**45.8%**	**0.8%**	**53.4%**

(a) Company Form 10-K and Annual Reports.
(b) The Value Line Investment Survey (Feb. 29, Mar. 28 & May 9, 2008).

VERIFICATION

STATE OF TEXAS)
) **SS:**
COUNTY OF TRAVIS)

The undersigned, **William E. Avera**, being duly sworn, deposes and says 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 17th day of July, 2008.

CHARLES SMAISTRLA
Notary Public, State of Texas
My Commission Expires
JAN. 14, 2012

NOTARY PUBLIC STATE OF TEXAS

(SEAL)
Notary Public

My Commission Expires:

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

APPLICATION OF KENTUCKY	)	
UTILITIES COMPANY FOR AN	)	CASE NO. 2008-00251
ADJUSTMENT OF BASE RATES	)	

TESTIMONY OF
VALERIE L. SCOTT
CONTROLLER
KENTUCKY UTILITIES COMPANY

Filed: July 29, 2008

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 have testified before the Commission, including in the Companies' most recent base rate cases, Case Nos. 2003-00433 and 2003-00434, and 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 April 30, 2008. 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
- Capital Construction Budget Section 10(7)(b) Tab 43
- Pro Forma Adjustments – Plant Additions Section 10(7)(c) Tab 44
- Operating Budget for the period encompassing the Pro Forma Adjustments Section 10(7)(d) Tab 45

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

A. This adjustment has been made to reflect increases in labor and labor-related costs as applied to the twelve months ended April 30, 2008, and includes specific adjustments for labor, payroll taxes and KU's 401(k) match. Page 1 of 4 presents an overview of the adjustment.

Page 2 of 4 of Reference Schedule 1.15 of Exhibit 1 shows the adjustment for labor expenses. The adjustment reflects the annualized base labor at April 30, 2008, of all union employees for whom new union contract rates effective August 8, 2007, and for non-union KU employees and certain Servco employees for whom new salaries became effective during the test year. The adjustment conforms labor 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 1.15 of 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.

Finally, page 4 of Reference Schedule 1.15 of Exhibit 1 shows the calculation of the component of the labor adjustment to reflect the resulting increases in KU's match of 401(k) contributions as applied to the twelve months ended April 30, 2008, due to the adjustments to the increases in labor and an increase in the Company match from 60% to 70% as of November 12, 2007.

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 cases, Case No. 2003-00434, and in Case No. 2000-00080.

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

A. This adjustment is necessary to adjust the pension and post-retirement medical benefit expenses for the test year. The adjustment conforms the net periodic cost during the test year to the 2008 annual net periodic cost as calculated by Mercer, the Company's actuarial consultant, in February 2008. 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 cases, Case No. 2003-00434, and in Case No. 2000-00080.

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

A. This adjustment is to reflect the appropriate amount of post-employment benefits in the test year. The cost of post employment benefits is based on the actuarial present value of continued medical benefits and life insurance for disabled former employees and their dependents until the former employees reach age 65. In December 2007, an adjustment was made to the post-employment benefits based on a revised liability calculation for 2007 from Mercer. This revised calculation was substantially lower than the amount that was used during the calendar year for the allocation of labor related costs through the burden rates. The reason for the large decrease was threefold: the discount rate was changed from 5.4% to 5.95%, there was a decrease in the number of dependents of disabled former employees and a decrease in the related claims costs for those beneficiaries. Based on the most recent information received from Mercer in April 2008, the post-employment liability for 2008 will be greater than that in the test year. This adjustment is the difference between the 2008 expense based on calculations provided by Mercer in April 2008, and the expense included in the test year.

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

A. This adjustment is the Company's proposed base rate treatment of the Midwest Independent Transmission System Operator, Inc. ("MISO") exit regulatory asset and

Schedule 10 regulatory liability. In its May 31, 2006 Order in Case No. 2003-00266, the Commission authorized LG&E and KU to exit the MISO. The Order further prescribed the following accounting treatment for the MISO exit fee and the MISO Schedule 10 fees then and currently embedded in base rates:

> [T]he Commission concludes that it is reasonable to establish a regulatory asset for the actual amount of the exit fee, subject to adjustment for future MISO credits, if any, and a regulatory liability for the MISO Schedule 10 charges, which are the only MISO costs now included in existing rates. This accounting treatment will have no immediate impact on LG&E's and KU's rates as it defers the rate-making disposition of these amounts until subsequent base rate cases.

This adjustment nets the cumulative Schedule 10 regulatory liability with the MISO exit fee regulatory asset, and then implements a five-year amortization of the remaining net exit fee asset as of the end of the test year. The Company further requests approval to discontinue any deferral of any amount for MISO Schedule 10 expense, effective when new rates go into effect, because Schedule 10 expenses will no longer be included in the Company's expenses, and therefore not included in the base rates, at that time. The Company further requests that revenues related to MISO Schedule 10 expenses deferred between the end of the test year and the date new rates go into effect, as well as any future adjustments to the exit fee, be deferred as regulatory liabilities until the amounts can be amortized in a future base rate case.

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

A. As discussed in Mr. Bellar's testimony, this adjustment has been made to defer the East Kentucky Power Cooperative ("EKPC") transmission settlement costs recorded as expense during the test year and to amortize those expenses as part of the

Company's costs to exit MISO. These costs would not have been incurred without the MISO exit. As noted in the Company's Application in this proceeding, the Company requests that the Commission establish a regulatory asset for EKPC transmission depancaking settlement costs and amortize that regulatory asset over a five-year period. A five year period is consistent with both the amortization period used for the net MISO exit fee regulatory asset on Reference Schedule 1.23 of Exhibit 1 and the five-year term during which the Company will make payments to EKPC pursuant to the settlement agreement.

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

A. This adjustment has been made to conform the allocation of demand charges paid to Ohio Valley Electric Corporation ("OVEC") to the Company's relative ownership share of the combined LG&E and KU investment in OVEC. During 2007, demand charges were allocated based on the percent of generation contributed to off-system sales by each company. In 2008, the allocation method was modified to reflect the relative ownership share, to better align it with the charges for OVEC energy used to serve native load customers. This adjustment conforms the 2007 demand charges during the test year to the allocation method used for the 2008 demand charges during the test year.

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

A. This adjustment is to remove the Kentucky coal tax credit received by the Company during the test year and applied to property taxes. The coal tax credit was established by Kentucky Revised Statute 141.0405 and is contingent on the Company's annual level of Kentucky coal purchases versus the 1999 baseline 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, and any remaining credit may be applied to property taxes. The coal tax credit statute expires in 2009. Due to its upcoming expiration and its contingent nature, the credit is not fixed, cannot be considered to be an on-going reduction to property tax expenses, and is removed from the test year.

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

A. This adjustment is for use tax expenses from September 2004 through April 2007 that were recorded in the test year. These expenses were recorded upon discovery of an error in the computer program that calculates use tax on inventory items, which was corrected in 2007. This adjustment reverses the use taxes recorded in the test year that relate to periods prior to the test year.

Q. Please explain the adjustment to operating expenses shown in Reference Schedule 1.39 of Exhibit 1.

A. This adjustment is for federal and state income taxes corresponding to the base revenue and expense adjustments. 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. 2003-00434. Reference Schedule 1.39 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. As shown on Reference Schedule 1.39, the composite federal and state income tax rate is 37.602802%.

Q. Please explain the adjustment to operating expenses shown in Reference Schedule 1.40 of 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. 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 cases, Case No. 2003-00434, and in Case No. 2000-00080. 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 1.39 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 1.41 of Exhibit 1.

A. This adjustment is for income tax true-ups related to the 2006 federal and state income tax returns and adjustments booked to income tax expense during the test year for the Kentucky coal tax credit. The Kentucky coal tax credit adjustment removes the coal tax credit accrued for 2007 income taxes and the adjustment recorded to reclassify the 2006 coal tax credit applied to property taxes as included in the adjustment on Reference Schedule 1.33. 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. 2003-00434.

Q. Please explain Reference Schedule 1.42 of 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 Exhibit 8 to determine the 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 for fiscal year 2008-2009 based on a current assessment from the Commonwealth of Kentucky Finance and Administrative Cabinet; and the Section 199 deduction related to domestic production activities from Reference Schedule 1.39. 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.

Q. Does this conclude your testimony?

A. Yes.

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VERIFICATION

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

The undersigned, **Valerie L. Scott,** being duly sworn, deposes and says she is the Controller for Kentucky Utilities Company, that she has personal knowledge of the matters set forth in the foregoing testimony, and 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 24th day of July, 2008.

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

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. 2008-00251

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

Filed: July 29, 2008

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 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 40202. A statement of my qualifications is included in the Appendix attached hereto.

Q. Have you previously testified before this Commission?

A. Yes, I have presented testimony before the Commission in the Environmental Surcharge Six Month and Two Year Review cases and most recently in the Companies' depreciation study proceedings, 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 for the twelve months ended April 30, 2008. 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:

- Current Chart of Accounts Section 10(6)(j) Tab 29

- Depreciation Study Section 10(6)(n) Tab 33

Pro Forma Adjustments

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

A. This adjustment has been made to eliminate brokered electric sales revenues and expenses. Brokered transactions do not utilize company generation or transmission assets; accordingly, the related revenues and expenses are eliminated in determining base rates. 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. 2003-00434 and Case No. 98-474. Expenses associated with brokered electric revenues and expenses are not included in the calculation of cash working capital on Exhibit 3.

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

A. This adjustment has been made to remove the effects of accrued Environmental Cost Recovery ("ECR"), Merger Surcredit ("MSR"), Value Delivery Team ("VDT"), and Fuel Adjustment Clause ("FAC") revenues in FERC Accounts 440-445. 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. 2003-00434.

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

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. 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. 2003-00434.

Q. Please explain the adjustment to operating expenses shown in Reference Schedule 1.14 of 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, excluding depreciation on assets set up for asset retirement obligations and depreciation on ECR assets, as of April 30, 2008, using proposed depreciation rates recommended by KU's expert, John Spanos of Gannett Fleming, Inc., in the study he prepared for KU and filed in Case No. 2007-00565. Mr. Spanos's testimony explains the changes in depreciation rates and the analysis supporting the changes.

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

A. This adjustment has been made to reflect a normalized level of storm damage expenses based upon a nine-year average adjusted for inflation. Because a full year of data is not available for 2008, the 2008 expense is for twelve months ending April 30, 2008; all other expense years are calendar years. The Company has only maintained a separate accounting of these expenses since 2000. This excludes the ice storm expenses from 2003 which were amortized over a five-year period. 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. 2003-00434.

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

A. This adjustment is made to normalize the expense levels 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 2008, the 2008 expense is for twelve months ending April 30, 2008; all other expense years are calendar years. 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. 2003-00434.

Q. Please explain the adjustment to operating expenses shown in Reference Schedule 1.20 of 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. 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. 2003-00434.

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

A. This adjustment has been made to remove amortization of Earnings Sharing Mechanism ("ESM") and management audit expenses which were allowed to be amortized over a three-year period per the Order in Case No. 2003-00434. The amortization period of these costs ended as of June 30, 2007. Since this is a non-recurring expense, an adjustment is made to remove the expenses from the test year.

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

A. This adjustment has been made to remove two out-of-period operating and maintenance ("O&M") expenses for the FERC assessment fee. The test year included expenses paid to the Midwest Independent Transmission System Operator, Inc. ("MISO") that will not be incurred going forward due to the Company's exit from the MISO. The test year also included a prior period adjustment that will not be incurred going forward. As a result of these adjustments, the appropriate level of on-going FERC assessments fees is included in the test year.

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

A. This adjustment to operating expenses is necessary to include the expenses incurred in conjunction with this base rate case. KU estimates the total rate case expense to be $1,170,000. The adjustment has been amortized over three years at a rate of $390,000 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. The test year contains no amortization of expenses from the previous rate case since those expenses were fully amortized as of June 2007 and the amounts for May and June 2007 were removed through this adjustment. 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. 2003-00434, and in Case No. 2000-00080.

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

A. This adjustment has been made to remove the operating and maintenance expenses from the test year for retirement of Tyrone Units 1 and 2. Since these units are now retired, there should be no on-going operating and maintenance costs related to them. Tyrone Units 1 and 2 were retired on February 26, 2007. In Case No. 2006-00509, KU in its March 2, 2007 Supplemental Response to Commission Staff's Interrogatories and Requests for Production of Documents Dated February 8, 2007 provided a detailed report on the analysis performed in connection with the decision to retire Tyrone Units 1 and 2.

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

A. This adjustment is to properly reflect the amount of amortization for prepaid Information Technology ("IT") maintenance contracts in the test year. In July 2007, it was identified that the prepaid IT maintenance contracts were not being recorded as prepaid assets; instead, they were being recorded as expenses in the period in which the contracts were paid. To correct the accounting for these contracts, and comply with Generally Accepted Accounting Principles, an adjustment was made to the general ledger in July 2007, to debit prepaid assets and credit expense for the amount of the IT maintenance contracts that had already been paid and expensed, but related to future periods. While this adjustment to the general ledger was necessary to allow for the proper accounting of the prepaid maintenance contracts going forward, it created a large credit in the maintenance expense account during the test year. Thus, this pro forma adjustment is required to remove the credit related to the adjustment and to record the proper expenses for contracts in effect during the test year.

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

A. This adjustment is necessary to include increased postage expenses due to the impact of the \$.01 postage rate increase, which was announced in February 2008, and was effective in May 2008, on the total volume of mailings during the test year.

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

A. This adjustment is to reflect annualized vehicle fuel costs. Fuel costs continue to rise rapidly, necessitating an adjustment to test year costs. The adjustment effectively increases test year vehicle fuel expense to April 2008 price levels (i.e., the Companies' actual average per gallon cost of fuel for April 2008).

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 she is Director of Utility Accounting and Reporting for Kentucky Utilities Company, that she 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 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 24th day of July, 2008.

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. LLC

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 Anderson 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	)	**CASE NO. 2008-00251**
ADJUSTMENT OF BASE RATES	)	

TESTIMONY OF
LONNIE E. BELLAR
VICE PRESIDENT OF STATE REGULATION AND RATES
KENTUCKY UTILITIES COMPANY

Filed: July 29, 2008

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 "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 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, most recently in Case Nos. 2007-00562 (LG&E) and 2007-00563 (KU) concerning the disposition of KU's and LG&E's merger surcredit mechanisms.

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 present the Company'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; and (3) 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 Sidney L. "Butch" Cockerill will address changes to the terms and conditions of KU's electric services.

Q. Why is KU filing for a general adjustment of its rates?

A. KU has not sought an increase in its base electric and gas rates in nearly 5 years. Several factors have affected KU's cost of doing business in recent years. Since September 30, 2003, the end of the test year used in Case No. 2003-00434, KU has increased its net investment in plant for electric operations by over $1.25 billion.

Since its last base rate increase, KU has continued its efforts to control the rising cost of doing business. However, our ability to continue to provide safe and reliable energy service to our customers, as well as to continue our investment in facilities to serve customers, is predicated on our ability to earn sufficient revenues to operate in such a manner, as well as to attract capital at competitive costs. KU now seeks an increase in its electric rates in order to provide it an opportunity to recover sufficient revenues to operate in a safe and reliable manner, to continue its investment in facilities to serve customers, maintain its financial integrity, and properly compensate its shareholders for the risks assumed with respect to jurisdictional operations. The proposed rates are reasonable, and will permit recovery of the increased costs of doing business.

Revenue Effect

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 $22,109,840.

Q. If the Commission approves the proposed base rates, what will be the percentage increase in monthly residential electric bills?

A. The monthly residential electric bill increase due to the proposed electric base rates will be 5.3%, or approximately $3.70, for a customer using 1,000 kWh of electricity; however, as I explain herein, because certain surcredits will no longer apply when new base rates go into effect, the total monthly residential electric bill increase will be 6.5%, or approximately $4.50, for a customer using 1,000 kWh of electricity.

Revenue Allocation

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. The study used the Base-Intermediate-Peak methodology that the Commission has followed for years. The details of that study are presented in the direct testimony of Mr. Seelye; however, a 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
Residential	3.58%
General Service Rate	11.92%
All Electric Schools	6.32%
Large Power and STOD	11.43%
Large Power TOD	7.90%
Coal Mining Power	13.04%

Coal Mining TOD	12.81%
Large Industrial TOD	25.00%
Lighting	8.41%
Total Kentucky Jurisdiction	7.15%

These returns show that there are significant disparities among the class rates of return in KU's electric operations when compared to the system average rate of return, especially with the residential rate class.

Q. How will KU's recommendation for the allocation of the rate increases among its customer classes affect the rates of return for those classes?

A. The rates of return for the principal customer classes, which result from KU's proposed allocation of the rate increases, are summarized in the following tables:

Bellar Table II –

Pro Forma Electric Rates of Return as Adjusted for Proposed Increase

Customer Class	**KU Electric**
Residential	4.61%
General Service Rate	12.17%
All Electric Schools	7.51%
Large Power and STOD	11.53%
Large Power TOD	7.90%
Coal Mining Power	15.53%
Coal Mining TOD	12.90%
Large Industrial TOD	25.00%
Lighting	9.20%
Total Kentucky Jurisdiction	7.77%

The Prime Group's study presents the details of this analysis.

Q. Please explain KU's rationale for the proposed allocation of its electric revenue deficiency among rate classes.

A. The proposed allocation is designed to transition towards a better balance between class rates of return, while at the same time recognizing other ratemaking objectives such as customer acceptance, gradualism, and the need to maintain price stability by avoiding overly disruptive changes.

Q. Did KU provide any guidance to The Prime Group in developing the electric rates for this proceeding?

A. Yes. First, we advised that the cost-of-service study should guide the revenue increase to the customer classes. Second, 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. Finally, we advised The Prime Group to simplify rate design whenever feasible.

Q. Please elaborate on why you allocated the increase for the electric customers' classes you have proposed.

A. As discussed in the testimony of Mr. Seelye, the cost-of-service study demonstrates that the rates for the electric residential and other classes, when compared to the overall revenue increase of 2.0% requested by KU for electric operations, shows a significant subsidy.

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 April 30, 2008. 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. For KU's electric operations, $6,878,000 of unbilled revenues were removed from test-year operating results. An adjustment to remove unbilled revenues was accepted by the Commission in KU's most recent base rate case, Case No. 2003-0434. This adjustment is included in Schedule 1.00 of Rives Exhibit 1.

Q. Has an adjustment been made to eliminate KU's merger surcredit mechanism?

A. Yes. Through June 30, 2008, the merger surcredit mechanisms provided a total of $143.4 million in savings to KU's customers and $145.7 million to LG&E's customers. Pursuant to the settlement agreement approved by the Commission on June 26, 2008, in Case Nos. 2007-00562 and 2007-00563, on July 1, 2008, the merger savings passed on to customers through the merger surcredit mechanism decreased to approximately $880,000 per month, at which level the surcredit will continue until new base rates go into effect for KU. Once that occurs, KU's and LG&E's customers will enjoy the full benefit of all merger savings, which will be fully embedded in base rates, negating the need for the merger surcredit. This adjustment therefore removes the merger surcredit from the test year and is included in Schedule 1.01 of Rives Exhibit 1.

Q. Has an adjustment been made to eliminate the Value Delivery Surcredit ("VDT")?

A. Yes. In Case Nos. 2005-00351 (KU) and 2005-00352 (LG&E), the Companies and intervenors filed with the Commission on February 28, 2006, a settlement agreement concerning the termination of the Companies' VDT surcredit mechanisms. The Commission approved the settlement agreements by orders dated March 24, 2006. In accord with the terms of the settlement agreements and the Commission's orders, the Companies filed tariffs, now in force, which state:

> The Value Delivery Surcredit shall terminate following completion of the billing month in which the Company files an application for an adjustment of electric [or gas] base rates pursuant to KRS 278.190 or the Commission enters an order reducing electric [or gas] base rates pursuant to KRS 278.260 and KRS 278.270.[1]

Under the terms of the Companies' tariffs, the Commission's orders, and the VDT settlement agreements, therefore, KU's VDT surcredit mechanism terminates

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[1] Louisville Gas and Electric Company, P.S.C. of Ky., Electric No. 6, First Revision of Original Sheet No. 75.1 (effective April 1, 2006); Louisville Gas and Electric Company, P.S.C. of Ky., Gas No. 6, First Revision of Original Sheet No. 75.1 (effective April 1, 2006); Kentucky Utilities Company, P.S.C. No. 13, First Revision of Original Sheet No 75.1 (effective April 1, 2006).

concurrently with the filing of KU's application in this base rate proceeding under KRS 278.190. This adjustment is included in Schedule 1.02 of Rives Exhibit 1.

Q. How does eliminating the VDT and merger surcredits impact the Company's requested revenue increase?

A. Absent the termination of the VDT and merger surcredits, the Company's revenue shortfall would have been significantly greater, which would have decreased the Company's return on equity, thereby increasing the urgency and need for an adjustment in base rates; indeed, if these surcredits continued (which they would if KU did not seek new base rates in this proceeding), the adjusted earned returns for KU's electric operations would be only 9.08 percent, far below the return on equity William E. Avera recommends for KU's utility operations, 11.25%. Therefore, the elimination of these surcredits and associated rate treatment of the shareholder portion of the savings in base rates clearly reduces the revenue deficiency presented in this application from the amount that it otherwise would be if the VDT and merger surcredit mechanisms were continued following the change in base rates.

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

A. LG&E and KU have signed a settlement agreement in Federal Energy Regulatory Commission ("FERC") Docket No. ER06-1458-000, which will settle issues related to the agreement between East Kentucky Power Cooperative, Inc. ("EKPC") and E.ON U.S. regarding E.ON's withdrawal from the Midwest Independent Transmission System Operator, Inc. ("MISO"). The primary issue settled in the agreement relates to a dispute on pancaked transmission rates when EKPC is purchasing transmission from the MISO while having load on the E.ON U.S. transmission system. The settlement results in E.ON U.S. making payments of $550,000 per year to EKPC for the years 2008-2012. In the test year, KU accrued the sum of its obligation to make this series of payments. This adjustment is to remove the amount of the payments that would be outside of the test year.

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

A. This adjustment is for reserve margin demand purchases. KU has 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. The purchase is necessary for KU to maintain an adequate planning reserve margin for the summer periods (June through September) in 2008 and 2009. The contract was executed in February 2008 and requires KU to pay a monthly capacity payment of $346,500 during June through September 2008 (annual amount of $1,386,000, of which $1,199,403 is Kentucky-jurisdictional).

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 he is the Vice President of State Regulation and Rates for Kentucky Utilities Company, that he has personal knowledge of the matters set forth in the foregoing testimony, and 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 24th day of July, 2008.

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.

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

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

APPLICATION OF KENTUCKY	**)**	
UTILITIES COMPANY FOR AN	**)**	**CASE NO. 2008-00251**
ADJUSTMENT OF BASE RATES	**)**	

TESTIMONY OF
ROBERT M. CONROY
DIRECTOR – RATES
KENTUCKY UTILITIES COMPANY

Filed: July 29, 2008

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

A. My name is Robert M. Conroy. I am the Director – Rates 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 40202. A statement of my qualifications is included in Appendix A attached hereto.

Q. Have you previously testified before this Commission?

A. Yes, I have testified before the Commission on a number of occasions, including the Company's fuel adjustment clause ("FAC") and environmental cost recovery ("ECR") proceedings, and most recently in the Company's depreciation study filing proceeding, Case No. 2007-00565.

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- or under-recoveries were taken directly from KU's monthly FAC filings. This adjustment is included in Reference Schedule 1.03 of Rives Exhibit 1.

Q. Has an adjustment been made to reflect the roll-in of the FAC and Environmental Cost Recovery ("ECR") for a full year?

A. Yes. The Commission's Order dated October 31, 2007 in Case No. 2006-00509 authorized the roll-in of the FAC into base rates effective December 2007. In addition, the Commission's Order dated March 28, 2008 in Case No. 2007-00379 authorized the roll-in of the ECR into base rates effective May 2008. 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. This adjustment is consistent with the methodology utilized in Case No. 2003-00434.

Q. Please explain the adjustment made to eliminate ECR revenues and expenses shown in Reference Schedule 1.05 of Rives Exhibit 1?

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

$54,342,557 of ECR revenues and $16,467,656 in ECR expenses. The ECR surcharge provides for full recovery of environmental costs that qualify for the surcharge and contains a mechanism to true up actual ECR revenues to allowed ECR revenues under the surcharge. The adjustment to revenues of $54,342,557 includes all ECR billings during the test year. The adjustment to expenses of $16,467,656 includes operating expenses recovered under the ECR during the test year for compliance costs that will continue to be recovered through the surcharge. This adjustment is consistent with the methodology utilized in Case No. 2003-00434.

Q. Please explain the off-system sales revenue adjustment for the ECR calculation shown in Reference Schedule 1.07 of Rives Exhibit 1.

A. In the determination of the ECR surcharge, a portion of KU's environmental compliance costs recovered through the surcharge are allocated to off-system sales. However, by including off-system revenues in test-year operating results, off-system revenues are credited to jurisdictional customers. This results in an overstatement of margins from off-system sales and a mismatch of the revenues and expenses relating to the off-system sales portion of the allocated environmental surcharge monthly revenue requirement. Therefore, 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 utilized in Case No. 2003-00434, an adjustment of $371,295 was made to reduce revenues to reflect the environmental surcharge calculations recognized in the determination of off-system sales.

Q. Please describe the ratemaking treatment for the cost of Owensboro Municipal Utilities ("OMU") nitrogen oxide ("NOx") expenses reflected in Section 3.19 of

the Partial Settlement Agreement, Stipulation and Recommendation approved by the Commission in Case No. 2003-00434.

A. In accordance with the Commission's Order in Case No. 2003-00434, KU has reported 1/12 of the agreed upon $1.0 million for a portion of KU's OMU NOx expense as a line item on ES Form 1.10 and recovered through the ECR mechanism because the cost is not included in current base rates; however, because the OMU NOx cost is in the test year in this proceeding, the cost will be embedded in base rates and does not require a pro forma adjustment. Following the change in base rates, ES Form 1.10 will be amended to remove the line associated with this expense beginning with the expense month in which new base rates become effective.

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 the rate schedules where possible and have consolidated schedules, renamed schedules, added schedules and revised language to be as consistent as possible between the two Companies. The table below summarizes the changes being made to the current rate schedule designations to transition towards a uniform set of rate schedules between the two Companies. Although we are not yet able to completely harmonize the rate schedules between LG&E and KU, the transition which began in the last rate cases has continued through this proceeding. Conroy Exhibit 3 shows a visual comparison between the LG&E and KU rate schedules.

Current Rate Schedule	Proposed Rate Schedule	Availability - kW
RS	RS	all
GS Secondary	GS Secondary	0 - 50
GS Primary	PS Primary	0 - 250
LP Secondary	PS Secondary	50 - 250
LP Primary	PS Primary	0 - 250
LP Transmission	RTS	0 - 50,000
MP Primary	PS Primary	0 - 250
MP Transmission	RTS	0 - 50,000
LCI-TOD Primary	LTOD Primary	5,000 - 50,000
LCI-TOD Transmission	RTS	0 - 50,000
LMP-TOD Primary	LTOD Primary	5,000 - 50,000
LMP-TOD Transmission	RTS	0 - 50,000
STOD Secondary	TOD Secondary	250 - 5,000
STOD Primary	TOD Primary	250 - 5,000
STOD Transmission	RTS	0 - 50,000
LITOD	IS	20,000 - 50,000

Q. Are there any tariff changes being proposed that will affect multiple rate schedules?

A. Yes. Because the Merger and Value Delivery Surcredits have been removed from service, none of the tariffs lists these surcredits among applicable adjustment clauses and these two rate schedules have been removed. Also, KU proposes to express energy charges in dollars per kWh rather than cents per kWh, a purely cosmetic change.

Q. What rate design is being proposed for Residential Service under Rate RS?

A. We are proposing to retain the existing two-part rate structure consisting of a customer charge and a flat energy charge. We are proposing a customer charge of $8.49 per month and no change to the current energy charge of $0.05774/kWh. These charges are supported by the testimony and exhibits of W. Steven Seelye.

Q. Is KU proposing any change to the Volunteer Fire Department Rate (Rate VFD) for electric service?

A. Yes. Consistent with the changes above for Rate RS, we are proposing a customer charge of $8.49 per month and no change to the current energy charge of $0.05774/kWh.

Q. What rate design is being proposed for General Service, Rate GS?

A. As with Residential Service, we propose to retain the existing two-part rate structure consisting of a customer charge and a flat energy charge. We propose a customer charge of $10.00 per month for single-phase customers (the same customer charge the Commission approved in KU's most recent base rate case, Case No. 2003-00434), a new $10.00 per month customer charge for three-phase customers, and no change to the current energy charge of $0.06745/kWh. Previously, single-phase and three-phase customer charges were not separately identified. These charges are supported by the testimony and exhibits of Mr. Seelye.

Q. Does KU propose any other changes to its General Service Tariff, Rate GS?

A. Yes, KU proposes several significant revisions to Rate GS. First, the rate will be available only to secondary customers whose average maximum loads do not exceed 50 kW (the current average maximum is 500 kW). Secondary customers currently on Rate GS whose loads exceed the new average maximum will have the option to stay on Rate GS.

Second, KU proposes to eliminate the requirement that customers on Rate GS execute a one-year contract for the rate.

Third, KU proposes to eliminate the Rate GS 5% Primary Discount previously offered to primary voltage delivery customers with demands over 50 kW in a billing period. Because KU will offer Rate GS only to customers whose average loads do not exceed 50 kW, the discount would be moot. The elimination of this discount will apply to all customers taking service under this schedule, including those "grandfathered" onto the rate during the previous general rate case. Those "grandfathered" customers will be migrated to the proposed Power Service Rate PS addressed later.

Q. Does KU propose to change its All Electric School Tariff, Rate AES?

A. Yes. KU proposes an energy charge of $0.05815/kWh. In addition, KU proposes to limit the future availability of the tariff only to those customers currently taking service under the tariff. These charges are supported by the testimony and exhibits of Mr. Seelye.

Q. Is KU proposing to modify Large Power Rate LP and eliminate Coal Mining Power Rate MP?

A. Yes. KU proposes to rename Large Power Rate LP to Power Service Rate PS and merge the Coal Mining Power Rate MP into Rate PS. Currently, Rate LP is available for secondary, primary or available transmission service on an annual basis for lighting, heating, or power, and is limited to minimum average secondary loads of 200 kW and maximum average loads not exceeding 5,000 kW. Rate MP currently is available for minimum 50 kW primary or transmission service for the operation of coal mines, coal cleaning, processing, or other related operations incidental to such operation and is limited to maximum loads not exceeding 5,000 kW. Because there is no clear reason to differentiate between the two kinds of service provided under Rates LP and MP, KU proposes to eliminate Rate MP and effectively to combine them into a single rate schedule, which draws largely from the current Rate LP, albeit with certain changes described below. One notable change is that the transmission service previously available under Rates LP and MP will be available under a separate Retail Transmission Service tariff (Rate RTS).

Q. Please describe proposed Power Service Rate PS.

A. The proposed Power Service Rate PS rate schedule is identical to the current Rate LP rate schedule, with the following changes. First, Rate PS will be available for secondary or primary service and will be limited to minimum average secondary loads of 50 kW and maximum average loads not exceeding 250 kW. Secondary or primary customers receiving service under Rates LP or MP, as of September 1, 2008, with loads not meeting these criteria may elect to have service under Rate PS or may choose a rate that conforms to their load characteristics.

Second, Rate PS has three components, a monthly customer charge, a flat energy charge, and a demand charge. For primary customers, the customer charge will be \$75.00 per month, the flat energy charge will be \$0.03282 per kWh, and the demand charge will be \$7.26 per kW. For secondary customers, the customer charge will be \$75.00 per month, the flat energy charge will be \$0.03282 per kWh, and the demand charge will be \$7.65 per kW. These are the same charges as currently exist on Rate LP. These charges are supported by the testimony and exhibits of Mr. Seelye.

Third, Rate PS is subject to an annual minimum of $91.80 per kW for secondary delivery and $87.12 per kW for primary delivery based on the greatest of: (a) the highest monthly maximum load during such yearly period; (b) the contract capacity, based on the expected maximum kW demand upon the system; (c) sixty percent of the kW capacity of facilities specified by the customer; or (d) $918,200 per year for secondary delivery or $2,178.00 for primary delivery. The annual minimum charge may be adjusted where the customer's service requires an abnormal investment in special facilities.

Q. Is KU proposing to modify Large Commercial/Industrial Time-of-Day Rate LCI-TOD and eliminate Large Mine Power Time-of-Day Rate LMP-TOD?

A. Yes. KU proposes to rename Large Commercial/Industrial Time-of-Day Rate LCI-TOD to Large Time-of-Day Service Rate LTOD and merge Large Mine Power Time-of-Day Rate LMP-TOD into Rate LTOD. Currently, Rate LCI-TOD is available to, and mandatory for, all customers served primary or transmission voltage, with an average demand of 5,000 kW or greater, limited to maximum loads not exceeding 50,000 kW. Rate LMP-TOD currently has the same availability criteria as LCI-TOD, but is available only to mining operations. Just as is the case with current Rates LP and MP, there is no clear reason to differentiate between the two kinds of service provided under Rates LCI-TOD and LMP-TOD, therefore KU proposes to eliminate Rate LMP-TOD and effectively to combine them into a single schedule, which draw largely from the current Rate LCI-TOD, albeit with certain changes described below. One notable change is that the transmission service previously available under Rates

LCI-TOD and LMP-TOD will be available under the new Retail Transmission Service tariff (Rate RTS).

Q. Please describe proposed the Large Time-of-Day Service Rate LTOD service schedule.

A. The proposed Large Time-of-Day Service Rate LTOD service schedule is identical to the current Rate LCI-TOD rate schedule, with the following change. Rate LTOD will be available to primary customers only with minimum average loads of 5,000 kW and maximum average loads not exceeding 50,000 kW.

Rate LTOD has three components, a monthly customer charge, an energy charge, and an on-peak/off-peak demand charge. The customer charge will be $120.00 per month, the energy charge will be $0.03282 per kWh, the on-peak demand charge will be $5.12 per kW, and the off-peak demand charge will be $1.27 per kW. These charges are supported by the testimony and exhibits of Mr. Seelye.

Rate LTOD will require a fixed contract of not less than one year, with annual renewal terms, and is subject to an annual minimum of $61.44 per kW for primary on-peak delivery based on the greatest of: (a) the highest monthly on-peak maximum load during such yearly period; (b) the contract capacity, based on the expected on-peak maximum kW demand upon the system; (c) sixty percent of the kW capacity of facilities specified by the customer; or (d) $307,200 per year. The annual minimum charge may be adjusted where the customer's service requires an abnormal investment in special facilities.

Q. Please describe proposed Time-of-Day Service Rate TOD service schedule.

A. The proposed Time-of-Day Service Rate TOD service schedule is identical to the current Rate LCI-TOD rate schedule, with the following changes. First, Rate TOD will be available to primary and secondary service customers with minimum average loads of 250 kW and maximum average loads not exceeding 5,000 kW.

Second, Rate TOD has three components, a monthly customer charge, an energy charge, and an on-peak/off-peak demand charge. For primary customers, the customer charge will be $120.00 per month, the energy charge will be $0.03282 per kWh, the on-peak demand charge will be $6.00 per kW, and the off-peak demand charge will be $1.27 per kW. For secondary customers, the customer charge will be $90.00 per month, the energy charge will be $0.03282 per kWh, the on-peak demand charge will be $6.39 per kW, and the off-peak demand charge will be $1.27 per kW. These charges are supported by the testimony and exhibits of Mr. Seelye.

Third, Rate TOD will require a fixed contract of not less than one year, with annual renewal terms, and is subject to an annual minimum of $76.68 per kW for secondary and $72.00 per kW for primary delivery based on the greatest of: (a) the highest monthly on-peak maximum load during such yearly period; (b) the contract capacity, based on the expected on-peak maximum kW demand upon the system; (c) sixty percent of the kW capacity of facilities specified by the customer; or (d) $918,200 per year for secondary delivery or $2,178.00 for primary delivery. The annual minimum charge may be adjusted where the customer's service requires an abnormal investment in special facilities.

Q. Does KU propose to eliminate its current Small Time-of-Day Rate STOD pilot program service schedule as part of implementing Rate TOD?

A. Yes, Rate STOD will be discontinued. As indicated in the filed report on STOD made with the Commission on April 30, 2008, as required by the Commission's Order in Case No. 2003-00433, there was no appreciable reduction or shift in load by the participating customer in the pilot program. Because the proposed Rate TOD service schedule will be available to primary and secondary service customers with minimum average loads of 250 kW and maximum average loads not exceeding 5,000 kW, there will be no need to maintain the current Rate STOD pilot program service schedule, which is available to commercial customers whose average maximum monthly demands are greater than 250 kW and less than 2,000 kW. Also, as a pilot program, Rate STOD is available to no more than 100 customers, whereas Rate TOD will be available to all customers that meet the availability criteria.

Q. Does KU propose to add a new rate schedule, Retail Transmission Service Rate RTS?

A. As discussed above, KU proposes to remove the transmission service component from Rates LP, MP, LCI-TOD, and LMP-TOD and create a new rate schedule, Retail Transmission Service Rate RTS.

Rate RTS will be limited to maximum average loads not exceeding 50,000 kVA and will have three components, a monthly customer charge, a flat energy charge, and an on-peak/off-peak demand charge. The customer charge will be $120.00 per month, the flat energy charge will be $0.03252 per kWh, the on-peak demand charge will be $4.39 per kVA, and the off-peak demand charge will be $1.13 per kVA. These charges are supported by the testimony and exhibits of Mr. Seelye.

Rate RTS will also require a fixed contract of not less than one year, with annual renewal terms, and will have a minimum annual charge of $52.68 per kVA transmission on-peak delivery for each yearly period based on the greatest of: (a) the highest monthly on-peak maximum load during such yearly period; (b) the contract capacity, based on the expected on-peak maximum kW demand upon the system; or (c) sixty percent of the kW capacity of facilities specified by the customer. The annual minimum charge may be adjusted where the customer's service requires an abnormal investment in special facilities.

Q. What change does KU propose to the Large Industrial Time-of-Day Rate LI-TOD service schedule?

A. The only change will be to rename it Industrial Service Rate IS. New Rate IS will be identical to Rate LI-TOD in all particulars except the name and sheet number of the schedule.

Q. What other tariff change does KU propose to make that is relevant to its proposed service schedule Rate IS?

A. KU proposes to amend the Curtailable Service Rider 3 (CSR3), to restrict its availability only to Rate IS customers as of the effective date of the CSR3 tariff sheet.

Q. What changes does KU propose to make to its lighting rates?

A. Some lighting rates are being increased more than others; however, the lighting rates as a group are being increased by an average of approximately 4.22%. These charges are supported by the testimony and exhibits of Mr. Seelye.

Q. Is KU proposing a new Lighting Energy Service Rate LE service schedule?

A. Yes. The new Rate LE service schedule will be available to municipalities, county governments, divisions or agencies of the state or federal government, civic associations, and other public or quasi-public agencies for service to public street and highway lighting systems, where the municipality or other agency owns and maintains all street lighting equipment and other facilities on its side of the point of delivery of the energy supplied. The flat-rate energy charge set out in Rate LE is \$0.04782 per kWh. These charges are supported by the testimony and exhibits of Mr. Seelye.

Q. Is KU proposing a new Traffic Energy Service Rate TE service schedule?

A. Yes. The new Rate TE service schedule will be available to municipalities, county governments, divisions of the state or federal government, or any other governmental agency for service to traffic control devices including signals, cameras, or other traffic lights which operate on an all-day, every-day basis, where the governmental agency owns and maintains all equipment on its side of the point of delivery of the energy supplied. (All traffic lights and related equipment not operated on an all-day, every-day basis will be served under Rate GS.) Each point of delivery will be considered to be a separate customer subject to the monthly customer charge of \$3.84 per month. There will also be a flat-rate energy charge of \$0.05848 per kWh. These charges are supported by the testimony and exhibits of Mr. Seelye.

Q. What changes does KU propose to make to its Net Metering Service Rider (Rider NMS)?

A. KU proposes to add biomass to the list of generation fuel types a customer may use to qualify for Rider NMS, as well as to increase the maximum capacity of a qualifying generation system from 15 kW to 30kW. KU proposes these changes in accord with Kentucky Senate Bill No. 83 (2008 General Session), which Governor Beshear signed into law on April 24, 2008 (Acts Chapter 138). KU further proposes conforming changes to its Net Metering Program Notification Form, currently Original Sheet No. 48.3, which will become Original Sheet No. 57.3.

Q. What changes does KU propose to make to its Excess Facilities Rider?

A. KU proposes to amend its Excess Facilities Rider to clarify that KU will provide normal operation and maintenance of the facilities a customer leases from the company, but if the leased facilities suffer catastrophic failure, the customer must provide for replacement of the facilities or, at the customer's option, terminate the lease agreement.

Q. What changes does KU propose to make to its Redundant Capacity Rider?

A. KU proposes that the Redundant Capacity Rider be amended to state that it is available to customers requesting the reservation of capacity on KU's facilities only when KU has and is willing to reserve such capacity. KU proposes further to amend the rider to provide for one-year automatic contract renewal terms after the initial five-year term expires until either party provides the other with 90 days' written notice to terminate the contract.

Q. Does KU propose to add a new service schedule, Supplemental or Standby Service Rate SS?

A. Yes. As part of their efforts to harmonize their tariffs, KU is adding the Supplemental or Standby Service Rate SS service schedule to its tariff, which service schedule is identical to LG&E's current service schedule with the same name. This service is available to customers whose premises or equipment are regularly supplied with electric energy from generating facilities other than KU's and who desire to have reserve, breakdown, supplemental, or standby service. Under Rate SS, secondary customers will pay a demand charge of $6.15 per kVA, primary customers will pay a demand charge of $5.80 per kVA, and transmission customers will pay a demand charge of $5.63 per kVA per month. All customers will be subject to a minimum monthly charge of the greater of the Rate SS demand charge or the rates prescribed under the otherwise applicable service schedule. These charges are supported by the testimony and exhibits of Mr. Seelye.

Q. Are you supporting any changes to KU's Line Extension Plan, Rate Sheet No. 106?

A. Yes, Section I deals with protecting the Company's other customers from baring the costs associated with providing facilities at the request of a customer. In situations where a customer requests the Company to provide facilities, which the Company does provide, and such load ultimately does not materialize, the other customers on the KU system should not be burdened with such costs. The customer requesting the facilities, in such situations, will incur the cost.

Customer contributions toward the cost of construction will be refunded over a ten-year period just as are contributions for single-phase line extensions over 1,000 feet. The refund will be based on both the customer's actual load and the load of any future customers who take service directly from the provided facilities; again this is in keeping with the 1,000 foot rule. An annual refund to the customer making the contribution will be determined by a ratio of actual revenues to the revenues required to support the investment times the investment made for the facilities. The actual revenues used in the calculation will be base rate demand revenues only since revenue associated with fuel cost does not support the investment made in the facilities.

Q. What changes does KU propose to make to its Environmental Cost Recovery (ECR) Surcharge rider?

A. KU proposes to make only a minor change by listing the specific rate schedules to which the ECR applies under the section for "Availability of Service".

Q. How will this proceeding affect the Company's draft Real-Time Pricing ("RTP") Rider submitted in Case No. 2007-00161?

A. The Company does not propose to make any substantive changes to the RTP Rider as a result of this proceeding, though the Company will make basic formatting and other generally applicable changes to the draft rider before filing the final tariff.

Q. Does this conclude your testimony?

A. Yes, it does.

KENTUCKY UTILITIES COMPANY
Calculations showing the effect on Base Rate Revenue of the ECR and FAC Roll-in's for a full year
Based on Sales for the 12 months ended April 30, 2008

	As Billed Base Rates Revenues	FAC Rollin Rates For a Full Year		ECR Rollin Rates For a Full Year	
		Calculated Base Rates Revenue	Increased Revenue	Calculated Base Rates Revenue	Increased Revenue
Residential Rate - RS (Rate Code 010, 050)	$ 170,338,466	$ 184,540,823	$ 14,202,357	$ 188,421,833	$ 3,881,009
Residential Rate - RS (Rate Code 020, 060, 080)	194,351,991	207,119,436	12,767,444	211,555,693	4,436,258
General Service Rate GS - Secondary	121,479,709	129,652,783	8,173,074	132,313,364	2,660,581
General Service Rate GS - Primary	2,654,163	2,818,926	164,763	2,890,020	71,094
		-			
All Electric School Service Rate - AES	6,648,873	7,194,795	545,922	7,350,487	155,692
Large Power Rate LPS - Secondary	186,103,586	204,356,034	18,252,448	208,817,741	4,461,707
Large Power Rate LPP - Primary	70,244,702	78,018,953	7,774,251	79,627,495	1,608,542
Large Power Rate LPT - Transmission	1,110,048	1,228,340	118,293	1,254,069	25,729
Small Time-of-Day - STODS Secondary	7,580,016	8,469,363	889,347	8,619,748	150,385
Small Time-of-Day - STODP Primary	607,081	676,281	69,199	687,676	11,395
Small Time-of-Day - STODT Transmission	-	-	-	-	-
Large Comm./Industrial Time-of-Day - LCI-TOD Primary	107,983,348	120,963,560	12,980,212	123,483,561	2,520,001
Large Comm./Industrial Time-of-Day - LCI-TOD Transmission	32,985,640	36,725,123	3,739,483	37,497,758	772,635
Curtailable Service Rider Credits - Primary - LCI -TOD Primary	(96,313)	(96,313)	-	(96,313)	-
Curtailable Service Rider Credits - Transmission -LCI-TOD Transmission	(5,446,292)	(5,446,292)	-	(5,446,292)	-
Large Industrial Time of Day - LITOD	19,489,144	21,094,596	1,605,452	21,293,989	199,393
Coal Mining Power Service Rate - MP Primary	5,800,666	6,278,689	478,023	6,430,565	151,877
Coal Mining Power Service Rate - MP Transmission	3,326,359	3,642,689	316,330	3,723,197	80,508
Large Mine Power Time-of-Day Rate - LMP-TPD Primary	4,055,754	4,448,718	392,964	4,562,563	113,845
Large Mine Power Time-of-Day Rate - LMP-TPD Transmission	11,327,500	12,493,982	1,166,482	12,790,113	296,131
Street Lighting - SL	6,845,641	7,038,223	192,583	7,169,559	131,336
Decorative Street Lighting - SLDEC	1,321,287	1,340,556	19,268	1,364,718	24,162
Private Outdoor Lighting - POL	3,767,361	3,909,679	142,318	3,983,877	74,198
Customer Outdoor Lighting - OL	5,549,604	5,764,477	214,873	5,873,653	109,176
TOTAL	$ 958,028,333	$ 1,042,233,420	$ 84,205,087	$ 1,064,169,074	$ 21,935,653

KENTUCKY UTILITIES COMPANY
Calculations showing the effect on Base Rate Revenue of the ECR and FAC Roll-in's for a full year
Based on Sales for the 12 months ended April 30, 2008

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
		Base Rates Billings During 12 Month Period - As Billed					Fuel Clause Rollin Rates - Full Year				ECR Rollin Rates - Full Year			
	Bills	May07-Nov07 Pre-Rollin KWH	Dec07-Apr08 Post-Rollin KWH	P.S.C. 13 Effective 3/5/2007	P.S.C. 13 Effective 12/3/2007	Base Rates Billings	Bills	Total KWH	P.S.C. 13 Effective 12/3/2007	Calculated Base Rates Billing	Bills	Total KWH	P.S.C. 13 Effective 5/2/2008	Calculated Base Rates Billing
RS - Rate Codes 010, 050														
Customer Charges	2,670,330			$ 5.00	$ 5.00	$ 13,351,650	2,670,330		$ 5.00	$ 13,351,650	2,670,330		$ 5.00	$ 13,351,650
All Energy		1,818,445,872	1,213,529,725	$ 0.04865	$ 0.05646	156,983,280		3,031,975,597	$ 0.05646	171,185,342		3,031,975,597	$ 0.05774	175,066,271
Minimum Energy						3,533				3,828				3,908
Total Calculated at Base Rates						$ 170,338,463				184,540,820				$ 188,421,829
Correction Factor						1.000000				1.000000				1.000000
Total After Application of Correction Factor						$ 170,338,466				$ 184,540,823				$ 188,421,833
INCREASE IN BASE RATES REVENUE										$ 14,202,357				$ 3,881,009
DECREASE IN FAC REVENUE										$ (14,200,571)				

KENTUCKY UTILITIES COMPANY
Calculations showing the effect on Base Rate Revenue of the ECR and FAC Roll-in's for a full year
Based on Sales for the 12 months ended April 30, 2008

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
		Base Rates Billings During 12 Month Period - As Billed					Fuel Clause Rollin Rates - Full Year				ECR Rollin Rates - Full Year			
	Bills	May07-Nov07 Pre-Rollin KWH	Dec07-Apr08 Post-Rollin KWH	P.S.C. 13 Effective 3/5/2007	P.S.C. 13 Effective 12/3/2007	Base Rates Billings	Bills	Total KWH	P.S.C. 13 Effective 12/3/2007	Calculated Base Rates Billing	Bills	Total KWH	P.S.C. 13 Effective 5/2/2008	Calculated Base Rates Billing
RS - Rate Codes 020, 060, 080														
Customer Charges	2,287,781			$ 5.00	$ 5.00	11,438,905	2,287,781		$ 5.00	$ 11,438,905	2,287,781		$ 5.00	$ 11,438,905
All Energy		1,634,759,465	1,831,074,189	$ 0.04865	$ 0.05646	182,913,497		3,465,833,654	$ 0.05646	195,680,968.10		3,465,833,654	$ 0.05774	200,117,235
Minimum Energy						(391)				(417)				(426)
Total Calculated at Base Rates						194,352,011				$ 207,119,457				$ 211,555,715
Correction Factor						1.000000				1.000000				1.000000
Total After Application of Correction Factor						$ 194,351,991				$ 207,119,436				$ 211,555,693
INCREASE IN BASE RATES REVENUE										$ 12,767,444				$ 4,436,258
DECREASE IN FAC REVENUE										$ (12,767,844)				

KENTUCKY UTILITIES COMPANY
Calculations showing the effect on Base Rate Revenue of the ECR and FAC Roll-in's for a full year
Based on Sales for the 12 months ended April 30, 2008

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
		Base Rates Billings During 12 Month Period - As Billed					Fuel Clause Rollin Rates - Full Year				ECR Rollin Rates - Full Year			
	Bills	May07-Nov07 Pre-Rollin KWH	Dec07-Apr08 Post-Rollin KWH	P S C 13 Effective 3/5/2007	P S C 13 Effective 12/1/2007	Base Rates Billings	Bills	Total KWH	P S C 13 Effective 12/1/2007	Calculated Base Rates Billing	Bills	Total KWH	P.S.C. 13 Effective 5/2/2008	Calculated Base Rates Billing
GSS - Rate Codes 110, 113, 150, 153, 710														
Customer Charges	938,420			$ 10.00	$ 10.00	9,384,200	938,420		$ 10.00	$ 9,384,200	938,420		$ 10.00	$ 9,384,200
All KWH		1,044,935,068	774,676,043	$ 0.05818	$ [illegible]	[illegible]		1,819,611,111	$ 0.06599	120,076,137		1,819,611,111	$ 0.06745	122,732,769
Minimum Energy						18[illegible],917				193,110				197,073
Total Calculated at Base Rates						[illegible]				$ 129,653,448				$ 132,314,043
Correction Factor						1.000005				1.000005				1.000005
Total After Application of Correction Factor						$ 121,479,709				$ 129,652,783				$ 132,313,364
INCREASE IN BASE RATES REVENUE										$ 8,173,074				$ 2,660,581
DECREASE IN FAC REVENUE										$ (8,163,701)				

KENTUCKY UTILITIES COMPANY

Calculations showing the effect on Base Rate Revenue of the ECR and FAC Roll-in's for a full year

Based on Sales for the 12 months ended April 30, 2008

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
		Base Rates Billings During 12 Month Period - As Billed					Fuel Clause Rollin Rates - Full Year				ECR Rollin Rates - Full Year			
	Bills	May07-Nov07 Pre-Rollin KWH	Dec07-Apr08 Post-Rollin KWH	P.S.C. 13 Effective 3/5/2007	P.S.C. 13 Effective 12/3/2007	Base Rates Billings	Bills	Total KWH	P.S.C. 13 Effective 12/3/2007	Calculated Base Rates Billing	Bills	Total KWH	P.S.C. 13 Effective 5/2/2008	Calculated Base Rates Billing
GSP - Rate Codes 111, 151														
Customer Charges	872			$ 10.00	$ 10.00	$ 8,720	872		$ 10.00	$ 8,720	872		$ 10.00	$ 8,720
All KWH		22,733,271	20,987,413	$ 0.05818	$ 0.06599	2,707,581		43,720,684	$ 0.06599	2,885,128		43,720,684	$ 0.06745	2,948,960
Minimum Energy						75,205				80,120				81,888
Demand Discount						(137,925)				(146,941)				(150,182)
Total Calculated at Base Rates						$ 2,653,580				$ 2,818,307				$ 2,889,386
Correction Factor						0.999780				0.999780				0.999780
Total After Application of Correction Factor						$ 2,654,163				$ 2,818,926				$ 2,890,020
INCREASE IN BASE RATES REVENUE										$ 164,763				$ 71,094
DECREASE IN FAC REVENUE										$ (198,343)				

KENTUCKY UTILITIES COMPANY
Calculations showing the effect on Base Rate Revenue of the ECR and FAC Roll-in's for a full year
Based on Sales for the 12 months ended April 30, 2008

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
		Base Rates Billings During 12 Month Period - As Billed					Fuel Clause Rollin Rates - Full Year				ECR Rollin Rates - Full Year			
	Bills	May07-Nov07 Pre-Rollin KWH	Dec07-Apr08 Post-Rollin KWH	P.S.C. 13 Effective 3/5/2007	P.S.C. 13 Effective 12/3/2007	Base Rates Billings	Bills	Total KWH	P.S.C. 13 Effective 12/3/2007	Calculated Base Rates Billing	Bills	Total KWH	P.S.C. 13 Effective 5/2/2008	Calculated Base Rates Billing
AES - Rate Code 220														
Number of Customers	3,668						3,668				3,668			
All KWH		69,895,101	62,036,824	$ 0.04672	$ 0.05453	$ 6,648,367		131,931,925	$ 0.05453	$ 7,194,248		131,931,925	$ 0.05571	$ 7,349,928
Minimum Energy						506				548				559
Total Calculated at Base Rates						$ 6,648,873				$ 7,194,795				$ 7,350,487
Correction Factor						1.000000				1.000000				1.000000
Total After Application of Correction Factor						$ 6,648,873				$ 7,194,795				$ 7,350,487
INCREASE IN BASE RATES REVENUE										$ 545,922				$ 155,692
DECREASE IN FAC REVENUE										$ (545,878)				

KENTUCKY UTILITIES COMPANY
Calculations showing the effect on Base Rate Revenue of the ECR and FAC Roll-in's for a full year
Based on Sales for the 12 months ended April 30, 2008

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
		Base Rates Billings During 12 Month Period - As Billed					Fuel Clause Rollin Rates - Full Year				ECR Rollin Rates - Full Year			
	Bills	May07-Nov07 Pre-Rollin KWH	Dec07-Apr08 Post-Rollin KWH	P.S.C. 13 Effective 3/5/2007	P.S.C. 13 Effective 12/3/2007	Base Rates Billings	Bills / KW	Total KWH	P.S.C. 13 Effective 12/3/2007	Calculated Base Rates Billing	Bills / KW	Total KWH	P.S.C. 13 Effective 5/2/2008	Calculated Base Rates Billing
LPS - Rate Codes 562, 568														
Customer Charges	107,045			$ 75.00	$ 75.00	$ 8,028,375	107,045		$ 75.00	$ 8,028,375	107,045		$ 75.00	$ 8,028,375
Demand (KW)		5,995,381	3,895,477	$ 7.20	$ 7.20	71,214,175	9,890,858		$ 7.20	71,214,175	9,890,858		$ 7.65	75,665,061
Minimum Demand Charges						433,877				476,430				486,832
All KWH		2,331,392,952	1,465,616,331	$ 0.02501	$ 0.03282	106,409,666		3,797,009,283	$ 0.03282	124,617,845		3,797,009,283	$ 0.03282	124,617,845
Minimum Energy						17,402				19,108				19,525
Total Calculated at Base Rates						$ 186,103,494				$ 204,355,933				$ 208,817,638
Correction Factor						1.000000				1.000000				1.000000
Total After Application of Correction Factor						$ 186,103,586				$ 204,356,034				$ 208,817,741
INCREASE IN BASE RATES REVENUE										$ 18,252,448				$ 4,461,707
DECREASE IN FAC REVENUE										$ (18,201,574)				

KENTUCKY UTILITIES COMPANY

Calculations showing the effect on Base Rate Revenue of the ECR and FAC Roll-in's for a full year

Based on Sales for the 12 months ended April 30, 2008

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
		Base Rates Billings During 12 Month Period - As Billed					Fuel Clause Rollin Rates - Full Year				ECR Rollin Rates - Full Year			
	Bills	May07-Nov07 Pre-Rollin KWH	Dec07-Apr08 Post-Rollin KWH	P.S.C. 13 Effective 3/5/2007	P.S.C. 13 Effective 12/3/2007	Base Rates Billings	Bills / KW	Total KWH	P.S.C. 13 Effective 12/3/2007	Calculated Base Rates Billing	Bills / KW	Total KWH	P.S.C. 13 Effective 5/2/2008	Calculated Base Rates Billing
LPP - Rate Codes 561, 566														
Customer Charges	4,202			$ 75.00	$ 75.00	$ 315,150	4,202		$ 75.00	$ 315,150	4,202		$ 75.00	$ 315,150
Demand (KW)		2,168,901	1,403,453	$ 6.81	$ 6.81	24,327,730	3,572,354		$ 6.81	24,327,730	3,572,354		$ 7.26	25,935,289
Minimum Demand Charges						62,182				69,064				70,488
All KWH		994,814,556	630,060,877	$ 0.02501	$ 0.03282	45,558,910		1,624,875,433	$ 0.03282	53,328,412		1,624,875,433	$ 0.03282	53,328,412
Minimum Energy						(19,317)				(21,455)				(21,897)
Total Calculated at Base Rates						$ 70,244,655				$ 78,018,901				$ 79,627,441
Correction Factor						0.999999				0.999999				0.999999
Total After Application of Correction Factor						$ 70,244,702				$ 78,018,953				$ 79,627,495
INCREASE IN BASE RATES REVENUE										$ 7,774,251				$ 1,608,542
DECREASE IN FAC REVENUE										$ (7,768,615)				

KENTUCKY UTILITIES COMPANY
Calculations showing the effect on Base Rate Revenue of the ECR and FAC Roll-in's for a full year
Based on Sales for the 12 months ended April 30, 2008

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
		Base Rates Billings During 12 Month Period - As Billed					Fuel Clause Rollin Rates - Full Year				ECR Rollin Rates - Full Year			
	Bills	May07-Nov07 Pre-Rollin KWH	Dec07-Apr08 Post-Rollin KWH	P.S.C. 13 Effective 3/5/2007	P S C 13 Effective 12/3/2007	Base Rates Billings	Bills / KW	Total KWH	P S C 13 Effective 12/3/2007	Calculated Base Rates Billing	Bills / KW	Total KWH	P.S.C. 13 Effective 5/2/2008	Calculated Base Rates Billing
LPT - Rate Codes 560, 567														
Customer Charges	24			$ 75.00	$ 75 00	$ 1,800	24		$ 75.00	$ 1,800	24		$ 75.00	$ 1,800
Demand (KW)		33,354	23,822	$ 6.47	$ 6 47	369,929	57,176		$ 6.47	369,929	57,176		$ 6.92	395,659
Minimum Demand Charges						0				-				-
All KWH		15,146,285	10,953,981	$ 0.02501	$ 0 03282	738,318		26,100,266	$ 0 03282	856,611		26,100,266	$ 0.03282	856,611
Minimum Energy						(0)				-				-
Total Calculated at Base Rates						$ 1,110,048				$ 1,228,340				$ 1,254,069
Correction Factor						1.000000				1.000000				1.000000
Total After Application of Correction Factor						$ 1,110,048				$ 1,228,340				$ 1,254,069
INCREASE IN BASE RATES REVENUE										$ 118,293				$ 25,729
DECREASE IN FAC REVENUE										$ (118,292)				

KENTUCKY UTILITIES COMPANY
Calculations showing the effect on Base Rate Revenue of the ECR and FAC Roll-in's for a full year
Based on Sales for the 12 months ended April 30, 2008

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
		Base Rates Billings During 12 Month Period - As Billed					**Fuel Clause Rollin Rates - Full Year**				**ECR Rollin Rates - Full Year**			
	Bills	May07-Nov07 Pre-Rollin KWH	Dec07-Apr08 Post-Rollin KWH	P S C 13 Effective 3 5/2007	P S C 13 Effective 12 3 2007	Base Rates Billings	Bills KW	Total KWH	P S C 13 Effective 12 3 2007	Calculated Base Rates Billing	Bills / KW	Total KWH	P.S.C. 13 Effective 5/2/2008	Calculated Base Rates Billing
LCIP - Rate Code 563														
Customer Charge	466			$ 120.00	$ 120.00	$ [illegible]	[illegible]		$ 120.00	$ 55,920	466		$ 120.00	$ 55,920
On-Peak Demand (KW)		3,152,690	2,043,321	$ 5.16	$ 5.16	[illegible]	[illegible]		$ 5.16	26,811,416	5,196,011		$ 5.12	26,603,575
Off-Peak Demand (KW)		3,113,365	2,028,544	$ 0.74	$ 0.74	[illegible]	[illegible]		$ 0.74	3,805,012	5,141,908		$ 1.27	6,530,223
Minimum Demand										-				
Energy		1,660,264,625	1,086,994,384	$ 0.02501	$ 0.03282	[illegible]		2,747,259,009	$ 0.03282	90,165,041		2,747,259,009	$ 0.03282	90,165,041
Minimum Energy						112,630				126,176				128,806
Total Calculated at Base Rates						$ 107,983,352				$ 120,963,564				$ 123,483,565
Correction Factor						1.000000				1.000000				1.000000
Total After Application of Correction Factor						$ 107,983,348				$ 120,963,560				$ 123,483,561
CSR -1						(96,312.96)				(96,313)				(96,313)
INCREASE IN BASE RATES REVENUE										$ 12,980,212				$ 2,520,001
DECREASE IN FAC REVENUE										$ (12,959,017)				

KENTUCKY UTILITIES COMPANY
Calculations showing the effect on Base Rate Revenue of the ECR and FAC Roll-in's for a full year
Based on Sales for the 12 months ended April 30, 2008

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
		Base Rates Billings During 12 Month Period - As Billed					Fuel Clause Rollin Rates - Full Year				ECR Rollin Rates - Full Year			
	Bills	May07-Nov07 Pre-Rollin KWH	Dec07-Apr08 Post-Rollin KWH	P.S.C. 13 Effective 3/5/2007	P.S.C. 13 Effective 12/3/2007	Base Rates Billings	Bills / KW	Total KWH	P.S.C. 13 Effective 12/3/2007	Calculated Base Rates Billing	Bills / KW	Total KWH	P.S.C. 13 Effective 5/2/2008	Calculated Base Rates Billing
LCIT - Rate Code 564														
Customer Charge	79			$ 120.00	$ 120.00	$ 9,480	79		$ 120.00	$ 9,480	79		$ 120.00	$ 9,480
On-Peak Demand (KW)		922,037	668,312	$ 4.97	$ 4.97	7,904,037	1,590,349		$ 4.97	7,904,037	1,590,349		$ 4.93	7,840,423
Off-Peak Demand (KW)		916,753	660,628	$ 0.74	$ 0.74	1,167,262	1,577,381		$ 0.74	1,167,262	1,577,381		$ 1.27	2,003,274
Minimum Demand						-				-				-
Energy		478,660,031	363,298,346	$ 0.02501	$ 0.03282	23,894,739		841,958,377	$ 0.03282	27,633,074		841,958,377	$ 0.03282	27,633,074
Minimum Energy						10,067				11,208				11,444
Total Calculated at Base Rates						$ 32,985,584				$ 36,725,061				$ 37,497,694
Correction Factor						0.999998				0.999998				0.999998
Total After Application of Correction Factor						$ 32,985,640				$ 36,725,123				$ 37,497,758
CSR-3						(5,446,292.04)				(5,446,292)				(5,446,292)
INCREASE IN BASE RATES REVENUE										$ 3,739,483				$ 772,635
DECREASE IN FAC REVENUE										$ (3,738,335)				

KENTUCKY UTILITIES COMPANY
Calculations showing the effect on Base Rate Revenue of the ECR and FAC Roll-in's for a full year
Based on Sales for the 12 months ended April 30, 2008

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
		Base Rates Billings During 12 Month Period - As Billed					Fuel Clause Rollin Rates - Full Year				ECR Rollin Rates - Full Year			
	Bills	May07-Nov07 Pre-Rollin KWH	Dec07-Apr08 Post-Rollin KWH	P.S.C. 13 Effective 3/5/2007	P.S.C. 13 Effective 12/3/2007	Base Rates Billings	Bills / KW	Total KWH	P.S.C. 13 Effective 12/3/2007	Calculated Base Rates Billing	Bills / KW	Total KWH	P.S.C. 13 Effective 5/2/2008	Calculated Base Rates Billing
STOD-T Rate Code 580														
Customer										$ -				
Demand										-				
Minimum Demand										-				
On Peak Energy										-				
Off Peak Energy														
Minimum Energy														
Total Calculated at Base Rates										$ -				
Correction Factor										#DIV/0!				
Total After Application of Correction Factor										$ -				

KENTUCKY UTILITIES COMPANY
Calculations showing the effect on Base Rate Revenue of the ECR and FAC Roll-in's for a full year
Based on Sales for the 12 months ended April 30, 2008

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
		Base Rates Billings During 12 Month Period - As Billed					Fuel Clause Rollin Rates - Full Year				ECR Rollin Rates - Full Year			
	Bills	May07-Nov07 Pre-Rollin KWH	Dec07-Apr08 Post-Rollin KWH	P.S.C. 13 Effective 3/5/2007	P.S.C. 13 Effective 12/3/2007	Base Rates Billings	Bills / KW	Total KWH	P.S.C. 13 Effective 12/3/2007	Calculated Base Rates Billing	Bills / KW	Total KWH	P.S.C. 13 Effective 5/2/2008	Calculated Base Rates Billing
STOD-P Rate Code 582														
Customer	24			$ 90.00	$ 90.00	$ 2,160	24		$ 90.00	$ 2,160	24		$ 90.00	$ 2,160
Demand (KW)		15,650	11,288	$ 6.81	$ 6.81	183,451	26,938		$ 6.81	183,451	26,938		$ 7.26	195,573
Minimum Demand						0				0				0
On Peak Energy		3,504,400	4,483,694	$ 0.03098	$ 0.03879	282,489		7,988,094	$ 0.03879	309,858		7,988,093.65	$ 0.03879	309,858
Off Peak Energy		5,698,000	2,163,106	$ 0.01815	$ 0.02596	159,573		7,861,106	$ 0.02596	204,074		7,861,106.35	$ 0.02596	204,074
Minimum Energy						(20,591)				(23,262)				(23,990)
Total Calculated at Base Rates						$ 607,081				$ 676,281				$ 687,676
Correction Factor						1.000000				1.000000				1.000000
Total After Application of Correction Factor						$ 607,081				$ 676,281				$ 687,676
INCREASE IN BASE RATES REVENUE										$ 69,199				$ 11,395
DECREASE IN FAC REVENUE										$ (71,871)				

KENTUCKY UTILITIES COMPANY
Calculations showing the effect on Base Rate Revenue of the ECR and FAC Roll-in's for a full year
Based on Sales for the 12 months ended April 30, 2008

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
		Base Rates Billings During 12 Month Period - As Billed					Fuel Clause Rollin Rates - Full Year				ECR Rollin Rates - Full Year			
	Bills	May07-Nov07 Pre-Rollin KWH	Dec07-Apr08 Post-Rollin KWH	P.S.C. 13 Effective 3/5/2007	P.S.C. 13 Effective 12/3/2007	Base Rates Billings	Bills / KW	Total KWH	P.S.C. 13 Effective 12/3/2007	Calculated Base Rates Billing	Bills / KW	Total KWH	P.S.C. 13 Effective 5/2/2008	Calculated Base Rates Billing
STOD-S Rate Code 584														
Customer	612			$ 90.00	$ 90.00	$ 55,080	612		$ 90.00	$ 55,080	612		$ 90.00	$ 55,080
Demand (KW)		221,177	130,202	$ 7.20	$ 7.20	2,529,930	351,379		$ 7.20	2,529,930	351,379		$ 7.65	2,688,050
Minimum Demand						-				$ -				-
On Peak Energy		46,309,534	48,314,928	$ 0.03098	$ 0.03879	3,308,805		94,624,461	$ 0.03879	$ 3,670,483		94,624,461	$ 0.03879	3,670,483
Off Peak Energy		71,038,766	23,641,056	$ 0.01815	$ 0.02596	1,903,075		94,679,823	$ 0.02596	$ 2,457,888		94,679,823	$ 0.02596	2,457,888
Minimum Energy						(216,875)				(244,018)				(251,753)
Total Calculated at Base Rates						$ 7,580,016				$ 8,469,363				$ 8,619,748
Correction Factor						1.000000				1.000000				1.000000
Total After Application of Correction Factor						$ 7,580,016				$ 8,469,363				$ 8,619,748
INCREASE IN BASE RATES REVENUE										$ 889,347				$ 150,385
DECREASE IN FAC REVENUE										$ (916,875)				

KENTUCKY UTILITIES COMPANY

Calculations showing the effect on Base Rate Revenue of the ECR and FAC Roll-in's for a full year

Based on Sales for the 12 months ended April 30, 2008

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
		Base Rates Billings During 12 Month Period - As Billed					Fuel Clause Rollin Rates - Full Year				ECR Rollin Rates - Full Year			
	Bills	May07-Nov07 Pre-Rollin KWH	Dec07-Apr08 Post-Rollin KWH	P.S.C. 13 Effective 3/5/2007	P.S.C. 13 Effective 12/3/2007	Base Rates Billings	Bills / KW	Total KWH	P.S.C. 13 Effective 12/3/2007	Calculated Base Rates Billing	Bills / KW	Total KWH	P.S.C. 13 Effective 5/2/2008	Calculated Base Rates Billing
MPP - Rate Codes 681, 686														
Customer Charge	364			$ 75.00	$ 75.00	$ 27,300	364		$ 75.00	$ 27,300	364		$ 75.00	$ 27,300
Demand (KW)		227,977	183,230	$ 5.10	$ 5.10	2,097,153	411,206		$ 5.10	2,097,153	411,206		$ 5.45	2,241,075
Minimum demand billings						5,523				5,978				6,123
All KWH		58,000,865	51,955,814	$ 0.02698	$ 0.03479	3,372,406		109,956,679	$ 0.03479	3,825,393		109,956,679	$ 0.03479	3,825,393
Minimum energy billings						298,241				322,819				330,628
Total Calculated at Base Rates						$ 5,800,623				$ 6,278,643				$ 6,430,518
Correction Factor						0.999993				0.999993				0.999993
Total After Application of Correction Factor						$ 5,800,666				$ 6,278,689				$ 6,430,565
INCREASE IN BASE RATES REVENUE										$ 478,023				$ 151,877
DECREASE IN FAC REVENUE										$ (451,324)				

KENTUCKY UTILITIES COMPANY

Calculations showing the effect on Base Rate Revenue of the ECR and FAC Roll-in's for a full year

Based on Sales for the 12 months ended April 30, 2008

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
		Base Rates Billings During 12 Month Period - As Billed					Fuel Clause Rollin Rates - Full Year				ECR Rollin Rates - Full Year			
	Bills	May07-Nov07 Pre-Rollin KWH	Dec07-Apr08 Post-Rollin KWH	P.S.C. 13 Effective 3/5/2007	P.S.C. 13 Effective 12/3/2007	Base Rates Billings	Bills / KW	Total KWH	P.S.C. 13 Effective 12/3/2007	Calculated Base Rates Billing	Bills / KW	Total KWH	P.S.C. 13 Effective 5/2/2008	Calculated Base Rates Billing
MPT - Rate Codes 680, 687														
Customer Charge	123			$ 75.00	$ 75.00	$ [illegible]	123		$ 75.00	$ 9,225	123		$ 75.00	$ 9,225
Demand (KW)		128,261	91,959	$ 4.98	$ 4.98	[illegible]	222,219		$ 4.98	1,106,652	222,219		$ 5.33	1,184,429
Minimum demand billings						2,471				2,708				2,768
All KWH		39,129,000	29,949,000	$ 0.02698	$ 0.03479	[illegible]		69,078,000	$ 0.03479	2,403,224		69,078,000	$ 0.03479	2,403,224
Minimum energy billings						110,381				120,878				123,549
Total Calculated at Base Rates						$ 3,326,357				$ 3,642,686				$ 3,723,194
Correction Factor						0.999999				0.999999				0.999999
Total After Application of Correction Factor						$ 3,326,359				$ 3,642,689				$ 3,723,197
INCREASE IN BASE RATES REVENUE										$ 316,330				$ 80,508
DECREASE IN FAC REVENUE										$ (305,597)				

KENTUCKY UTILITIES COMPANY
Calculations showing the effect on Base Rate Revenue of the ECR and FAC Roll-in's for a full year
Based on Sales for the 12 months ended April 30, 2008

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
		Base Rates Billings During 12 Month Period - As Billed					Fuel Clause Rollin Rates - Full Year				ECR Rollin Rates - Full Year			
	Bills	May07-Nov07 Pre-Rollin KWH	Dec07-Apr08 Post-Rollin KWH	P.S.C. 13 Effective 3/5/2007	P.S.C. 13 Effective 12/3/2007	Base Rates Billings	Bills / KW	Total KWH	P.S.C. 13 Effective 12/3/2007	Calculated Base Rates Billing	Bills / KW	Total KWH	P.S.C. 13 Effective 5/2/2008	Calculated Base Rates Billing
LMPP - Rate Code 683														
Customer Charge	39			$ 120.00	$ 120.00	$ 4,680	39		$ 120.00	$ 4,680	39		$ 120.00	$ 4,680
On-Peak Demand (KW)		163,035	108,720	$ 5.75	$ 5.75	1,562,591	271,755		$ 5.75	1,562,591	271,755		$ 5.79	1,573,462
Off-Peak Demand (KW)		159,014	105,024	$ 0.74	$ 0.74	195,388	264,038		$ 0.74	195,388	264,038		$ 1.13	298,363
Minimum Demand Charge						-				-				-
Energy		50,315,519	36,837,600	$ 0.02301	$ 0.03082	2,293,095		87,153,119	$ 0.03082	2,686,059		87,153,119	$ 0.03082	2,686,059
Minimum Energy Charge						0				-				-
Total Calculated at Base Rates						$ 4,055,754				$ 4,448,718				$ 4,562,563
Correction Factor						1.000000				1.000000				1.000000
Total After Application of Correction Factor						$ 4,055,754				$ 4,448,718				$ 4,562,563
INCREASE IN BASE RATES REVENUE										$ 392,964				$ 113,845
DECREASE IN FAC REVENUE										$ (392,865)				

KENTUCKY UTILITIES COMPANY
Calculations showing the effect on Base Rate Revenue of the ECR and FAC Roll-in's for a full year
Based on Sales for the 12 months ended April 30, 2008

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
		Base Rates Billings During 12 Month Period - As Billed					Fuel Clause Rollin Rates - Full Year				ECR Rollin Rates - Full Year			
	Bills	May07-Nov07 Pre-Rollin KWH	Dec07-Apr08 Post-Rollin KWH	P.S.C. 13 Effective 3/5/2007	P.S.C. 13 Effective 12/3/2007	Base Rates Billings	Bills / KW	Total KWH	P.S.C. 13 Effective 12/3/2007	Calculated Base Rates Billing	Bills / KW	Total KWH	P.S.C. 13 Effective 5/2/2008	Calculated Base Rates Billing
LMPT - Rate Code 684														
Customer Charge	82			$ 120.00	$ 120 00	$ 9,840	82		$ 120.00	$ 9,840	82		$ 120.00	$ 9,840
On-Peak Demand (KW)		408,148	308,670	$ 5.21	$ 5.21	3,734,623		716,818	$ 5.21	3,734,623	716,818		$ 5.25	3,763,296
Off-Peak Demand (KW)		398,992	288,449	$ 0.74	$ 0 74	508,706		687,441	$ 0.74	508,706	687,441		$ 1.13	776,808
Minimum Demand Charge						-				-				-
Energy		149,682,000	118,584,000	$ 0.02301	$ 0.03082	7,098,942		268,266,000	$ 0.03082	8,267,958		268,266,000	$ 0.03082	8,267,958
Minimum Energy Charge						-				-				-
Total Calculated at Base Rates						$ 11,352,111				$ 12,521,127				$ 12,817,902
Correction Factor						1.002173				1.002173				1.002173
Total After Application of Correction Factor						$ 11,327,500				$ 12,493,982				$ 12,790,113
INCREASE IN BASE RATES REVENUE										$ 1,166,482				$ 296,131
DECREASE IN FAC REVENUE										$ (1,169,016)				

KENTUCKY UTILITIES COMPANY
Calculations showing the effect on Base Rate Revenue of the ECR and FAC Roll-in's for a full year
Based on Sales for the 12 months ended April 30, 2008

(1)	(2)	(3)	(4)	(5)	(6)	(7)
		Base Rates Billings During 12 Month Period - As Billed				
	Bills	May07-Nov07 Pre-Rollin KWH	Dec07-Apr08 Post-Rollin KWH	P.S.C. 13 Effective 3/5/2007	P.S.C. 13 Effective 12/3/2007	Base Rates Billings
LI-TOD Billing Code 730						
Customer Charge	12			$ 120.00	$ 120.00	$ 1,440
On-Peak Demand (KW)		836,325	683,968	$ 4.66	$ 4.66	7,084,567
Off-Peak Demand (KW)		1,016,107	673,454	$ 0.74	$ 0.74	1,250,275
Minimum Demand Charge						-
Energy		205,563,639	183,172,320	$ 0.02501	$ 0.03282	11,152,862
Minimum Energy Charge						0
Total Calculated at Base Rates						$ 19,489,144
Correction Factor						1.000000
Total After Application of Correction Factor						$ 19,489,144

(1)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
	Fuel Clause Rollin Rates - Full Year				ECR Rollin Rates - Full Year			
	Bills / KW	Total KWH	P.S.C. 13 Effective 12/3/2007	Calculated Base Rates Billing	Bills / KW	Total KWH	P.S.C. 13 Effective 5/2/2008	Calculated Base Rates Billing
LI-TOD Billing Code 730								
Customer Charge	12		$ 120.00	$ 1,440	12		$ 120.00	$ 1,440
On-Peak Demand (KW)		1,520,293	$ 4.66	7,084,567	1,520,293		$ 4.58	6,962,943
Off-Peak Demand (KW)		1,689,560	$ 0.74	1,250,275	1,689,560		$ 0.93	1,571,291
Minimum Demand Charge				-				-
Energy		388,735,959	$ 0.03282	12,758,314		388,735,959	$ 0.03282	12,758,314
Minimum Energy Charge				0				0
Total Calculated at Base Rates				$ 21,094,596				$ 21,293,989
Correction Factor				1.000000				1.000000
Total After Application of Correction Factor				$ 21,094,596				$ 21,293,989
INCREASE IN BASE RATES REVENUE				$ 1,605,452				$ 199,393
DECREASE IN FAC REVENUE				$ (1,605,452)				

KENTUCKY UTILITIES COMPANY
Calculations showing the effect on Base Rate Revenue of the ECR and FAC Roll-in's for a full year
Based on Sales for the 12 months ended April 30, 2008

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
		Base Rates Billings During 12 Month Period - As Billed						**Fuel Clause Rollin Rates - Full Year**				**ECR Rollin Rates - Full Year**		
		May07-Nov07	Dec07-Apr08	P.S.C. 13	P.S.C. 13				P.S.C. 13	*Calculated*			P.S.C. 13	*Calculated*
		Pre-Rollin	Post-Rollin	Effective	Effective	Base Rates		Total	Effective	Base Rates		Total	Effective	Base Rates
	KWH	Lights	Lights	3/5/2007	12/3/2007	Billings		Lights	12/3/2007	Billing		Lights	5/2/2008	Billing
Street Lighting														
Incandescent Street Lighting														
01000L INC STD ST LT *	30,601	525	375	$ 2.43	$ 2.70	$ 2,288		900	$ 2.70	$ 2,430		900	$ 2.76	$ 2,484
02500L INC STD ST LT *	1,028,530	9,078	6,294	$ 3.04	$ 3.56	50,004		15,372	$ 3.56	54,724		15,372	$ 3.64	55,954
04000L INC STD ST LT *	500,061	2,847	1,751	$ 4.40	$ 5.25	21,720		4,598	$ 5.25	24,140		4,598	$ 5.37	24,691
06000L INC STD ST LT *	6,650	31	15	$ 5.88	$ 7.04	288		46	$ 7.04	324		46	$ 7.19	331
02500L INC ORN ST LT *	6,432	56	40	$ 3.87	$ 4.39	392		96	$ 4.39	421		96	$ 4.48	430
04000L INC ORN ST LT *	52,140	299	185	$ 5.37	$ 6.22	2,756		484	$ 6.22	3,010		484	$ 6.35	3,073
06000L INC ORN ST LT *	2,561	20	-	$ 6.95	$ 8.11	139		20	$ 8.11	162		20	$ 8.28	166
Mercury Vapor Street Lighting														
07000L MV STD ST LT	1,128,653	9,701	6,680	$ 7.04	$ 7.58	118,929		16,381	$ 7.58	124,168		16,381	$ 7.73	126,625
010000L MV STD ST LT	1,119,282	6,762	4,665	$ 8.18	$ 8.95	97,065		11,427	$ 8.95	102,272		11,427	$ 9.12	104,214
020000L MV STD ST LT	3,088,066	12,002	8,460	$ 9.72	$ 10.90	208,873		20,462	$ 10.90	223,036		20,462	$ 11.13	227,742
07000L MV ORN ST LT	103,502	875	625	$ 9.36	$ 9.90	14,378		1,500	$ 9.90	14,850		1,500	$ 10.09	15,135
010000L MV ORN ST LT	634,541	3,796	2,678	$ 10.24	$ 11.01	68,356		6,474	$ 11.01	71,279		6,474	$ 11.22	72,638
020000L MV ORN ST LT	2,649,502	10,291	7,264	$ 11.38	$ 12.56	208,347		17,555	$ 12.56	220,491		17,555	$ 12.81	224,880
High Pressure Sodium Street Lighting														
05800L HPS DEC ACORN ST LT	1,992	42	30	$ 11.34	$ 11.56	823		72	$ 11.56	832		72	$ 11.77	847
09500L HPS DEC ACORN ST LT	64,530	934	716	$ 12.06	$ 12.37	20,121		1,650	$ 12.37	20,411		1,650	$ 12.59	20,774
04000L HPS HISTORIC ACORN S	35,760	1,043	745	$ 16.84	$ 17.00	30,229		1,788	$ 17.00	30,396		1,788	$ 17.29	30,915
05800L HPS HISTORIC ACORN S	23,905	504	360	$ 17.41	$ 17.63	15,121		864	$ 17.63	15,232		864	$ 17.94	15,500
09500L HPS HISTORIC ACORN S	188,349	2,779	2,040	$ 18.15	$ 18.46	88,097		4,819	$ 18.46	88,959		4,819	$ 18.78	90,501
05800L HPS POL	61,534	1,129	968	$ 4.55	$ 4.77	9,754		2,097	$ 4.77	10,003		2,097	$ 4.86	10,191
04000L HPS STD ST LT	1,685,220	49,211	35,048	$ 5.21	$ 5.37	444,597		84,259	$ 5.37	452,471		84,259	$ 5.46	460,054
05800L HPS STD ST LT	2,822,338	59,470	42,540	$ 5.67	$ 5.89	587,756		102,010	$ 5.89	600,839		102,010	$ 6.00	612,060
09500L HPS STD ST LT	9,120,054	*135,679*	98,038	$ 6.40	$ 6.71	1,526,181		233,717	$ 6.71	1,568,241		233,717	$ 6.84	1,598,624
022000L HPS STD ST LT	5,356,942	38,613	27,786	$ 9.54	$ 10.17	650,952		66,399	$ 10.17	675,278		66,399	$ 10.36	687,894
050000L HPS STD ST LT	1,599,629	5,761	4,133	$ 15.49	$ 16.75	158,466		9,894	$ 16.75	165,725		9,894	$ 17.07	168,891
04000L HPS ORN ST LT	943,032	27,613	19,552	$ 7.90	$ 8.06	375,732		47,165	$ 8.06	380,150		47,165	$ 8.20	386,753
05800L HPS ORN ST LT	2,762,804	58,126	41,697	$ 8.36	$ 8.58	843,694		99,823	$ 8.58	856,481		99,823	$ 8.74	872,453
09500L HPS ORN ST LT	1,278,676	18,871	13,893	$ 9.29	$ 9.60	308,684		32,764	$ 9.60	314,534		32,764	$ 9.77	320,104
022000L HPS ORN ST LT	4,158,893	29,900	21,618	$ 12.41	$ 13.04	652,958		51,518	$ 13.04	671,795		51,518	$ 13.29	684,674
050000L HPS ORN ST LT	859,382	3,108	2,208	$ 18.35	$ 19.61	100,331		5,316	$ 19.61	104,247		5,316	$ 19.99	106,267

KENTUCKY UTILITIES COMPANY
Calculations showing the effect on Base Rate Revenue of the ECR and FAC Roll-in's for a full year
Based on Sales for the 12 months ended April 30, 2008

High Pressure Sodium Granville Configurations						.						
016000L GRANVILLE STLT-CON	75,007	875	625	$ 39.52	$ 39.92	59,530	1,500	$ 39.92	59,880	1,500	$ 40.55	60,825
016000L GRANVILLE STLT-CON	16,201	189	135	$ 63.97	$ 64.37	20,780	324	$ 64.37	20,856	324	$ 65.07	21,083
016000L GRANVILLE STLT-CON	25,201	294	210	$ 43.42	$ 43 82	21,968	504	$ 43.82	22,085	504	$ 44.46	22,408
016000L GRANVILLE STLT-CON	3,000	35	25	$ 45.15	$ 45 55	2,719	60	$ 45.55	2,733	60	$ 46.19	2,771
016000L GRANVILLE STLT-CON	600	7	5	$ 46 34	$ 46 74	558	12	$ 46.74	561	12	$ 47.39	569
016000L GRANVILLE STLT-CON	3,600	42	30	$ 62 00	$ 62 40	4,476	72	$ 62.40	4,493	72	$ 63.09	4,542
016000L GRANVILLE STLT-CON	5,999	70	50	$ 60.27	$ 60 67	7,252	120	$ 60.67	7,280	120	$ 61.36	7,363
016000L GRANVILLE STLT-CON	-	-	-	$ 44.83	$ 45 23	-	-	$ 45.23	-	-	$ 45.75	-
016000L GRANVILLE STLT-CON	1,200	14	10	$ 40.72	$ 41 12	981	24	$ 41.12	987	24	$ 41.75	1,002
016000L GRANVILLE STLT-CON	9,001	105	75	$ 56.37	$ 56 77	10,177	180	$ 56.77	10,219	180	$ 57.45	10,341
016000L GRANVILLE STLT-CON	-	-	-	$ 81.05	$ 81 45	-	-	$ 81.45	-	-	$ 81.97	-
016000L GRANVILLE STLT-CON	600	7	5	$ 63.19	$ 63.59	760	12	$ 63.59	763	12	$ 64.29	771
016000L GRANVILLE STLT-CON	12,001	140	100	$ 56.37	$ 56.77	13,569	240	$ 56.77	13,625	240	$ 57.45	13,788
016000L GRANVILLE STLT-CON	2,400	28	20	$ 57.57	$ 57.97	2,771	48	$ 57.97	2,783	48	$ 58.65	2,815
016000L GRANVILLE STLT-CON	1,800	21	15	$ 60.27	$ 60.67	2,176	36	$ 60.67	2,184	36	$ 61.36	2,209
016000L GRANVILLE STLT-CON	15,603	182	130	$ 58.79	$ 59.19	18,394	312	$ 59.19	18,467	312	$ 59.87	18,679
016000L GRANVILLE STLT-CON	30,602	357	255	$ 47.30	$ 47.70	29,050	612	$ 47.70	29,192	612	$ 48.35	29,590
016000L GRANVILLE STLT-CON	5,401	63	45	$ 40.72	$ 41.12	4,416	108	$ 41.12	4,441	108	$ 40.55	4,379
0107800L MH DIRECTIONAL -M	381,116	620	437	$ 35.77	$ 38.58	39,037	1,057	$ 38.58	40,779	1,057	$ 39.32	41,561
Sub-Total	41,902,893	492,115	352,576			$ 6,845,645	844,691		$ 7,038,228	844,691		$ 7,169,563
Total Calculated at Base Rates						$ 6,845,645			$ 7,038,228			$ 7,169,563
Correction Factor						1.000001			1.000001			1.000001
Total After Application of Correction Factor						$ 6,845,641			$ 7,038,223			$ 7,169,559
INCREASE IN BASE RATES REVENUE									$ 192,583			$ 131,336
DECREASE IN FAC REVENUE									$ (178,906)			

KENTUCKY UTILITIES COMPANY
Calculations showing the effect on Base Rate Revenue of the ECR and FAC Roll-in's for a full year
Based on Sales for the 12 months ended April 30, 2008

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
		Base Rates Billings During 12 Month Period - As Billed						**Fuel Clause Rollin Rates - Full Year**				**ECR Rollin Rates - Full Year**		
	KWH	May07-Nov07 Pre-Rollin Lights	Dec07-Apr08 Post-Rollin Lights	P S C 13 Effective 3/5/2007	P S C 13 Effective 12/3/2007	Base Rates Billings		Total Lights	P S C 13 Effective 12/3/2007	Calculated Base Rates Billing		Total Lights	P.S.C. 13 Effective 5/2/2008	Calculated Base Rates Billing
Street Lighting -- Decorative														
04000L HPS COLONIAL ST LT	160,854	4,616	3,406	$ 7.11	$ 7.27	$ [illegible]		[illegible]	$ 7.27	$ 58,320		8,022	$ 7.40	$ 59,363
05800L HPS COLONIAL ST LT	309,845	6,459	4,710	$ 7.60	$ 7.82	[illegible]		[illegible]	$ 7.82	87,498		11,189	$ 7.96	89,064
09500L HPS COLONIAL ST LT	619,118	8,766	7,020	$ 8.25	$ 8.56	[illegible]		[illegible]	$ 8.56	135,128		15,786	$ 8.71	137,496
032000L MH DIRECTIONAL -M P	388,127	1,431	1,144	$ 21.67	$ 22.84	[illegible]		2,575	$ 22.84	58,813		2,575	$ 23.27	59,920
05800L HPS CONTEMPORARY S	1,260,005	37,741	19,360	$ 13.04	$ 13.26	748,856		57,101	$ 13.26	757,159		57,101	$ 13.50	770,864
09500L HPS CONTEMPORARY S	234,286	4,127	2,520	$ 15.56	$ 15.87	[illegible]		6,647	$ 15.87	105,488		6,647	$ 16.15	107,349
022000L HPS CONTEMPORARY :	445,967	4,131	2,314	$ 18.16	$ 18.79	118,499		6,445	$ 18.79	121,102		6,445	$ 19.13	123,293
050000L HPS CONTEMPORARY :	102,820	424	265	$ 23.69	$ 24.95	16,656		689	$ 24.95	17,191		689	$ 25.42	17,514
Sub-Total	3,521,022	67,695	40,759			$ 1,321,428		108,454		$ 1,340,698		108,454		$ 1,364,863
Total Calculated at Base Rates						$ 1,321,428				$ 1,340,698				$ 1,364,863
Correction Factor						1.000106				1.000106				1.000106
Total After Application of Correction Factor						$ 1,321,287				$ 1,340,556				$ 1,364,718
INCREASE IN BASE RATES REVENUE										$ 19,268				$ 24,162
DECREASE IN FAC REVENUE										$ (14,694)				

KENTUCKY UTILITIES COMPANY
Calculations showing the effect on Base Rate Revenue of the ECR and FAC Roll-in's for a full year
Based on Sales for the 12 months ended April 30, 2008

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
		Base Rates Billings During 12 Month Period - As Billed						Fuel Clause Rollin Rates - Full Year				ECR Rollin Rates - Full Year		
	KWH	May07-Nov07 Pre-Rollin Lights	Dec07-Apr08 Post-Rollin Lights	P.S.C. 13 Effective 3/5/2007	P.S.C. 13 Effective 12/3/2007	Base Rates Billings		Total Lights	P.S.C. 13 Effective 12/3/2007	Calculated Base Rates Billing		Total Lights	P.S.C. 13 Effective 5/2/2008	Calculated Base Rates Billing
Private Outdoor Lighting														
Decorative (Served Underground)														
04000L HPS COLONIAL DEC POI	12,031	360	245	$ 7.11	$ 7.27	$ 4,341		605	$ 7.27	$ 4,398		605	$ 7.40	$ 4,477
05800L HPS COLONIAL DEC POI	57,712	1,197	886	$ 7.60	$ 7.82	16,026		2,083	$ 7.82	16,289		2,083	$ 7.96	16,581
09500L HPS COLONIAL DEC POI	778,055	11,352	8,575	$ 8.25	$ 8.56	167,056		19,927	$ 8.56	170,575		19,927	$ 8.71	173,564
05800L HPS CONTEMPORARY D	16,936	357	255	$ 13.04	$ 13.26	8,037		612	$ 13.26	8,115		612	$ 13.50	8,262
09500L HPS CONTEMPORARY D	129,472	1,914	1,406	$ 15.56	$ 15.87	52,095		3,320	$ 15.87	52,688		3,320	$ 16.15	53,618
022000 HPS CONTEMPORARY D	621,161	4,459	3,241	$ 18.16	$ 18.79	141,874		7,700	$ 18.79	144,683		7,700	$ 19.13	147,301
050000 HPS CONTEMPORARY D	1,706,928	6,100	4,450	$ 23.69	$ 24.95	255,537		10,550	$ 24.95	263,223		10,550	$ 25.42	268,181
Directional (Served Overhead)														
09500L HPS DIRECTIONAL POL	4,867,927	72,353	52,209	$ 6.27	$ 6.58	797,189		124,562	$ 6.58	819,618		124,562	$ 6.70	834,565
022000L HPS DIRECTIONAL POL	5,933,517	42,702	30,891	$ 8.98	$ 9.61	680,326		73,593	$ 9.61	707,229		73,593	$ 9.79	720,475
050000L HPS DIRECTIONAL POL	14,702,952	52,740	38,189	$ 13.78	$ 15.04	1,301,120		90,929	$ 15.04	1,367,572		90,929	$ 15.34	1,394,851
Metal Halide Contemporary														
012000L MH CONTEMPORARY I	45,669	382	280	$ 10.42	$ 10.96	7,049		662	$ 10.96	7,256		662	$ 11.17	7,395
012000L MH CONTEMPORARY -	143,197	1,204	872	$ 19.04	$ 19.58	39,998		2,076	$ 19.58	40,648		2,076	$ 19.94	41,395
032000L MH CONTEMPORARY I	522,484	2,010	1,467	$ 14.65	$ 15.82	52,654		3,477	$ 15.82	55,006		3,477	$ 16.13	56,084
032000L MH CONTEMPORARY -	979,440	3,664	2,829	$ 23.25	$ 24.42	154,272		6,493	$ 24.42	158,559		6,493	$ 24.87	161,481
0107800L MH CONTEMPORARY	207,637	359	225	$ 29.78	$ 32.59	18,024		584	$ 32.59	19,033		584	$ 33.23	19,406
0107800L MH CONTEMPORARY	652,302	1,077	741	$ 38.38	$ 41.19	71,857		1,818	$ 41.19	74,883		1,818	$ 41.99	76,338
Sub-Total	*31,377,420*	*202,230*	*146,761*			$ 3,767,454		348,991		$ 3,909,775		348,991		$ 3,983,975
Total Calculated at Base Rates						$ 3,767,454				$ 3,909,775				$ 3,983,975
Correction Factor						1.000025				1.000025				1.000025
Total After Application of Correction Factor						$ 3,767,361				$ 3,909,679				$ 3,983,877
INCREASE IN BASE RATES REVENUE										$ 142,318				$ 74,198
DECREASE IN FAC REVENUE										$ (133,089)				

KENTUCKY UTILITIES COMPANY
Calculations showing the effect on Base Rate Revenue of the ECR and FAC Roll-in's for a full year
Based on Sales for the 12 months ended April 30, 2008

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
		Base Rates Billings During 12 Month Period - As Billed						Fuel Clause Rollin Rates - Full Year				ECR Rollin Rates - Full Year		
	KWH	May07-Nov07 Pre-Rollin Lights	Dec07-Apr08 Post-Rollin Lights	P.S.C. 13 Effective 3/5/2007	P.S.C. 13 Effective 12/3/2007	Base Rates Billings		Total Lights	P.S.C. 13 Effective 12/3/2007	Calculated Base Rates Billing		Total Lights	P.S.C. 13 Effective 5/2/2008	Calculated Base Rates Billing
Outdoor Lighting														
02500L INC COL *	-	-	-	$ 5.10	$ 5.10	$ -		-	$ 5.10	$ -		-	$ 5.10	$ -
03500L MV COL *	-	-	-	$ 6.23	$ 6.23	-		-	$ 6.23	-		-	$ 6.23	-
07000L MV COL *	2,484	14	10	$ 7.34	$ 7.34	176		24	$ 7.34	176		24	$ 7.47	179
020000L MV SPECIAL LIGHTING	812,654	3,171	2,219	$ 6.76	$ 6.76	36,436		5,390	$ 6.76	36,436		5,390	$ 6.88	37,083
050000L HPS SPECIAL LIGHTIN(	354,052	1,286	906	$ 9.02	$ 9.02	19,772		2,192	$ 9.02	19,772		2,192	$ 9.18	20,123
Standard (Served Overhead)														
07000L MV POL	8,701,195	74,392	51,820	$ 8.05	$ 8.59	1,043,989		126,212	$ 8.59	1,084,161		126,212	$ 8.76	1,105,617
020000L MV POL	984,179	3,857	2,670	$ 9.72	$ 10.90	66,593		6,527	$ 10.90	71,144		6,527	$ 11.13	72,646
09500L HPS POL	15,623,163	232,154	167,488	$ 5.21	$ 5.52	2,134,056		399,642	$ 5.52	2,206,024		399,642	$ 5.62	2,245,988
022000L HPS POL	1,404,988	10,126	7,301	$ 9.54	$ 10.17	170,853		17,427	$ 10.17	177,233		17,427	$ 10.36	180,544
050000L HPS POL	4,231,587	15,245	10,922	$ 15.49	$ 16.75	419,089		26,167	$ 16.75	438,297		26,167	$ 17.07	446,671
Decorative (Served Underground)														
04000L HPS DEC ACORN D/D PO	477	14	10	$ 10.75	$ 10.91	260		24	$ 10.91	262		24	$ 11.11	267
05800L HPS DEC ACORN D/D PO	13,568	294	196	$ 11.34	$ 11.56	5,600		490	$ 11.56	5,664		490	$ 11.77	5,767
09500L HPS DEC ACORN D/D PO	113,943	1,693	1,220	$ 12.07	$ 12.38	35,538		2,913	$ 12.38	36,063		2,913	$ 12.61	36,733
04000L HPS HIST ACORN D/D PC	14,641	427	305	$ -	$ -	-		732	$ -	-		732	$ -	-
05800L HPS HIST ACORN D/D PC	24,675	518	374	$ 16.84	$ 17.00	15,081		892	$ 17.00	15,164		892	$ 17.29	15,423
09500L HPS HIST ACORN D/D PC	255,935	3,770	2,779	$ 18.15	$ 18.46	119,726		6,549	$ 18.46	120,895		6,549	$ 18.78	122,990
05800L HPS COACH DEC POL	7,969	168	120	$ 25.94	$ 26.16	7,497		288	$ 26.16	7,534		288	$ 26.62	7,667
05800L HPS COACH DEC POL	121,707	1,770	1,350	$ 26.58	$ 26.89	83,348		3,120	$ 26.89	83,897		3,120	$ 27.36	85,363
05800L HPS COACH DEC POL	6,972	147	105	$ 25.94	$ 26.16	6,560		252	$ 26.16	6,592		252	$ 26.62	6,708
09500L HPS COACH DEC POL	4,681	70	50	$ 26.58	$ 26.89	3,205		120	$ 26.89	3,227		120	$ 27.36	3,283
Metal Halide Directional														
012000L MH DIRECTIONAL POL	414,824	3,447	2,554	$ 9.30	$ 9.84	57,188		6,001	$ 9.84	59,050		6,001	$ 10.03	60,190
012000L MH DIRECTIONAL -W F	98,345	812	613	$ 11.32	$ 11.86	16,462		1,425	$ 11.86	16,901		1,425	$ 12.08	17,214
012000L MH DIRECTIONAL -M P	9,172	78	55	$ 17.91	$ 18.45	2,412		133	$ 18.45	2,454		133	$ 18.78	2,498
032000L MH DIRECTIONAL POL	6,984,958	26,826	19,670	$ 13.07	$ 14.24	630,717		46,496	$ 14.24	662,103		46,496	$ 14.52	675,122
032000L MH DIRECTIONAL -W F	1,459,773	5,685	4,045	$ 15.09	$ 16.26	151,558		9,730	$ 16.26	158,210		9,730	$ 16.58	161,323
0107800L MH DIRECTIONAL POI	5,071,356	8,276	5,830	$ 27.17	$ 29.98	399,642		14,106	$ 29.98	422,898		14,106	$ 30.58	431,361
0107800L MH DIRECTIONAL -W	1,281,044	2,129	1,443	$ 29.97	$ 32.78	111,108		3,572	$ 32.78	117,090		3,572	$ 33.43	119,412
Sub-Total	47,998,342	396,369	284,055			$ 5,536,867		123,010		$ 5,751,246		123,010		$ 5,860,172
Total Calculated at Base Rates						$ 5,536,867				$ 5,751,246				$ 5,860,172
Correction Factor						0.997705				0.997705				0.997705
Total After Application of Correction Factor						$ 5,549,604				$ 5,764,477				$ 5,873,653
INCREASE IN BASE RATES REVENUE										$ 214,873				$ 109,176
DECREASE IN FAC REVENUE										$ (205,077)				

KENTUCKY UTILITIES COMPANY
Calculations showing the effect on Base Rate Revenue of the ECR and FAC Roll-in's for a full year
Based on Sales for the 12 months ended April 30, 2008

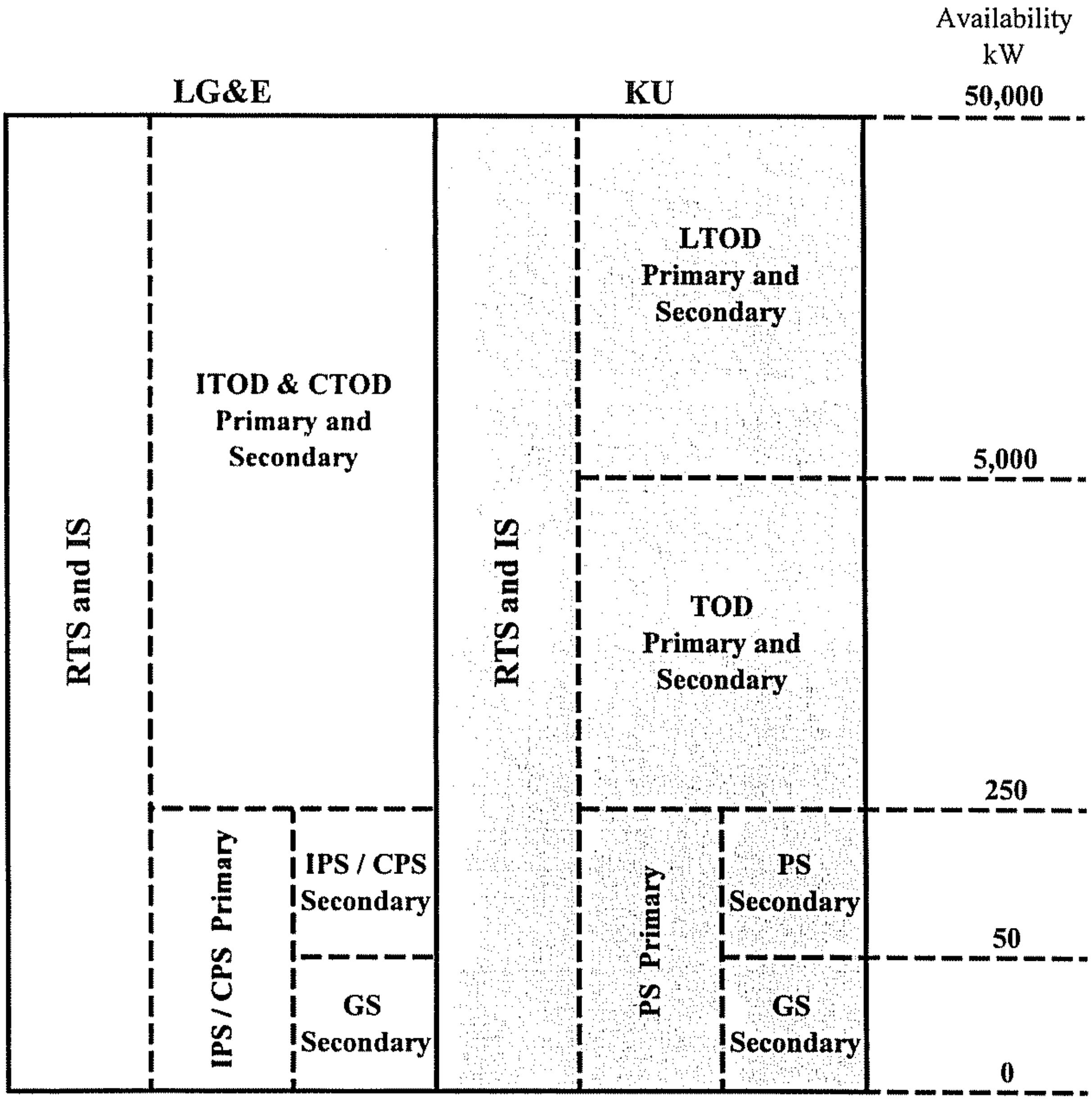
	Jan-08	Feb-08	Mar-08	Apr-08	May-07	Jun-07	Jul-07	Aug-07	Sep-07	Oct-07	Nov-07	Dec-07	TOTAL 12 Mos. Ended
	FUEL ADJUSTMENT CLAUSE ACTUAL BILLINGS												
Residential Rate - RS (Rate Code 010, 050)	2,279,116	329,418	(24,445)	946,882	1,181,953	2,808,323	2,579,783	1,642,461	2,487,569	2,887,248	1,353,117	588,819	19,060,244
Residential Rate - RS (Rate Code 020, 060, 080)	3,489,762	544,852	(38,323)	1,256,321	1,265,513	2,467,723	2,169,493	1,335,823	2,019,910	2,580,438	1,579,290	823,989	19,494,791
General Service Rate GS - Secondary	1,368,864	206,331	(15,644)	670,416	796,060	1,619,608	1,383,413	828,854	1,293,030	1,832,590	929,933	361,883	11,275,338
General Service Rate GS - Primary	35,680	5,289	(419)	20,389	23,659	40,776	26,645	13,948	29,832	41,741	26,939	10,065	274,544
All Electric School Service Rate - AES	109,446	17,060	(1,259)	50,346	61,741	100,228	71,992	49,119	93,175	134,599	70,690	30,299	787,436
Large Power Rate LPS - Secondary	2,465,727	386,279	(27,430)	1,379,574	1,904,038	3,723,765	3,016,528	1,781,257	2,764,798	4,153,449	2,094,084	737,707	24,379,776
Large Power Rate LPP - Primary	1,040,522	161,287	(11,347)	595,920	852,734	1,618,299	1,278,144	724,877	1,114,884	1,788,893	944,306	318,600	10,427,117
Large Power Rate LPT - Transmission	15,851	3,125	(213)	9,889	11,771	26,001	16,968	11,045	19,528	26,439	14,864	5,921	161,188
Small Time-of-Day - STODS Secondary	125,825	17,196	(1,350)	69,190	94,820	184,074	154,109	91,209	136,558	206,310	109,228	37,738	1,224,906
Small Time-of-Day - STODP Primary	12,278	1,563	(117)	6,838	9,095	14,326	10,786	6,561	9,983	16,822	9,008	3,288	100,431
Small Time-of-Day - STODT Transmission	-	-	-	-	-	-	-	-	-	-	-	-	-
Large Comm./Industrial Time-of-Day - LCI-TOD Primary	1,731,276	278,505	(17,302)	1,039,000	1,447,059	2,670,775	2,093,343	1,228,191	1,860,869	3,126,339	1,499,037	565,053	17,522,144
Large Comm./Industrial Time-of-Day - LCI-TOD Transmission	600,113	91,133	(7,108)	383,725	471,118	805,042	621,158	336,009	472,854	769,512	495,883	167,380	5,206,819
Large Industrial Time of Day - LITOD	266,630	45,304	(3,640)	206,811	268,717	392,265	292,646	132,913	161,533	202,618	215,358	89,077	2,270,232
Coal Mining Power Service Rate - MP Primary	88,151	14,078	(996)	47,916	56,093	94,144	59,650	40,293	61,735	101,790	66,632	23,990	653,476
Coal Mining Power Service Rate - MP Transmission	43,455	7,801	(658)	31,688	31,935	53,873	39,169	31,010	48,897	83,167	38,646	13,325	422,307
Large Mine Power Time-of-Day Rate - LMP-TPD Primary	57,188	8,948	(750)	38,993	51,757	99,652	55,081	32,077	48,131	87,699	50,584	18,005	547,364
Large Mine Power Time-of-Day Rate - LMP-TPD Transmission	217,321	30,437	(2,190)	109,074	134,303	243,966	160,752	106,809	158,993	284,051	164,846	58,247	1,666,608
Street Lighting - SL	33,918	4,536	(363)	15,446	18,536	29,919	24,902	15,541	24,693	49,139	29,753	11,056	257,077
Decorative Street Lighting - SLDEC	2,907	394	(32)	1,347	1,476	2,424	2,025	1,277	2,026	4,089	2,510	941	21,385
Private Outdoor Lighting - POL	25,615	3,297	(237)	11,732	13,812	22,193	18,589	11,501	18,349	36,634	22,178	8,259	191,922
Customer Outdoor Lighting - OL	38,791	5,143	(351)	17,487	21,334	34,128	28,652	17,732	28,381	56,294	34,011	12,556	294,158
Total Ultimate Consumers	14,048,435	2,161,976	(154,171)	6,908,985	8,717,525	17,051,503	14,103,829	8,438,503	12,855,725	18,469,860	9,750,896	3,886,199	116,239,264

KENTUCKY UTILITIES COMPANY
Calculations showing the effect on Base Rate Revenue of the ECR and FAC Roll-in's for a full year
Based on Sales for the 12 months ended April 30, 2008

	Jan-08	Feb-08	Mar-08	Apr-08	May-07	Jun-07	Jul-07	Aug-07	Sep-07	Oct-07	Nov-07	Dec-07	TOTAL 12 Mos. Ended
	FUEL ADJUSTMENT CLAUSE BILLINGS REFLECTING BASE RATE ROLL-IN FOR FULL YEAR												
Residential Rate - RS	2,279,116	329,418	(24,445)	946,882	(283,274)	839,229	266,607	(944,353)	(170,109)	1,116,660	(84,876)	588,819	4,859,674
Full Electric Residential Service Rate - FERS	3,489,762	544,852	(38,323)	1,256,321	(303,310)	737,171	224,227	(768,414)	(138,115)	997,753	(98,967)	823,989	6,726,947
General Service Rate GS - Secondary	1,368,864	206,331	(15,644)	670,416	(190,705)	483,991	142,939	(477,130)	(88,457)	707,411	(58,262)	361,883	3,111,638
General Service Rate GS - Primary	35,680	5,289	(419)	20,389	(5,671)	12,189	2,753	(7,856)	(2,146)	7,614	(1,686)	10,065	76,202
All Electric School Service Rate - AES	109,446	17,060	(1,259)	50,346	(14,798)	29,961	7,439	(28,223)	(6,373)	52,086	(4,424)	30,299	241,558
Large Power Rate LPS - Secondary	2,465,727	386,279	(27,430)	1,379,574	(456,370)	1,114,550	311,517	(1,022,786)	(189,143)	1,609,536	(130,960)	737,707	6,178,202
Large Power Rate LPP - Primary	1,040,522	161,287	(11,347)	595,920	(204,386)	483,746	132,070	(416,469)	(76,258)	693,736	(58,918)	318,600	2,658,502
Large Power Rate LPT - Transmission	15,851	3,125	(213)	9,889	(2,821)	7,772	1,753	(6,346)	(1,336)	10,231	(930)	5,921	42,896
Small Time-of-Day - STODS Secondary	125,825	17,196	(1,350)	69,190	(22,727)	55,024	15,884	(52,408)	(9,340)	79,836	(6,836)	37,738	308,031
Small Time-of-Day - STODP Primary	12,278	1,563	(117)	6,838	(2,180)	4,282	1,115	(3,770)	(683)	6,510	(564)	3,288	28,561
Small Time-of-Day - STODT Transmission	-	-	-	-	-	-	-	-	-	-	-	-	-
Large Comm./Industrial Time-of-Day - LCI-TOD Primary	1,731,276	278,505	(17,302)	1,039,000	(346,835)	798,356	216,304	(698,051)	(127,282)	1,217,922	(93,817)	565,053	4,563,128
Large Comm./Industrial Time-of-Day - LCI-TOD Transmission	600,113	91,133	(7,108)	383,725	(112,919)	240,645	64,184	(193,070)	(32,343)	297,778	(31,035)	167,380	1,468,484
Large Industrial Time of Day - LITOD	266,630	45,304	(3,640)	206,811	(64,407)	117,257	30,239	(76,371)	(11,049)	78,407	(13,478)	89,077	664,780
Coal Mining Power Service Rate - MP Primary	88,151	14,078	(996)	47,916	(13,454)	28,460	6,157	(23,152)	(4,265)	39,430	(4,164)	23,990	202,151
Coal Mining Power Service Rate - MP Transmission	43,455	7,801	(658)	31,688	(7,654)	16,104	4,047	(17,818)	(3,344)	32,183	(2,419)	13,325	116,709
Large Mine Power Time-of-Day Rate - LMP-TPD Primary	57,188	8,948	(750)	38,993	(12,405)	29,788	5,691	(18,431)	(3,292)	33,937	(3,172)	18,005	154,499
Large Mine Power Time-of-Day Rate - LMP-TPD Transmission	217,321	30,437	(2,190)	109,074	(32,190)	72,927	16,610	(61,372)	(10,875)	109,919	(10,317)	58,247	497,592
Street Lighting - SL	33,918	4,536	(363)	15,446	(4,443)	8,956	2,573	(8,930)	(1,689)	19,016	(1,862)	11,056	78,214
Decorative Street Lighting - SLDEC	2,907	394	(32)	1,347	(354)	725	209	(733)	(139)	1,583	(157)	941	6,691
Private Outdoor Lighting - POL	25,615	3,297	(237)	11,732	(3,303)	6,638	1,922	(6,618)	(1,253)	14,167	(1,388)	8,259	58,833
Customer Outdoor Lighting - OL	38,791	5,143	(351)	17,487	(5,089)	10,212	2,952	(10,233)	(1,938)	21,752	(2,130)	12,556	89,152
Total Ultimate Consumers	14,048,435	2,161,976	(154,171)	6,908,985	(2,089,295)	5,097,983	1,457,195	(4,842,535)	(879,431)	7,147,464	(610,362)	3,886,199	32,132,443

KENTUCKY UTILITIES COMPANY
Calculations showing the effect on Base Rate Revenue of the ECR and FAC Roll-in's for a full year
Based on Sales for the 12 months ended April 30, 2008

	Jan-08	Feb-08	Mar-08	Apr-08	May-07	Jun-07	Jul-07	Aug-07	Sep-07	Oct-07	Nov-07	Dec-07	TOTAL 12 Mos. Ended
	REDUCED FUEL ADJUSTMENT CLAUSE BILLINGS REFLECTING BASE RATE ROLL-IN FOR FULL YEAR (MAY 2007 - NOV. 2007)												
UNIT CHARGES BILLED -	0.00795	0.00126	-0.00010	0.00490	0.00630	0.01114	0.00871	0.00496	0.00731	0.01274	0.00735	0.00254	
AMOUNT OF ROLLIN -	0.00000	0.00000	0.00000	0.00000	-0.00781	-0.00781	-0.00781	-0.00781	-0.00781	-0.00781	-0.00781	0.00000	
CHARGE AFTER ROLLIN -	0.00795	0.00126	-0.00010	0.00490	-0.00151	0.00333	0.00090	-0.00285	-0.00050	0.00493	-0.00046	0.00254	
	No change	No change	No change	No change								No change	
Residential Rate - RS					(1,465,227)	(1,969,094)	(2,313,176)	(2,586,814)	(2,657,678)	(1,770,589)	(1,437,993)		(14,200,571)
Full Electric Residential Service Rate - FERS					(1,568,822)	(1,730,552)	(1,945,266)	(2,104,238)	(2,158,025)	(1,582,685)	(1,678,257)		(12,767,844)
General Service Rate GS - Secondary					(986,765)	(1,135,616)	(1,240,474)	(1,305,983)	(1,381,487)	(1,125,180)	(988,195)		(8,163,701)
General Service Rate GS - Primary					(29,330)	(28,587)	(23,891)	(21,804)	(31,978)	(34,127)	(28,625)		(198,343)
All Electric School Service Rate - AES					(76,539)	(70,268)	(64,553)	(77,342)	(99,548)	(82,513)	(75,115)		(545,878)
Large Power Rate LPS - Secondary					(2,360,408)	(2,609,215)	(2,705,011)	(2,804,043)	(2,953,941)	(2,543,913)	(2,225,043)		(18,201,574)
Large Power Rate LPP - Primary					(1,057,120)	(1,134,552)	(1,146,074)	(1,141,346)	(1,191,142)	(1,095,158)	(1,003,224)		(7,768,615)
Large Power Rate LPT - Transmission					(14,593)	(18,229)	(15,215)	(17,391)	(20,863)	(16,208)	(15,794)		(118,292)
Small Time-of-Day - STODS Secondary					(117,547)	(129,050)	(138,225)	(143,617)	(145,899)	(126,474)	(116,064)		(916,875)
Small Time-of-Day - STODP Primary					(11,275)	(10,044)	(9,672)	(10,331)	(10,665)	(10,312)	(9,572)		(71,871)
Small Time-of-Day - STODT Transmission					-	-	-	-	-	-	-		-
Large Comm./Industrial Time-of-Day - LCI-TOD Primary					(1,793,893)	(1,872,420)	(1,877,039)	(1,926,242)	(1,988,152)	(1,908,417)	(1,592,854)		(12,959,017)
Large Comm./Industrial Time-of-Day - LCI-TOD Transmission					(584,037)	(564,396)	(556,974)	(529,079)	(505,197)	(471,734)	(526,918)		(3,738,335)
Large Industrial Time of Day - LITOD					(333,124)	(275,008)	(262,407)	(209,285)	(172,581)	(124,211)	(228,836)		(1,605,452)
Coal Mining Power Service Rate - MP Primary					(69,546)	(65,685)	(53,493)	(63,445)	(66,000)	(62,360)	(70,796)		(451,324)
Coal Mining Power Service Rate - MP Transmission					(39,589)	(37,769)	(35,122)	(48,828)	(52,241)	(50,984)	(41,065)		(305,597)
Large Mine Power Time-of-Day Rate - LMP-TPD Primary					(64,163)	(69,863)	(49,389)	(50,508)	(51,423)	(53,762)	(53,756)		(392,865)
Large Mine Power Time-of-Day Rate - LMP-TPD Transmission					(166,494)	(171,039)	(144,141)	(168,181)	(169,868)	(174,132)	(175,163)		(1,169,016)
Street Lighting - SL					(22,979)	(20,963)	(22,329)	(24,471)	(26,382)	(30,123)	(31,615)		(178,863)
Decorative Street Lighting - SLDEC					(1,830)	(1,699)	(1,816)	(2,010)	(2,165)	(2,507)	(2,667)		(14,694)
Private Outdoor Lighting - POL					(17,115)	(15,555)	(16,668)	(18,118)	(19,602)	(22,466)	(23,565)		(133,089)
Customer Outdoor Lighting - OL					(26,423)	(23,916)	(25,700)	(27,965)	(30,318)	(34,542)	(36,141)		(205,005)
Total Ultimate Consumers					(10,806,819)	(11,953,521)	(12,646,633)	(13,281,038)	(13,735,156)	(11,322,395)	(10,361,258)		(84,106,820)


Availability
kW
LG&E
KU
50,000
RTS and IS
ITOD & CTOD
Primary and
Secondary
IPS / CPS Primary
IPS / CPS
Secondary
GS
Secondary
RTS and IS
LTOD
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Secondary
5,000
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Secondary
250
PS Primary
PS
Secondary
50
GS
Secondary
0

VERIFICATION

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

The undersigned, **Robert M. Conroy**, being duly sworn, deposes and says he is Director – Rates for Kentucky Utilities Company, 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.

ROBERT M. CONROY

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 24th day of July, 2008.

Tammy J. Elzy (SEAL)
Notary Public

My Commission Expires:

November 9, 2010

APPENDIX A

Robert M. Conroy
Director - Rates
E.ON U.S. LLC
220 West Main Street
Louisville, Kentucky 40202
(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

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

APPLICATION OF KENTUCKY	)	
UTILITIES COMPANY FOR AN	)	**CASE NO. 2008-00251**
ADJUSTMENT OF BASE RATES	)	

TESTIMONY OF
SIDNEY L. "BUTCH" COCKERILL
DIRECTOR, REVENUE COLLECTIONS
KENTUCKY UTILITIES COMPANY

Filed: July 29, 2008

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

A. My name is Sidney L. "Butch" Cockerill. I am the Director, Revenue Collections 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 40202. A statement of my qualifications is included in the Appendix attached hereto.

Q. What are the duties and responsibilities of your current position?

A. Since May 2003 I have been LG&E's and KU's Director, Revenue Collections. In this position, I have responsibility for all meter assets, meter reading, customer accounting (including utility billing), revenue protection, remittance processing, and revenue collections for both LG&E and KU. Also, I have responsibility for all fleet procurement and maintenance for both companies.

Q. Have you testified previously before the Commission?

A. Yes, I have previously testified before the Commission, and did so in the Company's last general rate case, Case No. 2003-00434. More recently, I testified in Case Nos. 2007-00117 and 2007-00161, concerning responsive pricing and real-time pricing pilot programs, respectively.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to describe and support the proposed revisions to the Company's terms and conditions for furnishing electric service. In addition, I will discuss the proposed changes to some of the Company's non-recurring charges. Finally, I will review several of the Company's successful programs, including its

Demand-Side Management and energy efficiency programs, real-time pricing pilot program, and its efforts to assist its low-income customers.

Q. What is the primary purpose of the proposed revisions to KU's tariff?

A. In addition to reflecting the proposed rates, which are discussed in detail in the testimony of Robert M. Conroy and W. Steven Seelye, the proposed revisions also attempt to harmonize the tariffs of KU and LG&E, to simplify the language in KU's existing tariff, to eliminate redundancy, thus allowing some business processes to run more efficiently. Mr. Conroy discusses in his testimony the Companies' tariff harmonization efforts.

Changes in KU's Electric Tariff

Q. What changes were made to the Company's non-recurring charges?

A. The most generally applicable change to non-recurring charges both KU and LG&E have made is to eliminate the policy that the Companies will pay for customers' meter bases. Moreover, the Companies will no longer supply single-phase meter bases of the kinds used in residential applications, which are standardized, off-the-shelf commodities that contractors can find very easily. The Companies will continue to supply three-phase meter bases due to the multiple types of bases and the importance of having the proper equipment.

KU has also added the following special charges: (1) a $9 monthly charge per meter point per pulse for meter data pulses; and (2) a $2.75 charge for each meter data profile report a customer requests. The schedules attached hereto as SLC Exhibit 1 and SLC Exhibit 2 provide the cost support for the proposed charges.

Q. Please explain the proposed revision to KU's tariff to increase its Disconnect/ Reconnect charge following disconnection for nonpayment of bills or for violation of the Company's Rules and Regulations.

A. KU currently under-recovers its costs for disconnecting and reconnecting service associated with nonpayment of bills or for violation of the Company's Rules and Regulations. As a result, the Company proposes to increase its charge in order to collect the cost of this service from any reconnecting customer. Pursuant to 807 KAR 5:006, Section 8(3)(b), customers qualifying for service reconnection under 807 KAR 5:006, Section 15, will continue to be exempt from this charge.

Based upon the above analysis, the Company proposes to increase its Charge for Disconnecting and Reconnecting Service to $25.00, which is applied only when a customer's service is reconnected. The schedule attached hereto as SLC Exhibit 3 provides the cost support for the proposed change.

Q. The Company is proposing a tariff revision to update its meter test charge when the customer has requested the test and the results show that the meter was not more than two percent fast. Will you please explain the reason for this change?

A. Yes. KU currently under-recovers its costs for performing such a meter test and for the associated transportation costs. As a result, the Company proposes to increase its meter test charge to $60.00 in order to collect the reasonable costs of this service. The schedule attached hereto as SLC Exhibit 4 provides the cost support for the revised charge.

Q. Does KU propose to adjust the returned payment charge contained in its tariff?

A. Yes. The costs associated with this charge include the following three items: (1) bank fees associated with returned payments; (2) labor associated with the processing and recovery of returned payments; and (3) postage for customer correspondence directly related to returned payments. These costs are routinely tracked by the Company. KU proposes to raise its charge for returned payments to $10.00 per returned payment. The schedule attached hereto as SLC Exhibit 5 provides the cost support for the proposed charge for returned payments.

Q. Please describe KU's proposed revisions to its deposit policy.

A. We have recalculated and increased the amount of residential customers' deposits pursuant to 807 KAR 5:006, Section 7(1)(b), to $150 for KU. For General Service customers, the Company proposes tariff changes that would allow the Company to charge such customers a class-of-service, flat-fee deposit of $140, whereas the deposit for a non-residential and non-general service customer would be calculated not to exceed 2/12 of the customer's actual or estimated annual bill.

The testimony and exhibits of Mr. Seelye support the deposit amounts stated above.

Q. Please describe the proposed changes to KU's collection cycle and late payment policy.

A. In its final order in Case No. 2007-00410, the Commission stated, "LG&E and KU shall either propose to synchronize their collection cycles and late payment policies or explain why synchronization is not appropriate."[1] To comply with the Commission's order to harmonize the collection cycles and procedures of LG&E and KU, and to

[1] *In the Matter of: Application of Louisville Gas and Electric Company for Approval of a Revised Collection Cycle for Payment of Bills*, Case No. 2007-00410, Order at 4 (April 24, 2008).

bring KU's tariffs further into alignment with principles of cost causation, KU's and LG&E's proposed tariffs include a late payment charge of 5% of the current month's charges for Rates RS and GS, and a 1% late payment charge for all other rate schedules, with the exception of street lighting. LG&E currently has such a charge, but it will be an addition to KU. The addition of this charge for KU actually serves to decrease base rates and places financial responsibility for late payments on the cost-causers. KU's collection cycle will remain at ten days and it is proposed that LG&E will move to a ten-day collection cycle, pursuant to which customers whose payments are received more than ten days after customers' bills are issued will have their behavioral scores affected in the Companies' behavioral scoring systems; however, under the proposed tariffs LG&E's and KU's late payment charges will not be applied until fifteen days after customers' bills are issued.

Due to the constraints of its current billing system, KU will not begin charging its customers late fees until the first full billing cycle after implementing its new Customer Care System, which KU anticipates will occur in the first quarter of 2009.

The addition of the late payment fee to KU's tariff is reflected in the tariff sheets for the various rates, as well as in the Billing sheet of the Terms and Conditions.

Q. The Company is proposing a revision to its Temporary and/or Seasonal Electric Service Rate TS tariff sheet. Will you please explain the reason for this change?

A. Yes. The Company's current Rate TS "Availability of Service" restricts the service only to situations in which existing facilities are adequate to serve a potential customer's temporary or seasonal requirements without impairing service to other customers. Under the proposed revised rate rider, the Company can provide seasonal or temporary service for not less than one month for construction sites and any other applications where customers need such service and the Company has facilities it is willing to provide. To receive such service, a customer will be served on the rate schedule that otherwise would apply to the customer, but without requiring a yearly contract or minimum charge.

A customer receiving temporary or seasonal service will pay for all labor and non-salvageable materials costs necessary to provide such service, as well as the cost of removing the service when the customer no longer requires it. Concerning materials costs, a temporary or seasonal service customer will pay for non-salvageable materials at the carrying cost charge set out in the Company's Excess Facilities Rider, Sheet No. 60. This will ensure that customers bear the full cost of their temporary services.

Q. Please explain KU's proposal to eliminate current Sheet No. 91, Special Terms/Conditions for Electric Service.

A. KU proposes to eliminate its Special Terms/Conditions for Electric Service because most of its provisions are redundant, being addressed in the proposed Character of Service, Line Extension Plan, and other tariff sheets.

Q. Does the Company propose to make any changes to its Character of Service?

A. Yes. First, the Company has added and altered several different service voltages under the headings "Secondary Voltages," "Primary Voltages," and "Transmission Voltages," in order to match the formatting and voltage values in LG&E Electric's Character of Service. Second, the Company proposes to clarify that, except for minor loads and with Company's prior approval, two-wire service will continue to be available only to those customers who currently have such service. Third, the Company proposes to restructure and re-title the section currently titled "Application of Service Voltage Differentials" to "Restrictions," adding to that section a provision allowing the Company to require a customer who needs an additional transformer (to reduce delivery voltage) to make a one-time, non-refundable payment to cover the additional cost associated with providing service to that customer.

Q. Does KU propose to make any changes to its Terms and Condition for providing service?

A. Yes. Under the Customer Responsibilities section, we have added language requiring a customer, before beginning construction, to notify the Company of the customer's intent to build or extend its own transmission or distribution system over property the customer owns, controls, or has rights to when the construction may extend into the service territory of another utility company.

Q. Does KU propose to make any changes to its Line Extension Plan?

A. Yes, KU proposes to update the Line Extension Plan ("LEP") to make it more comprehensive. In its proposed form, KU's LEP is identical to LG&E's. Expanded language has been added to the LEP regarding the requirements for underground extensions, specifically with respect to how KU ensures the recovery of the differential in cost between overhead and underground extensions in compliance with 807 KAR 5.041 Section 21. The schedule attached hereto as SLC Exhibit 6 provides the cost support for the proposed cost differential for underground extensions.

Mr. Conroy discusses in his testimony the "Special Cases" section of the LEP, which concerns when KU may require a refundable deposit from a customer who requests facilities beyond those outlined in the other sections of the LEP.

Q. What impacts will KU and LG&E's new Customer Care System ("CCS") have on the rates and tariffs the Company is submitting for approval in this proceeding?

A. KU and LG&E's new CCS is a comprehensive business system that will operate as the foundation for all of the Companies' wide-ranging interactions with customers. It is far more than a billing system. The major functional categories of the CCS include customer interaction, billing, reporting, customer self-serve, payment and collections, and service orders. The CCS project addresses approximately 200 business processes and will require approximately 100 interfaces to existing software systems used by the Companies. The output of this effort will drive certain common processes to be used for LG&E and KU in the future. Certain of these common processes are set out in the additional tariff-driven harmonization the Companies are proposing in this proceeding.

Q. Does this conclude your testimony?

A. Yes, it does.

Kentucky Utilities Company
Meter Pulse
Cost Justification

Pulse Initiator Board		74.00
Relay Enclosure		80.00
3 Hours Labor (loaded)		185.00
Vehicle		17.13
Pulse Relay		175.00
		531.13
Charge per pulse per meter per month (5 Year Contract)	$	8.85

Kentucky Utilities Company
Meter Data Processing
Cost Justification

Labor - One Hour	$	41.26
Labor costs per minute	$	0.69
Estimated minutes to prepare report		4
Total Charge	$	2.75

Average hourly rate for all employees including overheads ($41.26)

Kentucky Utilities Company
Disconnect/Reconnect
Cost Justification

Disconnect Service	$	12.22
Reconnect Service		12.22
Total Charge	$	24.45

Based on average cost per service order. ($12.22) Cost per service order consist of labor, transporation, supplies, and equipment. Front and back office service order processing expenses are not included.

Kentucky Utilities Company
Electric Meter Test
Cost Justification

Labor - One Hour	$	54.69
Vehicle - 2/3 Hour		3.80
Total Charge	$	58.50

Average hourly rate for all employees including overheads ($54.69) and vehicles ($5.71) used in the performance of this work multiplied by the time associated with performing this work including travel, test, set-up, etc..

Kentucky Utilities Company
Returned Check/ACH
Cost Justification

KU Returned Check/ACH Costs

	Returns	Cost	Reclears	Cost	Total Returns	Total Cost	Avg Cost
Chase-Lexington	411	$ 617	707	$ 1,414	1,118	$ 2,031	$ 1.82
BofA	1,601	$ 4,003	992	$ 1,488	2,593	$ 5,491	$ 2.12
Local Office Banks	6,288	$ 3,874	-	$ -	6,288	$ 3,874	$ 0.62
Chase - Chicago	2,936	$ 5,872	2,812	$ 2,109	5,748	$ 7,981	$ 1.39
APS	1,109	$ 4,436	0	0	1,109	$ 4,436	$ 4.00
					16,856	$ 23,812	$ 1.41
Labor (incl. burdens)	15 minutes @ avg. of $18/hour + burdens @ .88735 = $33.48						8.37
Postage/Material	$.37 postage, plus $.09 letterhead & $.05 envelope						0.51
Total Per Item Cost							$ 10.29

KENTUCKY UTILITIES COMPANY

SUPPORTING DATA
OVERHEAD TO UNDERGROUND COST DIFFERENATIAL
AND
DEPOSIT REQUIREMENTS
ON AN AGGREGATE FRONT FOOT BASIS
FOR ELECTRIC UNDERGROUND RESIDENTIAL DISTRIBUTION

Estimated costs are based on typical designs and construction practices for two KU operations centers for a common model representing a typical single family residential subdivision. Costs are a weighted average value between operations centers based on an assumed ratio of subdivisions completed in each center in a year.

Overhead to Underground Differential On An Aggregate Front Footage Basis

A. Representative underground costs for model subdivision:

1. Projected construction cost	$ 107,959
2. Aggregate subdivision front-footage	4,268
3. Average unit cost per front-foot	$ 25.30

B. Representative overhead costs for model subdivision:

1. Projected construction cost	$ 78,601
2. Aggregate subdivision front-footage	4,268
3. Average unit cost per front-foot	$ 18.42

C. Estimated average differential (A3 - B3) (per aggregate front foot)	$ 6.88

Deposit Requirement On An Aggregate Front Footage Basis (If Required)

D. Representative unrecoverable underground costs for model subdivision:

1. Projected underground construction cost (less salvageable transformers)	$ 67,462
2. Aggregate subdivision front-footage	4,268

E. Average project deposit per front-foot (D1/D2)	$ 15.81

KENTUCKY UTILITIES COMPANY
2008 COST DIFFERENTIAL
OVERHEAD vs UNDERGROUND

	UNDERGROUND					OVERHEAD				
MODEL SUBDIVISION NAME	FRONT FOOTAGE	WEIGHTED CONSTRUCTION COST	WEIGHTED ASSOCIATED COST	WEIGHTED TRANSFORMER COST	WEIGHTED TOTAL COST	NUMBER OF LOTS	WEIGHTED CONSTRUCTION COST	WEIGHTED ASSOCIATED COST	WEIGHTED TRANSFORMER COST	WEIGHTED TOTAL COST
DUFF ESTATES	4,268	$ 67,462.43		$ 40,497.04	$ 107,959.48	63	$ 53,442.77		$ 25,158.62	$ 78,601.39
COST PER FRONT FOOT		$ 15.81	$ -	$ 9.49	$ 25.30					$ 18.42
COST EXCLUSIVE OF TRANSFORMERS					$ 15.81					
ESTIMATED COST DIFFERENCE PER FRONT FOOT						=				**$ 6.88**

PREPARED BY BRENT BIRCHELL/MICHAEL LEAKE
7/18/08

VERIFICATION

COMMONWEALTH OF KENTUCKY)
) SS:
COUNTY OF JEFFERSON)

The undersigned, **Butch Cockerill**, being duly sworn, deposes and says he is Director – Revenue Collections for E.ON U.S. LLC, 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.

Butch Cockerill
BUTCH COCKERILL

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 21st day of July, 2008.

_____________________(SEAL)
Notary Public

My Commission Expires:
10-16-2008

APPENDIX A

S. L. "Butch" Cockerill
Director, Revenue Collections
E.ON U.S. Services Inc.
220 West Main Street
P. O. Box 32010
Louisville, Kentucky 40202
(502) 627-4772

Education

Spaulding University, B.A. in Business Administration – 1998

Previous Positions

Louisville Gas and Electric Company, Louisville, Kentucky
2002-2003 - Director of Distribution Operations
2000-2002 - Director of Gas Control and Storage
1997-2000 - Manager of Gas Storage Operations
1995-1997 - Manager of Gas Distribution
1990-1995 - Manager of Transportation Department

Professional Trade Memberships

American Gas Association
Kentucky Gas Association
Electric Utilities Fleet Management
Civic Activities
Kentucky Derby Festival, Director