COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:	)	
	)	
AN ADJUSTMENT OF THE ELECTRIC RATES, TERMS AND CONDITIONS OF KENTUCKY UTILITIES COMPANY	)))	**CASE NO: 2003-00434**

VOLUME 4 OF 6

TESTIMONY

Filed: December 29, 2003

Kentucky Utilities Company
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Mr. Staffieri

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

AN ADJUSTMENT OF THE ELECTRIC RATES, TERMS AND CONDITIONS OF KENTUCKY UTILITIES COMPANY	)))))	CASE NO: 2003-00434

DIRECT TESTIMONY OF
VICTOR A. STAFFIERI
CHAIRMAN OF THE BOARD
CHIEF EXECUTIVE OFFICERAND PRESIDENT
LG&E ENERGY CORP.
LOUISVILLE GAS AND ELECTRIC COMPANY
KENTUCKY UTILITIES COMPANY

December 29, 2003

Filed: December 29, 2003

Q. Please state your name and business address.

A. My name is Victor A. Staffieri. My business address is 220 West Main Street, Louisville, KY 40202.

Q. Where are you employed, and what is your position?

A. I am employed by LG&E Energy Services, Inc., a service company subsidiary wholly-owned by LG&E Energy Corp. ("LG&E Energy"). I am Chairman of the Board, Chief Executive Officer and President of LG&E Energy and its subsidiaries, Louisville Gas and Electric Company ("LG&E") and Kentucky Utilities Company ("KU" or "the Company").

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, LG&E, and KU. I assumed my current position on May 1, 2001. Descriptions of my employment history, educational background, and civic involvement are attached to this testimony as Exhibit A.

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

A. Yes. I 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 LG&E and KU, respectively, for approval of an alternative method of regulation, which proceedings resulted in the development and implementation of KU's current Earnings Sharing Mechanism ("ESM"). 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 of and control over 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 – Mr. Thompson will describe, from a generation and transmission function perspective, how the Company has been able to provide safe and reliable service to its customers for years without having to seek a base rate increase, and explain why a rate increase is needed at this time;
- Chris Hermann – Mr. Hermann will describe how LG&E has been able to effectively manage costs while providing reliable, safe service for our retail operations and electric and gas distribution businesses, and will explain why a rate increase is needed at this;
- S. Bradford Rives – 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 September 30, 2003, and support the different valuations of the Company's property;

- Valerie L. Scott – Ms. Scott will support certain pro forma adjustments to the Company's operating income for the twelve months ended September 30, 2003, demonstrate that those adjustments are known, measurable and reasonable, and support certain reference schedules supporting the Company's application;
- Earl M. Robinson – Mr. Robinson will present the results of his depreciation study and his recommendations for new depreciation rates and depreciation expense related to the Company's plant in service;
- Robert G. Rosenberg – Mr. Rosenberg will present the results of his analysis of the cost of equity for the Company, and discuss his conclusion that the cost of equity for our electric operations should be in the 10.75-11.25 percent range, with 11.25 percent recommended as the return that should be allowed in this proceeding;
- Michael S. Beer – Mr. Beer will support certain exhibits required by the Commission's regulations, 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, discuss the effect of various billing mechanisms on the requested rate increase, and present the Company's position on the expenses it has incurred for its membership in Midwest Independent Transmission System Operator, Inc. ("MISO");
- W. Steven Seelye – Mr. Seelye will support certain pro forma adjustments to the Company's operating income for the twelve months ended September 30, 2003, demonstrate that those adjustments are known, measurable and reasonable, support certain reference schedules supporting the Company's application, present

the results of his cost-of-service study, and recommend rate structures and rates; and

- Sidney L. "Butch" Cockerill – Mr. Cockerill will describe and support the proposed revisions to the Company's terms and conditions for furnishing electric and gas services, discuss the proposed changes to some of KU's nonrecurring charges, and review the Company's efforts to assist its low-income customers.

Q. What is the purpose of your testimony?

A. I will explain why KU's proposed adjustment to its base rates should be approved. I will describe some of the significant changes that have occurred since KU last requested an increase in base rates, and will explain why the proposed rate increase is necessary to allow KU to earn a fair, just and reasonable return while continuing to provide low cost, safe and reliable energy service. Finally, I will discuss KU's ongoing commitment to the community and low income customers.

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

A. KU has not had a base rate increase for over twenty years, and in fact had a reduction in base rates in 2000. During that time, we have kept our costs down and have passed along substantial savings, generated by integration and best practice initiatives, to our customers.

KU understands that no customer wants higher prices. However, KU's cost of doing business has risen to the point that an increase in its base rates is necessary to allow the Company to continue to provide reliable, high quality service and at the same time earn a fair and reasonable return. For these reasons, and the reasons set forth in KU's application, KU is requesting an overall 8.54%, or $58.3 million a year, increase in its base rates. A KU residential customer using 1000 Kwh of electricity per month will see an increase of 7.96%, or about $4.00 per bill.

The testimonies of Mr. Rives, Ms. Scott, Mr. Seelye, and Mr. Robinson provide a detailed explanation of the calculation of KU's revenue requirement. The testimony of Mr. Rosenberg 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.

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 base rate increase in 1983. As discussed in the testimony of Mr. Thompson and Mr. Hermann, KU has undertaken numerous initiatives to create efficiencies and, in turn, optimize savings in the face of rising costs. KU has a long track record of operating very efficiently and avoiding price increases, and we have been able to extend this price performance since the merger of KU and LG&E by taking advantage of synergies, combined work practices, lower overheads and administrative staff expenses, and other economies of scale.

Q. Why is KU now seeking an increase in its electric rates?

A. As noted above, the Company's cost of doing business has increased to the point that it is not earning a fair and reasonable return. For example, since December 31, 1998, the end of the test year used in Case No. 98-474, KU has increased its jurisdictional net investment in plant for electric operations by over $412 million. And, comparing the twelve months ended September 30, 2003 with the test year used in Case No. 98-474, the Company has incurred approximately $15 million in additional depreciation expense, on a pro forma basis, associated with those net investments in plant. During that same time period, KU's employee pension and post-retirement expenses have increased about $4 million, on a pro forma basis, as a result of the decline in financial market performance, and the Company has seen an approximately $4 million rise in property insurance costs. KU has also incurred over $3 million in MISO Schedule 10 administrative costs, which are not currently being recovered, and has experienced significant increases in its operating expenses, such as higher wage rates, due in part to inflation.

Q. What efforts has KU made to ensure continued reliability of its system?

A. 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. In the latter regard, KU has added 635 megawatts of generation capacity in the form of six combustion turbines.

Q. Please describe KU's performance in response to the customer outages resulting from the February 2003 Ice Storm.

A. The February, 2003 Ice Storm was one of the worst winter storms ever faced in Kentucky. The duration of the storm, number of customers affected, and extent of damage to the electric system far exceeded that of any winter storm in Kentucky in the last decade. In the days that followed, over 2,000 KU, LG&E and contractor personnel worked diligently to restore power as quickly as possible, with an initial focus on critical community organizations and facilities. Over 1500 of those personnel were skilled workers from regional utilities who are highly effective at providing restoration services. That assistance was secured by KU through its membership in the Edison Electric Institute Mutual Aid Organization. The quality and experience of these crews is evident by the outstanding safety record for both Company and contractor crews during the entire storm. Although the Company's response to the storm was immediate and effective, we continue to strive to improve operations. The Company's response to the Ice Storm is also discussed in the testimony of Mr. Hermann.

Q. Why has the Company waited so long to seek a base rate adjustment?

A. Providing safe, reliable and affordable service to our customers has been the cornerstone of KU's retail business for many years. We are very proud of the fact that our rates are among the lowest in the nation, and we have carried out many programs over the years to keep them that way. Much the same as any utility or other business, we have faced risings costs for items such as materials, labor, pension and post-retirement benefits, and insurance. Nevertheless, we have been able to mitigate or offset many of those cost increases through efficiency initiatives and debt refinancing.

And, importantly, our efficiency-driven initiatives have not unduly affected our service quality or performance. Throughout the last several years, KU has achieved a standard of excellence in overall customer satisfaction very nearly unsurpassed in the industry. In fact, in both 2002 and 2003, J.D. Power & Associates, an international marketing information firm widely recognized as the "voice of the customer," ranked KU, together with its sister utility LG&E, first in the nation among investor-owned utilities in overall satisfaction among residential electric customers. Those rankings are not arbitrary – 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.

Q. Given KU's success over the last several years in maintaining high quality service without raising rates, what prompted the Company's application at this time?

A. KU, like any responsible utility, has sought to balance between providing a high level of service at the most affordable price and aggressively controlling costs without eroding our commitment to safe and reliable service. However, we have now exhausted all prudent means of reducing costs internally, and must seek a reasonable rate adjustment to preserve our financial integrity and, in turn, our ability to sustain the high quality of service our customers have come to expect. It is not in the public interest to have a financially weakened utility. A rate increase will allow the Company to continue to provide the safe and reliable service its customers have come to expect, while also having the opportunity to earn a fair and reasonable return.

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

A. Yes. KU recognizes that its proposed rate adjustment will result in an increase of approximately $4.00 to the monthly bill of a residential customer using 1000 Kwh of electricity. We do not take lightly the effect of any increase on our customers, but this needed increase will ensure that our customers continue to receive a high level of service while still enjoying among the lowest rates in the nation.

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

A. We are proud of our employees, who give freely of their time and talent, actively volunteering, from boardrooms and classrooms to Little League fields and soup kitchens, to improve the quality of life in the communities where they work and live. KU helps to maintain LG&E Energy's 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 is a self-sufficient, non-profit business entity established to support education, community outreach, environment, and arts in the communities served by LG&E Energy and its subsidiaries. Caring about people and being a good neighbor are much more than a corporate obligation to LG&E Energy. Social responsibility is deeply rooted in our culture. We develop valuable relationships with our employees, customers and fellow citizens in order to enrich lives and build better places to live. We simply see it as the right thing to do.

Since the inception of the LG&E Energy Foundation in 1994, the Foundation has awarded more than $11.3 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. Despite lower returns on, and decline in, the market value of its investments, the Foundation is on track to contribute approximately $1.7 million to worthy causes in 2003.

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

A. Over the years, KU has developed a number of programs to assist our low-income customers. The Company's Helping Hands brochure is a quick reference guide of assistance programs, and the WinterCare Energy Assistance Fund allows us to partner with our customers to help those that need assistance in paying their bills from time to time.

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.

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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 LG&E Energy Corp., Louisville Gas and Electric Company and 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.

VICTOR A. STAFFIERI

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 29th day of December 2003.

Melody L Hulsal
Notary Public (SEAL)

My Commission Expires:

November 26, 2007

Appendix A

Victor A. Staffieri

Chairman, Chief Executive Officer, and President
LG&E Energy Corp., Louisville, Gas & Electric Company and Kentucky Utilities
220 West Main Street
Louisville, KY 40202
Phone: (502) 627-3912
Board member Powergen plc.

Education

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

Previous Positions

LG&E Energy Corp., 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

Industry Affiliations

Edison Electric Institute, Washington, DC - Board of Directors -- June 2001 - May 2004
Electric Power Research Institute, Palo Alto, CA - Board of Directors -- May 2001 - April 2002

Civic Activities

Boards

Metro United Way -- Board of Directors -- 1998 - 2004
MidAmerica Bancorp -- Board of Directors -- 2000 - 2003
Kentucky Country Day -- Board of Directors -- 1996 – 2002

Civic Activities, Continued

Boards, Continued

Bellarmine University - Board of Trustees -- 1995 - 1998, 2000 - 2003
  Executive Committee -- 1997 - 1998
  Finance Committee -- 1995 - 1997, 2000 - 2003
  Strategic Planning Committee -- 1997
Jefferson County/Louisville Area Chamber of Commerce Family Business Partnership
  Co-Chair -- 1996-1997
Louisville Area Chamber of Commerce -- Board of Directors -- 1994-1997; 2000-2006

Other

Louisville Area Chamber of Commerce -- Chair -- 1997
Louisville Area Chamber of Commerce -- African-American Affairs Committee -- 1996-1997
Louisville Area Chamber of Commerce -- Vice Chairman, Finance and Administration
  Steering Committee -- 1995
The National Conference - Dinner Chair -- 1997
Chairman of the Coordination Council for Economic Development Activities
  -- Regional Economic Development Strategy -- 1997
Metro United Way – Chair of Community Campaign -- 2002
Metro United Way - Cabinet Member -- 1995 and 2000 Campaigns
Boy Scouts of America -- 1996 Annual Explorer Campaign

Mr. Thompson

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

AN ADJUSTMENT OF THE ELECTRIC RATES, TERMS AND CONDITIONS OF KENTUCKY UTILITIES COMPANY	))))))	CASE NO: 2003-00434

TESTIMONY OF
PAUL W. THOMPSON

SENIOR VICE PRESIDENT, ENERGY SERVICES
LG&E ENERGY CORP.
LOUISVILLE GAS AND ELECTRIC COMPANY
KENTUCKY UTILITIES COMPANY

December 29, 2003

Filed: December 29, 2003

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

A. My name is Paul W. Thompson. I am employed by LG&E Energy Services, Inc. I am the Senior Vice President, Energy Services for LG&E Energy Corp. ("LG&E Energy"), Louisville Gas and Electric Company ("LG&E"), and Kentucky Utilities Company ("KU" or "the Company"). 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 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 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. 97-300, *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 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. 2003-00266.

Q. **Please provide an overview of your testimony, and comment on the Company's request for a base rate increase in this case.**

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. KU has always strived to offer its customers an exceptional value in electric service by striking a balance between two key attributes: low price and high reliability. The Company's success in achieving this balance to date – measured at least in part by KU's ability to avoid a base rate increase for 20 years, despite national and industry-specific cost pressures – is a credit to the Company's innovation and initiative.

The innovative steps taken to this point, however, are no longer sufficient to offset the increasing cost of meeting the Company's service obligations and commitments. As demonstrated in my testimony and the testimonies of Bradford Rives and Chris Hermann, the Company is at a point where it must implement a base rate increase to reflect fully the costs of providing reliable service to its customers, thereby allowing it 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 Company's 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 KU's customers.

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. 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 4,100 MW of generating capacity with a net book value of approximately $760 million. The Company serves approximately 508,000 electricity customers over a transmission and distribution network extending across 77 counties. KU's transmission plant covers approximately 4,450 circuit miles, and has a net book value of approximately $210 million. KU provides its customers with some of the lowest-cost energy in the nation.

Q. What efforts has Energy Services undertaken in the last several years to create efficiencies and manage costs?

A. Energy Services has undertaken a number of initiatives over the last several years aimed at managing costs through enhanced 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 KU's assets and eliminate costly duplication and other inefficiencies 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 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 KU's asset management initiatives?

A. Yes. On the generation side, Energy Services recently 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, KU has begun to install digital control technology (Distributed Control Systems or DCS) across parts of its generation fleet, allowing the Company 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 KU's operating and maintenance staff.

Further, and again on the generation side, KU has transitioned from a more rigid, time-based preventive maintenance approach to a predictive, reliability-centered maintenance process, allowing KU to efficiently prioritize and allocate maintenance activities and resources consistent with the actual needs of its equipment, as determined by the Company consistent with prudent utility practice. Under KU's 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.

Q. Has KU implemented any technological initiatives to support its reliability-centered maintenance process?

A. Yes. KU utilizes MAXIMO®, a computerized maintenance management system that complements and supports KU's reliability-centered maintenance process. The MAXIMO® system tracks anomalous test results, equipment operating problems, and equipment failure trends. MAXIMO® also stores replacement/spare part information and makes that information readily accessible; and tracks testing schedules and any corrective or preventative work undertaken, allowing KU to manage its resources as efficiently as possible over their respective lifecycles.

Q. Please provide an example of asset management as applied to KU's transmission operations.

A; KU has optimized the use of its transmission system assets through various means. First, Energy Services has adopted enhanced data collection and analysis capabilities similar to those offered by MAXIMO® on the generation side. Specifically, the Company has enhanced the real-time diagnostics capabilities of its Energy Management System ("EMS"), a computer-based network control system designed to continuously monitor (and store) various transmission data.

In addition, KU has begun 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 Company's assets. One indication of this productivity increase is the significant decrease in the number of Transmission Line Loading Relief ("TLR") directives called on KU's system by KU's regional transmission grid operator since the Company's adoption of a thermal-based rating approach.

Further, KU 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 continuous monitoring capabilities.

Q. **In addition to the asset management initiatives you just described, has KU 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 KU and LG&E merger), KU has increased its employee training and capabilities with respect to both its 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, continuous emission monitor testing services). 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.

Q. Please explain why the use of a variable workforce is well-suited to Energy Services.

A. With regard to transmission, work performed on the transmission system typically consists of sporadic, large-scale, projects. Such work calls for the periodic use of varying types of expensive, heavy equipment that, if separately owned by the utility, could sit idle for several months each year. Accordingly, it is more cost-effective to outsource most of this work to capable and qualified contractors. KU currently uses four transmission line contractors and two right-of-way clearing contractors to undertake transmission maintenance and repair projects, as applicable, throughout the year.

Similarly, with respect to generation, the Company uses a variable workforce primarily for periodic scheduled maintenance and other specific projects such as boiler retrofits, coal mill overhauls, duct work refurbishment, and cooling tower reconstruction. Again, the reasons are straightforward: the periodic nature of the work involved and the level of specialization required call for the use of specialists contracted on a project-by-project basis. Such practice is not only supported by economics, but it also, because of these contractors' specialized focus, fosters both reliability and safety in the repair of major system components.

Q. How has the reliability of KU's generation system fared over the last several years?

A. KU's generation system as a whole has 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' combined system 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; the system-wide EFOR for the coal-fired generating units was 6.8 percent in calendar year 1999, 4.1 percent in calendar year 2000, 5.4 percent in calendar year 2001, 10.5 percent in calendar year 2002, and only 4.7 percent through November 2003. Although these numbers do show that Energy Services experienced difficulties in 2002, reliability performance has dramatically improved in 2003.

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

A. KU's internal analyses show a relatively consistent upward trend in the steam capacity factor of the Company's coal-fired baseload generating units since 1991. As of November 2003, the year-to-date average steam capacity factor of the Company's coal-fired units was almost 70 percent.

Q. Would you explain in more detail how KU benchmarks the reliability of its generation assets to others in the industry?

A. KU and LG&E perform their reliability (again, as measured by an Equivalent Forced Outage Rate or "EFOR") benchmarking on a combined system basis (the combined system EFOR is determined by capacity weighting the average of each individual coal unit EFOR target) and on a similar unit basis. The benchmarking exercise is essentially a two-step process. First, KU and LG&E establish a "target" performance quartile for each unit, based on the Company's determination of the appropriate balance of reliability and cost. For example, KU has historically targeted second quartile performance for its baseload units at its Tyrone and Green River facilities, in recognition of these units' lower capacity factors and age. It does not make economic sense to target top quartile performance for these units, given the incremental costs necessary to achieve such top quartile status.

Second, once a target performance quartile is established, LG&E and KU compare the actual EFORs of the units and the combined system EFOR to the EFORs of (i) baseload coal-fired units nationwide, and (ii) a more limited group of generating units with characteristics most comparable to KU's and LG&E's units. KU relies on EFOR data reported by other utilities to the North American Electric Reliability Council ("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, LG&E's/KU's overall system EFOR (the capacity weighted average EFOR of all coal-fired generating units) consistently achieves top 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. Has KU invested any capital in its generation system for reliability purposes over the last several years?

A. Yes. Most of the Company's coal-fired generating units were built before 1980. Only Ghent Unit Nos. 3 and 4 were built after 1980. Because of the corrosive and extremely high temperature, high pressure environments in which these units operate, KU has had to make significant incremental capital investment in its coal-fired units over the last several years to ensure their safe and reliable operation. Specifically, KU, among other things, has installed new distributed control systems, replaced turbine blading and coal handling equipment, built cooling towers, and refurbished boilers and precipitators across the fleet.

In addition, KU has added six new gas-fired combustion turbines (jointly owned with LG&E) for increased system capacity, particularly during peak periods. These units, jointly owned by LG&E and KU, are a product of the Companies' joint planning capabilities, which allow for the most efficient procurement and use of capacity system-wide. Specifically, KU has added approximately 635 MW of gas-fired combustion turbine capacity since the summer of 1999, at a cost of $218 million. Another 383 MW of combustion turbine capacity is scheduled to come on-line by the summer of 2004, at a cost through September 30, 2003 of $108 million. KU has long recognized the importance of maintaining an adequate reserve margin of capacity, and the volatile pricing in the late 1990's and the experience of California have only strengthened its resolve in this regard. For generation planning purposes, KU currently targets a reserve margin of 14 percent, within a range of 13 percent to 15 percent. The added combustion turbine capacity is of key importance in achieving this reserve margin target.

Q. Turning to transmission, how has the reliability of KU's transmission system fared over the last several years?

A. Like its generation system, KU's transmission system has historically been highly reliable, a consequence, at least in part, of the Company's commitment to, and membership in, the East Central Area Reliability Council, a regional member of NERC. It is incumbent on KU to take whatever prudent steps are necessary to comply fully with the relevant reliability standards set by NERC, whose mission is to ensure that the bulk power system is dependable, adequate and secure. KU takes its responsibilities seriously in this regard.

Apart from its commitment to meet the reliability criteria established by NERC, KU tracks, for internal purposes, the average duration of service interruptions related to transmission. Because KU's transmission system is integrated with the transmission system of its sister company, LG&E, KU tracks performance on a combined company basis. Although a duration of service interruption tracking measure is of limited value to transmission systems, KU uses this measure to gauge and trend its performance over time, and has historically fared well. In fact, on a combined-company basis, reliability performance has consistently surpassed performance targets on an annual basis.

Q. Has KU made any capital or other investments in its transmission system over the last several years?

A. Yes. KU invested more than $40 million over the last four years to preserve the reliability of its transmission system. Among other things, the Company has increased transformer capacity in areas of high load growth and added transmission lines to serve as back-up circuits in the event primary circuits are interrupted. In addition, KU expended approximately $9 million during this period in vegetation management.

Q. You indicated earlier that KU has a strong interest in promoting a safe working environment for its workforce. Please discuss KU's safety performance in the areas of generation and transmission.

A. KU has worked extremely hard to develop a higher level of trust and partnering among our employees to move towards our ultimate goal of zero injuries in the workplace. We have also performed better and more consistent hazard assessments to prevent the occurrence of injuries. In fact, based upon a comparison of recordable injuries for the years 2002 and 2003, there were approximately 50 percent fewer recordable employee injuries in the first 11 months of 2003, as compared to the same period in 2002; and approximately 30 percent fewer injuries in calendar year 2002, as compared to calendar year 2000. The trend is clearly encouraging.

Q. Does KU's use of independent contractors compromise KU's commitment to safety in any way?

A. Absolutely not. Based upon current contractor injury trends, our contractors have a safety rating that beats the most recent national benchmark by 32 percent. Although we are pleased with that performance, our goal is zero injuries, for both employees and contractors, and we will continue to focus on safety for our entire 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, overlapping objectives: (i) maximizing the performance and investment life of the Company's 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 KU's 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 Company cannot continue to meet these goals without the ability to adequately recover its costs. A base rate increase now will allow KU to continue to provide the reliable service its customers have grown to expect, at rates still ranking among the lowest in the nation.

Q. Does this conclude your testimony?

A. Yes.

290528.15

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 LG&E Energy Corp., Louisville Gas and Electric Company and 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.

Paul W Thompson

PAUL W. THOMPSON

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 29th day of December 2003.

Melody L. Hulse

Notary Public (SEAL)

My Commission Expires:

November 24, 2007

APPENDIX A

Paul W. Thompson

Senior Vice President, Energy Services
LG&E Energy Corp.
220 West Main Street
Louisville, KY 40202
(502) 627-3861

Education

University of Chicago, MBA in Finance and Accounting -- 1981
Massachusetts Institute of Technology (MIT), BS in Mechanical Engineering -- 1979
Leadership Louisville -- 1997-98

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

Civic Activities

Friends of the Waterfront Board
Library Foundation Board
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

Mr. Hermann

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:	)	
	)	
AN ADJUSTMENT OF THE	)	CASE NO: 2003-00434
ELECTRIC RATES, TERMS	)	
AND CONDITIONS OF KENTUCKY	)	
UTILITIES COMPANY	)	

TESTIMONY OF
CHRIS HERMANN
SENIOR VICE PRESIDENT – ENERGY DELIVERY
LG&E ENERGY CORP.
LOUISVILLE GAS AND ELECTRIC COMPANY
KENTUCKY UTILITIES COMPANY

December 29, 2003

Filed: December 29, 2003

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

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

Q. Please describe your educational and professional background.

A. I received a B.S. degree in Mechanical Engineering from the University of Louisville in 1970. I joined LG&E that same year. In 1978, I began working for LG&E as the Plant Manager for the Cane Run generating station. I held a number of other positions before assuming my current duties in December 2000. 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 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. Our mission is straightforward. We strive to provide safe, reliable, and low cost service to our customers while maintaining excellent customer satisfaction. As a constant backdrop to these objectives, we must also achieve sufficient earnings and earnings growth opportunities to continue to accomplish our customer-oriented goals.

Q. Have you previously appeared before this Commission?

A. Yes. I have appeared before this Commission in informal conferences and participated in the merger proceedings of LG&E and KU before the Kentucky Public Service

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. PURPOSE OF TESTIMONY AND DESCRIPTION OF BUSINESS

Q. What is the purpose of your testimony?

A. By effectively managing costs, KU has been able to provide reliable, safe service for years without having to seek base rate increases. My testimony will describe how KU has been able to accomplish this goal for our retail operations and electric distribution business, and will explain why a rate increase is needed at this time.

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

A. Despite the cost management initiatives undertaken by the Company over the last several years, as discussed below and in the testimony of Paul W. Thompson, the Company is now at a point at which we must implement an increase in our electric base rates in order to continue to provide the reliable, safe service our customers have come to expect while also being afforded the opportunity to earn a reasonable return on our investment. KU's base rates for electric service must be adjusted to a level which will provide KU: (1) the ability to generate sufficient revenue to continue to provide safe and reliable service to its customers; (2) the ability to maintain its financial integrity; and (3) the ability to adequately compensate investors for the risks assumed with respect to its operations.

It has been nearly twenty years since KU's base rates were last increased, and four years since its electric rates were reduced and reset in conjunction with the establishment of KU's Earnings Sharing Mechanism ("ESM"). As set out in detail in the testimonies of S. Bradford Rives, Valerie L. Scott and Robert G. Rosenberg, KU's current rates do not provide sufficient revenue to recover the costs of its electric business including a fair and reasonable return on investment.

Q. Please describe KU's electric distribution business.

A. KU's distribution business serves about 478,000 electric customers in 77 counties across the Commonwealth. The electric distribution assets we manage include over 460 substations and over 15,000 miles of electric lines. Our electricity is primarily produced by our coal-fired generating stations which are discussed in greater detail in the testimony of Mr. Thompson.

Q. How does the Energy Delivery division operate and maintain 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 supply to our customers in the event of outages, emergencies, or damage to our distribution system. We also provide the associated 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 low costs, excellence in safety, customer satisfaction, and reliability in the provision of energy services. We also provide energy conservation options to our customers, including innovative programs like Demand Conservation. And, of course, we strive to achieve award-winning levels of customer satisfaction.

II. EFFORTS TO ACHIEVE EFFICIENCIES

Q. Please describe KU's initiatives and efforts in recent years to manage costs from a retail and electric distribution standpoint.

A. Over the past several years, we have undertaken a number of initiatives aimed at managing costs by increasing efficiencies and achieving synergies, while maintaining safety, reliability, and customer satisfaction. Following the merger of KU and LG&E, we implemented our "One Utility" initiative. That initiative was followed by our "Value Delivery" initiative.

Q. What are some the key business practices that KU uses to achieve efficiencies and maintain low operating costs?

A. KU has adopted process changes focusing on asset management, improved work practices, and new technologies that have helped achieve operating efficiencies and synergies, and, in turn, mitigate the increased costs of doing business. I will discuss each of these practices throughout my testimony.

Notwithstanding our constant focus on cost management and performance, we are now at the point where our revenues are insufficient to continue to meet customer demand, provide safe and reliable service, and position ourselves to meet the needs of our customers. We want to be able to continue to offer some of the lowest rates in the industry, and to also maintain reliable and safe energy delivery and high levels of customer service.

Q. Describe how asset management has changed the ways in which KU's distribution operation is managed.

A. Since the merger of LG&E and KU, we have created an asset management organization. Asset management relies in part upon improved system modeling and analysis techniques. Enhanced assessment capabilities support the development of optimum repair or replacement decisions as well as optimum identification and timing of system enhancement investments required to serve growing system loads. KU's asset management processes focus on three main areas: (1) operating policies and standards, (2) investment strategy, and (3) asset information.

Our operating policies and standards area focuses on the development of materials standards, design and construction standards, operating/maintenance standards, Reliability Centered Maintenance programs, practices and procedures for regulatory compliance, and benchmarking. These activities allow us to adopt uniform practices and material standards across all areas of LG&E's and KU's energy distribution activities, and to thereby better manage our costs.

Our investment strategy area allows KU and LG&E to better plan their short- and long-term investment activities to ensure compliance with regulatory guidelines and to optimize asset life cycles.

Our asset information area includes facility and equipment data, records management, and asset history data which will allow us to more readily determine the condition of our assets and their performance.

These functions are designed to give us more information to help us better assess the assets that we own. In turn, asset management functions help us to determine how best to manage and optimize asset life cycles in order to maintain operating and spending efficiencies.

Q. Can you provide an example of asset management as applied by LG&E and KU?

A. Yes. One example is the use of Reliability Centered Maintenance ("RCM") processes. The RCM process relies upon a condition-based diagnostic maintenance program supporting appropriate funding and prioritization of maintenance activities and resources. Equipment operation is now tested as a first step in the maintenance process. If the equipment test results show that it is operating within acceptable parameters, further maintenance can be avoided until the next scheduled test. Testing schedules can be time-based; they can be based on the number of equipment operations, or they can be based on other factors. Before we implemented RCM, KU practiced a time-based and invasive maintenance process on its substation equipment. Large substation equipment would be completely dismantled and overhauled regardless of current or historical equipment performance. Equipment overhauls are very time-consuming, and thus expensive. In some cases we were completing extensive, invasive maintenance on equipment that had experienced very few operations and was performing well within the prescribed parameters. The move to a condition-based diagnostic maintenance process has reduced maintenance costs by optimizing maintenance schedules and activities based on our risk analyses, testing results, and actual experience with equipment makes and models.

Q. In addition to asset management, has KU undertaken other new work processes and methods?

A. KU has implemented several important work process improvements, such as Contractor Performance Management and materials outsourcing.

Q. Please discuss how KU manages its use of contractors.

A. KU outsources a portion of its activities for two reasons: (1) to reduce costs (e.g., for substation maintenance); or (2) to provide for a variable workforce (e.g., for construction requirements driven by load growth). An important aspect of outsourcing is the selection of quality contractors and the efficient management of those contractors. KU solicits bids based upon specific criteria, such as safety records, cost structures, resource capabilities, and worker qualifications, when selecting its contractors in order to retain only high quality contractors. KU has instituted a Contractor Performance Management initiative, which has allowed us to more effectively manage our contractors. That initiative involves a focus on safety, cost management and quality of work. KU establishes measurements and controls designed to ensure the productivity, safety, and quality of the work performed by our contractors. We also provide contractors with reviews and feedback on their performance and, as a part of that process, establish targets for unit measures of the work to be performed. Many of KU's Contractor Performance Management processes incorporate the use of incentive mechanisms to increase productivity without diminishing reliability or safety.

Q. Did the use of a variable contractor workforce prove valuable to KU in managing the February 2003 ice storm?

A. Yes. During the ice storm of February 2003, more than two inches of ice accumulated on wires, electric poles, and trees. The weight of the ice was more than eight times the structural design for the infrastructure of KU's electrical system. Damage caused by the ice storm resulted in interruption of service to 141,000 KU customers. Restoration efforts began immediately, with an initial focus on the critical community organizations and facilities affecting the majority of customers. Thanks in large part to the immediate availability of a variable workforce, KU was able to mobilize a workforce of over 2,000 people which included 483 LG&E and KU employees and 1,851 contract workers from regional utilities to assist with the restoration work. These workers were able to restore service to the majority of KU's customers by week's end, and within one week, all but 9,000 customers had their service restored and over 4,500 miles of electric line were inspected. While the storm enabled KU to identify issues to improve overall restoration response and customer service, overall KU repaired the storm damage effectively and efficiently.

Q. What is materials outsourcing and how has it helped achieve efficiencies?

A. Materials outsourcing allows us to shift the responsibility from KU to our suppliers for managing, handling and delivering electric materials. KU initiated this process in mid-2002.

Under this process, materials orders are sent directly to the supplier's warehouse and the materials are delivered on a timely basis consistent with our work schedules. This outsourced materials handling process has allowed the Company to reduce in-house inventory and materials handling costs.

Q. Please describe some of the recent information systems in which KU has invested.

A. KU has implemented new information technology such as GEMINI, MAXIMO®, IVRU, and SMILE. They are designed to help us to better serve our customers.

Q. Please describe GEMINI and some of the efficiencies it can help to create.

A. The Geospatial Enterprise Management Integration Network Initiative ("GEMINI") will allow LG&E and KU to obtain improved data, thus allowing us to better manage and optimize our work force to achieve efficiencies. Specifically, GEMINI will help the two companies through improved work order scheduling and improved response to customer requests for service through streamlined data access and management. Secondarily, but importantly, GEMINI also allows us to provide customers with better information on the status of service restoration and service installations. This system integrates a work management system, outage management system, geographic information system, and graphical work design system.

GEMINI will be utilized by both KU and LG&E. The outage management component will 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. The work management function will keep track of planned construction work and available internal and external construction personnel to enable effective and efficient use of these resources. The Geospatial Information System ("GIS") will overlay geographical data such as roads and other landmarks in order to more reliably and effectively locate our distribution facilities. We have spent a total of $27 million to date on our GEMINI technology, including costs for software, hardware, supporting infrastructure, and data conversion.

Q. Please describe MAXIMO® and some of the efficiencies it can help to create.

A. LG&E and KU have completed the installation of the MAXIMO® maintenance management system. The MAXIMO® system is designed to identify, analyze and maintain physical assets such as substations. The MAXIMO® maintenance management system tracks equipment condition, testing results, and maintenance/testing schedules. MAXIMO® can flag test results that are out of range, equipment operating levels triggering scheduled maintenance, regulatory compliance maintenance schedules, and testing schedules, in order to optimize maintenance activities. This innovative technology also helps achieve efficiencies by accurately tracking materials and their usage, thus allowing for the maintenance of appropriate inventory levels. It allows us to track maintenance work and testing performed on our assets so that we can optimize our resources and maintain productivity. MAXIMO® supports our ability to implement consistent maintenance practices throughout the distribution operations of LG&E and KU.

Q. Describe KU's efforts to achieve efficiencies in the provision of its retail call-center and other customer services.

A. One of the ways in which we have achieved operational efficiencies is through the integration of the LG&E and KU call centers. Those call centers, located in Louisville, Lexington and Pineville, operate together as a single virtual call center. The three center locations were integrated in 2001 so that calls can be answered by representatives in any location. It is only through new technology that these call centers can operate as if they were located in one physical location. These technologies are used to provide timely responses to customers by managing the call load among the three centers, allowing a customer to report an outage or request service without undue delay.

The Integrated Voice Response Unit ("IVRU"), which we implemented in late 1999, allows us to keep costs down, to handle larger volumes of calls, and to route calls more effectively to representatives with the most appropriate skills based upon the customer's stated reason for calling.

We have also engaged in specialized training of our representatives to better respond to customer inquiries, and have started utilizing bilingual staff to better serve and communicate with our growing number of Hispanic customers. Procedural changes, such as the use of an open queue, which eliminates busy signals, have also been implemented. As a result of procedural changes and streamlined operations, the average wait time to speak with a customer service representative has decreased from almost two minutes in 2000 to just over 30 seconds in 2003.

Q. Please describe the SMILE system and some of the efficiencies it can help to create.

A. One of our new information systems is called SMILE. SMILE is an acronym for "Service Makes It Look Easy." The SMILE system creates a common data presentation system for data drawn from both the LG&E and KU customer information systems. This single system manages the data in such a way as to assist KU and LG&E customer representatives to be trained more efficiently and effectively to respond to inquiries from either LG&E or KU customers. The use of the SMILE system has facilitated KU's efforts to create a virtual call center, optimize call center personnel, and reduce training time.

III. MEETING CUSTOMER GROWTH AND OTHER CHALLENGES

Q. What have been some of KU's more significant challenges?

A. Maintaining high levels of safety, reliability and customer satisfaction with increased electric customer growth have presented significant challenges for KU over the past several years.

Q. Describe the impact of customer growth on KU.

A. As a utility, we have a public service obligation to serve all customers in our electric service area. We make continuing investments in our utility infrastructure in order to meet the demands of new and existing customers.

The increased number of electric customers over the past several years has been quite significant. In the time frame since KU's ESM was first placed into effect in 2000, our net customer count at KU has grown by almost 30,000 customers, and the Company has expended about $193 million in capital on its electric distribution business. These increases put additional strain on our system and require additional capacity. As noted, we have a public service obligation to serve these customers. New distribution facilities required to serve new customers account for almost 70% of the capital expended in KU's electric distribution system.

IV. BENCHMARKING: SAFETY, RELIABILITY, AND COST MANAGEMENT

Q. Discuss the role of benchmarking in KU's retail and distribution operations.

A. We continually benchmark our distribution and retail activities (both against others in the industry and against our own prior achievements) not merely to measure our performance, but also to better understand our performance. Our benchmarking activities focus on areas such as reliability, safety, and cost management. For example, as indicated below, we have a "No Compromise" policy in the area of safety, and benchmarking is one tool used to determine the effectiveness of our safety efforts.

Benchmarking enables us to identify areas of focus and to validate how we operate our retail and distribution businesses. We believe that benchmarking, in the appropriate context, is a valuable management tool.

Q. Please discuss the Company's commitment to safety and its overall safety performance.

A. We have a "No Compromise" policy on safety that emphasizes individual accountability. This policy 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. Our goal is a low-risk, safe work environment. Our "No Compromise" policy states that it is unacceptable for anyone to work in an unsafe manner. In order to ensure that the policy is operating as it should, we utilize such programs as random field audits, safety tailgates, and quarterly safety meetings.

By leveraging the synergies and resources available to both KU and LG&E, we have been able to move from an environment with different programs operating at different levels to a safety program for the whole of Energy Delivery which exceeds the mandates of both OSHA and the National Electrical Safety Code ("NESC"). We have also received numerous Governor's Safety and Health Awards; our OSHA recordable incident rates are significantly below the national average, and our OSHA recordable incident rates continue to decline. In fact, our benchmarking efforts, in terms of safety, demonstrate that we are a leader in the industry.

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

A. The reliability of our electric service is measured by tracking the system's average length of interruption and the system's average frequency of interruption. Our electric reliability measures for the duration and frequency of interruptions from 1999 through 2002 represent improvements from our 1998 performance measures. These post-merger measures represent solid performance when compared to the industry.

However, our measures indicate an upward trend in the duration and frequency of interruptions. We are concerned about that trend and, in response, are increasing our focus on reliability. Our focused efforts will help to target our reliability-related investments in order to reverse this trend.

Q. How has KU performed in the area of cost management?

A. One cost management benchmark on which we focus is cash cost per customer. Cash cost per customer measures the combination of operating/maintenance costs and capital costs expended on a per customer basis. In terms of cash cost per customer, KU is a low cost provider in the industry.

Benchmarking is one tool that helps us maintain the proper balance between cost and reliability. KU delivers reliable electric service at a reasonable cost. We are seeking this increase in our revenues in order to continue to maintain the appropriate balance between cost and reliability.

V. CUSTOMER SATISFACTION AND FOCUS

Q. Describe KU's customer satisfaction levels.

A. KU continues to be nationally recognized for its strong customer focus and outstanding customer satisfaction. J.D. Power and Associates ranked LG&E Energy (LG&E and KU) first in the Midwest in its 2003 residential survey of the nation's 77 largest electric utilities. LG&E Energy also ranked highest nationally in customer satisfaction in J.D.

Power's 2003 survey of midsize business customers. The J.D. Power electric studies focus on customer service, power quality and reliability, company image, price/value and billing. In total, we have earned eight J.D. Power awards for customer satisfaction since 1999.

Q. How has KU achieved such excellence in customer satisfaction?

A. The bedrock of excellence in customer satisfaction is the efforts of our hardworking employees. Not only have they formulated the initiatives discussed above, they have implemented them. In addition to those initiatives, KU has instituted a number of programs designed to improve customer service and satisfaction, including customer self-service through the Internet using electronic billing and payment. Customers participating in our electronic billing program receive an e-mail each month instead of a traditional paper bill. A special link in the e-mail allows members to view their bill and bill inserts, along with a detailed account of their usage and billing history. For added convenience, customers can also pay their bill through the Internet or by phone. This program is an easy, convenient way for customers to pay their bill quickly and at any time, day or night. It is safe and secure and offers customers freedom from writing checks, buying postage stamps and worrying about postal delays.

Still another option available to customers is our Automatic Bank Club ("ABC") program. Our ABC program eliminates the need for customers to write checks, pay for postage, and mail their payments. Instead, the amounts owed by customers are deducted automatically from the customer's checking account on the due date. The ABC program is also cost-effective for KU, because handling and process costs are reduced.

Customers may also receive a credit for helping the environment and mitigating peak load growth by signing up for the Demand Conservation program. As part of Demand Conservation, electric customers reduce energy demand by signing up for a program under which a device is connected to their central air conditioner which controls the cycling of the unit. Demand Conservation helps 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. As a reward, a customer's utility billing is credited up to $20 annually, per central air conditioning unit.

VI. CONCLUSION

Q. Can you briefly summarize your testimony?

A. Yes. KU and LG&E have undertaken a number of efforts over the past few years in an effort to achieve efficiencies and maintain low operating costs, all the while striving to meet challenges arising from increased customer demands and increased costs. KU's current rates do not provide sufficient revenue to recover the expenses incurred to maintain safety, reliability and high levels of customer satisfaction and allow for a reasonable return. As a result, our base rates must be increased.

Q. Does this conclude your testimony?

A. Yes.

290551.12

VERIFICATION

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

The undersigned, **Chris Hermann**, being duly sworn, deposes and says he is the Senior Vice President – Energy Delivery for LG&E Energy Corp., Louisville Gas and Electric Company and 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.

CHRIS HERMANN

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 29th day of December 2003.

Notary Public (SEAL)

My Commission Expires:

Notary Public, State at Large, KY
My commission expires Nov. 5, 2006

Appendix A

Chris Hermann

Senior Vice President – Energy Delivery
LG&E Service Company
220 West Main Street
Louisville, Kentucky 40202
(502) 627-2703

Education

University of Louisville, B.S. in Mechanical Engineering -- 1970
Duke University – Program for Management Development
Harvard University – Program on Negotiations
Edison Electric Institute – Program on Senior Middle Management
E.ON Executive Program—Leading Corporate Transformation, Harvard University

Previous Positions

LG&E Service Company, Louisville, KY:
December 2000 – Present -- Senior Vice President Distribution Operations

Louisville Gas and Electric, Louisville, KY:
January 2000 – December 2000 -- Vice President Supply & Logistics
May 1999 – December 1999 -- Vice President Business Integration
June 1998 – April 1999 -- Vice President Power Generation & General Services
May 1997 -- May 1998 -- Vice President Business Integration
1993 -- May 1997 – V.P. 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
1977 – 1978 – Assistant Plant Manager, Cane Run
1974 – 1977 -- Efficiency Engineer, Cane Run
1970 – 1974 – Mechanical Engineer

Professional/Trade Memberships

American Management Association
American Society of Mechanical Engineers
Association for Quality Participation
Southern Gas Association Executive Council
American Gas Association Leadership Council

Previous Professional/Trade Memberships

OVEC (Ohio Valley Electric Corp) -- Board of Directors & Executive Committee
EEI 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 Executive Board and Executive Board Working Group

Present Civic Activities

Louisville Orchestra Development Committee --2001, 2002, 2003
University of Louisville Speed Scientific School:
Board of Industrial Advisors -- 1992 - current

Previous Civic Activities

Redeemer Lutheran Church:
President of Congregation -- 1984 – 1997, 1999 – 2002
Chairman Call Committee, 1999 -- 2000
Chairman of Building Committee -- 1985 – 1991
Fund for the Arts Corporate Campaign – 2002
Technology Network of Louisville:
Executive Committee Member – 2002
Founding Member -- 2001
Board Member -- 2001, 2002
Advanced Technology Council – Board Member – 1999, President – 2000
Leadership Louisville -- 1994
Bingham Fellows Class of 2000
LG&E Employees Credit Union:
Chairman of the Board -- 1984 - 1992
Board Member -- 1978 - 1992
University of Louisville: Board of Overseers' Mentor Program -- 1993 – 1994
University of Louisville: Commissioner, Bicentennial Celebration
University of Louisville Speed Scientific School:
Elected Chairman Board of Industrial Advisors for 1993 - 1994
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

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In Re the Matter of:	)	CASE NO. 2003-00434
AN ADJUSTMENT OF THE ELECTRIC RATES, TERMS AND CONDITIONS OF KENTUCKY UTILITIES COMPANY	))))	

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

December 29, 2003

Filed: December 29, 2003

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

A. My name is S. Bradford Rives. I am the Chief Financial Officer for LG&E Energy Corp. and Kentucky Utilities Company ("KU"). 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 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 conditions of KU require 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 September 30, 2003, and support the different valuations of KU's property.

KU's Current Financial Condition

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

A. As pointed out in the testimonies of Mr. Victor A. Staffieri, Mr. Paul Thompson and Mr. Chris Hermann, KU's operational performance remains strong, but its financial condition has substantially deteriorated. Even with ongoing initiatives to control costs and improve efficient operations described by Mr. Thompson and Mr. Hermann, KU's financial results for the twelve-month period ending September 30, 2003, are well below a reasonable level.

It is essential that KU achieve and maintain a strong financial condition to allow it to continue to provide safe, reliable service to its customers. Despite KU's substantial cost reductions and process improvements, KU's revenues must be adjusted to reflect its cost of providing service and to continue to effectively meet its service obligation both now and in the future. KU's weakened current financial condition is not in the best interest of its shareholders or its customers. Approval of this rate increase is imperative to improve the Company's financial health.

Q. Has KU's investment in utility plant increased since December 31, 1998, the test period used by the Commission in Case No. 98-474?

A. Yes. The following chart shows KU's investment in net utility plant has increased by approximately $450.3 million since December 31, 1998:

Net Electric Utility Plant

	December 31, 1998	September 30, 2003	Increase
Electric utility plant	$2,685,527,353	$3,527,901,229	$842,373,876
Accumulated depreciation	1,208,182,682	1,600,258,255	392,075,573
Net electric utility plant	$1,477,344,671	$1,927,642,974	$450,298,303

Q. Did KU earn its authorized return on equity in 2002 or for the twelve months ended September 30, 2003?

A. No. The results of KU's annual earnings sharing mechanism for 2002 shows the Company earned a return on equity of 7.9% and a return on capital of 6.16% well below the 11.5% return on common equity and the overall cost of capital of 9.58% approved by the Commission in Case No. 98-474. For the twelve months ended September 30, 2003, the return on equity has further declined to 6.22% and the return on capital has declined to 4.63% for electric operations.

Based on the analyses presented in Mr. Robert G. Rosenberg's testimony, he has determined that the return on equity for KU's electric operations should be in the 10.75% – 11.25% range and has recommended the Commission adopt an 11.25% allowed rate of return on equity in this proceeding. This equity return is necessary for the Company to regain and preserve its financial health. However, as my testimony has shown, KU's earned return on common equity for the twelve-month period ending September 30, 2003, is well below this return

For the reasons described in my testimony, the Commission should approve KU's proposed adjustment to base rates to afford KU the opportunity to earn a reasonable return on common equity of 11.25%.

<u>PSC Financial Exhibits</u>

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

A. Yes. The Financial Exhibit required by this regulation was filed with KU's Application in this case and includes the required financial information for the twelve months ended September 30, 2003.

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 of 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 Ms. 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.

Net Operating Income

Q. Please describe Rives Exhibit 1 and its purpose.

A. Rives Exhibit 1 shows electric operating revenues and expenses, and net operating income per books for electric jurisdictional operations, for the twelve months ended September 30, 2003. 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 the 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. A further description of, and support for, each adjustment is contained in supporting Reference Schedules 1.00 through 1.36 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 September 30, 2003 on Rives Exhibit 1.

A. For the electric operations as reflected in the twelve month period ended September 30, 2003, KU has made adjustments which:

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

b) Remove the impact of items included in other rate mechanisms (Reference Schedules 1.01, 1.03, 1.05, 1.07, 1.08, 1.09, 1.20 and 1.22),

c) Annualize year end facts and circumstances and adjust for other known and measurable changes to revenues and expenses (Reference Schedules 1.02, 1.04, 1.06, 1.10, 1.11, 1.12, 1.13, 1.16, 1.17, 1.24 and 1.35),

d) Adjust for other excludable unusual, non-recurring or out-of-test period items in the test year (Reference Schedules 1.14, 1.15, 1.18, 1.19, 1.21, 1.23, 1.25, 1.26, 1.27, 1.28, 1.29, 1.30, 1.31, 1.32, 1.33, and 1.36), and

e) Adjust for Federal and state income tax expenses for these pro-forma adjustments (Reference Schedules 1.34 and 1.37).

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. This adjustment was prepared by Mr. W. Steven Seelye and will be explained in detail in his testimony.

Q. Please explain the adjustment to operating revenues and expenses shown in Reference Schedule 1.01 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 September 30, 2003. This adjustment was prepared by Mr. Seelye and will be explained in detail in his testimony.

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

A. Reference Schedule 1.02 presents the adjustment necessary to annualize the full twelve months of the test year for the FAC roll-in as directed by the Commission's April 23, 2003 Order in Case No. 2002-00433. This adjustment was prepared by Mr. Seelye and will be explained in detail 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 removes environmental cost recovery revenues and expenses from net operating income because those revenues and expenses are addressed by a separate rate mechanism. This adjustment was prepared by Mr. Seelye and will be explained in detail in his testimony.

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

A. This adjustment has been made to reflect a full year of the environmental cost recovery roll-in as ordered in the Commission's October 17, 2003 Order in Case No. 2003-0068. This adjustment was prepared by Mr. Seelye and will be explained in detail in his testimony.

Q. Please explain the adjustment to operating revenues shown in Reference Schedule 1.05 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. 95-060 that KU should assign eligible environmental compliance costs attributable to off-system sales that are otherwise eligible for environmental surcharge recovery. This adjustment was prepared by Mr. Seelye and will be explained in detail 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 eliminate electric brokered sales revenues and expenses as directed by the Commission in Case No. 98-474. This adjustment was prepared by Ms. Scott and is discussed in her testimony.

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

A. This adjustment is necessary to eliminate the impact of the Earnings Sharing Mechanism revenues collected during the test period and not included in Rate Refund Account 449. The impact of rate mechanisms, like the Earnings Sharing Mechanism, should be removed from test year revenues when assessing the adequacy of base rates. This adjustment was prepared by Ms. Scott and is discussed in her testimony.

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

A. This adjustment has been made to eliminate the impact of the revenues recorded in the test year associated with the Earnings Sharing Mechanism, Environmental Cost Recovery and Fuel Adjustment Clause from Rate Refund Account 449. The impact of rate mechanisms, such as these, should be removed from test year revenues when assessing the adequacy of base rates. 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 1.09 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. The impact of rate mechanisms, like the demand-side management mechanism, should be removed from test year revenues when assessing the adequacy of base rates. This adjustment was prepared by Mr. Seelye and is discussed in his 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 annualize revenues based on actual customers at September 30, 2003. This adjustment was prepared by Mr. Seelye and will be explained in detail in his testimony.

Q. Please explain the adjustment to operating expenses shown in Reference Schedule 1.11 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 September 30, 2003. The calculation of the adjustment was prepared by Ms. Scott and is discussed in her testimony. The proposed new rates are based on a depreciation study conducted by AUS Consultants. The justification for these new rates is covered in Mr. Earl Robinson's testimony.

Q. Please explain the adjustment to operating expenses shown in Reference Schedule 1.12 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 September 30, 2003, and includes specific adjustments for wages, payroll taxes and KU's 401(k) match. 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 1.13 of Exhibit 1.

A. This adjustment is necessary to annualize pension and post-retirement medical benefit 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 1.14 of Exhibit 1.

A. This adjustment has been made to reflect a normalized level of storm damage 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 1.15 of Exhibit 1.

A. This adjustment eliminates advertising expenses, 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 include the expenses incurred in conjunction with this base rate case. 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 is necessary to reflect the expenses incurred by KU for the Earnings Sharing Mechanism audit. 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. The adjustment is necessary to remove the amortization of One-Utility costs as a non-recurring expense because these costs were completely amortized by September 30, 2003. 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 1.19 of Exhibit 1.

A. This adjustment is made to normalize the expense levels in Account 925 "Injuries and Damages." 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 1.20 of Exhibit 1.

A. This adjustment is to reflect the Value Delivery Team net savings to shareholders recognized by the Commission in its December 3, 2001 Order in Case No. 2001-169. The adjustment was prepared by Ms. Scott based on the values in the Value Delivery Surcredit Rider 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 is to true-up the Value Delivery Team customer surcredit and amortization of expenses approved by the Commission its December 3, 2001 Order in Case No. 2001-169. 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 1.22 of Exhibit 1.

A. This adjustment is made to reflect the current customers' and shareholders' portions of the merger savings approved by the Commission in its October 16, 2003 Order in Case No. 2002-00429. 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 1.23 of Exhibit 1.

A. This adjustment is necessary to reflect the elimination of merger amortization expenses from the LG&E Energy Corp. acquisition of KU Energy Corporation approved by the Commission in Case No. 97-300. The merger expenses were fully amortized by September 30, 2003. 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 necessary to reverse MISO Schedule 10 expense credits received in the test year that are not ongoing after 2003. 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 1.25 of Exhibit 1.

A. This adjustment is necessary to fairly reflect the adoption of SFAS 143, *Accounting for Asset Retirement Obligations*, for ratemaking purposes. 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 1.26 of Exhibit 1.

A. This adjustment has been made to reflect the October 2003, reduction of 27 employees in the Information Technology department of LG&E Energy Services, Inc. This adjustment was prepared by Ms. Scott and is discussed in her testimony.

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

A. This adjustment is necessary to remove expenses incurred by KU in connection with the Alstom combustion turbine litigation in the test year. This adjustment was prepared by Ms. Scott and is discussed in her testimony.

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

A. This adjustment is made to reflect the rate schedule switch by North American Stainless to KU's proposed Non-Conforming Load Tariff rate schedule. This adjustment was prepared by Mr. Seelye and will be explained in detail in his testimony.

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

A. This adjustment is for sales tax refund KU received during the test year that related to sales tax expenses incurred prior to 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 1.30 of Exhibit 1.

A. This adjustment is to reflect an increase in purchase power demand costs in the purchase power contract with Owensboro Municipal Utilities. 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 1.31 of Exhibit 1.

A. This adjustment is to reflect the normalization of net expenses incurred by KU as a result of the 36-hour ice storm during February 15 and 16, 2003. 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 1.32 of Exhibit 1.

A. This adjustment is for management audit fees for the 1992 Commission audit of KU. 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 1.33 of Exhibit 1.

A. The adjustment is to reduce operation and maintenance expenses for the amounts incurred for KU's Green River units 1 and 2 during the test period. Since these units will be retired by early 2004, these operation and maintenance expenses associated with these units should be removed from 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 for federal and state income taxes corresponding to the base revenues and expense adjustments discussed above. Reference Schedule 1.34 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 8.25%. As shown on the Reference Schedule 1.34, the composite federal and state income tax rate is 40.3625%.

Q. Please explain the adjustment to operating expenses shown in Reference Schedule 1.35 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 calculated following the methodology used by the Commission in its order in Louisville Gas and Electric Company ("LG&E") Case No. 2000-080. 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 has been applied to the interest synchronization amount.

Q. Please explain the adjustment to operating expenses shown in Reference Schedule 1.36 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 LG&E Case No. 2000-080.

<u>Capitalization and Weighted Average Cost of Capital</u>

Q. Please explain the capital structure strategy of KU.

A. As I have expressed in previous testimony before the Commission in Case No. 2001-104, 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. The midpoint of the total debt to total capital range for utilities with a business position "4" (KU's current business position) is 46.25%. This midpoint was established by Standard and Poor's in an article entitled "Utility Financial Targets Are Revised" dated June 18, 1999. The range established by Standard and Poor's is 43% to 49.5%. This indicates an acceptable range for the equity component of capital of 50.5% to 57%.

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 obligations in contracts with Electric Energy Inc., Owensboro Municipal Utilities, and Ohio Valley Electric Corporation. Although these contracts are attractively priced, the rating agencies consider these payments to be debt equivalents in establishing the ratings. Standard and Poor's recently released review of KU noted that they have imputed $125 million of debt equivalent to KU for 2003. If this adjustment is made to the capital structure shown in Rives Exhibit 2, KU's debt to total capitalization ratio increases to 49.38% - just below the maximum debt in the range published by Standard and Poor's. This indicates an equity component of capital of 50.62% (common and preferred), 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. Can you explain what is contained in Rives Exhibit 2?

A. Yes, Rives Exhibit 2 calculates adjusted capitalization as of September 30, 2003, as well as the weighted average cost of capital to apply to the adjusted capitalization.

Q. Please explain the calculation of the adjusted capitalization.

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 September 30, 2003. 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 6, column 1 equals line 1, column 2). Columns 3 through 8 are adjustments to capitalization that are totaled in column 9 of Rives Exhibit 2. The first three adjustments are to remove undistributed subsidiary earnings, to remove KU's equity investment in Electric Energy Inc., and to remove KU's investment in Ohio Valley Electric Corporation consistent with the adjustments approved in the Commission's Order in Case No. 90-158. The remaining three adjustments are the capital invested to repair the combustion turbines at Units 6 and 7 at the E. W. Brown Generation Station, to remove the capitalization related to the impending retirement of Green River Units 1 and 2, and to reverse the impact of KU's minimum pension liability adjustment to Other Comprehensive Income. Column 10 is the total of column 1 and column 9. Column 11 of Exhibit 2 contains the allocation factor to jurisdictionalize KU's Kentucky capitalization. The factor in column 11 was calculated based on net original cost base as shown on Rives Exhibit 3. Column 12 calculates the relative Kentucky jurisdictional capitalization components by multiplying column 10 by the factor in column 11. Column 13 equals column 12. Column 14 calculates the relative capitalization percentages of each component of capitalization to the total capitalization (e.g., line 1, column 13 divided by line 6, column 13 equals line 1, column 14). Column 15 removes KU's 2001 environmental surcharge plan using the relative capitalization percentage in column 14. Column 16 is the total of column 13 and column 15.

Q. Please explain the adjustment shown in Column 6 of Exhibit 2 for repairs to the E. W. Brown Power Station.

A. KU capitalized some of the repairs to the combustion turbines Nos. 6 and 7 at the E. W. Brown Power Station. In its settlement agreement with Alstom, KU will receive payments from Alstom in 2004 that reimburse the capitalized cost of these repairs. KU used its ownership percentage of the combustion turbines to allocate the settlement amounts. The adjustment to capital is necessary to remove the impact of the cost of the reimbursed repairs that are currently included in KU's capitalization and rate base.

Q. Please explain the adjustment shown in Column 7 of Exhibit 2 for the retirement of Green River Units 1 and 2.

A. KU plans to retire Green River Units 1 and 2 from service by early 2004. This adjustment is to reflect a reduction in capital employed for these two units.

Q. Please explain the minimum pension liability adjustment from Column 8 of Exhibit 2.

A. The purpose of this adjustment is to address the impact of SFAS No. 130, *Reporting Comprehensive Income*. With the issuance of SFAS No. 130, the FASB established the Other Comprehensive Income ("OCI") component of shareholders' equity, which included the offsetting balance sheet accounting for a minimum pension liability. SFAS 130 defines Comprehensive Income to include, in addition to net income of the owners, other changes in a company's equity from transactions and other events and circumstances from non-owner sources. The stated purpose of OCI is to report a measure of all changes in equity, not just those included in the income statement that result from transactions and economic events currently reflected in the determination of net income. These other changes, that are not currently reflected in net income, are called OCI items. SFAS No. 130's list of OCI items includes, among other things, minimum pension liability. For OCI items like minimum pension liability, the liability is fully recognized on the balance sheet but not yet on the income statement, because the losses these unrealized changes in value may eventually cause have not yet been realized and, as such, have not yet been included in the income statement under Generally Accepted Accounting Principles ("GAAP") as required by SFAS 87, *Employers' Accounting for Pensions*.

With this adjustment, KU is proposing to record a regulatory asset to match the recognition of the adjustment to equity for the minimum unfunded pension liability to recognize the resultant increase in future periodic pension expense that will result from the unfunded pension obligation. The proper ratemaking treatment of a minimum pension liability OCI equity charge would allow recording of a regulatory asset and the recovery of that asset in base rates through pension expense as the charge is realized.

GAAP does not permit the Company to record the <u>entire</u> OCI minimum pension liability amount as a pension expense on the income statement in the year in which the liability arises and is recognized on the balance sheet. Rather, GAAP provides for recording a portion of the minimum pension liability in periodic pension expense over time, if necessary – if the stock market performs better and interest rates rise, the pension underfunding may well disappear. Thus, the OCI adjustment results in a reduction to common equity for something that has not yet been reflected on the income statement because it is not a change in value that has been actually realized – it is only a contingency. It is premature to reduce common equity for ratemaking purposes for contingent losses that may never be realized and have not been recognized as an expense under GAAP. Such contingent costs are not fixed, known or measurable and have not yet been recorded in pension expense. Importantly, the Company has not been provided with the opportunity to include such (contingent) costs in its cost of service, along with the concomitant opportunity to recover such (contingent) costs in rates.

If such costs are no longer contingent but become realized, it is highly likely, as I explain below, that the costs will then be recoverable in rates. Under those circumstances, the common equity will not, at that time, have to be reduced to reflect a loss. Therefore, reducing common equity today for a loss not yet recorded on the income statement would be an unfair regulatory policy. Regulation should try to reflect a representative level of costs in the test year. Reducing common equity for the entire contingent minimum pension liability in the period it is recognized as inconsistent with this objective, especially when this contingent liability may not ultimately be realized in future periodic pension expense and the cost of service.

When the average equity in KU's application is appropriately adjusted to remove the minimum pension liability from equity, GAAP will support recording a regulatory asset going forward in order to properly match KU's equity with its regulated revenues and in order to reflect the ratemaking process in KU's financial statements. KU submits that it would be preferable to record a regulatory asset up front when the minimum pension liability is initially recorded. This would bring the accounting in line with the expected and appropriate ratemaking and properly reflect the economics of the ratemaking for pension costs in KU's financial statements as required by SFAS 71.

SFAS 71 and FERC's USofA instructions for Account 182.3 Other Regulatory Assets require that to record a regulatory asset it must be probable of recovery. The fact that ERISA precludes taking away any of the pension benefits that participants of a pension plan have earned requires KU to provide for those benefits over the participants' working lives and should encourage the Commission to provide for the recovery of those benefit provisions which are clearly represented by a minimum unfunded pension liability. KU's obligation to provide reasonable pension benefits to its employees has always been recognized by this Commission, which has consistently provided for recovery of SFAS 87 pension costs. SFAS 87 periodic pension expense has been and will be a reasonable and appropriate recoverable cost of providing regulated utility service.

The minimum pension liability adjustment is shown in Column 7 on Page 2 of 2, Exhibit 2. The amount was calculated by Mercer and is included in the books and records of KU in December 2002.

Q. Please explain the adjustment shown in Column 15 of Exhibit 2 for the Environmental Surcharge 2001 Plan.

A. Removing the environmental surcharge rate base from the capital structure is necessary because KU is recovering a return on its investment through the environmental surcharge.

Q. Please explain how the weighted average cost of capital is calculated.

A. Column 17 of Rives Exhibit 2 calculates the respective capitalization percentages for the components of adjusted capitalization from column 16 (e.g., line 1, column 16 divided by line 6, column 16 equals line 1, column 17). Column 18 includes the embedded costs of the components of capital except the return on equity. The annual rate used for Short Term Debt and the A/R Securitization is the actual rate as of September 30, 2003. At present, the Company anticipates the accounts receivable financing will be terminated in the first quarter 2004. The annual cost rate for Long Term Debt is the embedded cost of the first mortgage bonds and intercompany loans outstanding as of September 30, 2003. The intercompany loans were approved by the Commission in its April 30, 2003 Order in Case No. 2003-00059. The annual cost rate for Preferred Stock is its embedded cost as of September 30, 2003. The cost of equity is the amount recommended by Mr. Rosenburg and supported in his testimony. Column 19 then calculates the weighted average cost of capital by multiplying column 17 by column 18, resulting in 7.25%.

<u>Property Valuation</u>

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 recognized by the law of the land for ratemaking purposes.

Q. Have you prepared an exhibit showing KU's net original cost rate base as of September 30, 2003?

A. Yes. Page 1 of Rives Exhibit 3 shows KU's net original cost rate base at September 30, 2003, using the same format LG&E 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.

Q. Have you developed a reproduction cost rate base?

A. Yes. The reproduction cost rate base at September 30, 2003, is shown on Rives Exhibit 4. The calculation of the reproduction cost of plant less depreciation used in developing the reproduction cost rate base was calculated under my supervision and is shown on Rives Exhibit 5.

Q. Please explain Rives Exhibit 5.

A. Rives Exhibit 5 shows KU's estimated reproduction (or current) cost of utility plant and the applicable accumulated depreciation on the reproduction cost of utility as of September 30, 2003. The estimated reproduction cost – net at September 30, 2003, is approximately $1.4 billion greater, on a total company basis, than the original historical cost – net as recorded on KU's books. The current costs were determined principally by indexing the surviving plant and equity by use of the Handy-Whitman Index of Public Utility Construction Costs and the Consumer Price Index.

Q. Have you prepared a calculation of the rate of return for the twelve months ended September 30, 2003 on capitalization, net original cost rate base and reproduction cost rate base?

A. Yes. As I previously stated the rate of return on capital for the twelve months ended September 30, 2003, was 6.22%. Rives Exhibit 6 shows the actual rate of return earned for the twelve months ended September 30, 2003, was 5.56% on net original cost rate base and 3.13 % on 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 6.18% on net original cost rate base and 3.48% on reproduction cost rate base. As indicated on Exhibit 2 the requested rate of return on capital as of September 30, 2003, is 7.25%,

Q. Have you prepared an exhibit showing the overall revenue deficiency at September 30, 2003 for KU?

A. Yes. Rives Exhibit 7 shows the overall revenue deficiency at September 30, 2003, for KU to be $58,254,344.

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

A. Kentucky Utilities Company recommends the Commission approve the recovery of this revenue deficiency through a change in electric base rates.

Q. Does this conclude your testimony?

A. Yes.

278702.13

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.

S Bradford Rives

S. BRADFORD RIVES

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 29th day of December 2003.

Melody L. Hulse (SEAL)
Notary Public

My Commission Expires:

November 24, 2007

APPENDIX A

S. Bradford Rives

Chief Financial Officer
LG&E Energy Corp.
220 West Main Street
Louisville, Kentucky 40202
(502) 627-3990

Education

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

Previous Positions

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

Professional/Trade Memberships

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

Civic Activities

African - American Venture Capital Fund – Investment Committee
Lincoln Heritage Council, Boy Scouts of America – Executive Board
Metro United Way of Louisville – Board of Directors
National Kidney Foundation of Kentucky Cadillac Invitational Golf Tournament - Chair
St. Patrick Parish

KENTUCKY UTILITIES

Adjustments to Operating Revenues, Operating Expenses and Net Operating Income
For the Twelve Months Ended September 30, 2003

	Reference Schedule (1)	Operating Revenues (2)	Operating Expenses (3)	Net Operating Income (4)
1. Jurisdictional amount per books		$ 768,801,159	$ 682,633,628	$ 86,167,531
2. Adjustments for known changes and to eliminate unrepresentative conditions:	1.00	675,000	-	675,000
3. Adjustment to eliminate unbilled revenues	1.01	(35,887,728)	(31,644,777)	(4,242,951)
4. To adjust mismatch in fuel cost recovery	1.02	1,417,623	-	1,417,623
5. To adjust base rates and FAC to reflect a full year of the FAC roll-in	1.03	(25,039,979)	(248,468)	(24,791,511)
6. Adjustment to eliminate Environmental Surcharge revenues and expenses	1.04	17,986,813	-	17,986,813
7. To adjust base rate revenues to reflect a full year of the ECR roll-in	1.05	(776,418)	-	(776,418)
8. Off-System sales revenue adjustment for the ECR calculation	1.06	(5,571,256)	(7,725,329)	2,154,073
9. To eliminate Electric Brokered Sales Revenues and Expenses	1.07	(4,604,742)	-	(4,604,742)
10. To eliminate electric ESM revenues collected	1.08	1,630,147	-	1,630,147
11. To eliminate ESM,ECR, and FAC in Rate Refund Account 449	1.09	(2,942,935)	(2,946,471)	3,536
12. Eliminate DSM revenue and expenses	1.10	251,167	151,410	99,757
13. Adjustment to annualize year-end customers	1.11	-	2,091,278	(2,091,278)
14. Adjustment to reflect annualized depreciation expenses under proposed rates	1.12	-	1,002,076	(1,002,076)
15. Adjustment to reflect increases in labor and labor related costs	1.13	-	3,014,859	(3,014,859)
16. To adjust for pension and post retirement	1.14	-	(473,014)	473,014
17. Adjustment to reflect normalized storm damage expense				

KENTUCKY UTILITIES

Adjustments to Operating Revenues, Operating Expenses and Net Operating Income
For the Twelve Months Ended September 30, 2003

	Reference Schedule (1)	Operating Revenues (2)	Operating Expenses (3)	Net Operating Income (4)
18. Adjustment to eliminate advertising expenses pursuant to Commission Rule 807 KAR 5:016	1.15	-	(45,386)	45,386
19. Adjustment to reflect amortization of rate case expenses	1.16	-	352,456	(352,456)
20. Adjustment to reflect amortization of ESM audit expenses	1.17	-	58,333	(58,333)
21. Adjustment to remove One-Utility costs	1.18	-	(1,550,907)	1,550,907
22. Adjustment for Injuries and Damages FERC Account 925	1.19	-	261,138	(261,138)
23. Adjustment for VDT net savings to shareholders	1.20	-	2,895,000	(2,895,000)
24. Adjust VDT to settlement agreement	1.21	85,337	(466,280)	551,617
25. Adjustment for merger savings	1.22	(2,564,269)	18,968,825	(21,533,094)
26. Adjustment to eliminate LG&E/KU merger amortization expense	1.23	-	(2,726,510)	2,726,510
27. Adjustment for MISO Schedule 10 credits	1.24	-	843,344	(843,344)
28. Adjustment for cumulative effect of accounting change	1.25	-	8,434,618	(8,434,618)
29. Adjustment for IT staff reduction	1.26	-	(601,682)	601,682
30. To remove E.W. Brown legal expenses	1.27	-	(3,126,995)	3,126,995
31. To adjust for customer rate switching	1.28	(1,898,980)	-	(1,898,980)
32. Adjustment for sales tax refunds	1.29	-	120,391	(120,391)
33. Adjustment for OMU NOx expense	1.30	-	1,959,879	(1,959,879)
34. To adjust for ice storm expenses	1.31	-	(5,277,336)	5,277,336

KENTUCKY UTILITIES

Adjustments to Operating Revenues, Operating Expenses and Net Operating Income
For the Twelve Months Ended September 30, 2003

		Reference Schedule (1)	Operating Revenues (2)	Operating Expenses (3)	Net Operating Income (4)
35. Adjustment for management audit fees		1.32	-	163,982	(163,982)
36. Adjustment to O&M expenses for Retirement of Green River Units 1 and 2		1.33	-	(705,035)	705,035
37. Total of above adjustments			$ (57,240,220)	$ (17,220,601)	$ (40,019,619)
38. Federal and state income taxes corresponding to base revenue and expense adjustments and above adjustments -	40.3625 %	1.34		(16,152,919)	16,152,919
39. Federal and state income taxes corresponding to annualization and adjustment of year-end interest expense.		1.35		653,076	(653,076)
40. Prior income tax true-ups and adjustments		1.36		681,889	(681,889)
41. Total rate case adjustments page 2 of 2			$ (57,240,220)	$ (32,038,555)	$ (25,201,665)
42. Adjusted Net Operating Income			$ 711,560,939	$ 650,595,073	$ 60,965,866

KENTUCKY UTILITIES

Adjustment to Eliminate Unbilled Revenues

1. Unbilled revenues at September 30, 2002	$	29,493,000
2. Unbilled revenues at September 30, 2003		(28,818,000)
3. Decrease in book revenues due to unbilled revenues	$	675,000

Rives Exhibit 1
Reference Schedule 1.01
Sponsoring Witness: Steve Seelye

KENTUCKY UTILITIES

To Adjust Mismatch in Fuel Cost Recovery
For the Twelve Months Ended September 30, 2003

Expense Month	Revenue Form A Page 4 of 5 Line 3	Expense Form A* Page 4 of 5 Line 8
Oct-02	$ 4,028,950	$ 4,280,800
Nov-02	4,241,409	3,521,367
Dec-02	5,013,276	2,787,457
Jan-03	4,231,897	4,510,322
Feb-03	3,062,898	4,259,284
Mar-03	3,823,692	798,672
Apr-03	3,622,905	2,151,622
May-03	763,466	2,226,354
Jun-03	5,156,416	(1,571,337)
Jul-03	2,683,786	1,053,068
Aug-03	(1,776,754)	3,357,880
Sep-03	1,035,787	4,269,288
Total	$ 35,887,728	$ 31,644,777
Adjustment	$ (35,887,728)	$ (31,644,777)

* NOTE : Expenses are recovered in the second succeeding month. For example, January 2003 would be reflected in March 2003.

Rives Exhibit 1
Reference Schedule 1.02
Sponsoring Witness: Steve Seelye

KENTUCKY UTILITIES

To Adjust Base Rates and FAC to Reflect a Full Year of the FAC Roll-in
For the Twelve Months Ended September 30, 2003

1. Adjustment to base rate revenues to reflect a full year of the FAC roll-in	$	24,570,078
2. Adjustment to FAC revenues to reflect a full year of the FAC roll-in		(23,152,455)
3. Net adjustment	$	1,417,623

Rives Exhibit 1
Reference Schedule 1.03
Sponsoring Witness: Steve Seelye

KENTUCKY UTILITIES

Adjustment to Eliminate Environmental Surcharge Revenues and Expenses
For the Twelve Months Ended September 30, 2003

Expense Month	Revenues All Plans	Expenses Post '94 Plan	Net
Oct-02	$ 1,607,206	$ 18,078	
Nov-02	1,481,967	18,078	
Dec-02	1,970,378	18,078	
Jan-03	2,183,055	24,893	
Feb-03	2,311,836	33,583	
Mar-03	1,905,993	24,893	
Apr-03	1,877,008	24,893	
May-03	1,814,947	24,893	
Jun-03	2,085,716	24,893	
Jul-03	2,581,906	24,893	
Aug-03	2,416,293	24,893	
Sep-03	2,803,674	24,893	
		286,961	
Jurisdictional %		86.586%	
Total	$ 25,039,979	$ 248,468	$ 24,791,511
Adjustment	$(25,039,979)	$ (248,468)	$ (24,791,511)

Rives Exhibit 1
Reference Schedule 1.04
Sponsoring Witness: Steve Seelye

KENTUCKY UTILITIES

To Adjust Base Rate Revenues to Reflect a Full Year of the ECR Roll-In
For the Twelve Months Ended September 30, 2003

1. Adjustment to base rate revenues to reflect a full year of the ECR roll-in	$ 17,986,813

Rives Exhibit 1
Reference Schedule 1.05
Sponsoring Witness: Steve Seelye

KENTUCKY UTILITIES

Off-System Sales Revenue Adjustment for the ECR Calculation
For the Twelve Months Ended September 30, 2003

	(1) KU Off-System Sales Revenue	(2) KU Off-System Sales Intercompany Revenue	(3) KU Off-System Sales Revenue Less Intercompany (Col. 1 - 2)	(4) Monthly Environmental Surcharge Factor	(5) Average Environmental Surcharge Factor	(6) Off-System Sales Environmental Cost (Col. 3 * 5)
Oct-02	$ 2,880,544	$ 2,709,147	$ 171,397	3.25%	3.61%	$ 6,187
Nov-02	1,850,687	1,599,631	251,056	3.39%	3.61%	9,063
Dec-02	2,994,317	2,296,598	697,719	3.63%	3.61%	25,188
Jan-03	9,785,436	5,141,237	4,644,199	3.31%	3.61%	167,656
Feb-03	4,889,422	3,775,440	1,113,982	3.79%	3.61%	40,215
Mar-03	6,998,338	5,547,644	1,450,694	3.72%	3.61%	52,370
Apr-03	8,291,102	4,252,437	4,038,665	3.82%	3.61%	145,796
May-03	2,507,277	1,826,188	681,089	4.16%	3.61%	24,587
Jun-03	4,889,880	3,136,954	1,752,926	4.22%	3.61%	63,281
Jul-03	6,015,316	3,267,550	2,747,766	4.61%	3.61%	99,194
Aug-03	5,083,444	3,656,907	1,426,537	4.69%	3.61%	51,498
Sep-03	6,607,264	4,075,872	2,531,392	0.68%	3.61%	91,383
Total	$ 62,793,027	$ 41,285,605	$ 21,507,422			$ 776,418
Average				3.61%		
Adjustment						$ (776,418)

Rives Exhibit 1
Reference Schedule 1.06
Sponsoring Witness: Valerie Scott

KENTUCKY UTILITIES

To Eliminate Electric Brokered Sales Revenues and Expenses
For the Twelve Months Ended September 30, 2003

1. Brokered Sales	$ 26,222,116	
2. Brokered Expense recorded in revenues	19,750,985	
3. Net Brokered Sales revenue adjustment	6,471,131	
4. Kentucky Jurisdiction	86.094%	
5. Kentucky Jurisdiction Net Brokered Sales Revenue	$ 5,571,256	
6. Kentucky Jurisdiction Net Brokered Sales Revenue adjustment	$ (5,571,256)	
7. Brokered Expense recorded in power purchased	8,973,133	*
8. Kentucky Jurisdiction	86.094%	
9. Kentucky Jurisdiction Brokered Expense	$ 7,725,329	
10. Kentucky Jurisdiction Brokered Expense adjustment	$ (7,725,329)	
11. Net Kentucky Jurisdictional adjustment (Line 6 - Line 10)	$ 2,154,073	

*NOTE: Includes 4% of total labor and labor related costs from off-system sales activities of $58,532.

Effective January 1, 2003, KU adopted EITF No. 02-03, "Issues Involved in Accounting for Derivative Contracts Held for Trading Purposes and Contracts Involved in Energy Trading and Risk Management Activities". The EITF required KU to net brokered revenues and expenses together in the revenue section of the income statement. The brokered expenses from line 7 are amounts recorded in expense for October through December 2002, before the EITF was effective.

Rives Exhibit 1
Reference Schedule 1.07
Sponsoring Witness: Valerie Scott

KENTUCKY UTILITIES

To Eliminate Electric ESM Revenues Collected
During the Twelve Months Ended September 30, 2003

1. 2001 ESM settlement - refund	$ 1,023,407
2. 2002 final ESM revenues	(11,599,389)
3. Additional amounts refunded in December 2002 over estimate in 2001 settlement filing	61,411
4. ESM amounts still to be collected - Reference Schedule 1.08	5,909,829
5. Actual ESM revenue collected	$ (4,604,742)

Rives Exhibit 1
Reference Schedule 1.08
Sponsoring Witness: Valerie Scott

KENTUCKY UTILITIES

To Eliminate ESM, ECR, and FAC in Rate Refund Account 449
For the Twelve Months Ended September 30, 2003

1. ESM Revenue	$ (5,909,829)
2. ECR Revenue	7,814,301
3. FAC Revenue	(896,242)
4. Total Account 449	1,008,230
5. Less ODP FAC Revenue included in Line 3	(621,917)
6. Kentucky Jurisdictional Account 449	$ 1,630,147

Rives Exhibit 1
Reference Schedule 1.09
Sponsoring Witness: Steve Seelye

KENTUCKY UTILITIES

Eliminate DSM Revenues and Expenses
For the Twelve Months Ended September 30, 2003

1. DSM Revenue adjustment	$	(2,942,935)
2. DSM Expense adjustment		(2,946,471)
3. Total	$	3,536

Rives Exhibit 1
Reference Schedule 1.10
Sponsoring Witness: Steve Seelye

KENTUCKY UTILITIES

Adjustment to Annualize Year-End Customers
At September 30, 2003

1. Revenue adjustment	$	251,167
2. Expense adjustment		151,410
3. Net adjustment	$	99,757

Rives Exhibit 1
Reference Schedule 1.11
Sponsoring Witness: Earl Robinson/Valerie Scott

KENTUCKY UTILITIES

Adjustment To Reflect Annualized Depreciation Expenses Under Proposed Rates At September 30, 2003

1. Depreciation expense per books excluding ARO and post-1994 ECR	$ 100,908,171
2. Annualized depreciation expense with new rates	103,303,706
3. Total increase	2,395,535
4. Kentucky Jurisdiction	87.299%
5. Kentucky Jurisdictional adjustment	$ 2,091,278

KENTUCKY UTILITIES

Adjustment to Reflect Increases in Labor and Labor-Related Costs
As Applied to the Twelve Months Ended September 30, 2003

1. Wages (Page 2)	$ 1,024,366
2. Payroll Taxes (Page 3)	78,364
3. 401(k) (Page 4)	25,404
4. Total	1,128,134
5. Kentucky Jurisdiction	88.826%
6. Kentucky Jurisdictional adjustment	$ 1,002,076

KENTUCKY UTILITIES

Adjustment to Reflect Increases in Labor and Labor-Related Costs
As Applied to the Twelve Months Ended September 30, 2003

	Operating	Construction/ Other	Total
1. Test Year Labor:			
2. Base	$ 33,426,867	$ 13,777,124	$ 47,203,991
3. Overtime and Premium	7,273,447	1,355,550	8,628,997
4. TIA	3,298,358	991,211	4,289,569
5. Total Test Year Ended September 30, 2003	$ 43,998,672	$ 16,123,885	$ 60,122,557
6. Total Operating and Construction/Other %	73.2%	26.8%	100.0%

		Employees	
7. Annualized base labor at September 30, 2003:			
8. Union - includes 3% increase effective August 1, 2003		158	$ 8,023,392
9. Exempt		138	9,221,543
10. Non-Exempt/Hourly		645	31,763,250
11. Total Annualized Labor		941	49,008,185
12. Union Overtime/Premiums (a)			2,027,332
13. Union wage increase applied to union overtime/premium for 10/12 of year (Line 12 x 3% x 10/12)			50,683
14. Non-Exempt/Hourly Overtime/Premium (a)			6,601,665
15. TIA - Exempt/Non-Exempt/Bargaining Unit (a)			4,289,569
16. Union wage increase applied to union TIA (Sum of Lines 8, 12, 13 x 6% x 3%)			18,183
17. Less additional TIA amount charged in test year to bring TIA levels to 100%			(473,302)
18. Total Annualized Labor			$ 61,522,316
19. Test Year Operating Labor			$ 43,998,672
20. Operating Labor based on annualized labor $ 61,522,316	x	73.2%	45,023,038
21. Labor Adjustment Total			$ 1,024,366

(a) Represents actual numbers taken from the Company's financial records for the 12 months ended September 30, 2003.

KENTUCKY UTILITIES

Adjustments to Reflect Increases in Payroll Taxes
As Applied to the Twelve Months Ended September 30, 2003

1. Operating Labor increase (Page 2 Line 21)	$ 1,024,366
2. Payroll Taxes - FICA	7.65%
3. Payroll Tax adjustment	$ 78,364

KENTUCKY UTILITIES

Adjustment to Reflect Increases in Company Match of 401(k)
As Applied to the Twelve Months Ended September 30, 2003

1. Direct total payroll for 12 months ended 09/30/03 (Page 2 Line 5)	$ 60,122,557
2. Total 401(k) Company Match for 12 months ended 09/30/03	1,492,593
3. 401(k) Company Match as a percent of payroll	2.48%
4. Operating Labor increase (Page 2 Line 21)	1,024,366
5. 401(k) Company Match operating increase (Line 3 x Line 4)	$ 25,404

Rives Exhibit 1
Reference Schedule 1.13
Sponsoring Witness: Valerie Scott

KENTUCKY UTILITIES

To Adjust for Pension and Post Retirement
For the Twelve Months Ended September 30, 2003

1. Pension and Post Retirement expenses in test year	$ 10,221,260
2. Pension and Post Retirement expenses annualized for 2003 per Mercer study	13,615,378
3. Total adjustment	3,394,118
4. Kentucky Jurisdiction	88.826%
5. Kentucky Jurisdictional adjustment	$ 3,014,859

Rives Exhibit 1
Reference Schedule 1.14
Sponsoring Witness: Valerie Scott

KENTUCKY UTILITIES

Adjustment to Reflect Normalized Storm Damage Expense
For the Twelve Months Ended September 30, 2003

1. Storm damage provision based upon four year average	$ 1,408,702
2. Storm damage expenses incurred during the 12 months ended September 30, 2003	1,916,353
3. Total adjustment	(507,651)
4. Kentucky Jurisdiction	93.177%
5. Kentucky Jurisdictional adjustment	$ (473,014)

Year	Expense *	CPI-All Urban Consumers	Amount
2003	$ 1,916,353	1.0000	$ 1,916,353
2002	1,460,495	1.0160	1,483,863
2001	1,102,683	1.0440	1,151,201
2000	1,005,000	1.0780	1,083,390
Total			$ 5,634,807
Four Year Average			$ 1,408,702

* NOTE: 2003 expenses are for the 12 months ended September 30, 2003.
All other years expenses are for the calendar year. 2003 expenses exclude ice storm.

KU storm damage expenses are available for a four year period only.

Rives Exhibit 1
Reference Schedule 1.15
Sponsoring Witness: Valerie Scott

KENTUCKY UTILITIES

Adjustment to Eliminate Advertising Expenses
Pursuant to Commission Rule 807 KAR 5:016
For the Twelve Months Ended September 30, 2003

1. Uniform System of Accounts - Account No. 930.1 General Advertising Expenses	$ 47,895
2. Account No. 913 Advertising Expenses	19
3. Total	47,914
4. Kentucky Jurisdiction	94.723%
5. Kentucky Jurisdictional amount	$ 45,386
6. Kentucky Jurisdictional adjustment	$ (45,386)

KENTUCKY UTILITIES

Adjustment to Reflect Amortization of Rate Case Expenses

1. Total estimated cost of rate case	$ 1,057,368
2. Amortization period in years	3
3. Annual amortization	352,456
4. Amortization included in test year	0
5. Net adjustment	$ 352,456

Rives Exhibit 1
Reference Schedule 1.17
Sponsoring Witness: Valerie Scott

KENTUCKY UTILITIES

Adjustment to Reflect Amortization of ESM Audit Expenses
For the Twelve Months Ended September 30, 2003

1. Total estimated cost of ESM audit by Barrington-Wellesley Group	$ 175,000
2. Amortization period in years	3
3. Annual amortization	58,333
4. Amortization included in test year	0
5. Net adjustment	$ 58,333

Rives Exhibit 1
Reference Schedule 1.18
Sponsoring Witness: Valerie Scott

KENTUCKY UTILITIES

Adjustment to Remove One-Utility Costs
For the Twelve Months Ended September 30, 2003

1. One-Utility amortization charged to Account 930.2	$	(1,746,005)
2. Kentucky Jurisdiction		88.826%
3. Kentucky Jurisdictional adjustment	$	(1,550,907)

Rives Exhibit 1
Reference Schedule 1.19
Sponsoring Witness: Valerie Scott

KENTUCKY UTILITIES

Adjustment for Injuries and Damages FERC Account 925
For the Twelve Months Ended September 30, 2003

1. Injury/Damage provision based upon five year average	$ 2,155,189
2. Injury/Damage expenses incurred during the 12 months ended September 30, 2003	1,861,201
3. Adjustment	293,988
4. Kentucky Jurisdiction	88.826%
5. Kentucky Jurisdictional adjustment	$ 261,138

Year	Amount	CPI-All Urban Consumers	Adjusted Amount
2002	$ 2,510,515	1.0160	$ 2,550,683
2001	1,609,827	1.0440	1,680,660
2000	1,637,520	1.0780	1,765,246
1999	2,126,017	1.1000	2,338,619
1998	2,187,039	1.1160	2,440,735
Total			$ 10,775,944
Five Year Average			$ 2,155,189

Rives Exhibit 1
Reference Schedule 1.20
Sponsoring Witness: Valerie Scott

KENTUCKY UTILITIES

Adjustment for VDT Net Savings to Shareholders
For the Twelve Months Ended September 30, 2003

1. Adjustment for net VDT Savings to Shareholders		$ 2,895,000

2002 Shareholders portion of VDT Savings per Tariff (a)	$ 960,000	
October - December 2002 (25%)	240,000	$ 240,000
2003 Shareholders portion of VDT Savings per Tariff (a)	3,540,000	
January - September 2003 (75%)	2,655,000	2,655,000
		$ 2,895,000

NOTE: (a) Third revision of original sheet No. 24.3 dated January 21, 2002.

Rives Exhibit 1
Reference Schedule 1.21
Sponsoring Witness: Valerie Scott

KENTUCKY UTILITIES

Adjust VDT to Settlement Agreement
For the Twelve Months Ended September 30, 2003

1. Actual VDT surcredit refunded	$ 2,015,337
2. VDT surcredit per settlement	1,930,000
3. VDT revenue adjustment	$ 85,337
4. Actual VDT costs	$ 11,966,280
5. VDT settlement cost amortization	11,500,000
6. VDT cost adjustment	$ (466,280)
7. Total adjustment	$ 551,617

Rives Exhibit 1
Reference Schedule 1.22
Sponsoring Witness: Valerie Scott

KENTUCKY UTILITIES

Adjustment for Merger Savings
For the Twelve Months Ended September 30, 2003

1. Customer portion of merger surcredit per agreement	$ 18,968,825
2. Revenue returned to customers through the merger surcredit for 12 months ended September 30, 2003	16,404,556
3. Additional savings due customers	$ (2,564,269)
4. Shareholder's portion of merger surcredit per agreement	$ 18,968,825

NOTE: Merger surcredit per Commission's order dated October 16, 2003 in Case No. 2002-00429.

Rives Exhibit 1
Reference Schedule 1.23
Sponsoring Witness: Valerie Scott

KENTUCKY UTILITIES

Adjustment to Eliminate LG&E/KU Merger Amortization Expense
For the Twelve Months Ended September 30, 2003

1. LG&E/KU Merger amortization expense Account 930.2	$ 3,069,495
2. Kentucky Jurisdiction	88.826%
3. Kentucky Jurisdictional amount	$ 2,726,510
4. Kentucky Jurisdictional adjustment	$ (2,726,510)

Rives Exhibit 1
Reference Schedule 1.24
Sponsoring Witness: Valerie Scott

KENTUCKY UTILITIES

Adjustment for MISO Schedule 10 Credits
For the Twelve Months Ended September 30, 2003

1. MISO Schedule 10 credits received in test period	$ 979,892
2. Kentucky Jurisdiction	86.065%
3. Kentucky Jurisdictional adjustment	$ 843,344

Rives Exhibit 1
Reference Schedule 1.25
Sponsoring Witness: Valerie Scott

KENTUCKY UTILITIES

Adjustment for Cumulative Effect of Accounting Change
For the Twelve Months Ended September 30, 2003

1. Adjustment to move cumulative effect of accounting change to match regulatory credit that is above net operating income due to Asset Retirement Obligation, net of tax	$ 5,919,827
2. Grossed up by the composite income tax rate - Reference Schedule 1.34 (100% - 40.3625%)	59.6375%
3. Gross adjustment to offset net operating income impact of Asset Retirement Obligation regulatory credit	9,926,350
4. Kentucky Jurisdiction	84.972%
5. Kentucky Jurisdictional adjustment	$ 8,434,618

Rives Exhibit 1
Reference Schedule 1.26
Sponsoring Witness: Valerie Scott

KENTUCKY UTILITIES

Adjustment for IT Staff Reduction
For the Twelve Months Ended September 30, 2003

1. Total KU operating labor reduction	$ (733,623)
2. Payroll taxes	7.65%
3. Payroll tax reduction	$ (56,122)
4. Total KU operating labor reduction	$ (733,623)
5. 401(k) company match as a percent of payroll (a)	2.87%
6. 401(k) company match reduction	$ (21,055)
7. Total estimated cost reduction (Line 1 + Line 3 + Line 6)	$ (810,800)
8. Actual costs ($400,287 / 3 years amortization)	133,429
9. Net cost reduction	(677,371)
10. Kentucky Jurisdiction (b)	88.826%
11. Kentucky Jurisdictional adjustment	$ (601,682)

(a) LG&E Energy Services Company percentage:	
LG&E Energy Services Company total labor	$ 81,832,370
LG&E Energy Services 401(k) match	2,346,149
LG&E Energy Services 401(k) match as percent of payroll	2.87%

(b) Percentage taken from Reference Schedule 1.12.

Rives Exhibit 1
Reference Schedule 1.27
Sponsoring Witness: Valerie Scott

KENTUCKY UTILITIES

To Remove E.W. Brown Legal Expenses
For the Twelve Months Ended September 30, 2003

1. E.W. Brown legal expenses included in the test year	$ 5,678,000
2. KU combustion turbine ownership percentage	62%
3. KU's portion of E.W. Brown legal expenses	$ 3,520,360
4. Kentucky Jurisdiction	88.826%
5. Kentucky Jurisdictional amount	$ 3,126,995
6. Kentucky Jurisdictional adjustment	$(3,126,995)

Rives Exhibit 1
Reference Schedule 1.28
Sponsoring Witness: Steve Seelye

KENTUCKY UTILITIES

To Adjust for Customer Rate Switching
As Applied to the Twelve Months Ended September 30, 2003

1. Rate switch - North American Stainless	$(1,898,980)

Rives Exhibit 1
Reference Schedule 1.29
Sponsoring Witness: Valerie Scott

KENTUCKY UTILITIES

Adjustment for Sales Tax Refunds
For the Twelve Months Ended September 30, 2003

1. Sales tax refund received relating to a period outside the test year	$ 135,536
2. Kentucky Jurisdiction	88.826%
3. Kentucky Jurisdictional adjustment	$ 120,391

Rives Exhibit 1
Reference Schedule 1.30
Sponsoring Witness: Valerie Scott

KENTUCKY UTILITIES

Adjustment for OMU NOx Expense
For the Twelve Months Ended September 30, 2003

1.	Expenditures for NOx compliance pursuant to the OMU contract	$ 2,277,208
2.	Kentucky Jurisdiction	86.065%
3.	Kentucky Jurisdictional adjustment	$ 1,959,879

KENTUCKY UTILITIES

To Adjust for Ice Storm Expenses
For the Twelve Months Ended September 30, 2003

1. Operating expenses charged in test year	$ 15,540,679
2. Insurance recovery in test year	(8,944,009)
3. Total	6,596,670
4. Amortization period in years	5
5. Annual amortization	1,319,334
6. Remove 4 years from test year	x 4
7. Net reduction to operating expenses	$ 5,277,336
8. Adjustment	$ (5,277,336)

Rives Exhibit 1
Reference Schedule 1.32
Sponsoring Witness: Valerie Scott

KENTUCKY UTILITIES

Adjustment for Management Audit Fees
For the Twelve Months Ended September 30, 2003

1. Management Audit fees	$ 491,945
2. Amortization period in years	3
3. Amortization per year	$ 163,982

KENTUCKY UTILITIES

Adjustment to O&M Expenses for Retirement of Green River Units 1 and 2
For the Twelve Months Ended September 30, 2003

1. Green River units 1 and 2 operation and maintenance expenses included in test year	$ 832,067
2. Kentucky Jurisdiction	84.733%
3. Kentucky Jurisdictional amount	$ 705,035
4. Kentucky Jurisdictional adjustment	$ (705,035)

Rives Exhibit 1
Reference Schedule 1.34
Sponsoring Witness: Brad Rives

KENTUCKY UTILITIES

Calculation of Composite Federal and Kentucky Income Tax Rate (Based on Law in Effect September 30, 2003)

1. Assume pre-tax income of	$ 100.0000
2. State income tax at 8.25%	8.2500
3. Taxable income for Federal income tax	91.7500
4. Federal income tax at 35% (Line 3 x 35%)	32.1125
5. Total State and Federal income taxes (Line 2 + Line 4)	$ 40.3625

6. Therefore, the composite rate is:

7.	Federal	32.1125%
8.	State	8.2500%
9.	Total	40.3625%

Rives Exhibit 1
Reference Schedule 1.35
Sponsoring Witness: Brad Rives

KENTUCKY UTILITIES

Calculation of Current Tax Adjustment Resulting
From "Interest Synchronization"

1. Adjusted Jurisdictional Capitalization - Exhibit 2	$ 1,318,124,983
2. Weighted Cost of Debt - Exhibit 2	1.25%
3. "Interest Synchronization"	16,476,562
4. Kentucky Jurisdictional Interest per books (excluding other interest)	18,094,590
5. "Interest Synchronization" adjustment	1,618,028
6. Composite Federal and State tax rate	40.3625%
7. Current tax adjustment from "Interest Synchronization"	$ 653,076

Rives Exhibit 1
Reference Schedule 1.36
Sponsoring Witness: Brad Rives

KENTUCKY UTILITIES

Adjustment for Prior Period Income Tax True-Ups and Adjustments
For the Twelve Months Ended September 30, 2003

1. 2002 Income Tax True-up:		
2. Federal Tax (benefit)	$	(310,641)
3. State Tax (benefit)		(394,627)
4. Total 2002 Income Tax True-up in test year		(705,268)
5. Percentage of 2002 pre-tax income through September 30, 2002		72.5%
6. Total 2002 Income Tax True-up in test period	$	(511,319)
7. 2002 Other Tax adjustments in test period:		
8. Kentucky Coal Credit - 2001	$	(322,612)
9. Total 2002 Other Tax adjustments in test period:	$	(322,612)
10. Total adjustment (Line 6 + Line 9)	$	(833,931)
11. Kentucky Jurisdiction		81.768%
12. Kentucky Jurisdiction amount	$	(681,889)
13. Kentucky Jurisdiction adjustment	$	681,889

KENTUCKY UTILITIES

Calculation of Revenue Gross Up Factor
(Based on Law in Effect September 30, 2003)

1. Assume pre-tax income of	$ 100.000000
2. Bad Debt at .23%	0.230000
3. PSC Assessment at .1823%	0.182300
4. Taxable income for State income tax	99.587700
5. State income tax at 8.25%	8.215985
6. Taxable income for Federal income tax	91.371715
7. Federal income tax at 35%	31.980101
8. Total Bad Debt, PSC Assessment, State and Federal income taxes (Line 2 + Line 3 + Line 5 + Line 7)	40.608386
9. Assume pre-tax income of	$ 100.000000
10. Gross Up Revenue Factor	59.391614

NOTE: Bad debt percent is percent of net charge-offs to revenue for the 12 months ended September 30, 2003.

KENTUCKY UTILITIES

Kentucky Jurisdictional Allocators
At September 30, 2003

Title	Reference Schedule	Factor	Allocation Based On
ECR Operating Expense	1.03	86.586%	Composite rate developed from steam depreciation allocator (86.065%) and net plant allocator for property tax (87.682%)
Brokered Energy	1.06	86.094%	Ratio of Kentucky retail kilowatt-hour sales to Total Company kilowatt-hour sales
Depreciation	1.11	87.299%	Composite rate developed by dividing Kentucky retail depreciation by Total Company depreciation
Labor	1.12	88.826%	Direct labor
Pension	1.13	88.826%	Direct labor
Distribution O&M	1.14	93.177%	Distribution plant
Advertising Expense	1.15	94.723%	Retail energy
One Utility	1.18	88.826%	Direct labor
Injuries/Damages	1.19	88.826%	Direct labor
Merger Amortization	1.22	88.826%	Direct labor
MISO	1.24	86.065%	Demand (12 CP)
ARO Accounting Change	1.25	84.972%	Production plant
IT Staff Reduction	1.26	88.826%	Direct labor
E.W. Brown Expense	1.27	88.826%	Direct labor
Sales Tax	1.29	88.826%	Direct labor
OMU NOx	1.30	86.065%	Demand (12 CP)
Green River Unit 1 and 2	1.33	84.733%	Steam plant
Prior Period Tax True-up	1.36	81.768%	Income tax expense

KENTUCKY UTILITIES

Capitalization at September 30, 2003

		Per Books 09-30-03 (1)	Capital Structure (2)	Undistributed Subsidiary Earnings (3)	Investment in EEI (Col 2 x Col 4 Line 6) (4)	Other Investments (Col 2 x Col 5 Line 6) (5)	E.W. Brown Repairs (a) (6)	Retire Green River Units 1 & 2 (7)	Minimum Pension Liability (8)	Adjustments to Total Co. Capitalization (9)	Adjusted Total Company Capitalization (10)	Jurisdictional Rate Base Percentage (Ex. 3) (11)	Kentucky Jurisdictional Capitalization (12)
1.	Short Term Debt	$ 98,730,542	5.91%	$ -	$ (605,130)	$ (47,165)	$ (323,219)	$ (72,171)	$ -	$ (1,047,685)	$ 97,682,857	87.97%	$ 85,931,609
2.	A/R Securitization	49,300,000	2.95%	-	(302,053)	(23,543)	(161,336)	(36,024)	-	(522,956)	48,777,044	87.97%	42,909,166
3.	Long Term Debt	613,712,167	36.73%	-	(3,760,814)	(293,125)	(2,008,771)	(448,535)	-	(6,511,245)	607,200,922	87.97%	534,154,651
4.	Preferred Stock	40,000,000	2.39%	-	(244,714)	(19,073)	(130,710)	(29,186)	-	(423,683)	39,576,317	87.97%	34,815,286
5.	Common Equity	869,020,543	52.02%	(8,943,279)	(5,326,368)	(415,147)	(2,844,984)	(635,253)	10,462,375	(7,702,656)	861,317,887	87.97%	757,701,345
6.	Total Capitalization	$1,670,763,252	100.00%	$ (8,943,279)	$ (10,239,079)	$ (798,053)	$ (5,469,020)	$ (1,221,169)	$ 10,462,375	$ (16,208,225)	$1,654,555,027		$1,455,512,057

		Kentucky Jurisdictional Capitalization (13)	Capital Structure (14)	Environmental Surcharge Post '94 Plan (Col 14 x Col 15 Line 6) (15)	Adjusted Kentucky Jurisdictional Capitalization (16)	Adjusted Capital Structure (17)	Annual Cost Rate (18)	Cost of Capital (Col 17 x Col 18) (19)
1.	Short Term Debt	$ 85,931,609	5.90%	$ (8,105,837)	$ 77,825,772	5.90%	1.06%	0.06%
2.	A/R Securitization	42,909,166	2.95%	(4,052,919)	38,856,247	2.95%	1.39%	0.04%
3.	Long Term Debt	534,154,651	36.70%	(50,421,056)	483,733,595	36.70%	3.12%	1.15%
4.	Preferred Stock	34,815,286	2.39%	(3,283,551)	31,531,735	2.39%	5.68%	0.14%
5.	Common Equity	757,701,345	52.06%	(71,523,711)	686,177,634	52.06%	11.25%	5.86%
6.	Total Capitalization	$1,455,512,057	100.00%	$(137,387,074)	$1,318,124,983	100.00%		7.25%

(a) E.W. Brown capital adjustment	$ 8,821,000
KU's combustion turbine ownership %	62%
KU's portion of E.W. Brown capital	$ 5,469,020

KENTUCKY UTILITIES

Net Original Cost Kentucky Jurisdictional Rate Base
At September 30, 2003

Title of Account (1)	Kentucky Jurisdictional Rate Base at September 30, 2003 (2)	Other Jurisdictional Rate Base at September 30, 2003 (3)	Total Company Rate Base at September 30, 2003 (4)
1. Utility Plant at Original Cost	$ 3,066,042,028	$ 461,895,529	$ 3,527,937,557
2. Deduct:			
3. Reserve for Depreciation	1,377,898,286	222,320,645	1,600,218,931
4. Net Utility Plant	1,688,143,742	239,574,884	1,927,718,626
5. Deduct:			
6. Customer Advances for Construction	1,455,980	48,637	1,504,617
7. Accumulated Deferred Income Taxes	244,795,245	41,932,500	286,727,745
8. Investment Tax Credit	5,453,270	1,065,870	6,519,140
9. Total Deductions	251,704,495	43,047,007	294,751,502
10. Net Plant Deductions	1,436,439,247	196,527,877	1,632,967,124
11. Add:			
12. Materials and Supplies (a)	57,926,039	9,055,498	66,981,537
13. Prepayments (a)(b)	2,935,464	425,228	3,360,692
14. Emission Allowances (a)	59,742	9,673	69,415
15. Cash Working Capital	52,060,124	5,787,609	57,847,733
16. Total Additions	112,981,369	15,278,008	128,259,377
17. Total Net Original Cost Rate Base	$ 1,549,420,616	$ 211,805,885	$ 1,761,226,501

18. Percentage of KY Jurisdictional Rate Base to Total Company Rate Base 87.97%

(a) Average for 13 months.
(b) Includes prepayments for property insurance only.

KENTUCKY UTILITIES

Estimated Net Reproduction Cost Kentucky Jurisdictional Rate Base
At September 30, 2003

Title of Account (1)	Kentucky Jurisdictional Rate Base at September 30, 2003 (2)	Other Jurisdictional Rate Base at September 30, 2003 (3)	Total Company Rate Base at September 30, 2003 (4)
1. Utility Plant at Reproduction Cost	$ 5,833,095,548	$ 928,941,256	$ 6,762,036,804
2. Deduct:			
3. Reserve for Depreciation	2,941,498,503	493,325,181	3,434,823,684
4. Net Utility Plant	2,891,597,045	435,616,075	3,327,213,120
5. Deduct:			
6. Customer Advances for Construction	1,455,980	48,637	1,504,617
7. Accumulated Deferred Income Taxes	244,795,245	41,932,500	286,727,745
8. Investment Tax Credit	5,453,270	1,065,870	6,519,140
9. Total Deductions	251,704,495	43,047,007	294,751,502
10. Net Plant Deductions	2,639,892,550	392,569,068	3,032,461,618
11. Add:			
12. Materials and Supplies (a)	57,926,039	9,055,498	66,981,537
13. Prepayments (a)(b)	2,935,464	425,228	3,360,692
14. Emission Allowances (a)	59,742	9,673	69,415
15. Cash Working Capital	52,060,124	5,787,609	57,847,733
16. Total Additions	112,981,369	15,278,008	128,259,377
17. Total Net Reproduction Cost Rate Base	$ 2,752,873,919	$ 407,847,076	$ 3,160,720,995
18. Percentage of KY Jurisdictional Rate Base to Total Company Rate Base			87.10%

(a) Average for 13 months.
(b) Includes prepayments for property insurance only.

KENTUCKY UTILITY COMPANY

Estimated Reproduction (or Current) Cost of Utility Plant And Applicable Reserve for Depreciation at September 30, 2003

	Original Cost 9/30/2003 (1)	Effect of Changing Prices (a) (2)	At 9/30/2003 (3)	Jurisdictional Factor (4)	Kentucky Jurisdictional Plant at 9/30/2003 (5)	Other Jurisdictional Plant at 9/30/2003 (6)
1. Plant in Service						
2. Electric Plant :						
3. Steam Production	$ 1,273,555,647	$ 1,595,777,573	$ 2,869,333,220	84.733%	$ 2,431,272,117	$ 438,061,103
4. Hydraulic Production	10,767,813	116,795,498	127,563,311	85.973%	109,670,005	17,893,306
5. Other Production	356,415,646	51,767,905	408,183,551	85.796%	350,205,159	57,978,392
6. Transmission	472,967,439	740,794,521	1,213,761,960	79.459%	964,443,116	249,318,844
7. Distribution	938,776,962	689,398,009	1,628,174,971	93.756%	1,526,511,726	101,663,245
8. General	89,303,194	29,500,253	118,803,447	88.826%	105,528,350	13,275,097
9. Intangible	21,759,199	2,449,708	24,208,907	86.941%	21,047,466	3,161,441
10. Transportation	23,749,240	7,663,368	31,412,607	88.826%	27,902,562	3,510,045
11. Total Plant in Service	3,187,295,140	3,234,146,835	6,421,441,974		5,536,580,501	884,861,473
12. Construction Work In Progress	340,594,830	0	340,594,830	87.058%	296,515,047	44,079,783
13. Total Utility Plant	$ 3,527,889,970	$ 3,234,146,835	$ 6,762,036,804		$ 5,833,095,548	$ 928,941,256
14. Less Reserve for Depreciation:						
15. Steam Production	$ 814,027,523	$ 1,019,984,377	$ 1,834,011,900	84.733%	$ 1,554,013,303	$ 279,998,597
16. Hydraulic Production	8,449,171	91,645,831	100,095,002	85.973%	86,054,676	14,040,326
17. Other Production	58,339,149	8,473,521	66,812,670	85.796%	57,322,598	9,490,072
18. Transmission	260,686,949	408,306,044	668,992,993	79.459%	531,575,142	137,417,851
19. Distribution	390,292,681	286,614,401	676,907,082	93.756%	634,641,004	42,266,078
20. General	33,488,779	11,062,621	44,551,400	88.826%	39,573,227	4,978,173
21. Intangible	13,288,368	1,496,039	14,784,407	86.941%	12,853,711	1,930,696
22. Transportation	21,674,375	6,993,856	28,668,230	88.826%	25,464,842	3,203,388
23. Total Reserve for Depreciation	$ 1,600,246,995	$ 1,834,576,690	$ 3,434,823,684		$ 2,941,498,503	$ 493,325,181
24. Total Utility Plant less Reserve for Depreciation	$ 1,927,642,975	$ 1,399,570,145	$ 3,327,213,120		$ 2,891,597,045	$ 435,616,075

(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 September 30, 2003

		Total (1)
1. Kentucky Jurisdictional Net Original Cost Rate Base - Exhibit 3		$ 1,549,420,616
2. Kentucky Jurisdictional Reproduction Cost Rate Base - Exhibit 4		2,752,873,919
3. Kentucky Jurisdictional Net Operating Income - Actual - Exhibit 1		86,167,531
4. Rate of Return (Actual):		
5. On Kentucky Jurisdictional Net Original Cost Rate Base		5.56%
6. On Kentucky Jurisdictional Reproduction Cost Rate Base		3.13%
7. Kentucky Jurisdictional Adjusted Net Operating Income - Exhibit 1		$ 60,965,866
8. Revenue Increase Applied for - Exhibit 7		58,254,344
9. Income Taxes - Exhibit 1, Reference Schedule 1.34	40.3625 %	(23,512,910)
10. Adjusted Kentucky Jurisdictional Net Operating Income Pro-formed for Rate Increase		95,707,300
11. Requested Rate of Return (Pro-forma):		
12. On Kentucky Jurisdictional Net Original Cost Rate Base		6.18%
13. On Kentucky Jurisdictional Reproduction Cost Rate Base		3.48%

KENTUCKY UTILITIES

Calculation of Overall Revenue Deficiency at September 30, 2003

		(1)
1. Net Operating Income Found Reasonable	$	95,564,061
2. Pro Forma Net Operating Income		60,965,866
3. Net Operating Income Deficiency	$	34,598,195
4. Gross Up Revenue Factor - Exhibit 1, Reference Schedule 1.37		0.59391614
5. Overall Revenue Deficiency	$	58,254,344

Ms. Scott

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In Re the Matter of:	)	
	)	
AN ADJUSTMENT OF THE ELECTRIC RATES, TERMS AND CONDITIONS OF KENTUCKY UTILITIES COMPANY	)))	**CASE NO: 2003-00434**

TESTIMONY OF
VALERIE L. SCOTT
DIRECTOR, FINANCIAL PLANNING AND ACCOUNTING – UTILITY OPERATIONS
KENTUCKY UTILITIES COMPANY

December 29, 2003

Filed: December 29, 2003

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

A. My name is Valerie L. Scott. I am Director of Financial Planning and Accounting – Utility Operations for Kentucky Utilities Company ("KU"). My business address is 220 West Main Street, Louisville, Kentucky.

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 September 30, 2003. 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
• FERC Audit Reports	Section 10(6)(l)	Tab 31
• FERC Form 1	Section 10(6)(m)	Tab 32
• Depreciation Study	Section 10(6)((n)	Tab 33
• 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
• Pro Forma Adjustments – Operating Budget	Section 10(7)(d)	Tab 45

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 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. It is calculated in accordance with the Commission's determination in its Order of January 7, 2000 in Case No. 98-474.

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

A. This adjustment is necessary to eliminate the Earnings Sharing Mechanism revenues collected during the test period that are included in the ultimate consumer revenue classes and are not included in Rate Refund Account 449. The impact of rate mechanisms like the Earnings Sharing Mechanism should be removed from the test year revenues when assessing the adequacy of base rates.

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

A. This adjustment has been made to eliminate the impact of the revenues recorded in the test year associated with the Earnings Sharing Mechanism, Environmental Cost Recovery and Fuel Adjustment Clause from Rate Refund Account 449. The impact of rate mechanisms, such as these, should be removed from the test year revenues when assessing the adequacy of base rates.

Q. Please explain the adjustment to operating expenses shown in Reference Schedule 1.11 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 on net plant in service as of September 30, 2003, using proposed depreciation rates recommended by KU's expert, Earl M. Robinson of AUS Consultants, in the study he prepared for KU and filed in this proceeding. Mr. Robinson's testimony explains the changes in depreciation rates and the analysis supporting the changes. The adjustment is calculated in accordance with the methodology approved by the Commission in Louisville Gas and Electric Company ("LG&E") Case No. 2000-080.

Q. Please explain the adjustment to operating expenses shown in Reference Schedule 1.12 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 September 30, 2003, and includes specific adjustments for wages, payroll taxes and KU 401(k) match. Page 1 of 4 presents an overview of the adjustment.

Page 2 of 4 of Reference Schedule 1.12 of Exhibit 1 shows the adjustment for wage expenses. The adjustment reflects the annualized base labor of all KU employees at September 2003.

Under the terms of the current union contracts, beginning August 1, 2003, union employees received a three percent wage increase, and a three percent increase in overtime wages. An adjustment has been made to increase union overtime for ten months of the test year prior to the August contract increase. The adjustment also reduces the Team Incentive Award ("TIA") by an amount guaranteed by E.ON as part of the acquisition of Powergen. As part of that transaction, E.ON guaranteed all eligible employees 100 percent of their payouts under the TIA program for 2002. For the 2002 TIA payment made in March 2003, KU has reduced the adjustment to remove the amount guaranteed by E.ON to the extent that it exceeded what employees would have been paid in March 2003, without the guarantee.

Page 3 of 4 of Reference Schedule 1.12 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 wages.

Finally, page 4 of Reference Schedule 1.12 of Exhibit 1 shows the calculation of the component of the labor adjustment to reflect the resulting increases KU's match of 401(k) contributions as applied to the twelve months ended September 30, 2003, due to the adjustments to the increases in wages.

The labor adjustment follows the methodology approved by the Commission for this type of adjustment in LG&E Case No. 2000-080.

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

A. This adjustment is necessary to annualize the pension and post-retirement medical benefit expenses for the test period. The adjustment is the difference in the net periodic cost calculated by Mercer for 2003 and the amount included in the test period.

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 a normalized level of storm damage expenses based upon a four-year average adjusted for inflation. KU has only four years of storm damage information available. This adjustment is calculated in accordance with the methodology approved by the Commission in Case No. 90-158.

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

A. This adjustment eliminates advertising expenses. 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. The advertising expenses eliminated by this adjustment are primarily institutional and promotional in nature.

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

A. This adjustment is necessary to include the expenses incurred in conjunction with this electric base rate case in operating expenses. KU estimates the total electric rate case expense to be $1,057,368. The adjustment has been amortized over three years at a rate of $352,456 per year. The adjustment will be trued-up as actual expenditures are incurred. The Commission approved the recovery of rate case expenses in LG&E Case No. 2000-080.

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

A. This adjustment is necessary to reflect the amortization expenses deferred by KU for the Earnings Sharing Mechanism audit in operating expenses. The amount of the adjustment is based on expenses incurred and projected to be incurred through the end of the Commission's investigation. The amount is then amortized over three years at a rate of $58,333 per year.

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

A. The adjustment is necessary to remove the amortization of One-Utility costs as a non-recurring expense because these costs were completely amortized by September 30, 2003. The remaining amount of the related regulatory asset was amortized during the test year. The Commission approved the establishment of the regulatory asset and the amortization of the One-Utility costs in LG&E Case No. 2000-080.

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." The normalization is based on five years. The adjustment is calculated consistent with the adjustment used in LG&E Case No. 2000-080. The amount was then adjusted for inflation to be consistent with the methodology used to calculate the storm damage normalization adjustment.

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

A. This adjustment is to recognize the Value Delivery Team net savings to shareholders recognized by the Commission in its Order of December 3, 2001 in Case No. 2001-169. In its December 3, 2001 Order in Case No. 2001-169, the Commission approved KU's Value Delivery Surcredit Rider as part of the Settlement Agreement in that proceeding. Under the terms of the Settlement Agreement, the net savings from the Value Delivery Team initiative are shared 40 percent with the customers and 60 percent with the shareholders. The customers' share of the savings is distributed through the Value Delivery Surcredit Rider that took effect in December 2001. Since the end of 2001, KU's customers have received a total of $3,480,000 in bill credits and will receive an additional $2,880,000 in bill credits in 2004. KU and LG&E have achieved substantial savings under the VDT initiative reviewed by the Commission in Case No. 2001-169. Absent such savings, the needed increase in rates would have been larger than the Company is actually requesting in this proceeding. Thus, although the adjustment to recognize the shareholder portion of savings under the VDT initiative results in an upward adjustment of operating expenses, the overall effect of the VDT program has been to lower customers' bills, with the benefit to be shared by customers and shareholders, as per the Commission Order. The $2,895,000 adjustment to operating expenses of KU's operations shown in Reference Schedule 1.20 of Exhibit 1 is necessary to reflect the shareholders' portion of the net savings from the Value Delivery Team initiative for the test year. The adjustment to expenses is consistent with the ratemaking treatment of the shareholders' portion of the merger surcredit savings in Case No. 98-474.

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

A. This adjustment is to true-up the Value Delivery Team customer surcredit and amortization of expenses recorded in the test year to the amount approved by the Commission in its December 3, 2001 Order in Case No. 2001-169.

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

A. This adjustment is made to reflect the customers' and shareholders' portions of the merger savings in accordance with the Settlement Agreement approved by the Commission's October 16, 2003 Order in Case No. 2002-00429. The customers' portion of the savings is trued-up to the amount attributed to the shareholder to reflect the 50/50 saving split per the Settlement Agreement. Absent this adjustment, shareholders would lose their share of such savings that were approved by the Commission in its Order.

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

A. This adjustment is necessary to reflect the elimination of merger amortization expenses from the LG&E Energy Corp. acquisition of KU Energy Corporation. The merger expenses were fully amortized by September 30, 2003, with the remaining amount of the related regulatory asset amortized during the test year. The amount amortized during the test year will not be a recurring expense. The Commission approved the establishment of the regulatory asset and the amortization of the merger expense amount in Case No. 97-300.

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

A. As a member of the Midwest Independent Transmission System Operator, Inc. ("MISO"), KU received monthly credits during a portion of the test year pursuant to an agreement with MISO to defer increased demand charges until 2007. These credits were applied to billings of MISO's Schedule 10 administrative costs. The credits are reversed from the test year to restate MISO Schedule 10 expenses to actual since the credits will not continue after 2003 when MISO begins charging the higher demand charges.

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

A. In June of 2001, the Financial Accounting Standards Board ("FASB") issued SFAS No. 143, *Accounting for Asset Retirement Obligations*. Under SFAS No. 143, entities are required to recognize and account for certain asset retirement obligations in a manner different from the way that KU and other public utilities have traditionally recognized and accounted for such costs. Specifically, if a legally enforceable asset retirement obligation ("ARO"), as defined by SFAS No. 143, is deemed to exist, an entity must measure and record the liability for the ARO on its books. The liability must be recorded at fair market value in the period during which the liability is incurred. SFAS No. 143 defines "fair market value" as the amount that the entity would be required to pay in an active market to settle the ARO. SFAS No. 143 also provides that if market prices are not available, estimates of their fair value can be calculated by discounting the estimated cash flows associated with the ARO to their present value at the date the liability is to be recorded. The value of the liability is accreted over the life of the asset to account for the time value of money, so that at the time of retirement the recorded ARO liability will be sufficient to provide the cash required to meet the legal obligation.

Under SFAS No. 143, at the time the liability is recorded, a corresponding and equivalent ARO asset is also recorded on the entity's books to recognize the cost of removal as an integral part of the cost of the associated tangible asset. The ARO asset is then depreciated over the life of the asset, similar to the depreciation of other assets.

In addition to the forward-looking requirements of SFAS No. 143, entities are required to recognize the cumulative impact on their financial statements resulting from the implementation of SFAS No. 143. This cumulative impact amounts to a transition entry on the entity's books. The cumulative effect impact represents the ARO asset depreciation and ARO liability accretion that would have been recorded had the asset and liability been recorded by the company when the original asset was placed in service. SFAS No. 143 recognized that many rate-regulated entities provide for costs related to retirement of certain long-lived assets and recover those amounts in rates charged to their customers. Where the timing of cost recognition under SFAS No. 143 and under rate recovery methods differ, this statement indicates a regulatory asset or liability shall be recorded for the difference subject to the provisions of SFAS No. 71, *Accounting for the Effects of Certain Types of Regulation*.

For ratemaking purposes, the impact of implementing SFAS No. 143 overstates KU's above-the-line income at a level that is not representative of its operations. The cumulative effect adjustments are recorded below-the-line in FERC USofA Account No.

435, while the corresponding amount of regulatory credit is recorded above-the-line in Account No. 407. While this accounting is required for the transition of implementing SFAS No. 143 in 2003, it overstates KU's net operating income for the test year ended September 30, 2003, for ratemaking purposes since the offsetting charge is recorded below-the-line.

On October 30, 2002, the Federal Energy Regulatory Commission ("FERC") issued *Notice of Proposed Rulemaking to Revise Accounting, Financial Reporting, and Rate Filing Requirements for Asset Retirement Obligations* in Docket No. RM02-7-000. Following the receipt and consideration of comments in response to this notice, on April 9, 2003, the FERC issued a final rule in Docket No. RM02-7-00, Order No. 631, Final Rule (Issued April 9, 2003) ("FERC Order No. 631"). Under FERC Order No. 631, a utility must recognize a liability for the fair value of an ARO, calculated on a net present value basis, at the time the asset is constructed or acquired, or when a change in law creates a legal obligation to perform the retirement activities. FERC Order No. 631 generally adopted the requirements of SFAS No. 143.

Reference Schedule 1.25 of Exhibit 1 shows the adjustment necessary to net the cumulative effect of this accounting change against the corresponding regulatory credit in the test year.

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

A. This adjustment has been made to reflect the October 2003, reduction of 27 employees in the Information Technology department of LG&E Energy Services, Inc. The adjustment to expense reflects the labor and labor-related expenses charged to KU in the test year reduced by one-third of the costs to achieve the savings in order to effectively amortize those costs over a three-year period.

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

A. This adjustment is necessary to remove legal expenses incurred by KU in the test year associated with the litigation against the supplier of two combustion turbines located at KU's E.W. Brown Power Station. The adjustment is necessary to remove KU's share of non-recurring legal expenses. KU owns a 62 percent interest in both of the combustion turbines.

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

A. This adjustment is for sales tax refunds KU received during the test year that related to sales tax expenses incurred prior to the test year. This adjustment removes the amount of the refund from the test year since these refunds will not occur in the future.

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

A. This adjustment is to reflect an increase in purchase power demand costs. Under the current power contract between KU and Owensboro Municipal Utilities ("OMU"), KU will pay OMU an increase in demand charges for KU's portion of the OMU's environmental compliance with NOx regulations beginning July 1, 2004. The adjustment reflects KU's estimate of increases in demand charges which will begin July 1, 2004.

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

A. This adjustment is to reflect the normalization of net expenses incurred by KU as a result of the 36-hour ice storm during February 15 and 16, 2003. Central Kentucky received over two inches of ice accumulation, interrupting electric service to over 141,000 KU customers. Some areas had ice accumulations in excess of two inches, increasing the load on structural members to more than eight times their design capability. The ensuing restoration effort involved over 2,000 KU, LG&E and contractor personnel. Within one week, all but 9,000 customers had service restored.

KU incurred $15.5 million in operating and maintenance costs because of the ice storm and received an insurance reimbursement during the test year of $8.9 million. The adjustment is to amortize the net amount of $6.6 million over a five-year period. The five-year period is consistent with the amortization approved by the Commission for LG&E's 1974 tornado damage in Case No. 6220.

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

A. This adjustment is for management audit fees for the 1992 Commission audit of KU. Following that audit, the Commission authorized KU to establish a regulatory asset of the management audit fee annualized over three years. KU is proposing to include a three year annualized amount of the management audit expense as part of its operating expenses in order to collect the management audit fee.

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

A. The adjustment is to reduce operation and maintenance expenses for the amounts incurred solely for the operation of KU's Green River Units 1 and 2 during the test period. These units will be retired by early 2004 and these costs will not be incurred in the future.

Q. Does this conclude your testimony?

A. Yes.

288511.06

VERIFICATION

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

The undersigned, **Valerie L. Scott**, being duly sworn, deposes and says she is Director of Financial Planning and Accounting – Utility Operations 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 29th day of December 2003.

Melody L. Hukle (SEAL)
Notary Public

My Commission Expires:

November 26, 2007

APPENDIX A

Valerie L. Scott

Director, Financial Planning & Accounting – Utility Operations
LG&E Energy Corp.
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)

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 LG&E Energy Corp.:

- 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

Mr. Robinson

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

AN ADJUSTMENT OF THE ELECTRIC RATES, TERMS AND CONDITIONS OF KENTUCKY UTILITIES COMPANY	)))))	CASE NO. 2003-00434

DIRECT TESTIMONY
OF
EARL M. ROBINSON
PRESIDENT AND CHIEF EXECUTIVE OFFICER
AUS CONSULTANTS -
WEBER FICK & WILSON DIVISION

Concerning
Depreciation Service Life Study

December 29, 2003

Filed: December 29, 2003

Q1. STATE YOUR NAME, OCCUPATION AND BUSINESS ADDRESS.

A1. My name is Earl M. Robinson. I am President and Chief Executive Officer of the Weber Fick & Wilson Division (WFW) of AUS Consultants - Utility Services. WFW is a public utility consulting firm specializing in the performance of various financial studies including depreciation, valuation, cost of service and other analysis for the utility industry and regulatory agencies. AUS Consultants provides a wide spectrum of consulting services through its various affiliated groups which include Utility Services, Valuation Services, ICR Survey Research, and Marketing Systems. The Weber Fick & Wilson Division is located at 1000 North Front Street, Suite 200, Wormleysburg, Pennsylvania 17043.

Q2. DO YOU HAVE AN APPENDIX WHICH CONTAINS YOUR QUALIFICATIONS, EXPERIENCE AND PRIOR APPEARANCES?

A2. Yes. Appendix A to my direct testimony contains a summary of all such information.

Q3. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A3. The purpose of my testimony is to set forth the results of my review and analysis of the plant in service of Kentucky Utilities (the Company) which was conducted in the process of conducting a depreciation study and report as of December 31, 2002. In completing the study, my task included an investigation and analysis of the Company's historical data, together with an interpretation of past experience and future expectancy to determine the remaining lives of the Company's property. The study also utilized the resulting remaining lives, the results of our salvage analysis, the Company's vintaged plant in service investment and depreciation reserve to develop recommended average remaining life depreciation rates, and depreciation expense related to the Company's plant in service.

Q4. WHAT IS YOUR PROFESSIONAL OPINION WITH REGARD TO THE COMPLETED DEPRECIATION STUDY RESULTS?

A4. In my opinion, the proposed depreciation rates resulting from the completion of the comprehensive depreciation study are reasonable and appropriate given that they incorporate the life and net salvage parameters anticipated for each of the property group investments over their average remaining lives.

Q5. WHAT STEPS WERE INVOLVED IN PREPARING THE SERVICE LIFE AND SALVAGE DATA BASE?

A5. The completion of the comprehensive depreciation analysis through December 31, 2002 included a detailed analysis of the Company's fixed capital books and records. The Company's historical investment cost records for each account have been assembled into a depreciation data base upon which detailed service life and salvage analysis can be performed using standard depreciation procedures.

Q6. WHAT IS THE PURPOSE OF DEVELOPING THE HISTORICAL DATA BASE?

A6. The historical data is a basic depreciation study tool that is assembled to enable the preparation of a depreciation study. The historical data base is a source from which to prepare historical analysis. These analytical results are used to make assessments and judgements concerning the life and salvage factors being achieved, and (along with information relative to current and prospective factors) to benchmark the estimated future lives over which to recover the Company's depreciable fixed capital investments. In utilizing this standard depreciation process, the Company's developed depreciation data base compiled through December 31, 2002 was used to develop observed life tables upon which historical analysis was performed. Likewise, the net salvage data base was used as a basis to identify historical experience and trends and to determine each property group's recommended net salvage factors.

Q7. IN THE PREPARATION OF THIS AND OTHER DEPRECIATION STUDIES, DO YOU DRAW INFORMATION FROM ADDITIONAL SOURCES WHEN ESTIMATING SERVICE LIFE AND SALVAGE PARAMETERS?

A7. Yes, in addition to the historical data obtained from the Company's books and records, information is obtained from Company personnel relative to current operations and future expectations. I also incorporated professional knowledge obtained from my more than thirty (30) years of utility industry depreciation experience, along with depreciation data assembled from other operating companies.

Q8. DO YOU HAVE A DEPRECIATION STUDY REPORT WHICH SUMMARIZES THE RECOMMENDATIONS RESULTING FROM THE DEPRECIATION SERVICE LIFE AND SALVAGE STUDY?

A8. Yes, the results are included in a separately bound volume (Appendix C) entitled "Kentucky Utilities Depreciation Study as of December 31, 2002" which summarize the results of my service life and salvage analysis.

Q9. DO YOU HAVE A SUMMARY OF THE DEPRECIATION RATES THAT YOU DEVELOPED AND ARE PROPOSING FOR EACH OF THE COMPANY'S DEPRECIABLE PROPERTY GROUPS?

A9. Yes, Appendix B-KU contains an account level summary of the present and proposed depreciation rates which are also set forth in detail in Section 2 of the depreciation study report.

Q10. RELATIVE TO THE COMPANY'S GENERATING STATION INVESTMENTS, HAVE YOU DEVELOPED DEPRECIATION RATES APPLICABLE TO EACH INDIVIDUAL PLANT SITE?

A10. Yes, Table 1-Plant Site, within Section 2 of the depreciation study report, contains depreciation rates for each plant site.

Q11. COULD YOU PLEASE BRIEFLY DESCRIBE THE INFORMATION INCLUDED WITH THE DEPRECIATION REPORT.

A11. The report is segregated into seven (7) sections. Two (2) key areas of the report are Section 2 and Section 4. Section 2 includes the summary schedules listing the present and proposed depreciation rates for each depreciable property group and other depreciation rate development schedules. Section 4 contains a narrative of factors considered in selecting service life parameters for the Company's property. The various other sections of the report contain detailed information and/or documentation supporting the schedules contained in Sections 2 and 4. A detailed table of contents following the letter of transmittal lists the complete contents of the report. In addition, Section 1 contains a brief narrative summary or overview of the entire report.

Q12. WHAT WAS THE SOURCE OF THE DATA WHICH WAS UTILIZED AS A BASIS FOR THE DEPRECIATION RATES?

A12. As previously discussed, all of the Company's historical data utilized in the course of performing the detailed service life and salvage study were obtained from the Company's books and records. The historical vintaged data (additions, retirements, adjustments, and balances), were obtained for each depreciable property group.

Q13. ARE THERE STANDARD METHODS UTILIZED TO COMPLETE THE SERVICE LIFE ANALYSIS OF A COMPANY'S HISTORICAL PROPERTY INVESTMENTS?

A13. Yes. As discussed in Section 3 of the depreciation study report (Appendix C) as well as later in this testimony, the two most common methods are the Retirement Rate Method and the Simulated Record Method.

Q14. WAS THE STUDY PREPARED UTILIZING THOSE ACCEPTED STANDARD METHODS?

A14. Yes. Those methods were utilized in the performance of the comprehensive depreciation study of the Company's property.

Q15. WHAT METHOD, PROCEDURE, AND TECHNIQUE WAS UTILIZED TO DEVELOP THE DEPRECIATION RATES FOR THE COMPANY'S PROPERTY?

A15. Inherent with all depreciation calculations, there is an overall method, such as the Straight Line Method, to depreciate property. Secondly, the property is grouped in a certain manner, such as by sub-groups of vintages to develop applicable service lives.

Finally, the investment needs to be recovered over a period, such as the Whole Life or Remaining Life segment of the property. The depreciation rates set forth in my depreciation study report (Appendix C) were developed by utilizing the Straight Line Method, the Broad Group Procedure, and the Average Remaining Life Technique.

Q16. WHY WAS THE INDICATED DEPRECIATION APPROACH UTILIZED?

A16. The Company, like any other business, includes as an annual operating expense an amount which reflects a portion of the capital investment which was consumed in providing service during the accounting period. The straight line method is widely understood, recognized, and utilized almost exclusively for depreciating utility property. The broad group procedure recovers the Company's investments over the average period of time in which the property is providing service to the Company's customers, and was the utilized depreciation procedure. Lastly, the annual depreciation amount utilized needs to be based upon the productive life over which the undepreciated capital investment is recovered. The Company's utilization of the applicable annual depreciation over the average remaining life assures that the Company's property investment is fully recovered over the useful life of the property, and inter-generational inequities are avoided. The determination of the productive remaining life for each property group includes a study of both past experience and future expectations. Finally, the approach is consistent with depreciation methods and procedures generally utilized and accepted by this Commission in the Company's rate Order at KPSC Case No. 2001-140 dated December 3, 2001.

Q17. PLEASE EXPLAIN THE UTILIZATION OF GROUP DEPRECIATION PROCEDURES.

A17. Group depreciation procedures are utilized to depreciate property when more than one item of property is being depreciated. Such an approach is appropriate because all of the items within a specific group typically do not have identical service lives, but have lives which are dispersed over a range of time. Utilizing a group depreciation procedure allows for a condensed application of depreciation rates to groups of similar property in lieu of extensive depreciation calculations on an item by item basis. The two more common group depreciation procedures are the Broad Group (BG) and Equal Life Group (ELG) approach.

The Broad Group Procedure recovers the investment within the asset group over the average service life of the property group. Given that there is dispersion within each property group there are variations of retirement ages for the many investments within each property group. That is, some properties retire early (before average service life) while others retire at older ages (after average service life) with the weighted average retirement age of the total property group being the attained average service life. The Broad Group Procedure was used consistent with the historic and current practice.

By comparison, the ELG Procedure allocates the capital cost of a group property to annual expense in accordance with the consumption of the property group providing service to customers. In this regard, the company's customers are charged with the cost of the property consumed in providing them service during the applicable service period.

The more timely return of plant cost is accomplished by fully accruing each unit's cost during its service life, thereby, reducing the risk of incomplete cost recovery.

Q18. WHAT TECHNIQUE DID YOU UTILIZE AND WHY DID YOU USE IT?

A18. I utilized the Average Remaining Life Technique because it incorporates all the Company's fixed capital cost components thereby better assuring full recovery of the Company's embedded net plant investment. The average remaining life technique gives consideration to not only the average service life and survival characteristic plus the net salvage component but also recognizes the level of depreciation which has been accrued to date in developing the proposed depreciation rate. The Average Remaining Life Technique is used by regulated companies and regulatory agencies because it allows full recovery by the end of the property's useful life -- no more and no less. Furthermore, the average remaining life technique is widely used by the electric, gas, water, and telephone industries throughout the nation as a basis for developing annual depreciation rates and expense. As previously noted, this is also the technique utilized in developing the Company's current depreciation rates.

Q19. WHAT FACTORS INFLUENCE THE DETERMINATION OF THE RECOMMENDED ANNUAL DEPRECIATION RATES INCLUDED IN THE COMPANY'S DEPRECIATION REPORT (APPENDIX C)?

A19. The depreciation rates reflect four (4) principal factors, namely (1) the plant in service by vintage, (2) the book depreciation reserve, (3) the future net salvage, and (4) the composite remaining life from the property group. Related factors to be considered in arriving at the service life are the average age, realized life and the survival characteristics. The net salvage estimate is influenced by both past experience and future estimates of cost of removal and gross salvage amounts.

Q20. WOULD YOU PLEASE EXPLAIN THE PRINCIPAL ASSUMPTIONS CONSIDERED WHEN UTILIZING THE COMPANY'S AUTHORIZED DEPRECIATION APPROACH?

A20. Through the utilization of the Company's depreciation approach, the Company will recover the undepreciated fixed capital investment via amounts of annual depreciation expense in each year throughout the useful life of the property. That is, the Average Remaining Life Technique incorporates the related future life expectancy of the property, the vintaged surviving plant in service, the survival characteristics, together with the book depreciation reserve balance and future net salvage in developing the amounts for each property account. Accordingly, Average Remaining Life depreciation meets the objective of providing a Straight Line recovery of the Company's fixed capital property investments.

Q21. IS THE COMPANY'S DEPRECIATION CALCULATION A UNIT OR GROUP DEPRECIATION APPROACH?

A21. The Company's depreciation calculation, as applied in this study, is a group depreciation approach. The "group" refers to the method of calculating annual depreciation on the summation of the investment in any one plant group rather than calculating depreciation for each individual unit. In theory, each unit achieves average service life by the time of retirement, accordingly, the full cost of the investment is credited to plant in service when the retirement occurs and likewise the depreciation reserve is debited with an equal retirement cost. No gain or loss is recognized at the time of property retirement because of the assumption that the retired property was at average service life.

Q22. WHAT ARE THE NET SALVAGE FACTORS THAT ARE INCLUDED IN THE DETERMINATION OF DEPRECIATION RATES?

A22. Net salvage is the difference between gross salvage, or what is received when an asset is disposed of, and the cost of removing it from service. Net salvage is said to be positive if gross salvage exceeds the cost of removal, but if cost of removal exceeds gross salvage the result is then negative salvage. Many retired assets generate little, if any positive salvage. Conversely, numerous of the Company's asset groups generate negative net salvage at end of their life from the cost of removal.

The cost of removal includes such costs as demolishing, dismantling, tearing down, disconnecting or otherwise retiring/removing plant, as well as any environmental clean up costs associated with the property. Salvage includes proceeds received for any sale of plant.

Net salvage experience is studied for a period of years to determine the trends which have occurred in the past. These trends are considered together with any changes that are anticipated in the future to determine the future net salvage factor for remaining life depreciation purposes. The net salvage percentage is determined by relating the total net positive or negative salvage to the book cost of the property investment retired.

The method used to estimate the retirement cost is a standard analysis approach which is used to identify a company's historical experience with regard to what the end of life cost will be relative to the cost of the plant when first placed into service. This information, along with knowledge about the average age of the historical retirements that have occurred to date, enables the depreciation professional to estimate the level of retirement cost that will be experienced by the Company at the end of each property group's useful life. The study methodology utilized has been extensively set forth in depreciation textbooks and has been the accepted practice by depreciation professionals for many decades. Furthermore, the cost of removal analysis approach is the current standard practice used for mass assets by essentially all depreciation professionals in estimating future net salvage for the purpose of identifying the applicable depreciation for a property group. There is a direct relationship to the installation of specific plant in service and its corresponding removal in that the installation is its beginning of life cost while the removal is its end of life cost. Also, it is important to note that average remaining life based depreciation rates incorporate future net salvage which is routinely more representative of recent versus long-term past average net salvage.

The Company's historical net salvage experience was analyzed to identify the historical net salvage factor for each applicable property group. This analysis routinely identifies that historical retirements have occurred at average ages significantly prior to the property group's average service life. This occurrence of historical retirements, at an age which is significantly younger than the average service life of the property category, clearly demonstrates that the historical data does not appropriately recognize the true level of retirement cost at the end of the property's useful life. An additional level of cost to retire will occur due to the passage of time until all the current in service plant is retired at end of life. That is, the level of retirement costs will increase over time until the average service life is attained. The estimated additional inflation, within the estimate of retirement cost, is related to those additional year's cost increases (primarily higher labor costs over time) that will occur prior to the end of the property group's average life.

To provide an additional explanation of the issue, several general principles surrounding property retirements and related net salvage need to be highlighted. Those are that as property continues to age, the retirement of assets, if generating positive salvage when retired, will typically generate a lower percent of positive salvage. By comparison, if the class of property is one that typically generates negative net salvage (cost of removal), with increasing age at retirement the negative percentage as related to original cost will typically be greater. This situation is routinely driven by the higher labor cost with the passage of time.

Next, a simple example will aid in a better understanding of the above discussed net salvage analysis and the required adjustment to the historical analysis results. Assume the following scenario. A company has two (2) cars, Car #1 and Car #2, each purchased for $20,000. Car #1 is retired after 2 years and Car #2, is retired after 10 years. Accordingly, the average life of the two cars is six (6) years (2 Yrs. Plus 10 Yrs./2). Car #1 generates 75% salvage or $15,000 when retired and Car #2 generates 5% salvage or $1,000 when retired.

Unit	Cost	Ret. Age (Yrs)	% Salv.	Salvage Amount
Car #1	$20,000	2	75%	$15,000
Car #2	20,000	10	5%	1,000
Total	40,000	6	40%	16,000

Assume an analysis of the experienced net salvage at year three (3). Based upon the Car #1 retirement, which was retired at a young age (2 Yrs.) as compared to the average six (6) year life of the property group, the analysis indicates that the property group would generate 75% salvage. This analysis indication is incorrect and is the result of basing the estimate on incomplete data. That is, the estimate is based upon the salvage generated from a retirement that occurred at an average age which is far less than the average service life of the property group. The actual total net salvage that occurred over the average life of the assets (which experienced a six (6) year average life for the property group) is 40% as opposed to the initial incorrect estimate of 75%.

This is exactly the situation with the majority of the Company's historical net salvage data except that most of the Company's plant property groups routinely experience negative net salvage (cost of removal) as opposed to positive salvage.

Q23. PLEASE EXPLAIN WHAT FACTORS AFFECT THE LENGTH OF THE AVERAGE SERVICE LIFE THAT THE COMPANY'S PROPERTY MAY ACHIEVE.

A23. Several factors contribute to the length of time or average service life which the property achieves. The three major categories under which these factors fall are: (1) physical; (2) functional; and, (3) contingent casualties.

The physical category includes such things as deterioration, wear and tear and the action of the natural elements. The functional category includes inadequacy, obsolescence and requirements of governmental authorities. Obsolescence occurs when it is no longer economically feasible to use the property to provide service to customers or when technological advances have provided a substitute of superior performance. The remaining factor of contingent casualties relates to retirements caused by accidental damage or construction activity of one type or another.

In performing the life analysis for any property being studied, both past experience and future expectations must be considered in order to fully evaluate the circumstances that may have a bearing on the remaining life of the property. This ensures the selection of an average service life that best represents the expected life of each property investment.

Q24. WHAT STUDY PROCEDURES WERE UTILIZED TO DETERMINE DEPRECIATION RATES FOR THE COMPANY'S PROPERTY?

A24. Several study procedures were used to determine the prospective service lives recommended for the Company's plant in service. These include the review and analysis of historical, as well as anticipated retirements, current and future construction technology, historical experience and future expectations of salvage and cost of removal as related to plant investment.

Service lives are affected by many different factors, some of which can be obtained from studying past experience, others of which may rely heavily on future expectations. When physical aspects are the controlling factor in determining the service life of property, historical experience is a useful tool in selecting service lives. In cases where there are changes in technology, regulatory requirements, Company policy or a less costly alternative develops, historical experience is of lesser or little value. However, even when considering physical factors, the future lives of various properties may vary from that experienced in the recent past.

While various methods are available to study historical data, the two (2) most commonly used methods utilized to determine average service lives for a Company's property are the Retirement Rate Method and the Simulated Plant Record Method. Given that the Company maintains vintaged investment records, for the majority of its plant accounts, the Retirement Rate Method was the method utilized to analyze those historical data. For the remaining property groups for which aged retirement data was not available, the Simulated Plant Record Method was utilized for life analysis.

Q25. PLEASE EXPLAIN THE USE OF THE RETIREMENT RATE METHOD.

A25. In this method of analysis, the Company's actuarial service life data, which is identified by age, is used to develop a survivor curve (observed life table). This survivor curve is the basis upon which smooth curves are fitted to subsequently determine the average service life being experienced by the account under study. Computer processing provides the opportunity to review various experience bands throughout the life of the account to observe trends and changes. For each experience band analysis, an "observed life table" is constructed using the exposure and retirement experience within the selected band of years. In some cases, the total life cycle of the property has not been achieved and the experienced life table, when plotted, results in a "stub curve." It is this "stub curve" or total life curve, if achieved, which is matched or fitted to the standard Iowa curves. The matching process is performed both by computer analysis, using a least squares technique, and by plotting the observed life tables to the selected smooth curves for visual reference. The fitted smooth curve is a benchmark that provides a basis to determine the estimated average service life for the property group under study.

Q26. DOES SECTION 5 OF THE DEPRECIATION STUDIES CONTAIN ANY CHARTS, ETC. WHICH COMPARE THE ANALYSIS OF THE COMPANY'S ACTUAL HISTORICAL DATA TO THE SERVICE LIFE PARAMETERS YOU ARE PROPOSING AS A BASIS FOR YOUR RECOMMENDED ANNUAL DEPRECIATION RATES?

A26. For the majority of the Company's plant accounts the Company's records included vintaged retirement data and were studied via the Retirement Rate Method. The resulting observed life tables and plottings of the selected Iowa curves are contained in the depreciation study reports included in Section 5 of Appendix C. Likewise, the accounts for which the Simulated Plant Record Method was used for analysis and plottings of the actual versus simulated balances are contained in Section 5.

Q27. IN DESCRIBING THE RETIREMENT RATE METHOD, YOU REFERRED TO THE USE OF THE IOWA OR SMOOTH SURVIVOR CURVES. COULD

YOU GENERALLY DESCRIBE THE CURVES AND THE PURPOSE FOR THEIR USE?

A27. The preparation of a depreciation study or theoretical depreciation reserve typically incorporates smooth curves to represent the experienced or estimated survival characteristics of the property. The "smoothed" or standard survivor curves generally used are the "Iowa" family of curves developed at Iowa State University which are widely used and accepted throughout the utility industry. The shape of the curves within the Iowa family are dependent upon whether the maximum rate of retirement occurs before, during or after the average service life. If the maximum retirement rate occurs earlier in life, it is a left (L) mode curve; if occurring at average life, it is a symmetrical (S) mode curve; if it occurs after average life, it is a right (R) mode curve. In addition, there is the origin (O) mode curve for plant which has heavy retirements at the beginning of life.

Many times, actual Company plant has not completed its life cycle; therefore, the survivor table generated from the Company is not complete. This situation requires an estimate be made with regard to the incomplete segment of the property group's life experience. Further, actual Company experience often varies, making its utilization for average service estimation difficult. Accordingly, the Iowa curves are used to both extend Company experience to zero percent surviving as well as to smooth actual Company data.

Q28. WHAT IS THE PRINCIPAL REASON FOR COMPLETING THE DETAILED HISTORIC LIFE AND SALVAGE ANALYSIS?

A28. The detailed historical analysis is prepared and used as a tool from which to make informed assessments as to the appropriate service life and salvage parameters over which to recover the Company's investment. In addition to the available historic data, consideration must be given to current events, the Company's ongoing operations, management's future plans, and general industry events which are anticipated to impact the life to be achieved by the plant in service.

Q29. WHAT IS THE BASIS OF THE COMPANY'S CURRENT DEPRECIATION?

A29. The depreciation rates are based upon depreciation parameters set forth in a study completed using investment data through December 31, 1999 together with the Broad Group Procedure applied on an Average Remaining Life basis. The current account level depreciation rates for Kentucky Utilities composite to an equivalent annual depreciation rate of 2.93% when applied to each of the December 31, 2002 account balances.

Q30. WHAT ARE THE MOST NOTABLE CHANGES IN ANNUAL DEPRECIATION RATES AND EXPENSE BETWEEN THE PRESENT AND PROPOSED DEPRECIATION AS PER SECTION 2 OF THE DEPRECIATION REPORT (APPENDIX C)?

A30. With regard to Kentucky Utilities plant in service (Appendix C) several of the accounts did reflect marked changes (as outlined in Section 4 of this report) from the previously utilized depreciation rates. Those accounts for which the most notable depreciation expense changes occurred in comparison to the present depreciation rates include Account 311 - Structures & Improvements, Account 312 - Boiler Plant Equipment, Account 314 - Turbogenerator Units, Account 315 - Accessory Electric Equipment, Account 343 - Prime Movers, Account 365 - Overhead Conductors and Devices, Account 369 - Services, and Account 370 - Meters.

The proposed depreciation rate for Account 312 - Boiler Plant Equipment, increased from 2.79 percent to 3.18 percent. The basic factors influencing the proposed annual depreciation rate for this account is the developed interim retirement rate, the probable retirement years, the estimated interim and terminal net salvage factors, the mandated pollution control (NOX Projects) cost and the current level of accrued depreciation reserve. The interim retirement rates were developed based upon a detailed analysis of the historically experienced retirements, and are designed to recognize the level of interim retirements that are anticipated to occur from the study date until the probable retirement date of each facility. The estimated terminal/probable retirement years for each of the Company's operating units were developed by the Company's engineering staff after considering all factors affecting the current and prospective operation of the facilities as well as full production requirements. The probable retirement data for each of the facilities, while having been modified to reflect the latest available data, are generally consistent with those underlying the Company's current depreciation rates.

The interim net salvage was based upon an analysis of the Company's historical experience, while the terminal net salvage is based upon detailed calculations using underlying information obtained from the Company's experience in decommissioning its Pineville plant, which was retired in place. Likewise, it is the

Company's expressed intent to continually retire its other existing generating facilities in place as it has done in the past. By comparison, based upon information obtained from decommissioning cost study data relative to totally dismantling plants, the Company's historical experience and future estimates are very modest. The detailed account level decommissioning study cost was used to distribute the Company's experienced cost relative to Steam Production facilities to the individual FERC account level.

The incorporation of the mandated pollution control (NOX Projects) cost is consistent with the inclusion of cost estimates for such expenditures into the present depreciation rates. These projects and the related costs are federally mandated and beyond the Company's managerial control. Finally, the current level of accrued depreciation directly impacts the prospective recovery levels given that the current unrecovered costs need to be ratable recovered over the average remaining life of each of the operating plants.

The depreciation rate for Account 343 - Prime Movers, increased from3.42 percent to 4.07 percent and the depreciation rate for Account 344 - Generators, increased from 3.15 to 3.57 percent. The drivers for the depreciation rate changes for these two Other Production Plant Accounts are consistent with those described above for Account 312 - Boiler Plant Equipment with the exception that the resulting depreciation rates were not impacted by future NOX related expenditures.

The depreciation rate for Account 365 - Overhead Conductors and Devices increased from 3.02 percent to 3.24 percent. The depreciation rate increase is being driven by a reduction in the underlying service life parameters from 44 years to 41 years. The estimated service life parameter for the proposed depreciation rate is more representative of the service life currently being experienced by the property group and is more consistent with the even shorter service life being experienced by this property class within the industry.

The depreciation rate for Account 369 - Services increased from 3.75 percent to 4.16 percent. The proposed depreciation rate is the product of the application of the estimated applicable service life (which was revised from thirty-six (36) years to thirty (30) years) and the estimated future net salvage (which was revised from negative sixty-five (65) to negative forty (40) percent).

Conversely, several of the property groups experienced depreciation rate decreases from the current levels.

The composite depreciation rate for Account 311 - Structures & Improvements declined from 2.97 percent to 1.75 percent, Account 314 - Turbogenerator Units declined from 2.51 percent to 2.17 percent, and Account 315 - Accessory Electric Equipment declined from 2.48 percent to 1.63 percent. The decrease of the depreciation rate for these property groups is a composite of applying the applicable life span and net salvage parameters as compared to that underlying the present depreciation rate. Furthermore, the drivers for the depreciation rate changes are consistent with those for Account 312, except that NOX expenditures were not a factor in the resulting proposals.

The depreciation rate relative to Account 370 - Meters declined from 2.79 percent to 2.20 percent. This depreciation expense reduction is the product of incorporating the estimated average service life (increased from 39 to 44 years) and net salvage factors identified through an in depth analysis of the Company's historical experience and future expectations.

Q31. WHAT IS THE NET CHANGE IN ANNUAL DEPRECIATION EXPENSE UNDER THE PROPOSED RATES AS APPOSED TO PRESENT DEPRECIATION RATES?

A31. The change in annual depreciation rates results in a net increase in annualized depreciation expense for Kentucky Utilities' plant in service of $3,949,872, (Table1, Section 2, page 2-2 of Appendix C) in comparison to the depreciation amount produced by the current depreciation rates when applied to the Company's plant in service investment as of December 31, 2002.

Q32. WHAT IS YOUR RECOMMENDATION TO THE COMMISSION?

A32. It is my recommendation that the proposed depreciation rates set forth in my depreciation study (Appendix C) should be uniformly and prospectively adopted by this Commission for regulatory purposes as well as by the Company for accounting purposes.

Q33. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A33. Yes, it does.

293271.04

VERIFICATION

STATE OF Pennsylvania)
) **SS:**
COUNTY OF Cumberland)

The undersigned, **Earl M. Robinson**, being duly sworn, deposes and says he is President and Chief Executive Officer of AUS Consultants – Weber Fick & Wilson Division, 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.

Earl M Robinson
EARL M. ROBINSON

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 29th day of December 2003.

Susan M Danner (SEAL)
Notary Public

My Commission Expires:

Nov 28, 2005

Notarial Seal
Susan M. Danner, Notary Public
Wormleysburg Boro, Cumberland County
My Commission Expires Nov. 28, 2005

Mr. Rosenberg

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In Re the Matter of:	)	
	)	
AN ADJUSTMENT OF THE ELECTRIC RATES, TERMS AND CONDITIONS OF KENTUCKY UTILITIES COMPANY	))))	**CASE NO: 2003-00434**

TESTIMONY

OF

ROBERT G. ROSENBERG
EDGEWOOD CONSULTING, INC.

December 29, 2003

Filed: December 29, 2003

INDEX

I. INTRODUCTION

Q. Will you give your name, business address and occupation?

A. My name is Robert G. Rosenberg. My business address is 541 Bear Ladder Road, West Fulton, New York. I am an economist and principal of the firm of Edgewood Consulting, Inc. My qualifications are described in Appendix A to this testimony.

Q. What is the purpose of your testimony in this proceeding?

A. The purpose of my testimony is to determine the cost of equity capital for Kentucky Utilities Company (hereinafter referred to as KU or the Company).

Q. Have you prepared an exhibit in conjunction with your testimony?

A. Yes. In support of my testimony, I have prepared RGR Exhibit 1, consisting of 3 Schedules.

Q. Were these schedules prepared by you or under your supervision?

A. Yes, they were.

II. EXECUTIVE SUMMARY

Q. What conclusions have you reached?

A. Based on the discussion and analyses presented in my testimony, I determine the cost of equity for the Company to be in the 10.75-11.25 percent range and recommend 11.25 percent—the upper end of the range—as the return that should be allowed in this proceeding.

Q. Would you provide a summary of your testimony?

A. I first review the current economic and financial climate facing utilities—one where bond downratings far outnumber upratings and where the regulatory commitment to allowing adequate returns is being questioned. I then discuss how the assessment of utility risk and potential performance is in flux currently. This can lead to larger measurement error in estimating the cost of equity than when utilities were facing a more status quo situation. In part because of this consideration, I employ four separate approaches to estimate the cost of equity including: (1) a discounted cash flow (DCF) analysis; (2) a capital asset pricing model (CAPM); (3) two risk premium analyses; and (4) a comparable earnings analysis.

Since KU is not, itself, publicly traded, I employ a proxy group of electric utility companies similar in risk to KU in my cost of equity analyses.

Turning first to the DCF approach, to recognize some of the more complex growth expectations which investors may possess today, I employ two-stage DCF analyses which produce a 10.00-10.75 percent cost of equity estimate for my comparison companies.

I perform CAPM calculations using two formulations of the CAPM method and two different estimates of the expected market risk premium. Employing historic data from Ibbotson Associates to estimate the expected market risk premium, I obtain CAPM cost of equity estimates in the range of 9.6-10.2 percent. Employing data for the S&P 500 to estimate the market risk premium, the CAPM cost of equity estimate is in the range of 11.3-12.2 percent. Research cited by the Ibbotson publication suggests that smaller companies, including many utilities, require higher returns than indicated by the basic CAPM formulation. To account for this phenomenon, I add a size premium of 60 basis points to the CAPM results reported above. Based on these analyses, I employed a CAPM cost of equity range of 10.75-11.50 percent in my further calculations.

I also perform two risk premium analyses directly on electric utilities. The first analysis uses the historic spread between Moody's electric utility common stock returns and utility bond yields. I obtain a cost of equity estimate of 10.8 percent using this approach. The second risk premium analysis measures the risk premium implied by allowed returns on equity since 1980. I perform a regression analysis wherein I calculate the risk premium as a function of the (lagged) level of interest rates. Under this approach I obtain a 10.9 percent cost of equity estimate.

My fourth calculation is a comparable earnings analysis. The Hope and Bluefield decisions stated, in part, that a fair rate of return to a regulated company is one that is equal to that earned in enterprises of similar risk. I gather a sample of companies of similar risk (i.e., a Safety Rank of 2) and find that recent historic and projected returns for these companies are in the 14.0-14.5 percent range.

Based on the above-described analyses, the cost of equity of the electric proxy group of companies is in the range of 10.75-11.25 percent. Given the difficulty of determining the cost of equity capital with exact precision, analysts and regulatory commissions often estimate a "range of reasonableness" for the return on equity and then use qualitative factors and judgment to determine where within this range a particular allowed return should be set. I recommend that KU be allowed a return of 11.25 percent—at the upper end of the 10.75-11.25 percent cost of equity range I have determined—to recognize KU's efficient operations and the current uncertain business climate for utilities.

III. THE RATE OF RETURN IN CONTEXT

Q. Would you briefly discuss the importance of the level of rate of return in the current economic and financial climate?

A. The financial community has put the utility industry under more intense scrutiny of late. Utility bond downratings have far outnumbered bond upratings. S&P reported that for the year-to-date 2003, there had been 41 utility issuer credit rating downgrades compared with 8 upgrades (Standard & Poor's *Ratings Trends*, October 20, 2003). Similarly, for the twelve months ended June 30, 2003, Moody's had downgraded about one-third of the utilities it follows—significantly higher than the approximate 10 percent annual average downgrade rate for utilities over the past nineteen years (Moody's *Rating Actions and Reviews*, July 2003, p. 3). Clearly the bond rating agencies have become less tolerant of financial weakness in utility companies. Furthermore, the cost of financial weakness to companies has increased recently, given the widening spreads in bond yields between stronger and weaker entities.

The heightened negative attention given to utilities, along with substantial bond downratings, have made utility financing problematic in some instances. Standard & Poor's in its February 12, 2003 *CreditWeek* article entitled "U.S. Power Industry Experiences Precipitous Credit Decline in 2002; Negative Slope Likely to Continue" indicated that deterioration of creditworthiness in the industry could be traced, in part, to:

> Increasingly constrained capital market access as a result of investor skepticism over accounting practices and disclosure, more and more federal and state investigations and subpoenas, audits, and failing

> confidence in future financial performance that has created a liquidity crisis.

FERC Commissioner William Massey in a March 17, 2003 speech entitled "Current Issues 2003" echoed a similar theme:

> Sadly, the tsunami of the western energy crisis, coupled with the collapse of Enron, have left a devastating wake within the industry. Investor confidence has been shaken by these events, by a declining national economy, indictments of energy traders, accounting irregularities, downgrades by rating agencies, and continuing investigations by the FERC, CFTC, the SEC and the Justice Department. [These investigations] do have an impact on investor confidence and credit availability.... Many sources of funds have dried up, yet energy companies have billions in debt to refinance over the next two years.

Rate of return on equity plays a significant part in how the financial community regards a particular utility company. Standard & Poor's in its May 24, 2002 publication *Regulatory Support For U.S. Electric Utility Credit Continues To Disappoint*, indicated that:

> Standard & Poor's views the future rating trend of the electric industry to be decidedly negative, with insufficient regulated authorized returns and expanding nonregulated investments providing the most downward pressure.

Standard & Poor's in its *Corporate Ratings Criteria*, page 23, also stressed the importance of the level of return on capital:

> Profit potential is a critical determinant of credit protection. A company that generates higher operating margins and returns on capital has a greater ability to generate equity capital internally, attract capital externally, and withstand business adversity. Earnings power ultimately attests to the value of the firm's assets as well.

S&P in "Regulation and Credit Quality in the U.S. Utility Sector," February 19, 2003, noted that:

> A Standard & Poor's-sponsored survey of regulatory commissioners throughout the U.S. a year ago indicated that credit quality ranked low on their list of priorities.... Notably, commission attention to having a strong and financially vibrant utility has waned in recent years. Certainly, commissions still want their utilities rated highly, but will they provide the returns necessary to that end? It will be interesting to see what type of working relationship electric companies and regulators form going forward.

Standard & Poor's also indicated in its November 18, 2002 report entitled *Constructive Regulation for U.S. Utilities is More Important Than Ever* that:

> ...regulation in general will once again play the pivotal, if not far and away the most pivotal, role in determining credit quality in the utility sector.

Thus, the level of a utility's allowed rate of return cannot be regarded in isolation, but instead is a key ingredient in overall financial integrity.

IV. <u>RATIONALE FOR USING SEVERAL EQUITY COSTING METHODOLOGIES</u>

Q. Do you believe it is reasonable to employ several approaches for estimating the cost of equity?

A. Yes. The cost of equity is not directly observable in the marketplace. Therefore, to estimate the cost of equity, one must take cognizance of financial theory, the legal and regulatory framework for ratemaking and investor perceptions and judgments. There is no one approach that is now recognized, or should be recognized, as <u>the</u> way to determine the cost of equity. Moreover, I believe that currently there is the potential for more error of estimation than normal in determining the cost of equity of a utility.

Q. Why do you believe that presently there is a potential for large measurement error associated in determining the cost of equity for utilities?

A. While it was always good financial practice to employ several methods to estimate the cost of equity in order to reduce measurement error associated with any particular methodology, that notion has special relevance today. The assessment of utility risk and potential performance is in flux currently due to the uncertainties associated with regulatory restructuring, competitive developments and consolidation in the industry. *The Value Line Investment Survey* of July 6, 2001 stated regarding the electric utility industry that:

> The industry is in a state of flux and will probably remain so for some time to come.

Value Line of April 4, 2003 continued the same theme by stating:

> The industry is still in a state of flux.

The Standard & Poor's *Electric Utility Industry Survey* of August 8, 2002 indicated that:

> We expect the performance of both the electric utility sector and the individual companies within the sector to remain volatile over the next several years.

The S&P *Electric Utility Industry Survey* of February 20, 2003 stated:

> Utility stocks often benefit the most (as in 2000) when the broader market is in a state of decline and investors look for a "safe haven" for their investments. However, this haven is not as safe as it once was: utility stocks have become much more volatile in recent years, sometimes experiencing sharp swings—often in the opposite direction of the broader market—within a short period of time.

Therefore, when we attempt to estimate the cost of equity for a particular utility, this uncertainty is likely to lead to more estimation error than under circumstances where that company's more easily forecasted fundamentals are the prime determinant of its stock prices and where that company's risk seems clearly delineated to investors.

Q. What conclusion do you reach from the above discussion?

A. As I indicated above, in part because I believe that there is more error of estimation than normal in determining the cost of equity of a utility, I will employ several different analyses in this proceeding. Such an approach leads to a broader-based set of estimates and will prevent any spurious results from biasing the cost of equity determination.

Q. What methods do you use in this proceeding to estimate the cost of common equity capital?

A. I will employ four separate approaches including: (1) a discounted cash flow (DCF) analysis; (2) a capital asset pricing model (CAPM) analysis; (3) two risk premium analyses; and (4) a comparable earnings analysis.

V. ESTIMATION OF THE COST OF EQUITY OF KU

A. Use of Comparison Companies to Determine the Cost of Equity of KU

Q. Why do you use comparison companies to estimate the cost of equity of KU in this proceeding?

A. Kentucky Utilities Company is a subsidiary of LG&E Energy and therefore is not, itself, publicly traded. LG&E Energy is a subsidiary of E.ON AG. E.ON is not covered by *The Value Line Investment Survey*—an important source of data that I employ in my equity costing analyses. Because of these considerations, it is my judgment that it is appropriate to use a proxy—a group of comparison companies—to obtain an estimate of the cost of equity of KU.

Q. Would you indicate how you selected the group of proxy companies upon which you conducted your cost of equity analysis?

A. I started by considering companies that were listed in *The Value Line Investment Survey*'s Electric Utility category and applied several further selection criteria to these companies. The comparison company utility subsidiaries had to have an overall senior bond rating of Aa/A from Moody's and AA/A from Standard & Poor's. In past testimonies, I have used an A/A bond rating as one of the criteria to select proxy groups. However, given the consolidation of the industry through mergers and the increase in unregulated activities, there are fewer candidate companies than formerly that can be included in the proxy group. To expand possible candidates for the proxy group, I have, in addition to the A/A bond rating criterion, also considered companies with an Aa/AA bond rating for inclusion in the proxy group. Currently, KU has a senior debt bond rating of A1/A. Since

Aa/AA companies are, if anything, less risky than KU as indicated by the bond rating, this expansion of the bond rating selection criterion is conservative. The median senior bond rating of the group that I have selected is A1/A-. Thus, the risk of the comparison companies, as indicated by bond rating, is comparable to KU.

Companies were excluded from the proxy group if they are currently involved in any major merger activity. Removing companies with merger activity from the cost of equity calculation eliminates companies whose prices and evaluations may be based on short-term merger-related considerations, rather than the long-term prospects of the company. As I explain in more detail in the discussion of the DCF methodology, merger activity has the potential for biasing the DCF result in a potentially significant manner. Companies were also excluded from the proxy group if they had significant unregulated operations. Since unregulated operations have the potential for being of different risk than regulated utility operations, this criterion insures that the companies in the proxy group have predominantly regulated utility operations. I also excluded companies not paying a dividend or for whom a dividend cut was forecast by Value Line.

The list of companies in the proxy group is shown on Schedule 1.

B. <u>DCF Analysis</u>

Q. Before proceeding with the presentation of the DCF analysis for estimating the cost of equity, would you please give a general description of the DCF method.

A. This method produces an estimate of the market-required return based upon investor evaluation of a company's earnings and dividends, as reflected by the prices that investors pay in the stock market. Basic DCF theory is predicated on the notion that the price that is paid for a company's stock in the market represents the sum of the present value of all future expected dividends. Algebraically, this can be written as:

$$(1) \qquad P_0 = \frac{D_1}{(1+k)^1} + \frac{D_2}{(1+k)^2} + \frac{D_3}{(1+k)^3} + \frac{D_4}{(1+k)^4} + \cdots$$

where: P_0 = the recent price of the stock

D = the expected dividend for the period specified

k = the investors' discount rate, or required rate of return (expressed in decimal form, *e.g.*, 0.15)

The dots at the end of this formula indicate that the equation continues to infinity—in other words, the next two terms would be $D_5/(1+k)^5$ and $D_6/(1+k)^6$, and so on. The above formula indicates that investors establish the price they are willing to pay for a stock based upon the expected future stream of dividends, discounted back to the present time.

Q. Do you believe that there is the potential for large measurement error associated with the DCF at the present time?

A. Yes, I do. To apply the DCF method, needed elements include the price that investors are paying for a stock in the marketplace and a reliable estimate of the growth expectations that led investors to bid the observed price. If investors' growth expectations have been correctly estimated, then such estimate is congruent with the market price. If all the factors influencing the market price are not reflected in the growth estimate used by an analyst, then measurement error is introduced into the DCF analysis and the resulting cost of equity estimate will be biased.

As can be seen from the formulation presented above, in order to correctly assess investors' required return in a DCF context, one must ascertain the dividend stream that investors are expecting over the long run. Analysts typically do this in a framework of estimating constant expected growth (if the future is expected to be relatively stable) or multiple stages of growth (if there is an expectation that growth may change in the future). It is my opinion that the DCF method is more prone to measurement error currently due to a lack of congruence between the market price and the growth estimate employed due to a lessening of the clarity of investor growth expectations. Many companies in the industry are in flux currently, transitioning to a restructured environment where the final rules have not yet been established.

Typically, investment analysts provide 5-year growth projections for the companies they cover and investors often employ these projections as their expected growth in the future. However, given the changes occurring in the industry, it is my opinion that these 5-year projections may not be good proxies for the long-term expected growth for utilities at the current time. Many utilities have been assuming a more conservative payout policy either due to the need for more internally generated cash flow or to help deal with the higher risk of earnings fluctuations.

Some utility companies are engaged in repurchases of their common stock. This near-term phenomenon of stock buybacks creates a short-term demand for the stock which raises stock prices above what they would have been, absent the buyback plan.[1]

Investors are also aware that mergers have occurred in the utility industry and more are possible in the near future. The potential for additional mergers could influence investor expectations in several ways. Mergers have generally occurred at a premium above the pre-merger-announcement market price, leading to capital gains for investors. Investors may see mergers as a win-win situation—offering both rate reductions to ratepayers and enhanced return prospects for stockholders. To the extent that there is speculation about future merger activity among utilities, such influence would be reflected in the price, but not in the growth projections made by analysts. The effect on the DCF of such speculation would be to bias the cost of equity estimate downward (due to the mismatch between the merger-speculation-inflated price and business-as-usual growth estimates).

The recent change in the level of income tax that investors must pay on dividends also complicates the DCF analysis currently. This tax change was enacted **during** the pricing period that I employ in my DCF analysis, specifically on May 28, 2003. While companies and investors base their payout policy and

[1] This is simply because, in a rising market, the fact that a company, itself, is buying back stock, merely adds to the buying pressure already in effect from a buoyant market. If investors think that stock prices might decline, the fact that the company is likely to be a large-scale buyer in a weak market would certainly provide investors with a cushion. Given both of these effects, stock buybacks would raise the price of a utility's stock above what it would be otherwise. Stock buyback plans often are implemented over a number of years. Thus any accretion in growth resulting from the buyback will be expected to be phased in gradually over time.

investment strategy, respectively, on long-term considerations, the dividend tax reduction has a sunset provision (i.e., unless specifically reauthorized, the dividend tax reduction will expire at the end of 2008). This serves to confound estimation of **long-term** growth expectations of investors.

Therefore, due to the complex set of phenomena currently affecting utility stock prices, it is my opinion that a DCF estimate will have the potential for more measurement error than DCF calculations performed in the past under more stable circumstances where investor expectations were determined with more certainty.

Q. Given the difficulties you outline above, how will you proceed with implementing the DCF approach for determining the cost of equity for the comparison companies?

A. The use of the constant-growth DCF formulation (D/P + g) for a regulated utility often may have been a reasonable assumption in the past when the financial and regulatory environment in which regulated utilities operated was more stable than currently. During that time, trends could reasonably be expected to continue and long-term future growth could be predicted with substantial accuracy. However, as established earlier in this testimony, the utility industry currently is in a state of flux. In light of this, I will employ a two-stage DCF approach to estimate the cost of equity of the comparison companies.

Q. How did you determine the appropriate pricing period for your DCF analysis?

A. The price component of the DCF analysis should reflect recent data over a representative period of time that is neither so short as to merely represent the "luck of the draw" nor so long as to encompass stale data. The pricing period should be long enough to smooth out the effects of any temporary market fluctuations. In the DCF analysis, I will employ a pricing period encompassing the six months ending September 2003.

On Schedule 2, I show the average prices for the comparison companies over the 6-month period ending September 2003. Each month's price was calculated by averaging the monthly high and low prices. The six-month average price is also shown in Column (1) of pages 1-3 of Schedule 3, which provides the inputs to the DCF calculation. The dividend level (*i.e.*, the dividends paid during my pricing period, annualized) for each of the comparison companies is shown in Column (2) of pages 1-3 of Schedule 3.

Q. How do you determine the expected growth component of the DCF model for the comparison companies?

A. As noted above, given the regulatory, competitive, risk, payout policy, and other changes noted above, it is difficult to ascertain, with great clarity, investor growth expectations at the current time. I will employ a two-stage growth formulation of the DCF method to estimate investors' future growth expectations. For the determination of near-term (*i.e.*, first-stage) growth, I rely on an average of earnings projections made by Value Line and First Call, a unit of Thomson Financial. These projections for the comparison companies and the average of the two are shown in Columns (3)-(5) of pages 1-3 of Schedule 3.

The estimation of second-stage, long-term growth is more problematic. I am not aware of any specific projections that are made by financial analysts for this timeframe. However, I will employ three proxies for investors' expected long-term growth.

First, I will employ the long-term projected nominal GDP (Gross Domestic Product) growth as a proxy for expected long-term second-stage growth for an individual company.[2] The Energy Information Administration (EIA) of the Department of Energy published the *Annual Energy Outlook 2003* which contains data that can be used to derive a long-term projection of growth in nominal GDP. Using data from that source, I have calculated projected growth in GDP for the period 2008-2025 to be 5.91 percent.

For the second proxy for investors' expected long-term growth, I employ projected sustainable growth, calculated using Value Line projections.[3] The projected sustainable growth rates are shown in Column (6) on page 2 of Schedule 3.

For the third estimate of investors' expected long-term growth, I employ a projection of expected industry growth. Given the competitive and regulatory uncertainties facing utilities, discussed above, investors might look at projected industry growth as a proxy for projected long-term growth for individual companies. Zacks, Value Line, S&P and First Call project growth for the industry

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[2] In the absence of a clear picture of long-term future growth specific to electric utilities, investors might employ a generalized measure of economy-wide growth as a proxy for expected utility growth.

[3] Sustainable growth is comprised of two factors—growth from the retention of earnings (i.e., internal growth) and growth from the sale of common stock (i.e., external growth). Internal growth can be calculated as the product of "b" (the expected retention ratio) and "r" (the expected return on equity). External growth can be calculated as the product of "s" (the growth in aggregate common equity due to the issuance of new common stock) and "v" (a function of the price-book ratio reflecting the fraction of funds obtained from the sale of common stock that accrues to the existing stockholders).

to be 4.5, 5.9, 5.7 and 5.0 percent, respectively. As a proxy for projected industry growth, I will use a figure of 5.3 percent.

Q. Would you review the components of the two-stage DCF analyses for the comparison companies?

A. The DCF analyses using GDP growth, sustainable growth and industry growth are shown on Schedule 3, pages 1, 2 and 3, respectively. Columns (1) and (2) of pages 1-3 of Schedule 3 show the 6-month average price and the dividend for the comparison companies. Columns (3)-(5) show the Value Line, First Call and average projected earnings growth rates. Column (6) of page 1 of Schedule 3 shows the long-term projected growth in GDP, which is assumed to occur after the first-stage growth period. Column (7) of page 1 of Schedule 3 shows the DCF cost of equity estimate for each company calculated by an iterative process employing the internal rate of return. (For calculational purposes, I continue the second-stage growth for 200 years because any growth after that point has a negligible effect on any present value or internal rate of return calculation.)

Page 2 of Schedule 3 shows the two-stage DCF analysis employing projected sustainable growth for the long-term expected growth rate. Columns (1)-(5) show the same inputs as on page 1 of Schedule 3. Column (6) of page 2 of Schedule 3 shows the projected sustainable growth, which I employ as the long-term projected growth assumed to occur after the first-stage growth period. Column (7) of page 2 Schedule 3 shows the DCF cost of equity estimate for each company.[4] Page 3 of Schedule 3 shows the two-stage DCF analysis employing projected industry growth for the long-term expected growth rate. Columns (1)-(5) show the same inputs as on pages 1 and 2 of Schedule 3. Column (6) of page 3 of Schedule 3 shows the projected industry growth, which I employ as the long-term projected growth assumed to occur after the first-stage growth period. Column (7) of page 3 of Schedule 3 shows the DCF cost of equity estimate for each company.

Q. What are the results of your DCF calculations?

A. Below, I show a table summarizing the results of the DCF calculations described above:

Long-Term Growth Rate	Schedule Page	Range	Midpoint of Range	Median	Average
GDP	Sch. 3, p.1	9.1 - 11.5	10.3	10.8	10.6
Sustainable	Sch. 3, p.2	8.2 - 15.8	12.0	9.8	10.7
Industry Avg.	Sch. 3, p.3	8.6 - 11.0	9.8	10.3	10.1

[4] Note that the cost of equity estimate for CH Energy is 6.8 percent which is only about at the level of utility bond yields. (CH Energy has been discussed in the financial press as a potential acquisition target and its stock price may well include an acquisition premium.) Since it is nearly universally agreed that the cost of equity does, and should, exceed the cost of debt, when a cost of equity estimate is only about at the level of bond yields, this is clearly an understated estimate and should be discarded. For example, FERC in Opinion No. 445 re Southern California Edison Company, July 26, 2000, 92 FERC ¶ 61,070, deleted a cost of equity estimate even somewhat above the concurrent bond yield. FERC indicated at page 27 of that Opinion that: "Because investors generally 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." FERC excluded this low figure from its calculation of the cost of equity. I will exclude this CH Energy estimate from further consideration in my DCF analysis using sustainable growth.

Based on the results and analysis presented above, I will use a DCF range of 10.00-10.75 percent in my further discussion of the determination of the cost of equity. However, noting the possibility of measurement error and understatement associated with the application of the DCF method currently, it is my opinion that these results should be considered in conjunction with the results of the other methods that I employ.

C. <u>CAPM Analysis</u>

Q. What is the basis of the CAPM approach you will employ?

A. Assuming rationality on the part of investors, the greater the risk of an investment, the higher the return that investors will demand of that investment. The yield on risk-free assets such as U.S. Treasury securities is readily determinable in the marketplace. Given that fact, if we know the risk premium that investors require to invest in the stock of the comparison companies rather than a U.S. Treasury security, we can determine the required rate of return, or cost of common equity, for the comparison companies. In this section of my testimony, I will employ the capital asset pricing model (CAPM) method to calculate this risk premium and the cost of equity for the comparison companies.

Q. Would you briefly outline the theory underlying the CAPM method?

A. In recent developments in financial theory, the total risk (variance) of an asset has been partitioned into two components: unsystematic risk and systematic risk. Unsystematic risk represents risk (*i.e.*, fluctuations in returns) due to events specific to the particular company in question (*e.g.*, a long strike at the company's plants; the loss of a large government contract; the release of a highly profitable motion picture, etc.). Unsystematic risk is company-specific and is unrelated to changes in the economy as a whole. Systematic risk, on the other hand, represents the variability in the returns on an investment due to the effect on the firm of economy-wide forces. The level of a firm's systematic risk is determined by the firm's sensitivity to the totality of macroeconomic forces in the economy.

Modern financial theory calls for the evaluation of an asset, not in isolation, but in the context of a well-diversified portfolio. If enough stocks are held in a well-diversified portfolio, the firm-specific (unsystematic) risks of the individual firms will tend to cancel each other out. The theory is that if there are enough assets in the portfolio from diverse industries, some of the assets will experience higher than expected returns while other assets will experience lower than expected returns, but the portfolio as a whole will yield the average expected return. Thus, the exposure of an investor to the risk related to firm-specific events (unsystematic risk) can be eliminated by holding a well-diversified portfolio. Systematic risk, on the other hand, cannot be diversified away in a portfolio context.

Since unsystematic risk can be eliminated in a well-diversified portfolio, according to CAPM theory the investor need only concern himself with the degree of systematic risk possessed by an asset. Beta is a measure of the systematic risk of an asset. The level of beta of an asset indicates the risk contribution of that asset to the overall risk of a well-diversified portfolio. The higher the expected risk (*i.e.*, beta) of an investment in an individual asset, the higher the risk contribution of that asset to the risk of a portfolio and, thus, the higher will be the return which an investor would require to be willing to make such an investment.

The beta value of all assets, on average, is equal to 1.0. If a particular asset has a beta of 1.0, this means that the variability in its returns due to macroeconomic events will be equal to, and in phase with, the variability of returns in the economy as a whole. An asset with a beta of, say, .5 is only half as responsive to economy-wide events as the market index. When the market index goes up 10 percent, the price of this stock will only go up 5 percent. If the market index declines 30 percent, the price of this investment will only decline 15 percent. An asset with a beta of 2.0 has twice the volatility of the market index. If the market index goes up 20 percent, the price of this asset will go up 40 percent. If the market index declines 5 percent, the price of this asset will decline 10 percent.

Under CAPM theory, the basic formula which can be used to determine the market-required rate of return for a company is:

$$R_i = R_f + b_i\ [E(RP)]$$

where:

R_i = required return on security i

R_f = current return on risk-free investments

b_i = beta for security i

$E(RP)$ = expected market risk premium, *i.e.*, the expected difference between the return in the market and the rate of return on a risk-free investment

In the above formulation, the required rate of return for a company is equal to the current return on a risk-free investment plus the product of that company's beta times the expected market risk premium. The market risk premium is that extra return that investors require for an investment in assets of the market as a whole as compared to the return on a risk-free investment.

In addition to the "traditional" formulation of the CAPM shown above, I will also employ an "empirical" formulation of the CAPM.[5] The empirical CAPM is used due to both empirical and theoretical concerns that the "traditional" CAPM may provide an understated required return estimate for utilities. Empirical tests in the academic literature show that the "traditional" CAPM understated the required return for companies with beta below 1.0 and overstated the required return for companies with beta above 1.0. The empirical version of the CAPM reflects considerations that no estimate of the market return—in particular just using a stock market proxy—can truly represent the whole range of investments and returns available to investors and that investors who borrow money incur a cost of funds that exceeds the risk-free rate. I will use an empirical formulation[6] that is designed to alleviate the biases that may be reflected in the "traditional" CAPM:

$$R_i = R_f + .75(b_i)(RP) + .25(RP).$$

Q. What data requirements are necessary to implement the CAPM approach?

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[5] This formulation of the CAPM is also sometimes known as the two-factor CAPM, or zero-beta CAPM.

[6] See Roger Morin, *Regulatory Finance*, pages 334-336.

A. In order to use the CAPM approach for the comparison companies, three parameters must be estimated—beta, the current risk-free rate and the expected market risk premium.

Q. How do you determine beta for the CAPM calculation?

A. The average beta of the comparison companies is 0.65, per *The Value Line Investment Survey*. I will employ a beta of 0.65 in the CAPM calculation.

Q. How do you determine the current risk-free rate of return?

A. Since we are trying to determine the cost of common equity capital for the comparison companies and equity capital is a long-term investment, it is my belief that the yield on long-term government bonds best reflects the risk-free rate in this context.

Common stock is a long-term investment—it has no maturity date.[7] In this context, it is interesting to note that the discounted cash flow (DCF) approach determines the cost of equity in terms of a long horizon—*i.e.*, dividends are discounted to infinity in the DCF calculation. Even if an investor sells his or her common stock after only a few years, the successor investor determines the price that the original investor can receive, and so on. Based on the above, equity capital should be considered as a long-term investment and, therefore, the yield on long-term Government bonds best reflects the risk-free rate in this context.

Under a long-term investment horizon, if one purchased, say, 3-month Treasury securities and then kept rolling over the proceeds each three months as the

[7] The common stock of a utility will remain outstanding unless a company merges or becomes defunct, or if an investor voluntarily sells his shares back to the company.

investment matures, there would be substantial uncertainty (risk) as to what return one would earn over a long horizon by just investing in 3-month Treasury bills. In contrast, in the context of a long horizon, if a long-term Treasury bond is held until maturity, then there is no uncertainty as to the expected return—the interest payments and principal are guaranteed in nominal terms. Thus, using a long-term Government bond more closely matches the long-term investment horizon of equity and is therefore appropriate to use in a CAPM analysis for estimating the cost of equity.

I note that short-term Treasury securities are used by the Federal Reserve to implement its policy objectives for credit tightening and expansion. Thus, short-term Treasury security yields are greatly influenced by short-term Federal Reserve policy moves. These short-term adjustments should not be used to measure the long-term risk and return evaluations of investors for common stock.

The average yields on long-term Treasury securities over the April-September 2003 period, per the *Federal Reserve Statistical Release*, were as follows:

	Average Yield
10-Year	3.9 %
20-Year	4.9
Long-Term*	5.0

* Bonds with at least 25 years or more remaining until maturity.

Recent long-term Treasury bond futures yields have been close to 5.5 percent. Based on all the above-described data, I believe it would be appropriate to use a risk-free rate of 5.0 percent in the CAPM calculation.

Q. How do you determine the expected market risk premium?

A. For the third parameter needed for the CAPM approach, we must estimate the expected market risk premium—*i.e.*, the expected difference between the market-required return on common stocks and the yield on long-term government bonds.

Expectational risk premium data are not directly observable in the marketplace. Therefore, to estimate the expected market risk premium, I follow two approaches. The first approach employs historic long-term risk premium data from Ibbotson Associates *Risk Premia Over Time Report: 2003*. In the second approach I calculate a current cost of equity estimate for the market, in general, using a DCF approach and then subtract the estimate of the risk-free rate from this figure in order to determine the expected market risk premium.

Q. Will you now describe how you will use historic data from the Ibbotson publication to estimate the expected market risk premium?

A. As I indicated earlier, expectational risk premium data are not directly observable in the marketplace. Therefore, one can use estimates of historic realized return spreads as proxies for expected risk premiums. This approach is reasonable since it is plausible to assume that investors use the historic experience as a guide when forming their expectations of risk premiums in the future.

Ibbotson Associates publishes the *Risk Premia Over Time Report: 2003* in which the returns on common stocks and long-term government bonds are reported for the 1926-2002 period. Based on these data, the spread between common stock returns and returns on long-term government bonds has been 7.0 percentage points on an historical basis. I will use this 7.0 percent figure as the expected market risk premium in this CAPM analysis.

In the above discussion, I have employed figures reflecting the arithmetic mean rather than the geometric mean of the data. I believe that a rational investor would employ the arithmetic mean and would not use the geometric mean, because that would provide an understatement of expected future return. (I note that Ibbotson Associates states that the arithmetic mean is the correct measure to use in estimating the cost of equity capital.) Since the explanation of why the arithmetic mean should be used is quite lengthy, I have included it in Appendix B to this testimony. Appendix B shows that the arithmetic mean is the appropriate figure to use when investors are making forecasts about the future and dealing with uncertainties inherent in making projections.

A simple example also shows that the arithmetic mean is the correct approach to use in this context. Let us assume that you are faced with the prospect of betting on a coin toss where you win 50 percent of your bet if the coin comes up heads, but lose 50 percent of the bet if the coin comes up tails.[8] Common sense indicates that because the coin is a fair coin (*i.e.*, a 50 percent chance of landing on heads and a 50 percent chance of landing on tails), the bettor would expect to only

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[8] Implicit in this discussion is an assumption that the coin used is fair—it is not biased (*e.g.*, weighted) to land disproportionately on either heads or tails.

break even (*i.e.*, they would expect to lose 50 percent of their bet half the time and expect to win 50 percent of their bet half the time). The arithmetic average of the return prospects a bettor would face in these circumstances is zero. Thus, the common sense expectation of a bettor in this example reflects the arithmetic average of return possibilities. In sharp contrast, the geometric average of an equal prospect of two returns (one plus 50 percent and one minus 50 percent) is -13.4 percent. A rational bettor would not go into a coin toss of the type described above with the expectation of a loss of 13.4 percent over time—they would expect to break even, as reflected in the arithmetic mean of zero. Clearly, they would <u>not</u> use a geometric average of return possibilities as their expected value, but would, instead, use the arithmetic average.

Q. Can you explain why it is reasonable to assume that investors look at achieved return spread results of the past in formulating their risk premium expectations for the future?

A. I examined historical return spread data over the 1926-2002 period and the results represent 77 years of return experience. The data that I examined, which represents the experience of a large number of companies over a lengthy period of time, indicates what return spreads investors have actually achieved, on average, in the past. It is not unreasonable to assume that, given the very extensive return spread experience examined, that investors would use this historic experience in formulating their expected risk premium for the future. Put simply, they see what return spread has been achieved in the past and use that experience as an expectation of what might be achieved in the future. Because of this consideration, I believe that the average historic return spread is appropriate to use as the expected risk premium in a CAPM analysis.

The 2002 Ibbotson *Yearbook* states that:

> A proper estimate of the equity risk premium requires a data series long enough to give a reliable average without being unduly influenced by very good and very poor short-term returns.... Some analysts estimate the expected equity risk premium using a shorter, more recent time period on the basis that recent events are more likely to be repeated in the near future; furthermore, they believe that the 1920s, 1930s, and 1940s contain too many unusual events. This view is suspect because all periods contain "unusual" events. Some of the most unusual events of this century took place quite recently, including the inflation of the late 1970s and early 1980s, the October 1987 stock market crash, the collapse of the high-yield bond market, the major contraction and consolidation of the thrift industry, the collapse of the Soviet Union, and the development of the European Economic Community—all of these happened in the last 20 years.... The 76-year period starting with 1926 is representative of what can happen: it includes high and low returns, volatile and quiet markets, war and peace, inflation and deflation, and prosperity and depression. Restricting attention to a shorter historical period underestimates the amount of change that could occur in a long future period. Finally, because historical event-types (not specific events) tend to repeat themselves, long-run capital market return studies can reveal a great deal about the future. Investors probably expect "unusual" events to occur from time to time, and their return expectations reflect this.

I agree with the sentiments expressed above and think it is appropriate to assume that investors would use the full range of experience available to them.

It should be noted that in individual years in the period under study, realized return spreads fluctuated significantly and even were negative in some cases. However, the <u>expected</u> risk premium of investors in each year must be positive; if not, a rational investor would never be willing to purchase a risky asset. One must always keep in mind that the risk premium concept is expectational. While investor ex ante risk premium expectations will not be matched in every year by the achieved ex post return spreads, investors will look at the average achieved return spread over a long period to get a sense of what would be realistic to expect for the future. The realized return spreads that I analyzed reflect a body of historic experience based on which investors would reasonably form their return expectations for the future. Of course, it is those future expectations that we are trying to ascertain. Atypically high or low results in any given historic period are not indicative of investors' expectations. Moreover, a negative return spread in any particular historic year or period does not cause investors to expect that in the future they will only be able to achieve negative return premiums, on average. It is, therefore, my view that the average realized return spread over a long period is likely to be viewed by investors as a reasonable estimate of the expected risk premium.

Q. How do you specifically implement the CAPM approach for the comparison companies using the Ibbotson market risk premium?

A. The beta for the comparison companies, per Value Line, is 0.65. The expected market risk premium is 7.0 percent. The risk-free rate is 5.0 percent. Using these inputs, the average required return for the comparison companies is calculated below:

<u>Traditional CAPM</u>

$$R_i = 5.0 + 0.65(7.0) = 9.6\%$$

<u>Empirical CAPM</u>

$$R_i = 5.0 + 0.75(.65)(7.0) + .25(7.0) = 10.2\%$$

Q. Will you now describe how you use S&P 500 data to estimate the expected market risk premium?

A. I first calculate an estimate of the expected (required) return for the S&P 500 using the DCF method and then subtract the risk-free rate employed in my analysis in order to determine the expected market risk premium under this second approach.

The recent dividend yield for the S&P 500 has been about at the 1.75 percent level. According to First Call, projected earnings growth for the companies in the S&P 500 averages about 12.0 percent. Per S&P, the average projected earnings growth for the companies it covers is about 14.0 percent. Using 13.0 percent as the estimate of expected growth and a 1.75 percent dividend yield, the DCF estimate of the expected return for the S&P 500 is 14.75 percent. Using a risk-free rate of 5.0 percent, the expected market risk premium would be 9.75 percent (14.75– 5.0 = 9.75). Employing this expected market risk premium for the S&P 500, the average required return for the comparison companies is calculated below:

<u>Traditional CAPM</u>

$$R_i = 5.0 + 0.65(9.75) = 11.3\%$$

<u>Empirical CAPM</u>

$$R_i = 5.0 + 0.75(.65)(9.75) + .25(9.75) = 12.2\%$$

Q. Are there any other factors to consider that may not be captured by the CAPM calculations described above?

A. Yes, there are. Ibbotson Associates indicates that companies with market capitalization in the mid- or low-capitalization range (including many utilities) require higher returns than indicated by the CAPM formulation I have employed above. As a way to account for this phenomenon, a size premium can be added to the CAPM results.

According to the Ibbotson Associates *Risk Premium Over Time Report: 2003*, size premiums of 82 and 152 basis points are appropriate for mid- or low-capitalization companies, respectively. I will use a 60 basis point size premium for the comparison group to recognize that six of the companies (Alliant, NSTAR, Pinnacle West, SCANA, Vectren and Wisconsin Energy) are in the mid-capitalization range, two of the companies (CH Energy and MGE Energy) are in the low-capitalization range and five of the companies (Ameren, Consolidated Edison, DTE, Exelon and Southern Company) required no adjustment.

Q. Would you summarize the results of your CAPM analyses?

A. The CAPM results are summarized in the table below:

CAPM Formulation	Market Risk Premium Based on:	CAPM Result	CAPM Result + Size Premium
Traditional	Ibbotson	9.6 %	10.2 %
	S&P 500	11.3	11.9
Empirical	Ibbotson	10.2	10.8
	S&P 500	12.2	12.8

Based on the above analyses and results, I conclude that the CAPM estimate of the cost of equity is in the 10.75-11.50 percent range.

D. <u>Risk Premium Analysis</u>

Q. Would you provide an overview of your risk premium calculations?

A. I employ two risk premium approaches. The first analysis is based on the historic average spread between utility stocks and bonds. The second relies on a regression analysis to measure how utility risk premiums vary with the level of interest rates.

Q. Will you explain the rationale behind a risk premium analysis?

A. The higher the perceived risk of an investment, the higher will be the return that investors require from that investment. If two investments offer the same expected return but have differing risks, investors will prefer the investment with lesser risk. Investors do so because they are said to be risk averse—*i.e.*, they prefer to take on less risk, rather than more risk, other things being equal.

It is nearly universally agreed that investors require a higher rate of return for an investment in the common equity for a particular company than they do in its debt. This is so for two important reasons. First, if an enterprise fails, debtholders have priority over equityholders as to the remaining assets of the company. Second, for an ongoing business, debtholders must be paid their contractual level of interest before equityholders can receive anything. Because of this basic fact of financial life, companies may reduce their dividend payments to equityholders when under some financial strain. The cessation of payments to debtholders is a much rarer occurrence and will usually result in bankruptcy, unless corrected. In summary, debt is thought to be less risky than equity because debtholders have priority over equityholders as to: (1) distribution of assets in the case of dissolution of the company and (2) distribution of earnings in the case of everyday operations. Because equityholders "take second," they require a higher return than do debtholders. In order to be induced to choose a higher risk investment, an investor would have to be offered an expectation of some increment in return—a premium for incurring additional risk. This incremental return is often known as the "risk premium" and it reflects the additional return that investors require to invest in common equity rather than debt.

The cost of equity is not directly observable, but must be estimated using inferences and judgment. In contrast, a bond yield is observable and if we know, or can estimate, the risk premium that common equity investors require to invest in common equity rather than debt, we can employ the risk premium approach to estimate the cost of common equity. In the well-known *Hope* decision, the U.S. Supreme Court said:

> From the investor or company point of view, it is important that there be enough revenue not only for operating expenses, but also for the capital costs of the business. These include service on the debt and dividends on the stock. By that standard the return to the equity owner should be commensurate with returns on investments in other enterprises having corresponding risks. That return, moreover, should be sufficient to assure confidence in the financial integrity of the enterprise, so as to maintain its credit and to attract capital. [Federal Power Commission v. Hope Natural Gas Co., 320 U.S. 591, 603 (1944).]

While this decision speaks in terms of returns commensurate with those being earned on investments of comparable risk, implicitly a company must also earn a return far enough above investments of lesser risk in order to be able to attract capital. Thus, if we apply the risk premium approach correctly, we will ensure that the subject company is allowed a high enough return on its common equity, compared with investments of lesser risk, so as to be able to attract capital and to meet the standards laid down by the *Hope* decision.

In general, the equity risk premium can be expressed in the following manner:

$$RP = K_e - K_d$$

The above equation implies that the equity risk premium is equal to the required return on equity (K_e) minus the required return on debt (K_d).

Q. Would you please describe your first risk premium analysis?

A. To measure the expected risk premium between utility common stock and utility bonds, I use the average return spread actually achieved by investors in these instruments in the past. Between 1932 and 2001, Moody's electric utility common stock index achieved a market return of 10.93 percent, on average. (The market return in any given year was calculated by summing the dividend paid during that year and the year-end market price and dividing that sum by the beginning-of-year market price.) Over that same period, the average of Moody's composite bond yields for utilities was 6.64 percent. Thus, the historically achieved spread between electric utility stock returns and utility bond yields was 4.29 percent (10.93 - 6.64 = 4.29). If we add this average spread to the recent level of bond yields, we can obtain an estimate of the return on utility common stocks that investors are currently expecting/requiring.

Over the six-month period ending September 2003, the average bond yield for Moody's A rated utility bonds was 6.52 percent. Adding this recent average bond yield to the historic average spread between electric utility common stock returns and utility bond yields of 4.29 percent, we obtain a cost of equity estimate for the proxy group of 10.81 percent.

Q. In your second risk premium analysis, is there a proxy for required returns on equity that you use?

A. Yes, there is—returns on common equity allowed to electric utilities by regulation.[9] Most regulatory commissions frequently refer to movements in, or the level of, interest rates in their decisions establishing an allowed return on equity. Since authorized returns appear to be interest-rate sensitive, employing allowed returns from across the United States in calculating the risk premium serves to use outside, objective evidence as to what the consensus of regulation believes is the spread between the cost of equity and bond yields.

Q. How specifically did you perform your second risk premium analysis?

A. I first conducted an analysis of risk premiums implied by allowed returns on equity since 1980. Specifically, quarterly average allowed returns for the first quarter 1980 through the third quarter 2003 were obtained from data in Regulatory Research Associates *Regulatory Focus*. These data reflect the average of allowed returns for all electric utility cases decided in the quarter specified. An implied risk premium (which can also be thought of as an allowed return spread) was derived

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[9] Regulators sometimes allow companies to keep earnings above the nominally allowed return on equity. Thus, the use of allowed returns in this analysis may well understate the returns investors actually expect a company to earn.

by comparing the average allowed return in a given quarter with the average yield for Moody's Utility Composite Bond Index in the two quarters prior to the average allowed return.

In deriving the implied risk premium, the utility bond yields were lagged behind the allowed returns on equity because of the likelihood that changes in allowed returns on equity often lag somewhat behind changes in bond yields. This could be so for two reasons—one economic and one practical. The economic reason is that commissions might want to be convinced that a change in interest rates actually represented a trend that might persist before reflecting such change in the allowed return on equity. The practical reason simply deals with the logistics of a rate case—the record that a commission examines may be several months old by the time it renders a decision. (While certain commissions update record data in their decisions, many commissions do not do so.) Furthermore, the simple logistics of writing a decision may cause a delay between the period upon which the allowed return was based and the date on which the decision was released to the public.

To determine the sensitivity of the implied risk premiums described above to the level of interest rates, a regression analysis was conducted. In this regression, the implied risk premium described above was the dependent variable and the level of interest rates, as proxied by the yield on long-term Treasury bonds lagged two quarters behind the allowed return on equity, was the independent variable. This model attempts to capture the statistical relationship between implied risk premiums (*i.e.*, allowed returns minus utility bond yields) and the level of interest rates (as indicated by the yields on long-term Treasury bonds), with the interest rates being lagged two quarters behind the allowed return on equity. The regression equation is reported below:

$$\text{Risk Premium} = 6.477 - 0.432 \begin{Bmatrix} \textit{Yield on Long-Term} \\ \textit{Treasury} \\ \textit{Bonds} \end{Bmatrix}$$

The adjusted R^2 of the regression (which measures the proportion of variation in the dependent variable explained by variation in the independent variable) is 0.78. Thus, this regression relationship demonstrates that changes in the level of interest rates explain a substantial proportion of the changes in implied risk premiums.

One might well ask why one should go through the process of creating the model described above when one could merely just examine recent levels of allowed returns. There are justifications for the model in this context. First, it is possible that in certain quarters there are an insufficient number of allowed returns to use as a guide by themselves. Second, allowed returns are not a perfect proxy for required returns and the use of the long-term relationship between allowed returns and bond yields allows us to overcome any unusual allowed return results in a particular period.

The average yield on long-term Treasury bonds for the six months ending September 2003 is 4.95 percent. Inserting this into the model shown above, I obtain a calculated risk premium of 4.36 percent as follows:

$$\text{Risk Premium} = 6.477 - 0.432(4.95)$$

$$\text{Risk Premium} = 4.34\%$$

The average yield on Moody's A rated bonds in the six months ending September 2003 was 6.52 percent. Adding the yield of 6.52 percent to the risk premium derived above of 4.34 percent produces an implied cost of equity of 10.86 percent. Thus, my second risk premium cost of equity estimate for the proxy group of utilities is 10.86 percent according to the above-described analysis.

Q. Would you summarize the results of your risk premium analyses?

A. The first risk premium approach that employs the historic average spread between utility common stock returns and utility bond yields produced a cost of equity estimate for the proxy group of 10.81 percent. The second risk premium approach which is based on a regression analysis measuring how utility risk premiums change as the level of interest rates change produced a cost of equity estimate of 10.86 percent for the proxy group. Based on these results, I will use a range of 10.8-10.9 percent as the risk premium cost of equity estimate in my further discussion.

E. <u>Comparable Earnings Analysis</u>

Q. Can you explain why the comparable earnings approach is helpful in assessing what return should be allowed in this proceeding?

A. The basic criteria for determining what constitutes a fair rate of return for a regulated enterprise were set forth by the U.S. Supreme Court in the *Bluefield* and *Hope Natural Gas* cases. In the *Bluefield* case the Court said:

> A public utility is entitled to such rates as will permit it to earn a return on the value of the property which it employs for the convenience of the public equal to that generally being made at the same time and in the same

> general part of the country on investments in other business undertakings which are attended by corresponding risks and uncertainties; but it has no constitutional right to profits such as are realized or anticipated in highly profitable enterprises or speculative ventures. [Bluefield Waterworks & Improvement Company v. Public Service Commission of West Virginia, 262 U.S. 679, 692-693 (1923).]

In *Hope*, the Court said:

> From the investor or company point of view, it is important that there be enough revenue not only for operating expenses, but also for the capital costs of the business. These include service on the debt and dividends on the stock. By that standard the return to the equity owner should be commensurate with returns on investments in other enterprises having corresponding risks. That return, moreover, should be sufficient to assure confidence in the financial integrity of the enterprise, so as to maintain its credit and to attract capital. [Federal Power Commission v. Hope Natural Gas Co., 320 U.S. 591, 603 (1944).]

In those decisions, the Court enumerated a two-part standard for a fair rate of return: (1) a fair rate of return to a regulated company is one that is equal to that earned in other enterprises of similar risk and (2) the fair rate of return must also provide enough earnings to enable the company to maintain its credit standing[10] and to attract capital. The first part has come to be known as the "comparable earnings standard" while the second part is referred to as "the capital attraction standard."

The comparable earnings approach (*i.e.*, determining the return earned by companies of similar risk) directly meets one of the basic criteria set forth by the

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[10] Bond rating agencies have subjected the financial ratios of utilities to more rigorous scrutiny of late. Since the rating agencies emphasize **cash flow** measures, adequate cash flow is crucial to a company's credit standing.

Supreme Court in the *Bluefield* and *Hope* decisions. But, in addition, the Court set forth the criterion that the rate of return on equity should also be sufficient for the company to attract capital. It must be acknowledged that a firm whose return is the same as that of "other enterprises having corresponding risks" is not necessarily earning enough to attract capital; but in reasonably prosperous periods, one can expect that the great majority of companies are earning enough to attract capital, and that one can also identify those that are not. Thus, if comparisons are made with a reasonably broad range of companies over a reasonably representative time period, one can be confident that a return high enough to match that of other enterprises with corresponding risks will probably also be high enough to attract capital and maintain financial integrity.

In addition to being prescribed as a standard by the *Bluefield* and *Hope* decisions, there are other reasons why a comparable earnings analysis may be helpful in determining the return to be allowed a regulated company. The comparable earnings method analyzes the question of what return should be allowed a regulated company from a different perspective than an approach such as the DCF method. It can be argued that the price that investors pay in the stock market for a utility depends, at least in part, on the return that investors expect a commission will allow that company. In turn, however, the return that a commission will allow a company depends, at least in part, on the price of that company in the stock market. As one commentator has stated:

> Moreover, since the most important risk to the investor is the risk as to the attitude of the regulatory commission, current security prices inevitably reflect projections not only of future physical and general

> economic developments of the utility and its area, but also of the anticipated rulings of the commission. For the commission to "rely" on such anticipations is palpably circular reasoning.... Commissions and investors cannot sensibly continue to look behind one another like endless images in multiple mirror.[11]

Thus there is an element of circularity in using an approach such as the DCF method to estimate the cost of equity of a utility. The comparable earnings method, which derives its results from a conceptually different approach, can shed additional light on the question of the appropriate allowed return for a utility.

Another advantage of a comparable earnings analysis is that it provides a perspective different from that implicitly employed using an approach that satisfies the capital attraction standard. If the capital attraction standard is strictly and rigidly applied, it would keep a company on the knife-edge of financial health—any shortfall in return might make it difficult for a company to attract capital. As another commentator has stated:

> It should be evident that a rate of return which is barely adequate to allow for the raising of new capital is not necessarily a fair rate of return.[12]

The comparable earnings approach is not a market-based methodology. However, the examination of returns earned, or expected to be earned, by a large group of companies with risks similar to electric utilities, in combination with the results of various other methodologies, will produce a reasonable estimate of the return to be allowed for electric utilities.

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11 Harold Leventhal, "Vitality of the Comparable Earnings Standard for Regulation of Utilities in a Growth Economy," *The Yale Law Journal*, May 1965, page 1007.

12 Herman Roseman, "Comparable Earnings and the Fair Rate of Return," 1970 *Annual Report*, Section of Public Utility Law of the American Bar Association, page 26.

Q. Would you now describe the comparable earnings analysis you conducted?

A. Under the comparable earnings approach, I first evaluate the risk of the comparison companies versus that of companies in the U.S. economy in general and based on this analysis determine what return on equity is appropriate.

Q. How do you evaluate the relative risk of the comparison companies versus companies in general?

A. I use the Value Line Safety Rank. *The Value Line Investment Survey* provides a safety rank for the 1700 or so companies that it follows. For the determination of Safety Rank, stocks are ranked from 1 to 5, with 1 being the safest and 5 being the most risky. Value Line defines the Safety Rank as a measure of the total risk of a stock and describes the Safety Rank as one of the main criteria investors should consider in selecting stocks. Value Line derives the Safety Rank by averaging two variables: (1) the volatility of the stock as measured by its Index of Price Stability and (2) the Financial Strength Rating as determined by Value Line analysts. Value Line defines the price stability index as being based upon a ranking of the standard deviation of weekly percent changes in price of a stock over the last five years. Value Line evaluates the Financial Strength of a company on a scale of A++ down to C. This is a relative ranking comparing the subject company's financial strength to all other companies. The rating is based upon financial leverage, business risk, company size and the judgment of Value Line analysts. The analysts examine various ratios such as coverage, return variability, accounting methods and size.

To implement the comparable earnings analysis, I examined recent earned and projected returns on shareholders' equity earned by companies with a safety factor of 2 as reported in *The Value Line Investment Survey.*[13]

Q. Does this group of companies with the Safety Rank of 2 include unregulated companies?

A. Yes, it does. It is a financial fact of life for a utility company that it competes in the marketplace to obtain capital not only with other utilities, but with all economic enterprises. Furthermore, the *Hope* decision, which is a touchstone in the area of rate of return regulation, indicates that a company should be compared to other firms of comparable risk and did not limit this comparison only to other regulated firms. Value Line measures the risk embodied in the safety rank it assigns consistently across the 1700 or so companies that it follows to derive its safety rank and thus it measures risk in a uniform manner for both regulated and unregulated firms.

Q. What returns are companies with a Safety Rank of 2 earning?

A. The earned return on shareholders' equity in any one given year is not necessarily the return that investors expect a firm to earn in the future. A company could have runs of good luck or bad luck or particular accounting adjustments so that the return earned in any one year is not necessarily a meaningful indicator of what it ought to be earning in light of the risks being borne. In order to temper the earned return data, I examined earned returns on shareholders' equity over two recent historic years. In addition, Value Line projected earned returns for 2003 (the

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[13] The safety rank of the proxy group I employ is 2.

current year), 2004 and for a period 3-5 years into the future were also employed. Thus, by looking at both the earnings experience of the recent past as well as projections for the future, unusual figures are smoothed and the end result is appropriate to employ as the comparable earnings result. To further temper the data, median results, rather than average figures, were used in any year.

The median returns on shareholders' equity in 2001 and 2002 for companies accorded by Value Line a safety factor of 2 are 14.2 and 13.7 percent, respectively. The median projected returns on shareholders' equity for these companies in 2003 and 2004 were 14.0 percent in both years. The median return for these companies projected by Value Line for the near-term future (2006-2008) is 14.5 percent.

In summary, a conservative estimate[14] of the return to be allowed on common equity using the comparable earnings approach is in the range of 14.0-14.5 percent.

F. Determination of the Cost of Equity of KU

Q. Would you describe the results of each of the four methods?

A. The DCF method produced a cost of equity range of 10.00-10.75 percent. As I indicated earlier in my testimony, I believe that a utility DCF estimate will have the potential for more measurement error than during periods in which a company's

[14] The data that I examined reflect the return earned on shareholders' equity, rather than the return on common equity. Since the companies examined are financed in part by some preferred equity in addition to common equity, the returns on common equity would be higher than those reported. In addition, Value Line reports return on year-end shareholders' equity, whereas it is appropriate to use return on average equity for the comparable earnings analysis.

more-readily-determined future earnings and dividends prospects were the main consideration. Therefore, I believe that it is important to also consider the results of the other methods that I presented, which approach the determination of the return on equity to be allowed in this proceeding from different perspectives.

The CAPM approach can be thought of as calculating a risk premium for the market as a whole and then adjusting it for the risk of the particular utility in question. Under the CAPM approach, risk is measured by a company's beta. My CAPM analysis produced a cost of equity range of 10.75-11.50 percent.

While the CAPM approach calculates a market-wide risk premium that is then adjusted for company-specific risk, the two risk premium analyses that I performed directly estimate the risk premium for a utility. The results of these risk premium analyses produced a cost of equity estimate in the range of 10.8-10.9 percent.

The comparable earnings approach (*i.e.*, determining the return earned by companies of similar risk) directly meets one of the basic criteria set forth by the Supreme Court in the *Bluefield* and *Hope* decisions. As utilities face a more competitive environment, investors will carefully evaluate how utility returns compare with those of unregulated enterprises. The comparable earnings analysis produced a return on equity[15] range of 14.0-14.5 percent. These expected returns on equity of comparable-risk investment alternatives would certainly be taken into account by investors in forming their return requirements for a utility. As

[15] As indicated above, the reported range reflects returns on year-end shareholders equity (including preferred equity); returns on average common equity would be somewhat higher.

discussed above, it is difficult to ascertain with clarity at the current time what the prospects of the utility industry will be in the future. However, the use of rates of return of companies of comparable risk across a diversity of industries provides an important benchmark as to the return to be allowed in this proceeding.

Below, I present a summary of the results I discussed above:

Cost of Equity Method	Range
1. DCF	10.00 - 10.75%
2. CAPM	10.75 - 11.50
3. Risk Premium	10.8 - 10.9
4. Comparable Earnings	14.0 - 14.5

Determination of the cost of equity requires inferences regarding investor expectations and requirements, which are not directly observable. Each of the above methods approaches the estimation of the cost of equity from a different perspective—which I believe to be a strength of this four-method approach. In my opinion, the cost of equity for the proxy group of companies used in my analysis is in the range of 10.75-11.25 percent.

Q. Are there any other factors to consider in reaching a recommendation about the return on equity to be allowed to KU in this proceeding?

A. Yes. Given the difficulty of determining the cost of equity capital with exact precision, analysts and regulatory commissions often estimate a "range of reasonableness" for the return on equity and then use qualitative factors and judgment to determine where within this range a particular allowed return should be set. I recommend that KU be allowed a return at the upper end of the 10.75-11.25 percent cost of equity range I have determined.

Q. Can you indicate the basis for this recommendation?

A. KU has been recognized as having very efficient operations. The Commission, at page 34 of the LG&E and KU merger proceeding, Case No. 97-300, noted that:

> LG&E and KU are recognized as efficient and high quality providers of electric service at rates that are among the lowest in the nation. Both companies also are well positioned financially and enjoy high debt ratings due to numerous factors including their low cost generation, desirable service territories and efficient management structures.

Since that time, KU's continued high level of efficiency has been recognized by several J.D. Powers awards. In addition, on page I-2 of its August 31, 2003 Final Report concerning the focused management audit of Louisville Gas and Electric's and KU's Earnings Sharing Mechanism, the Barrington-Wellesley Group stated:

> BWG found LG&E and KU to be well-managed utilities with a strong management team in place. The Companies have sound planning, budgeting and accounting processes and good expenditure control.

In the past there may have been somewhat of a perverse relationship between efficiency and returns allowed by regulation, in general. Less efficient companies may have been perceived as having higher risk and, other things being equal, may have been granted higher returns on equity because of that perception. Conversely, more efficient companies may have been considered less risky and, other things being equal, these companies may have been granted lower returns on equity. In my opinion, regulators should recognize efficient operations, to the extent it is within their discretion. A method of doing this would be to allow KU to earn a return on equity toward the upper end of the range of reasonableness that I derived above.

In addition, the unsettled nature of the industry discussed earlier in my testimony (e.g., the bond rating agencies are much quicker to downgrade now than in the past), indicates a need for a solid company financial condition at the current time. Furthermore, interest rates presently are lower than they have been in many years. It seems likely that upward changes in interest rates may be more likely than downward changes,[16] especially in light of very large projected Federal budget deficits over the next several years.

Q. Based on consideration of your discussion and analyses, what return do you recommend for KU?

A. I recommend that KU be allowed a return of 11.25 percent.

Q. Does this conclude your testimony?

A. Yes, it does.

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[16] For example, there is not much downside room to the Federal Funds rate—currently about at the 1 percent level—that the Federal Reserve uses to implement its monetary policy.

VERIFICATION

STATE OF NEW YORK)
) **SS:**
COUNTY OF SCHOHARIE)

The undersigned, **Robert G. Rosenberg,** being duly sworn, deposes and says he is an Economist and Principal of Edgewood Consulting, 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.

Robert G. Rosenberg
ROBERT G. ROSENBERG

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 9 day of December 2003.

Wanda J. King (SEAL)
Notary Public

My Commission Expires:

WANDA J. KING
Notary Public, State of New York #01KI4683925
Residing in Schoharie County
My Commission Expires Jan. 31, 20 07

**EDUCATION AND EMPLOYMENT BACKGROUND
OF
ROBERT G. ROSENBERG**

Education

I have a Bachelor of Arts degree in Political Science, with a minor in Economics, from Hunter College. I received a Master of Business Administration degree with a major in Finance at the New York University Graduate School of Business Administration.

Employment

From 1969 through mid-March 1983, I was employed by the firm of National Economic Research Associates (NERA), reaching the position of Senior Economic Analyst. In March of 1983, I became a principal of Benrose Economic Consultants, Inc., a consulting firm in New York City. In April 2000, I became a principal of Edgewood Consulting, Inc., a firm located in the Capital District area of New York. Edgewood Consulting performs economic research and consulting services for companies, law firms, government agencies and trade associations. Throughout this period, I have concentrated on the analysis of regulated industries, including electric and gas utilities, insurance and steamship companies. I have prepared direct and rebuttal testimony related to financial aspects of utility rate proceedings--e.g., cost of common equity, capital structure, etc. Along with these "typical" rate case issues, I have also testified regarding more unusual matters: intra-company royalty payments; the correct procedure to use in calculating the cost of debt; whether a cogeneration project met Qualifying Facility ownership standards; and responsibility for stranded costs.

I have had numerous assignments involving evaluation, consultation and/or internal reports to clients. Examples of this include: (1) analyzing issues relating to industry restructuring (e.g., implications of Commission-ordered divestiture, the risks associated with the institution of incentive plans, unbundling electric rates, etc.); (2) consulting with a utility company concerning the financial and regulatory aspects of a potential merger and the possible regulatory treatment of an acquisition premium; (3) evaluating the feasibility of instituting an administrative securitization proposal; (4) determining incremental risks flowing from purchased power contracts; and (5) analyzing studies regarding property values near transmission lines.

Outside the regulatory arena, I have estimated financial damages related to (1) breach of contract and (2) earnings losses as a result of injuries. I have also examined stock prices to see if alleged manipulation was likely and have performed economic valuation for employee stock option plan purposes.

I have presented lectures at the Pace University Center for International Business Studies regarding the regulatory process. A number of articles that I authored have been published in *Public Utilities Fortnightly* (PUF).

Appearances Before Regulatory Agencies

I have presented testimony before the Federal Energy Regulatory Commission and the regulatory agencies in the following states: Arizona, Kentucky, Massachusetts, Minnesota, Mississippi, New Hampshire, New Jersey, New York, Pennsylvania, Rhode

Island, South Dakota and Vermont. These testimonies were presented on behalf of: Blackstone Valley Electric Company, Boston Edison Company, Central Hudson Gas & Electric Corporation, Citizens Communications Company, Consolidated Edison Company, Kentucky Utilities Company, Long Island Lighting Company, Louisville Gas and Electric Company, Minnesota Power & Light Company, Mississippi Power Company, New York State Electric & Gas Corporation, Niagara Mohawk Power Corporation, Northern States Power, Orange & Rockland Utilities, Pacific Gas & Electric Company, Pike County Light & Power Company, Public Service Company of New Hampshire, Public Service Company of New Mexico, Rochester Gas & Electric Corporation and Rockland Electric Company. In addition, I have testified before: the Society of Maritime Arbitrators concerning the estimation of damages in the matter of Empresa Publica de Abastecimento de Cereais (an agency of the Government of Portugal) vs. Point Endeavor Corporation and Tradigrain, Inc.; U.S. Bankruptcy Court regarding financing for an office building in Chapter 11; and the Federal Maritime Commission regarding the fair return for Matson Navigation Company.

WHY THE ARITHMETIC, RATHER THAN THE GEOMETRIC, MEAN SHOULD BE USED IN ESTIMATING EXPECTED FUTURE RETURNS

It has been suggested that in using the Ibbotson historic rate of return data as a proxy for the expected future return, one should employ the geometric mean of the data, rather than the arithmetic mean. I will demonstrate why that contention is incorrect. The only appropriate historic average to use in forecasting expected returns for the future is the arithmetic mean. It is incorrect to use the geometric mean and the use of the geometric mean results in an understated expected future return, as will be demonstrated below.

Before beginning the discussion on this issue, it is perhaps helpful to review the basic definition of the return on an investment that an investor expects (requires). The expected (required) rate of return is the discount rate that equates the future cash flows that an investor expects to receive from an investment with the initial value (i.e., the present value) of that investment. Keeping that basic definition in mind, I will now explain why the arithmetic mean of historic return data is appropriate to use in trying to forecast the expected return in the future.

In examining complicated issues, economists often simplify the actual very complex data or situation of the real world so that the issue in question is more easily examined in the simplified context. I will do so in my discussion below, but note that the principles hold even in the more complex situation of the real world. Let us assume that over a past period, an investment earned a rate of return of either 15 percent or 5 percent, with equal probability. Thus, if we examined an historic period of, say, 100 years, we would expect to find that 50 of those years experienced a 15 percent return, while the remaining 50 years experienced a 5 percent return. Since the two possible returns in this simplified hypothetical example have the same probability, the arithmetic average of these two possible returns would be 10 percent. Having established that the arithmetic average of past returns for the series described is 10 percent, we will now examine whether it is appropriate to use that return as a proxy for expected future returns.

On Attachment 1, I show a hypothetical example of future possible investment outcomes if we assume that the distribution of possible returns from the past continues on into the future--i.e., that the only two possible returns are 15 percent or 5 percent, each with a 50 percent probability. In Column (1) of Attachment 1, I show the two possible returns that can be expected to occur in the future, given that these were the only two returns that occurred in the past in our hypothetical example. In Column (2) of Attachment 1, I show that the initial amount invested is assumed to be \$1.00. In Column (3) I show that at the end of Year 1 an investor could either end up with \$1.15 if the 15 percent return outcome happens or \$1.05 if the 5 percent return possibility happens. Since the \$1.15 outcome and the \$1.05 outcome are equally likely to happen under the hypothesized circumstances, the average possible result (known in financial parlance as the expected value) of this investment at the end of Year 1 is \$1.10--the average of the two possible outcomes that have equal probability. This expected value of the investment of \$1.10 is shown near the bottom of Column (3) of Attachment 1. If the expected value of this investment at the end of Year 1 is \$1.10 and \$1.00 had been invested in Year 0, then clearly the discount factor that equates the expected cash flow at the end of Year 1, should the security be sold, to the value of the initial investment is 1.10 or 10 percent.

Now let us see what are the possible investment outcomes for Year 2 under the hypothesized circumstances. The possible outcomes are shown in Column (4) of Attachment 1 and are explained below. If the investment earns \$1.15 in Year 1 and again, fortunately, earns a 15 percent return in Year 2, then the value of the investment would be \$1.3225 at the end of Year 2 (\$1.15 x 1.15 = \$1.3225). Another possible outcome would be if the investment earns \$1.15 in Year 1 but only earns a 5 percent return in Year 2. This would produce a value at the end of Year 2 of \$1.2075 (\$1.15 x 1.05 = \$1.2075). I will now explain how the third number in Column (4) is derived. If the investment in question earns a 5 percent return in Year 1, but then earns a 15 percent return in Year 2, then the expected value of the investment at the end of Year 2 would be \$1.2075 (\$1.05 x 1.15 = \$1.2075). The fourth possibility in Year 2 is if the investment, unfortunately, only reaches the \$1.05 level at the end of Year 1 and in Year 2 again only experiences a 5 percent return. This would produce the fourth outcome in Column (4), namely \$1.1025 (\$1.05 x 1.05 = \$1.1025).

I have thus explained how one obtains the four possible outcomes at the end of Year 2, as shown in Column (4) of Attachment 1. Given that each of these outcomes has the same probability (because in any given year there is an equal probability of experiencing either a 15 percent return, or a 5 percent return), if we add up the four possible returns and divide by 4, we obtain the expected value of the investment of \$1.21. Thus, even though there are several possible outcomes in Year 2, the expected value of this investment at the end of Year 2 is \$1.21 under the circumstances hypothesized. If the investor expects to be able to sell the investment at the end of Year 2 with a value of \$1.21, then the discount rate that equates the expected receipt of \$1.21 at the end of Year 2 with the initial investment of \$1.00 in Year 0 is 10 percent ($\$1.21/[(1.10)^2]=\$1.00$). Thus, again, as in Year 1, in Year 2 we find that the discount rate, or expected return, on this investment is 10 percent. This means that if an investor invested \$1.00 in Year 0 and expected the return possibilities shown on Attachment 1, that the investor would expect to earn a 10 percent return on his or her investment in either Year 1 or in Year 2.

The data shown for Years 3 and 4, in Columns (5) and (6) on Attachment 1, are derived in a similar manner. I will briefly discuss the data for Year 3 to provide continuity for this explanation. There are eight possible outcomes in Year 3, each with the same probability. Thus, if we sum up the eight possible investment outcomes for Year 3 and divide by 8, we have the average possible outcome or the expected value of the investment at the end of Year 3. As shown in Column (5) on Attachment 1, the expected value of the investment at the end of Year 3 is \$1.331. Thus, if an investor invested \$1.00 in Year 0 and could expect to sell his investment at the end of Year 3 for \$1.331, the expected return on that investment would be 10 percent. The data shown for Year 4, in Column (6) of Attachment 1, are derived in a similar manner and again it is indicated that were the investor to sell his investment at the end of Year 4, he would expect to earn a 10 percent return on the investment. This hypothetical example could be extended out further in time, but the calculations would obviously become very cumbersome. The point holds for future years, but the data for Years 1 through 4 will be used for illustrative purposes in the remainder of this discussion.

The hypothetical example shown on Attachment 1 has demonstrated that under the hypothesized circumstances, in each and every year in the future, investors will expect to earn a return of 10 percent. It is important to note that this 10 percent return that we have calculated that investors could expect in each of the years examined is the same return as the arithmetic average of the two possible return outcomes specified in the hypothetical example, namely 15 percent and 5 percent. Thus, if investors noted that historic return experience was either 5 or 15 percent, with an arithmetic average of 10 percent, and they used this arithmetic average of past returns as a projected return for the future, their projections would exactly match the expected return (or discount rate), derived in the hypothetical example on Attachment 1. Put simply, this demonstrates that the arithmetic average of past rates of return is the appropriate average to use in forecasting expected future returns, assuming that past conditions will continue on into the future.

Now let us leave the discussion of the arithmetic mean briefly in order to discuss the geometric mean. The geometric mean of two returns is calculated as follows:

$$\sqrt{(1 + r_1) \times (1 + r_2)} - 1$$

where r_1 and r_2 are the two returns in question and are expressed in decimal form.

Given that in the prior hypothetical example the only two possible returns were 15 percent or 5 percent, the geometric average of those returns would be calculated as follows:

$$\sqrt{(1+.15) \times (1+.05)} - 1 = .0989 \text{ or } 9.89\%$$

As can be noted above, the geometric mean rate of return for the hypothetical investment we have been discussing is 9.89 percent--less than the 10.00 percent arithmetic mean. From the calculations on Attachment 1, we have shown that if an investor invested $1.00 at Year 0 in our hypothetical investment, they could expect to have the following values of their investment for each of the years specified:

Initial Investment in Year 0	Expected Value of Investment			
	Year 1	Year 2	Year 3	Year 4
$1.00	$1.10	$1.21	$1.331	$1.4641

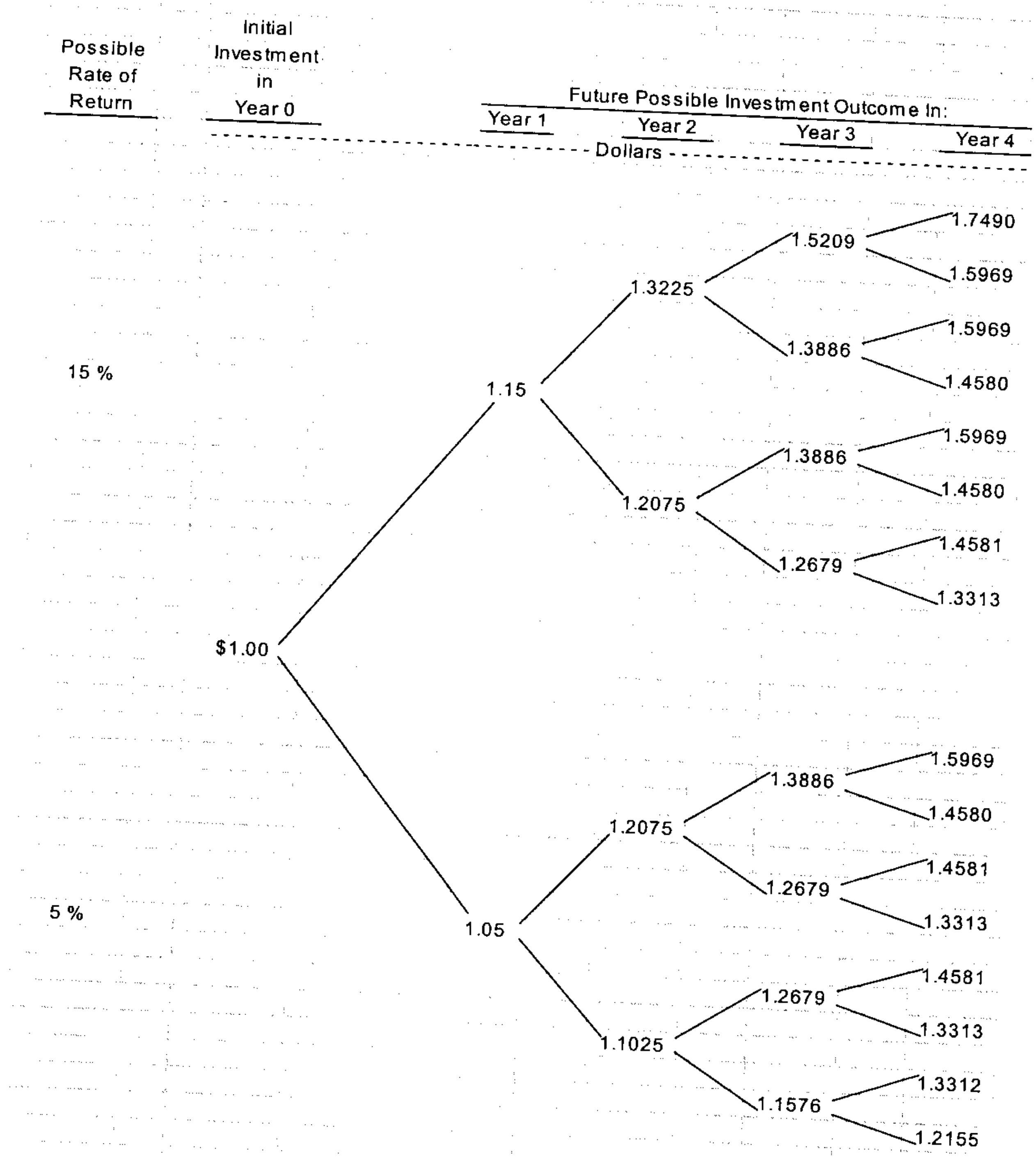
As noted previously, these expected values of the investment in each year could also be obtained by taking the arithmetic average of historic results (10 percent) and assuming that the investor expects to earn the arithmetic return in each year in the future.

Now let us assume that an investor mistakenly took the 9.89 percent geometric mean from the historic return series and used that to project the returns earned in the future. If an investor invested $1.00 in Year 0 and expected that he or she would only earn the 9.89 percent geometric mean, then using the geometric mean as a predictor would produce the following data:

Initial Investment in Year 0	Value Produced by Forecasting with Geometric Mean			
	Year 1	Year 2	Year 3	Year 4
$1.00	$1.0989	$1.2076	$1.3270	$1.4582

Note that the values produced above when one uses the geometric mean to forecast future investment outcomes are lower in each and every year than the actual expected value of the investment that was derived on Attachment 1. This means that the geometric mean will produce an understated prediction of the returns that investors expect in the future. As has been demonstrated throughout this discussion, the arithmetic mean of historic rate of return data produces the rate of return that investors expect in the future, assuming that future conditions parallel that of the past. In contrast, use of the geometric mean to forecast future rates of return based on past results will result in an understatement of the forecasted rate of return for the future.

HYPOTHETICAL EXAMPLE OF FUTURE POSSIBLE INVESTMENT OUTCOMES



	Year 1	Year 2	Year 3	Year 4
Expected Value of Investment	$1.10	$1.2100	$1.3310	$1.4641
Discount Factor	1.10	$(1.10)^2$	$(1.10)^3$	$(1.10)^4$

ELECTRIC COMPARISON GROUP

Alliant Energy Corporation

Ameren Corporation

CH Energy Group

Consolidated Edison

DTE Energy Company

Exelon Corporation

MGE Energy

NSTAR

Pinnacle West Capital Corporation

SCANA Corporation

Southern Company

Vectren Corporation

Wisconsin Energy Corporation

CALCULATION OF SIX-MONTH AVERAGE PRICE
April - September 2003

	Average of Monthly High and Low Price						6-Month Average Price
	April	May	June	July	August	September	
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
Alliant Energy	$16.96	$18.86	$19.78	$19.56	$20.62	$21.77	$19.59
Ameren	40.12	43.45	45.01	43.18	41.90	42.70	42.73
CH Energy Group	41.88	43.74	44.85	44.25	43.61	44.79	43.85
Consolidated Edison	39.08	41.34	43.09	41.65	39.62	40.15	40.82
DTE Energy	39.74	41.74	41.48	37.35	34.79	36.21	38.55
Exelon	51.55	56.13	59.17	57.30	58.42	61.43	57.33
MGE Energy	27.65	30.01	31.83	32.98	31.00	31.41	30.81
NStar	41.52	45.25	45.95	44.97	44.74	46.46	44.82
Pinnacle West Capital	33.10	35.20	38.50	36.17	33.66	35.46	35.35
SCANA	30.80	32.68	34.54	33.30	33.39	34.51	33.20
Southern Company	28.58	30.07	31.10	29.24	28.15	28.94	29.35
Vectren	22.35	23.98	25.27	23.77	22.87	23.38	23.60
Wisconsin Energy	25.72	26.94	28.67	28.58	27.85	29.94	27.95

Source: MSN Money Central website.

DCF COST OF EQUITY CALCULATION FOR THE COMPARISON GROUP

Company	6-Month Average Price	Indicated Dividend	Near-Term Projected EPS Growth: Value Line Projected 5-Year Growth	Near-Term Projected EPS Growth: First Call Projected 5-Year Growth	Near-Term Projected EPS Growth: Average: Value Line and First Call	Long-Term Projected Growth in GDP	DCF Cost of Equity Estimate
	(1)	(2)	(3)	(4)	[(3)+(4)]/2 (5)	(6)	(7)
Alliant Energy	$19.59	$1.00	5.0 %	4.8 %	4.9 %	5.91 %	11.1 %
Ameren	42.73	2.54	1.0	3.0	2.0	5.91	11.2
CH Energy Group	43.85	2.16	1.5	na	1.5	5.91	10.2
Consolidated Edison	40.82	2.24	1.0	3.0	2.0	5.91	10.8
DTE Energy	38.55	2.06	5.5	5.5	5.5	5.91	11.5
Exelon	57.33	1.92	7.0	5.0	6.0	5.91	9.5
MGE Energy	30.81	1.35	6.0	na	6.0	5.91	10.6
NSTAR	44.82	2.16	3.5	6.0	4.8	5.91	10.8
Pinnacle West	35.35	1.70	0.5	5.0	2.8	5.91	10.4
SCANA	33.20	1.38	5.0	5.0	5.0	5.91	10.1
Southern Company	29.35	1.38	6.5	5.0	5.8	5.91	10.9
Vectren	23.60	1.10	9.0	7.0	8.0	5.91	11.3
Wisconsin Energy	27.95	0.80	8.0	6.5	7.3	5.91	9.1
Median							10.8 %

NA --Not available.

Source: Col. (1) - Schedule 2.
Col. (2) - Derived from data on the MSN Money Central website.
Col. (3) - Derived from data in *The Value Line Investment Survey*.
Col. (4) - First Call website.
Col. (6) - Derived from data in Energy Information Administration Annual Energy Outlook, 2003.
Col. (7) - Derived iteration using an internal rate of return calculation.

DCF COST OF EQUITY CALCULATION FOR THE COMPARISON GROUP

Company	6-Month Average Price	Indicated Dividend	Near-Term Projected EPS Growth: Value Line Projected 5-Year Growth	Near-Term Projected EPS Growth: First Call Projected 5-Year Growth	Near-Term Projected EPS Growth: Average: Value Line and First Call [(3)+(4)]/2	Long-Term Projected Sustainable Growth	DCF Cost of Equity Estimate
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
Alliant Energy	$19.59	$1.00	5.0 %	4.8 %	4.9 %	3.0 %	8.7 %
Ameren	42.73	2.54	1.0	3.0	2.0	3.7	9.4
CH Energy Group	43.85	2.16	1.5	na	1.5	1.9	6.8
Consolidated Edison	40.82	2.24	1.0	3.0	2.0	3.4	8.7
DTE Energy	38.55	2.06	5.5	5.5	5.5	6.3	11.8
Exelon	57.33	1.92	7.0	5.0	6.0	13.0	15.8
MGE Energy	30.81	1.35	6.0	na	6.0	8.6	12.9
NSTAR	44.82	2.16	3.5	6.0	4.8	4.4	9.5
Pinnacle West	35.35	1.70	0.5	5.0	2.8	3.4	8.2
SCANA	33.20	1.38	5.0	5.0	5.0	5.2	9.5
Southern Company	29.35	1.38	6.5	5.0	5.8	7.1	11.9
Vectren	23.60	1.10	9.0	7.0	8.0	6.8	12.0
Wisconsin Energy	27.95	0.80	8.0	6.5	7.3	7.0	10.1
Median							9.5 %
Median excluding CH Energy							9.8 %

NA --Not available.

Source:	Col. (1)	- Schedule 2.
	Col. (2)	- Derived from data on the MSN Money Central website.
	Col. (3)&(6)	- Derived from data in *The Value Line Investment Survey*.
	Col. (4)	- First Call website.
	Col. (7)	- Derived iteration using an internal rate of return calculation.

DCF COST OF EQUITY CALCULATION FOR THE COMPARISON GROUP

			Near-Term Projected EPS Growth				
Company	6-Month Average Price	Indicated Dividend	Value Line Projected 5-Year Growth	First Call Projected 5-Year Growth	Average: Value Line and First Call	Long-Term Projected Industry Growth	DCF Cost of Equity Estimate
	(1)	(2)	(3)	(4)	[(3)+(4)]/2 (5)	(6)	(7)
Alliant Energy	$19.59	$1.00	5.0 %	4.8 %	4.9 %	5.3 %	10.6 %
Ameren	42.73	2.54	1.0	3.0	2.0	5.3	10.7
CH Energy Group	43.85	2.16	1.5	na	1.5	5.3	9.7
Consolidated Edison	40.82	2.24	1.0	3.0	2.0	5.3	10.3
DTE Energy	38.55	2.06	5.5	5.5	5.5	5.3	11.0
Exelon	57.33	1.92	7.0	5.0	6.0	5.3	8.9
MGE Energy	30.81	1.35	6.0	na	6.0	5.3	10.1
NSTAR	44.82	2.16	3.5	6.0	4.8	5.3	10.3
Pinnacle West	35.35	1.70	0.5	5.0	2.8	5.3	9.8
SCANA	33.20	1.38	5.0	5.0	5.0	5.3	9.6
Southern Company	29.35	1.38	6.5	5.0	5.8	5.3	10.4
Vectren	23.60	1.10	9.0	7.0	8.0	5.3	10.8
Wisconsin Energy	27.95	0.80	8.0	6.5	7.3	5.3	8.6
Median							10.3 %

NA --Not available.

Source: Col. (1) - Schedule 2.
Col. (2) - Derived from data on the MSN Money Central website.
Col. (3) - Derived from data in *The Value Line Investment Survey*.
Col. (4) - First Call website.
Col. (6) - See text.
Col. (7) - Derived iteration using an internal rate of return calculation.

Mr. Beer

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

AN ADJUSTMENT OF THE ELECTRIC RATES, TERMS AND CONDITIONS OF KENTUCKY UTILITIES COMPANY	)))))	CASE NO. 2003-00434

TESTIMONY OF
MICHAEL S. BEER
VICE PRESIDENT – RATES AND REGULATORY
LG&E ENERGY CORP.
LOUISVILLE GAS AND ELECTRIC COMPANY
KENTUCKY UTILITIES COMPANY

December 29, 2003

Filed: December 29, 2003

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

A. My name is Michael S. Beer. I am employed by LG&E Energy Services, Inc. ("LG&E Energy Services"). I am the Vice President of Rates and Regulatory for LG&E Energy Corp. ("LG&E Energy"), Louisville Gas and Electric Company ("LG&E"), and Kentucky Utilities Company ("KU" or "the Company"). My business address is 220 West Main Street, Louisville, Kentucky. A statement of my qualification is attached as Appendix A.

Q. What is the relationship between LG&E Energy Services and KU?

A. KU and LG&E Energy Services are both subsidiaries of LG&E Energy. LG&E Energy Services was formed and became operational in January 2001, following completion of the Powergen merger. The Public Utility Holding Company Act of 1935 ("PUHCA") requires that registered holding company systems form a service company to perform work, services or construction for, or provide goods to, affiliate companies. Employees, including officers, who regularly provide work or services for more than one affiliate, such as LG&E or KU, are employees of LG&E Energy Services in compliance with PUHCA. This type of arrangement is common in holding company structures throughout the utility industry.

Q. Have you previously testified before this Commission?

A. Yes. I testified on regulatory policies in Case No. 2001-104, *In the Matter of: Joint Application for Transfer of Louisville Gas and Electric Company and Kentucky Utilities Company in Accordance With E.ON AG's Planned Acquisition of Powergen plc*, and have testified in environmental surcharge proceedings and cases involving requests by LG&E and KU for Certificates of Convenience and Necessity.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to support certain exhibits identified below which are required by the Commission's regulations; to describe the revenue effect of the proposed rates; 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; to discuss the effect of the various billing mechanisms on the requested rate increase; and to present the Company's position on the expenses it has incurred for its membership in the Midwest Independent Transmission System Operator, Inc.

Q. Are you supporting the schedules that are required by Commission regulations 807 KAR 5:001, Section 10(1)(a)1-9 and 807 KAR 5:001, Sections 10(2) through Section 10(5)?

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

• Reason for Rate Adjustment	Section 10(1)(a)1	Tab 1
• Most Recent Annual Reports	Section 10(1)(a)2	Tab 2
• Articles of Incorporation	Section 10(1)(a)3	Tab 3
• Limited Partnership Agreement	Section 10(1)(a)4	Tab 4
• Certificate of Good Standing	Section 10(1)(a)5	Tab 5
• Certificate of Assumed Name	Section 10(1)(a)6	Tab 6
• Proposed Tariff	Section 10(1)(a)7	Tab 7
• Proposed Tariff Changes	Section 10(1)(a)8	Tab 8
• Statement of Customer Notice	Section 10(1)(a)9	Tab 9

I am also sponsoring the schedules filed in connection with Commission regulation 807 KAR 5:001, Section 10(2) – (5):

• Notice of Intent	Section 10(2)	Tab 10
• Customer Notice Information	Section 10(3)	Tab 11
• Sewer Utility Notices	Section 10(4)(a)	Tab 12
• Typewritten Notices by Mail	Section 10(4)(b)	Tab 13
• Other Customer Notices	Section 10(4)(c)	Tab 14
• Publisher's Affidavit	Section 10(4)(d)	Tab 15
• Verification – Mailed Notices	Section 10(4)(e)	Tab 16
• Sample Notices Posted	Section 10(4)(f)	Tab 17
• Compliance with 807 KAR 5:051, Section 2	Section 10(4)(g)	Tab 18
• Hearing Notice Published	Section 10(5)	Tab 19

Q. Who is supporting certain information required by Commission regulation 807 KAR 5:001, Section 10(6)(a)-(v) and Section 10(7)(e)?

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

• Local Telephone Exchange Companies	Section 10(6)(f)	Tab 25
• Local Telephone Exchange Companies	Section 10(6)(v)	Tab 41

The following required schedules will be sponsored by Mr. Seelye:

• 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
• Cost-of-Service Study	Section 10(6)(u)	Tab 40
• Period-End Customer Additions	Section 10(7)(e)	Tab 46

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

A. KU has not sought an increase in its electric base rates in twenty years. In that time, several factors have affected KU's cost of doing business. Since December 31, 1998, the end of the test year used in Case No. 98-474, KU has increased its jurisdictional net investment in plant for electric operations by over $412 million. And, comparing the twelve months ended September 30, 2003 with the test year used in Case No. 98-474, the Company has incurred approximately $15 million in additional depreciation expense, on a pro forma basis, associated with those net investments in plant. During that same time period, KU's employee pension and post-retirement expenses have increased about $4 million, on a pro forma basis, as a result of the decline in financial market performance, and the Company has seen an approximately $4 million rise in property insurance costs. KU has also incurred over $3 million in MISO Schedule 10 administrative costs, which are not currently being recovered, and has experienced significant increases in its operating expenses, such as higher wage rates, due in part to inflation.

Since our last base rate increase, KU has also made extraordinary efforts to control the rising cost of doing business. However, our ability to continue to provide safe and reliable energy service to our 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, 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 $58.3 million.

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

A. The monthly residential bill will increase by 7.96%, or approximately $4.00, for a customer using 1000 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 any significant cross-subsidization existed between customer classes. The Prime Group conducted a fully-allocated, time-differentiated, embedded cost-of-service study, the details of which are presented in the direct testimony of Mr. Seelye. A summary of the results of that study for the principal rate schedules, however, is set forth below:

Beer Table I – Pro Forma Rates of Return

Customer Class	KU Electric
Residential	0.53%
General Service Rate	5.11%
Large Power (LP & HLF)	8.06%
Large Power TOD	7.08%
Coal Mining Power	11.19%
Coal Mining TOD	8.77%
Special Contracts	9.35%
Total System	3.93%

These returns show that there are significant disparities among the class rates of return in both KU's operations.

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 table:

Beer Table II – Pro Forma Rates of Return as Adjusted for Proposed Increase

Customer Class	KU Electric
Residential	2.50%
General Service Rate	7.25%
Large Power (LP & HLF)	10.91%
Large Power TOD	9.96%
Coal Mining Power	14.30%
Coal Mining TOD	11.65%
Special Contracts	8.96%
Total System	6.17%

Again, this is a summary only. The Prime Group's study will discuss this issue in more detail.

Q. Please explain the rationale for allocating increases among the 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. To this end, although the proposal is based on, and uses as a starting point, the cost-of-service study summarized in Mr. Seelye's testimony, it does not give full effect to that cost-of-service study.

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

A. Yes. First, consistent with the ratemaking objectives noted above, the Company advised The Prime Group that, notwithstanding its cost-of-service study results, the total residential revenue increase should be no more than one percentage point above the overall percentage increase to ultimate consumers. KU advised that the cost-of-service study should otherwise guide the revenue increase to the other customer classes. Second, we advised The Prime Group, with regard to the rate design, that 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. You suggested that the ratemaking objectives of gradualism, rate stability and customer acceptance justified a departure from the cost-of-service study for

purposes of cost allocation among electric rate classes. Please elaborate on why you limited the increase for the electric residential class in the manner proposed.

A. As discussed in the testimony of Mr. Seelye, the cost-of-service study demonstrates that the rates for the electric residential class would have to be increased by approximately 25% to recover all of its costs. This compares an overall increase of 8.54% requested by KU. We were concerned that proposing an increase in rates fully consistent with the cost-of-service study would simply have too significant an impact on our residential customers. As a result, and again in recognition of the ratemaking principles of gradualism, rate continuity and customer acceptance, we limited the increase of total revenue from the residential class to 1% above the overall increase to all other customers. As noted, however, we did use the cost-of-service study as a guide in allocating increases to all other classes of electric customers.

<u>Relationship of Other Ratemaking Mechanisms to Base Rates</u>

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 tracked separately from base rates.

Q. Do ratemaking mechanisms such as the fuel adjustment clause, environmental cost recovery/environmental surcharge, ESM or demand-side management cost recovery have any effect on the base rate increase which KU is requesting?

A. No. As discussed in detail in the testimony of Bradford Rives, the impact of those mechanisms has been removed from KU's operating revenues and expenses for the test year ended September 30, 2003, and have no effect on the base rate increase which KU is requesting in this case. In addition, by allowing these costs to be handled separately, there is no double recovery of these costs.

MISO

Q. Has KU incurred new costs since its last electric rate case in 1983 because of the changes in regulation by the Federal Energy Regulatory Commission ("FERC")?

A. Yes. Since then, there have been significant changes in the methods used by the FERC to regulate the use and operation of the transmission systems of utilities, including the use of regional transmission organizations to facilitate transmission services and power sales in the wholesale power market. In 2001, MISO became the nation's first FERC approved Regional Transmission Organization ("RTO"). As an RTO, MISO's mission is to provide non-discriminatory, open access transmission service across its multi-state geographic footprint. LG&E and KU are members of MISO which, as of December 31, 2002, had 72 members.

For the 12 months ended September 30, 2003, KU incurred $3.1 million in jurisdictional MISO Schedule 10 administrative costs. Those FERC-approved charges are now part of KU's cost-of-service and represent costs that are not currently reflected in KU's base rates. KU has included a request for $3.9 million in its revenue requirement in this case to account for the ongoing jurisdictional costs of MISO membership. That number is higher than the costs noted above for the test year ended September 30, 2003, because, as discussed in the testimony of Valerie Scott, there were credits received during the test year which will not be received by the Company going forward.

Q. The Commission is currently investigating the membership of LG&E and KU in MISO, in Case No. 2003-00266. If KU is ordered to withdraw from MISO, would such a withdrawal require KU to incur any costs under the terms of the MISO Agreement?

A Yes, withdrawal would trigger the imposition of an exit fee under the MISO Agreement. Pursuant to the Transmission Owners Agreement, "[a]ll financial obligations and payments applicable to time periods prior to the effective date of [the withdrawing member's] withdrawal shall be honored by" MISO and the withdrawing member. MISO Agreement, Article Five, Section II(B). The amount of the exit fee payable by KU has been raised before the Commission in Case No. 2003-00266.

Q. If the Commission ultimately issues a decision in Case No. 2003-00266 authorizing or requiring KU to remain in MISO, would such an order alter KU's base rate recovery of the ongoing MISO costs we have proposed in this rate filing?

A. Provided the Commission allows the recovery of associated costs, it would not. If the Commission ultimately determines in Case No. 2003-00266 that KU's membership in MISO is in the public interest, KU will continue its membership in MISO and will continue to recover its ongoing MISO membership costs through the new base rates established in this proceeding.

Q. Alternatively, if the Commission ultimately issues a decision in Case No. 2003-00266 requiring KU to exit MISO, would such an order alter KU's base rate recovery of the ongoing MISO costs we have proposed in this rate filing?

A. Yes, but only after KU has received all necessary approvals to exit. Specifically, if the Commission issues an order in Case No. 2003-00266 that KU's membership in MISO is not in the public interest, and KU is ordered to seek withdrawal from MISO, KU would propose to continue to recover, through base rates as described above, all costs incurred in connection with its ongoing MISO membership obligations pending receipt of a FERC order authorizing such withdrawal. Upon receipt of such FERC authorization, the Company would take the requisite ratemaking steps (through a filing with the Commission) to remove the ongoing MISO-related expenses from base rates, and begin amortization and base rate recovery of the fixed exit fee described above over a specific term. Such a two-pronged recovery approach ensures that KU will not recover concurrently both ongoing MISO membership costs and exit fee costs.

Q. Does this conclude your testimony?

A. Yes.

278703.15

VERIFICATION

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

The undersigned, **Michael S. Beer**, being duly sworn, deposes and says he is the Vice President of Rates and Regulatory 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.

MICHAEL S. BEER

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 29th day of December 2003.

Notary Public (SEAL)

My Commission Expires:
November 26, 2007

APPENDIX A

Michael S. Beer

Vice President – Rates and Regulatory
LG&E Energy Corp.
220 West Main Street
Louisville, Kentucky 40202
(502) 627-3547

Education

Illinois Wesleyan University, B.A. in Business Administration -- 1980
The John Marshall Law School, Juris Doctor (with Distinction) -- 1987

Previous Positions

Louisville Gas and Electric Company, Louisville, KY.:
2000-2001 – Senior Counsel Specialist-Regulatory
1998 – 2000 – Senior Corporate Attorney

Illinois Power Company, Decatur, Illinois
1997 – 1998 – Director of Federal Regulatory Affairs
1995 – 1997 – Senior Attorney
1992 – 1995 – Attorney

Soyland Power Cooperative Inc., Decatur, Illinois
1998 – 1991 – Attorney
1982 – 1984 – Contract Buyer

Millikin University, Decatur, Illinois
January 1996 – December 1998 – Adjunct Associate Professor of Business Law
August 1988 – December 1995 – Adjunct Assistant Professor of Business Law

Samuels, Miller, Schroeder, Jackson & Sly, Decatur, Illinois
1987 – 1988 – Associate

Beerman, Swerdlove, Woloshin, Barezky & Berkson, Chicago, Illinois
1985 – 1987 – Law Clerk

Professional/Trade Memberships

American Bar Association
Energy Bar Association
Illinois State Bar Association

Civic Activities

Volunteers of America (Kentucky & Tennessee Chapter), Director
The Louisville Orchestra, Director

Mr. Seelye

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:	)	
	)	
AN ADJUSTMENT OF THE ELECTRIC	)	**CASE NO: 2003-00434**
RATES, TERMS AND CONDITIONS	)	
OF KENTUCKY UTILITIES COMPANY	)	

DIRECT TESTIMONY OF
WILLIAM STEVEN SEELYE

PRINCIPAL & SENIOR CONSULTANT
THE PRIME GROUP, LLC

December 29, 2003

Filed: December 29, 2003

Q. Please state your name and business address.

A. My name is William Steven Seelye and my business address is The Prime Group, LLC, 6435 West Highway 146, Crestwood, Kentucky, 40014.

Q. By whom are you employed?

A. I am a senior consultant and principal for The Prime Group, LLC, a firm located in Crestwood, Kentucky, providing consulting and educational services in the areas of utility marketing, regulatory analysis, cost of service, rate design and fuel and power procurement.

Q. What is the purpose of your testimony in this proceeding?

A. The purpose of my testimony is to sponsor fully allocated class cost of service studies based on Kentucky Utilities Company's ("Kentucky Utilities'" or "KU's") embedded cost of providing service for the 12 months ended September 30, 2003, to sponsor certain pro-forma revenue and expense adjustments, to describe the proposed allocation of the revenue increase, to sponsor KU's proposed rates for electric service, and to discuss the revenue impact of modifying certain miscellaneous charges.

Q. Please summarize your testimony.

A. We prepared a fully allocated, embedded cost of service study using cost of service methodologies that have been accepted by the Commission in previous rate cases. The purpose of this study is to determine the contribution that each customer class is making towards KU's overall rate of return. Rates of return are computed for each rate class. KU's cost of service study shows a significant variation in the class rates of return.

KU was guided by the embedded cost of service study in allocating the proposed revenue increase to the classes of service. However, to fully reflect the results of the cost of service study would have required the residential class to receive a rate increase of 25.3%. Therefore, in allocating the proposed electric increase KU moderated the increase allocated to residential and lighting customers. These increases were limited to approximately 1 percentage point above the overall percentage increase. Accordingly, KU is proposing an increase of 9.56% to the residential class as compared to 8.54% to ultimate consumers. The residential increase is thus slightly more than 1 percentage point above the overall increase. For other classes, we allocated the increase to facilitate the transition to cost of service as much as practicable.

In designing rates, we developed unit charges that more closely correspond to the unit costs indicated by the cost of service study. For residential rates, KU is proposing an increase in the customer charge that will reflect 63.3% of the customer-related costs shown in the cost of service study. Although we are not proposing to recover all of the customer-related costs through the customer charge, KU's proposed residential customer charge will represent a significant movement in the direction of reflecting cost of service.

KU is also proposing to eliminate the declining-block rate structure for residential customers. This rate structure cannot be strongly supported by cost of service results. In examining this issue we analyzed the relationship between customer load factor and customer usage and found that the relationship does not support a blocked rate structure. Specifically, three statistical analyses were performed: (i) a statistical analysis of the relationship between monthly non-coincident peak load factor and monthly kWh energy usage; (ii) a statistical analysis of the relationship between monthly coincident peak load factor and customer usage during the summer months, (iii) a statistical analysis of the relationship between coincident peak load factor and monthly kWh energy usage during the winter months. The purpose of these regression analyses was to correlate energy usage to key drivers in the cost of service study, namely summer coincident demand, winter coincident demand, and maximum customer demands. These analyses indicate that there is only moderate support for a declining-block rate structure, and as a result, KU is proposing a flat energy charge, which is easier for customers to understand.

KU is proposing to transition the customer charge for commercial and industrial customers toward the customer-related costs indicated in the cost of service study. Additionally, we are proposing to move the demand and energy charges toward cost of service. This generally translated into decreasing the energy charge and increasing the demand charge for demand/energy rates. KU is also proposing to increase the per kW credit provided to curtailable/interruptible customers based on the results of an analysis of current avoided capacity costs of a combustion turbine.

We are implementing a redundant capacity charge for customers with backup distribution feeds. As they rely more heavily on technology, commercial and industrial customers are installing backup distribution feeds with automatic swtichgear to guard against electric service interruptions. KU's proposed redundant capacity rate will allow the utility to provide this service without adversely impacting other customers that do not require the same level of reliability.

As much as possible, we are also trying to simplify KU's rate schedules and tariff language. KU is consolidating several rate schedules, including, for example, the residential service (Rate RS) is being consolidated with full electric residential service (Rate FERS), and the high load-factor rate (Rate HLF) is being consolidated with combined lighting and power service (Rate LP). Furthermore, we are making changes to harmonize the service schedules offered by KU and LG&E so that operating practices and policies are more consistent between the two companies. The companies have consolidated many of the operating departments that use the tariffs and explain the rate schedules to customers. Harmonizing the tariffs is important if the utilities are to achieve the cost savings contemplated by their merger.

Q. Are you supporting certain information required by Commission regulations 807 KAR 5:001, Section 10(6)(a)-(v)?

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
• Cost of Service Study	Section 10(6)(u)	Tab 40
• Period-End Customer Additions	Section 10(7)(e)	Tab 46

Q. How is your testimony organized?

A. My testimony is divided into the following sections: (I) Qualifications, (II) the Jurisdictional Separation Study, (III) Cost of Service, (IV) Pro-forma Adjustments, (V) Revenue Allocation and Rates, and (VI) Miscellaneous Service Charges.

I. QUALIFICATIONS

Q. Please describe your educational background and prior work experience.

A. I received a Bachelor of Science degree in Mathematics from the University of Louisville in 1979. I have also completed 54 hours of graduate level course work in Industrial Engineering and Physics. From May 1979 until July 1996, I was employed by Louisville Gas and Electric Company ("LG&E"). From May 1979 until December, 1990, I held various positions within the Rate Department of LG&E. In December 1990, I became Manager of Rates and Regulatory Analysis. In May 1994, I was given additional responsibilities in the marketing area and was promoted to Manager of Market Management and Rates. I left LG&E in July 1996 to form The Prime Group, LLC, with two other former employees of LG&E.

Since leaving LG&E, I have provided consulting services to numerous investor-owned utilities, rural electric cooperatives, and municipal utilities regarding utility rate and regulatory filings, cost of service and wholesale and retail rate designs. Specifically, I have prepared and filed Order No. 888 and Order No. 889 compliance filings at the Federal Energy Regulatory Commission ("FERC") for a number of electric utilities as well as Order No. 888 and Order No. 889 waiver requests for other utilities. I have prepared market power analyses in support of market-based rate filings at FERC for utilities and their marketing affiliates, as well as assisting other utilities with their market-based rate filings. I have assisted utilities with developing strategic marketing plans and implementing these plans. I have provided utility clients with assistance regarding regulatory policy and strategy; state and federal regulatory filing development; cost of service development and support; the development of innovative rates to achieve strategic objectives; the unbundling of rates and the development of menus of rate alternatives for use with customers; performance-based rate development; and energy marketing and brokering capability development. I have provided training to account executives in sales and customer negotiation, as well as providing training in ratemaking and utility finance regarding basic utility marketing. I have provided marketing, market research and marketing support services for utility clients and have assisted them in assessing their marketing capabilities and processes.

Q. Have you ever testified before any state or federal regulatory commissions?

A. Yes, on a number of occasions. In Kentucky, I testified in Administrative Case No. 244 regarding rates for cogenerators and small power producers, Case No. 8924 regarding marginal cost of service and in numerous 6-month and 2-year fuel adjustment clause proceedings. I testified in Case No. 96-161 and Case No. 96-362 regarding Prestonsburg City's Utilities Commission ("Prestonsburg") rates. I testified in Case No. 99-046 on behalf of Delta Natural Gas Company, Inc. ("Delta") concerning its rate stabilization plan and in Case No. 99-176 concerning cost of service, rate design and expense adjustments in connection with Delta's rate case. In Case No. 2000-080, I testified on behalf of Louisville Gas and Electric Company concerning cost of service, rate design, and pro-forma adjustments to revenues and expenses. In Florida, I testified in Docket No. 981827 on behalf of Lee County Electric Cooperative, Inc. concerning Seminole Electric Cooperative Inc.'s wholesale rates and cost of service. I also testified in Alabama in

Docket 28101 on behalf of Mobile Gas Service Corporation concerning rate design and pro-forma revenue adjustments. In Illinois, I testified in Docket No. 01-0637 on behalf of Central Illinois Light Company ("CILCO") concerning the modification of interim supply service and the implementation of black start service in connection with providing unbundled electric service. In Colorado, I testified in Consolidated Docket Nos. 01F-530E and 01A-531E on behalf of Intermountain Rural Electric Association in a territory dispute case. I submitted rebuttal testimony in Case No. 2000-548 on behalf of Louisville Gas and Electric Company regarding the company's prepaid metering program. I submitted testimony on behalf of Louisville Gas and Electric Company in Case No. 2002-00430 and on behalf of Kentucky Utilities Company in Case No. 2002-00429 regarding the calculation of merger savings. I testified before the FERC in Docket No. EL02-25-000 et al. concerning Public Service of Colorado's fuel cost adjustment. I testified before the Public Utilities Commission of Nevada on behalf of Nevada Power Company in Case No. 03-10001 regarding cash working capital. Most recently, I testified before the Public Utilities Commission of Nevada on behalf of Sierra Pacific Power Company in Case No. 03-12002 regarding cash working capital.

III. Jurisdictional Separation Study

Q. Was a jurisdictional separation study performed to allocate costs between the Kentucky retail jurisdiction and other jurisdictions not regulated by the Commission?

A. Yes. I supervised and participated in the preparation of a jurisdictional separation study based on KU's accounting costs per books for the 12 months ended September 30, 2003.

Q. Please explain how the study was performed.

A. We used the same methodology as in prior jurisdictional separation studies, including the one accepted by the Commission in KU's last general rate case. Continuity in the methodology used to perform the jurisdictional separation study is extremely important because the study is used to allocate costs among four different jurisdictions – Kentucky retail, Virginia retail, Tennessee retail, and FERC wholesale. A methodology consistent with the cost allocation principles followed by the FERC was used in the study. If different methodologies were to be used from one study to another or from one jurisdiction to another, the utility could be denied the opportunity to recover prudently incurred costs or perhaps even allowed to over collect its costs.

Q. What were the principal allocators used in the study?

A. Two key allocators were used in the study: (1) a demand allocator based on the Average 12 CP method which uses the 12 monthly system peak demands during the 12 months ended September 30, 2003, to allocate production and transmission fixed costs; (2) and an energy allocator based on the energy used within each jurisdiction. This methodology is consistent with the methodologies utilized at the FERC. Distribution costs are specifically assigned among jurisdictions in the study.

Q. Do the results of the jurisdictional separation study become the starting point for the embedded cost of service study that you performed?

A. Yes. The results of the jurisdictional separation study are entered in the functional assignment section of the cost of service study described below. The revenue requirement exhibits and pro-forma adjustment schedules sponsored by S. Bradford Rives and Valerie L. Scott also utilize results from the jurisdictional separation study.

Q. Is there an exhibit summarizing the results of the jurisdictional separation study?

A. The results of the study are summarized in Schedule 1.38 to Rives Exhibit 1 and a copy of the full output of the jurisdictional separation study itself is included as Seelye Exhibit 1.

III. COST OF SERVICE

Q. Did you prepare a cost of service study for Kentucky Utilities based on financial and operating results for the 12 months ended September 30, 2003?

A. Yes. I supervised the preparation of a fully allocated, time-differentiated, embedded cost of service study for electric operations based on jurisdictionally allocated costs from the jurisdictional separation study. The cost of service study corresponds to the pro-forma financial exhibits included in the testimony of Mr. Rives. The objective in performing the electric cost of service study is to determine the rate of return on rate base that KU is earning from each customer class, which provides an indication as to whether KU's electric service rates reflect the cost of providing service to each customer class.

Q. Did you develop the model used to perform KU's cost of service studies?

A. Yes. I developed the spreadsheet model used to perform the cost of service study being submitted in this proceeding.

Q. What procedure was used in performing the cost of service study?

A. The three traditional steps of an embedded cost of service study – functional assignment, classification, and allocation – were augmented to include a fourth step, assigning costs to costing periods. The cost of service study was therefore prepared using the following procedure: (1) costs were functionally assigned (*functionalized*) to the major functional groups; (2) costs were then *classified* as commodity-related, demand-related, or customer-related; (3) costs were assigned to the costing periods; and then (4) costs were allocated to KU's rate classes. These steps are depicted in the following diagram (Figure 1).

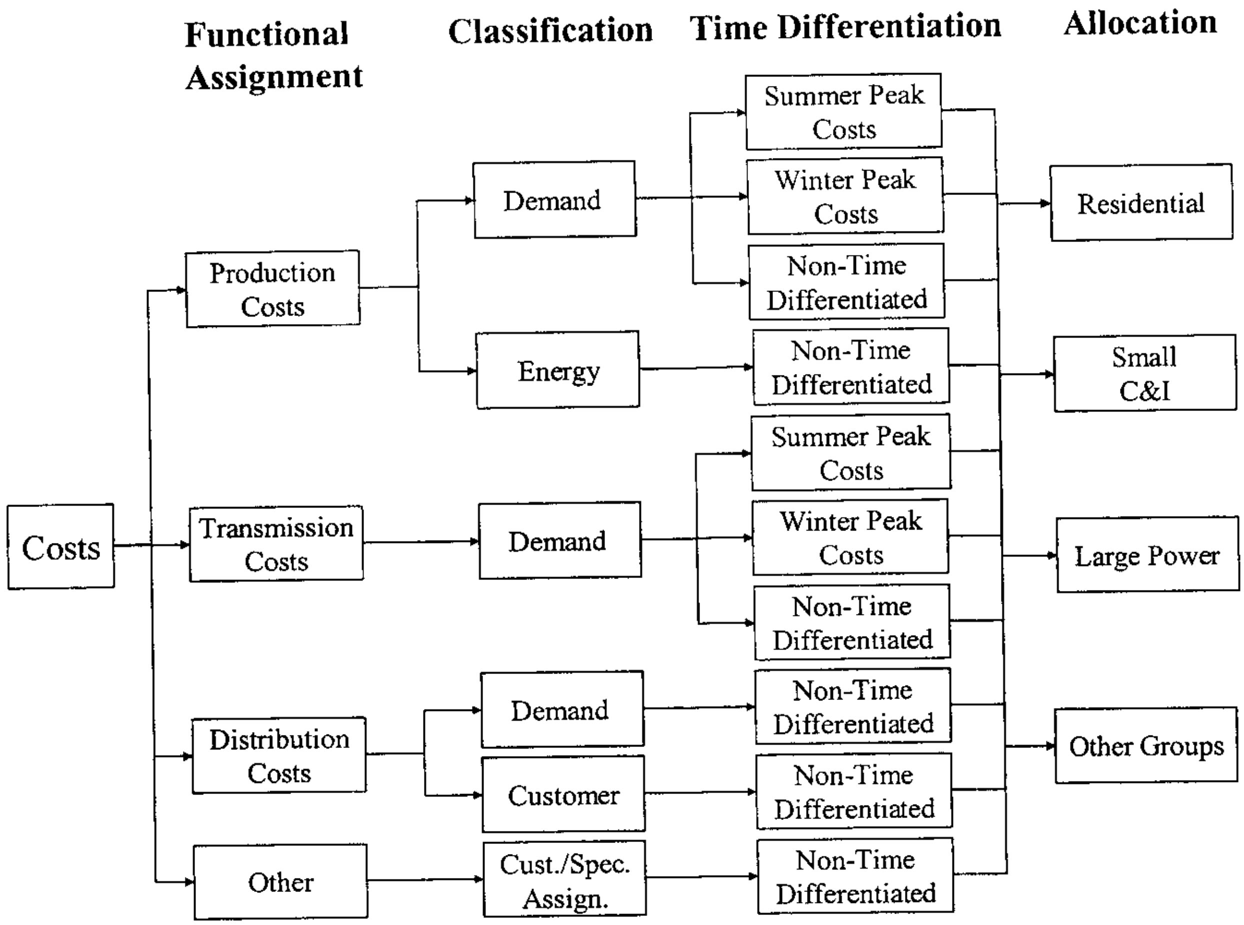


Figure 1

The following functional groups were identified in the cost of service study: (1) Production, (2) Transmission, (3) Distribution Substation (4) Distribution Primary Lines, (5) Distribution Secondary Lines (6) Distribution Line Transformers, (7) Distribution Services, (8) Distribution Meters, (9) Distribution Street and Customer Lighting, (10) Customer Accounts Expense, (11) Customer Service and Information, and (12) Sales Expense.

Q. Did you use the same methodology in KU's cost of service study as was used in LG&E's cost of service study filed concurrently in Case No. 2003-00433?

A. Yes.

Q. How were costs time differentiated in the study?

A. A modified Base-Intermediate-Peak ("BIP") methodology was used to assign production and transmission costs to the costing period.[1] Using this methodology, production and transmission demand-related costs were assigned to three categories of capacity – base, intermediate, and peak. Base costs were determined by dividing the minimum system demand by the maximum (summer) demand. Intermediate costs were calculated by dividing the winter peak demand by the summer peak demand and subtracting the base component. Peak costs included all costs not assigned to base and intermediate components.

Costs that were assigned as base, intermediate, and peak were then either assigned to the summer and winter peak periods or assigned as non-time-differentiated. Intermediate costs were pro-rated to the winter and summer peak periods in the same ratio as the number of hours contained in each costing period to the total. Peak costs are assigned to the summer peak period.

Q. How were the summer and winter peak periods determined?

A. The summer peak period corresponds to the four-month period from June through September. The winter peak period corresponds to the eight non-summer months of

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1 In Case No. 90-158, LG&E's last electric base rate case and the most recent rate case filed by either LG&E or KU, the Commission found LG&E's cost of service study, which utilized the modified BIP methodology, to be "acceptable and suitable for use as a starting point for electric rate design." (Order in Case No. 90-158, dated

October through May. The load curves included in Seelye Exhibit 2 showing the monthly peak days in the summer and winter months support the selection of the hours in the summer and winter peak periods. The hours between the hour ending 11 and the hour ending 21 of June through September were selected as the summer peak period. The hours between the hour ending 9 and the hour ending 22 of October through May were selected as the winter peak period. The load curve is flatter during the winter, thus necessitating a larger number of hours to be included in the peak period during the winter months.

We have shortened the peak periods from earlier cost of service studies, for a number of reasons. First, we believe that the costing periods are more reflective of the hours during which the company could realize a peak. Second, shortening the time periods in the company's time-of-day rates may provide customers with a greater opportunity to shift load to the off-peak period.

Q. In determining the costing periods and applying the modified BIP methodology, what demands were used?

A Demands for the combined LG&E and KU systems were used to determine the costing periods and in determining the percentages of production and transmission fixed cost assigned to the costing periods. Since the two systems are planned jointly it was important to develop costing periods and assign costs to the costing periods based on the combined loads for LG&E and KU. Developing the costing periods and allocation factors in the cost of service study do not result in any shifting in booked expenses of one

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December 21, 1990, page 58.)

utility to the other. LG&E's cost of service study relied on LG&E's accounting costs, and KU's cost of service study relied on KU's accounting costs. The modified BIP methodology simply affects how costs are assigned to the costing periods within the LG&E and KU cost of service studies.

Q. What percentages were assigned to the costing periods?

A Seelye Exhibit 3 shows the application of the modified BIP methodology. Using this methodology 26.45% of KU's production and transmission fixed costs were assigned to the summer peak period, 39.97% to the winter peak period, and 33.58% as non-time-differentiated.

Q. How were costs classified as energy related, demand related or customer related?

A. Classification provides a method of arranging costs so that the service characteristics that give rise to the costs can serve as a basis for allocation. Costs classified as *energy related* tend to vary with the amount of kilowatt-hours consumed. Fuel and purchased power expenses are examples of costs typically classified as energy costs. Costs classified as *demand related* tend to vary with the capacity needs of customers, such as the amount of generation, transmission or distribution equipment necessary to meet a customer's needs. Production plant and the cost of transmission lines are examples of costs typically classified as demand costs. Costs classified as *customer related* include costs incurred to serve customers regardless of the quantity of electric energy purchased or the peak requirements of the customers and include the cost of the minimum system necessary to provide a customer with access to the electric grid. As will be discussed later in my testimony, costs related to Distribution Primary Lines, Distribution Secondary Lines and

Distribution Line Transformers were classified as demand-related and customer-related using the zero-intercept methodology. Distribution Services, Distribution Meters, Distribution Street and Customer Lighting, Customer Accounts Expense, Customer Service and Information and Sales Expense were classified as customer-related.

Q. Have you prepared an exhibit showing the results of the functional assignment, time-differentiation and classification steps of the electric cost of service study?

A. Yes. Seelye Exhibit 4 shows the results of the first three steps of the electric cost of service study, functional assignment, time differentiation and classification.

Q. Please describe the allocation factors used in the electric cost of service study.

A. The following allocation factors were used in the KU electric cost of service study:

- **E01** – The energy cost component of purchased power costs was allocated on the basis of the kWh sales to each class of customers during the test year.
- **PPWDA and PPSDA** – The winter demand and summer demand cost components of production and transmission fixed costs were allocated on the basis of each class's contribution to the coincident peak demand during the winter and summer peak hour of the test year.
- **NCPP** – The demand cost component is allocated on the basis of the maximum class demands for primary and secondary voltage customer.

- **SICD** – The demand cost component is allocated on the basis of the sum of individual customer demands for secondary voltage customers.
- **C02** – The customer cost component of customer services is allocated on the basis of the average number of customers for the test year.
- **C03** – Meter costs were specifically assigned by relating the costs associated with various types of meters to the class of customers for whom these meters were installed.
- **YECust04** – Costs associated with lighting systems were specifically assigned to the lighting class of customers.
- **YECust05 and YECust06** – Meter reading, billing costs and customer service expenses were allocated on the basis of a customer weighting factor based on discussions with LG&E's meter reading, billing and customer service departments.
- **Cust05** – The customer cost component is allocated on the basis of the average number of customers for the test year.
- **YECust07** – The customer cost component is allocated on the basis of the year-end number of customers using line transformers and secondary voltage conductor.
- **YECust08** – The customer cost component is allocated on

the basis of the year-end number of customers using primary voltage conductor.

Q. In your cost of service model, once costs are functionally assigned and classified, how are these costs allocated to the customer classes?

A. In the cost of service model used in this study, KU's accounting costs are functionally assigned and classified using what are referred to in the model as "functional vectors". These vectors are multiplied (using *scalar multiplication*) by the various accounts in order to simultaneously assign costs to the functional groups and classify costs. Therefore, in the portion of the model included in Seelye Exhibit 4, KU's accounting costs are functionally assigned and classified using the explicitly determined functional vectors of the analysis and using internally generated functional vectors. The explicitly determined functional vectors, which are primarily used to direct where costs are functionally assigned and classified, are shown on pages 49 through 52. Internally generated functional vectors are utilized throughout the study to functionally assign costs on the basis of similar costs or on the basis of internal cost drivers. The internally generated functional vectors are also shown on pages 49 through 52 of Seelye Exhibit 4. An example of this process is the use of total operation and maintenance expenses less purchased power ("OMLPP") to allocate cash working capital included in rate base. Because cash working capital is determined on the basis of 12.5% of operation and maintenance expenses, exclusive of purchased power expenses, it is appropriate to functionally assign and classify these costs on the same basis. (See Seelye Exhibit 4, pages 9 through 12 for the functional assignment of cash working capital on the basis of

OMLPP shown on pages 49 through 52.) The functional vector used to allocate a specific cost is identified by the column in the model labeled "Vector" and refers to a vector identified elsewhere in the analysis by the column labeled "Name".

Once costs for all of the major accounts are functionally assigned and classified, the resultant cost matrix for the major cost groupings (e.g., Plant in Service, Rate Base, Operation and Maintenance Expenses) is then transposed and allocated to the customer classes using "allocation vectors" or "allocation factors". This process is illustrated in Figure 2 below.

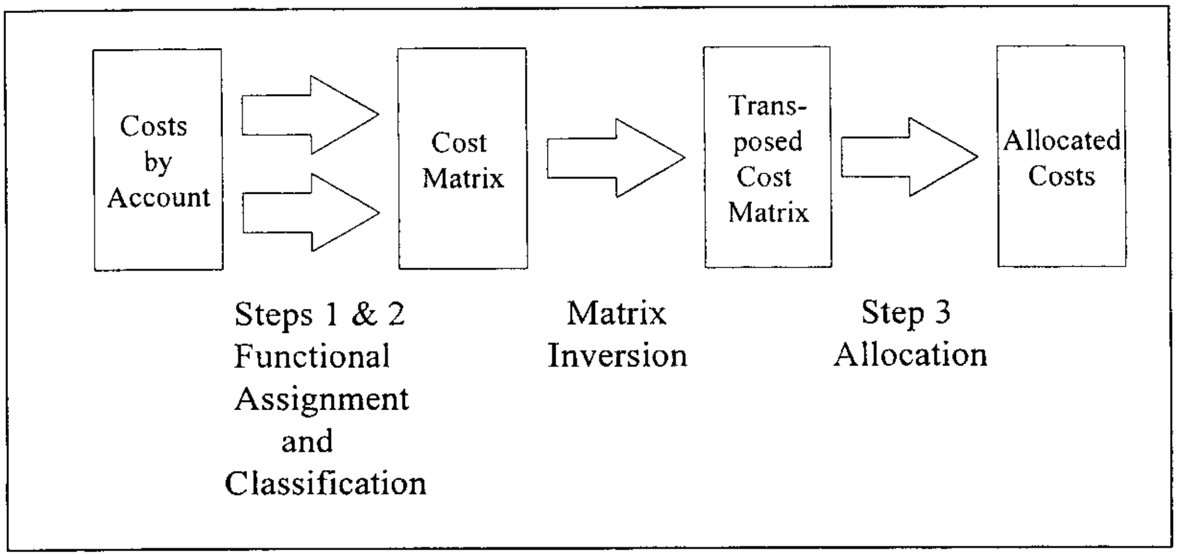


Figure 2

The results of the class allocation step of the cost of service study are included in Seelye Exhibit 5. The costs shown in the column labeled "Total System" in Seelye Exhibit 5 were carried forward *from* the functionally assigned and classified costs shown in Seelye Exhibit 4. The column labeled "Ref" in Seelye Exhibit 5 provides a reference to the results included in Seelye Exhibit 4.

Q. What methodologies are commonly used to classify distribution plant?

A. Two commonly used methodologies for determining demand/customer splits of distribution plant are the "minimum system" methodology and the "zero-intercept" methodology. In the minimum system approach, "minimum" standard poles, conductor, and line transformers are selected and the minimum system is obtained by pricing all of the applicable distribution facilities at the unit cost of these minimum size plant. The minimum system determined in this manner is then classified as customer-related and allocated on the basis of the number of customers in each rate class. All costs in excess of the minimum system are classified as demand-related. The theory supporting this approach maintains that in order for a utility to serve even the smallest customer, it would have to install a minimum size system. Therefore, the costs associated with the minimum system are related to the number of customers that are served, instead of the demand imposed by the customers on the system.

In preparing this study, the "zero-intercept" methodology was used to determine the customer components of overhead conductor, underground conductor, and line transformers. Because the zero intercept methodology is less subjective than the minimum system approach, the zero-intercept methodology is strongly preferred over the minimum system methodology when the necessary data is available. With the zero intercept methodology, we are not forced to choose a minimum size conductor or line transformer to determine the customer component. In the zero-intercept methodology, a zero-size conductor or line transformer is the absolute minimum system.

Q. What is the theory behind the zero-intercept methodology?

A. The theory behind the zero intercept methodology is that there is a linear relationship between the unit cost ($/ft or $/transformer) of conductor or line transformers and the load flow capability of the plant, which is proportionate to the cross-sectional area of the conductor or the kVA rating of the transformer. After establishing a linear relation, which is given by the equation:

$$y = a + bx$$

where:

y is the unit cost of the conductor or transformer,

x is the size of the conductor (MCM) or transformer (kVA), and

a, **b** are the coefficients representing the intercept and slope, respectively

it can be determined that, theoretically, the unit cost of a foot of conductor or transformer with zero size (or conductor or transformer with zero load carrying capability) is **a**, the zero intercept. The zero intercept is essentially the cost component of conductor or transformers that is invariant to the size (and load carrying capability) of the plant.

Like most electric utilities, the number of feet of conductor on KU's system is not uniformly distributed over all sizes of wire. For example, KU has over 13.4 million feet of #4 ACRS overhead conductor, but only 120 feet of #8 CU Duplex overhead conductor. For this reason, it was necessary to use a weighted regression analysis, instead of a standard least-squares analysis, in the determination of the zero intercept. Without performing a weighted regression analysis both types of conductor would have the same impact on the analysis, even though there is hundreds of thousands times more #4 ACRS conductor than #8 CU Duplex conductor.

Using a weighted regression analysis, the cost and size of each type of conductor or transformer is, in effect, weighted by the number of feet of installed conductor or the number of transformers. In a weighted regression analysis, the following weighted sum of squared differences

$$\sum_i w_i (y_i - \hat{y}_i)^2$$

is minimized, where **w** is the weighting factor for each size of conductor or transformer, and **y** is the observed value and **ŷ** is the predicted value of the dependent variable.

Q. Has the Commission accepted the use of the zero-intercept methodology?

A. Yes. The Commission found the cost of service studies (both electric and gas) submitted in LG&E's last two base rate cases (Case No. 2000-080 and Case No. 90-158) to be reasonable, thus providing a means of measuring class rates of return and suitable for use as a guide in developing appropriate revenue allocations and rate design. The Commission also found the embedded cost of service study submitted by Union Light Heat and Power in its recent gas base rate case (Case No. 2001-00092), which utilized a zero-intercept methodology, to be reasonable.

Q. Have you prepared exhibits showing the results of the zero-intercept analysis?

A. Yes. The zero-intercept analysis for overhead conductor, underground conductor, and line transformers are included in Seelye Exhibits 6, 7, and 8.

Q. Please summarize the results of the electric cost of service study.

A. The following table (Table 1) summarizes the rates of return for each customer class before and after reflecting the rate adjustments proposed by KU. The Actual Adjusted Rate of Return was calculated by dividing the adjusted net operating income by the adjusted net cost rate base for each customer class. The adjusted net operating income and rate base reflect the pro-forma adjustments discussed in Mr. Rives' testimony. The Proposed Rate of Return was calculated by dividing the net operating income adjusted for the proposed rate increase by the adjusted net cost rate base.

TABLE 1 Electric Class Rates of Return		
Customer Class	**Actual Adjusted Rate of Return**	**Proposed Rate of Return**
Residential	0.44%	2.41%
General Service Rate	5.66%	7.83%
Large Power (LP & HLF)	8.06%	10.91%
Large Power TOD	7.08%	9.96%
Coal Mining Power	11.19%	14.30%
Coal Mining TOD	8.77%	11.65%
Special Contracts	9.35%	8.96%
Lighting	2.84%	4.12%
Total System	3.93%	6.17%

VI. ELECTRIC PRO-FORMA ADJUSTMENTS

Q. Was an adjustment made to eliminate unbilled revenues for electric operations?

A. Yes. Consistent with prior rate cases, the effect of unbilled revenues was removed from test-year operating revenues. For KU's electric operations, $675,000 in unbilled revenue were added to test-year operating results. An adjustment to remove the effect of unbilled revenues was accepted by the Commission in LG&E's last two base rate cases, Case No. 2000-080 and Case No. 90-158. This adjustment is included in Schedule 1.00 of Rives Exhibit 1.

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 fuel adjustment clause ("FAC") has been eliminated. These over- or under-recoveries were taken directly from KU's monthly FAC filings. This adjustment is included in Schedule 1.01 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. Test-year revenues have been adjusted to reflect the rolled-in level of base rates and FAC and ECR billings for a full year. Seelye Exhibit 9 shows the impact on base rate revenues of the FAC and ECR roll-ins for a full year. Seelye Exhibit 10 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 Schedules 1.02 Rives Exhibit 1. The adjustment to reflect the ECR roll-in is included in Schedule 1.04 of Rives Exhibit 1.

Q. Was an adjustment made to eliminate environmental cost recovery ("ECR") revenues and expenses?

A. Yes. Consistent with the Commission's practice of eliminating the revenues and expenses associated with full-recovery cost trackers, an adjustment was made to eliminate $25,039,979 of ECR revenues and $248,468 in ECR costs. 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 $25,039,979 includes <u>all</u> ECR billings during the test year (including ECR recoveries for the 1994 Plan and for the post-1994 Plan). The adjustment to expenses of $248,468 includes operating expenses recovered under the ECR during the test year for compliance costs that will continue to be recovered through the surcharge (i.e., operating expenses relating to the post-1994 Plan). Because KU is proposing to eliminate the 1994 Plan from its monthly Environmental Surcharge filings on a going-forward basis, only the operating expenses associated with the post-1994 Plan are eliminated in this adjustment. However, all ECR revenues collected in the test year are eliminated because failure to do so would overstate KU's adjusted operating revenues by that portion of ECR revenues not eliminated. KU proposes to recover the revenue requirements on any remaining rate base in the 1994 Plan through base rates, and proposes to recover revenue requirements of remaining rate base in the post-1994 Plan through the monthly Environmental Surcharge filings. KU's capitalization includes an adjustment to eliminate the ECR rate base for the post-1994 Plan and does not include an adjustment for the ECR rate base for the 1994 Plan (see Rives Exhibit 2). This adjustment is included in Schedule 1.03 of Rives Exhibit 1.

Q. Please explain the off-system sales revenue adjustment for the ECR calculation shown in Schedule 1.05 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, consistent with the methodology prescribed in the Commission's Order on rehearing in Case No. 98-474 dated June 1, 2000, an adjustment of $776,418 was made to reduce revenues to reflect the environmental surcharge calculations recognized in the determination of off-system sales.

Q. Was an adjustment made to eliminate demand-side management revenues and expenses from test-year operating results?

A. Yes. Consistent with the Commission's practice of eliminating the revenues and expenses associated with full-recovery cost trackers, an adjustment was made to eliminate $2,942,935 of revenue recovered through the Demand-Side Management Cost Recovery Mechanism ("DSMRM") and the corresponding $2,946,471 of 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 included in Schedule 1.09 of Rives Exhibit 1.

Q. Was an adjustment made to annualize for year-end customers for the electric business?

A. Yes. The numbers of customers served at the end of the test period for the rate classes were higher than the average numbers of customers for the 12-month test period. The differences between the number of customers served at year-end and the average number for each rate class during the test period was multiplied by the average annual kWh usage per customer. The average usage for each rate class was then multiplied by the average revenue per kWh (including customer charges, energy charges, demand charges and minimum bills), resulting in an upward adjustment to electric operating revenue of $251,167.

The additional operating expenses associated with serving the higher number of customers and volumes were calculated by applying an operating ratio to the revenue adjustment. Consistent with the Commission's practice, the operating ratio of 60.28 percent was determined by dividing operation and maintenance expenses, exclusive of wages and salaries, pensions and benefits, and regulatory commission expenses, by base rate revenues calculated at the currently effective rates. When applied to the year-end revenue adjustment, the application of the operating ratio resulted in an upward adjustment to expenses of $151,410.

The detailed calculations of the electric year-end adjustment to revenues and expenses are contained in Seelye Exhibit 11. This adjustment is included in Schedule 1.10 of Rives Exhibit 1.

Q. Please explain the adjustment to reflect customers switching to other rates during the test year.

A. Seelye Exhibit 12 includes an adjustment to reflect the change in revenue due to a customer switching from a special contract rate to KU's proposed Non-Conforming Load Service Rate NCLS (with interruptible service) resulting in a decrease in revenue of $1,898,980. The transfer of the special contract customer is currently being considered in Case No. 2003-396, which has not been set for hearing. This adjustment is included in Schedule 1.28 of Rives Exhibit 1.

V. ALLOCATION OF ELECTRIC REVENUE INCREASE AND RATE DESIGN

Q. Have you prepared an exhibit reconstructing KU's test-year billing units for the electric business?

A. Yes. The reconstruction of KU's electric billing determinants is shown on Exhibit 13. As shown in the column labeled "Calculated Divided by Actual" of Seelye Exhibit 13, page 1, the net base rate revenues calculated on pages 2 through 32 of that exhibit were within a factor of 0.998557 of KU's actual net revenues, thus, confirming the accuracy of the test period billing determinants.

Q. After considering all of the required adjustments, what is the proposed increase in revenues and how is the increase allocated among the individual customer classes?

A. In this filing, KU is proposing to increase its annual electric revenues by $58,252,463 (reflecting a revenue deficiency of $58,254,344 shown on Exhibit 7 of Mr. Rives' testimony). Seelye Exhibit 14 shows that the proposed increase would result in an increase of 8.54% percent in jurisdictional revenues from sales to ultimate consumers. KU is also proposing to increase certain miscellaneous charges and to decrease lease charges, resulting in a net increase in miscellaneous revenues.

The proposed rates apportion the revenue increase among the customer classes as follows:

Table 2 Proposed Electric Increase		
Customer Class	**Proposed Increase**	**Percentage**
Residential	$24,185,323	9.56%
General Service	$ 5,792,730	8.74%
Combined Lighting & Power Service	$18,885,564	8.32%
Commercial/Industrial TOD	$ 6,725,688	7.99%
Coal Mining Power Service	$ 725,107	8.49%
Large Mine Power TOD	$ 513,353	8.49%
Special Contracts	($ 202,024)	(1.39%)
Lighting	$ 1,179,334	8.80%
Total Ultimate Consumers	$57,805,074	8.54%

As shown on Seelye Exhibit 15, the effects on individual class revenues were determined by applying both the current and proposed prices to the adjusted billing determinants for each customer class.

Q. **How was the proposed allocation among the rate classes determined?**

A. We were guided by the cost of service study in allocating the proposed increase among the rate classes, but did not follow the cost of service study precisely. If KU had tried to equalize the rates for return by rate classes, the residential rate would have received an increase of 25.30%, as shown in Seelye Exhibit 16. KU thus limited the increase that Rate RS could receive to approximately one percentage point above the overall percentage increase to ultimate consumers, as discussed in Mr. Beer's testimony. Consequently, KU is proposing an increase of 9.56% to the residential class and 8.54% to ultimate consumers. The Company provided me with strong guidance that the residential increase should be no more than approximately 9.6%. KU wanted 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. How were the increases allocated to the other rate classes?

A. The class rates of return fell within a pattern of four groups. One group contained rate classes that were reasonably close to the overall rate of return. Another group contained classes significantly below the overall rate of return. Yet, another group contained classes above the overall rate of return, and, finally, one rate class (All Electric Schools and one special contract) were significantly above the overall rate of return. Therefore, we developed three increase tiers for allocating the KU electric increase. The first tier, applicable to customer classes with rates of return below the overall rate of return, such as the residential class, was set at *approximately* 9.6%. This approximate increase was applied to the residential class and lighting customer classes. The second tier was determined by applying the overall approximate increase to certain classes, such as some of the lighting rates and mining rates. With the exception of mining rates, this increase was applied to customer classes whose return was reasonably close to the overall return. Our objective with increasing mining rates at the overall percentage increase was to begin moving in the direction of transitioning these customers to the otherwise applicable standard rate schedule (either LP or LCI). The third tier was developed on the basis of the percentage required to produce the required increase requested by KU. This increase tier was approximately 8.3%. KU is not proposing an increase to either All Electric Schools Rate AES or National American Stainless. Given the high rates of return, an increase for these two classes cannot be justified.

Q. If you used only three tiers, why do some of the increases to the rate classes appear to vary from these percentages?

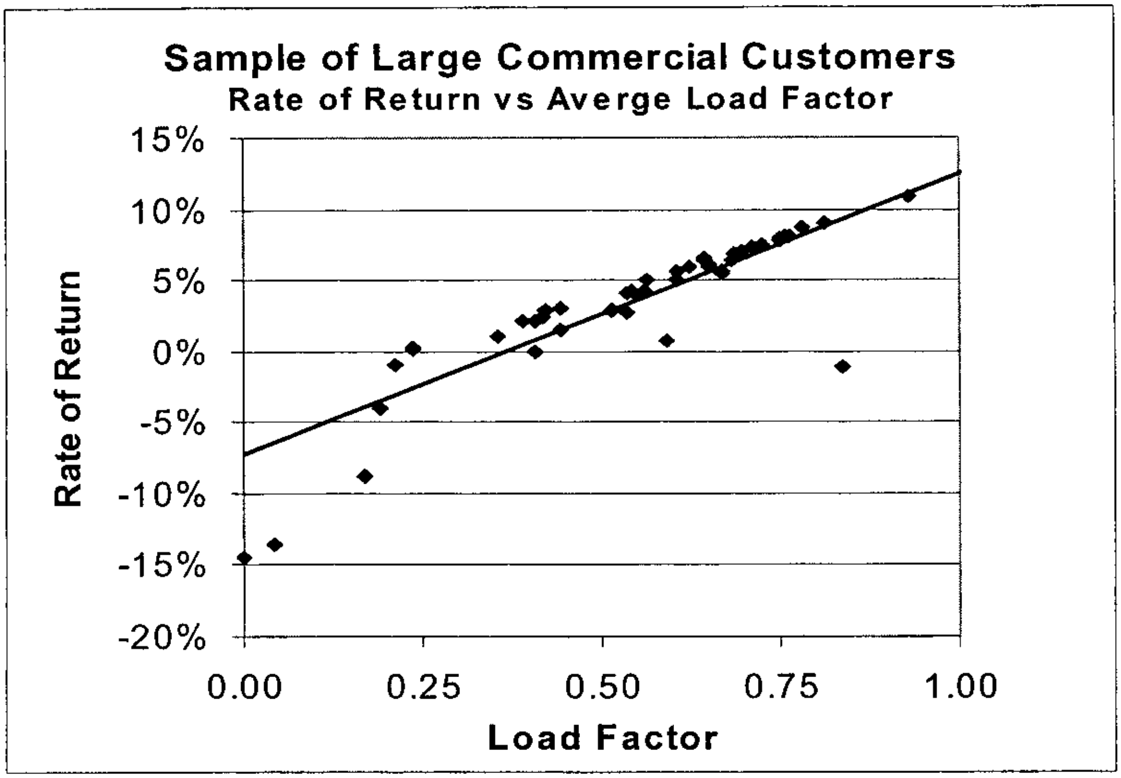
A. There are several reasons. First, the three-tier approach described previously was a general rule that was not strictly followed. Rate design for this number of rate schedules is too complex to use a simple "one size fits all" rule of thumb. Second, and more significantly, there were other rate design objectives that we followed. For example, because we also tried to more accurately reflect the demand/energy cost relationship in the company's demand/energy rates, some customers will be impacted more than others. It is virtually impossible to transition toward cost of service without producing these sorts of effects. Third, some of the apparent increases are due to the fact that KU is proposing a significant increase in the Curtailable Service Rider ("CSR") credit. Customers taking interruptible service will see a lower overall increase. Changes to Curtailable Service will be discussed later in my testimony.

Q. What guidelines were followed in designing the electric rates?

A. Unit charges were developed that would transition toward the unit costs indicated in the electric cost of service study. For KU's two-part rates consisting of a customer charge and energy charge, such as Residential Rate RS and General Service Rate GS, the customer charges were increased to cover more of the customer-related costs identified in the cost of service study, and energy charges were set at a level that more properly reflected energy- and demand-related costs. Similarly, for KU's three-part rates consisting of a customer charge, demand charge and energy charge, such as the Lighting & Power and Large Commercial & Industrial rates, unit charges were selected that more closely followed the unit costs determined in the cost of service study, which in most cases translated into increasing the customer and demand charges but lowering the energy charge.

Q. Why is it important to develop energy and demand charges for commercial and industrial rates that reflect unit costs identified in the cost of service study?

A. Just as there are different rates of return from one class of service to another, there are different rates for return from one customer to another within any given customer class. If the unit charges in a utility's rate schedule do not reflect cost of service, then the differences in intra-class rates of return (as opposed to inter-class rates of return) can be significant. The following graph of a typical group of large commercial customers illustrates this point.



In this graph, individual rates of return (or "individual customer profitability") are graphed against load factor. The upward slope in the graph illustrates that with a demand-energy rate that does not properly reflect the cost of providing service, the individual rates of return for customers with high load factors are significantly greater than customers with low load factors within the same class. High load-factor customers are thus being penalized instead of rewarded for having a more constant usage pattern. This situation can be alleviated, or at least mitigated, by designing rates that do not recover too much of a utility's fixed costs through the energy charge. A properly designed rate will flatten the linear trend line shown in the graph, thus eliminating intra-class subsidies. Ignoring the results of a cost of service study can cause individual rates of return within a class to get further and further out of line, creating even greater intra-class subsidies.

Q. Has KU made any general changes to the electric tariffs or other changes not specifically discussed in your testimony?

A. Yes. KU's electric rate schedules have been updated to include a listing of all applicable adjustment clauses. There are a number of changes that have been proposed to simplify or clarify the language in the electric tariff or to re-organize the structure of the tariff which are not detailed in my testimony. Other changes are discussed in Sidney L. "Butch" Cockerill's testimony.

Q. Please describe the current rate structure for Rate RS.

A. Rate RS is a two-part rate consisting of a customer charge and an energy charge. The energy charge is structured as a declining-block rate. KU is proposing to eliminate the declining-block structure.

Q. What is a declining-block rate structure?

A. A declining-block rate, or "declining step" rate as it is sometimes called, is a rate where the charges *decrease* at specified increments of usage. For example, in the case of KU's current Residential Rate RS, the price for the first 100 kWh of customer usage is currently \$0.05017 per kWh, the price for the next 300 kWh of customer usage in \$0.04572 per kWh, and all usage over 400 kWh the energy charge is \$0.04172 per kWh of customer usage. With a declining-block rate structure, a customer using a large amount of electric energy would receive a lower average price than a customer using a small amount of electric energy. In other words the rate goes down with increased usage. A declining-block rate is still a pricing structure that is commonly used within the industry.

Q. How can a declining-block rate structure be supported based on the cost of providing service?

A. Within a rate class, if the non-customer-related cost per kilowatt-hour for serving a smaller customer is higher than the cost per kilowatt-hour of serving a larger customer, then a declining-block rate can be supported.

Q. Based on the cost drivers identified in the cost of service study, is there any basis for a declining block rate structure?

A. A standard justification for a declining-block rate structure is to provide for recovery of customer-related costs through the initial block of the rate. If customer-related costs are recovered through the energy charge rather than through a customer-charge, then the cost per kilowatt-hour would certainly decrease in proportion with customer usage. However, if all customer-related costs are recovered through the customer charge, then there is less of a justification for a declining-block structure. However, a declining block rate structure could be justified if it can be shown that demand-related costs, which would still be recovered through the energy charge in a two-part rate, go down as customer usage levels go up. Likewise, an inverted block rate structure (which consists of a pricing pattern that increases as usage goes up) could be justified if it can be shown that demand-related costs go up as customer usage levels go up. This would be equivalent to showing that customer load factor is either positively or negatively correlated with customer usage.

Q. What do you mean by customer load factor?

A. Customer load factor is the relationship between a customer's kWh usage and maximum demand, and can be calculated by dividing a customer's kWh usage by the customer's maximum demand multiplied by the number of hours over which the kWh usage was measured. Load factor can be determined by measuring the customer's maximum monthly demand or by measuring the customer's kW demand at the time of the utility system peak. A blocked rate structure can be supported if there is a positive or negative correlation between a customer's load factor and kWh usage. If load factors within a customer class increase with greater usage, then a declining-block rate structure can be supported. However if load factors within a customer class decrease in relation to greater usage, then an inverted block rate structure can be supported.

Q. Have you performed an analysis of this relationship?

A. Yes. A statistical analysis was performed on KU's load research data to determine whether there is a relationship between load factor and kWh energy for residential customers. The data that was used was monthly load research data that contained observations for individual customer energy usage, non-coincident peak demand and coincident peak demand. Coincident peak demands and non-coincident peak demands are key drivers in the electric cost of service study. Specifically, three statistical analyses were performed. First, the monthly non-coincident peak load factor for all customers in the sample for all months of the year was regressed on customers' monthly kWh energy usage. Second, the coincident peak load factor for all customers in the sample for the summer months of June, July, August, and September was regressed on customers' monthly kWh energy usage for those same months. Third, the coincident peak load factor for all customers in the sample for the non-summer months of January through May and October through December was regressed on customers' monthly kWh energy usage for those same months. The purpose of these regression analyses was to correlate energy usage to key drivers in the cost of service study, namely summer coincident demand, winter coincident demand, and maximum customer demands.

Q. What did these analyses indicate?

A. The linear regression analysis indicated a statistically significant relationship between monthly *non-coincident peak load factor* and monthly *energy usage* for KU residential customers based on observations for all months during the year. The regression coefficient for kWh energy usage is positive which indicates that kWh energy usage has a relationship with non-coincident peak load factor, with a t-value of 36.746 which indicates statistical significance at the 99% confidence level. In other words, the analysis indicated that non-coincident peak load factor increases with customer usage. However, the R-Square is only 0.38, which indicates that only 38% of the variation in the non-coincident peak load can be explained kWh usage. The results of this statistical analysis are contained in Seelye Exhibit 17. These results suggest that *there is a moderate basis for a declining-block rate structure* year around based on non-coincident peak load factors.

The linear regression analysis did not indicate a statistically significant relationship between monthly *coincident peak load factor* and monthly *energy usage* for KU residential customers based on observations for the *summer months*. The t-value for kWh energy usage is -1.895, which is not statistically significant at the 95% level. This lack of relationship can be visually verified in the graph contained in Seelye Exhibit 18. The R-Square statistic of 0.005 shows that summer kWh energy usage for KU residential customers explains only about 0.5% of the variation in summer coincident peak load factor. Stated differently, about 99.5% of the variation in summer coincident peak load factor for KU residential customer is unexplained by this model. The results of this statistical analysis are contained in Seelye Exhibit 18. These results suggest that *there is no basis for either a declining-block or an inverted-block rate structure during the summer months* based on coincident peak load factors. This is extremely important given that summer peak period costs are allocated on the basis of coincident peaks during the summer months.

The linear regression analysis indicated a statistically significant relationship between monthly *coincident peak load factor* and monthly *energy usage* for the KU residential customers based on observations for the *winter months*. The regression coefficient for kWh energy usage is negative which indicates that kWh usage has an inverse relationship with winter coincident peak load factor, with a t-value of -5.522 which indicates statistical significance at the 99% confidence level. However, the R-Square statistic of 0.021 shows that only about 2.1% of the variation in winter coincident peak load factor can be explained by kWh usage. The results of this statistical analysis are contained in Seelye Exhibit 19. These results suggest that *there is no basis for either a declining-block or an inverted-block rate structure during the winter months* based on coincident peak load factors.

Q. Do you believe that a declining-block rate or inverted-block rate can be strongly supported based on these analyses?

A. No. The only support indicated by any of these analyses is for a year around declining-block rate as shown in the analysis of the non-coincident peak load factor. However, the R-Square supporting this conclusion is not strong. Furthermore, this analysis only relates to distribution demand-related costs. Even if, in spite of the relatively poor R-Square, a year around declining-block rate were developed based on distribution costs, the step in the rate would be very small because distribution demand-related costs are a relatively small portion of KU's total demand-related costs.

Q. **But doesn't the fact that production and transmission demand-related costs are higher in the summer than in the winter support an inverted block rate in the summer months and a declining-block rate in the winter months?**

A. No. It is important not to confuse seasonal differences in costs with differences that would translate into an inverted- or declining-block structure. The higher costs in the summer months only support a seasonally differentiated rate, not an inverted block rate. A seasonally differentiated rate fully addresses the seasonal nature of the costs, while blocked rates should address any cost changes resulting from load factor differences across usage levels within each costing period. As indicated by the load factor analyses described above, there are no material load-factor differences across usage levels within each costing period that would justify a blocked rate structure.

Q. Are you proposing to eliminate the block rate structure for residential service?

A. Yes. A flat energy charge is more reflective of the cost of providing service and is easier for customers to understand. Furthermore, with a higher customer charge there is less need to retain the declining-block rate structure.

Q. What rate design is being proposed for residential service?

A. We are proposing a two-part rate consisting of a customer charge and a flat energy charge. We are proposing to eliminate the declining block rate structure. We are proposing a customer charge of $9.00 per month and a flat energy charge of $0.04145/kWh.

Q. Why is KU not proposing a seasonal rate structure?

A. Although a seasonal rate structure could be supported based on the results of the cost of service study, the implementation of a seasonal rate would require major modifications to KU's billing system. The company did not feel that the benefits justified the additional billing costs and customer education effort required to implement seasonal rates.

Q. What is the relationship between the proposed customer charge and the customer-related costs identified in the cost of service study?

A. As shown in Seelye Exhibit 20, the cost of service study indicates that customer-related costs for Rate RS are $14.21 per month. A $9.00 per month customer charge would represent a significant movement in the direction of reflecting KU's customer-related costs in rates. Even so, a \$9.00 customer charge represents only 63.3% of total customer-related costs (\$9.00 ÷ \$14.21 = 63.3 %).[2]

Q. Is KU proposing to eliminate Full Electric Residential Service Rate FERS?

A. Yes. Because the cost structures and unit charges of Rate RS and Rate FERS are so similar, we determined that there is no valid justification for maintaining two separate rates. Consequently, KU is proposing to eliminate Rate FERS and move the customers served under Rate FERS to Rate RS.

Q. Are any other changes being proposed to the residential rate schedule?

A. Yes. KU is proposing to limit future service under Rate RS to single phase service. Customers already receiving three phase service under this rate schedule as of its effective date will continue to be served under Rate RS. In addition, the availability of service description has been simplified, a reference to the terms and conditions for service has been added, and the minimum demand charge has been deleted.

Q. Is KU proposing to change the Volunteer Fire Department Rate ("VFD") for electric service?

A. Yes. Rate VFD currently contains the same charges as Rate FERS. Because FERS is being eliminated and the customers moved to Rate RS, Rate VFD will be modified to match the rates being proposed for Rate RS. Consequently, we are proposing a customer charge of \$9.00 per month and an energy charge of \$0.04145/kWh.

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[2] The increase in the customer charge would be similar to the increase toward cost of service with respect to the residential gas customer charge in LG&E's last gas rate case, Case No. 2000-080. In that proceeding, the customer charge was increased to \$7.00, with the cost of service study then indicating that customer-related costs were \$11.48. Thus, in the last gas base rate case the Commission approved a customer charge that reflected 61.0% of total customer-related costs (\$7.00 ÷ \$11.48 = 61.0%).

Q. Is KU proposing to retain the Combined Off-Peak Water Heating rider?

A. No. Rate CWH is an old promotional water-heating rate that is no longer justified. The number of customers served under this rate schedule has been declining steadily for a number of years. We are proposing to consolidate this schedule with Rates RS and GS, as applicable. Customers currently served under this rate schedule would take service under either Rate RS or Rate GS. The electric cost of service study indicates an extremely low rate of return for this customer class.

Q. Is KU proposing any changes to the rate structure of General Service Rate GS?

A. Yes. We are proposing to eliminate the declining block rate structure and increase the customer charge. The proposed customer charge is $20.00 per meter per month and the proposed energy charge is $0.04697/kWh

Q. Are any other changes being proposed to the Rate GS service schedule?

A. Yes. The availability of future service under this rate schedule has been limited to secondary service at maximum loads no greater than 200 kW per month. Customers already receiving primary service, or service with loads greater than 200 kW, under this rate schedule as of its effective date will continue to be served under this schedule.

Q. Why has KU proposed that future service under Rate GS be limited to secondary service at load no greater than 200 kW?

A. KU proposes to limit service under this schedule to secondary service because customers should be served on a rate schedule that provides the appropriate price signals through demand and energy charges. Ideally, all customers should be served under a three-part rate consisting of a customer charge, demand charge and energy charge. A three-part rate more properly reflects the principal cost drivers of utilities – namely number of customers served, maximum demand, and the amount of energy used. However, the higher cost of installing metering equipment to measure demands has been a prohibiting factor to implementing three-part rates on a wider scale.

Q. Is KU proposing to eliminate Electric Space Heating Rider Rate 33?

A. Yes. This is an old promotional rate that is no longer justified. There are relatively few customers served under this rate and we are proposing to merge Rate 33 with Rate GS. Any existing customers are served under Rate GS for their non-space heating usage and we are proposing that their space heating usage will also be billed on Rate GS.

Q. What changes is KU proposing to Large Power Rate LP?

A. We are proposing to implement a customer charge and eliminate the declining block structure of the energy charge. Additionally, we are proposing to recover more fixed costs through the demand charge rather than continue to recover a portion of demand-related fixed costs through the energy charge. We have also eliminated redundant or unnecessary language and limited single-phase service to a minimum average of 200 kW. All service under this rate schedule remains limited to a maximum average of 5000 kW.

Q. Is KU proposing to merge any of its other rate schedules with its Rate LP?

A. Yes. We are proposing to eliminate High Load Factor Rate HLF and Water Pumping Rate M and merge them into Rate LP. None of these schedules are used to serve many customers. KU wants to simplify its rates, eliminate some of its specialized schedules, and combine rates that serve customers of similar size.

Q. Please explain the proposed changes to the Large Industrial/Commercial Time of Day Rate LCI-TOD?

A. KU is proposing to implement a customer charge and to recover more fixed costs through the demand charge rather than through the energy charge. We have deleted the limiting reference to large commercial/industrial customers, eliminated redundant or unnecessary language and have added language regarding the determination of maximum load under the schedule.

Q. Is KU proposing to change the peak periods set forth in Rates LCI-TOD and Large Mine Power Time-of-Day Rate LMP-TOD?

A. Yes. The hours during the peak period of KU's time-of-day rates are the same in the winter as they are during the summer. Consistent with the costing periods identified in the cost of service study, we are proposing different hours for the summer billing months of June through September than for the winter billing months of October through May. The peak period will be reduced by 3 hours during the summer months. The shorter peak period during the summer billing months should provide large commercial and industrial customers with slightly greater opportunity to shift load to off-peak periods. The following table summarizes the changes to the peak periods:

Table 3 **Changes to Peak Periods** **Rates LCI-TOD and LMP**	
Current Peak Periods	**Proposed Peak Period**
Peak Period (Both Winter and Summer) Weekdays, 8 A.M. to 10 P.M., Eastern Standard Time (EST), year round.	**Summer Peak Period** Weekdays, from 10 A.M. to 9 P.M. Eastern Standard Time (EST) during the 4 monthly billing periods of June through September.
	Winter Peak Period Weekdays, from 8 A.M. to 10 P.M Eastern Standard Time (EST) during the 8 monthly billing periods of October through May.

Q. What changes are being proposed to the Curtailable Service Rider?

A. KU is proposing several major changes to this rider. First, the credit would be increased to $4.19 for customers served at primary voltages and to $4.09 for customers served at transmission voltages. Second, the hours of interruption would be increased to 500 hours of interruption per year, thus eliminating the rate differentials for different hours of curtailment. Because the credit will be determined on the basis of the full capacity cost of a combustion turbine generating unit, it is important that customers receiving the credit be subject to interruption for a number of hours representative of the amount of time that combustion turbines could be expected to operate according to the company's resource planning models. Third, KU is proposing to charge $16/kW for non-compliance during a requested interruption. This charge will apply to *__each__* failure to interrupt. Fourth, certain provisions of the CSR schedule have been modified to harmonize the rate schedule with LG&E's CSR schedule.

Q. What is basis of the proposed CSR credit?

A. The credit will be based on the avoided capacity cost of a combustion turbine generator. The avoided cost was determined by applying a levelized annual carrying charge to the installed cost per kW of a combustion turbine. Levelized fixed operation and maintenance expenses were also included in the avoided cost calculation. Additionally, the avoided cost was increased to reflect KU's planning reserve margin. The credits were loss adjusted to calculate a credit for transmission and primary voltage customers. The avoided cost calculation is included in Seelye Exhibit 21. The utility depends on being able to call upon the interruptible load during periods of capacity constraint. If the customer fails to curtail its load, then there can be serious consequences. Furthermore, if the customer does not interrupt, no avoided costs are realized for KU and its customers.

Q. What is the basis of the proposed charge for failure to curtail?

A. The $16/kW non-compliance charge was based on approximately 4 months of the credit. The foundation for the charge is that each failure to comply with a request to curtail the customer's load should result in the customer paying back 4 months of the credit, which is not an unreasonable charge given that in its resource planning scenarios the company does not plan to serve load that can be curtailed.

Q. What changes are being proposed to KU's lighting rates?

A. The lighting rates are being increased by approximately 8.8%. In addition, we have eliminated redundant or unnecessary language, eliminated reference to five lights which are no longer used by customers, and restricted certain mercury vapor lights. KU is also proposing to merge the Decorative Street Lighting Rate DEC. St. Lt. into Street Lighting Service Rate St. Lt. so that we have only one rate schedule applicable to street lighting. It should be noted that this does not reflect a withdrawal of service. The charges are simply being shown on Rate St. Lt. KU has also eliminated redundant or unnecessary language contained in Private Outdoor Lighting Rate P.O.Lt. Additionally, KU is proposing to eliminate Customer Outdoor Lighting Rate C.O.Lt. and move the customers to Rate P.O.Lt so that all outdoor lighting will be served by a single rate schedule. The lights being eliminated are inefficient and used by very few customers.

Q. Is KU proposing to add a Rider for Intermittent and Fluctuating Loads ("IFL")?

A. Yes. We are proposing that the IFL rider be added to address concerns about loads having a detrimental effect on the system, thus potentially adversely affecting other KU customers or KU's facilities.

Q. Is KU proposing to implement an Excess Facilities rider?

A. Yes. KU is implementing an Excess Facilities rider to standardize its practices and offerings across LG&E and Kentucky Utilities. Kentucky Utilities has a widely-used facilities lease arrangement that is similar in purpose to LG&E's Excess Facilities rider. If a customer on Kentucky Utilities' system requires non-standard facilities (such as a second back-up feed or automatic switchgear) or wanted to lease transformers from the utility to take service at a lower voltage, Kentucky Utilities' longstanding practice was to lease the facilities to the customer at an annual lease rate of 28% of the cost of the facilities. The lease payment was intended to cover the carrying costs on the investment, depreciation, and operation and maintenance expenses. The payment would continue for as long as the customer required the facilities. The way that the 28% was determined, the lease payment in effect provided for the eventual replacement of the facilities through the application of a straight carrying charge methodology (as opposed to a levelized carrying charge methodology). Kentucky Utilities has been offering lease arrangements since at least the early 1980s and has numerous such arrangements with customers.

Q. Are there any problems KU's facilities lease arrangement?

A. No. We are simply updating the charges in the lease arrangements to reflect current costs and incorporating KU's facilities lease arrangements under an Excess Facilities rider.

Q. How is KU proposing to structure the Excess Facilities rider?

A. We are proposing to separate the rate into two components: (i) a carrying charge component and (ii) an operating expenses component. For KU the carrying charge component for distribution facilities would be 0.94% per month as applied to the original cost of the facilities, and the operating expenses component would be 0.56%. The carrying charge component would cover the utility's cost of capital, grossed up for income taxes related to the investment. The operating expenses component would cover the operation and maintenance expenses, property taxes, ***and*** the cost of replacing the facilities. A customer can choose either to pay for the facilities up front through a contribution in aid of construction or pay the carrying charge set forth in the rate. If a customer chooses to make a contribution in aid of construction for the facilities then only the operating expenses component of the rate (0.56%) would apply. If a customer does not want to pay for the facilities up front, then both the carrying charge component and the operating expenses component would apply. In either case, the utility would be responsible for replacing the facilities should the facilities fail.

Q. Have you prepared an exhibit showing the calculation of the charges set forth in the proposed Excess Facilities rider?

A. Yes. The cost support for the charges is included in Seelye Exhibit 22. As can be seen from this exhibit, the carrying charge component of the rate corresponds to the weighted cost of capital proposed by KU in this proceeding, grossed up for income taxes. The operating expenses component includes operating expenses, maintenance expenses, insurance, taxes other than income taxes, and depreciation expenses. The depreciation expenses are intended to cover the replacement over time of the facilities.

Q. Have you prepared an exhibit showing the revenue impact of replacing the special lease arrangements with the Excess Facilities rider?

A. Yes, this impact is shown in Seelye Exhibit 23.

Q. Please describe the Redundant Capacity rider proposed by KU.

A. The purpose of the Redundant Capacity rider is to allow customers that have one or more redundant feeds to reserve back-up capacity on the distribution system. As customers come to rely on greater use of electric technology, there is more and more customer interest in having a redundant feed along with automatic relay equipment capable of switching from a principal circuit to a backup circuit in the event that electric service from the primary feed is lost. With the greater use of technology, some customers are finding it increasingly difficult to tolerate electrical outages for even short periods of time. A customer who wants a second feed must pay the cost of the customer-specific facilities required to provide the feed, including the second distribution line, automatic relay equipment, or other customer-specific facilities that may be required. Customers can pay for the customer-specific facilities by either making a contribution in aid of construction or by taking service under the Excess Facilities rider. If the customer wants to have full backup capacity on the second feed, there are additional costs incurred by KU of ensuring that there is sufficient network distribution capacity to provide full backup in the event that a relay occurs on the automatic switchgear. In order to ensure that there is sufficient backup capacity for the redundant feed the utility must plan the distribution facility as if there were two customers placing demands on the system. For this reason, KU is proposing to implement a demand charge to cover the distribution demand-related cost of providing backup service for new customers with redundant feeds. The demand charge would be applied to the customer's monthly billing demand determined under the standard rate schedule under which the customer receives electric service.

Q. What are the proposed Redundant Capacity charges?

A. The proposed demand charge for primary voltage customers is \$0.63 per kW per month of billing demand and the proposed demand charge for secondary voltage customers is \$0.80 per kW per month of billing demand.

Q. How was the demand charge for the proposed Redundant Capacity rider determined?

A. The demand charge was determined by computing the distribution demand-related revenue requirements from the electric cost of service study for primary and secondary voltage service under KU's large power rates and dividing this amount by the billing demands for this class of customers. KU is proposing different demand charges for customers served at primary and secondary voltages. The cost support for the proposed demand charges is included in Seelye Exhibit 24.

VI. MISCELLANEOUS SERVICE CHARGES

Q. Is KU proposing to change any of its miscellaneous non-recurring charges?

A. Yes. KU is proposing to change or add a number of miscellaneous non-recurring charges. First, KU is proposing to increase the disconnect/reconnect charge to $31.00. Second, KU is proposing to increase the returned check fee from $5.00 to $9.00. Third, KU is proposing to increase the meter test charge from $14.00 to $31.40. These three changes will be addressed in Mr. Cockerill's testimony.

Q. Have you prepared an exhibit showing the revenue impact of the proposed changes to the miscellaneous charges?

A. Yes. Seelye Exhibit 25 shows the impact on miscellaneous revenue of the proposed changes. Page 1 shows the revenue impact of modifying the disconnect/reconnect charge. This change results in an increase of $962,913 in annual revenue. Page 2 shows that the revenue impact of increasing the returned check charge is $39,441. Page 3 shows the revenue impact of modifying the meter-test charge. This change results in an increase of $1,409 in annual revenue. It should be pointed out that increasing these charges could result in a reduction in the utilization of these charges, thus producing slightly lower revenue than the proposed pro-forma amount requested in this proceeding. Nevertheless, economic efficiencies can be achieved by sending the correct price signal through the implementation of charges that properly reflect the cost of providing the service. This is what we have tried to do with all of the rate modifications discussed in my testimony.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, it does.

VERIFICATION

COMMONWEALTH OF KENTUCKY)
)
COUNTY OF JEFFERSON)

The undersigned, William Steven Seelye, being duly sworn, deposes and states that he is a Principle with The Prime Group, 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 STEVEN SEELYE

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 29 th day of December, 2003.

Tammy J. Elzy (SEAL)
Notary Public

My Commission Expires:

TAMMY J. ELZY
NOTARY PUBLIC
STATE AT LARGE
KENTUCKY
My Commission Expires Nov. 9, 2006

Mr. Cockerill

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:	)	
	)	
AN ADJUSTMENT OF THE ELECTRIC	)	**CASE NO. 2003-00434**
RATES, TERMS AND CONDITIONS OF	)	
KENTUCKY UTILITIES COMPANY	)	

TESTIMONY OF
SIDNEY L. "BUTCH" COCKERILL
DIRECTOR – REVENUE COLLECTIONS
KENTUCKY UTILITIES COMPANY

December 29, 2003

Filed: December 29, 2003

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

A. My name is Sidney L. "Butch" Cockerill. I am employed by LG&E Energy Services, Inc. as Director of Revenue Collections for Louisville Gas and Electric Company ("LG&E") and Kentucky Utilities Company ("KU" or the "Company"). 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 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 KU's non-recurring charges. Finally, I will review the Company's efforts to assist its low income customers.

Q. What is the primary purpose for the proposed revisions to KU's tariff?

A. In addition to reflecting the proposed rates, which are discussed in detail in the testimony of 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.

Q. Have you made any changes to the Company's tariffs that are not expressly discussed in your testimony?

A. Yes. There are a number of minor changes that have been proposed to simplify or clarify the language in the tariff or to re-organize the structure of the tariff which are not detailed in my testimony. For example, non-recurring charges have been moved from the general terms and conditions to Section I of the tariff under the subsection "Special Charges." Additionally, the section in the current electric tariff titled "Rules and Regulations

Governing the Supply of Electric Service" has been renamed to "Terms and Conditions" with the provisions being reorganized into appropriate subsections for ease of reference. These changes are, however, clearly identified in the proposed tariff located at Tab 7 of the Filing Requirements and in the side-by-side comparison of current versus proposed tariffs located at Tab 8 of the Filing Requirements attached to the Application.

Changes in KU's Electric Tariff

Q. What changes were made to the Company's non-recurring charges?

A. We have harmonized the language in KU's tariff to LG&E's tariff by changing the name of Reconnect charge to the Disconnect/Reconnect charge and increasing the charge from \$10.50 to \$31.00. We have also increased our meter test charge to \$31.40. Finally, we have modified our Returned Payment Fee from \$5.00 to \$9.00.

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 \$31.00 per transaction. The schedule attached hereto as SLC Exhibit 1 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 from $14.00 to $31.40 in order to collect the reasonable costs of this service. The schedule attached hereto as SLC Exhibit 2 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 $9.00 per returned payment. The schedule attached hereto as SLC Exhibit 3 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 the amount of customers deposits pursuant to 807 KAR 5:006, Section 7(1)(b). We have proposed changes to our deposits policy by moving the retention period from 18 months to 12 months for residential customers in order to harmonize that policy with LG&E's policy. We are also clarifying the conditions under which KU will refund residential customers' deposit. KU also proposes to use credit scoring for residential customers, like LG&E does. The proposed revisions also provide for the subsequent collection of a service deposit or alternate security from non-residential customers, even if initially waived, should their credit history decline.

Q. Please describe the proposed changes to KU's budget payment plan.

A. Our proposed changes will allow additional customers to become eligible for the budget payment plan and will make it easier for customers to join the plan at any time during the year.

Q. Please describe the other changes which the Company is proposing to the Terms and Conditions of its tariff.

A. We have also made a number of changes to better harmonize the language contained in KU's tariff with that contained in LG&E's tariff.

We have added new language relating to Company liability to the tariff.

We have proposed language to clarify that, in accordance with the Commission's regulations, customer-read information must be verified by the Company at least once per calendar year and that the remaining meters must be read at least quarterly, except if prevented from doing so by reasons beyond its control.

The Company is proposing new language to protect against theft of service in the absence of an active account at a given location.

We have also proposed changes to our Character of Service description by restricting two-wire service to those customers already on the RS schedule as of the effective date of the tariff, reclassifying 34.5kV service as primary service, and freezing existing 34.5kV customers on the present rate.

Finally, the Company's motor start requirements have been reworked to increase understanding and application without diminishing the enforcement provisions. The language proposed for both LG&E's and KU's tariff again seeks to harmonize the two tariffs for purposes of operational simplification and to eliminate out-dated standards.

<u>Low-Income Assistance</u>

Q. Describe KU's efforts to assist its low-income customers.

A. KU recognizes that winter can be a particularly difficult time for those in need. As a result, we have several means of providing assistance. For example, we match a portion of the contributions received from customers to the WinterCare Energy Assistance Fund ("WinterCare"), which is designed to assist low-income customers with their winter heating bills. The funds are administered by third parties with distribution based upon need and income level of the customer. In addition to encouraging customers to contribute, KU also advises customers how to apply for assistance.

In addition to WinterCare, KU offers services and options to assist all customers in better managing their energy bills. One such program is KU's WeCare program. The WeCare program offers energy education and weatherization to low-income families. WeCare helps to make low-income customers' homes healthier, safer, more comfortable and links them to other low-income services. Weatherization usually includes air sealing, duct sealing, and adding insulation among other things. WeCare has weatherized over 200 low-income homes served by KU in 2003. Other services and options include credit counseling, payment arrangements, and the budget payment plan.

Q. Does this conclude your testimony?

A. Yes, it does.

292500.07

VERIFICATION

COMMONWEALTH OF KENTUCKY)
) SS:
COUNTY OF JEFFERSON)

The undersigned, Sidney L. "Butch" Cockerill, being duly sworn, deposes and says he is Director of Revenue Collections for LG&E Energy Services, 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.

Sidney L Butch Cockerill
SIDNEY L. "BUTCH" COCKERILL

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 29th day of December 2003.

Melody L. Hulse (SEAL)
Notary Public

My Commission Expires:

November 24, 2007

Appendix A

S. L. "Butch" Cockerill

Director – Revenue Collection
LG&E Energy Services, Inc.
220 West Main Street
Louisville, KY 40202
(502) 627-4772

Education

Spaulding University, B.A. in Business Administration – 1998

Previous Positions

Louisville Gas and Electric Company

- 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

KU Disconnect/Reconnect Cost Justification

* Labor – One Hour at	$25.60
** Vehicle	5.40
Total Cost	**$31.00**

*This is the average hourly rate for all employees who perform this work, including our contract partners. It also includes all time (travel, set-up, etc.) associated with performing this work.

**This is the average hourly rate for the class of vehicle used to perform this work.

KU
Meter Test
Cost Justification

* Labor – One Hour at	$26.00
** Vehicle	5.40
Total Cost	**$31.40**

*This is the average hourly rate for all employees who perform this work. It also includes all time (travel, set-up, testing, etc.) associated with performing this work.

**This is the average hourly rate for the class of vehicle used to perform this work.

KU
Return Payment
Cost Justification

Average Bank Return Payment Charge	$2.45
KU Administration Cost	6.13
Postage/Material	.51
Total Cost	**$9.09**