COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

APPLICATION OF KENTUCKY UTILITIES COMPANY FOR AN ADJUSTMENT OF ITS ELECTRIC RATES	**)))**	**CASE NO. 2012-00221**

In the Matter of:

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

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

Filed: June 29, 2012

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

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

Q. Please describe your educational and professional background.

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 and KU. I assumed my current position on May 1, 2001. Descriptions of my employment history, educational background, professional appearances and civic involvement are contained in the Appendix attached hereto.

Q. Have you previously testified before this Commission?

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

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[1] Case No. 2009-00549, *In the Matter of: Application of Louisville Gas and Electric Company for an Adjustment of its Electric and Gas Base Rates* and in Case No. 2009-00548, *In the Matter of: Application of Kentucky Utilities Company for an Adjustment of Base Rates*; Case No. 2008-00252, *In the Matter of: Application of Louisville Gas and Electric Company for an Adjustment of its Electric and Gas Base Rates* and in Case No. 2008-00251, *In the Matter of: Application of Kentucky Utilities Company for an Adjustment of Base Rates*; Case No. 2003-00433, *In the Matter of: An Adjustment of the Gas and Electric Rates, Terms and Conditions of Louisville Gas and Electric Company* and in Case No. 2003-00434, *In the Matter of: An Adjustment of the Electric Rates, Terms and Conditions of Kentucky Utilities Company*.

[2] Case No. 2010-00204, *In the Matter of: The Joint Application of PPL Corporation, E.ON AG, E.ON U.S. Investments Corp., E.ON U.S. LLC, Louisville Gas and Electric Company and Kentucky Utilities Company for Approval of an Acquisition of Ownership and Control of Utilities'* Case No. 2001-104, *In the Matter of: Joint Application of E.ON AG, Powergen plc, LG&E Energy Corp., Louisville Gas and Electric Company and Kentucky Utilities Company For Approval of an Acquisition*; Case No. 2000-095, *In the Matter of: Joint Application of Powergen plc, LG&E Energy Corp., Louisville Gas and Electric Company and Kentucky Utilities Company For Approval of a Merger;* Case No. 97-300, *In the Matter of: Joint Application of Louisville Gas and Electric Company and Kentucky Utilities Company for Approval of Merger.*

Q. What is the purpose of your testimony?

A. My testimony will provide an overview of LG&E's and KU's applications in these proceedings and why it is important that the increases the Companies have proposed be approved. In so doing, I will briefly review the causes for the increased capital expenditures and operation and maintenance expenses incurred by LG&E and KU to provide adequate, efficient and reliable service at reasonable rates. Additionally, I will describe LG&E's and KU's ongoing commitment to the communities we serve, especially through our assistance to low-income customers.

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

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

- Paul W. Thompson, Senior Vice President, Energy Services – Mr. Thompson will describe the performance of the generation and transmission facilities of the Companies and Energy Services' capital investments in generation and transmission facilities, and the increase in operation and maintenance expenses since the test period in the last rate cases.
- Chris Hermann, Senior Vice President, Energy Delivery – Mr. Hermann will explain how the Companies are continuing to distribute safe and reliable service by providing an overview of LG&E's and KU's pipeline integrity efforts, including the Gas Line Program LG&E is proposing. Mr. Hermann will also provide an overview of the initiatives LG&E and KU have

implemented to improve customer service, including responsiveness to customer inquiries;

- Kent W. Blake, Chief Financial Officer – Mr. Blake will describe why the financial condition of the Companies requires the requested increase in rates, describe why the Companies are at a great risk of not earning the return on common equity awarded in this proceeding between rate cases, present the financial exhibits to LG&E's and KU's applications, discuss the Companies' accounting records, describe the calculation of LG&E's and KU's adjusted net operating income for the twelve-month period ended March 31, 2012, support the different valuations of the Companies' property, and support certain reference schedules supporting the Companies' applications;
- Valerie L. Scott, Controller – Ms. Scott will support certain pro forma adjustments to the Companies' operating income for the twelve months ended March 31, 2012, demonstrate that those adjustments are known and measurable and, therefore, reasonable, and support certain reference schedules supporting the Companies' applications;
- Shannon L. Charnas, Director of Accounting and Regulatory Reporting – Ms. Charnas will explain why the Companies requested and, upon review, accepted the depreciation study performed by John J. Spanos of Gannett Fleming, Inc., support certain pro forma adjustments to the Companies' operating income and rate base for the twelve months ended March 31, 2012, demonstrate that those adjustments are known and measurable and, therefore,

reasonable, and support certain reference schedules supporting the Companies' applications;

- John J. Spanos, Gannett Fleming, Inc. – Mr. Spanos will review his assessment of LG&E's and KU's current depreciation rates and will present his depreciation study;
- Daniel K. Arbough, Director, Corporate Finance and Treasurer – Mr. Arbough will discuss LG&E's and KU's current and target capital structures, as well as explain debt financing issues;
- William E. Avera, President, FINCAP, Inc. – Dr. Avera will present the results of his analysis, which demonstrates that the return on equity for the proxy groups of utilities and non-utility companies is from 10.30% to 11.70%. Additionally, Dr. Avera will present his recommendation that the Commission adopt an 11.00% allowed return on common equity for both LG&E's electric and gas operations and KU's electric operations;
- Lonnie E. Bellar, Vice President, State Regulation and Rates – Mr. Bellar will support certain exhibits that are required by the Commission's regulations, explain the revenue effects and impact to customers, present LG&E's and KU's recommendation for the allocation of proposed increases among the customer classes, describe LG&E's proposed Gas Line Tracker, the rate mechanism to recover capital investments in and expenses with facilities for its gas operations, and explain certain pro forma adjustments to the Companies' operating income for the twelve months ended March 31, 2012;

- J. Clay Murphy, Director, Gas Management, Planning, and Supply – Mr. Murphy will discuss certain changes that LG&E is proposing to its Gas Supply Clause, changes to its existing transportation programs, and certain other tariff changes required to facilitate those transportation programs; and
- Robert M. Conroy, Director, Rates – Mr. Conroy will explain and support certain exhibits that are required by the Commission's regulations, explain certain proposed pro forma adjustments, describe the results of the Companies' cost-of-service study, and discuss in detail LG&E's and KU's proposed changes to electric and gas rates, and the tariffs.

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

A. Yes. As explained in the testimonies of Messrs. Thompson and Hermann, the Companies continue to invest in facilities and incur costs in order to furnish customers with adequate, efficient, and reasonable service. In fact, since October 31, 2009, the end of the test year in the Companies' last rate cases, LG&E and KU have incurred over $1 billion in capital expenditures, excluding investments associated with the Companies' environmental compliance plans.

The Companies' substantial investments in generation and transmission facilities, which are discussed in detail in Mr. Thompson's testimony, are approximately $337.7 million and $145.3 million, respectively, since October 31, 2009, the end of the test year in the last rate cases. Similarly, as discussed in the testimony of Mr. Hermann, the Companies have made nearly $487.4 million in capital investments to their electric and gas distribution facilities.

Q. In addition to these capital expenditures, has there been an increase in operation and maintenance expenses since the last rate cases?

A. Yes. As with the capital expenditures, the testimonies of Messrs. Thompson and Hermann address the significant increase in operation and maintenance expenses since October 31, 2009, the end of the test year in the last rate cases. The catalysts for the increased operation and maintenance expenses are many, yet all of the increases are associated with the provision of safe, reliable and satisfactory customer service. The Companies are experiencing ever-increasing costs associated with complying with regulations promulgated by the Federal Energy Regulatory Commission ("FERC"). As FERC oversight continues to grow, the Companies must respond in order to operate in compliance. As explained by Mr. Thompson, the regulations have caused a substantial increase in the costs attributable to FERC compliance, including the hiring of additional personnel.

Additional personnel have also been hired as part of the initiatives implemented by the Companies to provide an even more satisfactory customer service experience, as explained by Mr. Hermann. In so doing, from June 2011 to February 20, 2012, LG&E and KU added 25% more residential service center customer service agents and 59% more business service center customer service agents. Metrics show these initiatives are working by enhancing the customer service experience. The cost of the initiatives, however, is not reflected in the Companies' existing rates.

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

A. Yes. Operating efficiently and controlling costs to the extent practicable are long-standing and predominant values in our business culture. These principles govern the Companies' business practices in the construction, operation and maintenance of our systems and services. As discussed in the testimonies of Messrs. Thompson and Hermann, the Companies have made every effort to contain the increasing costs of providing reliable service, including implementing initiatives that are designed, in part, to defray costs, such as those associated with unplanned outages.

Q. Please describe the decision to file these rate cases.

A. The decision to file for increases in rates is a serious matter. We understand it will impact customers. We do not make the decision to file rate cases without full consideration of the impact to our customers, the current economic conditions and their impact on customers, our duty to serve retail customers and the need to continue to invest in facilities to provide that service. Our business remains one of the most capital-intensive industries in the world, but is now more complex than ever. Customer revenues alone are not sufficient to fund all the facilities LG&E and KU need to provide electric and gas service. We must continue to raise money through financing, using both debt and equity. Given our additional costs since the last rate cases, we must now adjust those rates in order to earn a reasonable return that will continue to allow LG&E and KU to raise capital at reasonable rates.

Q. Please describe the proposed increase in base rates.

LG&E is requesting a 6.9%, or approximately $62.1 million a year increase in its electric base rates, and a 7.0%, or approximately $17.2 million a year, increase in its gas base rates. The monthly impact of the requested increase in base rates will increase an average residential electric bill by 8.6%, or approximately $7.25, for a customer using 1,010 kWh of electricity. The monthly impact of the requested increase in gas base rates will increase an average residential gas bill by 7.6%, or approximately $3.42, for a customer using 57 Ccf of gas.

KU is requesting a 6.5%, or approximately $82.4 million a year increase in its base rates. The monthly impact of the requested increase in base rates will increase an average residential electric bill by 8.0%, or approximately $7.41, for a customer using 1,178 kWh of electricity.

The testimonies of Mr. Blake, Ms. Scott, Ms. Charnas, Mr. Arbough, Mr. Conroy, and Mr. Bellar provide a comprehensive accounting of LG&E's and KU's revenue requirements and how the calculation was determined. Mr. Avera's testimony supports LG&E's and KU's proposed rate of return on equity through an independent and extensive cost of capital analysis. The testimonies of these witnesses demonstrate that LG&E and KU are not presently earning a fair and reasonable return adequate to attract capital investment and that an increase in rates is necessary.

Q. If the proposed rates are approved will customers continue to receive a good value for their service?

A. Yes, as demonstrated in Mr. Blake's testimony, because of the Companies' proficient cost performance, even if the proposed rates are approved, customers can be assured they are still receiving a very good value for their service.

Q. Would you please elaborate on the customer service initiatives?

A. Yes. Responsive service is as important to our customers as it is to LG&E and KU. Customers increasingly expect to have more timely information and access to customer service options. Since the last rate cases, LG&E and KU implemented a series of initiatives to enhance customer service. As explained more fully in the testimony of Mr. Hermann, the Companies have achieved measurable improvements as a result of the initiatives they have implemented. For example, the percentage of customer calls answered within thirty seconds, which is the Companies' goal, has increased significantly and meter reading accuracy has improved. I am proud that the Companies' customer service performance is so strong in many areas, however, LG&E's and KU's efforts to improve and enhance customer service are not yet finished.

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

A. LG&E and KU strive to not only operate in an environmentally conscious manner, but also encourage our customers to do the same. The Companies endeavor to do so even with regard to business practices that are not expressly governed by the United States Environmental Protection Agency ("EPA") or other environmental regulations. From constructing facilities that employ state-of-the-art energy efficiencies to utilizing printers that print on both sides of the page to reduce our paper consumption, LG&E and KU continue to implement initiatives that reaffirm our commitment to operating efficiently.

The Companies' commitment does not stop with our business practices. Indeed, LG&E and KU have endeavored to not only encourage our customers to practice energy conservation, but have developed and implemented a suite of demand-side management and energy efficiency programs that provide customers with specific and detailed information regarding their energy usage and means by which to reduce same. Our goal is to make our customers informed energy managers, and the Companies made another tangible step in achieving this goal by expanding its demand-side management and energy efficiency programs in Case No. 2011-00134.[3]

Because of the Companies' efforts, LG&E and KU were among 44 organizations named 2011 Partner of the Year by the EPA based in large part on their demand-side management and energy efficiency programs.

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

A. Our commitment to the communities which we serve is long-standing and truly part of LG&E's and KU's culture. This commitment is evidenced through our employees' giving of their time and talent throughout our service area to improve the quality of life in the communities in which they work and live. For example, in June 2011, nearly 200 LG&E and KU employees and their families performed community service across their service areas as part of the Companies' seventh annual Day of Caring. As part of the Day of Caring, employees performed activities such as painting, landscaping, debris removal, repairs and maintenance, washing and waxing nonprofit transportation vehicles and serving meals. In addition to this devotion of their time, for five consecutive years, the Companies' employees have donated at least $1 million annually as part of the Power of One campaign, which provides

[3] *In the Matter of: Joint Application of Louisville Gas and Electric Company and Kentucky Utilities Company for Review, Modification, and Continuation of Existing, and Addition of New Demand-Side Management and Energy-Efficiency Programs.*

assistance to more than twenty-five nonprofit organizations across the Commonwealth. In 2011, employees gave a record $1.6 million as part of the charitable giving campaign.

In addition to the efforts of our employees, the LG&E and KU Foundation contributes to our state in supporting education, diversity initiatives, the environment, and health and safety programs. The LG&E and KU Foundation was established in 1994. In July 2010, as part of an effort to leave a lasting philanthropic legacy in the Commonwealth, E.ON A.G, the parent company of then E.ON U.S., donated $2 million to the LG&E and KU Foundation as it prepared to consummate the change of control transaction with PPL Corporation. Since 1994 the LG&E and KU Foundation has awarded $25 million to hundreds of organizations to support benevolent endeavors across the Commonwealth.

A good example of the LG&E and KU Foundation's efforts occurred in March of this year when the devastating tornadoes struck Kentucky. The LG&E and KU Foundation quickly responded and provided $50,000 to the American Red Cross to support their relief efforts.

All of these donations are funded solely by our shareholders.

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

A. LG&E and KU, as part of an ongoing commitment to their low-income customers, have substantially increased their efforts and assistance since the last rate cases. As explained more fully in the testimony of Mr. Hermann, the Companies have not only increased their contributions to low-income customers to unprecedented levels, but have also made their business practices more flexible so as to provide additional support. Since the last rate case, KU agreed to contribute $100,000 annually to the WinterCare Energy Assistance Fund, a state-wide energy assistance fund supported privately by utilities and community action agencies that provide assistance to low-income persons with their utility expenses during the winter season through 2014. LG&E participates in a similar program, ACM/Metro Match, and has agreed to continue its current matching contribution of up to $225,000 annually through 2014. Moreover, the Companies agreed to make two additional annual contributions totaling $500,000 to LG&E's and KU's HEA programs, consisting of a shareholder contribution of $250,000 in 2011 and 2012.

In addition to these significant contributions, the Companies have modified certain business practices to afford low-income customers greater latitude in paying their bills. First, as discussed in the testimony of Mr. Hermann, the Companies have created a FLEX program by which residential customers who indicate they are on a limited income may receive a payment due date that more closely coincides with the receipt of their monthly income check. Second, residential customers who receive a pledge or notice of low-income energy assistance from an authorized agency are not assessed a late payment charge for the bill for which the pledge or notice is received, and will not be assessed a late payment charge in any of the following 11 months.

Q. Does this conclude your testimony?

A. Yes, it does.

VERIFICATION

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

The undersigned, **Victor A. Staffieri**, being duly sworn, deposes and says he is Chairman of the Board, Chief Executive Officer and President of Louisville Gas and Electric Company and Kentucky Utilities Company, and an employee of LG&E and KU Services 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

VICTOR A. STAFFIERI

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 19th day of June, 2012.

(SEAL)

Notary Public

My Commission Expires:

March 29, 2014

APPENDIX A

Victor A. Staffieri

Chairman, Chief Executive Officer and President
LG&E and KU Services Company

Civic Activities

Boards

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

Industry Affiliations

Edison Electric Institute, Washington, DC - Board of Directors -- June 2001 – 2011
Electric Power Research Institute, Palo Alto, CA - Board of Directors -- May 2001 – April 2002

Other

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

Education

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

Previous Positions

LG&E Energy LLC, Louisville KY

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

Long Island Lighting Company, Hicksville, NY

1989-1992 -- General Counsel and Secretary
1988-1989 -- Deputy General Counsel
1986-1988 -- Assistant General Counsel
1985-1986 -- Managing Attorney
1984-1985 -- Senior Attorney
1980-1984 – Attorney

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

APPLICATION OF KENTUCKY UTILITIES COMPANY FOR AN ADJUSTMENT OF ITS ELECTRIC RATES	**)))**	**CASE NO. 2012-00221**

In the Matter of:

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

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

Filed: June 29, 2012

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

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

Q. Please describe your educational and professional background.

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

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

A. In my position, I am responsible for power generation functions, electric transmission, and fuels and energy marketing activities. For purposes of this testimony, I will refer to these functions cumulatively as "Energy Services."

Q. Have you previously testified before this Commission?

A. Yes, I have testified in LG&E's and KU's last three base rate cases.[1] I testified in the proceeding involving the early termination of the lease between Western Kentucky

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[1] Case No. 2003-0433, *In re the Matter of: An Adjustment of the Gas and Electric Rates, Terms and Conditions of Louisville Gas and Electric Company*; Case No. 2003-0434, *In re the Matter of: An Adjustment of the Electric Rates, Terms and Conditions of Kentucky Utilities Company;* Case No. 2008-00252, *In re the Matter of: Application of Louisville Gas and Electric Company for an Adjustment of Its Electric and Gas Base Rates*;

Energy Corporation and Big Rivers Electric Corporation[2] and in the Commission's investigation of the Companies' membership in the Midwest Independent System Operator, Inc.[3] Additionally, I most recently testified in Case No. 2011-00375, in which the Companies received approval to construct a natural gas combined cycle combustion turbine.[4]

Q. Please provide an overview of your testimony and the activities in Energy Services that led to a need to increase base rates at this time.

A. In this testimony I will describe Energy Services' capital investments in generation and transmission facilities, in addition to describing the increased operation and maintenance expenses since the test period in the last rate cases. The changes in the cost of providing service result from, among other things, the operation of Trimble County Unit No. 2 ("TC2"), increased scope of planned maintenance work across the fleet, compliance with Federal Energy Regulatory Commission ("FERC") reliability regulations, and the greater number of Energy Services employees necessitated by TC2 operations and FERC compliance.

Case No. 2008-00251, *In re the Matter of: Application of Kentucky Utilities Company for an Adjustment of Base Rates;* Case No. 2009-00549, *In the Matter of: Application of Louisville Gas and Electric Company for an Adjustment of Its Electric and Gas Base Rates*; Case No. 2009-00548, *In the Matter of: Application of Kentucky Utilities Company for an Adjustment of Base Rates.*

[2] *In The Matter Of: The Applications Of Big Rivers Electric Corporation For (I) Approval Of Wholesale Tariff Additions For Big Rivers Electric Corporation, (II) Approval Of Transactions, (III) Approval To Issue Evidences Of Indebtedness, And (IV) Approval Of Amendments To Contracts; And Of E.On U.S., LLC, Western Kentucky Energy Corp., And LG&E Energy Marketing, Inc. For Approval Of Transactions*, Case No. 2007-00455.

[3] *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.

[4] *In the Matter of: Joint Application of Louisville Gas and Electric Company and Kentucky Utilities Company for a Certificate of Public Convenience and Necessity and Site Compatibility Certificate for the Construction of a Combined Cycle Combustion Turbine at the Cane Run Generating Station and the Purchase of Existing Simple Cycle Combustion Turbine Facilities from Bluegrass Generation Company, LLC in LaGrange, Kentucky*.

Every effort is made to contain costs in the construction of new generation and transmission facilities. Likewise, the Companies endeavor to defray rising operation and maintenance expenses where possible and are committed to operating as efficiently as practicable. These efforts, however, cannot fully offset the operating realities of the Companies' need to replace coal-fired generation with gas-fired generation, TC2 operations, and complying with FERC regulations, which ensure that customers receive the reliable and safe service they have rightfully come to expect.

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

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

Q. Have Energy Services' business practices and objectives changed due to any changes in the energy market?

A. No, while the energy market continues to evolve, Energy Services maintains the time-tested business philosophy of using the least-cost, most reasonable source of energy, based on known and measurable information. Certainly, the energy landscape is quite different than in LG&E's and KU's last rate cases for several reasons. A suite of regulations was implemented by the United States Environmental Protection Agency ("EPA") that required the Companies to determine whether it was economically prudent to continue to operate its coal-fired generation units. The results of the

Companies' analyses have been the subject of recent regulatory filings and are discussed later in my testimony.

Furthermore, native load growth is no longer the significant driver of energy supply costs that it was in the past. The most recent sales forecast, provided to the Commission in Administrate Case No. 387,[5] shows the compound annual growth rate for the 2012 to 2016 time period for energy sales is 0.6 percent for LG&E and 0.8 percent for KU. The Companies are not presently faced with the position of acquiring new generation resources in order to pursue an ever-increasing growth in native load. Resource acquisitions are now focused on replacing the coal-fired generation that has served customers so efficiently in the past to meet continuously increasing environmental requirements.

Moreover, the increased use of horizontal drilling and fracking recovery procedures in shale formations in the last few years has substantially increased estimates of natural gas reserves. Production from shale formations has led to dramatic decreases in natural gas prices in the short term and probably in the long term. Not only has this led to low wholesale power prices, but it has also positively impacted the viability of natural gas-fired power plants in this region for intermediate and base load production. In determining whether to include natural gas as an intermediate or base load fuel source, LG&E and KU are following their sound business philosophy of selecting the least-cost and most reasonable resource based upon the specific generation need. The Commission recently approved our analysis

[5] *In The Matter Of: A Review Of the Adequacy of Kentucky's Generation Capacity and Transmission System*, Administrative Case No. 387.

of certain proposed gas fired generation facilities as being the least cost alternative in Case No. 2011-00375.

Also, increased regulation from the North American Electric Reliability Corporation ("NERC"), especially with regard to Critical Infrastructure Protection, has required the Companies to devote additional operating costs, including the hiring of several personnel, simply to remain in compliance. Additional details regarding the increased NERC regulations are discussed later in my testimony.

In short, although the energy landscape is quite different than in LG&E's and KU's most recent rate cases, and continues to evolve, Energy Services' business philosophy, practices and objectives remain consistent in order to maintain sound operating and maintenance practices that promote reliable operations, least cost, most reasonable investments and practices, and a safe working environment.

Generation Systems

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

A. LG&E owns and operates approximately 3,352 MW of generating capacity with a net book value of approximately $1.20 billion. LG&E's generation system consists primarily of three coal-fired generating stations – Cane Run and Mill Creek, both located in Jefferson County, and Trimble County. LG&E also owns and operates multiple natural gas-fired combustion turbines, which supplement the system during peak periods, and the Ohio Falls hydroelectric station, which provides baseload supply, subject to river flow constraints.

Q. Please describe KU's generation system.

A. KU owns and operates approximately 4,833 MW of generating capacity with a net book value of approximately $2.73 billion. KU's generation system primarily consists of four generating stations – Ghent in Carroll County, E.W. Brown in Mercer County, Green River in Muhlenberg County and Tyrone in Woodford County. Additionally, KU owns and operates multiple natural-gas-fired combustion turbines, which supplement the system during peak periods, and a hydroelectric generating station at Dix Dam, located next to the Dix System Control Center.

Q. Do LG&E and KU jointly own certain of the generating units and combustion turbines?

A. Yes. As a result of their joint planning, LG&E and KU jointly own several generation units. LG&E and KU jointly own TC2. Moreover, the Companies jointly own Trimble County Units 5 through 10, E.W. Brown Units 5 through 7, and Paddy's Run Unit 13.

Q. Do LG&E and KU engage in joint planning of their generation and transmission resource needs?

A. Yes. LG&E and KU, as owners and operators of interconnected electric generation and transmission facilities, achieve economic benefits through joint integrated resource planning and acquisition. Moreover, the Companies achieve economies by their joint operation as a single interconnected utility. Finally, the joint dispatch of the generation units continues to produce energy efficiencies through joint dispatch capabilities and intercompany sales of power.

Q. Have the Companies begun implementing changes to their generating fleet since their last rate cases?

A. Yes. Since their last rate cases, the Companies have been forced to undertake a comprehensive review of their generating units and fuel sources due to stringent emission standards that were promulgated by the EPA in 2011. Because the rules contained emission standards that were the most stringent the industry has seen with regard to coal-fired generating units, the Companies were required to examine whether they would modify or retrofit their generating units to operate in compliance with the new rules, or retire the units.

After the Companies completed their analyses, they developed environmental surcharge plans that were filed with the Commission in Case Nos. 2011-00161 and 00162 for approval that sought to retrofit certain coal-fired steam generating units.[6] The Commission ultimately approved the environmental surcharge plans in its orders of December 15, 2011, with the exception of the proposed modification of the construction of a Particulate Matter Control System to serve Brown Units 1 and 2, which was deferred for further review at a later date and in a separate filing.

Based on the same economic analysis, KU determined to retire Green River Unit 3 and Unit 4, as well as Tyrone Unit 3, which has been on inactive reserve for periods of time since the last rate cases; and LG&E determined to retire Cane Run Unit 4, Unit 5 and Unit 6. The units are expected to be retired in 2015, leading to a capacity shortfall of 877 MW in 2015.

Q. Have the Companies continued to invest in their current generating facilities since their last rate cases to serve customers' needs?

[6] *In the Matter of: The Application of Kentucky Utilities Company for Certificates of Public Convenience and Necessity and Approval of Its 2011Compliance Plan for Recovery by Environmental Surcharge* (Case No. 2011-00161) and *In the Matter of: The Application of Louisville Gas and Electric Company for Certificates of Public Convenience and Necessity and Approval of Its 2011Compliance Plan for Recovery by Environmental Surcharge* (Case No. 2011-00162).

A. Yes. LG&E has invested approximately $21 million and KU has invested approximately $38 million to maintain and enhance the performance of their existing generation to serve customer needs.

Q. Have the Companies continued to invest in generation reliability and infrastructure since their last rate cases?

A. Yes. LG&E has invested over $145 million and KU has invested almost $133 million since the last rate cases in generation infrastructure and reliability projects associated with their generation fleet.

Q. How do the Companies plan to replace the generating capacity that will be lost as a result of the retirements?

A. On May 3, 2012, LG&E and KU received approval in Case No. 2011-00375 to construct a 640 MW net summer rating natural gas combined cycle combustion turbine at the Companies' Cane Run generating station, including a twenty inch natural gas pipeline, and for the purchase of Bluegrass Generation Company, LLC's facilities in LaGrange, Kentucky, which includes natural gas simple cycle combustion turbines.[7] The total projected capital cost for the natural gas combined cycle combustion turbine at Cane Run, including the gas pipeline, is $583 million. The Companies are not seeking recovery of the costs associated with the construction of the turbine or pipeline in this proceeding. The proposed acquisition of the Bluegrass Generation facility unfortunately was terminated due to the conditional market mitigation conditions included in the May 4, 2012 order by FERC.

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[7] *In the Matter of: Joint Application of Louisville Gas and Electric Company and Kentucky Utilities Company for a Certificate of Public Convenience and Necessity and Site Compatibility Certificate for the Construction of a Combined Cycle Combustion Turbine at the Cane Run Generating Station and the Purchase of Existing Simple Cycle Combustion Turbine Facilities from Bluegrass Generation Company, LLC in LaGrange, Kentucky* (Case No. 2011-00375) (May 3, 2012 Order).

Q. In the last rate cases, you discussed the construction of TC2, which is now in commercial operation. Please provide an update on TC2.

A. TC2 has been in commercial operation since January 21, 2011, and is providing LG&E's and KU's customers with low-cost, efficient energy with a minimal impact to the environment. TC2 was designed to be extremely efficient, with a projected heat rate of 8,662, equivalent availability factor of 88 percent and a capacity factor of 87 percent. In its first year of operation, the unit experienced a heat rate of 9,427, equivalent availability factor of 72 percent and a capacity factor of 70 percent. While the actual values during the first year of operation did not reach the projected amounts, this is expected during the warranty period for a generating unit of this size and the complexity of its multiple operating systems. While this first year of performance is somewhat less than the designed criteria, we remain confident that TC2 will operate effectively and efficiently going forward.

Q. Please describe TC2's impact on operation and maintenance costs.

A. One of the reasons why a base rate increase is needed at this time is that current rates do not include the operation and maintenance costs associated with TC2. Since the Companies' last base rate cases, TC2 began commercial operation and LG&E and KU have determined the costs of operating and maintaining the unit, which have increased expenses by $11 million. As these costs represent the expected going-forward operation and maintenance expenses associated with operating this generating unit, it is appropriate that these costs are included in base rates.

Q. Has TC2 impacted Energy Services' labor costs, as well?

A. Yes, as the Companies have hired nineteen additional persons to work at the Trimble County Station since the test year in the last rate cases. This was expected, as TC2 was not in commercial operation during those proceedings and additional personnel have been required to operate the unit.

Q. Would you please review the operation and maintenance expenses for planned outages since the last rate cases?

A. Yes. LG&E and KU routinely plan to take their generating units off-line or "out of service" for scheduled repairs and maintenance. These are "planned outages" and each generating unit has a long term multi-year maintenance plan. Non-labor expenses are assigned to planned outages for each generation unit. The planned outage costs thus represent the Companies' cyclical maintenance costs.

There are two primary types of planned outages for the coal-fired units. Firstly, as a general rule, the boiler and non-turbine/generator balance of plant outages typically occur every two years. These outages generally last three weeks, but can be shortened or extended based on the total scope of work required. Secondly, the turbine/generator outages typically occur every seven to eight years. This type of outage typically lasts five to eight weeks and other balance of plant work is done at this time also. The planned outages for all generation units in the fleet are interconnected, coordinated, and dependent, so as to maintain an adequate reserve margin at all times.

Historically, when each generating unit was simpler, that is, had less functional components attached, such as pollution control components, planning the fleet's maintenance was relatively easier. The scope of work and cost was lower. Over the last several years, we have added major components such as selective catalytic reduction ("SCR") facilities and flue gas desulfurization ("FGD") facilities. And, of course, in the next couple of years we will add baghouses, additive injection systems, coal combustion residue drying systems, and upgrades to existing FGDs. Furthermore, the core boiler and turbine/generator components of the coal-fired fleet continue to age. There are two important impacts on planned outage expenses from the trends I have described. First, the scope of work in each planned maintenance outage is larger and more complex. Meanwhile, the demand to reliably provide power to the grid has certainly not lessened, so the available length of time to do the work has not increased. Hence, the second impact has been that the overall costs of outages have increased. For these reasons I have described, the Companies saw an increase of $15 million in maintenance expenses during the test year from previous levels reflected in the last rate cases. The Companies expect to continue to incur this level of planned maintenance outage expense again in 2014, and thereafter, due to the maintenance requirements of an aging, more complex fleet that has ever-increasing levels of environmental controls and reliability demands.

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

A. LG&E and KU have a history of reliable and efficient generation performance. This is evidenced through Energy Services' weighted average Equivalent Forced Outage Rate ("EFOR") and capacity factors. The Companies' EFOR, a commonly used industry standard to measure the reliability of coal-fired generating units, has historically remained below the industry average. LG&E's and KU's weighted EFOR during the test year averaged 5.8%, which is well below the most recent three-year national average of 9.3%. Moreover, first quartile EFOR performance is 5.3%, which demonstrates that the Companies' performance is comparable to the most reliable generating units in the country.

Q. Please describe LG&E's and KU's 2011 capacity factors.

A. In 2011, LG&E's steam capacity factor was 69% and KU's was 64%. These numbers have decreased in recent years, in part, because of the flat to declining on- and off-system sales the Companies have experienced.

Q. Have the Companies implemented new initiatives with regard to asset management of their generating units since the last rate cases?

A. Yes, LG&E and KU contracted with Black & Veatch to facilitate the implementation of a Remote Performance Monitoring service that will monitor and analyze the Companies' Distributed Control Systems ("DCS") data. DCS data provides the Companies with enhanced control over the many interconnected operations occurring within the generation fleet, while also providing improved coordination and monitoring over these processes. While the DCS data currently permits the Companies to collect data for over one thousand operating parameters for each unit, such as pressure and temperature, the existing system did not provide the Companies with the detailed continuous analysis necessary to sufficiently diagnose and correct issues prior to reaching a DCS protection limit, which can ultimately lead to unplanned outages or unit de-ratings. A DCS protection limit is the point at which the system would alert the Companies of a problem.

Black & Veatch's proprietary software can, however, detect and analyze sub-optimal performance prior to the issue rising to a DCS protection limit, thus providing LG&E and KU with the ability to minimize the risk of unplanned outages and de-ratings. These benefits are expected to minimize unexpected costs, correction of thermal deficiencies, and prevention of reliability concerns.

Before deploying the software system-wide, on January 28, 2010, the Companies began utilizing Black & Veatch's tools successfully on Ghent Unit 1 and Mill Creek Unit 4, as the Companies learned of heat rate issues and numerous equipment reliability concerns. LG&E and KU then expanded the monitoring to other Mill Creek units.

The Companies have now engaged Black & Veatch to remotely monitor LG&E's and KU's coal-fired generating units for a period of five years by providing continuous data streaming, real-time monitoring of plant operating data for early detection of emerging performance and reliability issues, and assistance with issue identification and correction. LG&E and KU anticipate that their existing predictive maintenance capabilities will be significantly enhanced as a result of this initiative, ultimately increasing reliability while optimizing maintenance costs.

Off-System Sales and Native Load Growth

Q. Has the downward trend for off-system sales continued since the Companies' last rate cases?

A. Yes, the downward trend for off-system sales has continued because the weak economy and low natural gas prices have negatively impacted the ability to sell energy in the off-system market. While the Companies endeavor to sell excess power to others in the wholesale power market when the generation facilities are not otherwise required to serve native load customers, structural changes to the Companies' generation fleet and decreased natural gas prices have all but eliminated LG&E's and KU's opportunities for off-system sales. The chart below demonstrates the decline in off-system sales margins since 2005, as well as during the test year:

For Years Ended	Total $000
2005	116,022
2006	59,983
2007	27,083
2008	38,475
2009	4,147
2010	2,995
2011	10,905
Test Year	7,846

The chart demonstrates that since 2005, off-system sales margins have decreased dramatically and sharply.

Q. Is there any reason to expect that off-system sales will rebound any time soon?

A. No. To the contrary, evidence suggests that going forward, off-system sales opportunities will remain diminished for several reasons. First, because of structural changes to the Companies' generating fleet, LG&E and KU have less base load capacity to respond to opportunities for off-system sales. In the last several years, the composition of the Companies' generation capabilities have changed, such that a larger portion of LG&E's and KU's base load capacity is now serving native load customers during periods when off-system sales were typically made. This is the result of several changes to the Companies' mix of power sources: the power supply agreements with Electric Energy, Inc. and Owensboro Municipal Utilities are terminated; several units are preparing to be retired resulting in a reduction of 797

MW; and the Companies will be using a combined cycle unit with natural gas as a fuel resource. Even if the energy market becomes more robust, LG&E and KU no longer have the available capacity or cost structure to perform as competitively in the wholesale market as in previous years. This is true because the Companies simply do not have the significant available low-cost base-load capacity to profitably sell in the wholesale market that they did in previous years.

Secondly, the price for off-system sales for energy produced from coal-fired generation has declined as a result of the greatly expanded production volume of natural gas. This is due to the horizontal drilling advances and the “fracking” recovery procedures in shale formations. The domestic production of natural gas has increased dramatically due to these techniques, with production increasing from 50 to 59 billion cubic feet per day from January 2007 to December 2010. The greatly increased supply of natural gas, in turn, is leading to historically low gas prices. While the Companies have taken advantage of the low prices in deciding to construct a natural gas combined-cycle combustion turbine, the prices have negatively affected wholesale power market prices.

The structural changes to the Companies’ generating fleet, which has reduced the availability of base-load, coal-fired generation capacity to support off-system sales, and historically low gas prices have severely limited LG&E’s and KU’s ability to successfully execute off-system sales in the wholesale power market. This is very significant to the Companies, as off-system sales opportunities between rate cases have traditionally served as a revenue source by which the Companies can offset rising operating costs for its retail customers and helped mitigate the risk of cost increases between rate cases.

Q. Are there other changes that have occurred since the last rate case that are also significant to the operations of Energy Services?

A. Yes. As I mentioned earlier in my testimony, native load growth is no longer the significant driver of energy supply costs that it was in the past. The most recent sales forecast, provided to the Commission in Administrative Case No. 387, shows the compound annual growth rate for the 2012 to 2016 time period for energy sales is 0.6 percent for LG&E and 0.8 percent for KU. In previous years, the increase in native load sales between rate cases traditionally served as a revenue source by which the Companies could partially offset rising operating costs for their retail customers. Thompson Exhibit 1 summarizes the Companies' historic and projected sales and energy requirements.

Transmission Systems

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

A. LG&E serves approximately 394,000 electricity customers over its transmission and distribution network in nine Kentucky counties. LG&E's transmission plant covers approximately 910 circuit miles, and has a net book value of approximately $157 million.

Q. Please describe KU's transmission system.

A. KU serves approximately 509,000 electricity customers over a transmission and distribution network in seventy-seven Kentucky counties. KU's transmission plant covers approximately 4,371 circuit miles, and has a net book value of approximately $336 million.

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

A. Yes. LG&E and KU, as owners and operators of interconnected electric transmission facilities, achieve economic and reliability benefits through joint operation as a single interconnected and centrally dispatched system and have operated jointly following the acquisition of KU Energy Corporation by LG&E Energy in 1998.

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

A. Energy Services has made several necessary investments in transmission facilities since the last rate cases that permit the Companies to provide reliable energy in a manner that complies with FERC's expanding suite of regulations and requirements. The total investment in transmission facilities, including infrastructure and reliability since the last rate case is over $145 million ($113 million by KU, $32 million by LG&E), and includes the completion of the transmission facilities associated with TC2 and the expenditures associated with FERC and NERC compliance.

Q. Have the transmission facilities associated with TC2 been completed?

A. Yes, the transmission facilities were completed on July 1, 2010. Included in those facilities are a new 345KV interconnect with Duke Energy, and a 345 kV transmission line, approximately 42 miles in length, running from LG&E's Mill Creek Generating Station through Jefferson County, Bullitt County, Meade County and Hardin County to KU's Hardin County Substation near Elizabethtown, Kentucky. While completion of the project was delayed from initial projections due to litigation involving right-of-way acquisitions, it is now in commercial operation and performing well. The total cost of the TC2 transmission facilities is $107 million, with $20 million incurred since the test year in the last rate cases.

Q. Please describe the operation and performance of the Companies' transmission facilities.

A. The Companies' transmission performance continues to be strong, which reflects the emphasis Energy Services places upon the importance of reliable service. In addition to LG&E's and KU's emphasis on safe and reliable transmission service, FERC continues to develop regulations and augment its oversight of the Companies' activities, to which LG&E and KU must respond. Cumulatively, the Companies' efforts, and their mandatory compliance with FERC and NERC regulations and standards, have resulted in a continued strong performance.

Q. Please provide an overview of the expenditures Energy Services has incurred with regard to FERC and NERC clearance compliance.

A. On October 7, 1010, NERC issued a recommendation, *Consideration of Actual Field Conditions in Determination of Facility Ratings*, which requires transmission owners such as the Companies to assess all of their transmission facilities greater than 100kV to mitigate any discrepancies between actual field conditions and the National Electric Safety Code (NESC) operational requirements with regard to ground clearances, distribution crossing clearances, and horizontal clearances when displaced by wind. Many utilities, such as LG&E and KU, have transmission facilities that are sixty to seventy years old and while compliant when originally installed, do not currently satisfy more stringent NESC clearance regulations.

Due to the magnitude of NERC's recommendation, it identified three levels of priority based upon the voltage of the transmission facility. NERC has given utilities three years to analyze and address any discrepancies. The deadline for analyzing high priority facilities was December 31, 2011, with medium and low priority facilities required to be completed by December 31, 2012 and 2013, respectively. NERC has urged utilities to remedy any issues as quickly as practical, but remediation should occur, at most, within one year of identifying the issue.

This NERC mandate has required the Companies to undertake significant action, as LG&E and KU have 727 miles of high priority transmission facilities and 2,020 miles of medium and low priority transmission facilities that must be assessed. LG&E and KU have completed their assessment of high priority facilities and the investigation of medium and low priority facilities is ongoing. As the lines are evaluated and actual field conditions that are inconsistent with original design specifications are identified, remediating construction activities are undertaken in compliance with the NERC recommendation. The Companies began incurring costs to comply with this NERC requirement in 2011, and will continue to expend funds to identify and mitigate issues through 2014. The Companies have incurred $5.2 million through the test year in complying. LG&E and KU estimate that it will ultimately cost $62 million to complete the work.

Q. Have the Companies experienced greater FERC and NERC regulation in other areas as well?

A. Yes, as the Companies must comply with fourteen categories of reliability standards, which range from protection and control requirements, to standards regarding resource and demand balancing, emergency preparedness and operations, and interconnection reliability operations and compliance. It is crucial that the Companies comply with all of the reliability standards, as NERC has compliance and enforcement powers it can invoke to address violations.

Within the fourteen categories of reliability standards the Companies have seen a marked increase in the costs associated with complying with the CIP reliability standards. These standards have established policies, plans, and procedures to safeguard physical and electronic access to control systems that affect both a utility's generation and transmission processes. NERC's framework encompasses every segment of the utility industry by outlining the security benchmarks each utility must meet in order to secure their cyber assets. As the security of assets continues to be an emerging issue within the utility industry, LG&E's and KU's compliance obligations likewise continue to increase.

Q. What have the Companies done to comply with the CIP reliability standards?

A. LG&E and KU, of course, make every effort to comply with the CIP reliability standards. To do so adequately, the Companies continue to hire additional personnel that are focused, almost exclusively, on NERC and CIP compliance. In fact, since the test year in the last rate cases, Energy Services has added 27 employees to assist with their compliance efforts.

Q. Have LG&E and KU recently implemented any other new transmission initiatives?

A. Yes, the Companies have invested in multiple information technology system enhancements, including significant upgrades in the Energy Management System

("EMS") and telecommunications network, and CASCADE, a new substation work and asset management system for the Transmission Protection and Substation department. CASCADE is used by Energy Delivery, as well. The benefits of these information technology system improvements are many, providing the Transmission Protection and Substation department with a new centralized repository for asset and maintenance data and enhanced mobility in that users can access information in the field through laptops and handheld devices, as well as more enhanced user interfaces in EMS and a systems testing environment that includes a more robust telecommunications network.

Safety Performance and Recognitions

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

A. The safety of Energy Services' employees and independent contractors is of paramount importance. The importance placed upon operating safely is evident in LG&E's and KU's recordable injury rate, which continues to be well below the national average. In 2009, 2010, and 2011, the recordable injury rates for employees were 1.09, 2.57, and 1.69, respectively. The recordable injury rates for independent contractors during the same time period were similar: 1.98, 1.98, and 2.97, respectively. These rates are well below OSHA's 2011 average for utility industry employees of 3.50 and its 4.70 average for construction contractors. To maintain the level of safety to which the Companies are accustomed, LG&E and KU continue to conduct safety summits that emphasize the importance of teamwork and the value of shared knowledge in improving safety.

Our employees' and contractors' genuine commitment to safety in their daily working habits is evidenced by the numerous safety recognitions that have recently been received by the Companies. For example, in 2010 and 2011, several of the Companies' plants received Kentucky Governor's Health and Safety Awards. Many significant milestones have likewise been reached, including in 2011 when Transmission Aerial Patrol achieved thirty-five years without a recordable injury and in 2012 when employees at the Brown generating unit achieved six years without a recordable injury and fifteen years without a lost time injury.

Research and Development

Q. Please describe Energy Services' recent research and development activities.

A. In addition to our continued funding of collaborative research with the Electric Power Research Institute, which was $2.2 million during the test year, Energy Services continues to invest in greenhouse gas research. Beginning in 2008, the Companies, along with other parties, formed the Western Kentucky Carbon Storage Foundation ("WKCSF") to provide funding for the Kentucky Geological Survey to drill a well in Hancock County to determine the feasibility of carbon dioxide storage in the western Kentucky coal field region. The Companies, along with the other principal members, donated $1.8 million, with the Commonwealth of Kentucky donating $1.3 million. The drilling of the well and initial testing was completed in 2009, and additional testing was done in 2010.

Moreover, in 2010, LG&E and KU made commitments to provide matching funds for two Department of Energy carbon capture demonstration studies. The first study is a self-concentrating absorbent process developed by 3H Company with a two-year annual commitment of $114,000. The second is an amine process under development by the University of Texas at Austin with a three-year annual commitment of $39,000. LG&E and KU also continue to support the research efforts of the University of Kentucky's Center for Applied Energy Research, with an annual investment of $200,000.

Q. Has KU continued to invest in Dix Dam?

A. Yes, as the Companies continue to overhaul the three units at Dix Dam, which first began providing service in 1925. The project involves rewinding the generators, refurbishing the turbine sections, and upgrading controls. As a result of the overhaul, each until will increase by 25% from 8 to 10 MW, for a total increase of 25%, or 6 MW, at the current lake level target range. The overhaul for Unit 3 was completed in 2009, with final testing completed in early 2010. Unit 2 will be completed in 2012, and Unit 1 will be completed in 2013. Since the end of the last test year KU has invested nearly $20 million in Dix Dam equipment and structure.

Q. In addition to its investments, has KU worked to ensure the integrity of Dix Dam?

A. Yes, as KU continues to utilize inspection processes that cyclically examines the different components of the Dix Dam. The Commission's order in Case No. 2010-00204 encouraged KU to continue to discuss the safety of Dix Dam with the Kentucky Council for Dix Dam Safety and the Division of Water. Prior to receiving the Commission's order, KU had already undertaken a series of activities purposed upon ensuring its integrity and communicating information regarding same. In February 2010, KU conducted an informational meeting that was attended by Arcadis Engineering, the firm that performs integrity assessments on Dix Dam, the Kentucky

Council for Dix Dam Safety and the Division of Water in order to communicate the current status of the facility and the planned improvements for same. Since then, KU has continued to discuss the safety of Dix Dam with the Kentucky Council for Dix Dam Safety and the Division of Water upon request.

Q. Please describe the activities LG&E has undertaken at McAlpine Dam.

A. Ohio Falls Hydro Station was built from 1925 to 1928 and became operational in 1928. In 2005, LG&E renewed its license with FERC to operate the facility and is investing $130 million to update and refurbish the eight existing turbine and generator units by the end of 2015. LG&E is nearly half-way through completing the rehabilitation of the facility's eight generating units. Upon completion of the rehabilitation project, the facility’s total generation capacity will increase from 80 megawatts to 100 megawatts.

Conclusion

Q. Does this conclude your testimony?

A. Yes, it does.

VERIFICATION

COMMONWEALTH OF KENTUCKY)
) SS:
COUNTY OF JEFFERSON)

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

____
Paul W. Thompson

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 20th day of June 2012.

______________________________(SEAL)
Notary Public

My Commission Expires:

July 21, 2015

APPENDIX A

Paul W. Thompson

Senior Vice President, Energy Services
LG&E and KU Energy LLC
220 West Main Street
Louisville, KY 40202

Industry Affiliations

Center for Applied Energy Research, Advisory Board Member
Electric Energy Inc., Board Member
Ohio Valley Electric Corporation, Board Member

Civic Activities

Jefferson County Public Education Foundation Board
University of Kentucky College of Engineering, Project Lead The Way, Council Member
Greater Louisville Inc. Board
Louisville Downtown Development Corporation Board, Finance Committee Chair
Louisville Free Public Library Foundation Board, Chairman
  Chair, Annual Appeal 2002 & 2203
  Co-Chair Annual Children's Reading Appeal 1999, 2000, & 2001
March of Dimes 1997 & 1998 - Honorary Chair
Habitat for Humanity - Representing LG&E as co-sponsor
Friends of the Waterfront Board 1998 – 2002
Leadership Louisville -- 1997-98

Education

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

Previous Positions

LG&E Energy Marketing, Louisville, KY
  1998 - 1999 – Group Vice President
Louisville Gas and Electric Company, Louisville, KY
  1996 - 1999 – Vice President, Retail Electric Business
LG&E Energy Corp., Louisville, KY
  1994 - 1996 (Sept.) – Vice President, Business Development
  1994 - 1994 (July) – Louisville Gas & Electric Company, Louisville, KY
    General Manager, Gas Operations
  1991 - 1993 – Director, Business Development
Koch Industries Inc.
  1990 - 1991 – Koch Membrane Systems, Boston, MA
    National Sales Manager, Americas
  1989 - 1990 – John Zink Company, Tulsa, OK
    Vice President, International

Lone Star Technologies (a former Northwest Industries subsidiary)

1988 - 1989 – John Zink Company, Tulsa, OK
Vice Chairman

1986 - 1988 – Hydro-Sonic Systems, Dallas, TX
General Manager

1986 – 1986 (July) –- Ft. Collins Pipe, Dallas, TX,
General Manager

1985 - 1986 – Lone Star Technologies, Dallas, TX,
Assistant to Chairman

1980 - 1985 – Northwest Industries, Chicago, IL,
Manager, Financial Planning

Thompson Exhibit 1

LG&E and KU Historic and Projected Sales and Energy Requirement

KY Retail Sales of Electricity (GWh)

	LG&E	KU Total	*Source*
2000	11,329	18,818	*1*
2001	11,397	18,478	*1*
2002	11,810	19,558	*1*
2003	11,503	19,496	*1*
2004	11,724	20,178	*2*
2005	12,292	20,990	*2*
2006	11,965	20,675	*3*
2007	12,658	21,642	*3*
2008	12,083	21,191	*3*
2009	11,405	20,260	*3*
2010	12,338	21,938	*3*
2011	11,641	21,162	*4, 5a-b*
2012	11,814	22,027	*6a-b*
2013	11,903	22,224	*6a-b*
2014	11,911	22,308	*6a-b*
2015	12,000	22,493	*6a-b*
2016	12,109	22,758	*6a-b*

CAGR

	LG&E	KY-Retail	KY-Wholesale	KY-Total	Virginia	KU Total
2006-2011	-0.5%					0.5%
2001-2011	0.2%					1.4%
2000-2010	0.9%	1.7%	0.8%	1.6%	0.9%	1.5%
2011-2016	0.8%					1.5%
2012-2016	0.6%					0.8%

Sources

1	2005 IRP	http://psc.ky.gov/pscscf/2005%20cases/2005-00162/LG&E_IRP_Vol1-03_Section5_Plan_Summary_042105.pdf
		See: Table 5.(3)-4 (p. 5-19) and Table 5.(3)-9 (p. 5-26)
2	2008 IRP	http://psc.ky.gov/PSCSCF/2011%20cases/2011-00140/20110421_LG%26E-KU_IRP_Volume%20I.pdf
		See: Table 5.(3)-4 (p. 5-20) and Table 5.(3)-9 (p. 5-28)
3	2011 IRP	http://psc.ky.gov/pscscf/2008%20cases/2008-00148/LG&E%20&%20KU_IRP%20Application%20Vol.%201_042108.pdf
		See: Table 5.(3)-4 (p. 5-20) and Table 5.(3)-9 (p. 5-28)
4	EIA-826	http://www.eia.gov/cneaf/electricity/page/eia826.html
5a, 5b	2011 FERC Form 1	http://www.ferc.gov/docs-filing/forms/form-1/data.asp
6a, 6b	2012 387 Filing	Table 6a

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

APPLICATION OF KENTUCKY UTILITIES COMPANY FOR AN ADJUSTMENT OF ITS ELECTRIC RATES	**)))**	**CASE NO. 2012-00221**

In the Matter of:

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

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

Filed: June 29, 2012

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

A. My name is Chris Hermann. I am Senior Vice President – Energy Delivery for Louisville Gas and Electric Company ("LG&E") and Kentucky Utilities Company ("KU") (collectively, the "Companies") and an employee of LG&E and KU Energy, LLC, which provides services to LG&E and KU. My business address is 220 West Main Street, Louisville, Kentucky 40202.

Q. Please describe your educational and professional background.

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

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

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

Q. Have you previously appeared before this Commission?

A. Yes. I have testified in each of the Companies' last three base rate cases.[1] I have also appeared before this Commission in informal conferences and participated in merger proceedings of LG&E and KU before the Commission.[2]

Q. What is the purpose of your testimony?

A. My testimony will explain how the Companies have continued to provide safe and reliable service to our customers. Moreover, I will provide an overview of the various initiatives LG&E and KU have implemented to enhance our customers' experience, including investments in system infrastructure and initiatives related to improving the Companies' response to customer inquiries. Finally, I will explain why a rate increase is needed at this time as it relates to Energy Delivery.

Q. Please explain Energy Delivery's business objectives.

A. Energy Delivery's objective is to satisfy its customers' expectations by delivering safe, reliable and cost-effective electric and gas service, while also providing high quality customer service. Achieving these goals requires Energy Delivery to safely and efficiently operate complex gas and electric systems, invest in new and replacement infrastructure, and oversee the wide-ranging and ever-changing issues our customers often have across our service territory. Satisfying customer expectations is certainly not a simple endeavor; however, Energy Delivery's current performance is strong, marked

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[1] Case No. 2003-0433, *In re the Matter of: An Adjustment of the Gas and Electric Rates, Terms and Conditions of Louisville Gas and Electric Company*; Case No. 2003-0434, *In re the Matter of: An Adjustment of the Electric Rates, Terms and Conditions of Kentucky Utilities Company;* Case No. 2008-00252, *In re the Matter of: Application of Louisville Gas and Electric Company for an Adjustment of Its Electric and Gas Base Rates*; Case No. 2008-00251, *In re the Matter of: Application of Kentucky Utilities Company for an Adjustment of Base Rates;* Case No. 2009-00549, *In the Matter of: Application of Louisville Gas and Electric Company for an Adjustment of Its Electric and Gas Base Rates*; Case No. 2009-00548, *In the Matter of: Application of Kentucky Utilities Company for an Adjustment of Base Rates.*

[2] 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*.

with an exceptional safety record and a record of reliable delivery that is among the best in the Commonwealth.

Energy Distribution Systems

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

A. LG&E's electric distribution business serves approximately 394,000 electric customers in Jefferson County and 8 surrounding counties. LG&E's service area covers approximately 700 square miles. The electric distribution facilities we operate include 98 substations (32 of which are shared with transmission) and 3,890 miles of overhead and about 2,370 miles of underground electric lines. LG&E's gas distribution business serves approximately 319,000 gas customers in Jefferson County and 16 surrounding counties. The gas distribution facilities we operate include approximately 4,290 miles of gas distribution pipe, over 380 miles of transmission pipe, and five underground gas storage fields, which are the Muldraugh and Doe Run fields in Meade County and the Magnolia Upper, Magnolia Center, and Magnolia Deep fields in Larue County.

Q. Please describe KU's distribution business.

A. KU's distribution business serves approximately 509,000 electric customers in 77 counties in Kentucky. KU's service area covers approximately 4,800 noncontiguous square miles. The electric distribution facilities we operate include 478 substations (57 of which are shared with transmission) and 12,970 miles of overhead and approximately 2,230 miles of underground electric lines.

Energy Delivery's Safety Record

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

A. The importance of public, employee and contractor safety within Energy Delivery is best espoused by the policy that has been in effect for a decade, which is "No Compromise."

Our employees and contractors demonstrate this policy daily in their attitude and behaviors, which has resulted in a safety record that exceeds its peers. In 2011, our employees had a recordable injury rate of 1.08, which was consistent with the 2010 rate, which was 1.05.[3] The recordable injury rate for our independent contractors was similar, with a rate of 1.05 in 2011 and 1.75 in 2010. These rates are well below the average recordable injury rates of 3.3 for the utility industry and 4.30 for general industry. These rates indicate that our "No Compromise" approach to safety is top-of-mind with our employees and independent contractors, and has resulted in a safety record that is substantially better than the industry average.

As a result of our efforts, Energy Delivery continues to receive numerous safety awards, which are listed in Appendix B. While these awards demonstrate that LG&E and KU are certainly leaders among utility companies in safety performance, we will continually seek improvement and strive for an incident-free workplace.

Delivery of Reliable Electric Service

Q. How do LG&E and KU measure its distribution performance?

A. LG&E and KU track the reliability of their distribution facilities through analyzing performance metrics such as the System Average Interruption Duration Index ("SAIDI") and System Average Interruption Frequency Index ("SAIFI"). SAIDI measures the average electric service interruption duration in minutes per customer for the specified period and system, while SAIFI measures the average electric service interruption frequency per customer for the specified period and system.

[3] The recordable injury rate is calculated by multiplying the number of recordable cases by 200,000, and then dividing that number by the number of labor hours at the company.

The Companies' distribution performance continues to be strong, despite the damage to the system resulting from the severe storms in 2008 and 2009. In 2011, LG&E and KU again experienced significant weather events that affected reliability performance, as data from the National Weather Service indicates that Kentucky experienced nearly twice as many wind events in 2011 than in 2010. Despite these external challenges, LG&E and KU achieved a distribution system SAIDI of 100.28 and 100.98 in 2010 and 2011, respectively, which places them among the top performers in the region.

Q. In the Companies' last rate cases, LG&E and KU had just received the report issued by the Commission relating to the 2008 Wind Storm and 2009 Winter Storm. Have the Companies now completed its review of the report?

A. Yes. LG&E and KU carefully reviewed the report and the recommendations contained therein. The Companies were pleased to find they had already implemented many of the Commission's recommendations, and have since implemented or are in the process of implementing the remaining recommendations as indicated in the responses filed with the Commission.

For example, since March 2009, the Companies have constructed or upgraded approximately 60 miles of lines to the National Electrical Safety Code "heavy" loading standard. Beginning in October 2010, LG&E and KU implemented an Enhanced Hazard Tree Program, consistent with the recommendations in the Commission's report. The plan includes the removal of dead, dying and diseased trees inside and outside of the Companies' easements, which is purposed upon reducing the likelihood of tree damage to the electrical infrastructure during severe weather events. Through early 2012, over

31,000 trees have been removed. Moreover in 2010, the Companies implemented a pilot program to underground approximately 500 existing overhead electric services in their territories. Also, in 2011 the Companies participated in a four-day NLE-11 National Earthquake Exercise and in the Southern Gas Association Emergency Management Disaster Drill.

The Companies place an emphasis on storm preparedness and the Edison Electric Institute recognized LG&E and KU for the efforts to restore power following the 2009 ice and subsequent wind storm with the Emergency Recovery Award. As always, however, LG&E and KU continue to investigate other means by which to improve.

Q. Please discuss the Companies' vegetation management efforts.

A. For years, LG&E and KU have employed a vegetation management plan that emphasizes flexibility in recognition of the variances within their service areas with regard to growth and tree density. This enables the Companies to maintain a proactive trim cycle while balancing the reactive needs of circuits targeted for reliability improvement. The Companies' goal is to maintain an average trim cycle of 5 years or less, while ensuring that all circuits targeted for improvement are trimmed in the year that they have been so identified.

To improve our customers' understanding of the importance of vegetation management, the Companies have enhanced their communications to customers before trimming on their property. For example, the Companies provide educational materials to affected customers, make automated phone calls to notify customers of upcoming tree trimming, engage in face-to-face conversations with customers on the day the trimming occurs, in addition to further developing the Companies' website to include frequently asked questions and guidelines regarding tree planting. The Companies also conducted customer service training to the more than 440 personnel that contract with LG&E and KU to provide trimming services.

The Companies are conducting quarterly surveys of customers to measure the impact of these efforts. To date, the results reveal that most customers believe that tree trimming makes electric service more reliable, and customers are generally satisfied with the Companies' tree trimming process.

Q. Have LG&E and KU continued to make investments in infrastructure and electric reliability since the last rate case?

A. Yes. Since the last rate case, the Companies have invested $210.3 million in electric system distribution reliability and infrastructure in two key areas to ensure that our customers benefit from a safe and reliable distribution system. First, the Companies have invested in system enhancements. Although the economic downturn has decreased the demand for new service, there are areas where load growth has resulted in electric demand approaching the limits of the infrastructure. As such, new and upgraded electric distribution circuits and substations have been constructed to ensure adequate capacity and reliability to serve existing load demand.

Second, the Companies have made investments to address reliability and aging infrastructure, including targeted circuit improvements and the replacement and life extension of infrastructure such as transformers, circuit breakers and protective devices, as well as underground and overhead conductors. Likewise, the Companies are replacing support structures, such as wood pole and cross arms, to reduce the likelihood of failure.

Q. Have LG&E and KU continued to make other investments to distribution facilities to serve customers since the last rate case?

A. Yes. Since the last rate case, LG&E and KU have invested $129.2 million in distribution facilities to serve customers, principally through the installation of new and upgraded infrastructure, including circuits and substations to serve the Companies' new business. Additionally, LG&E and KU have invested $21.1 million in technology, metering and equipment.

Q. In the Companies' last rate cases you discussed several initiatives LG&E and KU were implementing with regard to severe weather events and restoration efforts following same. Can you provide an update on these initiatives?

A. Yes. Following the recent severe weather events that impacted LG&E's and KU's service areas, the Companies looked to establish initiatives that would provide our customers with more information regarding restoration efforts. For example, LG&E and KU added outage maps to their website and deployed mobile outage map applications for smart phones, which show current power conditions across the service territories. Customers can view this information online or on their smart phones, searchable by location, county or ZIP code, with information regarding the number of customers affected, when the outage was reported and the estimated restoration time. Outage information is updated multiple times per day.

Customers have responded positively by using these initiatives. For example, during the August 2011 windstorm, traffic to our online outage maps increased dramatically, as approximately 27,000 unique visitors went to the site, which is 10 times the previous high of just over 2,600. Likewise, over 33,500 smart phone applications were downloaded by March 2012. Currently, the Companies' Twitter account has over 1,500 followers.

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

A. Yes, as stated previously, data from the National Weather Service indicates that Kentucky experienced nearly twice as many wind events in 2011 than in 2010. The worst of these events was a severe thunderstorm carrying high winds that affected LG&E's and KU's service territories on August 13, 2011, that necessitated significant repairs and restorations. Distribution facilities were heavily impacted, initially causing 165,000 of the Companies' customers to lose power. Of this number, 126,000 were LG&E customers, which meant that one-third of LG&E's electric customers were without power. This number exceeded the amount of LG&E customers that were affected by any event since the ice and subsequent windstorm that struck Louisville in January and February 2009. Damage from the August 13, 2011 storm was caused by straight-line winds, possibly in the form of successive downbursts, which are powerful winds a thunderstorm releases once the storm reaches the ground. Wind gusts in the Louisville area reached as high as 69 mph.

Q. Please describe LG&E's storm preparedness efforts.

A. LG&E continuously monitors the weather, because advance warning of severe weather is essential to emergency preparedness. For example, LG&E subscribes to DTN Televent Weather Service, which provides 24/7 weather prediction services to the Companies' service areas. In fact, if LG&E posts a question, the DTN meteorologists will respond within 15 minutes. Both LG&E and KU participate in all National Weather Service conference calls regarding weather events in the Companies' service areas. Finally, LG&E and KU serve on the Kentucky Weather Preparedness Committee and participate in the Kentucky Emergency Management Weather Conference and Kentucky Emergency Management State Weather Exercise.

In order to help ensure adequate restoration resources are available, the Companies are members of, actively participate in, and frequently communicate with three regional mutual assistance groups: Great Lakes Mutual Assistance, Midwest Mutual Assistance and Southeastern Electric Exchange. Additionally, the Companies work closely with state and local emergency response and planning agencies and personnel to coordinate planning for responding to disasters, including severe weather events.

LG&E fully utilized these resources to monitor the weather leading up to the August 13, 2011 storm and was adequately prepared to respond to this storm described by a National Weather Service meteorologist as "a freak one-two punch of straight-line winds followed by a powerful downburst of air."[4]

Q. Please provide an overview of the Companies' restoration efforts.

A. As soon as customers began losing power, LG&E engaged in day-and-night efforts to restore power. Restoring power required significant investment and labor: 1,492 lines were downed; 84 poles were broken; and more than 136,484 outage calls from customers were received. At the peak of the restoration efforts, 1,552 employees and contractors were working to restore service. As a result of these efforts, all power was restored four days later by August 17, 2011.

During this time, LG&E used the online outage maps on its website so that customers would be apprised of the remaining outages and estimated restoration times.

[4] Dan Klepal, *Unusual Storm Caused Heavy Damage in Area*, The Courier-Journal, Aug. 16, 2011, at A6 (citing National Weather Service meteorologist John Gordon).

Finally, the employees and contractors that worked long day-and-night shifts to restore service continued to adhere to the Companies' "No Compromise" approach and there were no injuries.

Q. How did LG&E monitor the reasonableness of the costs incurred?

A. In restoring service when a severe weather event occurs, LG&E and KU employ a suite of controls to ensure that all incurred costs are necessary and reasonable. In restoring service after the storm, LG&E utilized those controls successfully. LG&E ultimately incurred capital costs of approximately $1.5 million and operation and maintenance expenses of approximately $8.4 million. To ensure these costs were reasonable, LG&E adhered to the following well-established controls.

LG&E utilized the Incident Command System that Energy Delivery has adopted, which consists of three key sections: Operations, Logistics, and Work Planning. These sections are essential to timely and effective restoration of customer service and repair of infrastructure damage. Operations has the overall responsibility for developing and managing tactical responses to emergencies and outage events, including public safety, restoration prioritization, critical customer identification, work assignment and resource allocation. Work Planning has the responsibility for working with Operations to identify and secure resource needs. Work Planning also tracks resources against estimated restoration times to assure that resources are reasonably distributed, while simultaneously tracking and reporting on associated costs throughout the event. Logistics is responsible for assuring that supplies, lodging and related needs are adequately available and effectively managed throughout a restoration effort. All three of these sections coordinated well during the August 13, 2011 storm.

A significant percentage of the independent contractors LG&E utilized to restore service were the employees of LG&E's existing business partners, which means that the independent contractors were familiar with LG&E and its system. When the storm occurred, LG&E already had in place emergency restoration contract agreements with these business partners, which assured that LG&E received market-based, competitive pricing for the services performed. Moreover, because LG&E is a member of multiple Regional Mutual Assistance Groups, it, as well as the other members, adheres to established guidelines that assure consistency in cost reimbursement.

Each off-system crew that assisted with restoration efforts was assigned to a LG&E representative, who was responsible for tracking the hours worked, the nature of the work performed, and the equipment used during the restoration effort. Also, LG&E already had in place strategic and competitively sourced agreements with the suppliers of materials for the storm, including Brownstown Electric Service Corporation, which provided all electrical hardware materials, including wire, cable and all associated components; Brown Wood Preserving, which provided all wooden distribution and transmission poles; and Howard Industries, which provided all single-phase and three-phase distribution pole and pad mount transformers.

Cumulatively, these efforts ensured that the costs incurred in the restoration efforts were carefully monitored, with a majority of the costs already controlled based upon agreements with existing business partners and materials suppliers.

Q. Did LG&E request regulatory asset treatment for the costs associated with the storm?

A. Yes, because the damage and consequent restoration efforts were extraordinary. As discussed more fully in the testimony of Ms. Valerie Scott, LG&E is requesting in this case to recover the $8,052,125 regulatory asset over a period of five years.[5]

Delivery of Reliable Gas Service

Q. Has LG&E continued to make investments in infrastructure and gas system safety and reliability since the last rate case?

A**.** Yes. Since the last rate case, LG&E has invested approximately $109 million in its gas system, principally for distribution safety, reliability and infrastructure such as main replacements, transmission lines, compression stations and metering.

Q. Has LG&E continued to make other investments to distribution facilities to serve customers since the last rate case?

A. Yes. LG&E has invested approximately $8 million in gas distribution facilities, such as main extensions, since the last rate case. Additionally, LG&E has invested $9.2 million in technology, metering and equipment.

Q. Are the leak mitigation programs still ongoing?

A. Yes, LG&E has continued the leak mitigation program, which includes proactive replacement of certain older distribution mains and associated services. With regard to this main replacement program, since its inception LG&E has installed 474 miles of gas distribution piping in the replacement of aging cast iron, wrought iron, and bare steel mains. Eighty-eight miles of piping have been replaced since LG&E's last rate case, at an investment of $36.8 million. As part of this proactive program, there are 141 miles of

[5] In Case No. 2011-00380, the Commission permitted LG&E to establish, for accounting purposes, a regulatory asset based on its costs for storm damages and service restoration . *In the Matter of: Application of Louisville Gas and Electric Company for an Order Approving the Establishment of a Regulatory Asset* (Case No. 2011-00380) (December 27, 2011 Order).

distribution mains yet to be replaced. Additionally, LG&E has invested approximately $14 million since the last rate case in gas distribution service lines and small scale main replacements to ensure continued safety, improved reliability, enhanced operating efficiencies and lower operating costs for LG&E's gas customers.

Q. Are there actions LG&E has taken to maintain or improve the safety and reliability of gas system?

A. Yes. LG&E's gas transmission business must comply with the Pipeline Safety Improvement Act of 2002. In complying, LG&E has identified all High Consequence Areas in its gas transmission lines, conducted risk analyses of its pipeline segments and is scheduled to complete the initial baseline integrity assessments of all covered pipeline segments by the end of 2012. Since the last rate cases LG&E has invested over $8 million dollars modifying its gas transmission system to enable in-line inspections using high resolution magnetic flux leakage tools capable of indentifying pipeline defects such as wall losses, dents, and third-party damages. By the end of 2012 approximately 81% of LG&E's gas transmission system, excluding gas storage field pipelines, will be capable of in-line inspections. An additional $3.5 million has been invested in pipeline enhancements and replacements.

With regard to the gas distribution system, LG&E has implemented a Distribution Integrity program as required by the Pipeline, Inspection, Protection, Enforcement, and Safety Act of 2006 and also completed a five-year farm tap upgrade program and is scheduled to complete a ten-year gas service regulator upgrade program in 2012. Farm tap customers are directly served from a transmission or high pressure distribution pipeline operating above 60 psig. Both upgrade programs help ensure the safe and reliable delivery of gas supply to LG&E's customers. Since the last rate cases, LG&E has invested $8 million on these two programs and $5.8 million in upgrades to gas regulator facilities, city gate station equipment, customer metering and regulating facilities, and supervisory control and data acquisition equipment.

Additionally, since the last rate cases LG&E has invested $27.7 million in replacing and upgrading equipment in the compressor stations and storage fields to ensure the safe and reliable operation of the underground storage systems. This work has included upgrades to compressor control systems, gas processing units, and auxiliary systems within the compressor stations and replacement of pipelines, repairing, upgrading and drilling gas storage wells, and upgrading gas recovery systems in the gas storage fields.

Q. Is LG&E proposing to replace and assume ownership of certain gas service risers?

A. Yes, LG&E is proposing to replace certain gas service risers that have a compression type mechanical coupling to enhance the safe, reliable delivery of natural gas service to its customers. A gas service riser is a piping component protecting the plastic gas piping as it transitions from below ground to above ground and also serves as the transition from the plastic pipe to the steel pipe at the meter loop and delivers gas to the meter that is owned by LG&E. The gas service riser, as well as the service line, is currently owned by the customer. After considering the risk of natural gas leaks that can occur when a riser fails, LG&E decided to seek approval for a program by which it would replace these gas service risers. Although the gas service riser is owned by the customer, LG&E, based upon its knowledge of the issue, is proposing a cost effective solution to implement a replacement program and assume ownership to further assist customers with safe and reliable service.

Gas service risers with compression type mechanical couplings were widely utilized in the natural gas industry beginning in the 1970's and plumbers in the LG&E area began using these gas service risers in the 1980's. In March 2008, the Department of Transportation's Pipeline and Hazardous Materials Safety Administration issued an advisory bulletin regarding potential safety issues with mechanical couplings used in natural gas distribution systems, including in gas service risers. The recommendations in the advisory bulletin included improved record keeping in order to help identify a trend of problems that may occur and to consider whether to adopt a full replacement program if there are too many unknowns related to couplings in service. Consistent with the bulletin, LG&E revised its materials standard in May 2008 to eliminate the future use of gas service risers with compression type mechanical fittings not incorporating an anti-pull out design. In February 2009, LG&E began removing failed gas service risers for investigation. Moreover, LG&E conducted a review of its roughly 300,000 customer-owned gas services and found that approximately 213,000 have gas service risers with mechanical compression fittings not incorporating an anti-pull out design. Since February 2009, 370 customer-owned, gas service riser failures have occurred.

Q. Is LG&E proposing to assume ownership of the customers' service lines, as well?

A. Yes, because the gas service riser, which is currently owned by the customer, attaches to the service line, which is also currently owned by the customer. Under the proposed program, LG&E will proactively replace program gas service risers and assume ownership of them over the program period. The Company will not assume ownership of and responsibility for customers' service lines until a repair or replacement has occurred, or a new service line is installed by the Company. No accounting entry will be recorded with regard to the risers or service lines until replacement occurs. With LG&E assuming this responsibility, the customer is relieved of the burden and inconvenience associated with replacing a leaking gas service line or riser and ensures the replacement is completed safely, in a timely manner and by qualified personnel consistent with regulatory requirements. Hermann Exhibit 1 is attached to my testimony and contains a detailed description of how the Company plans to administer the program and the projected costs associated with same.

Q. Please describe the proposed locations where LG&E will be replacing gas service risers.

A. LG&E will be replacing gas service risers throughout its service area, as demonstrated by the maps attached to the Appendix of Hermann Exhibit 1. At the outset of the program, LG&E will conduct a random sample riser replacement and assessment effort by conducting replacements at 800 locations. The results of the assessment will be utilized to develop an overall gas riser replacement plan according to appropriate priorities.

Q. How is LG&E seeking to recover the costs associated with the proposed gas riser replacement program?

A. As discussed in the testimony of Lonnie E. Bellar, LG&E is proposing a gas line tracker to recover the costs associated with the gas service riser replacement program and the ongoing costs associated with replacement of gas service lines. As Mr. Bellar explains, the tracker allows LG&E to timely recover the costs of these programs, which are solely purposed upon ensuring our customers receive safe and reliable natural gas service.

Ownership of the customer service lines will result in estimated incremental operations and maintenance costs of $1.1 million in the first year of the program, and $6.1 million over the five-year riser replacement program. These costs are expected to be ongoing and will be primarily associated with expenses required to maintain customer meter loops.

Q. Is LG&E also proposing to include the costs associated with the leak mitigation program in the tracker?

A. Yes, LG&E is proposing to include the leak mitigation program as part of the tracker, as well. As explained above, there are 141 miles of distribution mains yet to be replaced, in addition to the associated services. As explained by Mr. Bellar, LG&E proposes to recover the costs associated with the remaining work through the gas line tracker.

<u>Customer Service and Satisfaction</u>

Q. Please provide an overview of the Companies' objective regarding customer service and satisfaction.

A. The Companies' "Customer Experience" objective seeks to achieve and remain superior providers of innovative customer experiences. LG&E and KU have met this objective by expanding relationships with customers by delivering outstanding customer experiences that create value and build trust. Along with this goal, the Companies employ their core values - which are: safety and health; customer focus; employee commitment and diversity; integrity and openness; performance excellence; and corporate citizenship - across the Companies to ensure these objectives are accomplished in a safe, effective and efficient manner.

Q. Please provide an overview of the Companies' customer contact channels that are available to help serve customers.

A. The Companies have implemented several initiatives since the last rate cases to better reflect customers' preferences across several new and/or enhanced contact channels including business and residential business offices, business and residential call centers, web self-service, integrated voice response systems, e-mail and outage mobile applications. Customers can complete transactions across these channels at their discretion. Customers, however, predominantly utilize our 24 walk-in business offices and our residential and business call centers. While the Companies assess operational performance across every customer contact channel, LG&E and KU also utilize a third-party research firm to conduct transactional studies to measure how customers evaluate the Companies' performance. Ratings for each contact channel have been excellent, routinely exceeding the 8.5 target on a scale of 1 to 10.

Q. Please provide an overview of the improvements the Companies have made to their business offices.

A. The Companies' business offices are critical to Energy Delivery's "Customer Experience" vision because a large segment of customers prefer to utilize the walk-in, face-to-face option to conduct transactions. The 24 business offices process 2,800,000 customer transactions annually and support call center operations by taking approximately 80,000 customer calls through the Voice Over Internet Protocol (VOIP) capability. With VOIP, the Companies can effectively manage customer contact volume and provide additional support during severe weather events. In an effort to focus on the quality of customer transactions, the business offices also have implemented a monitoring program to measure the success of customer service objectives by reviewing a portion of VOIP calls and incorporating their findings into training material.

Because of customers' increased knowledge of energy-related issues, the Companies must ensure that customer service representatives can provide information regarding, for example, smart grid technologies, electric vehicles and energy efficiency. By transitioning business offices from primarily payment centers to energy partner centers, customers benefit from a higher value transaction when they choose to walk-in to transact business.

Four offices have undergone extensive renovation to ensure a more satisfying customer experience. For example, sitting areas were updated, customer courtesy telephones that make debit and credit card payment available were relocated and clearly identified, and additional signage was installed to direct customers appropriately.

Q. Please provide an overview of the improvements the Companies have made to their call centers.

A. Because many customers prefer to interact directly with a customer service representative, the Companies have added a significant number of customer service agents to both its residential and business service centers. The most substantial addition to customer service agents is the new call center in Morganfield, Kentucky. The call center, which is the Companies' fourth in Kentucky, opened its doors on October 31, 2011, and currently houses 75 employees in the 23,000 square-foot facility that includes a walk-in center and a customer drive-up window. By February 2012, 51 residential service center customer service agents were hired, trained and handling customer calls.

While the majority of the employees working at the new call center are customer service agents, the facility likewise consolidates Morganfield's customer service business office representatives, a western Kentucky economic development representative, line technicians, meter readers and field service personnel all under one roof. Additionally, there is an on-site storage facility for distribution parts and equipment. The cost to construct the facility was approximately $5.3 million, and the annual operating cost for maintaining the facility is projected to be approximately $245,000.

Q. Have the Companies added additional customer service agents other than those at the new Morganfield call center?

A. Yes. From June 2011 to February 20, 2012, LG&E and KU added 25% more residential service center customer service agents and 59% more business service center customer service agents. The annual cost increase due to the greater number of customer service agents is expected to be approximately $3.5 million.

Q. Please describe the call centers' recent operational performance.

A. The residential call centers' operational performance is excellent, answering at least 80% of all calls within 30 seconds, with an average speed of approximately 27 seconds while processing approximately 2,200,000 calls annually. And of equal significance, the Companies have maintained or exceeded the goal of resolving at least 75% of all customer issues during the first phone call. Lastly, customer experience ratings for the residential call centers continue to improve and have remained at the target of 8.5 or higher.

The business call centers' operational performance has achieved answering at least 80% of all calls within 30 seconds, with an average speed of approximately 22 seconds while processing approximately 215,000 calls annually. Also, the Companies' first call resolution remains at a sustainable rate of 70% or greater. Moreover, customer experience ratings for the business call centers continue to improve and have remained at the target of 8.5 or higher, routinely exceeding 9.0 on a 10 point scale.

Q. Please provide an overview of the Companies' initiatives with regard to web self-service.

A. Since April 2009, when LG&E and KU launched an enhanced "My Account" website, the Companies have offered increased self-service functionality for customers. Residential and business customers can view and pay their bills, turn on/off or transfer their service, view energy usage, as well as register for many customer programs including automatic bank club, budget billing, energy efficiency and demand-side management offerings. In the past year, customers have completed between 115,000 and 141,000 online transactions on a monthly basis.

In 2010, LG&E and KU developed portals for low income assistance agencies and landlord/property managers. In 2011, LG&E and KU interfaced the low income agency portal with Community Action Agencies throughout the service territories to streamline administration of the Low Income Heating Energy Assistance Program ("LIHEAP"). For the 2011-12 heating season, approximately 65,000 LIHEAP customer pledges and payments were processed electronically, which resulted in higher satisfaction with the agencies, company employees and customers.

Also in 2010, LG&E and KU began offering a landlord/property managers portal where the landlord or owner of multiple properties could register and manage all their accounts online by using a single email address. Lastly, the customer experience ratings for residential and business customers who utilize web self-service options continues to improve and routinely averages above 9.0 for residential users and 8.5 for business users on a 10 point scale.

Q. Have the Companies recently upgraded its Interactive Voice Response system?

A. Yes. In November 2010, the Companies' Interactive Voice Response (IVR) system was updated with new menu options and additional information was made available to customers as a self-service option. The project included replacement of the hardware and software systems which allow for programming with the most current technology. The cost of the project was $1.25 million, which included hardware and software replacement costs, integration with other systems, vendor development, internal software development and customer focus groups to test the new options.

The percentage of residential customers resolving concerns while staying within the IVR system has improved from approximately 8% per month to steadily maintaining 32-34% per month for non-outage calls or approximately 825,000 calls annually. In addition, customers' satisfaction with IVR is continually measured through third-party telephone surveys, and, for the last year, LG&E and KU have achieved an 8.4 or higher rating on a 10 point scale.

Approximately 10% of business customers complete transactions using the IVR system, which corresponds to approximately 30,000 calls annually. As with the residential customers' satisfaction, for the last year, the Companies have achieved an 8.4 or higher rating on a 10 point scale.

Q. Please describe the Companies' efforts to increase email as a form of customer service.

A. LG&E and KU recently established a new 10-member dedicated team to assist in responding to customers that choose to do business by email, which are managed by the call routing systems used within the call centers to ensure the appropriate skill set and the shortest queue are utilized. Annually, the Companies address approximately 60,000 to 80,000 residential and business customer emails and often exceed the Companies' target of answering 85% of emails within 24 hours of receipt. Customer experience ratings continue to improve and remain at 8.4 or higher on a 10 point scale.

Q. Have LG&E and KU implemented actions to ensure that meter reading accuracy meets or exceeds targets?

A. Yes, the Companies have taken several steps to ensure that its meter reading accuracy meets or exceeds the accuracy target of 99.9%. First, an "all hands" meeting with all meter reading employees, as well as executives from our contract partners, was held in August 2011 to stress the Companies' commitment to meter reading accuracy. LG&E and KU identified utilities that excel in meter reading accuracy and compared their processes and procedures to isolate opportunities for improvement. The Companies also conducted field quality audits.

Following these steps, LG&E and KU changed the parameters of its meter reading system to tighten the tolerances for increases and decreases in consumption in monthly meter reads. The tolerance compares the customer's current month consumption to the same period in the prior year. The new tolerance parameter changed the consumption upper limit from 4 times higher to 1.75 times higher and changed the consumption lower limit from 99% lower to 50% lower (except for LG&E residential gas customers, which is 75% lower). Finally, the Companies have enhanced communications with meter reading employees to inform them of their performance, including a "How Are We Doing" bulletin board that posts their monthly and year-to-date performance.

Q. Please describe the changes associated with the Billing Integrity area.

A. Billing Integrity (BI) has worked closely with the Information Technology Customer Care System ("CCS") support to detect system errors, request system improvements, and identify more effective workflow processes. BI continues to enhance employee knowledge and understanding of CCS to reduce the period of time between identification of a concern and issuance of the associated bill or billing corrections.

To date, BI has completed several initiatives purposed upon improving customer billing performance. These include conducting monthly meetings with the BI leadership team to identify improvement needs and encourage standardization between the Companies; identifying new key performance indicators to better track performance; and performing a review of BI operational performance and long-term organizational needs. As a result of this review, BI created two new areas - Tariffs and Rates Analyst and Business Continuity and Data Integrity - which required hiring 10 additional full-time employees at an annual cost of over $800,000. The primary responsibilities of the Tariffs and Rates Analyst group are to provide expertise in understanding and applying billing components of the Companies' tariffs and ensuring correct billing. The primary roles of the Business Continuity and Data Integrity group are to pursue process standardization and continuous improvement between LG&E and KU.

Q. Have these successful initiatives led to increased expenses for the Companies?

A. Yes. While superior customer service continues to be a core value of the Companies, since the last rate case LG&E and KU have absorbed the costs of many external challenges, including an economic downturn, several extreme weather events, and investments to facilities to provide service.

In order to contain costs while simultaneously improving customer service, the Companies developed and implemented the suite of self-serve tools described above. The Companies learned, however, that while the self-serve tools were beneficial, additional personnel and training of personnel were necessary at this time to address customers' desire to speak directly with a customer representative about a particular issue.

Q. Have LG&E and KU implemented programs that increase customers' knowledge and transparency with regard to energy usage and conservation?

A. Yes, as customers are increasingly seeking more detailed information regarding their usage and conservation. In 2011, the Companies received approval to expand certain demand-side management ("DSM") programs, as well as establish new programs, that enable customers to better understand their consumption. For example, the Companies received approval to expand their Residential Conservation/Home Energy Performance Program, which is designed to help customers reduce home energy costs using either online or on-site energy audits. The goal of the program is for the Companies to work with customers to identify specific steps that can reduce energy costs, which will make our customers better energy managers. In the recent proceeding, the Companies received approval to propose new on-site audit incentives for this program. The Companies also received approval to establish a Smart Energy Profile Program, the purpose of which is to educate customers about their energy consumption, encourage them to reduce consumption and empower them to use energy more wisely. By utilizing available customer data, LG&E and KU will create an individualized household report for each participating customer.

The suite of programs is expected to achieve 500 MW's of demand reduction by 2018, with an annual investment of approximately $35 million. Additionally, these programs reduce an estimated 1% of the annual forecasted residential and commercial energy consumption. Currently, nearly one-third of all customers participate in at least one energy efficiency program. Expansion of the Companies' existing programs, and implementation of new programs, will ensure that customers are equipped to understand their energy usage and better manage their consumption, which is beneficial not only to our customers, but to the environment, as well.

Q. Are the Companies satisfied with their customer service performance?

A. Yes.. The metrics discussed earlier in my testimony demonstrate that the Companies are achieving many of their goals with regard to customer service. Although I am proud of our employees' efforts and our results, we view our progress as ongoing, as one of our business philosophies is to continuously look for opportunities to improve. Although mistakes may occur from time to time, each complaint is taken seriously and the Companies remain committed to providing quality customer service and our recent metrics demonstrate that commitment.

<u>Low Income Assistance</u>

Q. Please describe the commitments the Companies have made to benefit low income customers in their recent change of control proceeding.

A. LG&E and KU have recently made several commitments to increase their assistance to low income customers, which cumulatively represents an unprecedented increase in the Companies' contribution levels. The Companies are aware of the financial toll the economic downturn took on our customers, especially our low income customers, and have thus not only given additional contributions, but have made our business practices more flexible so as to provide those customers additional support.

As part of the change of control proceeding in which PPL Corporation was approved to become LG&E's and KU's parent, the Companies committed to extend the contributions agreed to in their most recent rate cases to Wintercare Energy Assistance Fund, ACM/Metro Match, and the Home Energy Assistance ("HEA") programs for two additional years.[6] KU participates in the WinterCare Energy Assistance Fund, a state-wide energy assistance fund supported privately by utilities and community action agencies that provide assistance to low income persons with their utility expenses during the winter season. KU agreed to contribute $100,000 annually to the program through 2014. LG&E participates in a similar program, ACM/Metro Match, and has agreed to continue its current matching contribution of up to $225,000 annually through July 2014. Finally, the Companies agreed to continue their 15-cent-per-meter charge for funding the HEA program for an additional three-year term through September 30, 2015.

Q. Did the Companies again increase their contributions in their recent environmental surcharge proceedings?

A. Yes. As part of the settlement of those cases, the Companies agreed to make two additional annual contributions totaling $500,000 to LG&E's and KU's HEA programs, consisting of a shareholder contribution of $250,000 in 2011 and 2012.[7] The

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[6] *In the Matter of: Joint Application of PPL Corporation, E.ON AG, E.ON US Investments, Corp., E.ON U.S. LLC, Louisville Gas and Electric Company and Kentucky Utilities Company for Approval of an Acquisition of Ownership and Control of Utilities* (Case No. 2010-00204) (September 30, 2010 Order).

[7] *In the Matter of: The Application of Kentucky Utilities Company for Certificates of Public Convenience and Necessity and Approval of Its 2011Compliance Plan for Recovery by Environmental Surcharge* (Case No. 2011-00161) (December 15, 2011 Order) and *In the Matter of: The Application of Louisville Gas and Electric Company*

contributions will be split evenly between the LG&E and KU program. Moreover, beginning January 1, 2012, the Companies increased the cent-per-meter charge for the HEA program from 15 to 16 cents until LG&E's and KU's next base rate cases. The increase is expected to produce an annual increase of $115,000 in HEA funds.

Q. In addition to these significant increases in shareholder contributions, have the Companies implemented measures that afford low income customers greater flexibility in paying their electric and gas bills?

A. Yes. First, the Companies have created a FLEX program by which residential customers that indicate they are on a limited income may receive a payment due date that more closely coincides with the receipt of their monthly income check. This option moves the due date of each bill from the current 12 days from the issuance of the invoice to 28 days from issuance, thereby effectively extending the customer's original due date by 16 days. This helps prevent the customer from incurring a late payment charge, and likewise minimizes the issuance of disconnection notices to these customers. Since its implementation in December 2009, the program has been widely used by low income customers. Through April 2012, a total of 13,601 customers were utilizing the FLEX program, with participation evenly distributed between LG&E and KU. LG&E's and KU's remaining customers currently have 12 days from the issuance of the invoice to pay their bills.

Second, since October 1, 2010, residential customers who receive a pledge or notice of low income energy assistance from an authorized agency are not assessed or required to pay a late payment charge for the bill for which the pledge or notice is

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for Certificates of Public Convenience and Necessity and Approval of Its 2011Compliance Plan for Recovery by Environmental Surcharge (Case No. 2011-00162) (December 15, 2011 Order).

received. Moreover, the customer will not be assessed or required to pay a late payment charge in any of the 11 months following receipt of the pledge or notice. This waiver of the late payment charge has inured significant benefit to low income customers. Since the inception of the program, LG&E and KU have waived approximately $3.5 million in late payment charges to help alleviate the financial burden our low income customers are facing.

Q. In addition to increased contributions and greater payment flexibility, do the Companies have DSM programs that specifically target low income customers?

A. Yes. In LG&E's and KU's recent DSM proceeding, the Companies obtained approval to expand its Residential Low Income Weatherization Program ("WeCare"). WeCare is an education and weatherization program purposed upon reducing the energy consumption of the Companies' low income customers. LG&E and KU, in its expanded program, will allow for increased weatherization measures, an increase in the number of customers served, as well as extension of the program for seven years.

Cumulatively, these efforts demonstrate that LG&E are KU are committed to provide assistance to its low income customers. The Companies are endeavoring to weatherize the homes of low income customers to decrease customers' monthly financial obligation for energy. If the customer is unable to pay their bill when due, the customer can seek to join the FLEX program which extends the due date to 28 days from issuance of the invoice. To the extent further assistance is required, the Companies have generously increased their giving to agencies that provide financial support and waive the late payment charges for customers receiving assistance. In short, the Companies are prepared to assist across the energy consumption spectrum – from before the energy is consumed until after the invoice is issued.

<u>Conclusion</u>

Q. Please summarize why a rate increase is needed as it relates to Energy Delivery.

A. LG&E and KU have taken numerous steps in safety, reliability and customer service, all of which have been quite successful. The Companies' performance of the Energy Delivery functions is very strong. These initiatives, however, have resulted in increased capital and operating and maintenance expenditures. For example, Energy Delivery has hired 100 additional employees since the test year in the last rate cases. In addition to benefiting our customers, the Companies' hiring efforts have been of significant value to LG&E's and KU's service areas during this economic downturn because job openings, especially full-time positions with benefits comparable to those of the Companies, have, at best, been scarce. As shown in the testimony of Mr. Kent Blake, Chief Financial Officer, the costs need to be included in base rates at this time to allow the Companies to continue to earn a reasonable rate of return that will attract capital investment.

Q. Does this conclude your testimony?

A. Yes, it does.

VERIFICATION

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

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

C Hermann
Chris Hermann

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 20th day of June 2012.

Joan A. Henry (SEAL)
Notary Public

My Commission Expires:

July 21, 2015

Appendix A

Chris Hermann

Senior Vice President, Energy Delivery
LG&E and KU Energy LLC
220 West Main Street
Louisville, Kentucky 40202

Current Major Accountabilities

- Business strategies and budgets that support the financial and best practice targets of LG&E and KU Energy and PPL.
- Natural gas and electric distribution operations focused on network enhancement, reliability, operation and maintenance.
- Service restoration and emergency operations that minimize adverse customer impact.
- Retail business and customer service functions, including metering, customer call center and business office operations, marketing, revenue collection and economic development.
- Real estate and right-of-way, facilities management, office services, corporate fleet and security operations.

Previous Accountabilities

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

Career History	**Dates**
LG&E Energy Corp., Louisville, KY	
Senior Vice President, Distribution Operations	2000-2003
Vice President, Supply Chain & Operating Services	2000-2000
Vice President, Power Generation & Generation Services	1998-2000
Vice President, Business Integration	1997-1998
Vice President & General Manager, Wholesale Electric Business	1993-1997
Louisville Gas & Electric Co., Louisville, KY	
General Manager, Wholesale Electric	1992-1993
General Manager, Power Production Department	1989-1992
Manager Administration, Power Production Department	1984-1989
Plant Manager, Cane Run Station	1978-1984
Assistant Plant Manager, Cane Run Station	1976-1978
Economy Engineer, Cane Run Station	1973-1975
Mechancial Engineer, Cane Run Station	1970-1972

Present Civic Activities

University of Louisville Speed Scientific School
Chair, Board Operating Sub-Committee
Past Board of Industrial Advisors Chair, 1993-1994

Metro United Way
Board of Directors
Executive Committee
Tocqueville Steering Committee
Red Feather Society Chair

Kentucky State Parks Foundation
Board Member
Chair Membership Committee

Kentucky Chamber of Commerce
Board Member
Executive Committee
Vice Chair Administration

KET Louisville Regional Board Member

Professional/Trade Memberships

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

Education

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

Appendix B

Energy Delivery's Safety Awards

2010

- SGA Safety Video Excellence Award Safety 2010 Technical Short
- Utility Communicators International – Second place award for the "Safety With An Attitude" video.
- Distribution Operations, Retail and Metering – Royal Society for the Prevention of Accidents for Occupational Safety – International Safety Award
- Paul R. Fields - KGA Lifesavings Efforts Award
- SGA – Second place award for Energy Delivery wellness posters
- Kentucky Governor's Health & Safety Awards:
    - Magnolia for 1,000,000 man-hours without a lost time injury
    - Gas Regulatory for 250,000 man-hours without a lost time injury
    - Gas Control for 500,000 man-hours without a lost time injury.
- Elizabethtown Operations received an EEI Safety Achievement Award and a National Safety Council award for achieving 250,000 man-hours without a lost time injury.
- 2010 AGA Safety Achievement Award for achieving the lowest DART (Days Away, Restricted, or Transferred) incident rate among medium sized combination companies.
- 2010 KGA Accident Prevention Award for Excellence in Safety

2011

- AGA DART award for Gas Operations achieving 531,193 hours with a dart rate of .15
- SGA Safety Video Excellence Award Safety 2011 Technical Short
- Distribution Operations, Retail and Metering – Royal Society for the Prevention of Accidents for Occupational Safety – International Safety Award
- EEI Safety Achievement Awards:
    - Danville SC&M for 500,000 man-hours without a lost time injury
    - Lexington SC&M for 750,000 man-hours without a lost time injury
    - Pineville Operations Center for 750,000 man-hours without a lost time injury
- Kentucky Governor's Health & Safety Award, Pineville Operations for 250,000 man-hours without a lost time injury

Hermann Exhibit 1

Gas Service Riser Replacement Program
&
Customer Service Ownership

Louisville Gas & Electric Company
2012 Gas Service Riser Replacement Program&
Customer Service Ownership

Introduction

Louisville Gas and Electric Company ("LG&E" or "Company") proposes to implement a systematic targeted replacement program for customer-owned gas service risers that contain a specific compression type mechanical coupling. This will enhance the safe, reliable delivery of natural gas service to LG&E's customers. A gas service riser is a piping component that protects plastic service pipe as it transitions from below ground to above ground and from plastic to steel just upstream of the customer meter loop.

Two prevailing types of failures have been recorded on gas service riser compression fittings in the industry: pullout or leakage. Pullouts involve the separation of the service piping from the coupling stiffener, and have been attributed to thermal cycling of the pipe, soil stresses, soil shifts, coupling deterioration, or improper installation. Leakage involves long-term viscous and elastic effects which cause a leak path to form between the mechanical coupling and plastic pipe.

The gas service riser, as well as the service line, is currently owned by the customer (see Figure 1, in the Appendix). As part of the program, LG&E proposes to assume ownership and responsibility for the gas service risers as they are replaced. LG&E is also proposing to assume ownership and responsibility of customer-owned service lines whenever an existing service line needs repair or replacement, or when a new customer service line is installed. Kentucky's four other largest natural gas utilities, Atmos Energy Corporation, Columbia Gas of Kentucky, Delta Natural Gas, and Duke Energy Kentucky assume ownership and responsibility for customer-owned service lines on their natural gas distribution systems whenever a new service is installed or existing services are replaced.

Background

LG&E has approximately 300,000 customer-owned gas service lines installed on its gas distribution system. Approximately 213,000 of these services contain service riser compression type mechanical couplings that do not incorporate an anti-pullout design. Risers with this design were widely used in the industry starting in the 1970's. Customers in LG&E's service territory started using them during the 1980's. Most of the risers on LG&E's system were installed by third party plumbers as part of customer service installations or replacements. Since February 2009, LG&E has responded to 370 customer service riser failures. LG&E's 2011 annual Department of Transportation (DOT) report included 167 mechanical coupling failures, 150 of which involved customer-owned gas service riser failures.

Incidents resulting from mechanical coupling fitting failures in the natural gas industry have prompted numerous studies and enhanced safety rules by regulatory entities.

1. During 2005, the Ohio Public Utility Commission (PUCO) initiated an investigation titled, ***"In the Matter of the Investigation of the Installation, Use, and Performance of Natural***

Gas Service Risers, Throughout the State of Ohio and Related Matters." The conclusions and safety recommendations resulting from the investigation were filed by the PUCO on November 24, 2006. In its report, the PUCO required gas distribution system operators to conduct system surveys and develop risk mitigation plans for at risk service risers. In response, Columbia Gas of Ohio proposed and received approval from the PUCO to implement a $200 million dollar replacement program over three years, which included replacement of approximately 350,000 service risers. Duke Energy implemented a similar program in Ohio and in northern Kentucky, which included the replacement of 220,000 gas service risers between 2008 and 2012.

2. In April 2007, the Railroad Commission of Texas (TRC) initiated a study to review the operational history of compression couplings installed at service riser locations. The study was later expanded to include mechanical fittings installed on any portion of the distribution pipeline. The TRC consulted with natural gas distribution utilities in Texas, the National Transportation Safety Board (NTSB), and the Pipeline and Hazardous Materials Safety Administration (PHMSA) to review coupling failure incidents in Texas and the nation. Fifteen months after initiating its review, the TRC released its findings and gas safety recommendations in the "***Study Report on Compression Type Couplings.***" After releasing its report, the TRC approved gas safety rulemaking related to the use of mechanical couplings, including mandated replacement of all service riser couplings that do not have secondary restraint or are not resistant to pull-outs.

3. The Federal DOT Pipeline and Hazardous Materials Administration issued an Advisory Bulletin on March 4, 2008 related to the use of mechanical couplings. The advisory bulletin included the following recommendations:

    a. Improve record keeping on specific couplings that exist.
    b. Consider whether to adopt a full replacement program.
    c. Work with Federal and State pipeline safety representatives, manufacturers, and industry partners to determine how to best resolve potential issues in a utility's respective state or region.

    Starting in 2011, the DOT's Distribution Integrity regulations included specific annual reporting requirements for mechanical coupling failures, including number of failures, location of failure, material type, manufacturer, nature of failure, and lot number.

Risk of Failures

The natural gas industry, including LG&E, continues to experience mechanical coupling failures on gas service risers. Based on LG&E's failure data, failures occur most frequently in cold temperatures, particularly following an extremely dry period.

Failures of customer gas service risers typically result in gas leaks near the foundation of buildings. The proximity of these leaks increases the likelihood of natural gas migration into buildings.

Completed Mitigation Actions

Since release of the 2008 DOT Advisory Bulletin, LG&E has initiated several actions to assess the operation and failure rates of gas service risers on LG&E's gas distribution system, and to mitigate risks posed by certain customer-owned gas service risers.

1. Material Standards Revision – In May 2008, LG&E revised its material standards to eliminate use of the gas service riser type prone to failure. The revised material standard required the use of gas service risers with category 1 type mechanical couplings that incorporate an anti-pull-out design.

2. Failed Risers Assessment – Starting in February 2009, LG&E began replacing failed customer gas service risers in order to assess and generate data on the mode, cause, time, and result of the failures. Since beginning this assessment, a total of 370 leaking gas service risers have been replaced (as of April 30, 2012).

3. Duke Energy Visit – During March 2010, several LG&E employees traveled to Duke Energy's Cincinnati offices to discuss Duke's gas service riser replacement program. Since 2001, Duke has assumed ownership of customer services whenever they replace a service line or riser.

   As part of Duke Energy's 2007 rate case, the PUCO approved Duke's program to proactively replace targeted gas service risers by the end of 2012, and report all future gas service riser failures to the PUCO. Duke subsequently implemented the riser replacement program in Kentucky.

4. Leak Survey – During early January 2011, LG&E conducted an incremental sample leak survey of gas service risers. More than 7,000 services were visited and no service riser leaks were discovered.

5. Gas Riser Survey – Between February and April 2011, LG&E conducted a field survey of customer services and identified 213,000 gas services with targeted risers.

Proposed Mitigation Actions

LG&E proposes to implement a program to systematically replace targeted customer-owned gas service risers located in the LG&E gas distribution system with a gas riser that incorporates an anti-pullout design. LG&E also proposes to assume ownership of and responsibility for (see Figure 2, in the Appendix):

- Customer-owned gas service risers as they are replaced; and
- Customer-owned service lines when a new service is installed or existing services are replaced or repaired.

1. <u>Program Scope</u>
    a. This proposed program will replace all targeted gas service risers over a five-year period. LG&E will take over ownership of each gas service riser upon its replacement.

    b. DOT regulations classify customer-owned services as jurisdictional piping, thus requiring operator qualified personnel to perform all covered tasks associated with gas service work. Accordingly, LG&E will assume ownership of and responsibility for installing, maintaining, and replacing all customer service lines, risers, and meter loops.

2. <u>Program Plan</u>
    a. Sample Riser Replacement and Assessment - The first step of the proposed program will be completion of a random sample riser replacement and assessment effort. Riser replacements will be completed at 800 locations for statistical significance. Figure 3, in the Appendix, displays the geographic locations for the targeted sample replacement risers. Risers targeted for the sample program were randomly selected and then qualified to assure adequate statistical significance for services installed by geographic area and decade installed.

       Replaced risers will be evaluated for proper installation, material defects, etc. Results from the sample replacement program will be utilized to develop the overall priorities of the gas riser replacement plan with priority to locations having the highest risk of failure.

    b. Replacement Plan - Upon completion of the sampling program and establishment of an overall prioritization plan and schedule, all targeted gas service risers will be replaced over a five-year period in accordance with LG&E standards (see Figure 4, in the Appendix). Approximately 213,000 customer-owned service line risers will be included in the program. Figure 5 in the Appendix, displays the gas service riser population density in LG&E's service area by geographical quadrant.

LG&E proposes to replace 15% of the target population of gas service risers during 2013. This provides for adequate time for customer communications and resource ramp up. An equal distribution of the remaining population of targeted risers will be replaced over the remaining four years of the proposed program period.

c. Riser Ownership - LG&E will assume ownership of each customer service riser as it is replaced. Assumption of ownership of gas service risers will result in on-going incremental annual expenses associated with replacement and installation of customer service risers.

d. Customer Experience - Upon receiving approval for this program, LG&E will begin a communications effort to advise customers of the program and explain its benefits. Various communication outlets will be utilized, including a program website, mailers, and a "helpline" to address customer questions or concerns. Drawings and schematics showing the proposed changes will be made available to customers so they can more readily understand the changes in ownership responsibilities.

   LG&E will notify customers of targeted risers in writing regarding the replacement program timeline, as it relates to their specific addresses. These notifications will occur via USPS mail, as well as with pamphlets delivered to each customer's residence.

   Throughout the program, emphasis will be placed on minimizing service disruptions and customer inconvenience. Customers will experience a brief service interruption and a minor excavation near the meter loop on their property when their gas service riser is replaced. Customer service risers are installed on polyethylene service lines, so typically a full replacement of the service will not be necessary, and the excavation required will be minor in comparison to a complete service replacement.

   Once service is interrupted, the old riser will be removed from service, and replaced with a new riser. The new riser, associated meter piping, and customer house piping will then be subjected to a pressure test. Once the pressure test is complete, the customer's gas utility service and yard will be restored, as appropriate.

3. Accelerated Customer Replacements Customers desiring expedited gas service riser replacements will be required to cover the associated replacement expenses. After program implementation, LG&E will provide an operator qualified inspector to assure the installer adheres to manufacturer recommendations and Company standards.

Financial Summary

The estimated financial impacts associated with the proposed Gas Service Riser and Customer Service Ownership programs are displayed in the following table.

Program Description	2013	2014	2015	2016	2017
Implement program to replace all at risk service risers and assume ownership of cust service lines as they are replaced.					
Opex	**$ 4,147,054**	**$ 2,156,437**	**$ 1,881,751**	**$ 1,595,027**	**$ 1,296,405**
Ongoing Maintenance and Repairs	$ 1,151,839	$ 1,186,394	$ 1,221,986	$ 1,258,646	$ 1,296,405
Leak Survey Remaining At-Risk Risers Annually	$ 903,458	$ 663,025	$ 450,950	$ 229,917	$ -
Accelerated Customer Riser Replacements	$ 2,091,757	$ 307,018	$ 208,815	$ 106,464	$ -
Capital	**$ 24,098,470**	**$ 31,125,964**	**$ 31,782,019**	**$ 32,516,320**	**$ 33,228,918**
Ongoing Construction and Replacement	$ 6,399,445	$ 6,591,428	$ 6,789,171	$ 6,992,846	$ 7,202,632
Replace At-Risk Service Risers	$ 17,699,025	$ 24,534,536	$ 24,992,848	$ 25,523,473	$ 26,026,286

1. Ongoing Maintenance and Repairs – Ownership of customer service lines will result in estimated incremental operations and maintenance costs of $1.1 million in year one, and $6.1 million over the five-year riser replacement program. These costs will continue thereafter and will be primarily associated with expenses required to maintain customer meter loops. Some existing customer service tasks and associated costs should be reduced, such as those associated with test and reconnects, cut and caps, and spot services.

2. Leak Survey Remaining Risers Annually – LG&E proposes to conduct an incremental leak survey of targeted service risers not yet replaced on an annual basis. Associated expenses are estimated to be $903,000 in year one, and $2.2 million over the life of the riser replacement program.

3. Accelerated Customer Riser Replacement Program – LG&E estimates that a small percentage of its customers may elect to accelerate the replacement of their gas service risers. The Company estimates that $2.1 million will be required in year 1 (5% of customers in year 1, and 1% of customers in year 2-4), and $2.7 million over the life of the replacement program to perform associated operating and maintenance activities and provide an operator qualified inspector for tasks completed by plumbers.

4. Ongoing Capital and Replacement Expenses - Ownership of customer service lines will result in estimated incremental capital expenses of $6.4 million in year one, and nearly $34 million over the five-year riser replacement program. These costs will continue for the

foreseeable future, and will be primarily associated with expenses required to install or replace customer services (property line to meter stopcock), service risers, and meter loops.

5. Gas Service Riser Replacement - LG&E identified approximately 213,000 plastic gas services with targeted service risers during the 2011 Gas Service Riser field survey. The estimated capital expenses to replace the inventory of program risers over a five-year period are $118.8 million (includes cost of removal).

Appendix

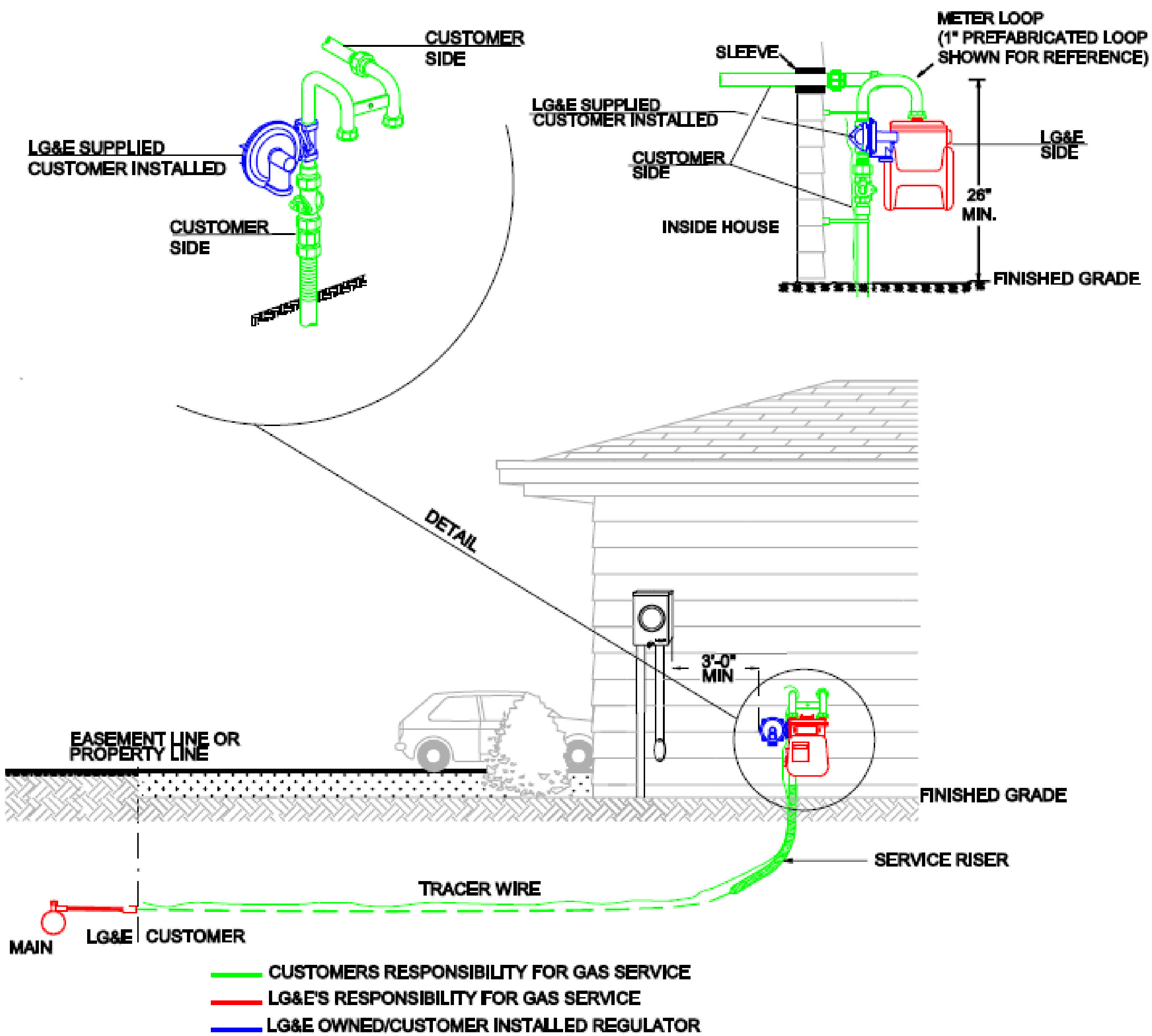


Figure 1– Existing LG&E Gas Service Ownership Responsibilities

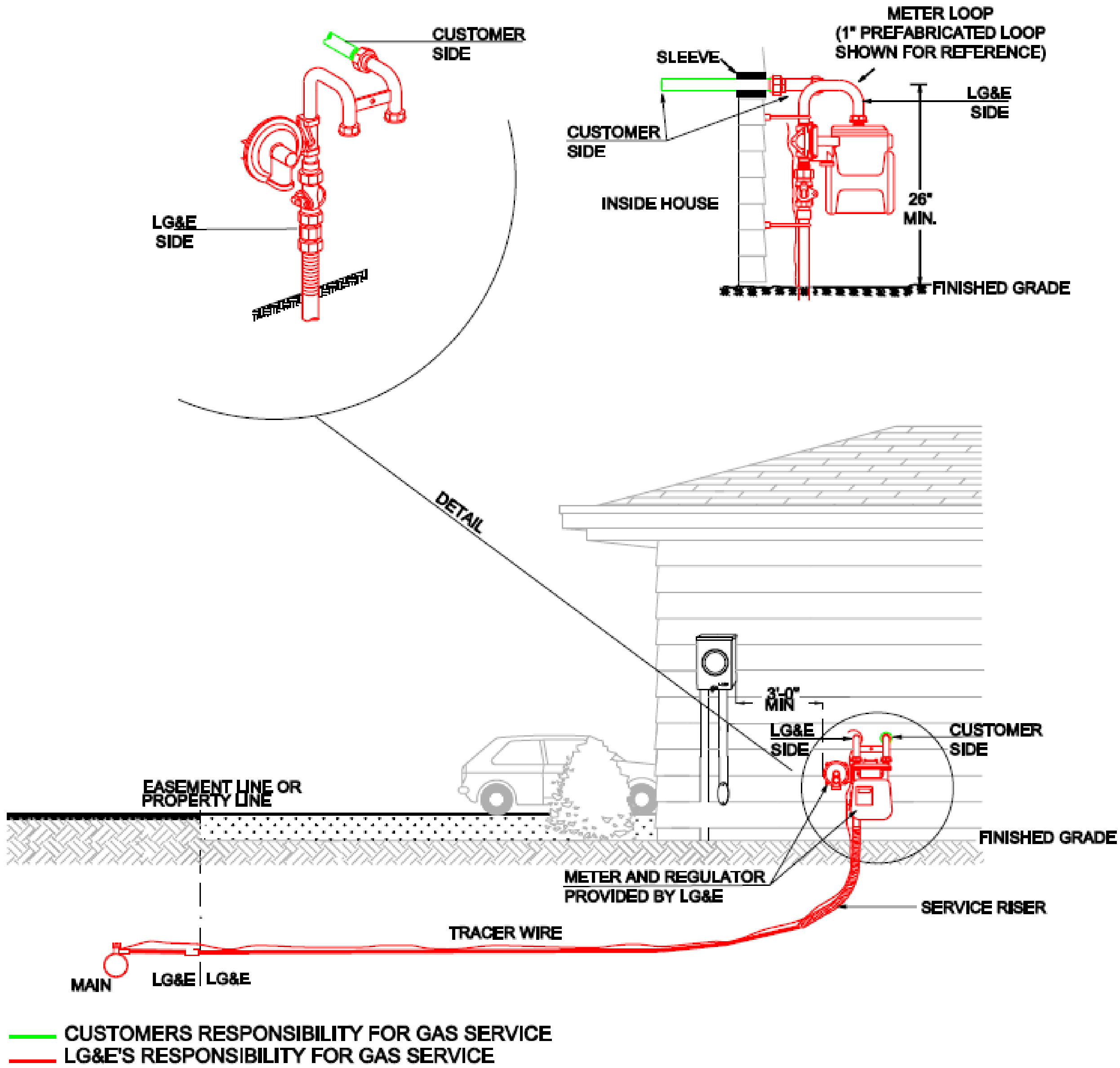


Figure 2 – Proposed LG&E Gas Service Ownership Responsibilities

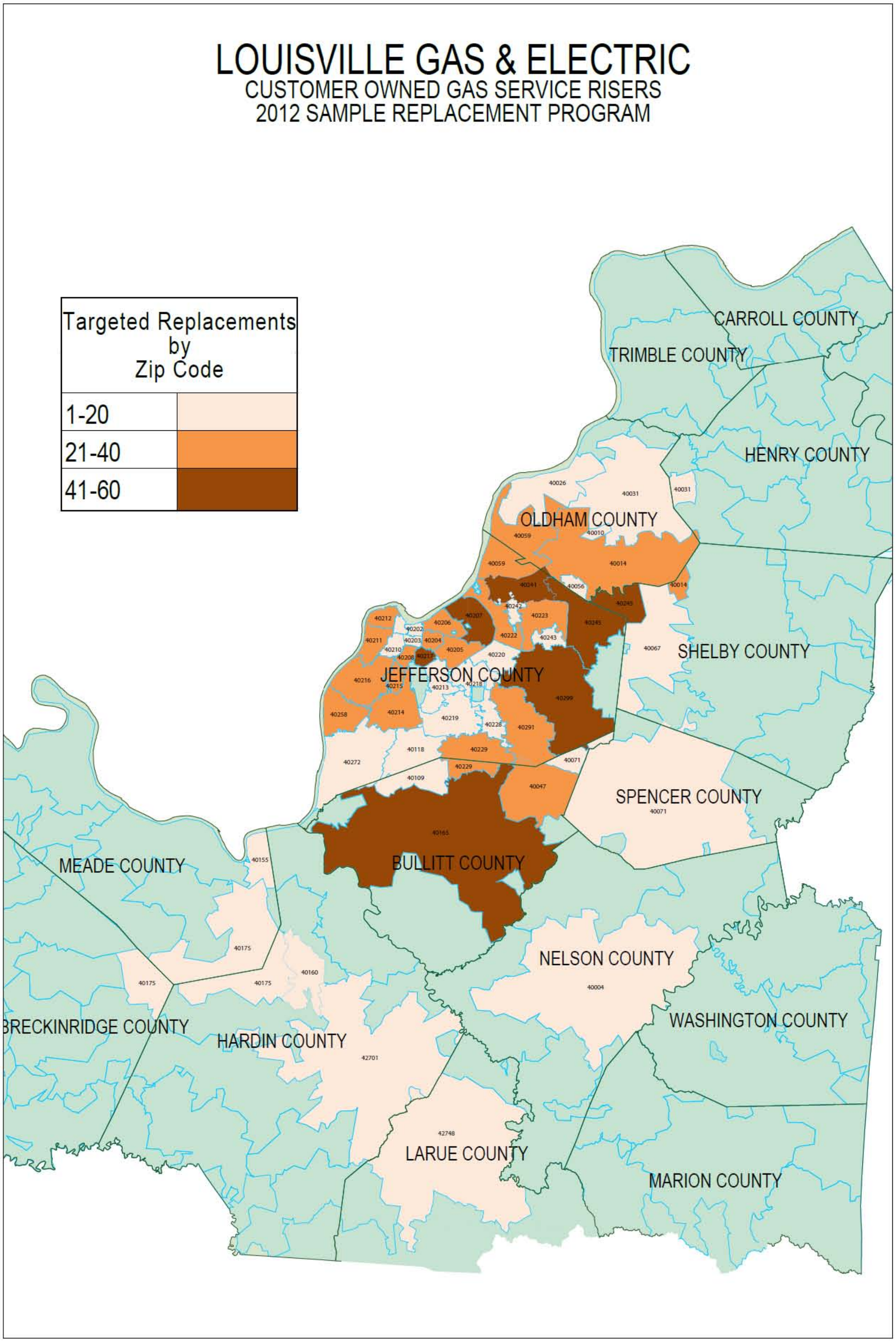


Figure 3 – 2012 Customer Service Riser Sample Replacement Program

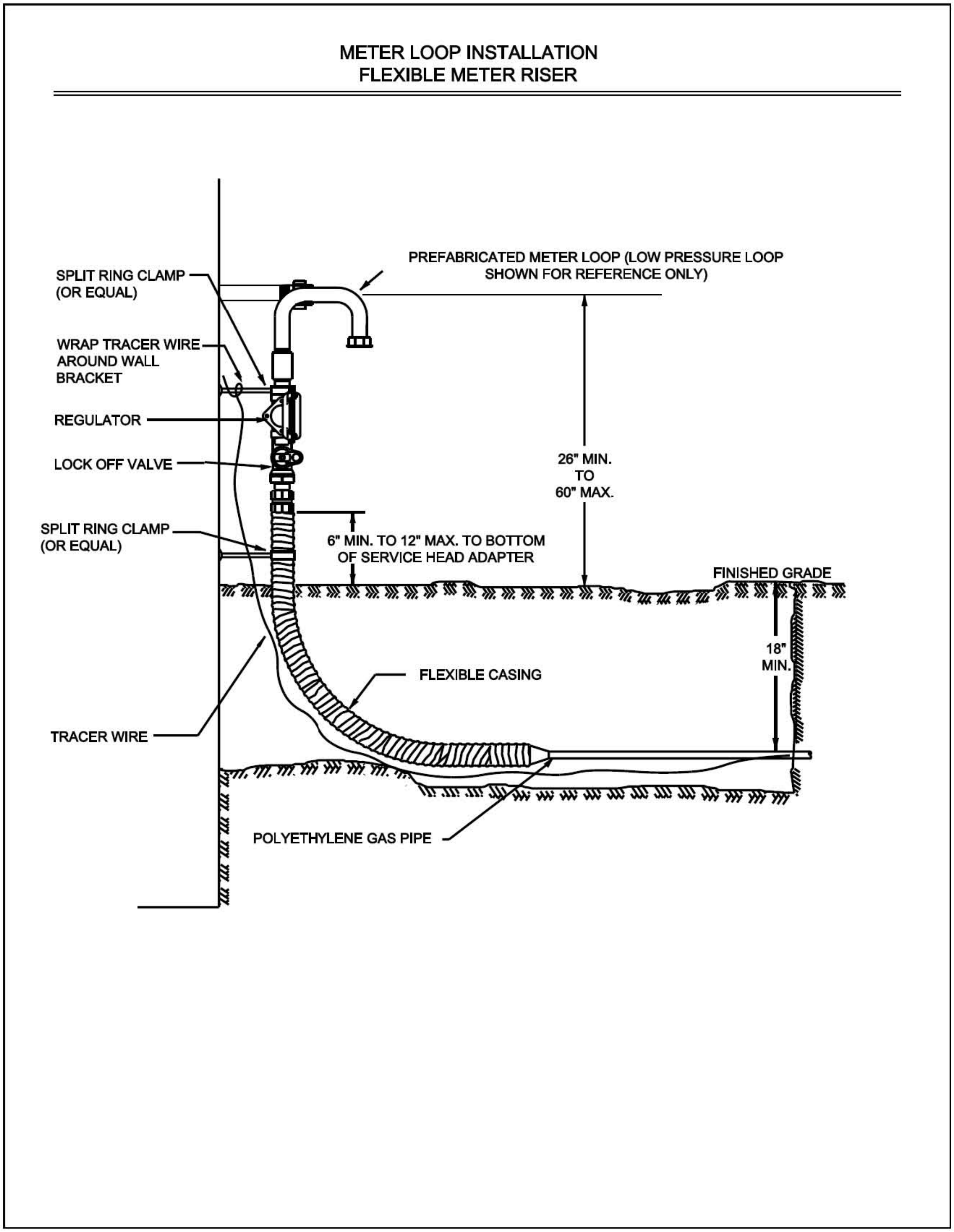
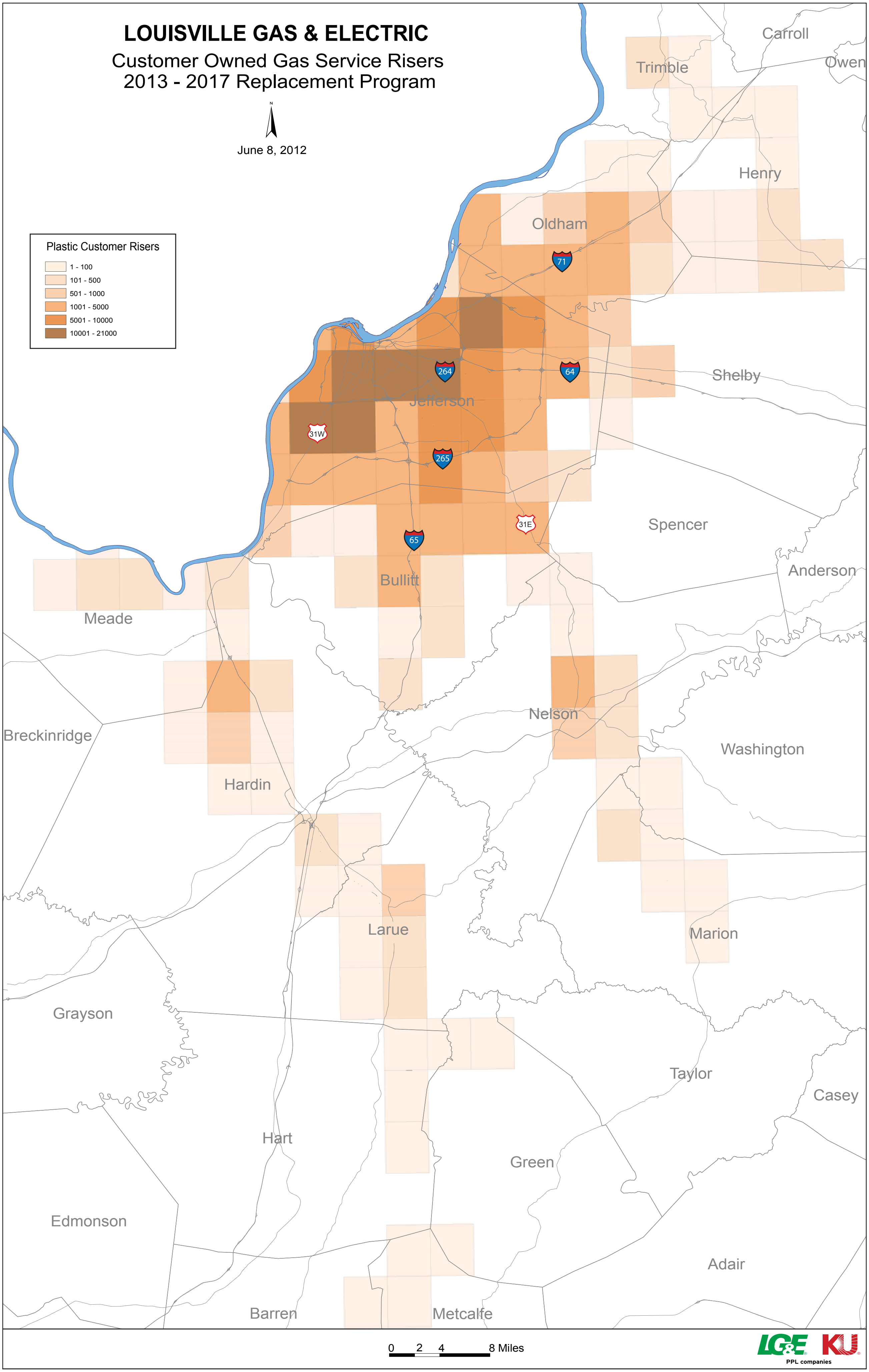


Figure 4 – Gas Service Riser Standard Drawing

See attached.

Figure 5 – Riser Replacement Program Map



LOUISVILLE GAS & ELECTRIC
Customer Owned Gas Service Risers
2013 - 2017 Replacement Program
N
June 8, 2012
Plastic Customer Risers
1 - 100
101 - 500
501 - 1000
1001 - 5000
5001 - 10000
10001 - 21000
Carroll
Owen
Trimble
Henry
Oldham
71
264
64
Shelby
Jefferson
31W
265
Spencer
31E
65
Anderson
Bullitt
Meade
Nelson
Breckinridge
Washington
Hardin
Larue
Marion
Grayson
Taylor
Casey
Hart
Green
Edmonson
Adair
Barren
Metcalfe
0 2 4 8 Miles
LG&E
KU
PPL companies

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

APPLICATION OF KENTUCKY	**)**	
UTILITIES COMPANY FOR AN	**)**	**CASE NO. 2012-00221**
ADJUSTMENT OF ITS	**)**	
ELECTRIC RATES	**)**	

TESTIMONY OF
KENT W. BLAKE
CHIEF FINANCIAL OFFICER
KENTUCKY UTILITIES COMPANY

Filed: June 29, 2012

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

A. My name is Kent W. Blake. I am Chief Financial Officer for Kentucky Utilities Company ("KU" or the "Company") and an employee of LG&E and KU Services Company which provides services to KU and Louisville Gas and Electric Company ("LG&E") (collectively, the "Companies"). My business address is 220 West Main Street, Louisville, Kentucky 40202. A statement of my qualifications is attached hereto in Appendix A.

Q. Have you previously testified before the Commission?

A. Yes, I last testified on behalf of KU in *The Application of Kentucky Utilities Company for a Certificate of Public Convenience and Necessity to Construct a Selective Catalytic Reduction System and Approval of Its 2006 Compliance Plan for Recovery by Environmental Surcharge*, Case No. 2006-00206, and on behalf of LG&E in *The Application of Louisville Gas and Electric Company for Approval of Its 2006 Compliance Plan for Recovery by Environmental Surcharge*, Case No. 2006-00208.

Q. What is the purpose of your testimony?

A. The purposes of my testimony are: (1) to describe why KU's financial condition requires the requested increase in base rates; (2) to present the Financial Exhibits to KU's application and support certain pro forma adjustments to same; (3) to review KU's accounting records; (4) to describe the calculation of KU's adjusted net operating income for the twelve month period ended March 31, 2012; (5) to discuss KU's capitalization and weighted cost of capital; and (6) to support the different valuations of KU's property required under KRS 278.290, such as KU's rate base.

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

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

A. As explained more fully in the testimony of Mr. Victor A. Staffieri, Mr. Paul W. Thompson, and Mr. Chris Hermann, since its last rate case, KU has made capital investments and sustained increased operation and maintenance expenses in order to provide customers with safe and reliable electric service, while also providing a positive customer experience. Given the additional costs since KU's last rate case, KU is not earning a reasonable rate of return. As noted in Mr. Staffieri's testimony, our business remains one of the most capital-intensive industries in the world, and is now more complex than ever. To provide electric service, KU must continue to raise money through financing, using both debt and equity. A weakened financial condition is not supportive of these financing efforts and is not in the best interest of KU's shareholders or its customers. Approval of this rate increase is of the upmost importance to improve the Company's financial health.

Q. Please explain why KU has sought a rate increase at this time.

A. As demonstrated in the chart below, since the last rate case, KU has invested hundreds of million dollars in its distribution, generation, and transmission systems in order to provide our customers with the reliable energy they expect. These investments, many of which are discussed more fully in the testimonies of Messrs. Thompson and Hermann, include hardening circuits; Trimble County Unit No. 2 and other generation plant investments; and poles, substations and transformers, only to name a few. All of these investments were necessary to provide customers with reliable and high quality distribution, generation, and transmission service.

Investments by Business Area Since October 31, 2009

	LG&E Electric	LG&E Gas	KU	Total
Distribution	$155.2 million	$126.7 million	$205.5 million	$487.4 million
Generation	$166.6 million	$0.0 million	$171.1 million	$337.7 million
Transmission	$32.2 million	$0.0 million	$113.0 million	$145.3 million
IT and Other	$9.6 million	$12.8 million	$26.7 million	$49.0 million
Total Capital Investment	$363.6 million	$139.5 million	$516.3 million	$1.019 billion

KU's present rates are simply inadequate to collect sufficient revenues to reasonably finance these investments and other cost increases. As a result, the Company must seek a rate increase at this time.

Q. Has KU's investment in utility plant increased since October 31, 2009, the test period used by the Commission in Case No. 2009-00548[1]?

A. Yes. The chart above shows KU's investments since the last rate case at their original cost. For ratemaking purposes, the net utility plant, reflecting the accounting adjustments for depreciation and cost of removal should be used. The following chart, which includes those adjustments and is appropriate for ratemaking use, shows KU's investment in net utility plant has increased by approximately $544 million since October 31, 2009:

Net Utility Plant

	October 31, 2009	March 31, 2012	Increase
Utility plant	$ 5,975,896,410	$ 6,837,808,461	$ 861,912,051
Accumulated depreciation	$ 2,101,470,902	$ 2,419,286,203	$ 317,815,301
Net utility plant	$ 3,874,425,508	$ 4,418,522,258	$ 544,096,750

[1] *In the Matter of: Application of Kentucky Utilities Company for an Adjustment of Base Rates.*

The approximately $544 million increase in net utility plant since the last rate case is supported by an increase in capitalization of $395 million.

Q. Did KU earn its authorized return on common equity for the twelve months ended March 31, 2012?

A. No. For the twelve months ended March 31, 2012, Blake Exhibit 9 to my testimony shows KU earned a return on common equity ("ROE") of 8.08% and a return on capital of 6.05%. The adjustments supporting this revenue requirement calculation in KU's application are supported by and are consistent with prior Commission orders

Based on the analyses presented in Dr. William E. Avera's testimony, he has determined that the ROE for KU should be in the 10.30% to 11.70% range and has recommended the Commission adopt an 11.00% allowed rate of return in this proceeding. KU's earned ROE for the twelve-month period ending March 31, 2012, falls well below even the lower end of the range of this return.

<u>Ability to Earn Authorized Return on Equity Under Current Conditions</u>

Q. In addition to the capital investments and operation and maintenance expenses already incurred, are there new and additional risks to KU that it may not earn its authorized return after this rate case under current conditions?

A. Yes, KU will likely not be able to earn its authorized rate of return awarded in this case for several reasons, and each of these factors should be taken into consideration in establishing the ROE in this proceeding. Most significant are the capital expenditures KU is preparing to incur. As demonstrated in the chart setting forth the projected capital expenditures by year, attached as Blake Exhibit 10 to my testimony, KU is projected to incur other capital expenditures of approximately $3.1 billion from

2012 to 2016. Less than half of these capital expenditures are related to environmental compliance projects that may be recovered through the environmental surcharge.

These capital expenditures include cost estimates associated with replacing generation capacity where it was determined to not be reasonable or cost-effective to retrofit certain KU and LG&E coal-fired units.[2] These capital expenditures represent a significant increase over the amount of capital expenditures in the test year in this proceeding, and will accumulate greatly in each of the next five years.

KU's last base rate adjustment took effect August 1, 2010, and was based on a test year ended October 31, 2009. That base rate adjustment was found reasonable by this Commission in Case No. 2009-00548 based on a 10.25% return on equity, used for analytical purposes. As demonstrated by its ASSD filing in Case No. 2012-00127, KU was earning an 8.50% return on equity by December 31, 2011, the first calendar year following its last base rate increase. KU had non-ECR capital expenditures of $472 million during this 26-month period between October 31, 2009, and December 31, 2011. By comparison, the non-ECR capital expenditures from Blake Exhibit 10 for the 26-month period following the test year in this base rate case

[2] *In the Matter of: The Application of Kentucky Utilities Company for Certificates of Public Convenience and Necessity and Approval of Its 2011Compliance Plan for Recovery by Environmental Surcharge* (Case No. 2011-00161) and *In the Matter of: The Application of Louisville Gas and Electric Company for Certificates of Public Convenience and Necessity and Approval of Its 2011Compliance Plan for Recovery by Environmental Surcharge* (Case No. 2011-00162); *In the Matter of: Joint Application of Louisville Gas and Electric Company and Kentucky Utilities Company for a Certificate of Public Convenience and Necessity and Site Compatibility Certificate for the Construction of a Combined Cycle Combustion Turbine at the Cane Run Generating Station and the Purchase of Existing Simple Cycle Combustion Turbine Facilities from Bluegrass Generation Company, LLC in LaGrange, Kentucky* (Case No. 2011-00375).

are projected to be $710 million, one-and-a-half times greater than those that contributed to the decline in KU's return on equity investment for 2011.

Because an ROE should allow a utility to earn a fair and reasonable return going forward and reflect the risk of cost increases between rate cases, the ROE established in this proceeding should take into consideration the financial risk associated with the expected increases in capital costs between rate cases. Otherwise, it is almost a certainty that the Company will not be able to achieve the return established in this proceeding, which will force KU into a declining financial condition within the first twelve months after new rates are established.

Q. Can KU rely on traditional revenue opportunities and native load growth in sales to mitigate these cost increases?

A. No, as explained in the testimony of Mr. Thompson, KU's sales forecast has decreased and there has been a substantial decline in off-system sales opportunities. The most recent sales forecast, provided to the Commission in Administrative Case No. 387, shows the compound annual growth rate for the 2012 to 2016 time period for energy sales is 0.8 percent for KU. Recent history reflects the decline in load growth as the economy and increased focus on energy efficiency have led to year over year declines in KU's retail electric load for two of the past three years.

Moreover, as explained more fully in the testimony of Mr. Thompson, the opportunities for off-system sales have diminished because of structural changes to the Companies' generating fleet and the decreased demand for coal-fired generation, which is attributable to the EPA's stringent emission limits and the historically low natural gas prices and volumes of natural gas as a result of the Marcellus Shale formation and the fracking advancements in horizontal drilling. Off-system sales have traditionally been a source by which KU can defray rising expenses from impacting its retail customers between rate cases. Due to recent changes in the energy market, however, KU has no reasonable expectation that off-system sales margins will meaningfully rebound and, in fact, have been nearly eliminated.

This is very significant to KU, as off-system sales opportunities and native load growth between rate cases have traditionally served as revenue sources by which KU can offset rising operating costs for its retail customers and help mitigate the regulatory lag associated with investments between test years on which KU is not recovering its cost of capital.

Q. If the rates KU has proposed are approved, will customers continue to receive a good value for their service?

A. Yes. If the proposed rates are approved, KU's customers will continue to receive a good value. As shown in Blake Exhibit 11, currently KU and LG&E are the only utilities in the entire country that have achieved top quartile status with regard to cost performance in four of the following five cost areas that FERC monitors: generation, transmission, distribution, retail, and corporate - administrative and general. In fact, the Companies are the fifth lowest in the country in cost per customer with regard to generation, and seventh in the country in the transmission cost area.

These metrics demonstrate that KU is currently among the most cost efficient utilities in the country, which provides assurance that our customers receive a good value. These cost comparisons demonstrate that even if the proposed rates are approved, KU's customers can be assured they are still receiving a good value for their service.

Q. Cumulatively, what do you recommend with regard to KU's return on equity?

A. I recommend that the Commission strongly consider the very real likelihood that KU will not be able to achieve its authorized return on equity between rate cases because of these risks - the capital investments KU is preparing to incur; the decreased load growth forecast for the same period; and the diminished opportunities for off-system sales - in establishing the Company's ROE in this proceeding. The ROE should prospectively allow KU to earn a fair and reasonable return and, quite simply, an ROE that does not consider these known risks will not.

PSC Financial Exhibits

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

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 March 31, 2012.

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

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

• Description of Adjustments	Section 10(6)(a)	Tab 20
• Revenue Requirements Determination	Section 10(6)(h)	Tab 27
• Reconcile Rate Base & Capitalization	Section 10(6)(i)	Tab 28

• Annual Auditor's Opinion(s)	Section 10(6)(k)	Tab 30
• Stock or Bond Prospectuses	Section 10(6)(p)	Tab 35
• Annual Reports to Shareholders	Section 10(6)(q)	Tab 36
• SEC Reports (10Ks, 10Qs and 8Ks)	Section 10(6)(s)	Tab 38

Accounting Records

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

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

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

A. Yes. They are also provided in KU's Application in Filing Requirements Tabs 32 and 37 and are supported by the testimony of 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 previously audited KU's financial statements, and audits are now performed annually by Ernst & Young. Because of the timeframe in which Ernst & Young became engaged by KU, the most recent opinion, which is provided in Filing Requirements Tab 30, was performed in part by PricewaterhouseCoopers and in part by Ernst & Young.

<u>Net Operating Income</u>

Q. Please describe Blake Exhibit 1 and its purpose.

A. Blake Exhibit 1 shows KU's operating revenues, operating expenses and net operating income per books for the twelve months ended March 31, 2012. The test year must be adjusted to reflect known and measurable changes in revenues and expenses that can be expected to occur during the period the proposed rates will be effective. This Exhibit sets forth adjustments for known and measurable changes, and eliminates unrepresentative conditions in order to "*pro form*" or make the test year suitable for use in determining the deficiency of current revenues. This Exhibit also includes adjustments to remove the effects of other independent rate mechanisms in order to limit the deficiency determination to base revenues. A further description of, and support for, each adjustment and calculation is contained in supporting Reference Schedules 1.00 through 1.34 of this Exhibit.

Q. Briefly describe the nature of the pro forma adjustments you have made to KU's operations for the test year ended March 31, 2012, shown on Blake Exhibit 1.

A. For the electric operations as reflected in the twelve month period ended March 31, 2012, KU has made adjustments for known and measurable changes, consistent with established regulatory precedent, which can be categorized as follows:

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

b) Remove the impact of items included in other rate mechanisms (Reference Schedules 1.01-1.07),

c) Annualize year-end facts and circumstances and adjust for other known and measurable changes to revenues and expenses (Reference Schedules 1.08-1.17, 1.19-1.23),

d) Adjust for other unusual, non-recurring, or out-of-period items in the test year (Reference Schedules 1.18), and

e) Adjust for federal and state income tax expenses for these pro forma adjustments (Reference Schedules 1.29-1.32).

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

A. This adjustment has been made to eliminate the effect of unbilled revenues, consistent with the Commission's long-standing practice of only including twelve months of customer billings in the calculation of the base rate revenue requirement. The Commission approved a similar adjustment in Case Nos. 2009-00548 and 2003-00434 and, KU proposed such an adjustment in Case No. 2008-00251, which was resolved by a settlement approved by the Commission. This adjustment was prepared by Mr. Lonnie E. Bellar and is discussed in his testimony.

Q. Please explain the adjustment to operating revenues and expenses shown in Reference Schedule 1.01, 1.02 and 1.03 of Blake Exhibit 1.

A. These adjustments, when combined with the FAC portion of the adjustment in Reference Schedule 1.07, remove the revenue and expense effects of the FAC mechanism as those expenses and associated recoveries are handled via that mechanism and not through base rates.

Reference Schedule 1.01 presents the adjustment to account for the timing mismatch in fuel cost expenses and revenues under the FAC for the twelve months ended March 31, 2012. The Commission approved a similar adjustment in Case Nos. 2009-00548 and 2003-00434,[3] and KU proposed such an adjustment in Case No. 2008-00251,[4] which was resolved by a settlement approved by the Commission. This adjustment was prepared by Mr. Robert M. Conroy and is discussed in his testimony.

Reference Schedule 1.02 presents the adjustment necessary to annualize the full twelve months of the test year for the "roll-in" or incorporation of the FAC into base rates as directed by the Commission's May 31, 2011, Order in Case No. 2010-00492.[5] The Commission approved a similar adjustment in Case Nos. 2009-00548 and 2003-00434, and KU proposed such an adjustment in Case No. 2008-00251, which was resolved by a settlement approved by the Commission. This adjustment was prepared by Mr. Conroy and is discussed in his testimony.

Reference Schedule 1.03 reflects a proposed change in how KU calculates its FAC, by including the complete recovery of the total system losses, instead of only Kentucky jurisdictional losses. If approved, this adjustment will begin in the first fuel adjustment clause expense month following the Commission's approval of the changes in rates in this case through KU's fuel adjustment clause tariff and removing the associated expense from base rates. Reference Schedule 1.03 also makes a revision to how KU calculates its FAC to correct a mismatch in the calculation of its monthly FAC billing factors relating to the inclusion of system losses as a component

[3] *In re the Matter of: An Adjustment of the Electric Rates, Terms and Conditions of Kentucky Utilities Company*
[4] *In re the Matter of: Application of Kentucky Utilities Company for an Adjustment of Base Rates*
[5] *In the Matter of: An Examination of the Application of the Fuel Adjustment Clause of Kentucky Utilities Company from November 1, 2008 Through October 31, 2010*

of sales under the Commission's Fuel Adjustment Clause regulation 807 KAR 5:056. This adjustment was prepared by Mr. Conroy and is discussed in his testimony.

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

A. This adjustment removes ECR revenues and expenses from net operating income because those revenues and expenses are addressed by a separate rate mechanism. The Commission approved a similar adjustment in Case Nos. 2009-00548 and 2003-00434, and KU proposed such an adjustment in Case No. 2008-00251, which was resolved by a settlement approved by the Commission. This adjustment also eliminates KU's 2005 and 2006 ECR Plans from its monthly ECR filings on a going-forward basis because the projects in those plans are now complete and in service, the costs of the projects in those plans are already included in base rates through a series of "roll-ins," and eliminating the two plans will simplify the oversight and administration of the ECR mechanism. This adjustment was prepared by Mr. Conroy and is discussed in his testimony.

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

A. KU has included in this adjustment a reduction to revenues associated with ECR-related off-system and intercompany sales revenues. The expenses are removed as part of the previous adjustment, but are put back in with this adjustment as base rates are the vehicle by which these costs are recovered. KU performed this adjustment in a manner generally consistent with the methodology prescribed in the Commission's

Order on rehearing in Case No. 98-474[6] dated June 1, 2000, and in the manner used in Case Nos. 2009-00548, 2008-00251 and 2003-00434. This adjustment was prepared by Mr. Conroy and is discussed in his testimony.

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

A. This adjustment has been made to remove the impact of the revenues and expenses associated with KU's DSM mechanism from the test year revenues and expenses. The impact of rate mechanisms, like the DSM mechanism, should be removed from the test year revenues when assessing the adequacy of base rates. The Commission approved a similar adjustment in Case Nos. 2009-00548 and 2003-00434, and KU proposed such an adjustment in Case No. 2008-00251, which was resolved by a settlement approved by the Commission. 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 Blake Exhibit 1.

A. This adjustment is necessary to eliminate accrued revenues associated with the Environmental Cost Recovery ("ECR"), Merger Surcredit ("MSR"), Value Delivery Surcredit ("VDT"), Demand-Side Management ("DSM"), and Fuel Adjustment Clause ("FAC") rate mechanisms in order to completely remove the effects of these mechanisms in determining the base revenue deficiency. The Commission approved a similar adjustment in Case Nos. 2009-00548 and 2003-00434, and KU proposed such an adjustment in Case No. 2008-00251, which was resolved by a settlement

[6] *The Application of Kentucky Utilities Company for Approval of an Alternative Method of Regulation of Its Rates and Service.*

approved by the Commission. 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 1.08 of Blake Exhibit 1.

A. This adjustment has been made to eliminate brokered and financial swap revenues. Revenues and expenses associated with brokered and financial swap transactions are eliminated in determining base rates because these transactions do not utilize Company generation or transmission assets. Labor and labor-related costs associated with executing these transactions are also eliminated. A similar adjustment was approved by the Commission in Case Nos. 2009-00548, 2003-00434 and 98-474, and KU proposed a similar adjustment in Case Nos. 2008-00251, which was resolved by a settlement approved by the Commission. This adjustment was prepared by Ms. Scott and is discussed in her testimony.

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

A. This adjustment is to adjust the test year level of off-system sales margins for known and measurable changes based upon actual margins from January 1 to March 31, 2012. This adjustment was prepared by Mr. Bellar and is discussed in his testimony.

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

A. This adjustment has been made to annualize revenues and expenses based on actual electric customers at March 31, 2012. The Commission approved a similar adjustment in Case Nos. 2009-00548 and 2003-00434, and KU proposed such an adjustment in Case No. 2008-00251, which was resolved by a settlement approved by the Commission. This adjustment was prepared by Mr. Conroy and is discussed in his testimony.

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

A. This adjustment reflects the change in revenue due to bill adjustments and certain customers switching rates. The Commission approved a similar adjustment in Case No. 2009-00548 and KU proposed such an adjustment in Case No. 2008-00251, which was resolved by a settlement approved by the Commission. Mr. Conroy prepared this adjustment and discusses it in his testimony.

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

A. This adjustment includes a full year's depreciation expense on net plant in service as of the end of the test year, excluding depreciation on assets set up for asset retirement obligations and depreciation on ECR assets remaining in the 2009 and 2011 ECR Plans, as of March 31, 2012. The rates reflect KU's continued use of Average Service Life methodology and are based upon the rates in John Spanos' depreciation study, which are discussed in his testimony. This adjustment was prepared by Ms. Shannon L. Charnas and is discussed in her testimony. The Commission approved a similar adjustment in Case No. 2009-00548 and KU proposed such an adjustment in Case No. 2008-00251, which was resolved by a settlement approved by the Commission.

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

A. This adjustment has been made to annualize labor and labor-related costs as of March 31, 2012, and includes specific adjustments for labor, payroll taxes, and KU's 401(k) contribution. This adjustment was prepared by Ms. Scott and is discussed in her testimony. The Commission approved a similar adjustment in Case Nos. 2009-00548 and 2003-00434. KU proposed a similar adjustment in Case No. 2008-00251, which was resolved by a settlement approved the Commission.

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

A. This adjustment is necessary to annualize pension, post-retirement, and other post-employment benefit expenses. The Commission approved a similar adjustment in Case Nos. 2009-00548 and 2003-00434, and KU proposed such an adjustment in Case No. 2008-00251, which was resolved by a settlement approved by the Commission. This adjustment was prepared by Mr. Daniel K. Arbough and is discussed in his testimony.

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

A. This adjustment has been made to reflect a normalized level of storm damage expenses based upon a ten-year average adjusted for inflation. A similar adjustment was also approved by the Commission in Case Nos. 2009-00548 and 2003-00434, and KU proposed a similar adjustment in Case No. 2008-00251, which was resolved by a settlement approved by the Commission. Ms. Scott prepared this adjustment and discusses it in her testimony.

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

A. This adjustment is made to normalize the expense levels in Account 925 "Injuries and Damages." The Commission approved a similar adjustment in Case Nos. 2009-00548 and 2003-00434, and KU proposed such an adjustment in Case No. 2008-00251, which was resolved by a settlement approved by the Commission. 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 Blake Exhibit 1.

A. This adjustment eliminates advertising expenses pursuant to 807 KAR 5:016 that are primarily institutional and promotional in nature. The Commission approved a similar adjustment in Case Nos. 2009-00548 and 2003-00434, and KU proposed such an adjustment in Case No. 2008-00251, which was resolved by a settlement approved by the Commission. 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 1.18 of Blake Exhibit 1.

A. This adjustment removes out of period items from test year operating revenues and expenses. The Commission approved a similar adjustment in Case Nos. 2009-00548 and 2003-00434, and KU proposed such an adjustment in Case No. 2008-00251, which was resolved by a settlement approved by the Commission. 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 Blake Exhibit 1.

A. This adjustment reflects the change in the Company's property insurance premium, which is renewed on April 1 of each year, from the test year to the period of April 1, 2012, to March 31, 2013. The Commission approved such an adjustment in Case No. 2009-00548. This adjustment was prepared by Mr. Arbough and is discussed in his testimony.

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

A. This adjustment reduces the amount of annual independent transmission operator ("ITO") expenses embedded in base rates as a result of KU transferring nearly all of the ITO functions currently performed by Southwest Power Pool, Inc. to TranServ International, Inc. and its subcontractor MAPPCOR. This adjustment was prepared by Mr. Bellar and is discussed in his testimony.

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

A. This adjustment reflects the continued amortization of the fee associated with KU's exit from the Midwest Independent System Transmission Operator, 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 1.22 of Blake Exhibit 1.

A. This adjustment is necessary to recover the expenses KU incurred as part of the general management audit conducted by The Liberty Consulting Group pursuant to the Commission's July 30, 2010 Order in Case No. 2009-00548. Pursuant to KRS 278.255(3), KU is permitted to recover the expenses. This adjustment was prepared by Mr. Bellar and is discussed in his testimony.

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

A. This adjustment amortizes the expenses incurred in conjunction with this base rate case. The Commission approved a similar adjustment in Case Nos. 2009-00548 and 2003-00434, and KU proposed such an adjustment in Case No. 2008-00251, which was resolved by a settlement approved by the Commission. This adjustment was prepared by Mr. Bellar and is discussed in his testimony.

Q. Please explain the calculation of the composite income tax rate shown in Reference Schedule 1.29 of Blake Exhibit 1.

A. This schedule, which I am sponsoring, shows the calculation of a composite federal and state income tax rate using a federal corporate income tax rate of 35%, and a Kentucky corporate income tax rate of 6%. The calculation includes a reduction of pre-tax income related to the domestic production activities deduction, enacted by the American Jobs Creation Act of 2004, and allowed by the Internal Revenue Code Section 199 (which was adopted by the state in Kentucky Revised Statutes 141.010), for both federal and state taxes. The current production activities deduction rate is 9% for federal income taxes and 6% for state income taxes. As shown on Reference Schedule 1.29 of Blake Exhibit 1, the composite federal and state income tax rate is

36.7293%. The method for calculating the composite tax rate KU used in this schedule is similar to the method approved by the Commission in Case Nos. 2009-00548 and 2003-00434, as well as the method proposed by KU in Case No. 2008-00251, which was resolved by a settlement approved by the Commission.

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

A. This adjustment, which I am sponsoring, is for federal and state income taxes corresponding to the adjustment of interest expense. The Commission has traditionally recognized the income tax effects of adjustments to interest expense through an "interest synchronization" adjustment. The interest expense included in KU's "Adjusted Kentucky Jurisdictional Capitalization" as of March 31, 2012, is computed from Blake Exhibit 2 and that amount is then compared to KU's interest per books (excluding other interest) to arrive at the interest synchronization amount. The composite federal and state income tax rate from Reference Schedule 1.29 of Blake Exhibit 1 is then applied to the interest synchronization amount. The adjustment will be trued-up as the weighted cost of debt is updated during this proceeding. A similar adjustment was approved by the Commission in Case Nos. 2009-00548 and 2003-00434. KU proposed a similar adjustment in Case No. 2008-00251, which was resolved by a settlement approved by the Commission.

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

A. This adjustment, which I am sponsoring, is to adjust test year income tax expense for out of period and non-recurring items. A similar adjustment was approved by the

Commission in Case Nos. 2009-00548 and 2003-00434. KU also proposed a similar adjustment in 2008-00251, which was resolved by a settlement accepted by the Commission. Specifically, the adjustment on Reference Schedule 1.31 includes income tax true-ups related to the 2011 federal and state income tax returns and the removal of the credit for increasing research activities under U.S. Internal Revenue Code Section 41 as that credit expired on December 31, 2011.

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

A. This adjustment to test year income tax expense adjusts for the permanent reduction in tax depreciation basis due to the proposed change in Trimble County Unit 2's ("TC2") service life. Specifically, the adjustment on Reference Schedule 1.32 relates to the annual amount of permanent reduction in depreciable tax basis required by Internal Revenue Code 50(c) and attributable to the Advanced Coal Investment Tax Credit ("ACITC") awarded to KU and LG&E for TC2. The annual amount of the lost tax basis is the ACITC awarded, amortized over the financial statement life of TC2. This is the same life used to record book depreciation expense. Amortization of this permanent depreciation basis difference is multiplied by the statutory combined federal and state tax rate of 38.9%. KU also proposed a similar adjustment in Case No. 2009-00548, which was resolved by a settlement approved by the Commission.

Q. Please explain the calculation of the gross up factor shown in Reference Schedule 1.34 of Blake Exhibit 1.

A. This schedule, which I am sponsoring, illustrates the calculation of the factor needed to gross up the net operating income deficiency on Blake Exhibit 8 to determine the overall revenue deficiency. The calculation begins with an assumed $100 of incremental revenue and is adjusted for the following charges against that incremental revenue: a factor for bad debt expense that is equal to the percent of net charged-off accounts to revenue during the test year; the Kentucky Public Service Commission assessment factor based on assessment from the Commonwealth of Kentucky Finance and Administrative Cabinet; and federal and state income taxes using the statutory 35% and 6% rates, respectively. The production tax credit, as calculated in Reference Schedule 1.29 is also factored in to the calculation.

The total of the bad debt, Kentucky Public Service Commission assessment, and state and federal income taxes is then divided by the assumed $100 of incremental revenue to express the gross up revenue factor as a percentage.

The Commission has historically recognized the use of a gross-up factor as part of the revenue requirement calculation. This calculation is similar to the method approved by the Commission in Case Nos. 2009-00548 and 2003-00434, as well as the method proposed by KU in Case No. 2008-00251, which was resolved by a settlement approved by the Commission.

Capitalization and Weighted Average Cost of Capital

Q. Have you prepared an exhibit showing KU's capitalization as of March 31, 2012?

A. Yes. Blake Exhibit 2 shows KU's capitalization at March 31, 2012, for electric operations. Mr. Arbough, Treasurer for KU, presents testimony on KU's capitalization structure, as well as on relevant bond financing matters and the cost of debt.

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

A. Yes. Blake Exhibit 2 shows the calculation of KU's adjusted Kentucky jurisdictional capitalization for electric operations as of March 31, 2012, as well as the weighted average cost of capital to apply to the adjusted capitalization in determining net operating income found reasonable on Blake Exhibit 8. As indicated on Blake Exhibit 2, the requested rate of return on electric capitalization as of March 31, 2012, is 7.62 percent, based on the proposed 11.00 percent return on common equity recommended by Dr. Avera, President of FINCAP, Inc., a firm providing financial, economic, and policy consulting services to business and government.

Q. Please explain the calculations of capitalization and cost of capital in Blake Exhibit 2.

A. Column 1 of Blake Exhibit 2 contains the components of capitalization as recorded on the Company's books and records as of the end of the test year, March 31, 2012. Column 2 of Blake Exhibit 2 calculates the relative percentages of each component of capitalization to the total capitalization. Adjustments are made in Columns 3, 4 and 5 to exclude KU's equity investment in Electric Energy Inc. and KU's investment in Ohio Valley Electric Corporation and other investments consistent with the adjustments approved in the Commission's Order in Case Nos. 2009-00548 and 2003-00434 and proposed by KU in Case No. 2008-00251, which was resolved by a settlement approved by the Commission. Those adjustments are accumulated in Column 6 and subtracted from Column 1 to arrive at "Adjusted Total Company Capitalization" in Column 7. Column 8 of Blake Exhibit 2 contains the allocation factor to jurisdictionalize KU's total capitalization to that portion for which rates are established by this Commission. The factor in column 8 was calculated based on net original cost rate base as shown on Blake Exhibit 3. Column 9 calculates the relative Kentucky jurisdictional capitalization components by multiplying column 7 by the factor in column 8. The relative percentage for each component of capitalization is then recomputed in Column 10. Column 11 removes KU's ECR rate base, as more fully explained below, to arrive at Column 12, the Adjusted Kentucky Jurisdictional Capitalization, which is the capitalization used to compute the revenue deficiency in this proceeding. The resulting capital structure in Column 13 is then multiplied by the cost rate for each component of capitalization as shown in Column 14 with the product being the weighted average cost of capital for KU shown in Column 15. The product of "The Adjusted Kentucky Jurisdictional Capitalization" in Column 12 and the "Cost of Capital" in Column 15 represents the net operating income found reasonable used to calculate the revenue deficiency in Blake Exhibit 8.

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

A. Yes. 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. In Column 11, the environmental surcharge rate base is removed from capitalization using a methodology similar to the one approved by the Commission in Case Nos. 98-00474, 2003-00434 and 2009-00548, and as proposed in Case No. 2008-00252, which was resolved by a settlement approved by the Commission. The methodology utilized to remove the ECR amounts from rate base is discussed in Mr. Conroy's testimony. Also, as discussed in Mr. Conroy's testimony, the amount of ECR rate base removed also reflects the elimination of the 2005 and 2006 ECR Plans from KU's monthly ECR filings.

Q. Please explain the annual cost rates included in Column 14 of Blake Exhibit 2.

A. Column 14 (Annual Cost Rate) includes the embedded costs of the components of capital, including the proposed return on equity. The cost of equity is the amount recommended by Dr. Avera and supported in his testimony. The annual rate used for Short Term Debt and Long-Term Debt are the actual rates as of March 31, 2012. Following the Commission's approval in its Orders in Case Nos. 2010-00204 and 2010-00206, on November 1, 2010, the Company replaced its loans totaling $1.5 billion from Fidelia Corporation with new loans from PPL Investment Corporation. KU issued the following three series of First Mortgage Bonds in November 2010: $250 million at 1.625% maturing November 1, 2015; $500 million at 3.250% maturing November 1, 2020; and $750 million at 5.125% maturing November 1, 2040. The weighted average interest rate on these first mortgage bonds is 3.92% and the average maturity is slightly over 19 years. When combined with the current rates on KU's tax-exempt pollution control bonds, the resulting weighted average rate on KU's long-term debt is 3.69%. The details of KU's financing are described in the testimony of Mr. Arbough.

Property Valuation

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

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

Q. Have you prepared an exhibit showing KU's net original cost rate base as of March 31, 2012?

A. Yes. Page 1 of Blake Exhibit 3 shows KU's net original cost rate base at March 31, 2012. Page 2 of Blake Exhibit 3 shows the calculation of the allowance for cash working capital. The 45-day (1/8) methodology was used in computing the allowance for cash working capital.

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

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

> 1) Approving the regulatory assets and liabilities associated with adopting SFAS No. 143 and going forward;[7]
>
> 2) Eliminating the impact on net operating income in the 2003 ESM annual filing caused by adopting SFAS No. 143;
>
> 3) To the extent accumulated depreciation related to the cost of removal is recorded in regulatory assets or regulatory liabilities, reclassifying such amounts to accumulated depreciation for rate-making purposes of calculating rate base; and
>
> 4) Excluding from rate base the ARO [Asset Retirement Obligation] assets, related ARO asset accumulated

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

> depreciation, ARO liabilities, and remaining regulatory assets associated with the adoption of SFAS No. 143.[8]

In Case No. 2003-00434, KU excluded ARO assets from rate base.[9] The Commission approved the exclusion in its June 30, 2004 Order in that proceeding.[10] The Commission approved the exclusion in the Company's most recent rate case, 2009-00548. KU similarly excluded such amounts in Case No. 2008-00251, which was resolved by a settlement approved by the Commission.

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

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

A. As approved in the Commission's order in Case No. 2007-00178, it is proper for KU to exclude from rate base the amount of investment tax credits it receives.[11] The deduction from rate base associated with the investment tax credits KU has received is shown in row 10 of Blake Exhibit 3, Page 1.

Q. Have you prepared an exhibit showing KU's pro forma rate base as of March 31, 2012?

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

[9] *In the Matter of: An Adjustment of the Electric Rates, Terms and Conditions of Kentucky Utilities Company*, Case No. 2003-00434, KU Response No. 38 to Commission Staff's Third Set of Data Requests (March 11, 2004).

[10] *In the Matter of: An Adjustment of the Electric Rates, Terms and Conditions of Kentucky Utilities Company*, Case No. 2003-00434, Order at 21 (June 30, 2004).

[11] *In the Matter of: Application of Kentucky Utilities Company for an Order Authorizing Inclusion of Investment Tax Credits in Calculation of Environmental Surcharge and Declaring Appropriate Rate-Making Methods for Base Rates*, Case No. 2007-00178, Order at 6-7 (September 7, 2007).

A. Yes. Blake Exhibit 4 shows KU's pro forma rate base as of March 31, 2012. This exhibit reflects the adjustments I previously described in connection with Blake Exhibit 2. In addition, the rate base impact of the annualized depreciation expense adjustment and cash working capital amount associated with the operations and maintenance expense adjustments are reflected. This exhibit also contains the adjustments I previously described in connection with Blake Exhibit 3 concerning the asset retirement obligation items and the investment tax credit.

Q. Have you prepared an exhibit showing KU's estimated net reproduction cost rate base as of March 31, 2012?

A. Yes. The estimated net reproduction cost rate base at March 31, 2012, is shown on Blake Exhibit 5. The calculation of the reproduction cost of plant less depreciation used in developing the reproduction cost rate base shown in Blake Exhibit 5 was calculated under my supervision and is shown on Blake Exhibit 6.

Q. Please explain Blake Exhibit 6.

A. Blake Exhibit 6 shows KU's estimated reproduction (or current) cost of utility plant and the applicable accumulated depreciation on the reproduction cost of utility plant as of March 31, 2012. The net estimated reproduction cost at March 31, 2012, is approximately $2.9 billion greater, on a total company basis, than the net original historical cost as recorded on KU's books. The current costs were determined principally by indexing the surviving plant and equity using the Handy-Whitman Index of Public Utility Construction Costs and the Consumer Price Index.

Q. Have you prepared an exhibit showing the calculation of the actual and proposed rate of return on net original cost rate base, pro forma rate base, and reproduction cost rate base for the twelve months ended March 31, 2012?

A. Yes. Blake Exhibit 7 shows the actual rate of return earned for the twelve months ended March 31, 2012, was 5.79 percent on jurisdictional net original cost rate base, 6.12 percent on jurisdictional pro forma rate base, and 3.31 percent on jurisdictional reproduction cost rate base. Using the adjusted net operating income from Blake Exhibit 1 and the revenue increase in the application, results in a requested rate of return of 7.18 percent on jurisdictional net original cost rate base, 7.59 percent on jurisdictional pro forma rate base, and 4.11 percent on jurisdictional reproduction cost rate base.

Q. Have you prepared an exhibit showing the calculation of the overall revenue deficiency at March 31, 2012 for KU?

A. Yes. Blake Exhibit 8 shows the calculation of the revenue deficiency at March 31, 2012 for KU to be $82,448,833.

Q. Have you prepared an exhibit showing the calculation of Kentucky jurisdictional rate of return on common equity for the twelve months ended March 31, 2012?

A. Yes. Blake Exhibit 9 shows the return for KU's Kentucky retail jurisdictional electric operations for the twelve months ended March 31, 2012, is 6.05 percent, including an 8.08 percent return on common equity.

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

A. Kentucky Utilities Company recommends the Commission approve the recovery of the revenue deficiency of $82,448,833 through the proposed changes in electric base rates.

Q. Does this conclude your testimony?

A. Yes.

VERIFICATION

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

The undersigned, **Kent W. Blake**, being duly sworn, deposes and says that he is Chief Financial Officer for Kentucky Utilities Company and Louisville Gas and Electric Company and an employee of LG&E and KU Services Company, and that he has personal knowledge of the matters set forth in the foregoing testimony, and that the answers contained therein are true and correct to the best of his information, knowledge and belief.

Kent W Blake
Kent W. Blake

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 15th day of June 2012.

Notary Public (SEAL)

My Commission Expires:

July 21, 2015

Kent W. Blake

Chief Financial Officer
LG&E and KU Energy LLC
220 West Main Street
P. O. Box 32010
Louisville, Kentucky 40202

Previous Positions

LG&E and KU Energy LLC (f.k.a. E.ON U.S., LG&E Energy LLC)

Vice President, Corporate Planning and Development	2007 – 2012
Vice President, State Regulation and Rates Director, State Regulation and Rates Director, Regulatory Initiatives	2003 – 2007
Director, Business Development Director, Finance and Business Analysis	2002 – 2003

Mirant Corporation (f.k.a. Southern Company Energy Marketing) Senior Director, Applications Development Director, Systems Integration Trading Controller	1998 – 2002
LG&E Energy Corp. Director, Corporate Accounting and Trading Controls	1997 – 1998
Arthur Andersen LLP Manager, Audit and Business Advisory Services Senior Auditor Audit Staff	1988 – 1997

Education

University of Kentucky, B.S. in Accounting, 1988
Certified Public Accountant, Kentucky, 1991

Professional and Community Affiliations

American Institute of Certified Public Accountants
Finance Executive Advisory Committee of the Edison Electric Institute
Financial Executives Institute
Leadership Louisville, 2007
CASA of the River Region, Vice Chair of the Board

Blake Exhibit 1

Adjustments to Operating Revenue, Operating Expenses and Net Operating Income

KENTUCKY UTILITIES

Adjustments to Operating Revenues, Operating Expenses and Net Operating Income
For the Twelve Months Ended March 31, 2012

	Reference Schedule (1)	Operating Revenues (2)	Operating Expenses (3)	Net Operating Income (4)
1. Jurisdictional amount per books		1,342,076,920	1,139,327,996	$ 202,748,924
2. Adjustments for known changes and to eliminate unrepresentative conditions:				
3. Adjustment to eliminate unbilled revenues	1.00	5,107,000	-	5,107,000
4. To adjust mismatch in fuel cost recovery	1.01	(9,156,061)	(12,785,149)	3,629,088
5. To adjust base rates and FAC to reflect a full year of the FAC roll-in	1.02	2,885,839	-	2,885,839
6. Adjustment to reflect changes to FAC calculations	1.03	(2,638,801)	(2,614,696)	(24,105)
7. Adjustment to eliminate Environmental Surcharge revenues and expenses	1.04	(14,710,734)	(9,309,387)	(5,401,347)
8. Off-system sales revenue adjustment for the ECR calculation	1.05	(296,088)	-	(296,088)
9. To eliminate DSM revenues and expenses	1.06	(15,401,724)	(13,589,518)	(1,812,206)
10. To eliminate rate mechanism revenue accruals	1.07	(8,438,658)	-	(8,438,658)
11. To eliminate net brokered and financial swap revenues and expenses	1.08	294,881	(6,018)	300,899
12. To adjust Off-system sales margins	1.09	(292,995)	-	(292,995)
13. Adjustment to annualize year-end customers	1.10	(3,407,542)	(1,909,033)	(1,498,509)
14. To adjust for customer rate switching and bill adjustments	1.11	(8,348,788)	-	(8,348,788)
15. Adjustment to reflect annualized depreciation expenses	1.12	-	712,846	(712,846)
16. Adjustment to reflect increases in labor and labor related costs	1.13	-	2,883,454	(2,883,454)

KENTUCKY UTILITIES

Adjustments to Operating Revenues, Operating Expenses and Net Operating Income
For the Twelve Months Ended March 31, 2012

	Reference Schedule (1)	Operating Revenues (2)	Operating Expenses (3)	Net Operating Income (4)
17. Adjustment for pension, post retirement, and post employment costs	1.14	-	(4,067,870)	4,067,870
18. Adjustment to reflect normalized storm damage expense	1.15	-	(834,318)	834,318
19. Adjustment for injuries and damages FERC account 925	1.16	-	(1,233,028)	1,233,028
20. Adjustment to eliminate advertising expenses pursuant to Commission Rule 807 KAR 5:016	1.17	-	(808,453)	808,453
21. Adjustment to remove out-of-period items	1.18	23,287	(475,875)	499,162
22. Adjustment to reflect increase in property insurance expense	1.19	-	1,079,050	(1,079,050)
23. Adjustment for transfer of Independent Transmission Operator functions	1.20	-	(3,328,434)	3,328,434
24. Adjustment for MISO exit regulatory asset / liability	1.21	-	(1,509,951)	1,509,951
25. Adjustment for General Management audit regulatory asset	1.22	-	47,507	(47,507)
26. Adjustment for rate case expense amortization	1.23	-	(25,313)	25,313
27. These adjustments left intentionally blank	1.24 - 1.28			
28. Total of above adjustments		(54,380,384)	(47,774,186)	(6,606,198)

KENTUCKY UTILITIES

Adjustments to Operating Revenues, Operating Expenses and Net Operating Income
For the Twelve Months Ended March 31, 2012

		Reference Schedule (1)	Operating Revenues (2)	Operating Expenses (3)	Net Operating Income (4)
29. Federal and state income taxes corresponding to base revenue and expense adjustments and above adjustments -	36.7473 %	1.29		(2,427,596)	2,427,596
30. Federal and state income taxes corresponding to annualization and adjustment of year-end interest expense		1.30		145,218	(145,218)
31. Prior income tax true-ups and adjustments		1.31		(436,228)	436,228
32. Adjustment for tax basis depreciation reduction		1.32		(331,159)	331,159
33. This adjustment left intentionally blank		1.33			
34. Total adjustments			(54,380,384)	(50,823,951)	(3,556,433)
35. Adjusted Net Operating Income			1,287,696,536	1,088,504,045	$ 199,192,491

Exhibit 1
Reference Schedule 1.00
Sponsoring Witness: Bellar

KENTUCKY UTILITIES

Adjustment to Eliminate Unbilled Revenues

1. Unbilled revenues at March 31, 2011	$	61,634,000
2. Unbilled revenues at March 31, 2012		(56,527,000)
3. Increase/(Decrease) in book revenues due to unbilled revenues	$	5,107,000

Exhibit 1
Reference Schedule 1.01
Sponsoring Witness: Conroy

KENTUCKY UTILITIES

To Adjust Mismatch in Fuel Cost Recovery
For the Twelve Months Ended March 31, 2012

Expense Month	Revenue Form A Page 5 of 6 Line 3	Expense Form A* Page 5 of 6 Line 8
Apr-11	(413,989)	373,214
May-11	(764,843)	1,868,842
Jun-11	442,436	1,659,021
Jul-11	2,203,882	5,453,175
Aug-11	1,897,425	4,052,858
Sep-11	5,048,751	2,211,016
Oct-11	3,444,797	(2,873,345)
Nov-11	2,048,455	(786,511)
Dec-11	(3,104,271)	(553,491)
Jan-12	(903,167)	(171,525)
Feb-12	(596,277)	834,055
Mar-12	(147,138)	717,840
Total	$ 9,156,061	$ 12,785,149
Adjustment	$ (9,156,061)	$ (12,785,149)

* NOTE : Expenses are recovered in the second succeeding month. For example, January 2012 would be reflected in March 2012.

Exhibit 1
Reference Schedule 1.02
Sponsoring Witness: Conroy

KENTUCKY UTILITIES

To Adjust Base Rates and FAC to Reflect a Full Year of the FAC Roll-In
For the Twelve Months Ended March 31, 2012

1. Adjustment to base rate revenues to reflect a full year of the FAC Roll-In (a)		(3,616,225)
2. Adjustment to FAC revenues to reflect a full year of the FAC Roll-In (a)		6,502,064
3. Net adjustment	$	2,885,839

(a) FAC roll-in pursuant to Commission's Order dated May 31, 2011 in Case No. 2010-00492.

Exhibit 1
Reference Schedule 1.03
Sponsoring Witness: Conroy

KENTUCKY UTILITIES

Adjustment to Reflect Changes to FAC Calculations
For the Twelve Months Ended March 31, 2012

1. Revenue adjustment	$	(2,638,801)
2. Expense adjustment		(2,614,696)
3. Net adjustment	$	(24,105)

Exhibit 1
Reference Schedule 1.04
Sponsoring Witness: Conroy

KENTUCKY UTILITIES

Adjustment to Eliminate Environmental Surcharge Revenues and Expenses
For the Twelve Months Ended March 31, 2012

Expense Month	(1) Environmental Compliance Revenues Collected in Base Rates (a)	(2) Environmental Compliance Revenues Collected in Environmental Surcharge (b)	(3) 2005-2006 Environmental Compliance Plans Jurisdictional Revenues (c)	(4) Net Revenues Environmental Compliance Plans (Col. 1 + 2 - 3)	(5) Total Expenses Environmental Compliance Plans (d)	(6) 2005-2006 Environmental Compliance Plans Expenses (c)	(7) Net Expenses Environmental Compliance Plans (Col. 5 - 6)
Apr-11	10,044,427	2,360,485	13,571,366		5,623,331	4,954,068	
May-11	9,618,565	2,471,733	13,144,590		5,865,737	5,071,649	
Jun-11	11,018,257	3,699,167	13,061,693		6,103,676	5,027,921	
Jul-11	11,760,729	4,011,785	13,189,522		5,974,461	5,008,839	
Aug-11	12,465,088	3,072,496	13,808,222		6,556,599	5,522,113	
Sep-11	11,546,729	2,188,184	13,315,107		5,920,213	4,965,558	
Oct-11	10,611,735	1,928,584	12,862,646		5,767,324	4,875,776	
Nov-11	9,449,751	2,749,517	13,266,778		6,090,400	5,198,650	
Dec-11	10,705,782	3,531,568	12,746,938		6,183,636	5,220,901	
Jan-12	11,614,699	5,588,609	12,518,128		6,251,449	5,298,360	
Feb-12	11,968,252	4,527,378	12,866,061		5,983,761	5,301,715	
Mar-12	12,765,005	2,508,560	13,145,301		6,607,594	5,740,205	
	$ 133,569,019	$ 38,638,067	$ 157,496,352	$ 14,710,734	$ 72,928,181	$ 62,185,755	$ 10,742,426
Kentucky Jurisdiction (Ref. Sch. Allocators)					86.660%	86.660%	86.660%
Total				$ 14,710,734	$ 63,199,562	$ 53,890,175	$ 9,309,387
Adjustment				$ (14,710,734)			$ (9,309,387)

(a) ES Form 1.10, Line 13 for Apr-Nov; Line 17 for Dec, Line 13 for Jan-Mar expense month filings.
(b) ES Form 3.00, Column 5 for Apr-Nov, Column 6 for Dec-Mar expense month filings.
(c) Conroy Exhibit P4, Page 2, Lines 22 and 23
(d) ES Form 2.00, Total Pollution Control Operations Expense and Net Beneficial Reuse Operations Expense less Proceeds from By-Product and Allowance Sales.

KENTUCKY UTILITIES

Off-System Sales Revenue Adjustment for the ECR Calculation
For the Twelve Months Ended March 31, 2012

	(1)	(2)	(3)	(4)
	KU Off-System Sales Revenue	Total Environmental Surcharge Factor	Average Environmental Surcharge Factor	Off-System Sales Environmental Cost (Col. 1 * 3)
		(Page 2, Col. 5)		
Apr-11	949,605	0.18%	1.13%	10,731
May-11	3,354,999	0.27%	1.13%	37,911
Jun-11	4,125,254	0.59%	1.13%	46,615
Jul-11	3,209,313	0.56%	1.13%	36,265
Aug-11	1,733,633	0.69%	1.13%	19,590
Sep-11	2,458,310	1.49%	1.13%	27,779
Oct-11	5,362,669	1.56%	1.13%	60,598
Nov-11	2,048,034	1.62%	1.13%	23,143
Dec-11	3,345,362	2.02%	1.13%	37,803
Jan-12	2,649,618	1.51%	1.13%	29,941
Feb-12	408,013	1.43%	1.13%	4,611
Mar-12	557,230	1.69%	1.13%	6,297
Total	$ 30,202,040			$ 341,284
Average		1.13%		
Kentucky Jurisdiction (Ref. Sch. Allocators)				86.757%
Total				$ 296,088
Adjustment				$ (296,088)

KENTUCKY UTILITIES

Off-System Sales Revenue Adjustment for the ECR Calculation
For the Twelve Months Ended March 31, 2012

	(1)	(2)	(3)	(4)	(5)
	Adjusted Jurisdictional E(m) (a)	'05-'06 Environmental Compliance Plans Jurisdictional Revenues (b)	Net Adjusted Jurisdictional E(m)	Jurisdictional R(m) (c)	Total Environmental Surcharge Factor
			(Col. 1 - 2)		(Col. 3 / 4)
Apr-11	13,768,044	13,571,366	196,678	107,531,674	0.18%
May-11	13,439,156	13,144,590	294,566	108,246,609	0.27%
Jun-11	13,701,297	13,061,693	639,604	109,115,040	0.59%
Jul-11	13,799,729	13,189,522	610,207	109,303,925	0.56%
Aug-11	14,565,804	13,808,222	757,582	109,140,745	0.69%
Sep-11	14,929,529	13,315,107	1,614,422	108,584,502	1.49%
Oct-11	14,559,276	12,862,646	1,696,630	108,871,982	1.56%
Nov-11	15,026,352	13,266,778	1,759,574	108,673,513	1.62%
Dec-11	14,920,920	12,746,938	2,173,982	107,595,608	2.02%
Jan-12	14,113,779	12,518,128	1,595,651	105,753,858	1.51%
Feb-12	14,375,570	12,866,061	1,509,509	105,423,640	1.43%
Mar-12	14,920,415	13,145,301	1,775,114	105,145,369	1.69%
Average					1.13%

(a) ES Form 1.10
(b) Conroy Exhibit P4, Page 2, Line 22
(c) ES Form 1.10 (Apr-11 through Dec-11); ES Form 3.00 (Jan-12 through Mar-12)

Exhibit 1
Reference Schedule 1.06
Sponsoring Witness: Scott

KENTUCKY UTILITIES

To Eliminate DSM Revenues and Expenses
For the Twelve Months Ended March 31, 2012

1. DSM Revenue adjustment	$	(15,401,724)
2. DSM Expense adjustment		(13,589,518)
3. Net Adjustment	$	(1,812,206)

KENTUCKY UTILITIES

To Eliminate Rate Mechanism Revenue Accruals
For the Twelve Months Ended March 31, 2012

1. ECR Accrued Revenue in Accounts 440-445	$	900,841
2. MSR and VDT Accrued Revenue in Accounts 440-445		640
3. FAC Accrued Revenue in Accounts 440-445		2,254,000
4. DSM Accrued Revenue in Accounts 440-445		5,283,177
5. Total Kentucky Jurisdictional Accrued Revenues	$	8,438,658
6. Total Adjustment	$	(8,438,658)

Exhibit 1
Reference Schedule 1.08
Sponsoring Witness: Scott

KENTUCKY UTILITIES

To Eliminate Net Brokered and Financial Swap Revenues and Expenses
For the Twelve Months Ended March 31, 2012

1. Brokered and Financial Swap Revenues	$	211,888	
2. Brokered and Financial Swap Expenses recorded in revenues		551,781	
3. Net Brokered and Financial Swap Revenues		(339,893)	
4. Kentucky Jurisdiction (Ref. Sch. Allocators)		86.757%	
5. Kentucky Jurisdiction Net Brokered and Financial Swap Revenues	$	(294,881)	
6. Kentucky Jurisdiction Net Brokered and Financial Swap Revenues adjustment	$	294,881	
7. Operating Expenses related to Brokered and Financial Swap		6,937	*
8. Kentucky Jurisdiction (Ref. Sch. Allocators)		86.757%	
9. Kentucky Jurisdiction Brokered and Financial Swap Operating Expenses	$	6,018	
10. Kentucky Jurisdiction Net Brokered and Financial Swap Operating Expenses adjustment	$	(6,018)	
11. Net Kentucky Jurisdictional adjustment (Line 6 - Line 10)	$	300,899	

*NOTE: Reflects 0.17% of total labor and labor related costs from regulated trading sales activities.

Exhibit 1
Reference Schedule 1.09
Sponsoring Witness: Bellar

KENTUCKY UTILITIES

To Adjust Off-System Sales Margins
For the Twelve Months Ended March 31, 2012

1. Off-System Sales Margins for 2012 (January - March 2012)	$	141,329
2. Annualized Off-System Sales Margins for 2012 (Line 1 x 4)	$	565,314
3. Off-System Sales Margins in test year	$	903,033
4. Off-System Sales Margins adjustment (Line 2 - Line 3)	$	(337,719)
5. Kentucky Jurisdiction (Ref. Sch. Allocators)		86.757%
6. Kentucky Jurisdictional adjustment	$	(292,995)

NOTE: Off-System sales margins defined as Total OSS revenues less assigned fuel and purchase power expense, transmission costs, environmental costs, and cost of losses.

Exhibit 1
Reference Schedule 1.10
Sponsoring Witness: Conroy

KENTUCKY UTILITIES

Adjustment to Annualize Year-End Customers
At March 31, 2012

1. Revenue adjustment	$	(3,407,542)
2. Expense adjustment		(1,909,033)
3. Net adjustment	$	(1,498,509)

Exhibit 1
Reference Schedule 1.11
Sponsoring Witness: Conroy

KENTUCKY UTILITIES

To Adjust for Customer Rate Switching and Bill Adjustments
As Applied to the Twelve Months Ended March 31, 2012

1. Rate Switch - to RS	$ (30,891)
2. Rate Switch - to GS	(3,346,954)
3. Rate Switch - to PS	(6,739,872)
4. Rate Switch - to TODS	2,518,028
5. Rate Switch - to TODP	4,838,577
6. Rate Switch - to AES	(20,438)
7. Rate Switch - to TE	70
8. Bill Adjustments	(5,567,308)
9. Total Adjustment	$ (8,348,788)

KENTUCKY UTILITIES

Adjustment To Reflect Annualized Depreciation Expenses
At December 31, 2011

1. Annualized direct depreciation expense under proposed rates	$ 144,441,326
2. Annualized depreciation for 2005 and 2006 ECR plans to be eliminated	45,422,676
3. Total annualized depreciation expense	$ 189,864,002
4. Depreciation expense per books for test year	$ 192,192,743
5. Depreciation expense for asset retirement costs (ARO)	(3,077,746)
6. Depreciation for environmental cost recovery (ECR) plans (1)	(67,949)
7. Depreciation expense per books excluding ARO and ECR	$ 189,047,048
8. Total Adjustment to reflect annualized depreciation expense (Line 3 - Line 7)	$ 816,954
9. Kentucky Jurisdiction (Ref. Sch. Allocators)	87.257%
10. Kentucky Jurisdictional adjustment	$ 712,846

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

KENTUCKY UTILITIES

Adjustment to Reflect Increases in Labor and Labor-Related Costs
As Applied to the Twelve Months Ended March 31, 2012

1	Wages (Page 2)	$	2,921,352
2	Payroll Taxes (Page 3)		208,708
3	401(k) (Page 4)		112,034
4	Total	$	3,242,094
5	Kentucky Jurisdiction (Ref. Sch. Allocators)		88.938%
6	Kentucky Jurisdictional Adjustment	$	2,883,454

KENTUCKY UTILITIES

Adjustment to Reflect Increases in Labor and Labor-Related Costs
As Applied to the Twelve Months Ended March 31, 2012

				Construction/	
1	Labor for 12 months ended March 31, 2012		Operating	Other	Total
2	Base		$ 89,007,797	$ 35,964,453	$ 124,972,250
3	Overtime and Premium		11,900,917	4,332,635	16,233,552
4	Total Labor (Sum of Lines 2 - 3)		$ 100,908,714	$ 40,297,088	$ 141,205,802
5	Total Operating and Construction/Other %		71.462%	28.538%	100.000%
6	Annualized base labor at March 31, 2012:				
7	Union - KU		100% of total		$ 9,418,594
8	Exempt - KU		100% of total		12,455,730
9	Non-Exempt - KU		100% of total		12,012,756
10	Hourly - KU		100% of total		31,062,533
11	Exempt - Servco (allocated to KU)		52.506% of total		49,064,097
12	Non-Exempt - Servco (allocated to KU)		52.506% of total		9,205,183
13	Union - LGE (allocated to KU)		8.132% of total		3,750,780
14	Exempt - LGE (allocated to KU)		8.132% of total		1,820,791
15	Non-Exempt - LGE (allocated to KU)		8.132% of total		214,421
16	Total Annualized Base Labor (Sum of Lines 7 - 15)				$ 129,004,885
17	Overtime & Premiums - (increases allocated as noted):				16,229,581
18	Wage increase applied to KU union and hourly overtime annualized (04/01/11 - 07/16/11 OT Labor x 3.0%)				4,603
19	Wage increase applied to KU non-exempt overtime annualized (04/01/11 - 02/25/2012 OT Labor x 3.0%)				20,167
20	Wage increase applied to LG&E union overtime annualized (04/01/11 -11/13/2011 OT labor x 2.5%)				18,057
21	Wage increase applied to LG&E non-exempt overtime annualized (04/01/2011 - 02/19/12 OT Labor x 3.0%)				198
22	Wage increase applied to Servco non-exempt overtime annualized (04/01/11 - 02/19/12 OT Labor x 3.0%)				16,603
23	Total Annualized Labor (Sum of Lines 16 - 22)				$ 145,294,094
24	Operating Labor based on annualized labor	$ 145,294,094 x	71.462%		$ 103,830,066
25	Less: Test Year Operating Labor for 12 months ending 03/31/2012 (Line 4)				100,908,714
26	Labor Adjustment Total (Line 24 - Line 25)				$ 2,921,352

KENTUCKY UTILITIES

Adjustments to Reflect Increases in Payroll Taxes
As Applied to the Twelve Months Ended March 31, 2012

1	Operating Labor increase (Page 2 Line 26)	$ 2,921,352
2	Percentage of wages that do not exceed Social Security (OASDI) limit	91.842%
3	Operating Labor increase subject to Social Security tax (Line 1 x Line 2)	$ 2,683,028
4	Medicare Tax (Line 1 x 1.45%)	$ 42,360
5	Social Security Tax (Line 3 x 6.2%)	166,348
6	Payroll Tax adjustment (Line 4 + Line 5)	$ 208,708

KENTUCKY UTILITIES

Adjustment to Reflect Increases in Company Contribution to 401(k)
As Applied to the Twelve Months Ended March 31, 2012

1	Total Labor (Page 2 Line 4)	$ 141,205,802
2	Total TIA for 12 months ended 03/31/2012	11,333,264
3	Direct total payroll for 12 months ended 03/31/2012 (Line 1 + Line 2)	$ 152,539,066
4	Total 401(k) Company Match for 12 months ended 03/31/2012	5,850,075
5	401(k) Company Match as a percent of payroll (Line 4÷ Line 3)	3.835%
6	Operating Labor increase (Page 2 Line 26)	2,921,352
7	401(k) Company Match operating increase (Line 5 x Line 6)	$ 112,034

Exhibit 1
Reference Schedule 1.14
Sponsoring Witness: Arbough

KENTUCKY UTILITIES

Adjustment for Pension, Post Retirement, and Post Employment Costs
For the Twelve Months Ended March 31, 2012

	Pension	Post Retirement	Post Employment	Total
1. Pension, Post Retirement and Post Employment expenses in test year	$ 17,858,278	$ 4,485,762	$ 966,658	$ 23,310,698
2. Pension, Post Retirement, and Post Employment expenses annualized for 2012 Mercer Study	14,294,397	4,147,547	294,927	18,736,871
3. Total adjustment (Line 2 - Line 1)	$ (3,563,881)	$ (338,215)	$ (671,731)	$ (4,573,827)
4. Kentucky Jurisdiction (Ref. Sch. Allocators)				88.938%
5. Kentucky Jurisdictional adjustment				$ (4,067,870)

Exhibit 1
Reference Schedule 1.15
Sponsoring Witness: Scott

KENTUCKY UTILITIES

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

1. Storm damage provision based upon ten year average	$	4,107,435
2. Storm damage expenses incurred during the 12 months ended March 31, 2012		4,994,206
3. Adjustment		(886,771)
4. Kentucky Jurisdiction		94.085%
5. Kentucky Jurisdictional adjustment	$	(834,318)

Year		Expense (a)		CPI-All Urban Consumers		Amount
2012	$	4,994,206		1.0000	$	4,994,206
2011		3,998,403		1.0069		4,025,992
2010		2,626,597		1.0387		2,728,246
2009		5,225,248	(b)	1.0558		5,516,817
2008		6,951,799	(b)	1.0520		7,313,293
2007		2,035,291		1.0924		2,223,352
2006		4,113,534		1.1235		4,621,555
2005		2,539,379		1.1598		2,945,172
2004		4,120,482		1.1990		4,940,458
2003		1,434,000		1.2310		1,765,254
Total					$	41,074,345
Ten Year Average					$	4,107,435

(a) 2012 expense is for 12 months ended March 31, 2012.
All other years expenses are for calendar year.

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

Exhibit 1
Reference Schedule 1.16
Sponsoring Witness: Scott

KENTUCKY UTILITIES

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

1. Injury/Damage provision based upon ten year average	$ 2,174,114
2. Injury/Damage expenses incurred during the 12 months ended March 31, 2012	3,560,504
3. Adjustment	(1,386,390)
4. Kentucky Jurisdiction (Ref. Sch. Allocators)	88.938%
5. Kentucky Jurisdictional adjustment	$ (1,233,028)

Year	Amount (a)	CPI-All Urban Consumers	Adjusted Amount
2012	$ 3,560,504	1.0000	$ 3,560,504
2011	3,080,346	1.0069	3,101,601
2010	2,451,761	1.0387	2,546,644
2009	1,840,625	1.0558	1,943,332
2008	1,226,235	1.0520	1,289,999
2007	1,178,212	1.0924	1,287,079
2006	1,690,654	1.1235	1,899,450
2005	2,268,036	1.1598	2,630,468
2004	1,080,732	1.1990	1,295,798
2003	1,776,006	1.2310	2,186,263
Total			$ 21,741,138
Ten Year Average			$ 2,174,114

(a) 2012 expense is for 12 months ended March 31, 2012.
All other years expenses are for calendar year.

KENTUCKY UTILITIES

Adjustment to Eliminate Advertising Expenses
Pursuant to Commission Rule 807 KAR 5:016
For the Twelve Months Ended March 31, 2012

1. Uniform System of Accounts - Account No. 930.1 General Advertising Expenses	$	827,234
2. Account No. 913 Advertising Expenses		23,966
3. Total		851,200
4. Kentucky Jurisdiction (Ref. Sch. Allocators)		94.978%
5. Kentucky Jurisdictional amount	$	808,453
6. Kentucky Jurisdictional adjustment	$	(808,453)

Exhibit 1
Reference Schedule 1.18
Sponsoring Witness: Scott

KENTUCKY UTILITIES

Adjustment to Remove Out-of-Period Items
For the Twelve Months Ended March 31, 2012

	Revenue	Expense
1. Out of Period adjustments:		
2. Prepaid Insurance	$ -	$ (251,390)
3. Reclassify from Capital to O&M		(156,554)
4. Transportation Management System		(104,151)
5. Injuries and Damages		(63,388)
6. Other	24,655	31,965
7. Total Out of Period adjustments	$ 24,655	$ (543,518)
8. Kentucky Jurisdiction (Ref. Sch. Allocators)	94.452%	87.554%
9. Kentucky Jurisdictional adjustment	$ 23,287	$ (475,875)

Exhibit 1
Reference Schedule 1.19
Sponsoring Witness: Arbough

KENTUCKY UTILITIES

Adjustment to Reflect Increase in Property Insurance Expense
For the Twelve Months Ended March 31, 2012

1. Property Insurance expense in test year	$	3,297,759
2. Property Insurance renewal premium for 2012/2013		4,537,049
3. Total Adjustment (Line 2 - Line 1)	$	1,239,290
4. Kentucky Jurisdiction (Ref. Sch. Allocators)		87.070%
5. Kentucky Jurisdictional adjustment	$	1,079,050

Exhibit 1
Reference Schedule 1.20
Sponsoring Witness: Bellar

KENTUCKY UTILITIES

Adjustment for Transfer of Independent Transmission Operator Functions
For the Twelve Months Ended March 31, 2012

1. SPP ITO Expenses in test year	$	5,659,872
2. TranServ ITO Expenses (12 months)		1,814,150
3. Total Adjustment (Line 2 - Line 1)	$	(3,845,722)
4. Kentucky Jurisdiction (Ref. Sch. Allocators)		86.549%
5. Kentucky Jurisdictional Adjustment	$	(3,328,434)

Exhibit 1
Reference Schedule 1.21
Sponsoring Witness: Scott

KENTUCKY UTILITIES

Adjustment for MISO Exit Regulatory Asset / Liability
For the Twelve Months Ended March 31, 2012

1. Kentucky Jurisdiction MISO Exit Fee Regulatory Asset at March 31, 2012	$	1,300,786
2. Kentucky Jurisdiction Cumulative MISO Exit Fee Refund Regulatory Liability at March 31, 2012		(949,289)
3. Kentucky Jurisdiction Net MISO Exit Fee Regulatory Asset / (Liability) at March 31, 2012 (Line 1 + Line 2)	$	351,496
4. Less Amortization accrual for post test year (April 2012 - December 2012)		918,058
5. Less Regulatory Liability accrual for post test year (April 2012 - December 2012)		291,061
6. Kentucky Jurisdiction Net MISO Exit Fee Regulatory Asset / (Liability) (before amortization) at December 31, 2012 (Line 3 - Line 4 - Line 5)	$	(857,622)
7. Amortization period in years		3
8. Amortization per year	$	(285,874)
9. Less Amortization recorded in test year (April 2011 - March 2012)		1,224,077
10. Adjustment to Test Year Amortization	$	(1,509,951)

Exhibit 1
Reference Schedule 1.22
Sponsoring Witness: Bellar

KENTUCKY UTILITIES

Adjustment for General Management Audit Regulatory Asset
For the Twelve Months Ended March 31, 2012

1. General Management Audit Regulatory Asset	$	142,521
2. Amortization period in years		3
3. Amortization per year	$	47,507
4. Less Amortization recorded in test year		-
5. Adjustment to Test Year Amortization	$	47,507

Exhibit 1
Reference Schedule 1.23
Sponsoring Witness: Bellar

KENTUCKY UTILITIES

Adjustment for Rate Case Expense Amortization
For the Twelve Months Ended March 31, 2012

1. Total Estimated cost of 2012 Rate Case	$	2,030,000
2. Amortization period in years		3
3. Annual amortization	$	676,667
4. 2012 Rate Case amortization included in test year		-
5. Net Adjustment for 2012 Rate Case expenses	$	676,667
6. 2009 Rate Case Annual amortization	$	391,722
7. 2009 Rate Case Annual amortization included in test year		(671,523)
8. Net Adjustment for 2009 Rate Case expenses	$	(279,801)
9. 2008 Rate Case Annual amortization	$	-
10. 2008 Rate Case Annual amortization included in test year		(422,179)
11. Net Adjustment for 2008 Rate Case expenses	$	(422,179)
12. Total Adjustment (Line 5 + Line 8 + Line 11)	$	(25,313)

KENTUCKY UTILITIES

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Exhibit 1
Reference Schedule 1.29
Sponsoring Witness: Blake

KENTUCKY UTILITIES

Calculation of Composite Federal and Kentucky Income Tax Rate (Based on Law in Effect January 1, 2012)

1. Assume pre-tax income of		$ 100.0000
2. State income tax at 6.00%		5.7582
3. Taxable income for Federal income tax before production deduction		94.2418
Production Rate	9%	
Allocation to Production Income	0.6717	
Allocated Production Rate	6.05%	
4. Less: Production tax deduction (6.05% of Line 3)		5.7016
5. Taxable income for Federal income tax (Line 3 - Line 4)		88.5402
6. Federal income tax at 35% (Line 5 x 35%)		30.9891
7. Total State and Federal income taxes (Line 2 + Line 6)		$ 36.7473

8. Therefore, the composite rate is:

9.	Federal	30.9891%
10.	State	5.7582%
11.	Total	36.7473%

State Income Tax Calculation

1. Assume pre-tax income of	$ 100.0000
2. Less: Production tax deduction (6% x 0.6717) (1)	4.0302
3. Taxable income for State income tax	95.9698
4. State Tax Rate	6.0000%
5. State Income Tax	5.7582

Notes: (1) Pursuant to KRS 141.010(11)(c) and (13)(c), for taxable years beginning on or after January 1, 2010, the amount of domestic production activities deduction calculated at six percent (6%) as allowed in Section 199(a)(2) of the Internal Revenue Code for taxable years beginning before 2010.

Exhibit 1
Reference Schedule 1.30
Sponsoring Witness: Blake

KENTUCKY UTILITIES

Calculation of Current Tax Adjustment Resulting
From "Interest Synchronization"

1. Adjusted Jurisdictional Capitalization - Exhibit 2	$	3,294,685,544
2. Weighted Cost of Debt - Exhibit 2		1.71%
3. "Interest Synchronization"	$	56,339,123
4. Kentucky Jurisdictional Interest per books (excluding other interest)		56,734,305
5. "Interest Synchronization" adjustment (Line 4 - 3)	$	395,182
6. Composite Federal and State tax rate		36.7473%
7. Current tax adjustment from "Interest Synchronization"	$	145,218

Exhibit 1
Reference Schedule 1.31
Sponsoring Witness: Blake

KENTUCKY UTILITIES

Adjustment for Prior Period Income Tax True-Ups and Adjustments
For the Twelve Months Ended March 31, 2012

1. Prior Year Income Tax True-up:		
2. Federal Tax expense (benefit)	$	807,582
3. State Tax expense (benefit)		(175,111)
4. Total Income Tax True-up	$	632,471
5. Other Tax adjustments:		
6. Removal of expired federal credit		(214,221)
7. Total Other Tax adjustments:	$	(214,221)
8. Federal benefit for State Tax adjustments		61,289
9. Total adjustments (Line 4 + Line 7 + Line 8)	$	479,539
10. Kentucky Jurisdiction (Ref. Sch. Allocators)		90.968%
11. Kentucky Jurisdiction amount (Line 9 x Line 10)	$	436,228
12. Kentucky Jurisdiction adjustment	$	(436,228)

Exhibit 1
Reference Schedule 1.32
Sponsoring Witness: Blake

KENTUCKY UTILITIES

Adjustment for Tax Basis Depreciation Reduction
For the Twelve Months Ended March 31, 2012

1. Permanent difference due to loss of depreciable tax basis	$	697,547
2. Permanent diff. due to loss of depreciable tax basis in test year		1,061,585
3. Total Adjustment (Line 1 - Line 2)	$	(364,038)
4. Kentucky Jurisdiction (Ref. Sch. Allocators)		90.968%
5. Kentucky Jurisdictional adjustment	$	(331,159)

Exhibit 1
Reference Schedule 1.33
Sponsoring Witness: Blake

KENTUCKY UTILITIES

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Exhibit 1
Reference Schedule 1.34
Sponsoring Witness: Blake

KENTUCKY UTILITIES

Calculation of Revenue Gross Up Factor
(Based on Law in Effect January 1, 2012)

	State	Federal
1. Assume pre-tax income of	$ 100.000000	$ 100.000000
2. Bad Debt at .4200%	0.420000	0.420000
3. PSC Assessment at .1529%	0.152900	0.152900
4. Production Tax Credit-State (Reference Schedule 1.29)	4.030200	
5. Taxable income for State income tax	95.396900	99.427100
6. State income tax at 6.00%	5.723814	5.723814
7. Production Tax Credit-Federal (Reference Schedule 1.29)		5.701630
8. Taxable income for Federal income tax		88.001656
9. Federal income tax at 35%		30.800580
10. Total Bad Debt, PSC Assessment, State and Federal income taxes (Line 2 + Line 3 + Line 6 + Line 9)		37.097294
11. Assume pre-tax income of		$ 100.000000
12. Gross Up Revenue Factor		62.902706

KENTUCKY UTILITIES

Kentucky Jurisdictional Allocators
At March 31, 2012

Title	Reference Schedule	Factor	Allocation Based On
ECR Operating Expense	1.04	86.660%	Composite rate developed from steam depreciation allocator (86.549%), steam plant O&M allocator (85.898%),energy allocator (86.757%) and net plant allocator for property tax (87.436%)
Brokered and Off-System Energy	1.05, 1.08, 1.09	86.757%	Ratio of Kentucky retail kilowatt-hour sales to Total Company kilowatt-hour sales
Depreciation	1.12	87.257%	Composite rate developed by dividing Kentucky retail depreciation by Total Company depreciation
Labor	1.13	88.938%	Direct labor
Pension and Post Retirement and Benefits	1.14	88.938%	Direct labor
Distribution O&M (Storm Damages)	1.15	94.085%	Distribution plant
Injuries/Damages	1.16	88.938%	Direct labor
Advertising Expense	1.17	94.978%	Retail energy
Miscellaneous Revenue	1.18	94.452%	Demand Non-Ferc
Total O&M	1.18	87.554%	Total O&M
Property Insurance	1.19	87.070%	Plant
ITO Transfer	1.20	86.549%	Demand 12CP
Income Taxes	1.31, 1.32	90.968%	Income tax expense

Blake Exhibit 2

Capitalization at March 31, 2012

KENTUCKY UTILITIES

Capitalization at March 31, 2012

		Per Books 3-31-2012 (1)	Capital Structure (2)	Undistributed Subsidiary Earnings (3)	Investment in EEI (Col 2 x Col 4 Line 4) (4)	Investments in OVEC and Other (Col 2 x Col 5 Line 4) (5)	Adjustments to Total Co. Capitalization (Sum of Col 3 - Col 5) (6)	Adjusted Total Company Capitalization (Col 1 + Col 6) (7)	Jurisdictional Rate Base Percentage (Exhibit 3 Line 19) (8)	Kentucky Jurisdictional Capitalization (Col 7 x Col 8) (9)
1.	Short Term Debt	$ -	0.00%	$ -	$ -	$ -	$ -	$ -	87.52%	$ -
2.	Long Term Debt	1,840,750,374	46.26%	-	(599,437)	(198,511)	(797,948)	1,839,952,426	87.52%	1,610,326,363
3.	Common Equity	2,138,484,751	53.74%	(3,158,501)	(696,363)	(230,610)	(4,085,474)	2,134,399,277	87.52%	1,868,026,247
4.	Total Capitalization	$ 3,979,235,125	100.00%	$ (3,158,501)	$ (1,295,800)	$ (429,121)	$ (4,883,422)	$ 3,974,351,703		$ 3,478,352,610

		Kentucky Jurisdictional Capitalization (9)	Capital Structure (10)	Environmental Compliance Plans (a) (Col 10 x Col 11 Line 4) (11)	Adjusted Kentucky Jurisdictional Capitalization (Col 9 + Col 11) (12)	Adjusted Capital Structure (13)	Annual Cost Rate (14)		Cost of Capital (Col 14 x Col 13) (15)
1.	Short Term Debt	$ -	0.00%	$ -	$ -	0.00%	0.41%	(b)	0.00%
2.	Long Term Debt	1,610,326,363	46.30%	(85,030,505)	1,525,295,858	46.30%	3.69%	(b)	1.71%
3.	Common Equity	1,868,026,247	53.70%	(98,636,561)	1,769,389,686	53.70%	11.00%	(c)	5.91%
4.	Total Capitalization	$ 3,478,352,610	100.00%	$ (183,667,066)	$ 3,294,685,544	100.00%			7.62%

(a) Supporting Schedule-Exhibit 3, Page 1, Line 19, Column 5 $ 183,667,066
(b) Embedded cost as of March 31, 2012
(c) Recommended Rate of Return on Common Equity

Blake Exhibit 3

Net Original Cost Kentucky Jurisdictional Rate Base at March 31, 2012

KENTUCKY UTILITIES

Net Original Cost Kentucky Jurisdictional Rate Base
At March 31, 2012

Title of Account (1)	Kentucky Jurisdictional Rate Base (2)	Other Jurisdictional Rate Base (3)	Total Company Rate Base (4)
1. Utility Plant at Original Cost	$ 5,952,611,566	$ 885,196,895	$ 6,837,808,461
2. Deduct:			
3. Reserve for Depreciation	2,091,528,460	327,757,743	2,419,286,203
4. Net Utility Plant	3,861,083,106	557,439,152	4,418,522,258
5. Deduct:			
6. Customer Advances for Construction	2,936,189	211,698	3,147,887
7. Accumulated Deferred Income Taxes	439,643,557	62,552,930	502,196,487
8. Asset Retirement Obligation-Net Assets	46,378,395	7,207,891	53,586,286
9. Asset Retirement Obligation-Regulatory Liabilities	3,062,358	475,936	3,538,294
10. Investment Tax Credit (a)	86,299,724	14,408,015	100,707,739
11. Total Deductions	578,320,223	84,856,470	663,176,693
12. Add:			
13. Materials and Supplies (b)	115,098,215	17,615,722	132,713,937
14. Prepayments (b)(c)	6,567,467	759,209	7,326,676
15. Emission Allowances (b)	415,671	64,601	480,272
16. Cash Working Capital (page 2)	96,090,910	7,976,529	104,067,439
17. Total Additions	218,172,263	26,416,061	244,588,324
18. Total Net Original Cost Rate Base	$ 3,500,935,146	$ 498,998,743	$ 3,999,933,889
19. Percentage of Rate Base to Total Company Rate Base	87.52%	12.48%	100.00%

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

KENTUCKY UTILITIES

Calculation of Cash Working Capital
At March 31, 2012

Title of Account (1)	Kentucky Jurisdictional Rate Base (2)	Other Jurisdictional Rate Base (3)	Total Company Rate Base (4)
1. Operating and maintenance expense for the 12 months ended March 31, 2012	$ 858,787,983	$ 122,073,407	$ 980,861,389
2. Deduct:			
3. Electric Power Purchased	90,060,701	13,768,569	103,829,270
4. Total Deductions	$ 90,060,701	$ 13,768,569	$ 103,829,270
5. Remainder (Line 1 - Line 4)	$ 768,727,282	$ 108,304,838	$ 877,032,120
6. Cash Working Capital	$ 96,090,910	$ 7,976,529	$ 104,067,439

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

KENTUCKY UTILITIES

Net Original Cost Kentucky Jurisdictional Rate Base
At March 31, 2012

Title of Account (1)	Kentucky Jurisdictional Rate Base (2)	Kentucky Jurisdictional ECR Rate Base (3) (Page 3 Col 2)	Kentucky Jurisdictional ECR Elimination (4) (Page 3 Col 5)	Kentucky Jurisdictional Net ECR (5) (3 - 4)	Kentucky Jurisdictional Base Rate Base (6) (2 - 5)	Other Jurisdictional Rate Base (7)	Total Company Rate Base (8) (5 + 6 + 7)
1. Utility Plant at Original Cost	$ 5,952,611,566	$ 1,312,398,572	$ 1,130,003,626	$ 182,394,946	$ 5,770,216,620	$ 885,196,895	$ 6,837,808,461
2. Deduct:							
3. Reserve for Depreciation	2,091,528,460	104,601,971	104,543,164	58,807	2,091,469,653	327,757,743	2,419,286,203
4. Net Utility Plant	3,861,083,106	1,207,796,601	1,025,460,462	182,336,139	3,678,746,967	557,439,152	4,418,522,258
5. Deduct:							
6. Customer Advances for Construction	2,936,189	-	-	-	2,936,189	211,698	3,147,887
7. Accumulated Deferred Income Taxes	439,643,557	88,236,954	88,089,601	147,353	439,496,204	62,552,930	502,196,487
8. Asset Retirement Obligation-Net Assets	46,378,395	-	-	-	46,378,395	7,207,891	53,586,286
9. Asset Retirement Obligation-Regulatory Liabilities	3,062,358	-	-	-	3,062,358	475,936	3,538,294
10. Investment Tax Credit (a)	86,299,724	22,632,203	22,632,203	-	86,299,724	14,408,015	100,707,739
11. Total Deductions	578,320,223	110,869,157	110,721,804	147,353	578,172,870	84,856,470	663,176,693
12. Net Plant Deductions	3,282,762,883	1,096,927,444	914,738,658	182,188,786	3,100,574,097	472,582,682	3,755,345,565
13. Add:							
14. Materials and Supplies (b)	115,098,215	828,915	828,915	-	115,098,215	17,615,722	132,713,937
15. Prepayments (b)(c)	6,567,467	-	-	-	6,567,467	759,209	7,326,676
16. Emission Allowances (b)	415,671	299,323	(60,078)	359,401	56,270	64,601	480,272
17. Cash Working Capital (page 2)	96,090,910	2,472,255	1,353,376	1,118,879	94,972,031	7,976,529	104,067,439
18. Total Additions	218,172,263	3,600,493	2,122,213	1,478,280	216,693,983	26,416,061	244,588,324
19. Total Net Original Cost Rate Base	$ 3,500,935,146	$ 1,100,527,937	$ 916,860,871	$ 183,667,066	$ 3,317,268,080	$ 498,998,743	$ 3,999,933,889
20. Percentage of Rate Base to Total Company Rate Base	87.52%	27.51%	22.92%	4.59%	82.93%	12.48%	100.00%

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

KENTUCKY UTILITIES

Calculation of Cash Working Capital
At March 31, 2012

Title of Account (1)	Kentucky Jurisdictional Rate Base (2)	Kentucky Jurisdictional ECR Rate Base (3)	Kentucky Jurisdictional ECR Elimination (4)	Kentucky Jurisdictional Net ECR (5) (3 - 4)	Kentucky Jurisdictional Base Rate Base (4) (2 - 5)	Other Jurisdictional Rate Base (5)	Total Company Rate Base (6) (5 + 6 + 7)
1. Operating and maintenance expense for the 12 months ended March 31, 2012	$ 858,787,983	$ 19,778,040	$ 10,827,008	$ 8,951,032	$ 849,836,951	$ 122,073,407	$ 980,861,389
2. Deduct:							
3. Electric Power Purchased	90,060,701	-	-	-	90,060,701	13,768,569	103,829,270
4. Total Deductions	$ 90,060,701	$ -	$ -	$ -	$ 90,060,701	$ 13,768,569	$ 103,829,270
5. Remainder (Line 1 - Line 4)	$ 768,727,282	$ 19,778,040	$ 10,827,008	$ 8,951,032	$ 759,776,250	$ 108,304,838	$ 877,032,120
6. Cash Working Capital	$ 96,090,910	$ 2,472,255	$ 1,353,376	$ 1,118,879	$ 94,972,031	$ 7,976,529	$ 104,067,439

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

<u>KENTUCKY UTILITIES</u>

Net Original Cost Kentucky Jurisdictional Rate Base
<u>At March 31, 2012</u>

Title of Account (1)	Kentucky Jurisdictional ECR Rate Base (2)	Other Jurisdictional ECR Rate Base (3)	Total Company ECR Rate Base (4)	Kentucky Jurisdictional ECR '05 & '06 Rate Base (5)	Kentucky Jurisdictional Net ECR Rate Base (6) (2 - 5)
1. Utility Plant at Original Cost	$ 1,312,398,572	$ 203,966,230	$ 1,516,364,802	$ 1,130,003,626	$ 182,394,946
2. Deduct:					
3. Reserve for Depreciation	104,601,971	16,256,700	120,858,671	104,543,164	58,807
4. Net Utility Plant	1,207,796,601	187,709,530	1,395,506,131	1,025,460,462	182,336,139
5. Deduct:					
6. Customer Advances for Construction	-	-	-	-	-
7. Accumulated Deferred Income Taxes	88,236,954	13,713,333	101,950,287	88,089,601	147,353
8. Asset Retirement Obligation-Net Assets	-	-	-	-	-
9. Asset Retirement Obligation-Regulatory Liabilities	-	-	-	-	-
10. Investment Tax Credit (a)	22,632,203	3,778,592	26,410,795	22,632,203	-
11. Total Deductions	110,869,157	17,491,925	128,361,082	110,721,804	147,353
12. Net Plant Deductions	1,096,927,444	170,217,605	1,267,145,049	914,738,658	182,188,786
13. Add:					
14. Materials and Supplies	828,915	127,544	956,459	828,915	-
15. Prepayments	-	-	-	-	-
16. Emission Allowances	299,323	46,519	345,842	(60,078)	359,401
17. Cash Working Capital	2,472,255	380,896	2,853,151	1,353,376	1,118,879
18. Total Additions	3,600,493	554,959	4,155,452	2,122,213	1,478,280
19. Total Net Original Cost Rate Base	$ 1,100,527,937	$ 170,772,564	$ 1,271,300,501	$ 916,860,871	$ 183,667,066

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

Blake Exhibit 4

Pro Forma Kentucky Jurisdictional Rate Base at March 31, 2012

KENTUCKY UTILITIES

Pro Forma Kentucky Jurisdictional Rate Base
At March 31, 2012

	Title of Account (1)	Kentucky Jurisdictional Rate Base (a) (2)	Kentucky Jurisdictional Pro Forma Adjustments (b) (3)	Kentucky Jurisdictional Pro Forma Rate Base (4) (2 + 3)
1.	Utility Plant at Original Cost	$ 5,952,611,566	$ (182,394,946)	$ 5,770,216,620
2.	Deduct:			
3.	Reserve for Depreciation	2,091,528,460	654,039	2,092,182,499
4.	Net Utility Plant	3,861,083,106	(183,048,985)	3,678,034,121
5.	Deduct:			
6.	Customer Advances for Construction	2,936,189		2,936,189
7.	Accumulated Deferred Income Taxes	439,643,557	(147,353)	439,496,204
8.	Asset Retirement Obligation-Net Assets	46,378,395		46,378,395
9.	Asset Retirement Obligation-Regulatory Liabilities	3,062,358		3,062,358
10.	Investment Tax Credit	86,299,724		86,299,724
11.	Total Deductions	578,320,223	(147,353)	578,172,870
12.	Add:			
13.	Materials and Supplies	115,098,215	-	115,098,215
14.	Prepayments	6,567,467		6,567,467
15.	Emission Allowances	415,671	(359,401)	56,270
16.	Cash Working Capital	96,090,910	(6,828,843)	89,262,067
17.	Total Additions	218,172,263	(7,188,244)	210,984,019
18.	Total Net Original Cost Rate Base	$ 3,500,935,146	$ (190,089,876)	$ 3,310,845,270

(a) Exhibit 3, Column 2
(b) Supporting Schedule-Exhibit 4, Column 4

KENTUCKY UTILITIES

Pro Forma Adjustments to Kentucky Jurisdictional Rate Base
At March 31, 2012

	Title of Account (1)	Environmental Compliance Plans (2)		Kentucky Jurisdictional Expense Adjustments (3)		Total Kentucky Jurisdictional Pro Forma Adjustments (4) (2 + 3)
1.	Utility Plant at Original Cost	$ (182,394,946)		$ -		$ (182,394,946)
2.	Deduct:					
3.	Reserve for Depreciation	(58,807)		712,846	(b)	654,039
4.	Net Utility Plant	(182,336,139)		(712,846)		(183,048,985)
5.	Deduct:					
6.	Customer Advances for Construction	-		-		-
7.	Accumulated Deferred Income Taxes	(147,353)		-		(147,353)
8.	Asset Retirement Obligation-Net Assets	-		-		-
9.	Asset Retirement Obligation-Regulatory Liabilities	-		-		-
10.	Investment Tax Credit	-		-		-
11.	Total Deductions	(147,353)		-		(147,353)
12.	Add:					
13.	Materials and Supplies	-		-		-
14.	Prepayments	-		-		-
15.	Emission Allowances	(359,401)		-		(359,401)
16.	Cash Working Capital	(1,118,879)		(5,709,964)	(c)	(6,828,843)
17.	Total Additions	(1,478,280)		(5,709,964)		(7,188,244)
18.	Total Net Original Cost Rate Base	$ (183,667,066)	(a)	$ (6,422,810)		$ (190,089,876)

(a) Adjustment to remove Environmental Compliance Plans (Exhibit 2 Col 11).
(b) Adjustment to reflect annualized depreciation expenses (Reference Schedule 1.12).
(c) Using the 1/8th formula and change in Operation and Maintenance Expenses adjusted for FAC roll-in and ECR expense adjustments ((Exhibit 1 Col 3, Line 28 - Line 7 - Line 15 - Ref Sch 1.02 Line 2) / 8).

Blake Exhibit 5

Estimated Net Reproduction Cost Kentucky Jurisdictional Rate Base at March 31, 2012

KENTUCKY UTILITIES

Estimated Net Reproduction Cost Kentucky Jurisdictional Rate Base
At March 31, 2012

Title of Account (1)	Kentucky Jurisdictional Rate Base (2)	Other Jurisdictional Rate Base (3)	Total Company Rate Base (4) (2 + 3)
1. Utility Plant at Estimated Reproduction Cost	$ 11,630,274,388	$ 1,659,314,530	$ 13,289,588,918
2. Deduct:			
3. Reserve for Depreciation	5,151,380,315	758,425,763	5,909,806,078
4. Net Utility Plant	6,478,894,073	900,888,767	7,379,782,840
5. Deduct:			
6. Customer Advances for Construction	2,936,189	211,698	3,147,887
7. Accumulated Deferred Income Taxes	439,643,557	62,552,930	502,196,487
8. Asset Retirement Obligation-Net Assets	46,378,395	7,207,891	4,890,630
9. Asset Retirement Obligation-Regulatory Liabilities	3,062,358	475,936	(2,254,925)
10. Investment Tax Credit (a)	86,299,724	14,408,015	100,707,739
11. Total Deductions	578,320,223	84,856,470	608,687,818
12. Add:			
13. Materials and Supplies (b)	115,098,215	17,615,722	85,963,079
14. Prepayments (b)(c)	6,567,467	759,209	1,664,279
15. Emission Allowances (b)	415,671	64,601	223,085
16. Cash Working Capital	96,090,910	7,976,529	104,067,439
17. Total Additions	218,172,263	26,416,061	191,917,882
18. Total Net Reproduction Cost Rate Base	$ 6,118,746,113	$ 842,448,358	$ 6,963,012,904

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

Blake Exhibit 6

Estimated Reproduction (or Current) Cost of Utility Plant
And Applicable Reserve for Depreciation at March 31, 2012

KENTUCKY UTILITIES

Estimated Reproduction (or Current) Cost of Utility Plant
And Applicable Reserve for Depreciation at March 31, 2012

	Original Cost 3-31-2012 (1)	Effect of Changing Prices (a) (2)	At 3-31-2012 (3)	Jurisdictional Factor (4)	Kentucky Jurisdictional Plant at 3-31-2012 (5)	Other Jurisdictional Plant at 3-31-2012 (6)
1. Plant in Service						
2. Electric Plant :						
3. Steam Production	$ 3,627,150,142	$ 2,741,179,187	$ 6,368,329,329	86.549%	$ 5,511,725,351	$ 856,603,978
4. Hydraulic Production	28,756,470	155,965,304	184,721,774	86.549%	159,874,848	24,846,926
5. Other Production	533,383,145	380,889,759	914,272,904	86.549%	791,294,056	122,978,848
6. Transmission	667,945,984	1,279,954,034	1,947,900,018	80.246%	1,563,111,848	384,788,170
7. Distribution	1,434,552,256	1,813,968,409	3,248,520,665	94.085%	3,056,370,668	192,149,997
8. General	140,021,374	74,743,833	214,765,207	88.938%	191,007,880	23,757,327
9. Intangible	60,204,133	5,636,450	65,840,583	87.069%	57,326,737	8,513,846
10. Total Plant in Service	6,492,013,504	6,452,336,976	12,944,350,480		11,330,711,388	1,613,639,092
11. Construction Work In Progress	345,238,438	-	345,238,438	86.770%	299,563,000	45,675,438
12. Total Utility Plant	$ 6,837,251,942	$ 6,452,336,976	$ 13,289,588,918		$ 11,630,274,388	$ 1,659,314,530
13. Less Reserve for Depreciation:						
14. Steam Production	$ 1,265,653,049	$ 1,837,066,115	$ 3,102,719,164	86.549%	$ 2,685,372,409	$ 417,346,755
15. Hydraulic Production	7,812,064	63,608,252	71,420,316	86.549%	61,813,569	9,606,747
16. Other Production	179,735,465	145,788,502	325,523,967	86.549%	281,737,738	43,786,229
17. Transmission	326,784,475	680,376,974	1,007,161,449	80.246%	808,206,776	198,954,673
18. Distribution	564,629,473	734,159,518	1,298,788,991	94.085%	1,221,965,622	76,823,369
19. General	55,605,423	28,134,674	83,740,097	88.938%	74,476,767	9,263,330
20. Intangible	19,066,254	1,385,840	20,452,094	87.069%	17,807,434	2,644,660
21. Total Reserve for Depreciation	$ 2,419,286,203	$ 3,490,519,875	$ 5,909,806,078		$ 5,151,380,315	$ 758,425,763
22. Total Utility Plant less Reserve for Depreciation	$ 4,417,965,739	$ 2,961,817,101	$ 7,379,782,840		$ 6,478,894,073	$ 900,888,767

(a) Based on Handy -Whitman Index

Blake Exhibit 7

Rates of Return – Actual and Requested Pro Forma for the Rate Increase
For the Twelve Months Ended March 31, 2012

KENTUCKY UTILITIES

Rates of Return - Actual and Requested
Pro-Formed for the Rate Increase
For the Twelve Months Ended March 31, 2012

			Total (1)
1. Kentucky Jurisdictional Net Original Cost Rate Base - Exhibit 3		$	3,500,935,146
2. Kentucky Jurisdictional Pro Forma Rate Base - Exhibit 4		$	3,310,845,270
3. Kentucky Jurisdictional Reproduction Cost Rate Base - Exhibit 5		$	6,118,746,113
4. Kentucky Jurisdictional Net Operating Income - Actual - Exhibit 1		$	202,748,924
5. Rate of Return (Actual):			
6. On Kentucky Jurisdictional Net Original Cost Rate Base			5.79%
7. On Kentucky Jurisdictional Pro Forma Rate Base			6.12%
8. On Kentucky Jurisdictional Reproduction Cost Rate Base			3.31%
9. Kentucky Jurisdictional Adjusted Net Operating Income - Exhibit 1		$	199,192,491
10. Revenue Increase Applied for - Exhibit 8			82,448,833
11. Income Taxes - Exhibit 1, Reference Schedule 1.29	36.7473 %		(30,297,680)
12. Adjusted Kentucky Jurisdictional Net Operating Income Pro-formed for Rate Increase		$	251,343,644
13. Rate of Return (Pro-forma):			
14. On Kentucky Jurisdictional Net Original Cost Rate Base			7.18%
15. On Kentucky Jurisdictional Pro Forma Rate Base			7.59%
16. On Kentucky Jurisdictional Reproduction Cost Rate Base			4.11%

Blake Exhibit 8

Calculation of Overall Revenue Deficiency/(Sufficiency) at March 31, 2012

KENTUCKY UTILITIES

Calculation of Overall Revenue Deficiency/(Sufficiency) at March 31, 2012

	ELECTRIC (1)
1. Adjusted Kentucky Jurisdictional Capitalization (Exhibit 2, Col 12)	$ 3,294,685,544
2. Total Cost of Capital (Exhibit 2, Col 15)	7.62%
3. Net Operating Income Found Reasonable (Line 1 x Line 2)	$ 251,055,038
4. Pro-forma Net Operating Income	199,192,491
5. Net Operating Income Deficiency/(Sufficiency)	$ 51,862,547
6. Gross Up Revenue Factor - Exhibit 1, Reference Schedule 1.34	0.62902706
7. Overall Revenue Deficiency/(Sufficiency)	$ 82,448,833

Blake Exhibit 9

Kentucky Jurisdictional Rate of Return on Common Equity
For the Twelve Months Ended March 31, 2012

KENTUCKY UTILITIES

Kentucky Jurisdictional Rate of Return on Common Equity
For the Twelve Months Ended March 31, 2012

	Adjusted Kentucky Jurisdictional Capitalization (Exhibit 2 Col 12) (1)	Percent of Total (2)	Annual Cost Rate (Exhibit 2 Col 14) (3)		Weighted Cost of Capital (Col 2 x Col 3) (4)	
1. Short Term Debt	$0	0.00%	0.41%		0.00%	
2. Long Term Debt	$1,525,295,858	46.30%	3.69%		1.71%	
3. Common Equity	$1,769,389,686	53.70%	8.08%	(a)	4.34%	(b)
4. Total Capitalization	$3,294,685,544	100.00%			6.05%	
5. Pro-forma Net Operating Income					$199,192,491	(c)
6. Net Operating Income / Total Capitalization					6.05%	(d)

Notes: (a) - Column 4, Line 3 / Column 2, Line 3
(b) - Column 4, Line 4 - Line 1 - Line 2
(c) - Exhibit 1, Line 33, Column 4
(d) - Column 4, Line 5 divided by Column 1, Line 4

Blake Exhibit 10

Current Capital Expenditure Projection

KU's current capital expenditure projections for the years 2012 through 2016[12]

	Projected				
	2012	**2013**	**2014**	**2015**	**2016**
Construction expenditures					
Generating facilities (a)	$ 129	$ 177	$ 217	$ 173	$ 65
Distribution facilities	78	95	86	103	100
Transmission facilities (b)	57	49	53	43	40
Environmental	379	453	411	233	51
Other	13	21	21	24	22
Total Construction Expenditures	$ 656	$ 795	$ 788	$ 576	$ 278

[12] Securities and Exchange Commission 10K filing for 2011 for Kentucky Utilities Company.

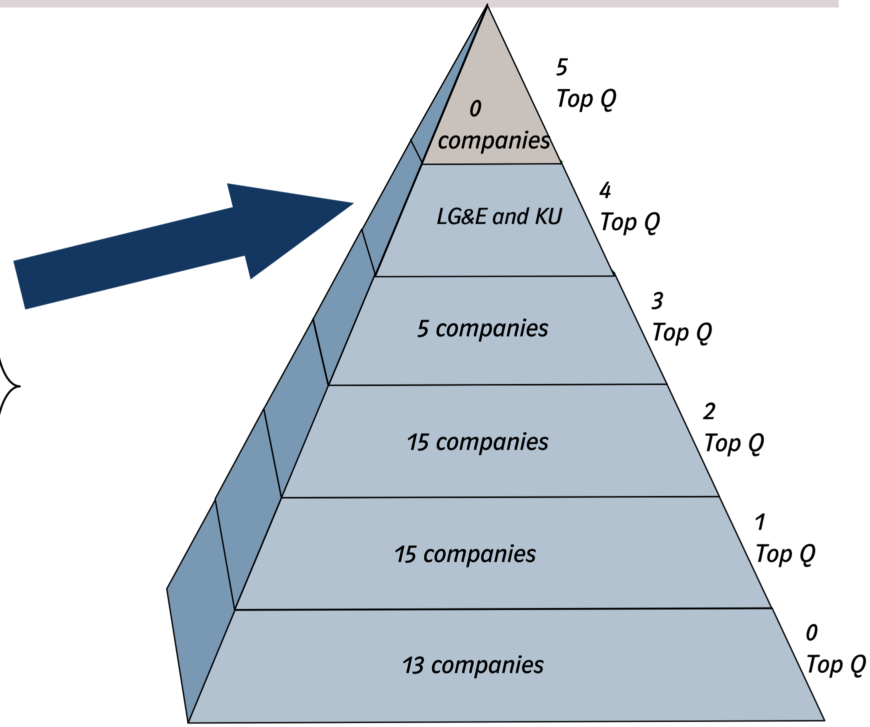
Blake Exhibit 11

2006-2010 Cost Performance Pyramid

Among Most Efficient Utilities in Country

LKE Metrics

Cost area	Metric	Performance	Ranking
Generation	Non-fuel O&M / MWh of production	$6.18	5th – top quartile
Transmission	Cash cost / transmission mile	$18,630	7th – top quartile
Distribution	Cash cost / retail customer	$237.18	28th – second quartile
Retail	O&M cost / retail customer	$57.93	15th – top quartile
Corporate A&G	A&G cost / MWh of sales	$3.87	8th – top quartile



Source: FERC Form 1 , SNL

Note: The Triangle = 49 US electric holding company's averages for 2007-2011 (only includes companies competing in all 5 segments).

LKE is the only utility with Top Quartile cost performance in four areas.

Blake Exhibit 11
Page 1 of 1

PPL companies

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

APPLICATION OF KENTUCKY	**)**	
UTILITIES COMPANY FOR AN	**)**	**CASE NO. 2012-00221**
ADJUSTMENT OF ITS	**)**	
ELECTRIC RATES	**)**	

TESTIMONY OF
VALERIE L. SCOTT
CONTROLLER
KENTUCKY UTILITIES COMPANY

Filed: June 29, 2012

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

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

Q. Have you testified previously before the Commission?

A. Yes, I testified in KU's and LG&E's last three base rate cases.[1] I have also testified in environmental surcharge proceedings.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to support certain pro forma adjustments to KU's operating income for the twelve months ended March 31, 2012. The pro forma adjustments are described on the Reference Schedules attached to Blake 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)?

---

[1] Case No. 2003-00433, *In re the Matter of: An Adjustment of the Gas and Electric Rates, Terms and Conditions of Louisville Gas and Electric Company*; Case No. 2003-00434, *In re the Matter of: An Adjustment of the Electric Rates, Terms and Conditions of Kentucky Utilities Company;* Case No. 2008-00252, *In re the Matter of: Application of Louisville Gas and Electric Company for an Adjustment of Its Electric and Gas Base Rates*; Case No. 2008-00251, *In re the Matter of: Application of Kentucky Utilities Company for an Adjustment of Base Rates;* Case No. 2009-00549, *In the Matter of: Application of Louisville Gas and Electric Company for an Adjustment of Its Electric and Gas Base Rates*; Case No. 2009-00548, *In the Matter of: Application of Kentucky Utilities Company for an Adjustment of Base Rates.*

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 Forms 1	Section 10(6)(m)	Tab 32
• 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)?

A. Yes. I am sponsoring the following Schedules for the corresponding filing requirements:

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

Pro Forma Adjustments

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

A. Consistent with the Commission's practice of eliminating the revenues and expenses associated with full-recovery cost trackers, an adjustment was made to eliminate electric revenues recovered through the DSM and the corresponding expenses recorded during the test year. The DSM includes a balancing adjustment that automatically adjusts unit charges under the mechanism to account for differences between revenues collected and costs incurred during the applicable period. The

Commission approved a similar adjustment in Case Nos. 2009-00548 and 2003-00434. KU also proposed a similar adjustment in Case No. 2008-00251, which was resolved by a settlement approved by the Commission.

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

A. This adjustment has been made to remove the effects of accrued Environmental Cost Recovery ("ECR"), Merger Surcredit ("MSR"), Value Delivery Surcredit ("VDT"), Fuel Adjustment Clause ("FAC") and Demand-Side Management ("DSM") revenues in FERC Accounts 440-445. The adjustment removes the effects of the accruals recorded at both the beginning and end of the test year. The Commission approved a similar adjustment in Case Nos. 2009-00548 and 2003-00434. KU also proposed a similar adjustment in Case No. 2008-00251, which was resolved by a settlement approved by the Commission.

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

A. This adjustment has been made to eliminate net brokered and financial swap revenues and related expenses. Net revenues associated with brokered and financial swap transactions are eliminated in determining base rates because these transactions do not utilize company generation or transmission assets. Labor and labor-related costs associated with executing these transactions are also eliminated. The Commission approved a similar adjustment in Case Nos. 2009-00548, 2003-00434, and 98-474[2].

[2] *In the Matter of: The Application of Kentucky Utilities Company for Approval of an Alternative Method of Regulation of Its Rates and Service.*

KU also proposed a similar adjustment in Case No. 2008-00251, which was resolved by a settlement approved by the Commission.

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

A. This adjustment has been made to annualize labor and labor-related costs as of March 31, 2012, and includes specific adjustments for labor, payroll taxes, and KU's 401(k) contribution. Page 1 of 4 presents an overview of the adjustment. The adjustment conforms labor costs for the applicable employees to the rates that were in effect as of the end of the test year.

Page 2 of 4 of Reference Schedule 1.13 of Blake Exhibit 1 shows the adjustment for labor expenses. The adjustment reflects the annualized base labor at March 31, 2012, of all union and non-union KU employees and KU's share of LG&E and KU Services Company labor costs as of that date. While this page also shows an allocation to KU for LG&E labor, these charges are only included for completeness and do not impact the adjustment as all such costs are included in the "Construction/Other" category. Overtime labor costs were adjusted by applying wage increases that became effective during the test year to overtime worked during the test year before the effective date of the increases. Page 3 of 4 of Reference Schedule 1.13 of Blake Exhibit 1 shows the calculation of the component of the labor adjustment to reflect the increases in the Federal Insurance Contributions Act employer payroll taxes due to the increase in labor costs. The Medicare tax rate was applied to the entire increase since all wages are subject to this tax. The same percentage of wages subject to Social Security taxes experienced during the twelve months ended March 31, 2012 was applied to the increased labor cost.

Finally, page 4 of Reference Schedule 1.13 of Blake Exhibit 1 shows the increase in the Company contribution for the 401(k) plan as a result of the increased operating labor using the same contribution percentage as experienced during the twelve months ended March 31, 2012. Although KU has not increased its contribution percentage, the total amount of KU's 401(k) contribution has increased as a result of increased labor costs.

The Commission approved a similar adjustment in Case Nos. 2009-00548 and 2003-00434. KU proposed a similar adjustment in Case No. 2008-00251, which was resolved by a settlement approved the Commission.

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

A. This adjustment has been made to reflect a normalized level of storm damage expenses based upon a ten-year average adjusted for inflation. Because a full year of data is not available for 2012, the 2012 expense is for the twelve months ending March 31, 2012; all other expense years are calendar years. The Commission approved a similar adjustment in Case Nos. 2009-00548 and 2003-00434. KU also proposed a similar adjustment in Case No. 2008-00251, which was resolved by a settlement approved by the Commission.

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

A. This adjustment is made to normalize the expenses in Account 925 "Injuries and Damages" based on a ten-year average adjusted for inflation. Because a full year of data is not available for 2012, the 2012 expense is for the twelve months ending March 31, 2012; all other expense years are calendar years. The Commission approved a similar adjustment in Case Nos. 2009-00548 and 2003-00434. KU also proposed a similar adjustment in Case No. 2008-00251, which was resolved by a settlement approved by the Commission.

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

A. This adjustment eliminates advertising expenses that are primarily institutional and promotional in nature. Commission regulation 807 KAR 5:016, Section 2(1) provides that a utility will be allowed to recover, for ratemaking purposes, only those advertising expenses which produce a "material benefit" to its ratepayers. The Commission approved a similar adjustment in Case Nos. 2009-00548 and 2003-00434. KU also proposed a similar adjustment in Case No. 2008-00251, which was resolved by a settlement approved by the Commission.

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

A. This adjustment eliminates the impact of amounts recorded during the test period that relate to periods outside the test period. The Commission approved similar out-of-period adjustments in Case Nos. 2009-00548 and 2003-00434. KU also proposed a similar adjustment in Case No. 2008-00251, which was resolved by a settlement approved by the Commission.

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

A. This adjustment is to reflect the continued amortization of the Midwest Independent Transmission System Operator, Inc. ("MISO") exit fee and related revenues and refunds. In KU's Case No. 2008-00251, the Commission permitted KU to net the deferred MISO exit fee against the MISO Schedule 10 administrative fees recovered through base rates post-exit and to amortize this net amount over a five-year period. The Commission also permitted KU to continue deferring the MISO Schedule 10 administrative fees recovered through base rates from May 1, 2008, until the date rates from that case became effective, February 6, 2009, and to defer subsequent periodic refunds of any portion of the MISO exit fee. In KU's following Case No. 2009-00548, KU received approval to net the regulatory liabilities from revenues related to MISO Schedule 10 expenses that were deferred from May 1, 2008, until February 5, 2009, and the deferred periodic refunds of the MISO exit fee, against the net regulatory asset established in Case No. 2008-00251, and to amortize this revised net regulatory asset for five years from the effective date of the change in rates. KU now requests approval to net the regulatory liabilities from the deferred periodic refunds of the MISO exit fee, including accrued refunds through December 31, 2012, against the remaining net regulatory asset established in Case No. 2009-00548, net of amortization of the net asset through December 31, 2012, and to amortize this revised remaining net regulatory liability for three years from the effective date of the change in rates. KU proposes to adjust the test year amortization to an annual amount based on this revised net regulatory asset pursuant to the same adjustment the Commission accepted in Case No. 2009-00548 and proposed by KU in Case No. 2008-00251, which was resolved by a settlement approved by the Commission.

Q. Does this conclude your testimony?

A. Yes, it does.

VERIFICATION

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

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

Valerie L. Scott

Valerie L. Scott

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 30th day of June 2012.

______________________(SEAL)

Notary Public

My Commission Expires:

July 21, 2015

APPENDIX A

Valerie L. Scott
Controller
LG&E and KU Energy LLC
220 West Main Street
Louisville, Kentucky 40202
(502) 627-3660

Professional Memberships:

American Institute of Certified Public Accountants (AICPA)
Kentucky Society of Certified Public Accountants (KSCPA)

Chief Accounting Officers, Edison Electric Institute (EEI)
Accounting Executive Advisory Committee, Edison Electric Institute (EEI)

Education:

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

Previous Positions with LG&E and KU Energy LLC & its predecessors:

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

Previous Positions prior to LG&E and KU Energy LLC & its predecessors:

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

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

APPLICATION OF KENTUCKY	**)**	
UTILITIES COMPANY FOR AN	**)**	**CASE NO. 2012-00221**
ADJUSTMENT OF ITS	**)**	
ELECTRIC RATES	**)**	

TESTIMONY OF
SHANNON L. CHARNAS
DIRECTOR OF ACCOUNTING AND REGULATORY REPORTING
KENTUCKY UTILITIES COMPANY

Filed: June 29, 2012

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

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

Q. Have you previously testified before the Commission?

A. Yes, I testified in KU's and LG&E's last two rate cases.[1] I have also testified in or supported data responses in numerous environmental surcharge proceedings, as well as in depreciation study proceedings.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to (1) describe the reasons KU elected to choose John J. Spanos of Gannett Fleming, Inc. to conduct KU's new depreciation study; (2) to accept Mr. Spanos' recommended methodology to calculate new depreciation rates; (3) to support certain schedules to KU's application; and (4) to support certain pro forma adjustments to KU's operating income and rate base for the twelve months ended March 31, 2012. The pro forma adjustments are described on the Reference Schedules attached to Blake Exhibit 1. My testimony demonstrates that these adjustments are known and measurable and therefore, reasonable.

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[1] Case No. 2008-00252, *In re the Matter of: Application of Louisville Gas and Electric Company for an Adjustment of Its Electric and Gas Base Rates*; Case No. 2008-00251, *In re the Matter of: Application of Kentucky Utilities Company for an Adjustment of Base Rates;* Case No. 2009-00549, *In the Matter of: Application of Louisville Gas and Electric Company for an Adjustment of Its Electric and Gas Base Rates*; Case No. 2009-00548, *In the Matter of: Application of Kentucky Utilities Company for an Adjustment of Base Rates.*

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

A. Yes. I am sponsoring the Schedules for the corresponding filing requirements:

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

My testimony will explain why KU chose to accept the Study performed by Mr. Spanos. Mr. Spanos describes the details of the Study in his testimony.

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

A. Yes. I am sponsoring the following Schedules for the corresponding filing requirements:

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

<u>Depreciation Study</u>

Q. Why did KU choose Mr. Spanos of Gannett Fleming, Inc. to conduct its new depreciation study?

A. As described in the curriculum vitae attached to Mr. Spanos' testimony, Mr. Spanos has extensive experience in the regulated utility accounting field, and particularly in the area of depreciation rates. Mr. Spanos is a member of the Society of Depreciation Professionals, and has submitted testimony to over twenty-five regulatory commissions on the subject of utility plant depreciation. He previously prepared a depreciation study for KU that was presented to the Commission in Case No. 2007-00565.[2] Moreover, Mr. Spanos has presented studies to, and testified

[2] *In the Matter of: Application of Kentucky Utilities Company to File Depreciation Study.*

before, this Commission in cases such as Kentucky American Water Company's 2010 base rate proceeding in Case No. 2010-00036, and Union Light, Heat and Power Company's 2006 electric base rate case in Case No. 2006-00172. The Commission accepted Mr. Spanos' depreciation study without modification in the Kentucky American Water Company proceeding.[3] Because the Union Light, Heat and Power case was resolved by unanimous settlement, the Commission did not specifically rule upon Mr. Spanos' study.[4]

Q. What did KU ask Mr. Spanos to do?

A. Maintenance of sound depreciation rates requires periodic reviews and assessments. Five years have passed since KU's last study. KU's business policy is to review and update its depreciation rates every five to seven years. The Commission has also indicated that utilities should periodically review and update their depreciation rates. Accordingly, KU asked Mr. Spanos to perform an independent depreciation study, using data from "An Economic Life Assessment Study of Generating Assets LG&E and KU" by Ventyx, an ABB Company, and his generation asset life assessment analysis of KU's assets and extensive experience in depreciation studies. The purpose of the study was to evaluate KU's depreciation rates and, if necessary, recommend updated depreciation rates to reflect the actual deprecation of KU's assets.

Q. What did Mr. Spanos find and recommend?

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[3] *In the Matter of: Application of Kentucky-American Water Company for an Adjustment of Rates Supported by a Fully Forecasted Test Year* (Case No. 2010-00036) (December 14, 2010 Order).

[4] *In the Matter of: Application of the Union Light, Heat and Power Company d/b/a Duke Energy Kentucky for an Adjustment of Electric Rates* (Case No. 2006-00172) (December 21, 2006 Order).

A. As in the case of many depreciation studies, Mr. Spanos found that KU's current depreciation rates need to be updated to fully reflect the current or actual depreciation of KU's assets. After evaluating different methodologies, Mr. Spanos recommended that KU continue to use the Average Service Life ("ASL") and remaining life basis methodology of depreciation, consistent with the method and resulting rates the Commission accepted in the settlement of Case Nos. 2007-00565 and 2008-00251. The study resulted in revised life and salvage parameters based on updated historical information, industry benchmarks and site visits to KU's facilities.

Q. Did KU accept Mr. Spanos' recommendation to use the ASL methodology in its new depreciation study?

A. Yes. KU accepted Mr. Spanos' recommendation to continue to use the ASL and remaining life basis methodology because it reasonably allocates depreciation over the remaining useful lives of KU's assets.

Pro Forma Adjustments

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

A. This adjustment has been made to reflect annualized depreciation expenses. The purpose of this adjustment is to reflect a full year's depreciation expense on net plant in service, excluding depreciation on assets set up for asset retirement obligations and depreciation on assets remaining in the 2009 and 2011 Environmental Cost Recovery Plans, as of March 31, 2012. The Commission approved a similar adjustment in Case Nos. 2009-00548 and 2003-00434. KU also proposed a similar adjustment in 2008-00251, which was resolved by a settlement approved by the Commission. The depreciation rates used in calculating the adjustment are those proposed in the testimony of Mr. Spanos.

Q. Does this conclude your testimony?

A. Yes, it does.

VERIFICATION

COMMONWEALTH OF KENTUCKY)
) SS:
COUNTY OF JEFFERSON)

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

Shannon L Charnas
Shannon L. Charnas

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 20th day of June 2012.

[signature] (SEAL)
Notary Public

My Commission Expires:

July 21, 2015

APPENDIX A

Shannon L. Charnas
Director, Accounting and Regulatory Reporting
LG&E and KU Energy LLC
220 West Main Street
Louisville, KY 40202
(502) 627-4978

Professional Memberships:

American Institute of Certified Public Accountants (AICPA)
Kentucky Society of Certified Public Accountants (KSCPA)

Education:

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

Professional Experience:

LG&E and KU Energy LLC (and its predecessors)
2005 (Feb) – 2011 (Mar) – Director, Utility Accounting and Reporting
2001 (Mar) - 2005 (Feb) – Manager, Finance & Budgeting - Energy Services
1999 (Sept) - 2001 (Apr) – Senior Budget Analyst
1995 (Aug) - 1999 (Sept) – Accounting Analyst, various positions

Arthur Andersen LLP
1995 – Senior Auditor
1993 – 1994 – Audit Staff

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

APPLICATION OF KENTUCKY	**)**	
UTILITIES COMPANY FOR AN	**)**	**CASE NO. 2012-00221**
ADJUSTMENT OF ITS ELECTRIC	**)**	
RATES	**)**	

DIRECT TESTIMONY OF

JOHN J. SPANOS

ON BEHALF OF

KENTUCKY UTILITIES COMPANY

Filed: June 29, 2012

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I. INTRODUCTION AND PURPOSE

Q. PLEASE STATE YOUR NAME AND ADDRESS.

A. My name is John J. Spanos. My business address is 207 Senate Avenue, Camp Hill, Pennsylvania.

Q. ARE YOU ASSOCIATED WITH ANY FIRM?

A. Yes. I am associated with the firm of Gannett Fleming, Inc.

Q. HOW LONG HAVE YOU BEEN ASSOCIATED WITH GANNETT FLEMING, INC.?

A. I have been associated with the firm since college graduation in June, 1986.

Q. WHAT IS YOUR POSITION WITH THE FIRM?

A. I am a Senior Vice President.

Q. WHAT IS YOUR EDUCATIONAL BACKGROUND?

A. I have Bachelor of Science degrees in Industrial Management and Mathematics from Carnegie-Mellon University and a Master of Business Administration from York College.

Q. DO YOU BELONG TO ANY PROFESSIONAL SOCIETIES?

A. Yes. I am a member and current President of the Society of Depreciation Professionals and the American Gas Association/Edison Electric Institute Industry Accounting Committee.

Q. DO YOU HOLD ANY SPECIAL CERTIFICATION AS A DEPRECIATION EXPERT?

A. Yes. The Society of Depreciation Professionals has established national standards for depreciation professionals. The Society administers an examination to become certified in this field. I passed the certification exam in September 1997 and was recertified in August 2003 and February 2008.

Q. PLEASE OUTLINE YOUR EXPERIENCE IN THE FIELD OF DEPRECIATION.

A. In June, 1986, I was employed by Gannett Fleming Valuation and Rate Consultants, Inc. as a Depreciation Analyst. During the period from June, 1986 through December, 1995, I helped prepare numerous depreciation and original cost studies for utility companies in various industries. I helped perform depreciation studies for the following telephone companies: United Telephone of Pennsylvania, United Telephone of New Jersey, and Anchorage Telephone Utility. I helped perform depreciation studies for the following companies in the railroad industry: Union Pacific Railroad, Burlington Northern Railroad, and Wisconsin Central Transportation Corporation.

I helped perform depreciation studies for the following organizations in the electric utility industry: Chugach Electric Association, The Cincinnati Gas and Electric Company (CG&E), The Union Light, Heat and Power Company (ULH&P), Northwest Territories Power Corporation, and the City of Calgary - Electric System.

I helped perform depreciation studies for the following pipeline companies: TransCanada Pipelines Limited, Trans Mountain Pipe Line Company Ltd., Interprovincial Pipe Line Inc., Nova Gas Transmission Limited and Lakehead Pipeline Company.

I helped perform depreciation studies for the following gas utility companies: Columbia Gas of Pennsylvania, Columbia Gas of Maryland, The Peoples Natural Gas Company, T. W. Phillips Gas & Oil Company, CG&E, ULH&P, Lawrenceburg Gas Company and Penn Fuel Gas, Inc.

I helped perform depreciation studies for the following water utility companies: Indiana-American Water Company, Consumers Pennsylvania Water Company and The

York Water Company; and depreciation and original cost studies for Philadelphia Suburban Water Company and Pennsylvania-American Water Company.

In each of the above studies, I assembled and analyzed historical and simulated data, performed field reviews, developed preliminary estimates of service life and net salvage, calculated annual depreciation, and prepared reports for submission to state public utility commissions or federal regulatory agencies. I performed these studies under the general direction of William M. Stout, P.E.

In January, 1996, I was assigned to the position of Supervisor of Depreciation Studies. In July, 1999, I was promoted to the position of Manager, Depreciation and Valuation Studies. In December, 2000, I was promoted to the position as Vice-President of Gannett Fleming Valuation and Rate Consultants, Inc. and in April 2012, I was promoted to my present position as Senior Vice President of the Valuation and Rate Division of Gannett Fleming Inc. In my current position I am responsible for conducting all depreciation, valuation and original cost studies, including the preparation of final exhibits and responses to data requests for submission to the appropriate regulatory bodies.

Since January 1996, I have conducted depreciation studies similar to those previously listed, including assignments for Pennsylvania-American Water Company; Aqua Pennsylvania; Kentucky-American Water Company; Virginia-American Water Company; Indiana-American Water Company; Hampton Water Works Company; Omaha Public Power District; Enbridge Pipe Line Company; Inc.; Columbia Gas of Virginia, Inc.; Virginia Natural Gas Company; National Fuel Gas Distribution Corporation - New York and Pennsylvania Divisions; The City of Bethlehem - Bureau of Water; The City of Coatesville Authority; The City of Lancaster - Bureau of Water; Peoples Energy

Corporation; The York Water Company; Public Service Company of Colorado; Enbridge Pipelines; Enbridge Gas Distribution, Inc.; Reliant Energy-HLP; Massachusetts-American Water Company; St. Louis County Water Company; Missouri-American Water Company; Chugach Electric Association; Alliant Energy; Oklahoma Gas & Electric Company; Nevada Power Company; Dominion Virginia Power; NUI - Virginia Gas Companies; Pacific Gas & Electric Company; PSI Energy; NUI -Elizabethtown Gas Company; Cinergy Corporation - CG&E; Cinergy Corporation – ULH&P; Columbia Gas of Kentucky; South Carolina Electric & Gas Company; Idaho Power Company; El Paso Electric Company; Central Hudson Gas & Electric; Centennial Pipeline Company; CenterPoint Energy-Arkansas; CenterPoint Energy – Oklahoma; CenterPoint Energy – Entex; CenterPoint Energy - Louisiana; NSTAR – Boston Edison Company; Westar Energy, Inc.; United Water Pennsylvania; PPL Electric Utilities; PPL Gas Utilities; Wisconsin Power & Light Company; TransAlaska Pipeline; Avista Corporation; Northwest Natural Gas; Allegheny Energy Supply, Inc.; Public Service Company of North Carolina; South Jersey Gas Company; Duquesne Light Company; MidAmerican Energy Company; Laclede Gas; Duke Energy Company; E.ON U.S. Services Inc.; Elkton Gas Services; Anchorage Water and Wastewater Utility; Kansas City Power and Light; Duke Energy North Carolina; Duke Energy South Carolina; Duke Energy Ohio Gas; Duke Energy Kentucky; Duke Energy Indiana; Northern Indiana Public Service Company; Tennessee-American Water Company; Columbia Gas of Maryland; Bonneville Power Administration; NSTAR Electric and Gas Company; EPCOR Distribution, Inc.; B. C. Gas Utility, Ltd; Entergy Arkansas; Entergy Texas; Entergy Mississippi; Entergy Louisiana, Entergy Gulf States Louisiana, the Borough of Hanover, Madison Gas and Electric, Atlantic City Electric and Greater

Missouri Operations. My additional duties include determining final life and salvage estimates, conducting field reviews, presenting recommended depreciation rates to management for its consideration and supporting such rates before regulatory bodies.

Q. HAVE YOU SUBMITTED TESTIMONY TO ANY STATE UTILITY COMMISSION ON THE SUBJECT OF UTILITY PLANT DEPRECIATION?

A. Yes. I have submitted testimony to the Pennsylvania Public Utility Commission; the Commonwealth of Kentucky Public Service Commission; the Public Utilities Commission of Ohio; the Nevada Public Utility Commission; the Public Utilities Board of New Jersey; the Missouri Public Service Commission; the Massachusetts Department of Telecommunications and Energy; the Alberta Energy & Utility Board; the Idaho Public Utility Commission; the Louisiana Public Service Commission; the State Corporation Commission of Kansas; the Oklahoma Corporate Commission; the Public Service Commission of South Carolina; the Railroad Commission of Texas – Gas Services Division; the New York Public Service Commission; the Illinois Commerce Commission; the Indiana Utility Regulatory Commission; the California Public Utilities Commission; the Federal Energy Regulatory Commission ("FERC"); the Arkansas Public Service Commission; the Public Utility Commission of Texas; the Maryland Public Service Commission; the Washington Utilities and Transportation Commission; the Tennessee Regulatory Commission; the District of Columbia Public Service Commission; the Mississippi Public Service Commission; the Regulatory Commission of Alaska; Delaware Public Service Commission; Virginia State Corporation Commission; Colorado Public Utility Commission; Oregon Public Utility Commission; Wisconsin Public Service Commission; and the North Carolina Utilities Commission.

Q. HAVE YOU HAD ANY ADDITIONAL EDUCATION RELATING TO UTILITY PLANT DEPRECIATION?

A. Yes. I have completed the following courses conducted by Depreciation Programs, Inc.: "Techniques of Life Analysis," "Techniques of Salvage and Depreciation Analysis," "Forecasting Life and Salvage," "Modeling and Life Analysis Using Simulation," and "Managing a Depreciation Study." I have also completed the "Introduction to Public Utility Accounting" program conducted by the American Gas Association.

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

A. I sponsor the depreciation study performed for Kentucky Utilities Company attached hereto as Exhibit JJS-KU.

II. DEPRECIATION STUDY

Q. PLEASE DEFINE THE CONCEPT OF DEPRECIATION.

A. Depreciation refers to the loss in service value not restored by current maintenance, incurred in connection with the consumption or prospective retirement of utility plant in the course of service from causes which can be reasonably anticipated or contemplated, against which the Company is not protected by insurance. Among the causes to be given consideration are wear and tear, decay, action of the elements, inadequacy, obsolescence, changes in the art, changes in demand and the requirements of public authorities.

Q. DID YOU PREPARE THE DEPRECIATION STUDY FILED BY KENTUCKY UTILITIES COMPANY IN THIS PROCEEDING?

A. Yes. I prepared the depreciation study submitted by Kentucky Utilities Company with its filing in this proceeding. My report is entitled: "Depreciation Study - Calculated Annual

Depreciation Accruals Related to Electric Plant as of December 31, 2011." This report sets forth the results of my depreciation study for Kentucky Utilities Company.

Q. IN PREPARING THE DEPRECIATION STUDY, DID YOU FOLLOW GENERALLY ACCEPTED PRACTICES IN THE FIELD OF DEPRECIATION VALUATION?

A. Yes.

Q. ARE THE METHODS AND PROCEDURES OF THIS DEPRECIATION STUDY CONSISTENT WITH PAST PRACTICES?

A. The methods and procedures of this study are the same as those utilized in past studies of this Company as well as others before this Commission. Depreciation rates are determined based on the average service life procedure and the remaining life method.

Q. PLEASE DESCRIBE THE CONTENTS OF YOUR REPORT.

A. My report is presented in three parts. Part I, Introduction, presents the scope and basis for the depreciation study. Part II, Methods Used in Study, includes descriptions of the basis of the study, the estimation of survivor curves and net salvage and the calculation of annual and accrued depreciation. Part III, Results of Study, presents a description of the results, a summary of the depreciation calculations, graphs and tables that relate to the service life and net salvage analyses, and the detailed depreciation calculations.

The table on pages III-4 through III-10 presents the estimated survivor curve, the net salvage percent, the original cost as of December 31, 2011, the book depreciation reserve and the calculated annual depreciation accrual and rate for each account or subaccount. The section beginning on page III-11 presents the results of the retirement rate analyses prepared as the historical bases for the service life estimates. The section beginning on page III-209 presents the results of the salvage analysis. The section beginning on page III-274 presents the depreciation calculations related to surviving original cost as of December 31, 2011.

Q. PLEASE EXPLAIN HOW YOU PERFORMED YOUR DEPRECIATION STUDY.

A. I used the straight line remaining life method of depreciation, with the average service life procedure. The annual depreciation is based on a method of depreciation accounting that seeks to distribute the unrecovered cost of fixed capital assets over the estimated remaining useful life of each unit, or group of assets, in a systematic and reasonable manner.

For General Plant Accounts 391.1, 391.2, 391.31, 393, 394, 397.1, 397.2 and 397.3 in electric plant, I used the straight line remaining life method of amortization. The account numbers identified throughout my testimony represent those in effect as of December 31, 2011. The annual amortization is based on amortization accounting that distributes the unrecovered cost of fixed capital assets over the remaining amortization period selected for each account and vintage.

Q. HOW DID YOU DETERMINE THE RECOMMENDED ANNUAL DEPRECIATION ACCRUAL RATES?

A. I did this in two phases. In the first phase, I estimated the service life and net salvage characteristics for each depreciable group, that is, each plant account or subaccount identified as having similar characteristics. In the second phase, I calculated the composite remaining lives and annual depreciation accrual rates based on the service life and net salvage estimates determined in the first phase.

Q. PLEASE DESCRIBE THE FIRST PHASE OF THE DEPRECIATION STUDY, IN WHICH YOU ESTIMATED THE SERVICE LIFE AND NET SALVAGE CHARACTERISTICS FOR EACH DEPRECIABLE GROUP.

A. The service life and net salvage study consisted of compiling historical data from records related to Kentucky Utilities Company's plant; analyzing these data to obtain historical trends of survivor characteristics; obtaining supplementary information from management and operating personnel concerning practices and plans as they relate to plant operations; and interpreting the above data and the estimates used by other electric utilities to form judgments of average service life and net salvage characteristics.

Q. WHAT HISTORICAL DATA DID YOU ANALYZE FOR THE PURPOSE OF ESTIMATING SERVICE LIFE CHARACTERISTICS?

A. I analyzed the Company's accounting entries that record plant transactions during the period 1900 through 2011. The transactions included additions, retirements, transfers, sales and the related balances.

Q. WHAT METHOD DID YOU USE TO ANALYZE THESE SERVICE LIFE DATA?

A. I used the retirement rate method. This is the most appropriate method when retirement data covering a long period of time is available because this method determines the average rates of retirement actually experienced by the Company during the period of time covered by the depreciation study.

Q. PLEASE DESCRIBE HOW YOU USED THE RETIREMENT RATE METHOD TO ANALYZE KENTUCKY UTILITIES' SERVICE LIFE DATA.

A. I applied the retirement rate analysis to each different group of property in the study. For each property group, I used the retirement rate data to form a life table which, when plotted, shows an original survivor curve for that property group. Each original survivor curve represents the average survivor pattern experienced by the several vintage groups during the experience band studied. The survivor patterns do not necessarily describe the life characteristics of the property group; therefore, interpretation of the original survivor curves is required in order to use them as valid considerations in estimating service life. The Iowa type survivor curves were used to perform these interpretations.

Q. WHAT IS AN "IOWA-TYPE SURVIVOR CURVE" AND HOW DID YOU USE SUCH CURVES TO ESTIMATE THE SERVICE LIFE CHARACTERISTICS FOR EACH PROPERTY GROUP?

A. Iowa type curves are a widely-used group of survivor curves that contain the range of survivor characteristics usually experienced by utilities and other industrial companies. The Iowa curves were developed at the Iowa State College Engineering Experiment Station through an extensive process of observing and classifying the ages at which various types of property used by utilities and other industrial companies had been retired.

Iowa type curves are used to smooth and extrapolate original survivor curves determined by the retirement rate method. The Iowa curves and truncated Iowa curves were used in this study to describe the forecasted rates of retirement based on the observed rates of retirement and the outlook for future retirements.

The estimated survivor curve designations for each depreciable property group indicate the average service life, the family within the Iowa system to which the property group belongs, and the relative height of the mode. For example, the Iowa 43-R2 indicates an average service life of forty-three years; a right-moded, or R, type curve (the mode occurs after average life for right-moded curves); and a relatively low height, 2, for the mode (possible modes for R type curves range from 1 to 5).

Q. WHAT APPROACH DID YOU USE TO ESTIMATE THE LIVES OF SIGNIFICANT FACILITIES STRUCTURES SUCH AS PRODUCTION PLANTS?

A. I used the life span technique to estimate the lives of significant facilities for which concurrent retirement of the entire facility is anticipated. In this technique, the survivor characteristics of such facilities are described by the use of interim survivor curves and estimated probable retirement dates.

The interim survivor curves describe the rate of retirement related to the replacement of elements of the facility, such as, for a building, the retirements of plumbing, heating, doors, windows, roofs, etc., that occur during the life of the facility. The probable retirement date provides the rate of final retirement for each year of installation for the facility by truncating the interim survivor curve for each installation year at its attained age at the date of probable retirement. The use of interim survivor curves truncated at the date of probable retirement provides a consistent method for estimating the lives of the several years of installation for a particular facility inasmuch as a single concurrent retirement for all years of installation will occur when it is retired.

Q. HAS GANNETT FLEMING USED THIS APPROACH IN OTHER PROCEEDINGS?

A. Yes, we have used the life span technique in performing depreciation studies presented to and accepted by many public utility commissions across the United States and Canada, including Kentucky. This technique is currently being utilized by Kentucky Utilities Company in the same manner recommended in this case.

Q. WHAT ARE THE BASES FOR THE PROBABLE RETIREMENT YEARS THAT YOU HAVE ESTIMATED FOR EACH FACILITY?

A. The bases for the probable retirement years are life spans for each facility that are based on judgment, the life assessment study and incorporate consideration of the age, use, size, nature of construction, management outlook and typical life spans experienced and used by other electric utilities for similar facilities. The life assessment study is referred to in this case as "An Economic Life Assessment Study of Generating Assets LG&E and KU" by Ventyx, an ABB Company. Most of the life spans result in probable retirement years that are many years in the future. As a result, the retirements of these facilities are not yet subject to specific management plans. Such plans would be premature. At the appropriate time, detailed studies of the economics of rehabilitation and continued use or retirement of the structure will be performed and the results incorporated in the estimation of the facility's life span.

Q. DID YOU PHYSICALLY OBSERVE KENTUCKY UTILITIES COMPANY'S PLANT AND EQUIPMENT AS PART OF YOUR DEPRECIATION STUDY?

A. Yes. I made a field review of Kentucky Utilities Company's property as part of this study during October 2011 and previously reviewed assets in April 2007 to observe representative portions of plant. Field reviews are conducted to become familiar with Company operations and obtain an understanding of the function of the plant and information with respect to the reasons for past retirements and the expected future causes of retirements. This knowledge as well as information from other discussions with management was incorporated in the interpretation and extrapolation of the statistical analyses.

Q. PLEASE DESCRIBE HOW YOU ESTIMATED NET SALVAGE PERCENTAGES.

A. I estimated the net salvage percentages by incorporating the historical data for the period 1988 through 2011 and considered estimates for other electric companies.

Q. HAVE YOU INCLUDED A DISMANTLEMENT COMPONENT INTO THE OVERALL RECOVERY OF GENERATING FACILITIES?

A. Yes. A dismantlement component has been included to the net salvage percentage for steam, hydro and other production facilities.

Q. CAN YOU EXPLAIN HOW THE DISMANTLEMENT COMPONENT IS INCLUDED IN THE DEPRECIATION STUDY?

A. Yes. The dismantlement component is part of the overall net salvage for each location within the production assets. Based on studies for other utilities and the cost estimates of KU, it was determined that the dismantlement or decommissioning costs for steam production facilities is best calculated at 10% of the assets subject to final retirement. The percentage for dismantlement of hydro and other production facilities is 5% of the assets surviving at final retirement. These amounts at a location basis are added to the interim net salvage percentage of the assets anticipated to be retired on an interim basis to produce the weighted net salvage percentage for each location. The detailed calculation for each location is set forth on pages III-210 and III-211 of Exhibit JJS-KU.

Q. IS THIS METHODOLOGY A CHANGE FROM PAST PRACTICES?

A. Yes. The past practice for KU and almost all others in the industry was to apply the interim net salvage percentage to all plant in service at the account level. In the past, the account level methodology was supported by the historical analyses, but did not take into consideration individual plant balances. The new methodology is a more precise practice and utilized by most utilities. The weighting of the interim and final net salvage by location establishes a more precise recovery pattern for each location.

Q. PLEASE DESCRIBE THE SECOND PHASE OF THE PROCESS THAT YOU USED IN THE DEPRECIATION STUDY IN WHICH YOU CALCULATED COMPOSITE REMAINING LIVES AND ANNUAL DEPRECIATION ACCRUAL RATES.

A. After I estimated the service life and net salvage characteristics for each depreciable property group, I calculated the annual depreciation accrual rates for each group, using the straight line remaining life method, and using remaining lives weighted consistent with the average service life procedure.

Q. PLEASE DESCRIBE THE STRAIGHT LINE REMAINING LIFE METHOD OF DEPRECIATION.

A. The straight line remaining life method of depreciation allocates the original cost of the property, less accumulated depreciation, less future net salvage, in equal amounts to each year of remaining service life.

Q. PLEASE DESCRIBE AMORTIZATION ACCOUNTING.

A. In amortization accounting, units of property are capitalized in the same manner as they are in depreciation accounting. Amortization accounting is used for accounts with a large number of units, but small asset values, therefore, depreciation accounting is difficult for these assets because periodic inventories are required to properly reflect plant in service. Consequently, retirements are recorded when a vintage is fully amortized rather than as the units are removed from service. That is, there is no dispersion of retirement. All units are retired when the age of the vintage reaches the amortization period. Each plant account or group of assets is assigned a fixed period which represents an anticipated life during which the asset will render full benefit. For example, in amortization accounting, assets that have a 25-year amortization period will be fully recovered after 25 years of service and taken off the Company's books, but not necessarily removed from service. In contrast, assets that are taken out of service before 25 years remain on the books until the amortization period for that vintage has expired.

Q. AMORTIZATION ACCOUNTING IS BEING UTILIZED FOR WHICH PLANT ACCOUNTS?

A. Amortization accounting is only appropriate for certain General Plant accounts. These accounts are 391.1, 391.2, 391.31, 393, 394, 395, 397.1, 397.2 and 397.3 for electric plant which represents slightly less than one percent of depreciable plant.

Q. PLEASE USE AN EXAMPLE TO ILLUSTRATE HOW THE ANNUAL DEPRECIATION ACCRUAL RATE FOR A PARTICULAR GROUP OF PROPERTY IS PRESENTED IN YOUR DEPRECIATION STUDY.

A. I will use Account 368, Line Transformers, as an example because it is one of the largest depreciable mass accounts and represents approximately 4% of depreciable plant.

The retirement rate method was used to analyze the survivor characteristics of this property group. Aged plant accounting data was compiled from 1900 through 2011 and analyzed in periods that best represent the overall service life of this property. The life tables for the 1900-2011 and 1961-2011 experience bands are presented on pages III-168 through III-173 of the report. The life table displays the retirement and surviving ratios of the aged plant data exposed to retirement by age interval. For example, page III-168 shows \$1,000,135 retired at age 0.5 with \$315,972,575 exposed to retirement. Consequently, the retirement ratio is 0.0032 and the surviving ratio is 0.9968. These life tables, or original survivor curves, are plotted along with the estimated smooth survivor curve, the 43-R2 on page III-167.

My calculation of the annual depreciation related to the original cost at December 31, 2011, of utility plant is presented on pages III-395 and III-396. The calculation is based on the 43-R2 survivor curve, 15% negative net salvage, the attained age, and the allocated book reserve. The tabulation sets forth the installation year, the original cost, calculated accrued depreciation, allocated book reserve, future accruals, remaining life and annual accrual. These totals are brought forward to the table on page III-9.

Q. WERE THERE ANY SPECIFIC ACCOUNT CHANGES TO DEPRECIATION METHODS PROPOSED IN THE DEPRECIATION STUDY?

A. Yes. The depreciation rates for assets in accounts or subaccounts of 392, 396 and 397 were developed using different bases. First, Account 397, Communication Equipment was segregated into multiple subaccounts to represent the assets within the group. There was one subaccount created to represent assets that should have been retired. These assets were assigned an accumulated depreciation amount equal to the plant installed amount in order to insure full recovery at the time of actual retirement in 2012. The second established subaccount in Account 397 was the amortized assets. These assets are subject to amortization accounting which has been the current practice of this account. The final subaccount for Account 397 is structures and equipment related to communication facilities which is not ideally suited for amortization accounting. These assets have an average service life longer than 10 years and are subject to considerably different dispersion patterns.

The life parameters for subaccounts of Accounts 392, Transportation Equipment, and 396, Power Operated Equipment, are currently recovered over 5 years with no dispersion. This life expectancy is generally too short for these type of assets and expectations are that transportation and power operated equipment will have various dispersion patterns. Consequently, these assets will continue to be depreciated beyond the current 5 years based on survivor curves that are more appropriate for the assets in each group. Assets in Account 392 have been segregated into two subaccounts; 1) cars and light trucks and 2) heavy trucks and other. The assets in Account 396 have been categorized as large machinery. The overall level of the accumulated depreciation has not changed but the remaining investment will be depreciated over the remaining life of each asset class.

Q. WHAT IS THE EFFECT OF THESE CHANGES ON DEPRECIATION?

A. The depreciation rates have been lowered and depreciation expense reduced as of December 31, 2011.

Q. DOES THE DECREASED DEPRECIATION EXPENSE AFFECT ELECTRIC PLANT?

A. Yes, the general plant function in Electric Plant was decreased due to the changes in depreciation practices for Accounts 392, 396 and 397.

III. <u>CONCLUSION</u>

Q. WAS THE DEPRECIATION STUDY FILED BY KENTUCKY UTILITIES COMPANY IN THIS PROCEEDING PREPARED BY YOU OR UNDER YOUR DIRECTION AND CONTROL?

A. Yes.

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

A. Yes.

VERIFICATION

COMMONWEALTH OF PENNSYLVANIA)
) **SS:**
COUNTY OF CUMBERLAND)

The undersigned, **John J. Spanos**, being duly sworn, deposes and says that he is Senior Vice President, Valuation and Rate Division, for Gannett Fleming, 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.

John J. Spanos
JOHN J. SPANOS

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 5th day of June 2012.

Cheryl A. Rutter (SEAL)
Notary Public

My Commission Expires:
February 20, 2015

COMMONWEALTH OF PENNSYLVANIA
Notarial Seal
Cheryl Ann Rutter, Notary Public
East Pennsboro Twp., Cumberland County
My Commission Expires Feb. 20, 2015
MEMBER, PENNSYLVANIA ASSOCIATION OF NOTARIES

Exhibit JJS-KU

Depreciation Study Performed for Kentucky Utilities Company

KENTUCKY UTILITIES COMPANY

Louisville, Kentucky

DEPRECIATION STUDY

CALCULATED ANNUAL DEPRECIATION ACCRUALS

RELATED TO ELECTRIC PLANT

AS OF DECEMBER 31, 2011

GANNETT FLEMING, INC. - VALUATION AND RATE DIVISION

Harrisburg, Pennsylvania

Gannett Fleming

Excellence Delivered ***As Promised***

May 18, 2012

Kentucky Utilities Company
229 West Main Street
Louisville, KY 40202-1345

Attention Ms. Sara Wiseman
Manager, Plant Accounting

Ladies and Gentlemen:

Pursuant to your request, we have conducted a depreciation study related to the electric plant of Kentucky Utilities Company as of December 31, 2011. The attached report presents a description of the methods used in the estimation of depreciation, the summary of annual and accrued depreciation, the statistical support for the service life and net salvage estimates, and the detailed tabulations of annual and accrued depreciation.

Respectfully submitted,

GANNETT FLEMING, INC.

John J. Spanos

JOHN J. SPANOS
Sr. Vice President
Valuation and Rate Division

JJS:krm

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PART I. INTRODUCTION

PART II. METHODS USED IN THE ESTIMATION OF DEPRECIATION

PART III. RESULTS OF STUDY

CONTENTS, cont.

PART III. RESULTS OF STUDY, cont.

I-1

PART I. INTRODUCTION

KENTUCKY UTILITIES COMPANY

DEPRECIATION STUDY

CALCULATED ANNUAL DEPRECIATION ACCRUALS
RELATED TO ELECTRIC PLANT
AS OF DECEMBER 31, 2011

PART I. INTRODUCTION

SCOPE

This report presents the results of the depreciation study prepared for the Kentucky Utilities Company ("Company") as applied to electric plant in service as of December 31, 2011. It relates to the concepts, methods and basic judgments which underlie recommended annual depreciation accrual rates related to current electric plant in service.

The service life estimates resulting from the study were based on informed judgment which incorporated analyses of historical plant retirement data as recorded through December 2011; the net salvage analyses of historical plant retirements data recorded through December 2011; a review of Company practice and outlook as they relate to plant operation and retirement; and consideration of current practice in the electric industry, including knowledge of service life and salvage estimates used for other electric properties.

PLAN OF REPORT

Part I includes brief statements of the scope and basis of the study. Part II presents descriptions of the methods used in the service life and salvage studies and the methods and procedures used in the calculation of depreciation. Part III presents the results of the study, including a summary table, survivor curve charts and life tables resulting from the retirement rate method of analysis; tabular results of the historical net salvage analyses; and detailed tabulations of the calculated remaining lives and annual accruals.

BASIS OF STUDY

Depreciation

For most accounts, the annual depreciation was calculated by the straight line method using the average service life procedure and the remaining life basis. For certain General Plant accounts, the annual depreciation was based on amortization accounting. The calculated remaining lives and annual depreciation accrual rates were based on attained ages of plant in service and the estimated service life and salvage characteristics of each depreciable group.

Survivor Curve Estimates

The procedure for estimating survivor curves, which define service lives and remaining lives, consisted of compiling historical service life data for the plant accounts or other depreciable groups, analyzing the historical data base through the use of accepted techniques, and forecasting the survivor characteristics for each depreciable account or group. These forecasts were based on interpretations of the historical data analyses and the probable future. The combination of the historical data and the estimated future trend yields a complete pattern of life characteristics, i.e., a survivor curve, from which the average service life and remaining service life are derived.

The historical data analyzed for life estimation purposes were compiled through December 2011 from the Company's plant accounting records. Such data included plant additions, retirements, transfers and other activity recorded by the Company for each of its plant accounts and subaccounts.

The estimates of net salvage by account incorporated a review of experienced costs of removal and salvage related to plant retirements, and consideration of trends exhibited by the historical data. Each component of net salvage, i.e., cost of removal and salvage, was stated in dollars and as a percent of retirement.

An understanding of the function of the plant and information with respect to the reasons for past retirements and the expected causes of future retirements was obtained through discussions with operating and management personnel. The supplemental information obtained in this manner was considered in the interpretation and extrapolation of the statistical analyses.

Calculation of Depreciation

The depreciation accrual rates were calculated using the straight line method, the remaining life basis and the average service life depreciation procedure. The continuation of amortization accounting for certain accounts is recommended because of the disproportionate plant accounting effort required when compared to the minimal original cost of the large number of items in these accounts. An explanation of the calculation of annual and accrued amortization is presented on page II-33 of the report.

II-1

PART II. METHODS USED IN

THE ESTIMATION OF DEPRECIATION

PART II. METHODS USED IN THE ESTIMATION OF DEPRECIATION

DEPRECIATION

Depreciation, as defined in the Uniform System of Accounts, is the loss in service value not restored by current maintenance, incurred in connection with the consumption or prospective retirement of electric plant in the course of service from causes which are known to be in current operation and against which the utility is not protected by insurance. Among the causes to be given consideration are wear and tear, decay, action of the elements, inadequacy, obsolescence, changes in the art, changes in demand, requirements of public authorities, and, in the case of natural gas companies, the exhaustion of natural resources.

Depreciation, as used in accounting, is a method of distributing fixed capital costs, less net salvage, over a period of time by allocating annual amounts to expense. Each annual amount of such depreciation expense is part of that year's total cost of providing utility service. Normally, the period of time over which the fixed capital cost is allocated to the cost of service is equal to the period of time over which an item renders service, that is, the item's service life. The most prevalent method of allocation is to distribute an equal amount of cost to each year of service life. This method is known as the straight line method of depreciation.

The calculation of annual depreciation based on the straight line method requires the estimation of average life and salvage. These subjects are discussed in the sections which follow.

SERVICE LIFE AND NET SALVAGE ESTIMATION

Average Service Life

The use of an average service life for a property group implies that the various units in the group have different lives. Thus, the average life may be obtained by determining the separate lives of each of the units, or by constructing a survivor curve by plotting the number of units which survive at successive ages. A discussion of the general concept of survivor curves is presented. Also, the Iowa type survivor curves are reviewed.

Survivor Curves

The survivor curve graphically depicts the amount of property existing at each age throughout the life of an original group. From the survivor curve, the average life of the group, the remaining life expectancy, the probable life, and the frequency curve can be calculated. In Figure 1, a typical smooth survivor curve and the derived curves are illustrated. The average life is obtained by calculating the area under the survivor curve, from age zero to the maximum age, and dividing this area by the ordinate at age zero. The remaining life expectancy at any age can be calculated by obtaining the area under the curve, from the observation age to the maximum age, and dividing this area by the percent surviving at the observation age. For example, in Figure 1, the remaining life at age 30 is equal to the crosshatched area under the survivor curve divided by 29.5 percent surviving at age 30. The probable life at any age is developed by adding the age and remaining life. If the probable life of the property is calculated for each year of age, the probable life curve shown in the chart can be developed. The frequency curve presents the number of units retired in each age interval and is derived by obtaining the differences between the amount of property surviving at the beginning and at the end of each interval.

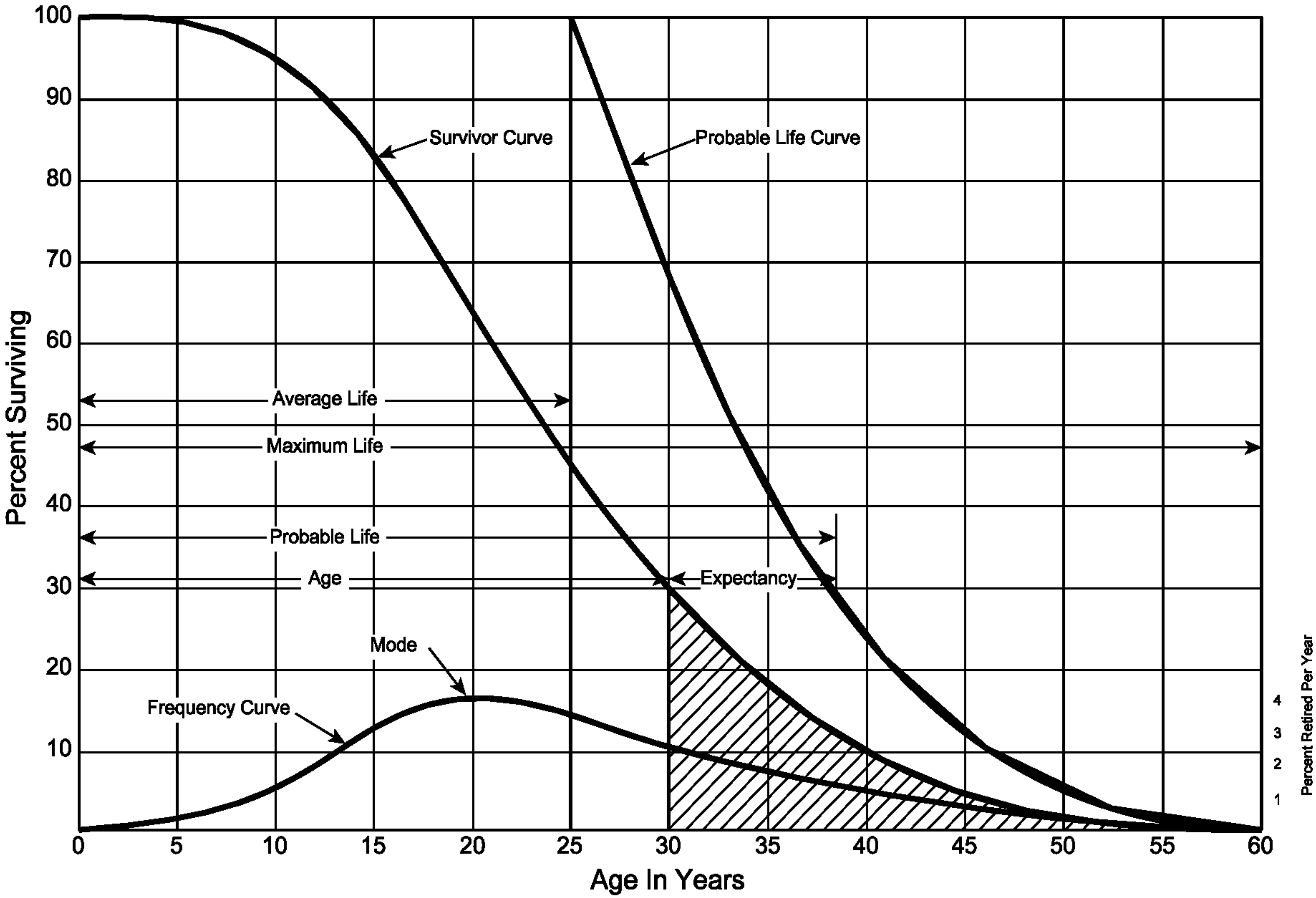

Figure 1. A Typical Survivor Curve and Derived Curves

Iowa Type Curves. The range of survivor characteristics usually experienced by utility and industrial properties is encompassed by a system of generalized survivor curves known as the Iowa type curves. There are four families in the Iowa system, labeled in accordance with the location of the modes of the retirements in relationship to the average life and the relative height of the modes. The left moded curves, presented in Figure 2, are those in which the greatest frequency of retirement occurs to the left of, or prior to, average service life. The symmetrical moded curves, presented in Figure 3, are those in which the greatest frequency of retirement occurs at average service life. The right moded curves, presented in Figure 4, are those in which the greatest frequency occurs to the right of, or after, average service life. The origin moded curves, presented in Figure 5, are those in which the greatest frequency of retirement occurs at the origin, or immediately after age zero. The letter designation of each family of curves (L, S, R or O) represents the location of the mode of the associated frequency curve with respect to the average service life. The numbers represent the relative heights of the modes of the frequency curves within each family.

The Iowa curves were developed at the Iowa State College Engineering Experiment Station through an extensive process of observation and classification of the ages at which industrial property had been retired. A report of the study which resulted in the classification of property survivor characteristics into 18 type curves, which constitute three of the four families, was published in 1935 in the form of the Experiment Station's Bulletin 125.[1] These type curves have also been presented in subsequent Experiment Station

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[1]Winfrey, Robley. Statistical Analyses of Industrial Property Retirements. Iowa State College, Engineering Experiment Station, Bulletin 125. 1935.

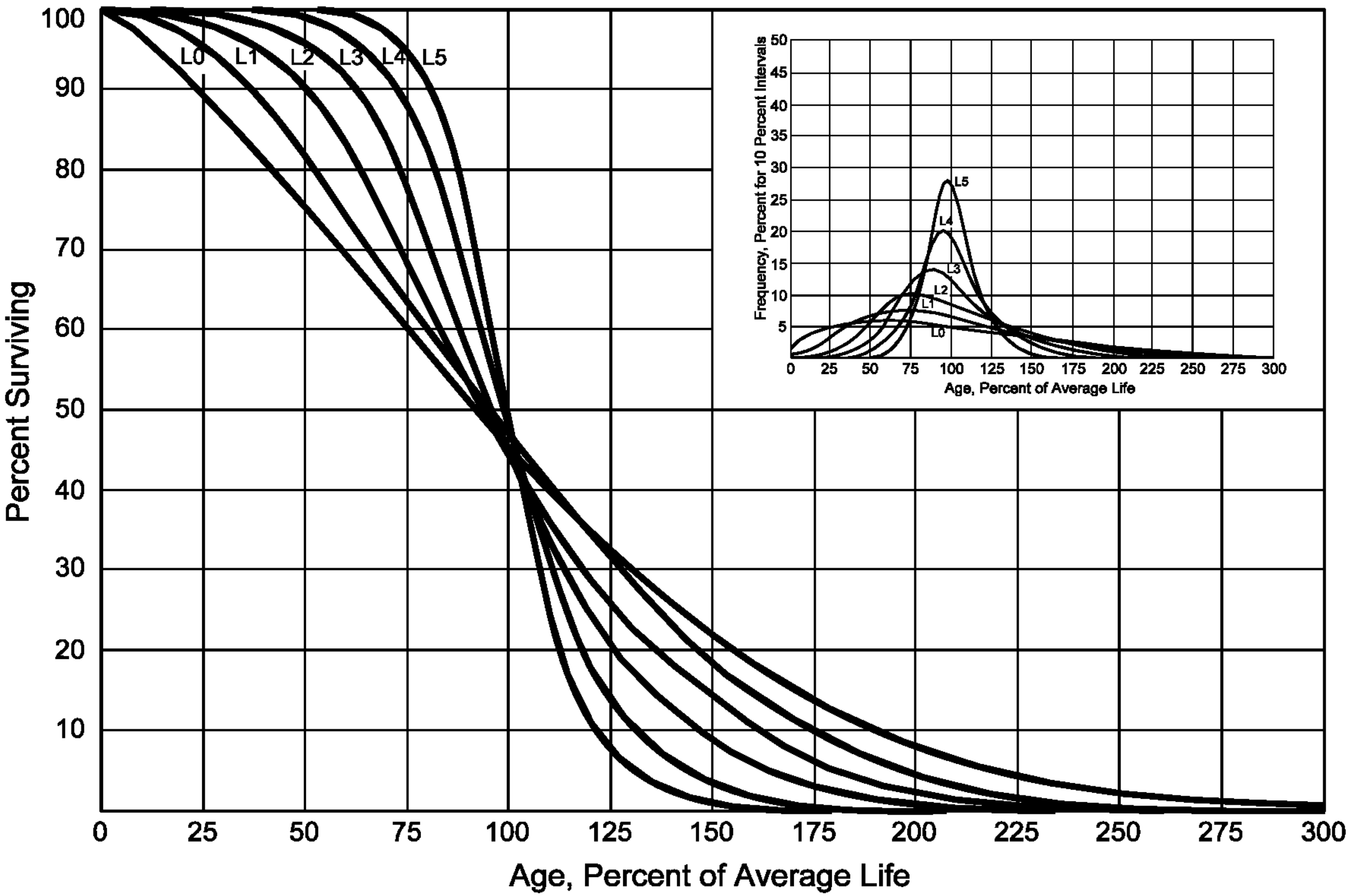

Figure 2. Left Modal or "L" Iowa Type Survivor Curves

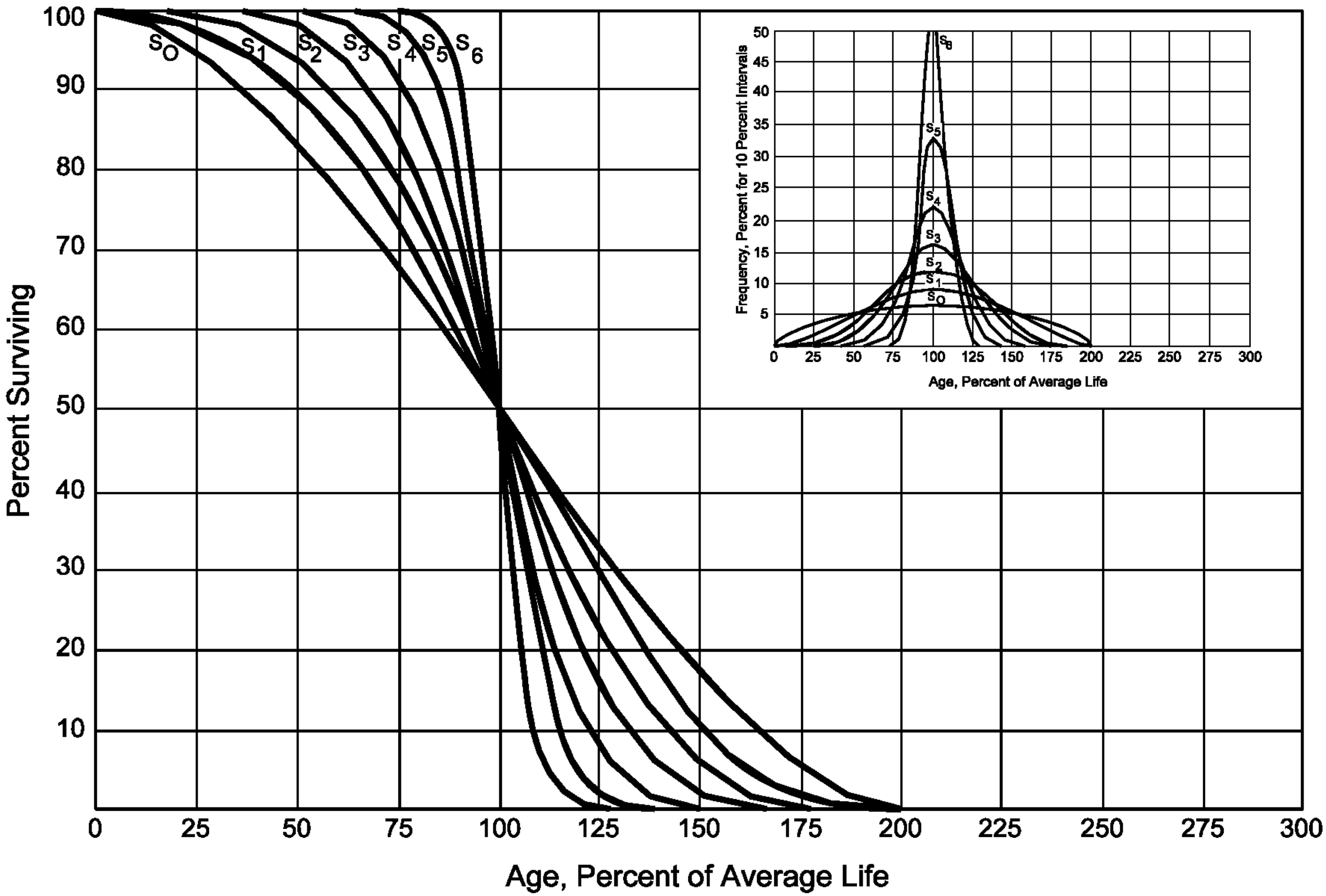

Figure 3. Symmetrical or "S" Iowa Type Survivor Curves

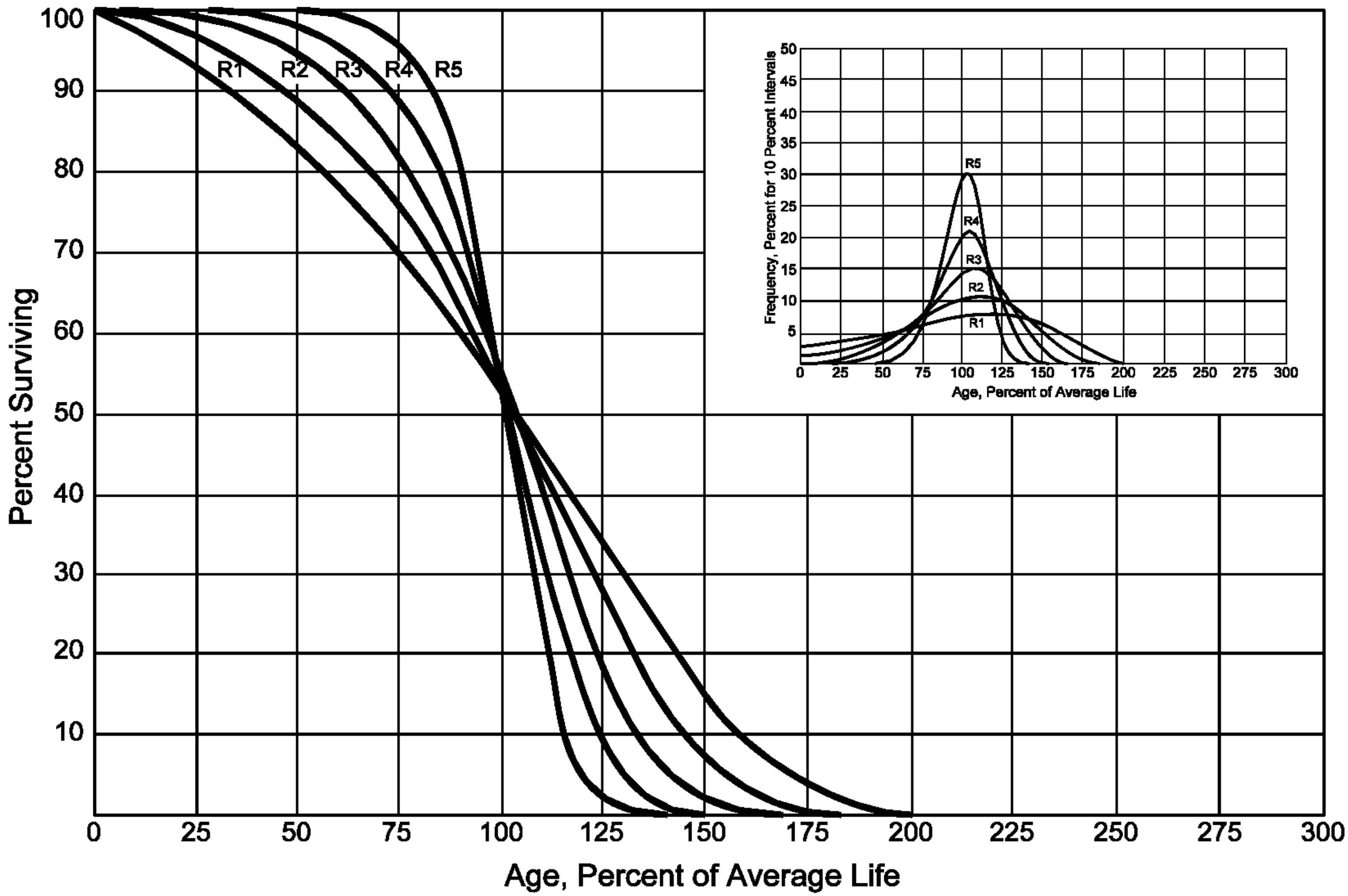

Figure 4. Right Modal or "R" Iowa Type Survivor Curves

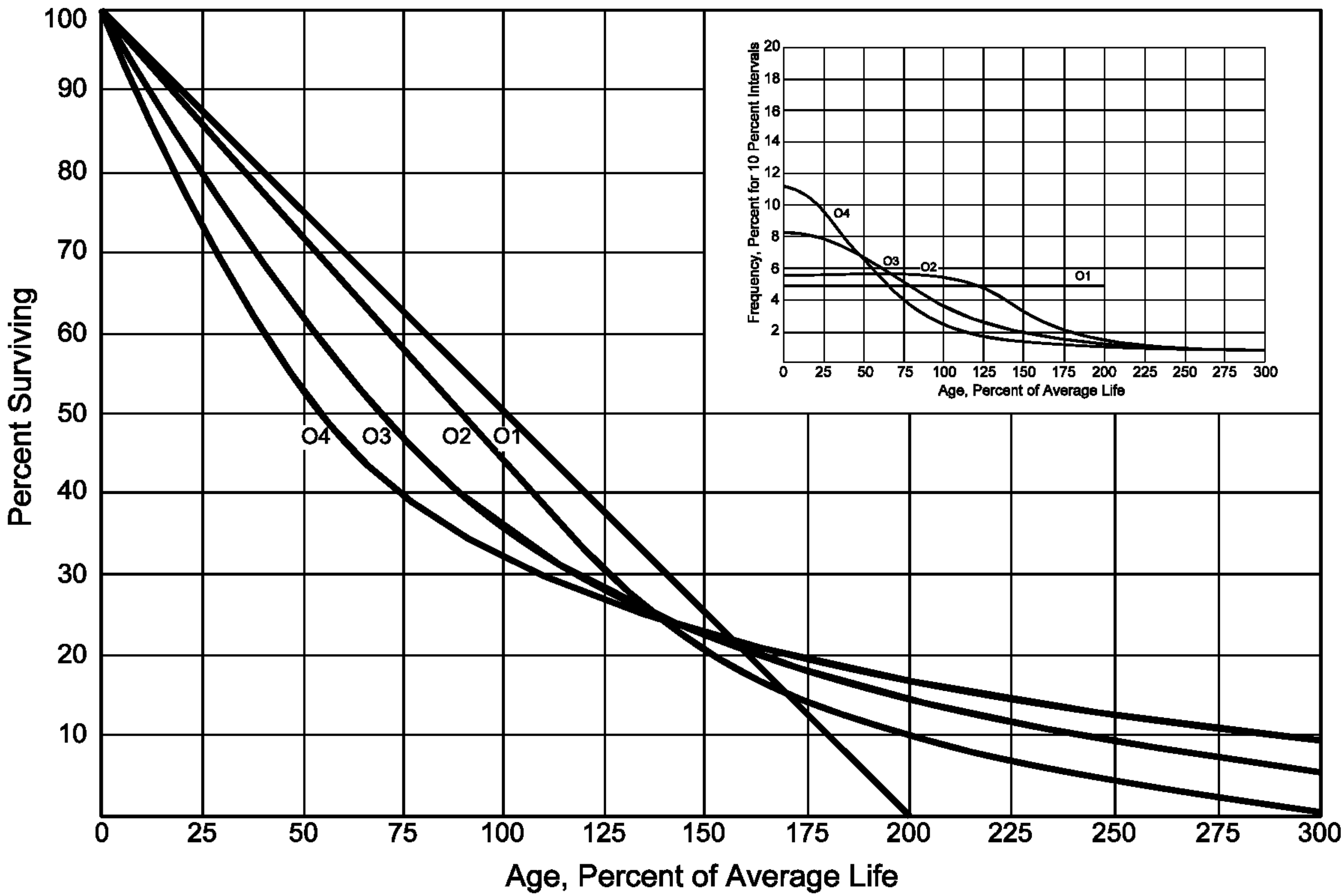

Figure 5. Origin Modal or "O" Iowa Type Survivor Curves

bulletins and in the text, "Engineering Valuation and Depreciation."[2] In 1957, Frank V. B. Couch, Jr., an Iowa State College graduate student, submitted a thesis[3] presenting his development of the fourth family consisting of the four O type survivor curves.

Retirement Rate Method of Analysis

The retirement rate method is an actuarial method of deriving survivor curves using the average rates at which property of each age group is retired. The method relates to property groups for which aged accounting experience is available or for which aged accounting experience is developed by statistically aging unaged amounts and is the method used to develop the original stub survivor curves in this study. The method (also known as the annual rate method) is illustrated through the use of an example in the following text, and is also explained in several publications, including "Statistical Analyses of Industrial Property Retirements,"[4] "Engineering Valuation and Depreciation,"[5] and "Depreciation Systems."[6]

The average rate of retirement used in the calculation of the percent surviving for the survivor curve (life table) requires two sets of data: first, the property retired during a period of observation, identified by the property's age at retirement; and second, the

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[2]Marston, Anson, Robley Winfrey and Jean C. Hempstead. Engineering Valuation and Depreciation, 2nd Edition. New York, McGraw-Hill Book Company. 1953.

[3]Couch, Frank V. B., Jr. "Classification of Type O Retirement Characteristics of Industrial Property." Unpublished M.S. thesis (Engineering Valuation). Library, Iowa State College, Ames, Iowa. 1957.

[4]Winfrey, Robley, Supra Note 1.

[5]Marston, Anson, Robley Winfrey, and Jean C. Hempstead, Supra Note 2.

[6]Wolf, Frank K. and W. Chester Fitch. Depreciation Systems. Iowa State University Press. 1994

property exposed to retirement at the beginnings of the age intervals during the same period. The period of observation is referred to as the experience band, and the band of years which represent the installation dates of the property exposed to retirement during the experience band is referred to as the placement band. An example of the calculations used in the development of a life table follows. The example includes schedules of annual aged property transactions, a schedule of plant exposed to retirement, a life table and illustrations of smoothing the stub survivor curve.

Schedules of Annual Transactions in Plant Records. The property group used to illustrate the retirement rate method is observed for the experience band 2002-2011 during which there were placements during the years 1997-2011. In order to illustrate the summation of the aged data by age interval, the data were compiled in the manner presented in Tables 1 and 2 on pages II-12 and II-13. In Table 1, the year of installation (year placed) and the year of retirement are shown. The age interval during which a retirement occurred is determined from this information. In the example which follows, \$10,000 of the dollars invested in 1997 were retired in 2002. The \$10,000 retirement occurred during the age interval between 4½ and 5½ years on the basis that approximately one-half of the amount of property was installed prior to and subsequent to July 1 of each year. That is, on the average, property installed during a year is placed in service at the midpoint of the year for the purpose of the analysis. All retirements also are stated as occurring at the midpoint of a one-year age interval of time, except the first age interval which encompasses only one-half year.

The total retirements occurring in each age interval in a band are determined by summing the amounts for each transaction year-installation year combination for that age

TABLE 1. RETIREMENTS FOR EACH YEAR 2002-2011
SUMMARIZED BY AGE INTERVAL

Experience Band 2002-2011

Placement Band 1997-2011

Year Placed (1)	2002 (2)	2003 (3)	2004 (4)	2005 (5)	2006 (6)	2007 (7)	2008 (8)	2009 (9)	2010 (10)	2011 (11)	Total During Age Interval (12)	Age Interval (13)
	Retirements, Thousands of Dollars During Year											
1997	10	11	12	13	14	16	23	24	25	26	26	13½-14½
1998	11	12	13	15	16	18	20	21	22	19	44	12½-13½
1999	11	12	13	14	16	17	19	21	22	18	64	11½-12½
2000	8	9	10	11	11	13	14	15	16	17	83	10½-11½
2001	9	10	11	12	13	14	16	17	19	20	93	9½-10½
2002	4	9	10	11	12	13	14	15	16	20	105	8½-9½
2003		5	11	12	13	14	15	16	18	20	113	7½-8½
2004			6	12	13	15	16	17	19	19	124	6½-7½
2005				6	13	15	16	17	19	19	131	5½-6½
2006					7	14	16	17	19	20	143	4½-5½
2007						8	18	20	22	23	146	3½-4½
2008							9	20	22	25	150	2½-3½
2009								11	23	25	151	1½-2½
2010									11	24	153	½-1½
2011	__	__	__	__	__	__	__	__	__	13	80	0-½
Total	53	68	86	106	128	157	196	231	273	308	1,606	

TABLE 2. OTHER TRANSACTIONS FOR EACH YEAR 2002-2011
SUMMARIZED BY AGE INTERVAL

Experience Band 2002-2011

Placement Band 1997-2011

Year Placed (1)	Acquisitions, Transfers and Sales, Thousands of Dollars During Year 2002 (2)	2003 (3)	2004 (4)	2005 (5)	2006 (6)	2007 (7)	2008 (8)	2009 (9)	2010 (10)	2011 (11)	Total During Age Interval (12)	Age Interval (13)
1997	-	-	-	-	-	-	60[a]	-	-	-	-	13½-14½
1998	-	-	-	-	-	-	-	-	-	-	-	12½-13½
1999	-	-	-	-	-	-	-	-	-	-	-	11½-12½
2000	-	-	-	-	-	-	-	(5)[b]	-	-	60	10½-11½
2001	-	-	-	-	-	-	-	6[a]	-	-	-	9½-10½
2002		-	-	-	-	-	-	-	-	-	(5)	8½-9½
2003		-	-	-	-	-	-	-	-	-	6	7½-8½
2004			-	-	-	-	-	-	-	-	-	6½-7½
2005				-	-	-	-	(12)[b]	-	-	-	5½-6½
2006					-	-	-	-	22[a]	-	-	4½-5½
2007						-	-	(19)[b]	-	-	10	3½-4½
2008							-	-	-	-	-	2½-3½
2009								-	-	(102)[c]	(121)	1½-2½
2010									-	-	-	½-1½
2011											-	0-½
Total	-	-	-	-	-	-	60	(30)	22	(102)	(50)	

[a] Transfer Affecting Exposures at Beginning of Year
[b] Transfer Affecting Exposures at End of Year
[c] Sale with Continued Use
Parentheses denote Credit amount.

interval. For example, the total of $143,000 retired for age interval 4½-5½ is the sum of the retirements entered on Table 1 immediately above the stairstep line drawn on the table beginning with the 2002 retirements of 1997 installations and ending with the 2011 retirements of the 2006 installations. Thus, the total amount of 143 for age interval 4½-5½ equals the sum of:

$$10 + 12 + 13 + 11 + 13 + 13 + 15 + 17 + 19 + 20.$$

In Table 2, other transactions which affect the group are recorded in a similar manner. The entries illustrated include transfers and sales. The entries which are credits to the plant account are shown in parentheses. The items recorded on this schedule are not totaled with the retirements, but are used in developing the exposures at the beginning of each age interval.

Schedule of Plant Exposed to Retirement. The development of the amount of plant exposed to retirement at the beginning of each age interval is illustrated in Table 3 on page II-15.

The surviving plant at the beginning of each year from 2002 through 2011 is recorded by year in the portion of the table headed "Annual Survivors at the Beginning of the Year." The last amount entered in each column is the amount of new plant added to the group during the year. The amounts entered in Table 3 for each successive year following the beginning balance or addition are obtained by adding or subtracting the net entries shown on Tables 1 and 2. For the purpose of determining the plant exposed to retirement, transfers-in are considered as being exposed to retirement in this group at the beginning of the year in which they occurred, and the sales and transfers-out are considered to be removed from the plant exposed to retirement at the beginning of the

TABLE 3. PLANT EXPOSED TO RETIREMENT
JANUARY 1 OF EACH YEAR 2002-2011
SUMMARIZED BY AGE INTERVAL

Experience Band 2002-2011

Placement Band 1997-2011

	Exposures, Thousands of Dollars											
	Annual Survivors at the Beginning of the Year											
Year Placed (1)	2002 (2)	2003 (3)	2004 (4)	2005 (5)	2006 (6)	2007 (7)	2008 (8)	2009 (9)	2010 (10)	2011 (11)	Total at Beginning of Age Interval (12)	Age Interval (13)
1997	255	245	234	222	209	195	239	216	192	167	167	13½-14½
1998	279	268	256	243	228	212	194	174	153	131	323	12½-13½
1999	307	296	284	271	257	241	224	205	184	162	531	11½-12½
2000	338	330	321	311	300	289	276	262	242	226	823	10½-11½
2001	376	367	357	346	334	321	307	297	280	261	1,097	9½-10½
2002	420[a]	416	407	397	386	374	361	347	332	316	1,503	8½-9½
2003		460[a]	455	444	432	419	405	390	374	356	1,952	7½-8½
2004			510[a]	504	492	479	464	448	431	412	2,463	6½-7½
2005				580[a]	574	561	546	530	501	482	3,057	5½-6½
2006					660[a]	653	639	623	628	609	3,789	4½-5½
2007						750[a]	742	724	685	663	4,332	3½-4½
2008							850[a]	841	821	799	4,955	2½-3½
2009								960[a]	949	926	5,719	1½-2½
2010									1,080[a]	1,069	6,579	½-1½
2011										1,220[a]	7,490	0-½
Total	1,975	2,382	2,824	3,318	3,872	4,494	5,247	6,017	6,852	7,799	44,780	

[a] Additions during the year.

following year. Thus, the amounts of plant shown at the beginning of each year are the amounts of plant from each placement year considered to be exposed to retirement at the beginning of each successive transaction year. For example, the exposures for the installation year 2007 are calculated in the following manner:

Exposures at age 0	= amount of addition	= $750,000
Exposures at age ½	= $750,000 - $ 8,000	= $742,000
Exposures at age 1½	= $742,000 - $18,000	= $724,000
Exposures at age 2½	= $724,000 - $20,000 - $19,000	= $685,000
Exposures at age 3½	= $685,000 - $22,000	= $663,000

For the entire experience band 2002-2011 the total exposures at the beginning of an age interval are obtained by summing diagonally in a manner similar to the summing of the retirements during an age interval (Table 1). For example, the figure of 3,789, shown as the total exposures at the beginning of age interval 4½-5½, is obtained by summing:

255 + 268 + 284 + 311 + 334 + 374 + 405 + 448 + 501 + 609.

Original Life Table. The original life table, illustrated in Table 4 on page II-17, is developed from the totals shown on the schedules of retirements and exposures, Tables 1 and 3, respectively. The exposures at the beginning of the age interval are obtained from the corresponding age interval of the exposure schedule, and the retirements during the age interval are obtained from the corresponding age interval of the retirement schedule. The retirement ratio is the result of dividing the retirements during the age interval by the exposures at the beginning of the age interval. The percent surviving at the beginning of each age interval is derived from survivor ratios, each of which equals one minus the

TABLE 4. ORIGINAL LIFE TABLE
CALCULATED BY THE RETIREMENT RATE METHOD

Experience Band 2002-2011 Placement Band 2007-2011

(Exposure and Retirement Amounts are in Thousands of Dollars)

Age at Beginning of Interval (1)	Exposures at Beginning of Age Interval (2)	Retirements During Age Interval (3)	Retirement Ratio (4)	Survivor Ratio (5)	Percent Surviving at Beginning of Age Interval (6)
0.0	7,490	80	0.0107	0.9893	100.00
0.5	6,579	153	0.0233	0.9767	98.93
1.5	5,719	151	0.0264	0.9736	96.62
2.5	4,955	150	0.0303	0.9697	94.07
3.5	4,332	146	0.0337	0.9663	91.22
4.5	3,789	143	0.0377	0.9623	88.15
5.5	3,057	131	0.0429	0.9571	84.83
6.5	2,463	124	0.0503	0.9497	81.19
7.5	1,952	113	0.0579	0.9421	77.11
8.5	1,503	105	0.0699	0.9301	72.65
9.5	1,097	93	0.0848	0.9152	67.57
10.5	823	83	0.1009	0.8991	61.84
11.5	531	64	0.1205	0.8795	55.60
12.5	323	44	0.1362	0.8638	48.90
13.5	167	26	0.1557	0.8443	42.24
					35.66
Total	44,780	1,606			

Column 2 from Table 3, Column 12, Plant Exposed to Retirement.
Column 3 from Table 1, Column 12, Retirements for Each Year.
Column 4 = Column 3 divided by Column 2.
Column 5 = 1.0000 minus Column 4.
Column 6 = Column 5 multiplied by Column 6 as of the Preceding Age Interval.

retirement ratio. The percent surviving is developed by starting with 100% at age zero and successively multiplying the percent surviving at the beginning of each interval by the survivor ratio, i.e., one minus the retirement ratio for that age interval. The calculations necessary to determine the percent surviving at age 5½ are as follows:

Percent surviving at age 4½	=	88.15				
Exposures at age 4½	=	3,789,000				
Retirements from age 4½ to 5½	=	143,000				
Retirement Ratio	=	143,000	÷	3,789,000	=	0.0377
Survivor Ratio	=	1.000	-	0.0377	=	0.9623
Percent surviving at age 5½	=	(88.15)	x	(0.9623)	=	84.83

The totals of the exposures and retirements (columns 2 and 3) are shown for the purpose of checking with the respective totals in Tables 1 and 3. The ratio of the total retirements to the total exposures, other than for each age interval, is meaningless.

The original survivor curve is plotted from the original life table (column 6, Table 4). When the curve terminates at a percent surviving greater than zero, it is called a stub survivor curve. Survivor curves developed from retirement rate studies generally are stub curves.

<u>Smoothing the Original Survivor Curve</u>. The smoothing of the original survivor curve eliminates any irregularities and serves as the basis for the preliminary extrapolation to zero percent surviving of the original stub curve. Even if the original survivor curve is complete from 100% to zero percent, it is desirable to eliminate any irregularities, as there is still an extrapolation for the vintages which have not yet lived to the age at which the curve reaches zero percent. In this study, the smoothing of the original curve with established type curves was used to eliminate irregularities in the original curve.

was compared to the Iowa curves using visual and mathematical matching in order to determine the better fitting smooth curves. In Figures 6, 7, and 8, the original curve developed in Table 4 is compared with the L, S, and R Iowa type curves which most nearly fit the original survivor curve. In Figure 6, the L1 curve with an average life between 12 and 13 years appears to be the best fit. In Figure 7, the S0 type curve with a 12-year average life appears to be the best fit and appears to be better than the L1 fitting. In Figure 8, the R1 type curve with a 12-year average life appears to be the best fit and appears to be better than either the L1 or the S0. In Figure 9, the three fittings, 12-L1, 12-S0 and 12-R1 are drawn for comparison purposes. It is probable that the 12-R1 Iowa curve would be selected as the most representative of the plotted survivor characteristics of the group, assuming no contrary relevant factors external to the analysis of historical data.

Field Trips.

In order to be familiar with the operation of the Company and to observe representative portions of the plant, field trips were conducted. A general understanding of the function of the plant and information with respect to the reasons for past retirements and the expected future causes of retirements was obtained during these trips. This knowledge and information was incorporated in the interpretation and extrapolation of the statistical analyses.

The plant facilities visited on October 10 through 12, 2011 and April 23 through 25, 2007:

October 10-12, 2011

E.W. Brown Generating Facility
Tyrone Generating Facility
Ghent Generating Facility
Trimble County Generating Facility

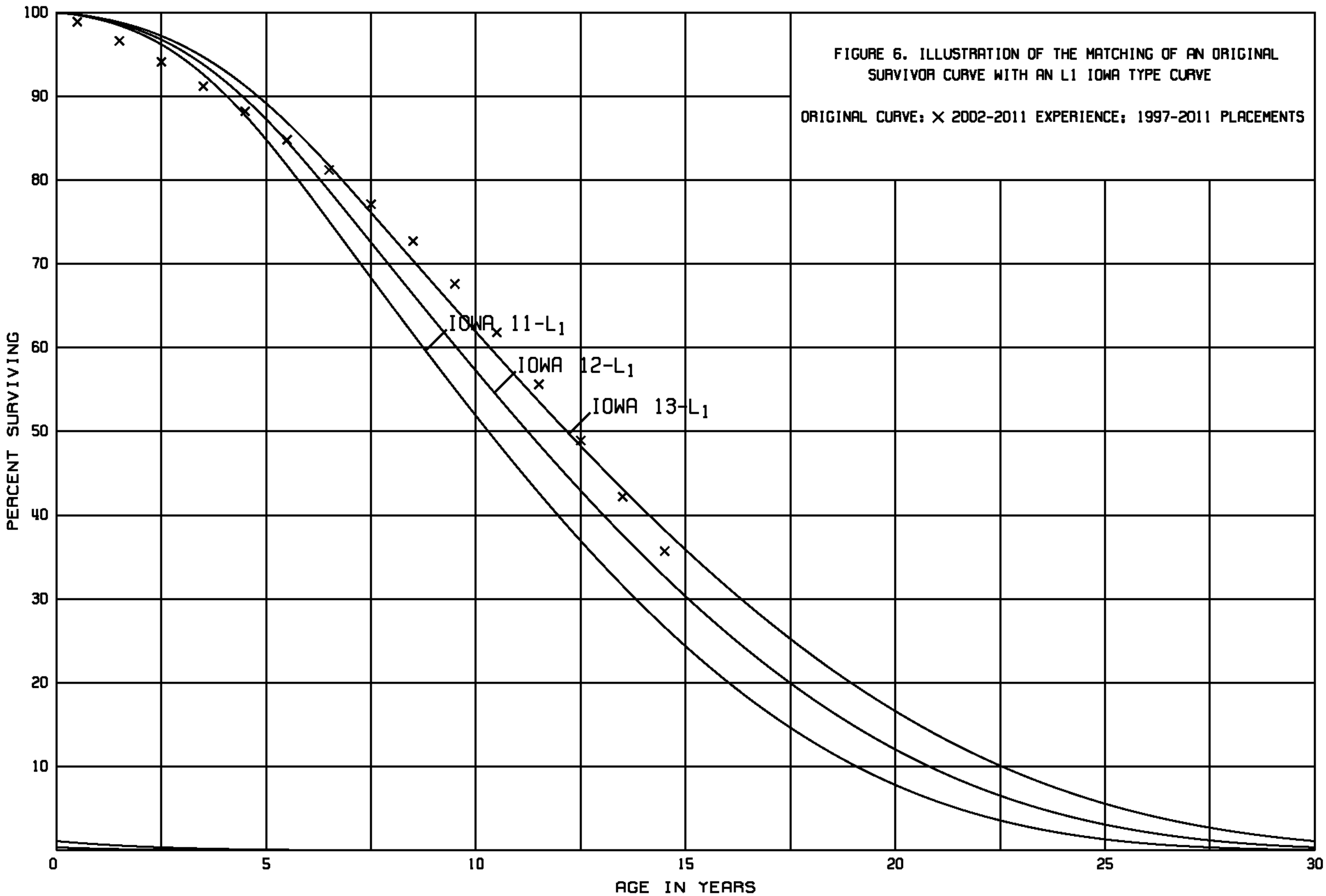

FIGURE 6. ILLUSTRATION OF THE MATCHING OF AN ORIGINAL SURVIVOR CURVE WITH AN L1 IOWA TYPE CURVE

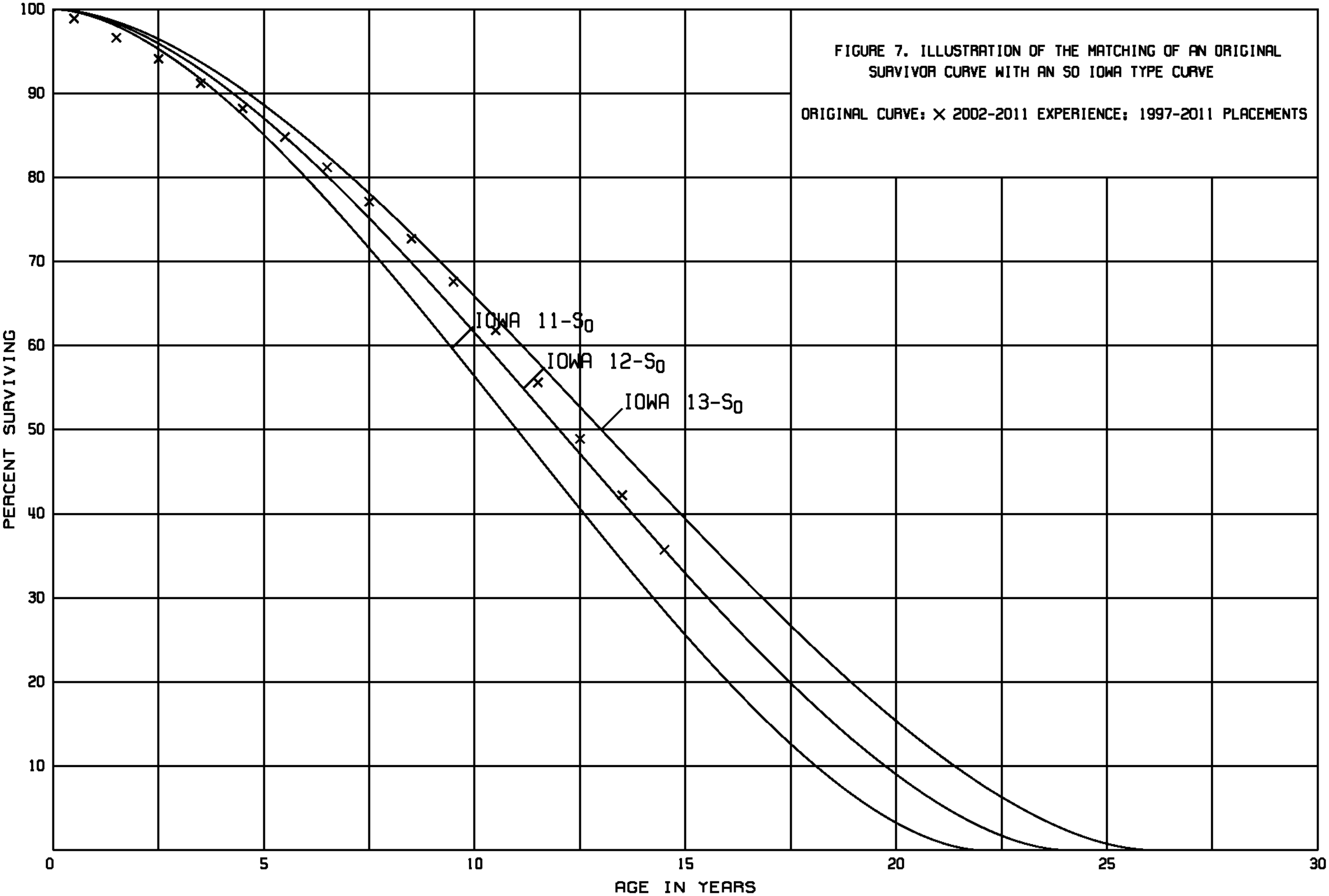
FIGURE 7. ILLUSTRATION OF THE MATCHING OF AN ORIGINAL SURVIVOR CURVE WITH AN SO IOWA TYPE CURVE
ORIGINAL CURVE: × 2002-2011 EXPERIENCE; 1997-2011 PLACEMENTS
IOWA 11-S0
IOWA 12-S0
IOWA 13-S0
PERCENT SURVIVING
AGE IN YEARS
100
90
80
70
60
50
40
30
20
10
0
5
10
15
20
25
30

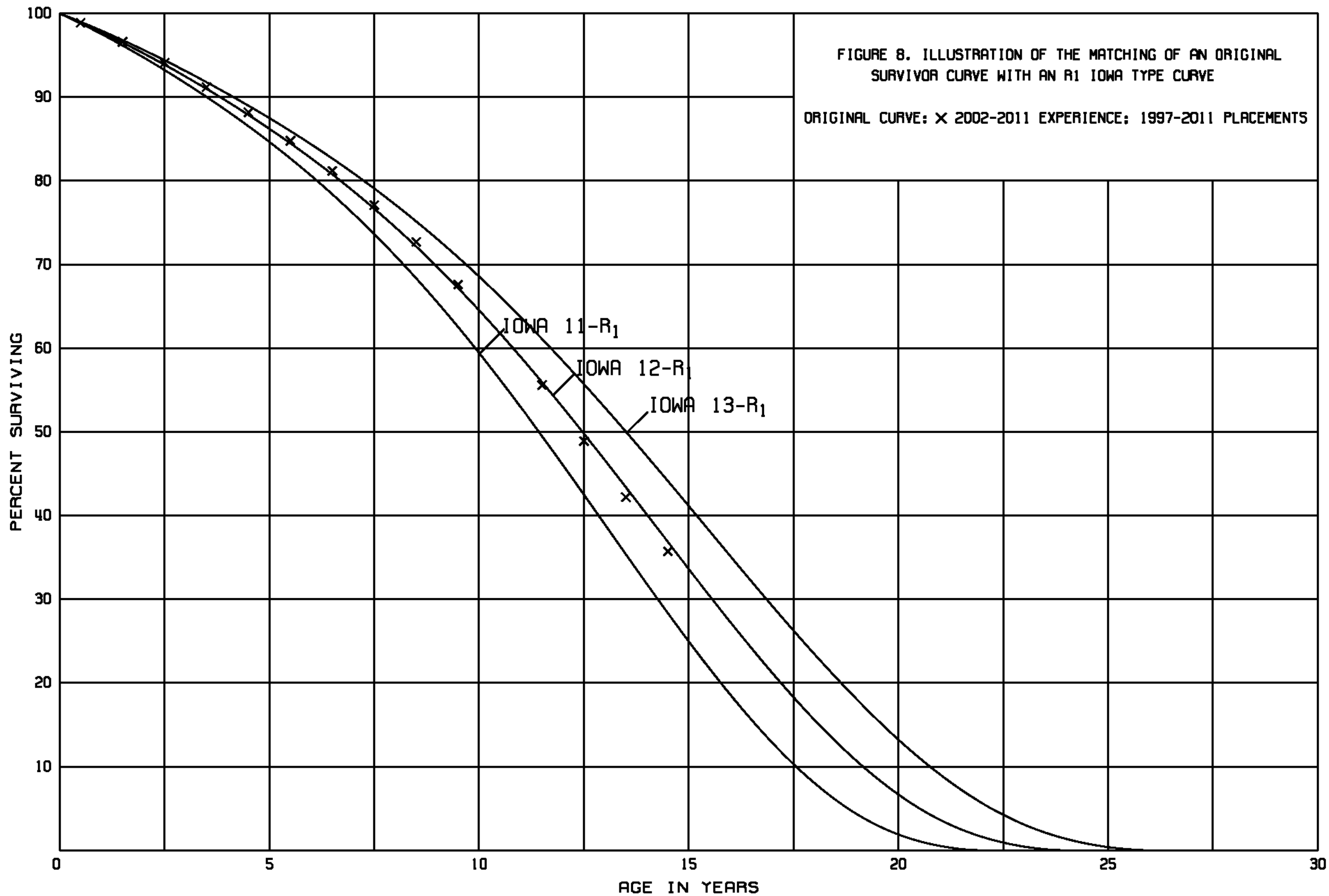
FIGURE 8. ILLUSTRATION OF THE MATCHING OF AN ORIGINAL SURVIVOR CURVE WITH AN R1 IOWA TYPE CURVE
ORIGINAL CURVE: × 2002-2011 EXPERIENCE: 1997-2011 PLACEMENTS
IOWA 11-R1
IOWA 12-R1
IOWA 13-R1
PERCENT SURVIVING
AGE IN YEARS
100
90
80
70
60
50
40
30
20
10
0
5
10
15
20
25
30

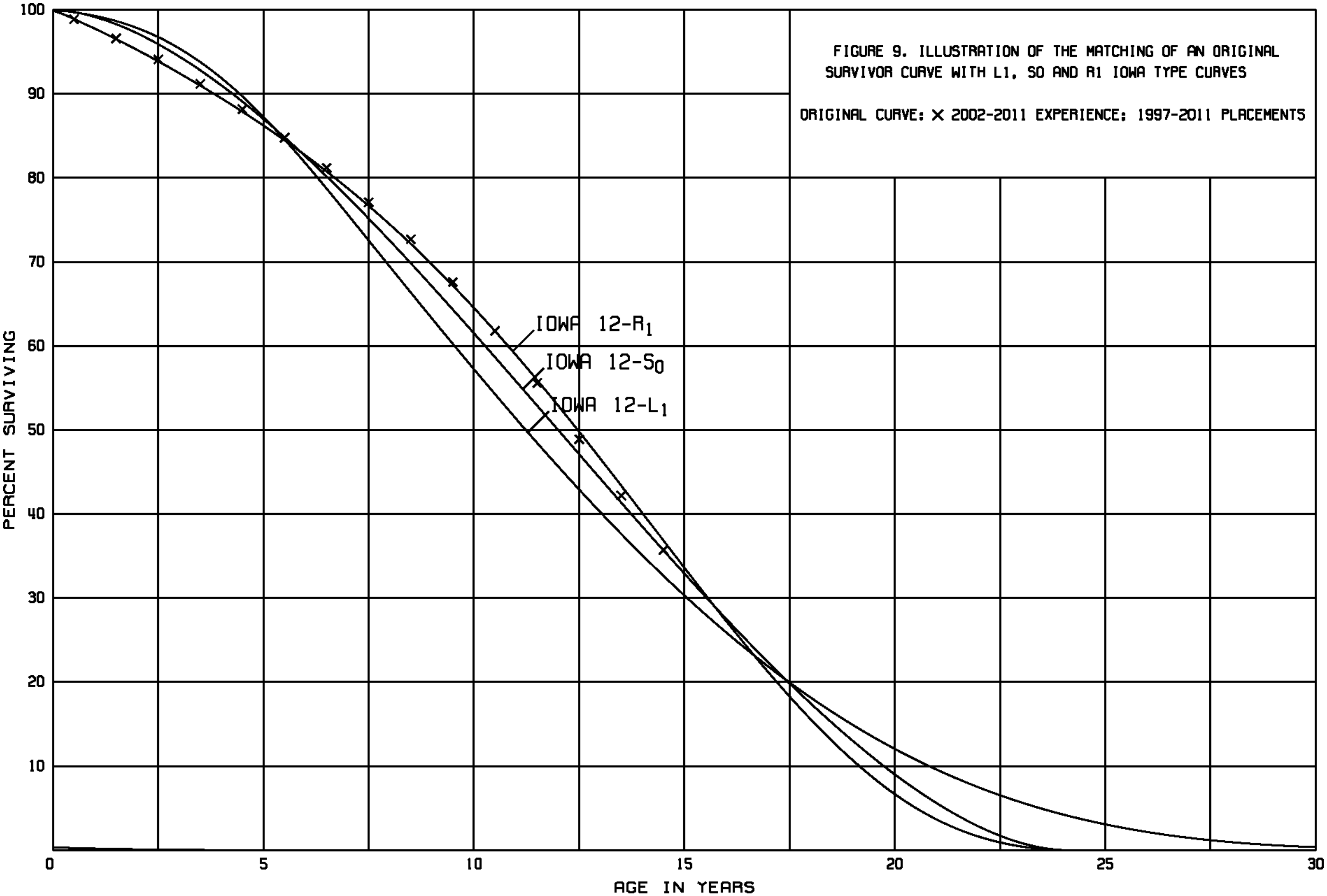

FIGURE 9. ILLUSTRATION OF THE MATCHING OF AN ORIGINAL SURVIVOR CURVE WITH L1, S0 AND R1 IOWA TYPE CURVES
ORIGINAL CURVE: × 2002-2011 EXPERIENCE: 1997-2011 PLACEMENTS
IOWA 12-R1
IOWA 12-S0
IOWA 12-L1
PERCENT SURVIVING
AGE IN YEARS
100
90
80
70
60
50
40
30
20
10
0
5
10
15
20
25
30

April 23-25, 2007

Trimble County Generating Facility
Ghent Generating Facilities
E. W. Brown Generating Facility
E. W. Brown Ice Plant
E. W. Brown Dispatch Center
Dix Dam Hydro Plant
Shelbyville General Office

Service Life Considerations

The service life estimates were based on judgment which considered a number of factors. The primary factors were the statistical analyses of data; current Company policies and outlook as determined during conversations with management; and the survivor curve estimates from previous studies of this company and other electric utility companies.

For 23 of the 57 plant accounts and subaccounts for which survivor curves were estimated, the statistical analyses resulted in good to excellent indications of the survivor patterns experienced. These accounts represent 84 percent of depreciable plant. Generally, the information external to the statistics led to no significant departure from the indicated survivor curves for the accounts listed below. The statistical support for the service life estimates is presented in the section beginning on page III-11.

STEAM PRODUCTION PLANT

312 Boiler Plant Equipment
314 Turbogenerator Units
316 Miscellaneous Power Plant Equipment

HYDRO PRODUCTION PLANT

333 Water Wheels, Turbines and Generators
335 Miscellaneous Power Plant Equipment

OTHER PRODUCTION PLANT

343 Prime Movers

TRANSMISSION PLANT

353.1 Station Equipment
353.2 Station Equipment - System Controls/Communication
354 Towers and Fixtures
355 Poles and Fixtures
356 Overhead Conductors and Devices

DISTRIBUTION PLANT

361	Structures and Improvements
362	Station Equipment
364	Poles, Towers and Fixtures
365	Overhead Conductors and Devices
366	Underground Conduit
367	Underground Conductors and Devices
368	Line Transformers
369	Services
371	Installations on Customers' Premises
373	Street Lighting and Signal Systems

GENERAL PLANT

390.1	Structures and Improvements - To Owned Property
390.2	Structures and Improvements - To Leased Property

Account 364, Poles, Towers and Fixtures and Account 368, Line Transformers, are used to illustrate the manner in which the study was conducted for the groups in the preceding list. Account 364 represents approximately 5 percent, and Account 368 represents approximately 4 percent, of the total depreciable plant. Aged plant accounting data have been compiled for the years 1905 through 2011 for poles and 1900 through 2011 for line transformers. These data have been coded in the course of the Company's normal record keeping according to account or property group, type of transaction, year in which the transaction took place, and year in which the electric plant was placed in service. The retirements, other plant transactions, and plant additions were analyzed by the retirement rate method.

The survivor curve estimate for Account 364, Poles, Towers and Fixtures, is based on the statistical indications for the periods 1905 through 2011 and 1977 through 2011. The Iowa 50-R1 is an excellent fit of the original survivor curve. The 50-year service life is within the typical service life range of 35 to 50 years for poles. The 50-year life reflects the Company's practices of longer lives through extensive maintenance on its poles and steady retirements for all vintages due to load demands. The previous estimate was the Iowa 48-S0.

The survivor curve estimate for Account 368, Line Transformers, is the 43-R2 and is based on the statistical indication for the periods 1900 through 2011 and 1961 through 2011. The 43-R2 is an excellent fit of the significant portion of the original survivor curve as set forth on page III-167 and consistent with management outlook for a continuation of historical experience, and within the typical service life range of 30 to 45 years for line transformers.

Inasmuch as production plant consists of large generating units, the life span technique was employed in conjunction with the use of interim survivor curves which reflect interim retirements that occur prior to the ultimate retirement of the major unit. An interim survivor curve was estimated for each plant account, inasmuch as the rate of interim retirements differ from account to account. The interim survivor curves estimated for steam, hydro and other production plant were based on the retirement rate method of life analysis which incorporated experienced aged retirements for the period 1926 through 2011 for steam, 1941 through 2011 for hydro and 1970 through 2011 for other production.

The life span estimates for power generating stations were the result of considering experienced life spans of similar generating units, type of construction, the age of surviving units, general operating characteristics of the units, major refurbishing, and discussions with management personnel concerning the probable long-term outlook for the units, observed features and conditions at the time of the field visit, and future plans from the life assessment study.

The life span estimate for most steam, base-load units is 51 to 72 years, which is on the upper end of the typical range of life spans for such units. The 100-year lifespan for the hydro production facility is within the typical range. Life spans of 30 to 37 years were estimated for the majority of combustion turbines. These life span estimates are typical for combustion turbines which are used primarily as peaking units.

A summary of the year in service, life span and probable retirement year for each power production unit follows:

Depreciable Group	Major Year in Service	Probable Retirement Year	Life Span
Steam Production Plant			
Tyrone Unit 3	1947,1953	2015	68,62
Tyrone Units 1 & 2	1947,1948	2007	60,59
Green River Unit 3	1954	2015	61
Green River Unit 4	1959	2015	56
Green River Units 1 & 2	1950	2004	54
Brown Unit 1	1956	2028	72
Brown Unit 2	1963	2034	71
Brown Unit 3	1971	2035	64
Pineville Unit 3	1951	2002	51
Ghent Unit 1	1974	2034	60
Ghent Unit 2	1977	2034	57
Ghent Unit 3	1981	2037	56
Ghent Unit 4	1984	2038	54
System Laboratory	1989	2040	51
Trimble County Unit 2	1990,2011	2066	76,55
Hydro Plant			
Dix Dam	1941	2041	100
Other Production Plant			
Paddy's Run Generator 13	2001	2031	30
Brown Unit 5	2001	2031	30
Brown Unit 6	1999	2029	30
Brown Unit 7	1999	2029	30
Brown Unit 8	1995	2025	30
Brown Unit 9	1994	2031	37
Brown Unit 10	1995	2031	36
Brown Unit 11	1996	2026	30
Trimble County Unit 5	2002	2032	30

Trimble County Unit 6	2002	2032	30
Trimble County Unit 7	2004	2034	30
Trimble County Unit 8	2004	2034	30
Trimble County Unit 9	2004	2034	30
Trimble County Unit 10	2004	2034	30
Haefling Units 1, 2, & 3	1970	2020	50

The survivor curve estimates for the remaining accounts were based on judgment incorporating the statistical analyses and previous studies for this and other electric utilities.

Salvage Analysis

The estimates of net salvage by account were based in part on historical data compiled through 2011. Cost of removal and salvage were expressed as percents of the original cost of plant retired, both on annual and three-year moving average bases. The most recent five-year average also was calculated for consideration. The net salvage estimates by account are expressed as a percent of the original cost of plant retired.

Net Salvage Considerations

The estimates of future net salvage are expressed as percentages of surviving plant in service, i.e., all future retirements. In cases in which removal costs are expected to exceed salvage receipts, a negative net salvage percentage is estimated. The net salvage estimates were based on judgment which incorporated analyses of historical cost of removal and salvage data, expectations with respect to future removal requirements and markets for retired equipment and materials.

The analyses of historical cost of removal and salvage data are presented in the section titled “Net Salvage Statistics” for the plant accounts for which the net salvage estimate relied partially on those analyses.

Statistical analyses of historical data for the period 1985 through 2011 contributed significantly toward the net salvage estimates for 23 plant accounts, representing 84 percent of the depreciable plant, as follows:

STEAM PRODUCTION
- 311 Structures and Improvements
- 312 Boiler Plant Equipment
- 314 Turbogenerator Units
- 316 Miscellaneous Power Plant Equipment

OTHER PRODUCTION
- 343 Prime Movers

TRANSMISSION PLANT
- 353.1 Station Equipment
- 353.2 Station Equipment - System Controls/Communication
- 354 Towers and Fixtures
- 355 Poles and Fixtures

DISTRIBUTION PLANT
- 362 Station Equipment
- 364 Poles, Towers and Fixtures
- 366 Underground Conduit
- 367 Underground Conductors and Devices
- 368 Line Transformers
- 369 Services
- 370 Meters
- 371 Installations on Customers' Premises
- 373 Street Lighting and Signal Systems

GENERAL PLANT
- 390.1 Structures and Improvements - To Owned Property
- 390.2 Structures and Improvements - To Leased Property
- 392.1 Transportation Equipment - Cars and Light Trucks
- 392.3 Transportation Equipment - Heavy Trucks and Other
- 396.3 Power Operated Equipment - Large Machinery

Account 368, Line Transformers, is used to illustrate the manner in which the study was conducted for the groups in the preceding list. Net salvage data for the period 1985 through 2011 were analyzed for this account. The data include cost of removal, gross salvage and net salvage amounts and each of these amounts is expressed as a percent of the original cost of regular retirements. Three-year moving averages for the 1985-1987 through 2009-2011 periods were computed to smooth the annual amounts.

Cost of removal was high during the four year period, 2006 through 2009, with a slight reduction for the year 2010. The high removal costs during the four year period are expected to continue based on the current practices for line transformers. Cost of removal for the most recent five years averaged 19 percent.

Gross salvage has increased drastically since 2005. The most recent five-year average of 26 percent gross salvage reflects recent trends of salvage value for line transformers due to new practices of refurbishing the assets. This trend is expected to continue for salvage value.

The net salvage percent based on the overall period 1985 through 2011 is 9 percent negative net salvage. The range of estimates made by other electric companies for line transformers is positive 5 to negative 10 percent. The net salvage estimate for line transformers is negative 10 percent, is within the range of estimates for other electric companies and reflects the level of negative net salvage for the 27 years.

The net salvage percents for the remaining accounts were based on judgment incorporating estimates of previous studies of this and other electric utilities.

CALCULATION OF ANNUAL AND ACCRUED DEPRECIATION

After the survivor curve and salvage are estimated, the annual depreciation accrual rate can be calculated. In the average service life procedure, the annual accrual rate is computed by the following equation:

$$Annual\ Accrual\ Rate,\ Percent = \frac{(100\% \quad Net\ Salvage,\ Percent)}{Average\ Service\ Life}.$$

The calculated accrued depreciation for each depreciable property group represents that portion of the depreciable cost of the group which will not be allocated to expense through future depreciation accruals if current forecasts of life characteristics are used as a basis for straight line depreciation accounting.

The accrued depreciation calculation consists of applying an appropriate ratio to the surviving original cost of each vintage of each account, based upon the attained age and the estimated survivor curve. The accrued depreciation ratios are calculated as follows:

$$Ratio = \left(1 - \frac{Average\ Remaining\ Life\ Expectancy}{Average\ Service\ Life}\right)(1 - Net\ Salvage,\ Percent).$$

The application of these procedures is described for a single unit of property and a group of property units. Salvage is omitted from the description for ease of application.

Single Unit of Property

The calculation of straight line depreciation for a single unit of property is straightforward. For example, if a $1,000 unit of property attains an age of four years and has a life expectancy of six years, the annual accrual over the total life is:

$$\frac{\$1{,}000}{(4 + 6)} = \$100\ per\ year.$$

The accrued depreciation is:

$$\$1{,}000\ \left(1 - \frac{6}{10}\right) = \$400.$$

Group Depreciation Procedures

When more than a single item of property is under consideration, a group procedure for depreciation is appropriate because normally all of the items within a group do not have identical service lives, but have lives that are dispersed over a range of time. There are two primary group procedures, namely, average service life and equal life group.

<u>Remaining Life Annual Accruals</u>

For the purpose of calculating remaining life accruals as of December 31, 2011, the depreciation reserve for each plant account is allocated among vintages in proportion to the calculated accrued depreciation for the account. Explanations of remaining life accruals and calculated accrued depreciation follow. The detailed calculations as of December 31, 2011, are set forth in the Results of Study section of the report.

<u>Average Service Life Procedure</u>

In the average service life procedure, the remaining life annual accrual for each vintage is determined by dividing future book accruals (original cost less book reserve) by the average remaining life of the vintage. The average remaining life is a directly weighed average derived form the estimated future survivor curve in accordance with the average service life procedure.

The calculated accrued depreciation for each depreciable property group represents that portion of the depreciable cost of the group which would not be allocated to expense through future depreciation accruals if current forecasts of life characteristics are used as the basis for such accruals. The accrued depreciation calculation consists of applying an appropriate ratio to the surviving original cost of each vintage of each account based upon the attained age and service life. The straight line accrued depreciation ratios are calculated as follows for the average service life procedure:

$$\text{Ratio} = 1 - \frac{\text{Average Remaining Life}}{\text{Average Service Life}}.$$

CALCULATION OF ANNUAL AND ACCRUED AMORTIZATION

Amortization, as defined in the Uniform System of Accounts, is the gradual extinguishment of an amount in an account by distributing such amount over a fixed period, over the life of the asset or liability to which it applies, or over the period during which it is anticipated the benefit will be realized. Normally, the distribution of the amount is in equal amounts to each year of the amortization period.

The calculation of annual and accrued amortization requires the selection of an amortization period. The amortization periods used in this report were based on judgment which incorporated a consideration of the period during which the assets will render most of their service, the amortization periods and service lives used by other utilities, and the service life estimates previously used for the asset under depreciation accounting.

Amortization accounting is appropriate for certain General Plant accounts that represent numerous units of property, but a very small portion of depreciable electric plant in service. The accounts and their amortization periods are as follows:

Account		Amortization Period, Years
391.1	Office Furniture and Equipment	20
391.2	Non PC Computer Equipment	5
391.31	Personal Computers	4
393	Stores Equipment	25
394	Tools, Shop and Garage Equipment	25
397.1	Communication Equipment - General Assets	10

For the purpose of calculating annual amortization amounts as of December 31, 2011, the book or ratemaking book depreciation reserve for each plant account or subaccount is assigned or allocated to vintages. The reserve assigned to vintages with an age greater than the amortization period is equal to the vintage's original cost. The remaining reserve is allocated among vintages with an age less than the amortization period in proportion to the calculated accrued amortization. The calculated accrued amortization is equal to the original cost multiplied by the ratio of the vintage's age to its amortization period. The annual amortization amount is determined by dividing the future amortization (original cost less allocated book reserve) by the remaining period of amortization for the vintage.

III-1

PART III. RESULTS OF STUDY

PART III. RESULTS OF STUDY

QUALIFICATION OF RESULTS

The calculated annual depreciation accrual rates are the principal results of the study. Continued surveillance and periodic revisions are normally required to maintain continued use of appropriate annual depreciation accrual rates. An assumption that accrual rates can remain unchanged over a long period of time implies a disregard for the inherent variability in service lives and salvage and for the change of the composition of property in service. The annual accrual rates were calculated in accordance with the straight line remaining life method of depreciation using the equal life group procedure based on estimates which reflect considerations of current historical evidence and expected future conditions.

The annual depreciation accrual rates are applicable specifically to the electric and common plant in service as of December 31, 2011. For most plant accounts, the application of such rates to future balances that reflect additions subsequent to December 31, 2011, is reasonable for a period of three to five years.

DESCRIPTION OF STATISTICAL SUPPORT

The service life and salvage estimates were based on judgment which incorporated statistical analyses of retirement data, discussions with management and consideration of estimates made for other electric utility companies. The results of the statistical analyses of service life are presented in the section titled "Service Life Statistics".

The estimated survivor curves for each account are presented in graphical form. The charts depict the estimated smooth survivor curve and original survivor curve(s), when applicable, related to each specific group. For groups where the original survivor curve was plotted, the calculation of the original life table is also presented.

The analyses of salvage data are presented in the section titled, "Net Salvage Statistics". The tabulations present annual cost of removal and salvage data, three-year moving averages and the most recent five-year average. Data are shown in dollars and as percentages of original costs retired.

DESCRIPTION OF DEPRECIATION TABULATIONS

A summary of the results of the study, as applied to the original cost of electric plant at December 31, 2011, is presented on pages III-4 through III-10 of this report. The schedule sets forth the original cost, the book reserve, future accruals, the calculated annual depreciation rate and amount, and the composite remaining life related to electric and common plant.

The tables of the calculated annual depreciation accruals are presented in account sequence in the section titled "Depreciation Calculations." The tables indicate the estimated survivor curve and salvage percent for the account and set forth for each installation year the original cost, the calculated accrued depreciation, the allocated book reserve, future accruals, the remaining life and the calculated annual accrual amount.

KENTUCKY UTILITIES COMPANY

SUMMARY OF ESTIMATED SURVIVOR CURVES, NET SALVAGE, ORIGINAL COST, BOOK DEPRECIATION RESERVE AND CALCULATED ANNUAL DEPRECIATION RATES AS OF DECEMBER 31, 2011

	ACCOUNT	SURVIVOR CURVE		NET SALVAGE PERCENT	ORIGINAL COST	BOOK DEPRECIATION RESERVE	FUTURE ACCRUALS	CALCULATED ANNUAL ACCRUAL AMOUNT	CALCULATED ANNUAL ACCRUAL RATE	COMPOSITE REMAINING LIFE
	(1)	(2)		(3)	(4)	(5)	(6)	(7)	(8)=(7)/(4)	(9)=(6)/(7)
	DEPRECIABLE PLANT									
	INTANGIBLE PLANT									
302.00	FRANCHISES AND CONSENTS	20-SQ		0	55,918.83	21,074.00	34,845	10,503	18.78	3.3
303.00	MISCELLANEOUS INTANGIBLE PLANT	5-SQ		0	18,338,712.02	7,484,852.00	10,853,860	2,801,459	15.28	3.9
303.10	CCS SOFTWARE	SQUARE	*	0	40,210,208.29	10,240,838.00	29,969,370	3,995,916	9.94	7.5
	TOTAL INTANGIBLE PLANT				**58,604,839.14**	**17,746,764**	**40,858,075**	**6,807,878**	**11.62**	
	STEAM PRODUCTION PLANT									
311.00	STRUCTURES AND IMPROVEMENTS									
	TRIMBLE COUNTY UNIT 2	100-S1	*	(15)	106,290,580.94	18,699,136	103,535,032	2,021,312	1.90	51.2
	TRIMBLE COUNTY UNIT 2 SCRUBBER	100-S1	*	(15)	5,522,306.98	2,689,746	3,660,907	75,374	1.36	48.6
	SYSTEM LABORATORY	100-S1	*	(1)	824,968.82	609,422	223,797	8,170	0.99	27.4
	TYRONE UNIT 3	100-S1	*	(10)	5,608,825.07	6,169,708	0	0	-	-
	TYRONE UNITS 1 AND 2	FULLY ACCRUED	*	(10)	583,381.44	641,720	0	0	-	-
	GREEN RIVER UNIT 3	100-S1	*	(10)	2,821,436.66	3,103,580	0	0	-	-
	GREEN RIVER UNIT 4	100-S1	*	(10)	5,476,054.30	4,320,817	1,702,843	426,905	7.80	4.0
	GREEN RIVER UNITS 1 AND 2	FULLY ACCRUED	*	(10)	2,560,764.18	2,816,841	0	0	-	-
	BROWN UNIT 1	100-S1	*	(11)	4,703,189.76	4,861,747	358,794	21,822	0.46	16.4
	BROWN UNIT 2	100-S1	*	(11)	2,232,100.04	2,028,873	448,758	20,077	0.90	22.4
	BROWN UNIT 3	100-S1	*	(11)	21,039,674.36	14,064,263	9,289,776	400,691	1.90	23.2
	BROWN UNITS 1, 2 AND 3 SCRUBBER	100-S1	*	(11)	43,917,221.15	1,760,616	46,987,499	2,010,590	4.58	23.4
	PINEVILLE UNIT 3	FULLY ACCRUED	*	(10)	16,204.29	17,825	0	0	-	-
	GHENT UNIT 1 SCRUBBER	100-S1	*	(12)	8,483,789.23	6,985,454	2,516,390	113,954	1.34	22.1
	GHENT UNIT 1	100-S1	*	(12)	18,842,151.21	18,621,064	2,482,145	111,264	0.59	22.3
	GHENT UNIT 2	100-S1	*	(12)	16,011,012.98	14,142,566	3,789,769	176,840	1.10	21.4
	GHENT UNIT 3	100-S1	*	(12)	42,177,125.67	30,851,643	16,386,738	671,100	1.59	24.4
	GHENT UNIT 4	100-S1	*	(12)	31,022,090.50	14,920,226	19,824,515	770,327	2.48	25.7
	GHENT UNIT 2 SCRUBBER	100-S1	*	(12)	15,817,337.72	12,919,945	4,795,473	218,174	1.38	22.0
	TOTAL ACCOUNT 311 - STRUCTURES AND IMPROVEMENTS				333,950,215.30	160,225,192	216,002,436	7,046,600	2.11	30.7
312.00	BOILER PLANT EQUIPMENT									
	TRIMBLE COUNTY UNIT 2	60-R2.5	*	(15)	505,158,968.57	44,042,332	536,890,482	11,040,635	2.19	48.6
	TRIMBLE COUNTY UNIT 2 SCRUBBER	60-R2.5	*	(15)	70,735,319.61	11,271,211	70,074,407	1,453,909	2.06	48.2
	TYRONE UNIT 3	60-R2.5	*	(10)	13,993,285.78	11,103,677	4,288,937	1,082,465	7.74	4.0
	TYRONE UNITS 1 AND 2	FULLY ACCRUED	*	(10)	421,899.96	464,090	0	0	-	-
	GREEN RIVER UNIT 3	60-R2.5	*	(10)	12,145,770.44	9,725,542	3,634,805	922,012	7.59	3.9
	GREEN RIVER UNIT 4	60-R2.5	*	(10)	25,165,914.24	20,127,163	7,555,343	1,903,819	7.57	4.0
	GREEN RIVER UNITS 1 AND 2	FULLY ACCRUED	*	(10)	349,297.88	384,228	0	0	-	-
	BROWN UNIT 1	60-R2.5	*	(11)	45,302,489.09	26,739,197	23,546,566	1,471,865	3.25	16.0
	BROWN UNIT 2	60-R2.5	*	(11)	41,956,868.14	19,641,359	26,930,765	1,252,209	2.98	21.5
	BROWN UNIT 3	60-R2.5	*	(11)	142,628,390.37	71,929,055	86,388,458	3,809,860	2.67	22.7
	BROWN UNITS 1, 2 AND 3 SCRUBBER	60-R2.5	*	(11)	323,725,098.68	18,469,817	340,865,043	14,820,202	4.58	23.0
	PINEVILLE UNIT 3	FULLY ACCRUED	*	(10)	236,470.42	260,117	0	0	-	-
	GHENT UNIT 1 SCRUBBER	60-R2.5	*	(12)	144,202,759.28	34,075,530	127,431,560	5,799,995	4.02	22.0
	GHENT UNIT 1	60-R2.5	*	(12)	198,785,055.46	96,800,340	125,838,922	5,834,075	2.93	21.6
	GHENT UNIT 2	60-R2.5	*	(12)	98,446,686.35	73,285,978	36,974,311	1,779,312	1.81	20.8
	GHENT UNIT 3	60-R2.5	*	(12)	254,967,909.72	146,662,379	138,901,680	5,879,680	2.31	23.6
	GHENT UNIT 4	60-R2.5	*	(12)	267,856,280.18	128,461,343	171,537,691	6,953,070	2.60	24.7

KENTUCKY UTILITIES COMPANY

SUMMARY OF ESTIMATED SURVIVOR CURVES, NET SALVAGE, ORIGINAL COST, BOOK DEPRECIATION RESERVE AND CALCULATED ANNUAL DEPRECIATION RATES AS OF DECEMBER 31, 2011

	ACCOUNT	SURVIVOR CURVE		NET SALVAGE PERCENT	ORIGINAL COST	BOOK DEPRECIATION RESERVE	FUTURE ACCRUALS	CALCULATED ANNUAL ACCRUAL AMOUNT	CALCULATED ANNUAL ACCRUAL RATE	COMPOSITE REMAINING LIFE
	(1)	(2)		(3)	(4)	(5)	(6)	(7)	(8)=(7)/(4)	(9)=(6)/(7)
312, cont.	GHENT UNIT 2 SCRUBBER	60-R2.5	*	(12)	93,278,511.28	55,024,079	49,447,854	2,270,953	2.43	21.8
	GHENT UNIT 3 SCRUBBER	60-R2.5	*	(12)	127,988,949.01	24,898,056	118,449,567	4,782,967	3.74	24.8
	GHENT UNIT 4 SCRUBBER	60-R2.5	*	(12)	307,100,358.50	41,271,827	302,680,575	11,768,189	3.83	25.7
	TOTAL ACCOUNT 312 - BOILER PLANT EQUIPMENT				2,674,446,282.96	834,637,320	2,171,436,966	82,825,217	3.10	26.2
314.00	TURBOGENERATOR UNITS									
	TRIMBLE COUNTY UNIT 2	55-S1.5	*	(15)	83,994,732.76	12,471,959	84,121,984	1,836,110	2.19	45.8
	TYRONE UNIT 3	55-S1.5	*	(10)	4,805,513.66	3,825,756	1,460,309	370,738	7.71	3.9
	TYRONE UNITS 1 AND 2	FULLY ACCRUED	*	(10)	68,205.72	75,026	0	0	-	-
	GREEN RIVER UNIT 3	55-S1.5	*	(10)	4,562,193.51	4,064,201	954,212	241,317	5.29	4.0
	GREEN RIVER UNIT 4	55-S1.5	*	(10)	10,390,485.90	9,545,563	1,883,971	472,404	4.55	4.0
	BROWN UNIT 1	55-S1.5	*	(11)	7,512,824.95	4,893,897	3,445,339	215,514	2.87	16.0
	BROWN UNIT 2	55-S1.5	*	(11)	12,299,721.87	8,687,176	4,965,515	228,841	1.86	21.7
	BROWN UNIT 3	55-S1.5	*	(11)	29,293,398.16	20,414,202	12,101,470	543,748	1.86	22.3
	GHENT UNIT 1	55-S1.5	*	(12)	36,687,321.40	20,194,109	20,895,691	978,789	2.67	21.3
	GHENT UNIT 2	55-S1.5	*	(12)	30,417,591.79	20,815,737	13,251,966	682,670	2.24	19.4
	GHENT UNIT 3	55-S1.5	*	(12)	42,595,556.80	28,152,257	19,554,767	887,493	2.08	22.0
	GHENT UNIT 4	55-S1.5	*	(12)	57,036,973.14	32,047,642	31,833,768	1,388,323	2.43	22.9
	TOTAL ACCOUNT 314 - TURBOGENERATOR UNITS				319,664,519.66	165,187,525	194,468,992	7,845,947	2.45	24.8
315.00	ACCESSORY ELECTRIC EQUIPMENT									
	TRIMBLE COUNTY UNIT 2	70-S3	*	(15)	41,600,356.80	4,958,709	42,881,701	836,186	2.01	51.3
	TRIMBLE COUNTY UNIT 2 SCRUBBER	70-S3	*	(15)	1,415,469.10	653,351	974,438	22,036	1.56	44.2
	TYRONE UNIT 3	70-S3	*	(10)	2,081,692.71	1,087,407	1,202,455	305,060	14.65	3.9
	TYRONE UNITS 1 AND 2	FULLY ACCRUED	*	(10)	99,210.72	109,132	0	0	-	-
	GREEN RIVER UNIT 3	70-S3	*	(10)	1,205,362.18	554,397	771,501	194,829	16.16	4.0
	GREEN RIVER UNIT 4	70-S3	*	(10)	2,695,328.66	1,846,556	1,118,306	283,879	10.53	3.9
	BROWN UNIT 1	70-S3	*	(11)	3,859,109.33	3,259,464	1,024,147	62,118	1.61	16.5
	BROWN UNIT 2	70-S3	*	(11)	2,165,576.99	1,331,430	1,072,360	47,686	2.20	22.5
	BROWN UNIT 3	70-S3	*	(11)	8,597,465.88	6,533,915	3,009,272	128,146	1.49	23.5
	BROWN UNITS 1, 2 AND 3 SCRUBBER	70-S3	*	(11)	29,503,821.45	1,205,108	31,544,134	1,342,875	4.55	23.5
	GHENT UNIT 1 SCRUBBER	70-S3	*	(12)	13,292,784.70	3,266,572	11,621,347	517,122	3.89	22.5
	GHENT UNIT 1	70-S3	*	(12)	8,872,543.26	8,274,863	1,662,385	77,332	0.87	21.5
	GHENT UNIT 2	70-S3	*	(12)	13,858,388.53	10,602,781	4,918,614	229,310	1.65	21.4
	GHENT UNIT 3	70-S3	*	(12)	30,932,405.42	22,826,297	11,817,997	490,361	1.59	24.1
	GHENT UNIT 4	70-S3	*	(12)	24,412,796.92	16,503,145	10,839,188	429,536	1.76	25.2
	GHENT UNIT 2 SCRUBBER	70-S3	*	(12)	1,155,753.06	73,909	1,220,534	54,270	4.70	22.5
	GHENT UNIT 3 SCRUBBER	70-S3	*	(12)	12,041,998.28	1,992,181	11,494,857	451,284	3.75	25.5
	GHENT UNIT 4 SCRUBBER	70-S3	*	(12)	3,844,595.46	381,019	3,924,928	148,278	3.86	26.5
	TOTAL ACCOUNT 315 - ACCESSORY ELECTRIC EQUIPMENT				201,634,659.45	85,460,236	141,098,164	5,620,308	2.79	25.1
316.00	MISCELLANEOUS POWER PLANT EQUIPMENT									
	TRIMBLE COUNTY UNIT 2	70-R1.5	*	(15)	3,502,446.96	126,166	3,901,648	81,004	2.31	48.2
	SYSTEM LABORATORY	70-R1.5	*	(1)	2,763,048.67	790,095	2,000,584	74,526	2.70	26.8
	TYRONE UNIT 3	70-R1.5	*	(10)	553,355.01	251,724	356,967	90,112	16.28	4.0
	TYRONE UNITS 1 AND 2	FULLY ACCRUED	*	(10)	50,126.84	55,140	0	0	-	-
	GREEN RIVER UNIT 3	70-R1.5	*	(10)	152,146.47	101,809	65,552	16,545	10.87	4.0
	GREEN RIVER UNIT 4	70-R1.5	*	(10)	2,408,142.84	1,418,850	1,230,107	310,000	12.87	4.0
	GREEN RIVER UNITS 1 AND 2	FULLY ACCRUED	*	(10)	84,749.53	93,224	0	0	-	-
	BROWN UNIT 1	70-R1.5	*	(11)	432,577.58	351,287	128,874	8,059	1.86	16.0
	BROWN UNIT 2	70-R1.5	*	(11)	106,658.32	109,842	8,549	395	0.37	21.6
	BROWN UNIT 3	70-R1.5	*	(11)	5,070,448.32	2,925,174	2,703,024	121,490	2.40	22.2

KENTUCKY UTILITIES COMPANY

SUMMARY OF ESTIMATED SURVIVOR CURVES, NET SALVAGE, ORIGINAL COST, BOOK DEPRECIATION RESERVE AND
CALCULATED ANNUAL DEPRECIATION RATES AS OF DECEMBER 31, 2011

	ACCOUNT (1)	SURVIVOR CURVE (2)		NET SALVAGE PERCENT (3)	ORIGINAL COST (4)	BOOK DEPRECIATION RESERVE (5)	FUTURE ACCRUALS (6)	CALCULATED ANNUAL ACCRUAL AMOUNT (7)	CALCULATED ANNUAL ACCRUAL RATE (8)=(7)/(4)	COMPOSITE REMAINING LIFE (9)=(6)/(7)
316, cont.	GHENT UNIT 1 SCRUBBER	70-R1.5	*	(12)	1,033,027.09	834,195	322,795	15,091	1.46	21.4
	GHENT UNIT 1	70-R1.5	*	(12)	1,747,526.86	1,578,287	378,943	18,058	1.03	21.0
	GHENT UNIT 2	70-R1.5	*	(12)	1,500,525.31	1,397,086	283,502	13,774	0.92	20.6
	GHENT UNIT 3	70-R1.5	*	(12)	3,150,437.55	2,534,754	993,736	42,799	1.36	23.2
	GHENT UNIT 4	70-R1.5	*	(12)	7,455,181.33	2,842,039	5,507,764	221,851	2.98	24.8
	TOTAL ACCOUNT 316 - MISCELLANEOUS POWER PLANT EQUIPMENT				30,010,398.68	15,409,672	17,882,045	1,013,704	3.38	17.6
	TOTAL STEAM PRODUCTION PLANT				**3,559,706,076.05**	**1,260,919,945**	**2,740,888,603**	**104,351,776**	**2.93**	
	HYDRAULIC PRODUCTION PLANT									
330.10	LAND RIGHTS									
	DIX DAM	100-R4	*	0	879,311.47	879,311	0	0	-	-
	TOTAL ACCOUNT 330.1 - LAND RIGHTS				879,311.47	879,311	0	0	-	-
331.00	STRUCTURES AND IMPROVEMENTS									
	DIX DAM	90-S2.5	*	(6)	616,526.69	353,805	299,713	10,702	1.74	28.0
	TOTAL ACCOUNT 331 - STRUCTURES AND IMPROVEMENTS				616,526.69	353,805	299,713	10,702	1.74	28.0
332.00	RESERVOIRS, DAMS AND WATERWAY									
	DIX DAM	100-S2.5	*	(6)	21,603,969.66	6,697,620	16,202,588	558,948	2.59	29.0
	TOTAL ACCOUNT 332 - RESERVOIRS, DAMS AND WATERWAYS				21,603,969.66	6,697,620	16,202,588	558,948	2.59	29.0
333.00	WATER WHEELS, TURBINES AND GENERATORS									
	DIX DAM	75-R3	*	(6)	4,430,624.31	19,710	4,676,752	166,967	3.77	28.0
	TOTAL ACCOUNT 333 - WATER WHEELS, TURBINES AND GENERATORS				4,430,624.31	19,710	4,676,752	166,967	3.77	28.0
334.00	ACCESSORY ELECTRIC EQUIPMENT									
	DIX DAM	40-L2.5	*	(6)	578,333.28	90,045	522,988	21,138	3.65	24.7
	TOTAL ACCOUNT 334 - ACCESSORY ELECTRIC EQUIPMENT				578,333.28	90,045	522,988	21,138	3.65	24.7
335.00	MISCELLANEOUS POWER PLANT EQUIPMENT									
	DIX DAM	35-L1	*	(6)	297,023.86	85,989	228,856	13,551	4.56	16.9
	TOTAL ACCOUNT 335 - MISCELLANEOUS POWER PLANT EQUIPMENT				297,023.86	85,989	228,856	13,551	4.56	16.9
336.00	ROADS, RAILROADS AND BRIDGES									
	DIX DAM	55-R4	*	(6)	176,359.59	49,946	136,995	7,394	4.19	18.5
	TOTAL ACCOUNT 336 - ROADS, RAILROADS & BRIDGES				176,359.59	49,946	136,995	7,394	4.19	18.5
	TOTAL HYDRAULIC PRODUCTION PLANT				**28,582,148.86**	**8,176,426**	**22,067,892**	**778,700**	**2.72**	

KENTUCKY UTILITIES COMPANY

SUMMARY OF ESTIMATED SURVIVOR CURVES, NET SALVAGE, ORIGINAL COST, BOOK DEPRECIATION RESERVE AND
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	ACCOUNT	SURVIVOR CURVE		NET SALVAGE PERCENT	ORIGINAL COST	BOOK DEPRECIATION RESERVE	FUTURE ACCRUALS	CALCULATED ANNUAL ACCRUAL AMOUNT	CALCULATED ANNUAL ACCRUAL RATE	COMPOSITE REMAINING LIFE
	(1)	(2)		(3)	(4)	(5)	(6)	(7)	(8)=(7)/(4)	(9)=(6)/(7)
	OTHER PRODUCTION PLANT									
340.10	LAND RIGHTS									
	BROWN CT GAS PIPELINE	SQUARE	*	0	176,409.31	99,438	76,971	3,947	2.24	19.5
	TOTAL ACCOUNT 340.1 - LAND AND LAND RIGHTS				176,409.31	99,438	76,971	3,947	2.24	19.5
341.00	STRUCTURES AND IMPROVEMENTS									
	TRIMBLE COUNTY CT 5	40-R2.5	*	(5)	3,740,231.32	1,170,949	2,756,294	144,756	3.87	19.0
	TRIMBLE COUNTY CT 6	40-R2.5	*	(5)	3,588,684.24	1,130,371	2,637,747	138,671	3.86	19.0
	TRIMBLE COUNTY CT 7	40-R2.5	*	(5)	3,559,154.97	909,260	2,827,853	135,304	3.80	20.9
	TRIMBLE COUNTY CT 8	40-R2.5	*	(5)	3,548,851.71	906,628	2,819,666	134,912	3.80	20.9
	TRIMBLE COUNTY CT 9	40-R2.5	*	(5)	3,655,976.41	923,545	2,915,230	139,485	3.82	20.9
	TRIMBLE COUNTY CT 10	40-R2.5	*	(5)	3,653,029.99	922,801	2,912,880	139,372	3.82	20.9
	BROWN CT 5	40-R2.5	*	(5)	775,081.85	270,065	543,771	30,044	3.88	18.1
	BROWN CT 6	40-R2.5	*	(5)	192,814.02	67,757	134,698	8,200	4.25	16.4
	BROWN CT 7	40-R2.5	*	(5)	544,965.97	207,252	364,962	22,379	4.11	16.3
	BROWN CT 8	40-R2.5	*	(5)	2,012,654.95	1,151,811	961,477	76,440	3.80	12.6
	BROWN CT 9	40-R2.5	*	(5)	4,641,054.86	2,628,903	2,244,205	130,408	2.81	17.2
	BROWN CT 10	40-R2.5	*	(5)	1,865,718.20	995,177	963,827	55,973	3.00	17.2
	BROWN CT 11	40-R2.5	*	(5)	1,895,013.50	960,868	1,028,896	75,771	4.00	13.6
	HAEFLING UNITS 1, 2 AND 3	40-R2.5	*	(5)	434,853.46	87,070	369,526	44,528	10.24	8.3
	PADDY'S RUN GENERATOR 13	40-R2.5	*	(5)	1,910,327.76	665,405	1,340,439	74,097	3.88	18.1
	TOTAL ACCOUNT 341 - STRUCTURES AND IMPROVEMENTS				36,018,413.21	12,997,862	24,821,471	1,350,340	3.75	18.4
342.00	FUEL HOLDERS, PRODUCERS AND ACCESSORIES									
	TRIMBLE COUNTY CT 5	45-R2.5	*	(5)	239,584.43	76,081	175,483	9,049	3.78	19.4
	TRIMBLE COUNTY CT 6	45-R2.5	*	(5)	239,245.54	75,986	175,222	9,036	3.78	19.4
	TRIMBLE COUNTY CT GAS PIPELINE	45-R2.5	*	(5)	4,850,114.73	1,572,837	3,519,783	166,771	3.44	21.1
	TRIMBLE COUNTY CT 7	45-R2.5	*	(5)	578,059.38	149,364	457,598	21,494	3.72	21.3
	TRIMBLE COUNTY CT 8	45-R2.5	*	(5)	576,385.74	148,931	456,274	21,431	3.72	21.3
	TRIMBLE COUNTY CT 9	45-R2.5	*	(5)	593,786.01	151,730	471,745	22,158	3.73	21.3
	TRIMBLE COUNTY CT 10	45-R2.5	*	(5)	622,872.60	157,134	496,882	23,324	3.74	21.3
	BROWN CT 5	45-R2.5	*	(5)	795,787.89	126,367	709,210	38,072	4.78	18.6
	BROWN CT 6	45-R2.5	*	(5)	406,460.01	17,424	409,359	24,066	5.92	17.0
	BROWN CT 7	45-R2.5	*	(5)	405,870.95	12,973	413,191	24,294	5.99	17.0
	BROWN CT 8	45-R2.5	*	(5)	252,005.73	22,171	242,435	18,266	7.25	13.3
	BROWN CT 9	45-R2.5	*	(5)	2,018,753.68	903,046	1,216,645	67,309	3.33	18.1
	BROWN CT 10	45-R2.5	*	(5)	264,130.81	29,700	247,637	13,099	4.96	18.9
	BROWN CT 11	45-R2.5	*	(5)	284,822.69	38,816	260,248	18,318	6.43	14.2
	BROWN CT GAS PIPELINE	45-R2.5	*	(5)	8,106,130.66	4,385,668	4,125,769	232,372	2.87	17.8
	HAEFLING UNITS 1, 2 AND 3	45-R2.5	*	(5)	518,704.54	88,960	455,680	55,109	10.62	8.3
	PADDY'S RUN GENERATOR 13	45-R2.5	*	(5)	1,995,101.02	695,267	1,399,589	75,845	3.80	18.5
	TOTAL ACCOUNT 342 - FUEL HOLDERS, PRODUCERS AND ACCESSORIES				22,747,816.41	8,652,455	15,232,750	840,013	3.69	18.1
343.00	PRIME MOVERS									
	TRIMBLE COUNTY CT 5	35-R1.5	*	(5)	31,137,756.05	10,133,882	22,560,762	1,259,343	4.04	17.9
	TRIMBLE COUNTY CT 6	35-R1.5	*	(5)	32,030,243.24	8,059,467	25,572,288	1,419,553	4.43	18.0
	TRIMBLE COUNTY CT 7	35-R1.5	*	(5)	23,223,115.61	6,218,174	18,166,097	926,898	3.99	19.6
	TRIMBLE COUNTY CT 8	35-R1.5	*	(5)	23,034,740.63	6,163,385	18,023,093	919,628	3.99	19.6
	TRIMBLE COUNTY CT 9	35-R1.5	*	(5)	22,902,195.54	5,896,000	18,151,305	925,844	4.04	19.6
	TRIMBLE COUNTY CT 10	35-R1.5	*	(5)	22,850,722.46	5,890,691	18,102,568	923,525	4.04	19.6
	BROWN CT 5	35-R1.5	*	(5)	14,666,936.33	4,448,405	10,951,878	635,708	4.33	17.2

KENTUCKY UTILITIES COMPANY

SUMMARY OF ESTIMATED SURVIVOR CURVES, NET SALVAGE, ORIGINAL COST, BOOK DEPRECIATION RESERVE AND
CALCULATED ANNUAL DEPRECIATION RATES AS OF DECEMBER 31, 2011

	ACCOUNT (1)	SURVIVOR CURVE (2)		NET SALVAGE PERCENT (3)	ORIGINAL COST (4)	BOOK DEPRECIATION RESERVE (5)	FUTURE ACCRUALS (6)	CALCULATED ANNUAL ACCRUAL AMOUNT (7)	CALCULATED ANNUAL ACCRUAL RATE (8)=(7)/(4)	COMPOSITE REMAINING LIFE (9)=(6)/(7)
343, cont.	BROWN CT 6	35-R1.5	*	(5)	34,600,149.28	7,991,509	28,338,648	1,813,591	5.24	15.6
	BROWN CT 7	35-R1.5	*	(5)	31,657,718.92	7,847,473	25,393,132	1,628,808	5.15	15.6
	BROWN CT 8	35-R1.5	*	(5)	26,710,989.99	10,068,236	17,978,303	1,455,318	5.45	12.4
	BROWN CT 9	35-R1.5	*	(5)	23,335,363.18	11,433,236	13,068,895	800,496	3.43	16.3
	BROWN CT 10	35-R1.5	*	(5)	20,074,765.96	9,663,038	11,415,466	700,567	3.49	16.3
	BROWN CT 11	35-R1.5	*	(5)	34,794,971.17	15,401,000	21,133,720	1,618,377	4.65	13.1
	PADDY'S RUN GENERATOR 13	35-R1.5	*	(5)	17,803,364.01	4,875,055	13,818,477	806,030	4.53	17.1
	TOTAL ACCOUNT 343 - PRIME MOVERS				358,823,032.37	114,089,551	262,674,632	15,833,686	4.41	16.6
344.00	GENERATORS									
	TRIMBLE COUNTY CT 5	55-S3	*	(5)	3,763,274.51	1,176,387	2,775,051	136,229	3.62	20.4
	TRIMBLE COUNTY CT 6	55-S3	*	(5)	3,757,946.57	1,174,917	2,770,927	136,027	3.62	20.4
	TRIMBLE COUNTY CT 7	55-S3	*	(5)	2,950,282.37	748,548	2,349,248	105,018	3.56	22.4
	TRIMBLE COUNTY CT 8	55-S3	*	(5)	2,937,930.22	745,414	2,339,413	104,578	3.56	22.4
	TRIMBLE COUNTY CT 9	55-S3	*	(5)	2,957,520.12	741,931	2,363,465	105,653	3.57	22.4
	TRIMBLE COUNTY CT 10	55-S3	*	(5)	2,954,148.53	741,085	2,360,771	105,533	3.57	22.4
	BROWN CT 5	55-S3	*	(5)	2,858,147.66	934,297	2,066,758	106,678	3.73	19.4
	BROWN CT 6	55-S3	*	(5)	3,712,619.52	1,492,911	2,405,339	138,397	3.73	17.4
	BROWN CT 7	55-S3	*	(5)	3,722,788.46	1,463,283	2,445,645	140,714	3.78	17.4
	BROWN CT 8	55-S3	*	(5)	4,953,960.72	2,809,555	2,392,104	178,782	3.61	13.4
	BROWN CT 9	55-S3	*	(5)	5,452,040.97	3,081,447	2,643,196	139,175	2.55	19.0
	BROWN CT 10	55-S3	*	(5)	4,944,422.71	2,624,840	2,566,804	134,599	2.72	19.1
	BROWN CT 11	55-S3	*	(5)	5,187,040.30	2,724,699	2,721,693	189,263	3.65	14.4
	HAEFLING UNITS 1, 2 AND 3	55-S3	*	(5)	4,023,002.37	3,504,167	719,985	92,815	2.31	7.8
	PADDY'S RUN GENERATOR 13	55-S3	*	(5)	5,185,636.11	1,792,632	3,652,286	188,553	3.64	19.4
	TOTAL ACCOUNT 344 - GENERATORS				59,360,761.14	25,756,113	36,572,685	2,002,014	3.37	18.3
345.00	ACCESSORY ELECTRIC EQUIPMENT									
	TRIMBLE COUNTY CT 5	45-R3	*	(5)	1,693,975.04	513,697	1,264,977	64,303	3.80	19.7
	TRIMBLE COUNTY CT 6	45-R3	*	(5)	4,324,591.46	1,036,892	3,503,929	178,222	4.12	19.7
	TRIMBLE COUNTY CT 7	45-R3	*	(5)	3,148,439.35	792,088	2,513,773	116,323	3.69	21.6
	TRIMBLE COUNTY CT 8	45-R3	*	(5)	3,139,331.68	789,796	2,506,502	115,986	3.69	21.6
	TRIMBLE COUNTY CT 9	45-R3	*	(5)	3,234,031.47	804,392	2,591,341	119,912	3.71	21.6
	TRIMBLE COUNTY CT 10	45-R3	*	(5)	7,196,618.34	1,451,369	6,105,080	282,456	3.92	21.6
	BROWN CT 5	45-R3	*	(5)	2,277,020.49	662,990	1,727,882	92,383	4.06	18.7
	BROWN CT 6	45-R3	*	(5)	1,975,216.41	691,980	1,381,997	82,329	4.17	16.8
	BROWN CT 7	45-R3	*	(5)	1,935,781.98	675,547	1,357,024	80,891	4.18	16.8
	BROWN CT 8	45-R3	*	(5)	2,720,729.67	1,361,195	1,495,571	115,931	4.26	12.9
	BROWN CT 9	45-R3	*	(5)	4,205,847.29	1,987,226	2,428,914	133,961	3.19	18.1
	BROWN CT 10	45-R3	*	(5)	2,744,492.70	1,316,949	1,564,768	86,963	3.17	18.0
	BROWN CT 11	45-R3	*	(5)	1,863,053.15	778,412	1,177,794	84,727	4.55	13.9
	HAEFLING UNITS 1, 2 AND 3	45-R3	*	(5)	1,451,957.03	563,545	961,010	116,933	8.05	8.2
	PADDY'S RUN GENERATOR 13	45-R3	*	(5)	2,456,320.01	844,832	1,734,304	92,743	3.78	18.7
	TOTAL ACCOUNT 345 - ACCESSORY ELECTRIC EQUIPMENT				44,367,406.07	14,270,910	32,314,866	1,764,063	3.98	18.3
346.00	MISCELLANEOUS POWER PLANT EQUIPMENT									
	TRIMBLE COUNTY CT 5	35-R2	*	(5)	28,963.63	8,377	22,035	1,171	4.04	18.8
	TRIMBLE COUNTY CT 7	35-R2	*	(5)	8,888.93	2,318	7,015	353	3.97	19.9
	TRIMBLE COUNTY CT 8	35-R2	*	(5)	8,861.01	2,310	6,994	352	3.97	19.9
	TRIMBLE COUNTY CT 9	35-R2	*	(5)	9,113.52	2,350	7,219	363	3.98	19.9
	TRIMBLE COUNTY CT 10	35-R2	*	(5)	41,868.51	4,157	39,805	1,922	4.59	20.7
	BROWN CT 5	35-R2	*	(5)	2,139,352.61	749,750	1,496,570	86,757	4.06	17.3

KENTUCKY UTILITIES COMPANY

SUMMARY OF ESTIMATED SURVIVOR CURVES, NET SALVAGE, ORIGINAL COST, BOOK DEPRECIATION RESERVE AND CALCULATED ANNUAL DEPRECIATION RATES AS OF DECEMBER 31, 2011

	ACCOUNT (1)	SURVIVOR CURVE (2)		NET SALVAGE PERCENT (3)	ORIGINAL COST (4)	BOOK DEPRECIATION RESERVE (5)	FUTURE ACCRUALS (6)	CALCULATED ANNUAL ACCRUAL AMOUNT (7)	CALCULATED ANNUAL ACCRUAL RATE (8)=(7)/(4)	COMPOSITE REMAINING LIFE (9)=(6)/(7)
346, cont.	BROWN CT 6	35-R2	*	(5)	53,748.85	17,904	38,532	2,404	4.47	16.0
	BROWN CT 7	35-R2	*	(5)	35,647.39	13,487	23,943	1,515	4.25	15.8
	BROWN CT 8	35-R2	*	(5)	285,932.33	133,886	166,343	13,435	4.70	12.4
	BROWN CT 9	35-R2	*	(5)	760,255.37	435,836	362,432	22,729	2.99	15.9
	BROWN CT 10	35-R2	*	(5)	274,390.87	136,467	151,643	9,323	3.40	16.3
	BROWN CT 11	35-R2	*	(5)	590,562.82	219,404	400,687	29,785	5.04	13.5
	HAEFLING UNITS 1, 2 AND 3	35-R2	*	(5)	35,805.20	34,289	3,306	597	1.67	5.5
	PADDY'S RUN GENERATOR 13	35-R2	*	(5)	1,089,550.03	384,938	759,090	44,055	4.04	17.2
	TOTAL ACCOUNT 346 - MISCELLANEOUS POWER PLANT EQUIPMENT				5,362,941.07	2,145,473	3,485,614	214,761	4.00	16.2
	TOTAL OTHER PRODUCTION PLANT				**526,856,779.58**	**178,011,802**	**375,178,989**	**22,008,824**	**4.18**	
	TRANSMISSION PLANT									
350.10	LAND RIGHTS	60-R3		0	23,413,728.55	15,953,928	7,459,801	225,538	0.96	33.1
352.10	STRUCTURES AND IMPROVEMENTS	65-S2.5		(25)	17,020,058.51	4,850,267	16,424,806	298,018	1.75	55.1
352.20	STRUCTURES AND IMPROVEMENTS - SYS. CONTROL/COM	60-R3		(25)	1,220,542.62	860,225	665,453	19,271	1.58	34.5
353.10	STATION EQUIPMENT	60-R2		(10)	191,753,788.17	67,092,664	143,836,503	3,211,159	1.67	44.8
353.20	STATION EQUIPMENT - SYS. CONTROL/COM	35-R2.5		(10)	14,668,403.51	16,135,244	0	0	-	-
354.00	TOWERS AND FIXTURES	70-R4		(25)	95,353,356.62	48,758,751	70,432,945	1,300,626	1.36	54.2
355.00	POLES AND FIXTURES	55-R2		(55)	148,658,780.48	68,401,548	162,019,562	3,485,089	2.34	46.5
356.00	OVERHEAD CONDUCTORS AND DEVICES	60-R3		(50)	160,446,879.27	109,283,433	131,386,886	3,105,267	1.94	42.3
357.00	UNDERGROUND CONDUIT	45-R4		0	448,760.26	187,418	261,342	10,209	2.27	25.6
358.00	UNDERGROUND CONDUCTORS AND DEVICES	35-R3		0	1,161,549.29	918,039	243,510	11,420	0.98	21.3
	TOTAL TRANSMISSION PLANT				**654,145,847.28**	**332,441,517**	**532,730,808**	**11,666,597**	**1.78**	
	DISTRIBUTION PLANT									
360.10	LAND RIGHTS	65-R4		0	2,039,033.29	1,485,249	553,784	11,896	0.58	46.6
361.00	STRUCTURES AND IMPROVEMENTS	60-R2.5		(20)	7,658,288.09	1,787,771	7,402,175	153,285	2.00	48.3
362.00	STATION EQUIPMENT	54-R2		(20)	141,200,430.90	40,173,683	129,266,834	3,198,522	2.27	40.4
364.00	POLES, TOWERS, AND FIXTURES	50-R1		(45)	287,791,923.15	133,160,672	284,137,617	6,719,281	2.33	42.3
365.00	OVERHEAD CONDUCTORS AND DEVICES	48-R1.5		(60)	276,285,758.81	108,982,197	333,075,017	8,911,891	3.23	37.4
366.00	UNDERGROUND CONDUIT	50-R4		(5)	1,861,963.15	653,383	1,301,678	50,337	2.70	25.9
367.00	UNDERGROUND CONDUCTORS AND DEVICES	44-R2		(10)	140,620,009.32	28,891,798	125,790,212	3,333,408	2.37	37.7
368.00	LINE TRANSFORMERS	43-R2		(15)	286,070,399.06	117,730,753	211,250,206	7,018,693	2.45	30.1
369.00	SERVICES	43-R1.5		(30)	89,050,180.39	57,697,779	58,067,456	1,811,200	2.03	32.1
370.00	METERS	39-R2		0	70,049,355.34	32,484,596	37,564,759	1,603,713	2.29	23.4
371.00	INSTALLATIONS ON CUSTOMERS' PREMISES	25-O1		(10)	18,253,214.45	17,404,873	2,673,663	148,124	0.81	18.1
373.00	STREET LIGHTING AND SIGNAL SYSTEMS	28-S0		(10)	81,534,875.55	20,703,034	68,985,329	3,261,361	4.00	21.2
	TOTAL DISTRIBUTION PLANT				**1,402,415,431.50**	**561,155,788**	**1,260,068,730**	**36,221,711**	**2.58**	

KENTUCKY UTILITIES COMPANY

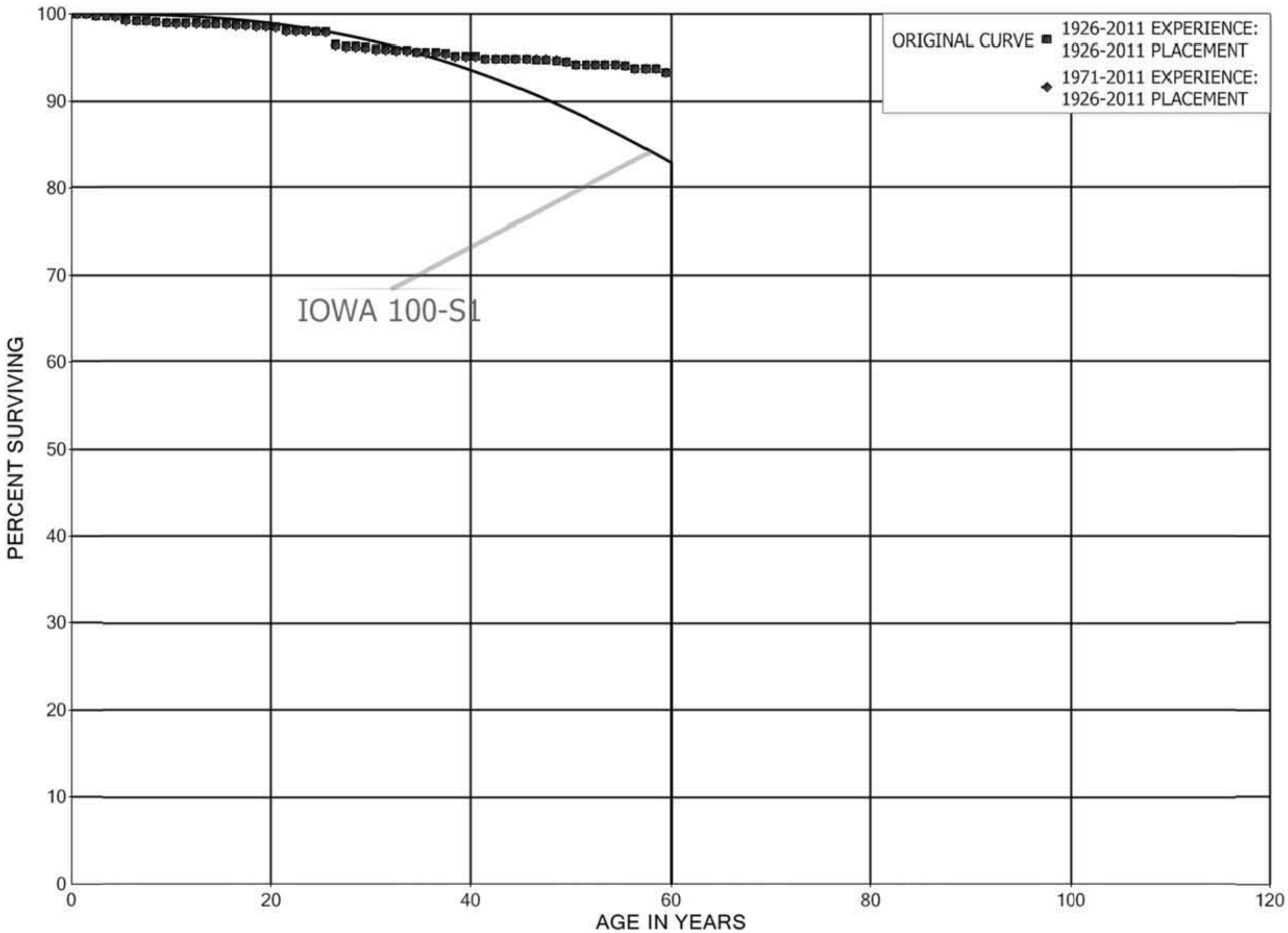
SUMMARY OF ESTIMATED SURVIVOR CURVES, NET SALVAGE, ORIGINAL COST, BOOK DEPRECIATION RESERVE AND
CALCULATED ANNUAL DEPRECIATION RATES AS OF DECEMBER 31, 2011

	ACCOUNT	SURVIVOR CURVE	NET SALVAGE PERCENT	ORIGINAL COST	BOOK DEPRECIATION RESERVE	FUTURE ACCRUALS	CALCULATED ANNUAL ACCRUAL AMOUNT	CALCULATED ANNUAL ACCRUAL RATE	COMPOSITE REMAINING LIFE
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)=(7)/(4)	(9)=(6)/(7)
	GENERAL PLANT								
390.10	STRUCTURES AND IMPROVEMENTS - TO OWNED PROPERTY	55-S0	(10)	47,011,269.52	9,650,596	42,061,800	945,113	2.01	44.5
390.20	STRUCTURES AND IMPROVEMENTS - TO LEASED PROPERTY	30-R1	(10)	531,973.44	413,480	171,691	9,139	1.72	18.8
391.10	OFFICE FURNITURE AND EQUIPMENT	20-SQ	0	7,513,787.56	4,161,871	3,351,917	335,131	4.46	10.0
391.20	NON PC COMPUTER EQUIPMENT	5-SQ	0	17,256,012.35	6,803,953	10,452,059	3,723,700	21.58	2.8
391.31	PERSONAL COMPUTERS	4-SQ	0	6,398,371.65	4,572,023	1,826,349	571,269	8.93	3.2
392.10	TRANSPORTATION EQUIPMENT - CARS AND LIGHT TRUCKS	7-L2.5	0	1,865,090.97	1,578,423	286,668	45,497	2.44	6.3
392.30	TRANSPORTATION EQUIPMENT - HEAVY TRUCKS AND OTHER	14-S1.5	0	14,101,987.63	13,160,795	941,193	76,623	0.54	12.3
393.00	STORES EQUIPMENT	25-SQ	0	551,794.27	164,539	387,255	27,960	5.07	13.9
394.00	TOOLS, SHOP AND GARAGE EQUIPMENT	25-SQ	0	7,648,755.44	1,767,311	5,881,444	326,703	4.27	18.0
396.30	POWER OPERATED EQUIPMENT - LARGE MACHINERY	12-L1.5	0	1,174,225.44	139,927	1,034,298	104,334	8.89	9.9
397.10	COMMUNICATION EQUIPMENT - GENERAL ASSETS	10-SQ	0	10,171,295.90	5,248,935	4,922,361	579,495	5.70	8.5
397.20	COMMUNICATION EQUIPMENT - SPECIFIC ASSETS	25-S1	0	19,915,035.90	5,655,027	14,260,009	746,086	3.75	19.1
397.30	COMMUNICATION EQUIPMENT - FULLY ACCRUED	FULLY ACCRUED	0	786,233.20	786,233	0	0	-	-
	TOTAL GENERAL PLANT			**134,925,833.27**	**54,103,113**	**85,577,044**	**7,491,050**	**5.55**	
	TOTAL DEPRECIABLE PLANT			**6,365,236,955.68**	**2,412,555,355**	**5,057,370,141**	**189,326,536**	**2.97**	
	NONDEPRECIABLE PLANT								
301.00	ORGANIZATION			44,455.58					
310.20	LAND			10,881,103.86					
340.20	LAND			118,514.41					
350.20	LAND			2,199,383.04					
360.20	LAND			3,271,807.48					
389.20	LAND			2,567,847.40					
	TOTAL NONDEPRECIABLE PLANT			**19,083,111.77**					
	TOTAL ELECTRIC PLANT			**6,384,320,067.45**	**2,412,555,355**	**5,057,370,141**	**189,326,536**		

* LIFE SPAN PROCEDURE IS USED. CURVE SHOWN IS INTERIM SURVIVOR CURVE

III-11 SERVICE LIFE STATISTICS

KENTUCKY UTILITIES COMPANY
ACCOUNT 311 STRUCTURES AND IMPROVEMENTS
ORIGINAL AND SMOOTH SURVIVOR CURVES



KENTUCKY UTILITIES COMPANY

ACCOUNT 311 STRUCTURES AND IMPROVEMENTS

ORIGINAL LIFE TABLE

PLACEMENT BAND 1926-2011 EXPERIENCE BAND 1926-2011

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	297,329,781		0.0000	1.0000	100.00
0.5	229,300,197		0.0000	1.0000	100.00
1.5	183,425,773	542,452	0.0030	0.9970	100.00
2.5	181,974,110		0.0000	1.0000	99.70
3.5	181,268,132	28,814	0.0002	0.9998	99.70
4.5	164,787,338	734,062	0.0045	0.9955	99.69
5.5	163,824,662	88,526	0.0005	0.9995	99.24
6.5	162,687,185	515	0.0000	1.0000	99.19
7.5	159,293,746	151,742	0.0010	0.9990	99.19
8.5	158,265,477	170,873	0.0011	0.9989	99.10
9.5	157,662,103	39,157	0.0002	0.9998	98.99
10.5	156,069,948	15,849	0.0001	0.9999	98.96
11.5	155,748,988	27,779	0.0002	0.9998	98.95
12.5	139,881,180	66,213	0.0005	0.9995	98.94
13.5	139,591,754	17,498	0.0001	0.9999	98.89
14.5	128,464,896	100,004	0.0008	0.9992	98.88
15.5	143,112,730	64,102	0.0004	0.9996	98.80
16.5	142,440,319	40,396	0.0003	0.9997	98.76
17.5	125,782,497	109,268	0.0009	0.9991	98.73
18.5	125,518,668	42,662	0.0003	0.9997	98.64
19.5	124,531,452	153,036	0.0012	0.9988	98.61
20.5	123,624,117	551,597	0.0045	0.9955	98.49
21.5	123,150,422		0.0000	1.0000	98.05
22.5	121,839,921		0.0000	1.0000	98.05
23.5	121,558,047	47,461	0.0004	0.9996	98.05
24.5	118,373,518	103,316	0.0009	0.9991	98.01
25.5	116,829,351	1,751,941	0.0150	0.9850	97.92
26.5	113,918,980	244,413	0.0021	0.9979	96.46
27.5	96,360,096	2,500	0.0000	1.0000	96.25
28.5	96,349,228	61,674	0.0006	0.9994	96.25
29.5	94,411,612	220,357	0.0023	0.9977	96.18
30.5	59,662,290	351	0.0000	1.0000	95.96
31.5	58,791,331	91,787	0.0016	0.9984	95.96
32.5	58,078,644		0.0000	1.0000	95.81
33.5	57,996,134	87,047	0.0015	0.9985	95.81
34.5	40,904,243	25,404	0.0006	0.9994	95.67
35.5	40,875,076		0.0000	1.0000	95.61
36.5	40,312,954	44,328	0.0011	0.9989	95.61
37.5	25,374,624	88,649	0.0035	0.9965	95.50
38.5	25,221,697	5,543	0.0002	0.9998	95.17

KENTUCKY UTILITIES COMPANY

ACCOUNT 311 STRUCTURES AND IMPROVEMENTS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1926-2011 EXPERIENCE BAND 1926-2011

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	25,140,502		0.0000	1.0000	95.15
40.5	17,434,732	60,725	0.0035	0.9965	95.15
41.5	17,346,884	2,128	0.0001	0.9999	94.82
42.5	17,312,631		0.0000	1.0000	94.80
43.5	17,312,537		0.0000	1.0000	94.80
44.5	17,305,825		0.0000	1.0000	94.80
45.5	17,294,821	5,000	0.0003	0.9997	94.80
46.5	17,270,931	2,942	0.0002	0.9998	94.78
47.5	17,251,773	17,705	0.0010	0.9990	94.76
48.5	15,953,656	23,812	0.0015	0.9985	94.66
49.5	15,929,844	60,621	0.0038	0.9962	94.52
50.5	15,854,566		0.0000	1.0000	94.16
51.5	15,037,603	1,141	0.0001	0.9999	94.16
52.5	12,657,734		0.0000	1.0000	94.16
53.5	12,657,091		0.0000	1.0000	94.16
54.5	11,529,161	13,326	0.0012	0.9988	94.16
55.5	9,078,814	30,823	0.0034	0.9966	94.05
56.5	9,012,350	829	0.0001	0.9999	93.73
57.5	7,247,111	1,385	0.0002	0.9998	93.72
58.5	5,376,228	23,982	0.0045	0.9955	93.70
59.5	5,352,246		0.0000	1.0000	93.28
60.5	5,287,901		0.0000	1.0000	93.28
61.5	3,620,283		0.0000	1.0000	93.28
62.5	3,582,130		0.0000	1.0000	93.28
63.5	3,258,529		0.0000	1.0000	93.28
64.5	1,041,808		0.0000	1.0000	93.28
65.5	1,041,808		0.0000	1.0000	93.28
66.5	1,041,808		0.0000	1.0000	93.28
67.5	1,041,808		0.0000	1.0000	93.28
68.5	1,041,808		0.0000	1.0000	93.28
69.5	1,041,808		0.0000	1.0000	93.28
70.5	1,041,808		0.0000	1.0000	93.28
71.5	1,041,808		0.0000	1.0000	93.28
72.5	1,041,808		0.0000	1.0000	93.28
73.5	1,041,808		0.0000	1.0000	93.28
74.5	1,041,808		0.0000	1.0000	93.28
75.5	1,041,808		0.0000	1.0000	93.28
76.5					93.28

KENTUCKY UTILITIES COMPANY

ACCOUNT 311 STRUCTURES AND IMPROVEMENTS

ORIGINAL LIFE TABLE

PLACEMENT BAND 1926-2011 EXPERIENCE BAND 1971-2011

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	279,497,381		0.0000	1.0000	100.00
0.5	211,577,148		0.0000	1.0000	100.00
1.5	165,735,423	542,452	0.0033	0.9967	100.00
2.5	164,287,072		0.0000	1.0000	99.67
3.5	163,599,290	28,814	0.0002	0.9998	99.67
4.5	147,130,073	709,034	0.0048	0.9952	99.66
5.5	146,212,600	79,197	0.0005	0.9995	99.17
6.5	145,115,829	515	0.0000	1.0000	99.12
7.5	143,002,802	151,742	0.0011	0.9989	99.12
8.5	141,974,533	170,873	0.0012	0.9988	99.02
9.5	141,391,344	35,941	0.0003	0.9997	98.90
10.5	139,858,786	6,176	0.0000	1.0000	98.87
11.5	141,931,798	27,779	0.0002	0.9998	98.87
12.5	126,144,500	47,026	0.0004	0.9996	98.85
13.5	125,875,897	17,498	0.0001	0.9999	98.81
14.5	117,254,111	100,004	0.0009	0.9991	98.80
15.5	131,943,729	64,102	0.0005	0.9995	98.71
16.5	133,050,121	39,075	0.0003	0.9997	98.66
17.5	118,263,975	107,012	0.0009	0.9991	98.64
18.5	118,002,680	42,662	0.0004	0.9996	98.55
19.5	117,840,146	153,036	0.0013	0.9987	98.51
20.5	119,735,155	551,297	0.0046	0.9954	98.38
21.5	119,301,298		0.0000	1.0000	97.93
22.5	118,403,124		0.0000	1.0000	97.93
23.5	120,338,476	47,461	0.0004	0.9996	97.93
24.5	117,153,947	100,762	0.0009	0.9991	97.89
25.5	115,612,334	1,701,956	0.0147	0.9853	97.81
26.5	112,751,948	244,413	0.0022	0.9978	96.37
27.5	95,193,064	2,500	0.0000	1.0000	96.16
28.5	95,182,196	61,174	0.0006	0.9994	96.16
29.5	93,245,080	220,357	0.0024	0.9976	96.09
30.5	58,495,758	351	0.0000	1.0000	95.87
31.5	57,624,799	91,787	0.0016	0.9984	95.87
32.5	56,912,112		0.0000	1.0000	95.71
33.5	56,829,602	87,047	0.0015	0.9985	95.71
34.5	39,737,711	25,404	0.0006	0.9994	95.57
35.5	39,708,544		0.0000	1.0000	95.51
36.5	39,146,422	44,328	0.0011	0.9989	95.51
37.5	24,208,092	88,649	0.0037	0.9963	95.40
38.5	24,077,902	5,543	0.0002	0.9998	95.05

KENTUCKY UTILITIES COMPANY

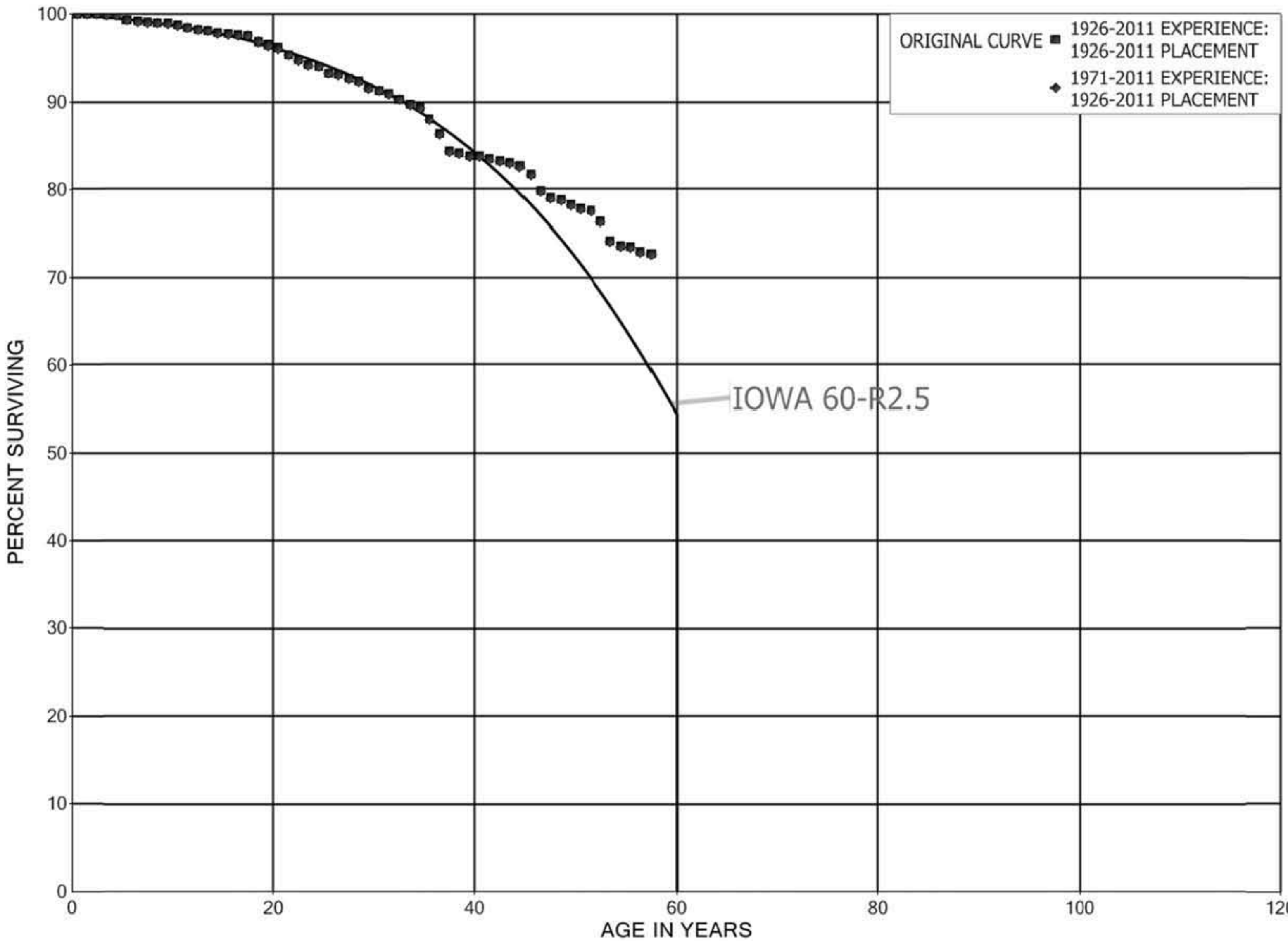
ACCOUNT 311 STRUCTURES AND IMPROVEMENTS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1926-2011 EXPERIENCE BAND 1971-2011

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	23,996,707		0.0000	1.0000	95.03
40.5	16,290,937	30,936	0.0019	0.9981	95.03
41.5	16,232,878	2,128	0.0001	0.9999	94.85
42.5	16,198,625		0.0000	1.0000	94.83
43.5	16,198,531		0.0000	1.0000	94.83
44.5	17,305,825		0.0000	1.0000	94.83
45.5	17,294,821	5,000	0.0003	0.9997	94.83
46.5	17,270,931	2,942	0.0002	0.9998	94.81
47.5	17,251,773	17,705	0.0010	0.9990	94.79
48.5	15,953,656	23,812	0.0015	0.9985	94.69
49.5	15,929,844	60,621	0.0038	0.9962	94.55
50.5	15,854,566		0.0000	1.0000	94.19
51.5	15,037,603	1,141	0.0001	0.9999	94.19
52.5	12,657,734		0.0000	1.0000	94.18
53.5	12,657,091		0.0000	1.0000	94.18
54.5	11,529,161	13,326	0.0012	0.9988	94.18
55.5	9,078,814	30,823	0.0034	0.9966	94.08
56.5	9,012,350	829	0.0001	0.9999	93.76
57.5	7,247,111	1,385	0.0002	0.9998	93.75
58.5	5,376,228	23,982	0.0045	0.9955	93.73
59.5	5,352,246		0.0000	1.0000	93.31
60.5	5,287,901		0.0000	1.0000	93.31
61.5	3,620,283		0.0000	1.0000	93.31
62.5	3,582,130		0.0000	1.0000	93.31
63.5	3,258,529		0.0000	1.0000	93.31
64.5	1,041,808		0.0000	1.0000	93.31
65.5	1,041,808		0.0000	1.0000	93.31
66.5	1,041,808		0.0000	1.0000	93.31
67.5	1,041,808		0.0000	1.0000	93.31
68.5	1,041,808		0.0000	1.0000	93.31
69.5	1,041,808		0.0000	1.0000	93.31
70.5	1,041,808		0.0000	1.0000	93.31
71.5	1,041,808		0.0000	1.0000	93.31
72.5	1,041,808		0.0000	1.0000	93.31
73.5	1,041,808		0.0000	1.0000	93.31
74.5	1,041,808		0.0000	1.0000	93.31
75.5	1,041,808		0.0000	1.0000	93.31
76.5					93.31

KENTUCKY UTILITIES COMPANY
ACCOUNT 312 BOILER PLANT EQUIPMENT
ORIGINAL AND SMOOTH SURVIVOR CURVES



KENTUCKY UTILITIES COMPANY

ACCOUNT 312 BOILER PLANT EQUIPMENT

ORIGINAL LIFE TABLE

PLACEMENT BAND 1926-2011 EXPERIENCE BAND 1926-2011

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	2,731,629,101	164,872	0.0001	0.9999	100.00
0.5	2,151,564,916	80,610	0.0000	1.0000	99.99
1.5	1,769,606,919	992,739	0.0006	0.9994	99.99
2.5	1,562,607,386	891,558	0.0006	0.9994	99.93
3.5	1,225,783,213	859,158	0.0007	0.9993	99.88
4.5	1,091,160,754	6,012,826	0.0055	0.9945	99.81
5.5	1,076,568,255	1,222,372	0.0011	0.9989	99.26
6.5	1,048,253,728	1,139,683	0.0011	0.9989	99.14
7.5	820,139,465	708,133	0.0009	0.9991	99.04
8.5	808,811,073	497,637	0.0006	0.9994	98.95
9.5	797,350,572	1,525,281	0.0019	0.9981	98.89
10.5	782,817,739	2,314,880	0.0030	0.9970	98.70
11.5	779,372,865	1,542,546	0.0020	0.9980	98.41
12.5	708,264,239	840,399	0.0012	0.9988	98.21
13.5	706,203,637	2,242,403	0.0032	0.9968	98.10
14.5	667,880,208	726,478	0.0011	0.9989	97.79
15.5	718,896,564	530,076	0.0007	0.9993	97.68
16.5	695,404,799	457,426	0.0007	0.9993	97.61
17.5	607,505,370	4,148,076	0.0068	0.9932	97.54
18.5	585,314,505	2,341,325	0.0040	0.9960	96.88
19.5	568,791,780	2,027,858	0.0036	0.9964	96.49
20.5	554,217,899	4,094,991	0.0074	0.9926	96.15
21.5	548,951,443	3,366,614	0.0061	0.9939	95.44
22.5	544,111,066	3,194,035	0.0059	0.9941	94.85
23.5	538,776,455	1,017,223	0.0019	0.9981	94.29
24.5	532,096,092	4,553,662	0.0086	0.9914	94.12
25.5	525,935,408	801,460	0.0015	0.9985	93.31
26.5	524,714,847	2,727,183	0.0052	0.9948	93.17
27.5	374,968,431	1,228,804	0.0033	0.9967	92.68
28.5	373,182,936	3,127,145	0.0084	0.9916	92.38
29.5	359,596,921	1,087,828	0.0030	0.9970	91.61
30.5	221,323,244	1,025,775	0.0046	0.9954	91.33
31.5	219,146,809	1,437,765	0.0066	0.9934	90.91
32.5	217,258,367	1,356,177	0.0062	0.9938	90.31
33.5	213,506,234	803,150	0.0038	0.9962	89.75
34.5	142,270,428	2,106,377	0.0148	0.9852	89.41
35.5	131,751,130	2,506,126	0.0190	0.9810	88.08
36.5	122,204,114	2,826,366	0.0231	0.9769	86.41
37.5	63,714,115	173,592	0.0027	0.9973	84.41
38.5	59,265,853	233,703	0.0039	0.9961	84.18

KENTUCKY UTILITIES COMPANY

ACCOUNT 312 BOILER PLANT EQUIPMENT

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1926-2011 EXPERIENCE BAND 1926-2011

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	58,719,751	32,104	0.0005	0.9995	83.85
40.5	32,579,171	111,516	0.0034	0.9966	83.80
41.5	32,281,184	95,961	0.0030	0.9970	83.52
42.5	32,175,785	58,268	0.0018	0.9982	83.27
43.5	32,104,517	169,154	0.0053	0.9947	83.12
44.5	31,891,516	358,176	0.0112	0.9888	82.68
45.5	31,532,880	721,056	0.0229	0.9771	81.75
46.5	30,789,189	318,881	0.0104	0.9896	79.88
47.5	30,384,201	83,359	0.0027	0.9973	79.05
48.5	24,895,301	185,306	0.0074	0.9926	78.84
49.5	24,708,402	115,749	0.0047	0.9953	78.25
50.5	24,589,160	69,590	0.0028	0.9972	77.88
51.5	22,604,953	381,692	0.0169	0.9831	77.66
52.5	18,380,071	526,895	0.0287	0.9713	76.35
53.5	17,772,851	138,991	0.0078	0.9922	74.16
54.5	13,583,278	17,373	0.0013	0.9987	73.58
55.5	9,533,983	65,919	0.0069	0.9931	73.49
56.5	9,464,307	29,854	0.0032	0.9968	72.98
57.5	6,442,313	539	0.0001	0.9999	72.75
58.5	3,229,413		0.0000	1.0000	72.74
59.5	1,587,783		0.0000	1.0000	72.74
60.5	547,055	6,415	0.0117	0.9883	72.74
61.5	419,684		0.0000	1.0000	71.89
62.5	363,068		0.0000	1.0000	71.89
63.5	362,814		0.0000	1.0000	71.89
64.5	127,433		0.0000	1.0000	71.89
65.5	127,433		0.0000	1.0000	71.89
66.5	127,433		0.0000	1.0000	71.89
67.5	127,433		0.0000	1.0000	71.89
68.5	127,433		0.0000	1.0000	71.89
69.5	127,433		0.0000	1.0000	71.89
70.5	127,433		0.0000	1.0000	71.89
71.5	127,433		0.0000	1.0000	71.89
72.5	127,433		0.0000	1.0000	71.89
73.5	127,433		0.0000	1.0000	71.89
74.5	127,433		0.0000	1.0000	71.89
75.5	127,433		0.0000	1.0000	71.89
76.5					71.89

KENTUCKY UTILITIES COMPANY

ACCOUNT 312 BOILER PLANT EQUIPMENT

ORIGINAL LIFE TABLE

PLACEMENT BAND 1926-2011 EXPERIENCE BAND 1971-2011

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	2,694,097,651	158,729	0.0001	0.9999	100.00
0.5	2,114,271,949	70,428	0.0000	1.0000	99.99
1.5	1,732,346,033	992,739	0.0006	0.9994	99.99
2.5	1,525,359,500	891,558	0.0006	0.9994	99.93
3.5	1,188,555,643	851,722	0.0007	0.9993	99.88
4.5	1,053,985,424	5,986,684	0.0057	0.9943	99.80
5.5	1,039,468,886	1,222,372	0.0012	0.9988	99.24
6.5	1,011,259,230	1,128,733	0.0011	0.9989	99.12
7.5	790,260,760	708,133	0.0009	0.9991	99.01
8.5	778,932,368	452,868	0.0006	0.9994	98.92
9.5	767,516,636	1,525,281	0.0020	0.9980	98.86
10.5	753,007,684	2,263,172	0.0030	0.9970	98.67
11.5	755,107,496	1,542,546	0.0020	0.9980	98.37
12.5	684,308,437	822,543	0.0012	0.9988	98.17
13.5	683,044,302	2,238,167	0.0033	0.9967	98.05
14.5	649,643,738	726,478	0.0011	0.9989	97.73
15.5	700,667,236	528,890	0.0008	0.9992	97.62
16.5	680,998,715	454,382	0.0007	0.9993	97.55
17.5	596,728,118	4,049,831	0.0068	0.9932	97.48
18.5	574,666,229	2,326,211	0.0040	0.9960	96.82
19.5	560,160,015	2,022,545	0.0036	0.9964	96.43
20.5	549,661,372	4,092,991	0.0074	0.9926	96.08
21.5	544,457,475	3,366,614	0.0062	0.9938	95.36
22.5	541,237,151	3,194,035	0.0059	0.9941	94.77
23.5	537,520,924	1,017,223	0.0019	0.9981	94.22
24.5	530,860,977	4,529,126	0.0085	0.9915	94.04
25.5	524,725,315	789,083	0.0015	0.9985	93.24
26.5	523,517,131	2,717,883	0.0052	0.9948	93.09
27.5	373,780,015	1,222,977	0.0033	0.9967	92.61
28.5	372,000,347	3,127,145	0.0084	0.9916	92.31
29.5	358,414,332	1,087,216	0.0030	0.9970	91.53
30.5	220,141,267	1,025,775	0.0047	0.9953	91.25
31.5	217,964,832	1,437,765	0.0066	0.9934	90.83
32.5	216,076,390	1,356,177	0.0063	0.9937	90.23
33.5	212,324,257	803,150	0.0038	0.9962	89.66
34.5	141,088,451	2,106,377	0.0149	0.9851	89.33
35.5	130,569,153	2,506,126	0.0192	0.9808	87.99
36.5	121,022,137	2,826,366	0.0234	0.9766	86.30
37.5	62,532,138	173,592	0.0028	0.9972	84.29
38.5	59,138,420	233,703	0.0040	0.9960	84.05

KENTUCKY UTILITIES COMPANY

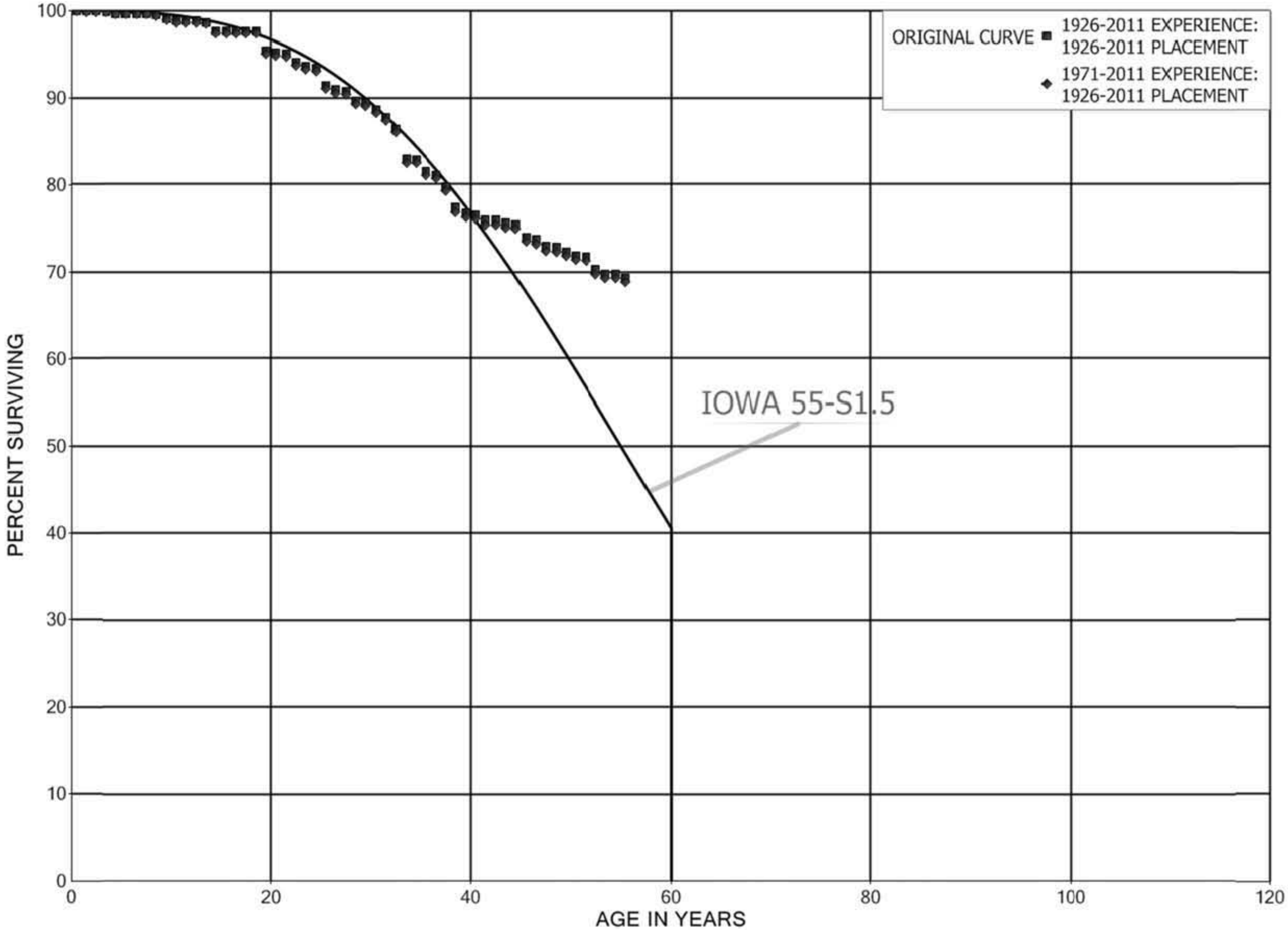
ACCOUNT 312 BOILER PLANT EQUIPMENT

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1926-2011 EXPERIENCE BAND 1971-2011

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	58,592,318	32,104	0.0005	0.9995	83.72
40.5	32,451,738	111,516	0.0034	0.9966	83.68
41.5	32,153,751	95,961	0.0030	0.9970	83.39
42.5	32,048,352	58,268	0.0018	0.9982	83.14
43.5	31,977,084	169,154	0.0053	0.9947	82.99
44.5	31,891,516	358,176	0.0112	0.9888	82.55
45.5	31,532,880	721,056	0.0229	0.9771	81.62
46.5	30,789,189	318,881	0.0104	0.9896	79.75
47.5	30,384,201	83,359	0.0027	0.9973	78.93
48.5	24,895,301	185,306	0.0074	0.9926	78.71
49.5	24,708,402	115,749	0.0047	0.9953	78.13
50.5	24,589,160	69,590	0.0028	0.9972	77.76
51.5	22,604,953	381,692	0.0169	0.9831	77.54
52.5	18,380,071	526,895	0.0287	0.9713	76.23
53.5	17,772,851	138,991	0.0078	0.9922	74.05
54.5	13,583,278	17,373	0.0013	0.9987	73.47
55.5	9,533,983	65,919	0.0069	0.9931	73.37
56.5	9,464,307	29,854	0.0032	0.9968	72.87
57.5	6,442,313	539	0.0001	0.9999	72.64
58.5	3,229,413		0.0000	1.0000	72.63
59.5	1,587,783		0.0000	1.0000	72.63
60.5	547,055	6,415	0.0117	0.9883	72.63
61.5	419,684		0.0000	1.0000	71.78
62.5	363,068		0.0000	1.0000	71.78
63.5	362,814		0.0000	1.0000	71.78
64.5	127,433		0.0000	1.0000	71.78
65.5	127,433		0.0000	1.0000	71.78
66.5	127,433		0.0000	1.0000	71.78
67.5	127,433		0.0000	1.0000	71.78
68.5	127,433		0.0000	1.0000	71.78
69.5	127,433		0.0000	1.0000	71.78
70.5	127,433		0.0000	1.0000	71.78
71.5	127,433		0.0000	1.0000	71.78
72.5	127,433		0.0000	1.0000	71.78
73.5	127,433		0.0000	1.0000	71.78
74.5	127,433		0.0000	1.0000	71.78
75.5	127,433		0.0000	1.0000	71.78
76.5					71.78

KENTUCKY UTILITIES COMPANY
ACCOUNT 314 TURBOGENERATOR UNITS
ORIGINAL AND SMOOTH SURVIVOR CURVES



KENTUCKY UTILITIES COMPANY

ACCOUNT 314 TURBOGENERATOR UNITS

ORIGINAL LIFE TABLE

PLACEMENT BAND 1926-2011 EXPERIENCE BAND 1926-2011

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	335,556,701		0.0000	1.0000	100.00
0.5	261,273,257	265,201	0.0010	0.9990	100.00
1.5	258,769,267		0.0000	1.0000	99.90
2.5	250,491,692	134,051	0.0005	0.9995	99.90
3.5	235,759,345	480,666	0.0020	0.9980	99.85
4.5	232,822,530		0.0000	1.0000	99.64
5.5	227,272,291		0.0000	1.0000	99.64
6.5	219,704,875		0.0000	1.0000	99.64
7.5	211,534,654	366,895	0.0017	0.9983	99.64
8.5	202,513,341	770,007	0.0038	0.9962	99.47
9.5	199,934,609	584,119	0.0029	0.9971	99.09
10.5	198,751,597	11	0.0000	1.0000	98.80
11.5	198,750,910	10,183	0.0001	0.9999	98.80
12.5	197,933,153	388,345	0.0020	0.9980	98.80
13.5	197,241,382	1,959,530	0.0099	0.9901	98.60
14.5	179,823,471	34,900	0.0002	0.9998	97.62
15.5	176,496,628		0.0000	1.0000	97.60
16.5	172,784,289		0.0000	1.0000	97.60
17.5	168,774,966	3,600	0.0000	1.0000	97.60
18.5	168,419,736	3,863,067	0.0229	0.9771	97.60
19.5	164,496,029	323,088	0.0020	0.9980	95.36
20.5	164,026,481	161,286	0.0010	0.9990	95.18
21.5	163,828,572	1,743,433	0.0106	0.9894	95.08
22.5	161,710,200	705,556	0.0044	0.9956	94.07
23.5	161,004,643	449,660	0.0028	0.9972	93.66
24.5	160,445,551	3,514,276	0.0219	0.9781	93.40
25.5	156,879,870	787,410	0.0050	0.9950	91.35
26.5	155,306,052	348,432	0.0022	0.9978	90.89
27.5	105,142,584	1,236,741	0.0118	0.9882	90.69
28.5	103,875,931	304,676	0.0029	0.9971	89.62
29.5	103,083,666	860,108	0.0083	0.9917	89.36
30.5	77,907,643	777,182	0.0100	0.9900	88.61
31.5	77,125,034	1,126,634	0.0146	0.9854	87.73
32.5	75,956,335	3,072,729	0.0405	0.9595	86.45
33.5	68,563,469	58,664	0.0009	0.9991	82.95
34.5	50,752,989	858,803	0.0169	0.9831	82.88
35.5	49,894,030	225,016	0.0045	0.9955	81.48
36.5	49,530,338	818,379	0.0165	0.9835	81.11
37.5	34,436,944	1,022,725	0.0297	0.9703	79.77
38.5	32,353,433	261,818	0.0081	0.9919	77.40

KENTUCKY UTILITIES COMPANY

ACCOUNT 314 TURBOGENERATOR UNITS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1926-2011 EXPERIENCE BAND 1926-2011

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	32,057,398	98,858	0.0031	0.9969	76.78
40.5	22,375,557	184,510	0.0082	0.9918	76.54
41.5	22,190,158		0.0000	1.0000	75.91
42.5	22,190,158	89,094	0.0040	0.9960	75.91
43.5	22,095,289	46,969	0.0021	0.9979	75.60
44.5	22,048,320	426,198	0.0193	0.9807	75.44
45.5	21,622,122	86,296	0.0040	0.9960	73.98
46.5	21,502,888	221,501	0.0103	0.9897	73.69
47.5	21,281,387	33,901	0.0016	0.9984	72.93
48.5	17,133,620	118,197	0.0069	0.9931	72.81
49.5	17,015,423	106,372	0.0063	0.9937	72.31
50.5	16,863,447	23,139	0.0014	0.9986	71.86
51.5	15,317,768	322,850	0.0211	0.9789	71.76
52.5	12,253,369	82,920	0.0068	0.9932	70.25
53.5	12,167,256	11,547	0.0009	0.9991	69.77
54.5	9,876,687	63,208	0.0064	0.9936	69.71
55.5	5,962,095	8,995	0.0015	0.9985	69.26
56.5	5,953,100		0.0000	1.0000	69.16
57.5	3,686,195		0.0000	1.0000	69.16
58.5	1,624,367		0.0000	1.0000	69.16
59.5	847,183		0.0000	1.0000	69.16
60.5	96,695		0.0000	1.0000	69.16
61.5	96,695		0.0000	1.0000	69.16
62.5	96,695		0.0000	1.0000	69.16
63.5	28,489		0.0000	1.0000	69.16
64.5	28,489		0.0000	1.0000	69.16
65.5	28,489		0.0000	1.0000	69.16
66.5	28,489		0.0000	1.0000	69.16
67.5	28,489		0.0000	1.0000	69.16
68.5	28,489		0.0000	1.0000	69.16
69.5	28,489		0.0000	1.0000	69.16
70.5	28,489		0.0000	1.0000	69.16
71.5	28,489		0.0000	1.0000	69.16
72.5	28,489		0.0000	1.0000	69.16
73.5	28,489		0.0000	1.0000	69.16
74.5	28,489		0.0000	1.0000	69.16
75.5	28,489		0.0000	1.0000	69.16
76.5					69.16

KENTUCKY UTILITIES COMPANY

ACCOUNT 314 TURBOGENERATOR UNITS

ORIGINAL LIFE TABLE

PLACEMENT BAND 1926-2011 EXPERIENCE BAND 1971-2011

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	310,173,224		0.0000	1.0000	100.00
0.5	235,897,134	265,201	0.0011	0.9989	100.00
1.5	233,393,144		0.0000	1.0000	99.89
2.5	225,128,924	134,051	0.0006	0.9994	99.89
3.5	210,396,577	480,666	0.0023	0.9977	99.83
4.5	207,459,762		0.0000	1.0000	99.60
5.5	201,945,289		0.0000	1.0000	99.60
6.5	194,378,101		0.0000	1.0000	99.60
7.5	191,587,817	366,895	0.0019	0.9981	99.60
8.5	182,566,505	770,007	0.0042	0.9958	99.41
9.5	179,994,639	584,119	0.0032	0.9968	98.99
10.5	178,812,283	11	0.0000	1.0000	98.67
11.5	183,073,540	10,183	0.0001	0.9999	98.67
12.5	182,263,242	388,345	0.0021	0.9979	98.66
13.5	181,571,470	1,959,530	0.0108	0.9892	98.45
14.5	168,402,837	34,900	0.0002	0.9998	97.39
15.5	165,075,995		0.0000	1.0000	97.37
16.5	163,869,043		0.0000	1.0000	97.37
17.5	162,179,808		0.0000	1.0000	97.37
18.5	161,864,087	3,863,067	0.0239	0.9761	97.37
19.5	159,469,764	319,488	0.0020	0.9980	95.05
20.5	161,320,776	161,286	0.0010	0.9990	94.86
21.5	161,122,867	1,743,433	0.0108	0.9892	94.76
22.5	159,849,885	705,556	0.0044	0.9956	93.74
23.5	159,894,816	449,660	0.0028	0.9972	93.32
24.5	159,335,724	3,495,878	0.0219	0.9781	93.06
25.5	155,788,441	787,410	0.0051	0.9949	91.02
26.5	154,214,623	348,432	0.0023	0.9977	90.56
27.5	104,051,155	1,236,741	0.0119	0.9881	90.35
28.5	102,784,502	304,676	0.0030	0.9970	89.28
29.5	101,992,237	855,578	0.0084	0.9916	89.01
30.5	76,820,744	777,182	0.0101	0.9899	88.27
31.5	76,038,135	1,126,634	0.0148	0.9852	87.38
32.5	74,869,436	3,072,729	0.0410	0.9590	86.08
33.5	67,476,570	58,664	0.0009	0.9991	82.55
34.5	49,666,090	858,803	0.0173	0.9827	82.48
35.5	48,807,131	225,016	0.0046	0.9954	81.05
36.5	48,443,439	818,379	0.0169	0.9831	80.68
37.5	33,350,045	1,022,725	0.0307	0.9693	79.31
38.5	32,324,944	261,818	0.0081	0.9919	76.88

KENTUCKY UTILITIES COMPANY

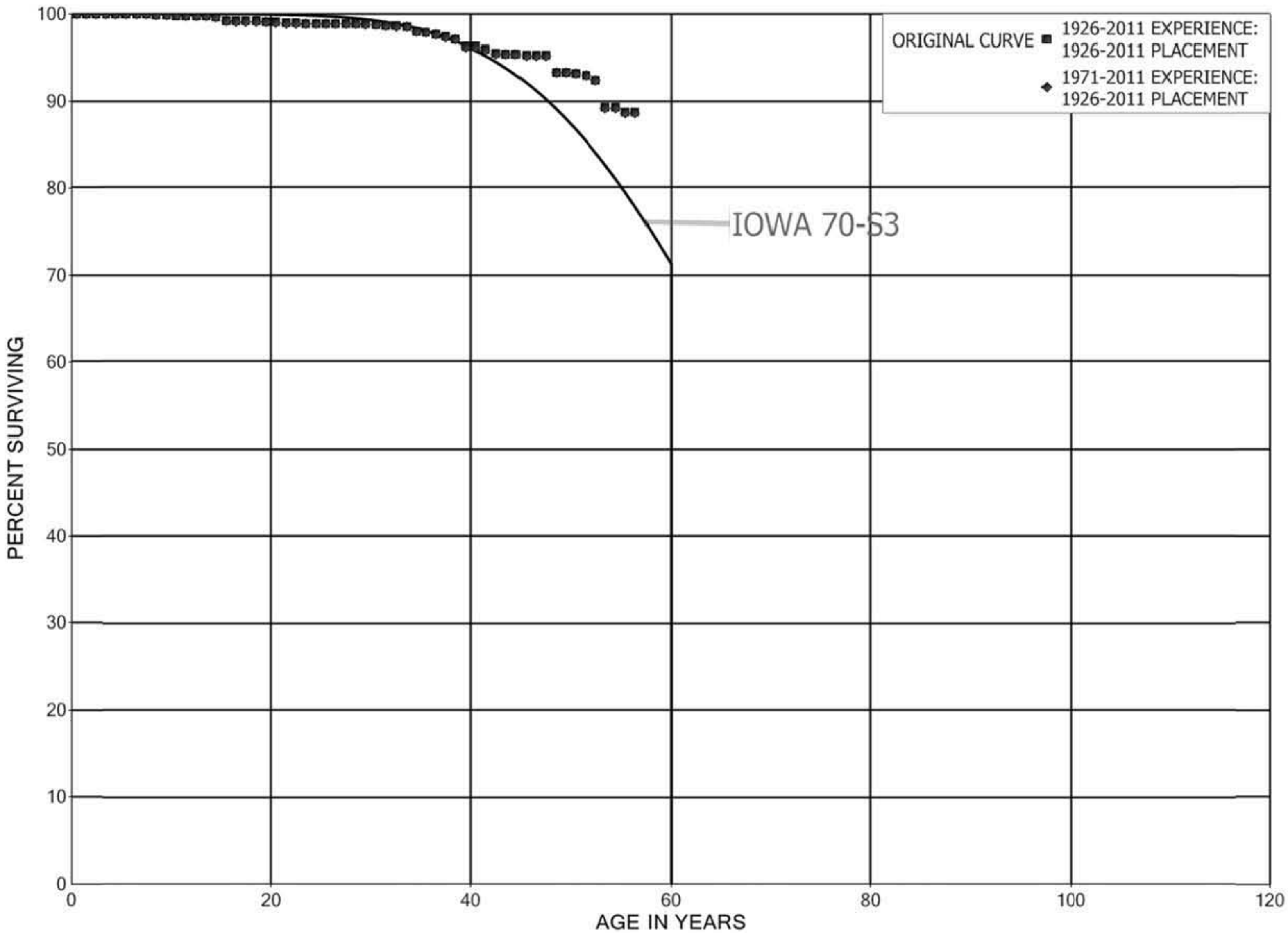
ACCOUNT 314 TURBOGENERATOR UNITS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1926-2011 EXPERIENCE BAND 1971-2011

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	32,028,909	98,858	0.0031	0.9969	76.26
40.5	22,347,068	184,510	0.0083	0.9917	76.02
41.5	22,161,669		0.0000	1.0000	75.40
42.5	22,161,669	89,094	0.0040	0.9960	75.40
43.5	22,066,800	46,969	0.0021	0.9979	75.09
44.5	22,048,320	426,198	0.0193	0.9807	74.93
45.5	21,622,122	86,296	0.0040	0.9960	73.48
46.5	21,502,888	221,501	0.0103	0.9897	73.19
47.5	21,281,387	33,901	0.0016	0.9984	72.44
48.5	17,133,620	118,197	0.0069	0.9931	72.32
49.5	17,015,423	106,372	0.0063	0.9937	71.82
50.5	16,863,447	23,139	0.0014	0.9986	71.37
51.5	15,317,768	322,850	0.0211	0.9789	71.28
52.5	12,253,369	82,920	0.0068	0.9932	69.77
53.5	12,167,256	11,547	0.0009	0.9991	69.30
54.5	9,876,687	63,208	0.0064	0.9936	69.24
55.5	5,962,095	8,995	0.0015	0.9985	68.79
56.5	5,953,100		0.0000	1.0000	68.69
57.5	3,686,195		0.0000	1.0000	68.69
58.5	1,624,367		0.0000	1.0000	68.69
59.5	847,183		0.0000	1.0000	68.69
60.5	96,695		0.0000	1.0000	68.69
61.5	96,695		0.0000	1.0000	68.69
62.5	96,695		0.0000	1.0000	68.69
63.5	28,489		0.0000	1.0000	68.69
64.5	28,489		0.0000	1.0000	68.69
65.5	28,489		0.0000	1.0000	68.69
66.5	28,489		0.0000	1.0000	68.69
67.5	28,489		0.0000	1.0000	68.69
68.5	28,489		0.0000	1.0000	68.69
69.5	28,489		0.0000	1.0000	68.69
70.5	28,489		0.0000	1.0000	68.69
71.5	28,489		0.0000	1.0000	68.69
72.5	28,489		0.0000	1.0000	68.69
73.5	28,489		0.0000	1.0000	68.69
74.5	28,489		0.0000	1.0000	68.69
75.5	28,489		0.0000	1.0000	68.69
76.5					68.69

KENTUCKY UTILITIES COMPANY
ACCOUNT 315 ACCESSORY ELECTRIC EQUIPMENT
ORIGINAL AND SMOOTH SURVIVOR CURVES



KENTUCKY UTILITIES COMPANY

ACCOUNT 315 ACCESSORY ELECTRIC EQUIPMENT

ORIGINAL LIFE TABLE

PLACEMENT BAND 1926-2011 EXPERIENCE BAND 1926-2011

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	180,192,703	36,975	0.0002	0.9998	100.00
0.5	142,920,837	15,361	0.0001	0.9999	99.98
1.5	113,659,942	1,251	0.0000	1.0000	99.97
2.5	101,318,204	12,111	0.0001	0.9999	99.97
3.5	97,467,332		0.0000	1.0000	99.96
4.5	83,960,653		0.0000	1.0000	99.96
5.5	83,173,911		0.0000	1.0000	99.96
6.5	83,461,477	30,588	0.0004	0.9996	99.96
7.5	83,378,748	61,116	0.0007	0.9993	99.92
8.5	82,358,578	9,673	0.0001	0.9999	99.85
9.5	89,128,686	55,311	0.0006	0.9994	99.83
10.5	88,952,959	7,030	0.0001	0.9999	99.77
11.5	82,145,834	24,289	0.0003	0.9997	99.76
12.5	82,121,545		0.0000	1.0000	99.73
13.5	82,003,308	101,913	0.0012	0.9988	99.73
14.5	77,916,882	366,252	0.0047	0.9953	99.61
15.5	77,382,409	9,852	0.0001	0.9999	99.14
16.5	75,706,380		0.0000	1.0000	99.13
17.5	74,580,683		0.0000	1.0000	99.13
18.5	74,425,481	49,990	0.0007	0.9993	99.13
19.5	74,368,941	38,097	0.0005	0.9995	99.06
20.5	74,256,028	77,507	0.0010	0.9990	99.01
21.5	74,201,140	5,521	0.0001	0.9999	98.91
22.5	74,824,175	19,505	0.0003	0.9997	98.90
23.5	74,757,418	4,526	0.0001	0.9999	98.88
24.5	73,992,829	7,439	0.0001	0.9999	98.87
25.5	76,091,348	21,218	0.0003	0.9997	98.86
26.5	76,021,045	15,600	0.0002	0.9998	98.83
27.5	52,119,633	2,400	0.0000	1.0000	98.81
28.5	52,117,233	8,680	0.0002	0.9998	98.81
29.5	51,420,710	17,787	0.0003	0.9997	98.79
30.5	26,333,656	33,300	0.0013	0.9987	98.76
31.5	27,168,673	17,207	0.0006	0.9994	98.63
32.5	27,036,696	27,147	0.0010	0.9990	98.57
33.5	26,779,491	150,784	0.0056	0.9944	98.47
34.5	16,720,341	10,163	0.0006	0.9994	97.92
35.5	15,726,771	31,596	0.0020	0.9980	97.86
36.5	15,695,175	47,001	0.0030	0.9970	97.66
37.5	9,801,628	26,933	0.0027	0.9973	97.37
38.5	9,600,250	83,656	0.0087	0.9913	97.10

KENTUCKY UTILITIES COMPANY

ACCOUNT 315 ACCESSORY ELECTRIC EQUIPMENT

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1926-2011 EXPERIENCE BAND 1926-2011

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	5,235,258	810	0.0002	0.9998	96.25
40.5	5,234,448	18,279	0.0035	0.9965	96.24
41.5	5,215,376	21,525	0.0041	0.9959	95.90
42.5	5,193,277	3,717	0.0007	0.9993	95.51
43.5	5,187,425		0.0000	1.0000	95.44
44.5	5,185,999	8,553	0.0016	0.9984	95.44
45.5	5,175,904		0.0000	1.0000	95.28
46.5	5,342,071	530	0.0001	0.9999	95.28
47.5	5,337,025	109,351	0.0205	0.9795	95.27
48.5	4,607,244		0.0000	1.0000	93.32
49.5	4,603,426	5,358	0.0012	0.9988	93.32
50.5	4,591,112	10,923	0.0024	0.9976	93.21
51.5	4,264,072	26,194	0.0061	0.9939	92.99
52.5	3,703,552	126,702	0.0342	0.9658	92.42
53.5	3,396,535		0.0000	1.0000	89.26
54.5	2,305,512	14,155	0.0061	0.9939	89.26
55.5	1,932,532		0.0000	1.0000	88.71
56.5	1,929,908	63,879	0.0331	0.9669	88.71
57.5	948,305		0.0000	1.0000	85.77
58.5	402,478		0.0000	1.0000	85.77
59.5	721,909		0.0000	1.0000	85.77
60.5	643,828		0.0000	1.0000	85.77
61.5	219,363		0.0000	1.0000	85.77
62.5	219,363		0.0000	1.0000	85.77
63.5	153,343		0.0000	1.0000	85.77
64.5	144,523		0.0000	1.0000	85.77
65.5	144,523		0.0000	1.0000	85.77
66.5	144,523		0.0000	1.0000	85.77
67.5	144,523		0.0000	1.0000	85.77
68.5	144,523		0.0000	1.0000	85.77
69.5	144,523		0.0000	1.0000	85.77
70.5	144,523		0.0000	1.0000	85.77
71.5	144,523		0.0000	1.0000	85.77
72.5	144,523		0.0000	1.0000	85.77
73.5	144,523		0.0000	1.0000	85.77
74.5	144,523		0.0000	1.0000	85.77
75.5	144,523		0.0000	1.0000	85.77
76.5					85.77

KENTUCKY UTILITIES COMPANY

ACCOUNT 315 ACCESSORY ELECTRIC EQUIPMENT

ORIGINAL LIFE TABLE

PLACEMENT BAND 1926-2011 EXPERIENCE BAND 1971-2011

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	174,651,499	36,975	0.0002	0.9998	100.00
0.5	137,380,426	15,361	0.0001	0.9999	99.98
1.5	108,119,531	461	0.0000	1.0000	99.97
2.5	95,780,719		0.0000	1.0000	99.97
3.5	91,941,957		0.0000	1.0000	99.97
4.5	78,435,675		0.0000	1.0000	99.97
5.5	77,713,938		0.0000	1.0000	99.97
6.5	78,001,503	30,504	0.0004	0.9996	99.97
7.5	78,616,725	55,034	0.0007	0.9993	99.93
8.5	77,602,638	9,673	0.0001	0.9999	99.86
9.5	84,375,812	55,311	0.0007	0.9993	99.85
10.5	84,206,373	7,030	0.0001	0.9999	99.78
11.5	78,005,718	24,289	0.0003	0.9997	99.77
12.5	77,995,514		0.0000	1.0000	99.74
13.5	77,910,486	101,913	0.0013	0.9987	99.74
14.5	74,812,005	366,252	0.0049	0.9951	99.61
15.5	74,285,408	9,852	0.0001	0.9999	99.12
16.5	73,145,583		0.0000	1.0000	99.11
17.5	73,144,033		0.0000	1.0000	99.11
18.5	72,995,427	48,931	0.0007	0.9993	99.11
19.5	73,264,988	37,072	0.0005	0.9995	99.04
20.5	73,731,279	77,507	0.0011	0.9989	98.99
21.5	73,676,391	5,521	0.0001	0.9999	98.89
22.5	74,439,446	19,505	0.0003	0.9997	98.88
23.5	74,477,152	4,526	0.0001	0.9999	98.86
24.5	73,733,815	5,706	0.0001	0.9999	98.85
25.5	75,834,067	21,218	0.0003	0.9997	98.84
26.5	75,763,764	15,600	0.0002	0.9998	98.81
27.5	51,862,352		0.0000	1.0000	98.79
28.5	51,862,352	8,680	0.0002	0.9998	98.79
29.5	51,165,829	17,787	0.0003	0.9997	98.78
30.5	26,078,775	33,300	0.0013	0.9987	98.74
31.5	26,913,792	17,207	0.0006	0.9994	98.62
32.5	26,781,815	27,147	0.0010	0.9990	98.55
33.5	26,524,610	150,784	0.0057	0.9943	98.45
34.5	16,465,460	10,163	0.0006	0.9994	97.89
35.5	15,471,890	31,596	0.0020	0.9980	97.83
36.5	15,440,294	47,001	0.0030	0.9970	97.63
37.5	9,546,747	26,933	0.0028	0.9972	97.34
38.5	9,450,369	83,656	0.0089	0.9911	97.06

KENTUCKY UTILITIES COMPANY

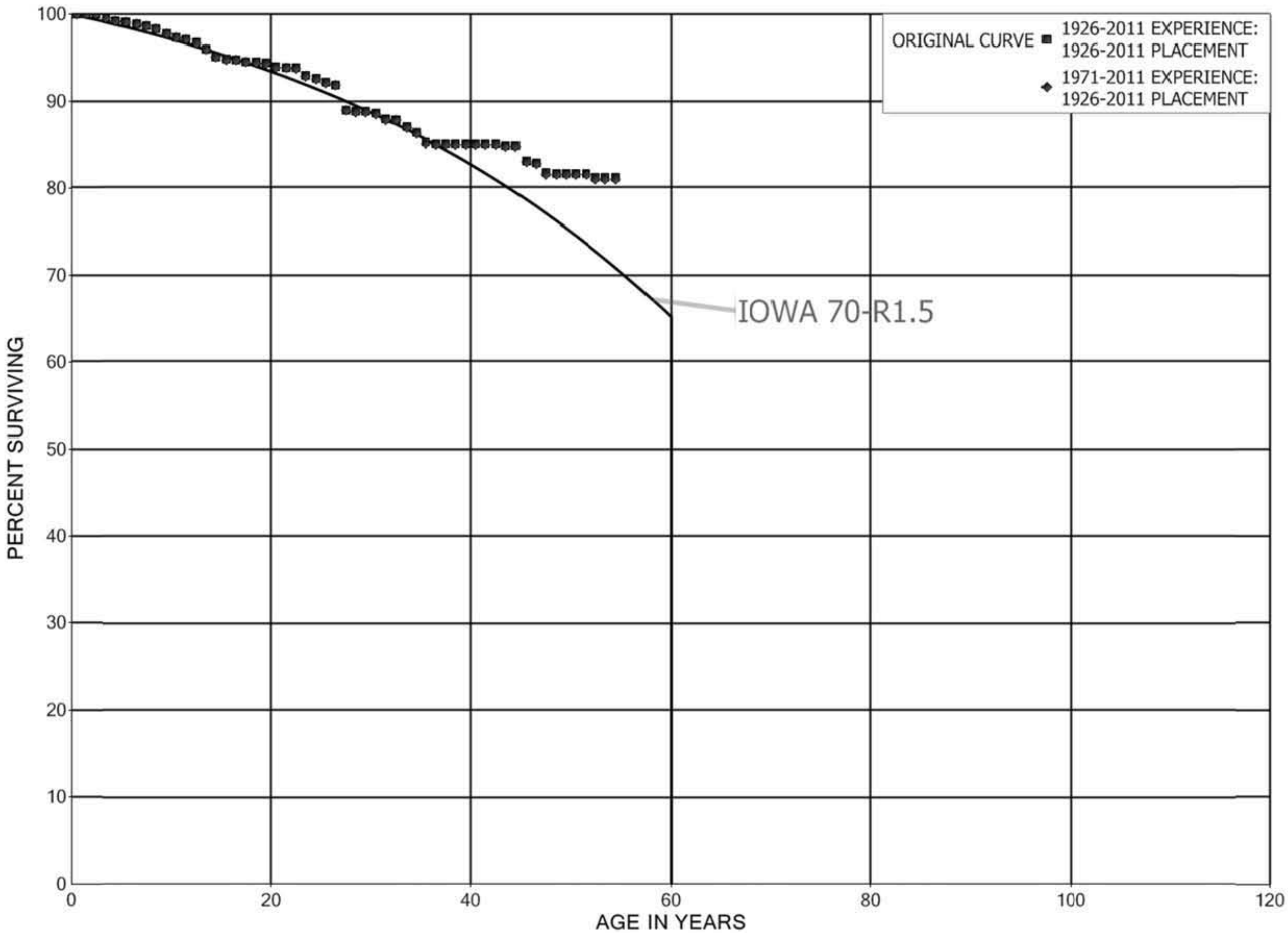
ACCOUNT 315 ACCESSORY ELECTRIC EQUIPMENT

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1926-2011 EXPERIENCE BAND 1971-2011

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	5,085,377	810	0.0002	0.9998	96.20
40.5	5,084,567	18,279	0.0036	0.9964	96.19
41.5	5,065,495	21,525	0.0042	0.9958	95.84
42.5	5,043,396	3,717	0.0007	0.9993	95.43
43.5	5,037,544		0.0000	1.0000	95.36
44.5	5,185,999	8,553	0.0016	0.9984	95.36
45.5	5,175,904		0.0000	1.0000	95.21
46.5	5,342,071	530	0.0001	0.9999	95.21
47.5	5,337,025	109,351	0.0205	0.9795	95.20
48.5	4,607,244		0.0000	1.0000	93.25
49.5	4,603,426	5,358	0.0012	0.9988	93.25
50.5	4,591,112	10,923	0.0024	0.9976	93.14
51.5	4,264,072	26,194	0.0061	0.9939	92.92
52.5	3,703,552	126,702	0.0342	0.9658	92.35
53.5	3,396,535		0.0000	1.0000	89.19
54.5	2,305,512	14,155	0.0061	0.9939	89.19
55.5	1,932,532		0.0000	1.0000	88.64
56.5	1,929,908	63,879	0.0331	0.9669	88.64
57.5	948,305		0.0000	1.0000	85.71
58.5	402,478		0.0000	1.0000	85.71
59.5	721,909		0.0000	1.0000	85.71
60.5	643,828		0.0000	1.0000	85.71
61.5	219,363		0.0000	1.0000	85.71
62.5	219,363		0.0000	1.0000	85.71
63.5	153,343		0.0000	1.0000	85.71
64.5	144,523		0.0000	1.0000	85.71
65.5	144,523		0.0000	1.0000	85.71
66.5	144,523		0.0000	1.0000	85.71
67.5	144,523		0.0000	1.0000	85.71
68.5	144,523		0.0000	1.0000	85.71
69.5	144,523		0.0000	1.0000	85.71
70.5	144,523		0.0000	1.0000	85.71
71.5	144,523		0.0000	1.0000	85.71
72.5	144,523		0.0000	1.0000	85.71
73.5	144,523		0.0000	1.0000	85.71
74.5	144,523		0.0000	1.0000	85.71
75.5	144,523		0.0000	1.0000	85.71
76.5					85.71

KENTUCKY UTILITIES COMPANY
ACCOUNT 316 MISCELLANEOUS POWER PLANT EQUIPMENT
ORIGINAL AND SMOOTH SURVIVOR CURVES



KENTUCKY UTILITIES COMPANY

ACCOUNT 316 MISCELLANEOUS POWER PLANT EQUIPMENT

ORIGINAL LIFE TABLE

PLACEMENT BAND 1926-2011 EXPERIENCE BAND 1926-2011

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	32,345,893	1,108	0.0000	1.0000	100.00
0.5	27,460,182	5,849	0.0002	0.9998	100.00
1.5	25,999,609	3,818	0.0001	0.9999	99.98
2.5	25,632,299	117,883	0.0046	0.9954	99.96
3.5	25,394,724	86,791	0.0034	0.9966	99.50
4.5	24,743,229	17,596	0.0007	0.9993	99.16
5.5	24,475,690	68,367	0.0028	0.9972	99.09
6.5	23,855,323	60,072	0.0025	0.9975	98.81
7.5	22,932,446	69,064	0.0030	0.9970	98.56
8.5	21,468,804	110,396	0.0051	0.9949	98.27
9.5	20,992,388	107,515	0.0051	0.9949	97.76
10.5	20,508,472	30,457	0.0015	0.9985	97.26
11.5	20,268,552	89,122	0.0044	0.9956	97.12
12.5	19,095,707	137,018	0.0072	0.9928	96.69
13.5	18,633,353	172,954	0.0093	0.9907	96.00
14.5	16,385,416	43,132	0.0026	0.9974	95.11
15.5	15,753,013	14,474	0.0009	0.9991	94.86
16.5	14,735,331	36,271	0.0025	0.9975	94.77
17.5	14,059,983	10,956	0.0008	0.9992	94.53
18.5	13,643,968	12,978	0.0010	0.9990	94.46
19.5	13,165,395	62,957	0.0048	0.9952	94.37
20.5	12,350,864	8,904	0.0007	0.9993	93.92
21.5	11,518,748	7,239	0.0006	0.9994	93.85
22.5	10,879,118	96,177	0.0088	0.9912	93.79
23.5	10,253,858	39,193	0.0038	0.9962	92.96
24.5	9,472,542	47,087	0.0050	0.9950	92.61
25.5	9,135,086	27,592	0.0030	0.9970	92.15
26.5	8,974,096	279,497	0.0311	0.9689	91.87
27.5	6,508,937	11,816	0.0018	0.9982	89.01
28.5	6,394,183	3,132	0.0005	0.9995	88.85
29.5	6,159,517	15,807	0.0026	0.9974	88.80
30.5	3,982,727	28,703	0.0072	0.9928	88.58
31.5	3,889,415	2,273	0.0006	0.9994	87.94
32.5	3,838,844	36,125	0.0094	0.9906	87.89
33.5	3,200,710	23,690	0.0074	0.9926	87.06
34.5	2,467,719	32,634	0.0132	0.9868	86.41
35.5	2,322,633	4,866	0.0021	0.9979	85.27
36.5	2,221,002		0.0000	1.0000	85.09
37.5	1,150,821		0.0000	1.0000	85.09
38.5	1,135,464	112	0.0001	0.9999	85.09

KENTUCKY UTILITIES COMPANY

ACCOUNT 316 MISCELLANEOUS POWER PLANT EQUIPMENT

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1926-2011 EXPERIENCE BAND 1926-2011

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	1,111,914	95	0.0001	0.9999	85.08
40.5	732,581		0.0000	1.0000	85.08
41.5	728,891		0.0000	1.0000	85.08
42.5	660,143	1,516	0.0023	0.9977	85.08
43.5	658,106		0.0000	1.0000	84.88
44.5	658,106	13,942	0.0212	0.9788	84.88
45.5	635,726	1,852	0.0029	0.9971	83.08
46.5	631,580	8,685	0.0138	0.9862	82.84
47.5	622,895	600	0.0010	0.9990	81.70
48.5	556,141		0.0000	1.0000	81.62
49.5	555,006		0.0000	1.0000	81.62
50.5	554,368		0.0000	1.0000	81.62
51.5	542,002	3,054	0.0056	0.9944	81.62
52.5	464,751		0.0000	1.0000	81.16
53.5	459,960		0.0000	1.0000	81.16
54.5	388,846	657	0.0017	0.9983	81.16
55.5	234,581		0.0000	1.0000	81.03
56.5	223,067		0.0000	1.0000	81.03
57.5	207,250	5,656	0.0273	0.9727	81.03
58.5	192,688		0.0000	1.0000	78.82
59.5	189,675		0.0000	1.0000	78.82
60.5	185,675		0.0000	1.0000	78.82
61.5	124,263		0.0000	1.0000	78.82
62.5	122,820		0.0000	1.0000	78.82
63.5	88,457		0.0000	1.0000	78.82
64.5	54,397		0.0000	1.0000	78.82
65.5	54,397		0.0000	1.0000	78.82
66.5	54,397		0.0000	1.0000	78.82
67.5	54,397		0.0000	1.0000	78.82
68.5	54,397		0.0000	1.0000	78.82
69.5	54,397		0.0000	1.0000	78.82
70.5	53,501		0.0000	1.0000	78.82
71.5	53,501		0.0000	1.0000	78.82
72.5	53,501		0.0000	1.0000	78.82
73.5	53,501		0.0000	1.0000	78.82
74.5	53,501		0.0000	1.0000	78.82
75.5	53,501		0.0000	1.0000	78.82
76.5					78.82

KENTUCKY UTILITIES COMPANY

ACCOUNT 316 MISCELLANEOUS POWER PLANT EQUIPMENT

ORIGINAL LIFE TABLE

PLACEMENT BAND 1926-2011 EXPERIENCE BAND 1971-2011

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	31,370,878	1,108	0.0000	1.0000	100.00
0.5	26,491,546	5,849	0.0002	0.9998	100.00
1.5	25,110,262	2,159	0.0001	0.9999	99.97
2.5	24,749,359	117,178	0.0047	0.9953	99.97
3.5	24,517,005	80,605	0.0033	0.9967	99.49
4.5	23,884,078	17,416	0.0007	0.9993	99.17
5.5	23,620,539	68,108	0.0029	0.9971	99.09
6.5	23,002,165	55,465	0.0024	0.9976	98.81
7.5	22,150,705	68,485	0.0031	0.9969	98.57
8.5	20,694,361	109,857	0.0053	0.9947	98.26
9.5	20,221,566	104,631	0.0052	0.9948	97.74
10.5	19,749,406	30,457	0.0015	0.9985	97.24
11.5	19,622,959	88,477	0.0045	0.9955	97.09
12.5	18,452,819	134,731	0.0073	0.9927	96.65
13.5	17,997,270	170,470	0.0095	0.9905	95.94
14.5	15,935,536	42,767	0.0027	0.9973	95.03
15.5	15,327,114	14,407	0.0009	0.9991	94.78
16.5	14,341,772	35,283	0.0025	0.9975	94.69
17.5	13,682,846	10,956	0.0008	0.9992	94.46
18.5	13,273,126	10,523	0.0008	0.9992	94.38
19.5	12,823,770	61,588	0.0048	0.9952	94.31
20.5	12,188,772	8,904	0.0007	0.9993	93.85
21.5	11,364,899	7,239	0.0006	0.9994	93.79
22.5	10,760,177	96,158	0.0089	0.9911	93.73
23.5	10,175,787	38,998	0.0038	0.9962	92.89
24.5	9,396,647	47,087	0.0050	0.9950	92.53
25.5	9,059,204	25,523	0.0028	0.9972	92.07
26.5	8,900,378	279,497	0.0314	0.9686	91.81
27.5	6,435,219	11,816	0.0018	0.9982	88.93
28.5	6,320,992	3,132	0.0005	0.9995	88.76
29.5	6,087,526	15,797	0.0026	0.9974	88.72
30.5	3,910,746	28,703	0.0073	0.9927	88.49
31.5	3,817,434	2,273	0.0006	0.9994	87.84
32.5	3,766,863	36,125	0.0096	0.9904	87.79
33.5	3,128,729	23,690	0.0076	0.9924	86.95
34.5	2,395,738	32,634	0.0136	0.9864	86.29
35.5	2,250,652	4,779	0.0021	0.9979	85.11
36.5	2,149,108		0.0000	1.0000	84.93
37.5	1,078,927		0.0000	1.0000	84.93
38.5	1,076,208	13	0.0000	1.0000	84.93

KENTUCKY UTILITIES COMPANY

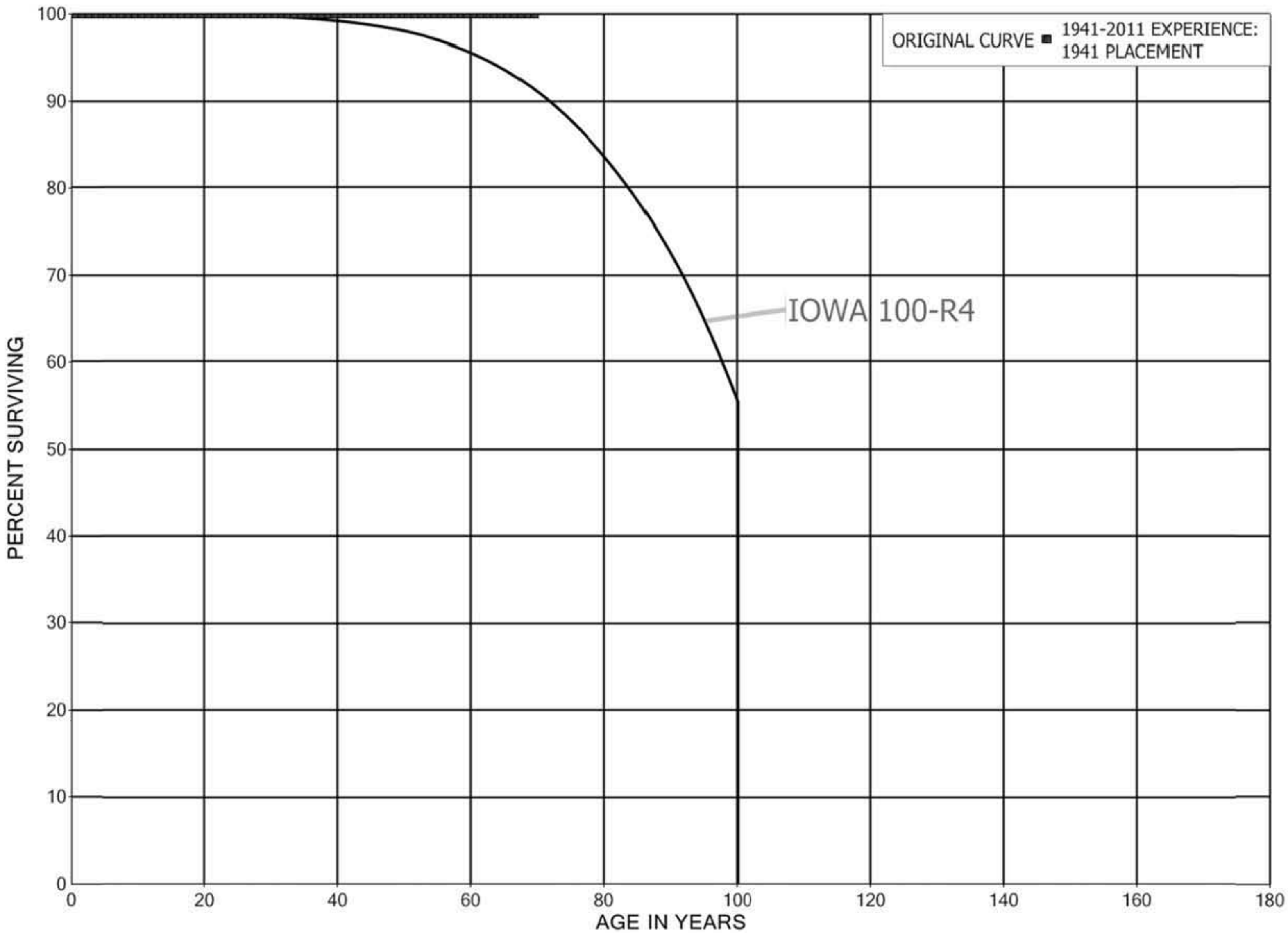
ACCOUNT 316 MISCELLANEOUS POWER PLANT EQUIPMENT

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1926-2011 EXPERIENCE BAND 1971-2011

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	1,052,757	95	0.0001	0.9999	84.93
40.5	673,424		0.0000	1.0000	84.92
41.5	669,734		0.0000	1.0000	84.92
42.5	600,986	1,516	0.0025	0.9975	84.92
43.5	598,949		0.0000	1.0000	84.71
44.5	658,106	13,942	0.0212	0.9788	84.71
45.5	635,726	1,852	0.0029	0.9971	82.91
46.5	631,580	8,685	0.0138	0.9862	82.67
47.5	622,895	600	0.0010	0.9990	81.53
48.5	556,141		0.0000	1.0000	81.46
49.5	555,006		0.0000	1.0000	81.46
50.5	554,368		0.0000	1.0000	81.46
51.5	542,002	3,054	0.0056	0.9944	81.46
52.5	464,751		0.0000	1.0000	81.00
53.5	459,960		0.0000	1.0000	81.00
54.5	388,846	657	0.0017	0.9983	81.00
55.5	234,581		0.0000	1.0000	80.86
56.5	223,067		0.0000	1.0000	80.86
57.5	207,250	5,656	0.0273	0.9727	80.86
58.5	192,688		0.0000	1.0000	78.65
59.5	189,675		0.0000	1.0000	78.65
60.5	185,675		0.0000	1.0000	78.65
61.5	124,263		0.0000	1.0000	78.65
62.5	122,820		0.0000	1.0000	78.65
63.5	88,457		0.0000	1.0000	78.65
64.5	54,397		0.0000	1.0000	78.65
65.5	54,397		0.0000	1.0000	78.65
66.5	54,397		0.0000	1.0000	78.65
67.5	54,397		0.0000	1.0000	78.65
68.5	54,397		0.0000	1.0000	78.65
69.5	54,397		0.0000	1.0000	78.65
70.5	53,501		0.0000	1.0000	78.65
71.5	53,501		0.0000	1.0000	78.65
72.5	53,501		0.0000	1.0000	78.65
73.5	53,501		0.0000	1.0000	78.65
74.5	53,501		0.0000	1.0000	78.65
75.5	53,501		0.0000	1.0000	78.65
76.5					78.65

KENTUCKY UTILITIES COMPANY
ACCOUNT 330.1 LAND RIGHTS
ORIGINAL AND SMOOTH SURVIVOR CURVES



KENTUCKY UTILITIES COMPANY

ACCOUNT 330.1 LAND RIGHTS

ORIGINAL LIFE TABLE

PLACEMENT BAND 1941 EXPERIENCE BAND 1941-2011

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	879,411		0.0000	1.0000	100.00
0.5	879,411		0.0000	1.0000	100.00
1.5	879,411		0.0000	1.0000	100.00
2.5	879,411	100	0.0001	0.9999	100.00
3.5	879,311		0.0000	1.0000	99.99
4.5	879,311		0.0000	1.0000	99.99
5.5	879,311		0.0000	1.0000	99.99
6.5	879,311		0.0000	1.0000	99.99
7.5	879,311		0.0000	1.0000	99.99
8.5	879,311		0.0000	1.0000	99.99
9.5	879,311		0.0000	1.0000	99.99
10.5	879,311		0.0000	1.0000	99.99
11.5	879,311		0.0000	1.0000	99.99
12.5	879,311		0.0000	1.0000	99.99
13.5	879,311		0.0000	1.0000	99.99
14.5	879,311		0.0000	1.0000	99.99
15.5	879,311		0.0000	1.0000	99.99
16.5	879,311		0.0000	1.0000	99.99
17.5	879,311		0.0000	1.0000	99.99
18.5	879,311		0.0000	1.0000	99.99
19.5	879,311		0.0000	1.0000	99.99
20.5	879,311		0.0000	1.0000	99.99
21.5	879,311		0.0000	1.0000	99.99
22.5	879,311		0.0000	1.0000	99.99
23.5	879,311		0.0000	1.0000	99.99
24.5	879,311		0.0000	1.0000	99.99
25.5	879,311		0.0000	1.0000	99.99
26.5	879,311		0.0000	1.0000	99.99
27.5	879,311		0.0000	1.0000	99.99
28.5	879,311		0.0000	1.0000	99.99
29.5	879,311		0.0000	1.0000	99.99
30.5	879,311		0.0000	1.0000	99.99
31.5	879,311		0.0000	1.0000	99.99
32.5	879,311		0.0000	1.0000	99.99
33.5	879,311		0.0000	1.0000	99.99
34.5	879,311		0.0000	1.0000	99.99
35.5	879,311		0.0000	1.0000	99.99
36.5	879,311		0.0000	1.0000	99.99
37.5	879,311		0.0000	1.0000	99.99
38.5	879,311		0.0000	1.0000	99.99

KENTUCKY UTILITIES COMPANY

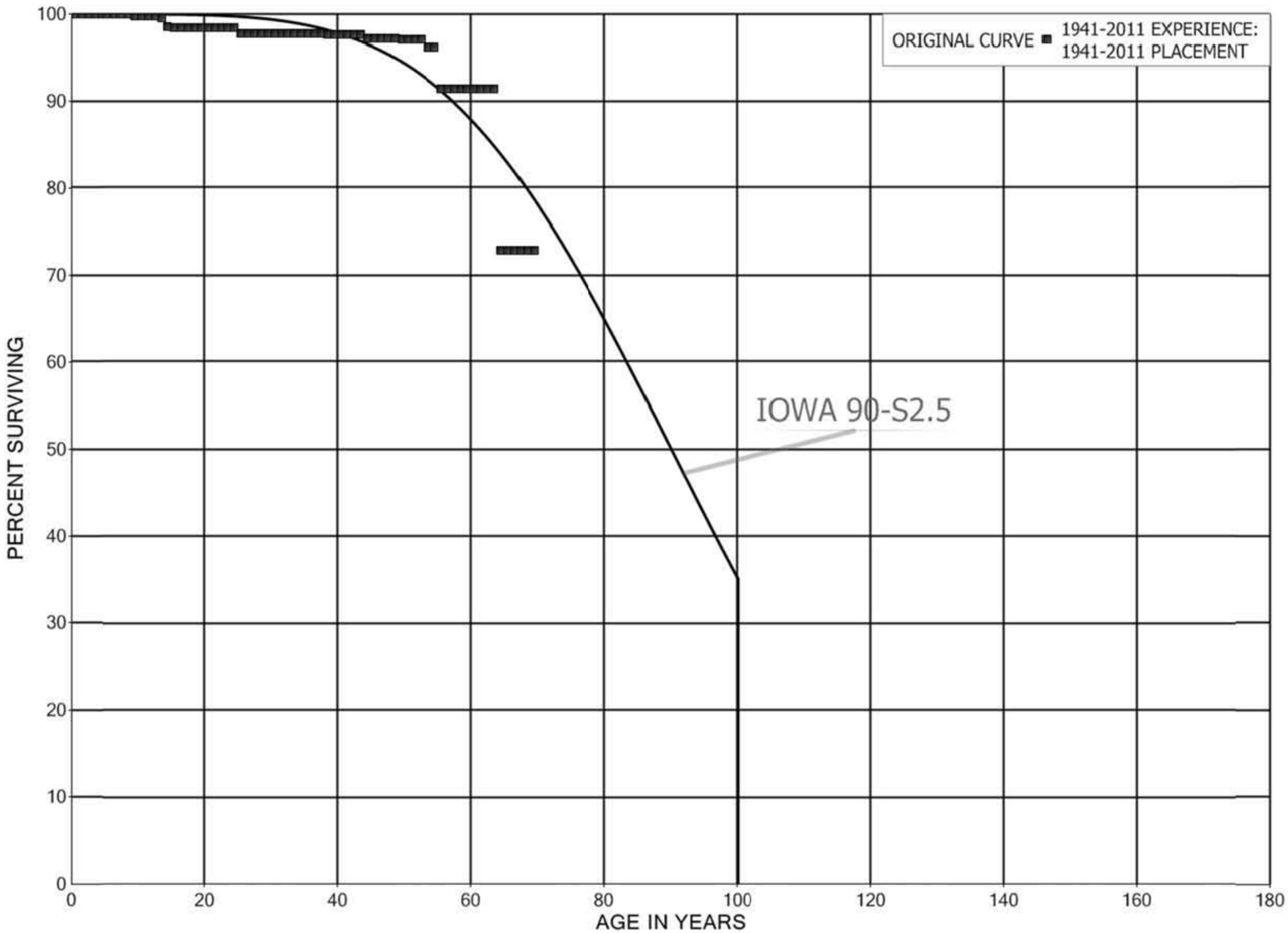
ACCOUNT 330.1 LAND RIGHTS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1941 EXPERIENCE BAND 1941-2011

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	879,311		0.0000	1.0000	99.99
40.5	879,311		0.0000	1.0000	99.99
41.5	879,311		0.0000	1.0000	99.99
42.5	879,311		0.0000	1.0000	99.99
43.5	879,311		0.0000	1.0000	99.99
44.5	879,311		0.0000	1.0000	99.99
45.5	879,311		0.0000	1.0000	99.99
46.5	879,311		0.0000	1.0000	99.99
47.5	879,311		0.0000	1.0000	99.99
48.5	879,311		0.0000	1.0000	99.99
49.5	879,311		0.0000	1.0000	99.99
50.5	879,311		0.0000	1.0000	99.99
51.5	879,311		0.0000	1.0000	99.99
52.5	879,311		0.0000	1.0000	99.99
53.5	879,311		0.0000	1.0000	99.99
54.5	879,311		0.0000	1.0000	99.99
55.5	879,311		0.0000	1.0000	99.99
56.5	879,311		0.0000	1.0000	99.99
57.5	879,311		0.0000	1.0000	99.99
58.5	879,311		0.0000	1.0000	99.99
59.5	879,311		0.0000	1.0000	99.99
60.5	879,311		0.0000	1.0000	99.99
61.5	879,311		0.0000	1.0000	99.99
62.5	879,311		0.0000	1.0000	99.99
63.5	879,311		0.0000	1.0000	99.99
64.5	879,311		0.0000	1.0000	99.99
65.5	879,311		0.0000	1.0000	99.99
66.5	879,311		0.0000	1.0000	99.99
67.5	879,311		0.0000	1.0000	99.99
68.5	879,311		0.0000	1.0000	99.99
69.5	879,311		0.0000	1.0000	99.99
70.5					99.99

KENTUCKY UTILITIES COMPANY
ACCOUNT 331 STRUCTURES AND IMPROVEMENTS
ORIGINAL AND SMOOTH SURVIVOR CURVES



KENTUCKY UTILITIES COMPANY

ACCOUNT 331 STRUCTURES AND IMPROVEMENTS

ORIGINAL LIFE TABLE

PLACEMENT BAND 1941-2011 EXPERIENCE BAND 1941-2011

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	671,660		0.0000	1.0000	100.00
0.5	651,834		0.0000	1.0000	100.00
1.5	567,312		0.0000	1.0000	100.00
2.5	621,605		0.0000	1.0000	100.00
3.5	621,605		0.0000	1.0000	100.00
4.5	555,577	112	0.0002	0.9998	100.00
5.5	555,465		0.0000	1.0000	99.98
6.5	531,795		0.0000	1.0000	99.98
7.5	531,795		0.0000	1.0000	99.98
8.5	531,795	1,226	0.0023	0.9977	99.98
9.5	530,569		0.0000	1.0000	99.75
10.5	530,569		0.0000	1.0000	99.75
11.5	530,569		0.0000	1.0000	99.75
12.5	530,569	1,338	0.0025	0.9975	99.75
13.5	529,231	5,000	0.0094	0.9906	99.50
14.5	524,231	590	0.0011	0.9989	98.56
15.5	523,641		0.0000	1.0000	98.45
16.5	523,641		0.0000	1.0000	98.45
17.5	523,641		0.0000	1.0000	98.45
18.5	523,641	461	0.0009	0.9991	98.45
19.5	522,143		0.0000	1.0000	98.36
20.5	444,997		0.0000	1.0000	98.36
21.5	390,219		0.0000	1.0000	98.36
22.5	390,219		0.0000	1.0000	98.36
23.5	368,566		0.0000	1.0000	98.36
24.5	368,566	2,268	0.0062	0.9938	98.36
25.5	366,298		0.0000	1.0000	97.75
26.5	366,298		0.0000	1.0000	97.75
27.5	366,298		0.0000	1.0000	97.75
28.5	366,298		0.0000	1.0000	97.75
29.5	366,298		0.0000	1.0000	97.75
30.5	366,298		0.0000	1.0000	97.75
31.5	366,298		0.0000	1.0000	97.75
32.5	366,298		0.0000	1.0000	97.75
33.5	366,298		0.0000	1.0000	97.75
34.5	366,298		0.0000	1.0000	97.75
35.5	366,298		0.0000	1.0000	97.75
36.5	366,004		0.0000	1.0000	97.75
37.5	366,004	379	0.0010	0.9990	97.75
38.5	365,625		0.0000	1.0000	97.65

KENTUCKY UTILITIES COMPANY

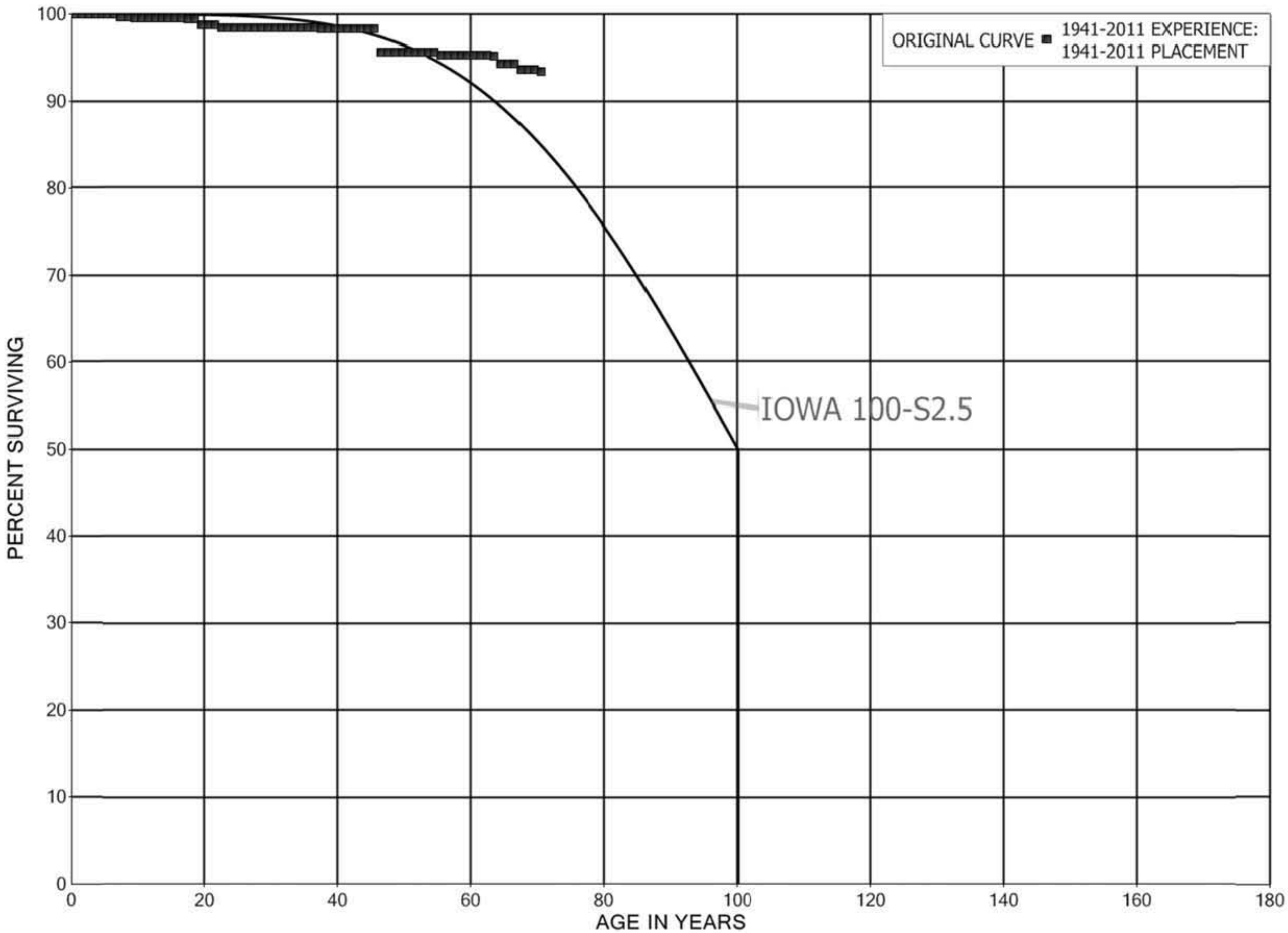
ACCOUNT 331 STRUCTURES AND IMPROVEMENTS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1941-2011 EXPERIENCE BAND 1941-2011

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	365,625		0.0000	1.0000	97.65
40.5	365,625		0.0000	1.0000	97.65
41.5	365,625		0.0000	1.0000	97.65
42.5	365,625		0.0000	1.0000	97.65
43.5	365,625	1,599	0.0044	0.9956	97.65
44.5	362,507		0.0000	1.0000	97.23
45.5	362,507		0.0000	1.0000	97.23
46.5	362,507		0.0000	1.0000	97.23
47.5	362,507	250	0.0007	0.9993	97.23
48.5	362,257	242	0.0007	0.9993	97.16
49.5	362,015		0.0000	1.0000	97.09
50.5	359,016		0.0000	1.0000	97.09
51.5	359,016		0.0000	1.0000	97.09
52.5	359,016	3,526	0.0098	0.9902	97.09
53.5	355,490		0.0000	1.0000	96.14
54.5	355,490	17,489	0.0492	0.9508	96.14
55.5	338,001		0.0000	1.0000	91.41
56.5	333,513		0.0000	1.0000	91.41
57.5	333,513		0.0000	1.0000	91.41
58.5	333,513		0.0000	1.0000	91.41
59.5	333,513		0.0000	1.0000	91.41
60.5	333,513		0.0000	1.0000	91.41
61.5	333,513		0.0000	1.0000	91.41
62.5	333,513		0.0000	1.0000	91.41
63.5	333,513	67,902	0.2036	0.7964	91.41
64.5	265,610		0.0000	1.0000	72.80
65.5	265,610		0.0000	1.0000	72.80
66.5	265,610		0.0000	1.0000	72.80
67.5	265,610		0.0000	1.0000	72.80
68.5	265,610		0.0000	1.0000	72.80
69.5	265,610		0.0000	1.0000	72.80
70.5					72.80

KENTUCKY UTILITIES COMPANY
ACCOUNT 332 RESERVOIRS, DAMS AND WATERWAYS
ORIGINAL AND SMOOTH SURVIVOR CURVES



KENTUCKY UTILITIES COMPANY

ACCOUNT 332 RESERVOIRS, DAMS AND WATERWAYS

ORIGINAL LIFE TABLE

PLACEMENT BAND 1941-2011 EXPERIENCE BAND 1941-2011

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	22,058,958		0.0000	1.0000	100.00
0.5	10,262,979		0.0000	1.0000	100.00
1.5	10,262,979		0.0000	1.0000	100.00
2.5	10,262,979		0.0000	1.0000	100.00
3.5	9,420,885		0.0000	1.0000	100.00
4.5	8,348,065		0.0000	1.0000	100.00
5.5	8,348,065		0.0000	1.0000	100.00
6.5	8,348,065	32,914	0.0039	0.9961	100.00
7.5	8,315,151		0.0000	1.0000	99.61
8.5	8,178,729	8,000	0.0010	0.9990	99.61
9.5	8,170,729		0.0000	1.0000	99.51
10.5	8,170,729		0.0000	1.0000	99.51
11.5	8,170,729	2,024	0.0002	0.9998	99.51
12.5	8,168,705		0.0000	1.0000	99.48
13.5	8,168,705		0.0000	1.0000	99.48
14.5	8,168,705		0.0000	1.0000	99.48
15.5	8,168,705		0.0000	1.0000	99.48
16.5	8,168,705	8,887	0.0011	0.9989	99.48
17.5	8,148,957		0.0000	1.0000	99.38
18.5	8,132,487	56,935	0.0070	0.9930	99.38
19.5	7,705,532		0.0000	1.0000	98.68
20.5	6,505,526		0.0000	1.0000	98.68
21.5	6,498,172	17,565	0.0027	0.9973	98.68
22.5	6,480,607		0.0000	1.0000	98.41
23.5	6,480,607		0.0000	1.0000	98.41
24.5	6,480,607	3,210	0.0005	0.9995	98.41
25.5	6,477,397		0.0000	1.0000	98.36
26.5	6,477,397		0.0000	1.0000	98.36
27.5	6,477,397		0.0000	1.0000	98.36
28.5	6,477,397		0.0000	1.0000	98.36
29.5	6,477,397		0.0000	1.0000	98.36
30.5	6,477,397		0.0000	1.0000	98.36
31.5	6,477,397		0.0000	1.0000	98.36
32.5	6,477,397		0.0000	1.0000	98.36
33.5	6,477,397		0.0000	1.0000	98.36
34.5	6,477,397		0.0000	1.0000	98.36
35.5	6,477,397		0.0000	1.0000	98.36
36.5	6,477,397	2,703	0.0004	0.9996	98.36
37.5	6,474,694		0.0000	1.0000	98.32
38.5	6,474,694		0.0000	1.0000	98.32

KENTUCKY UTILITIES COMPANY

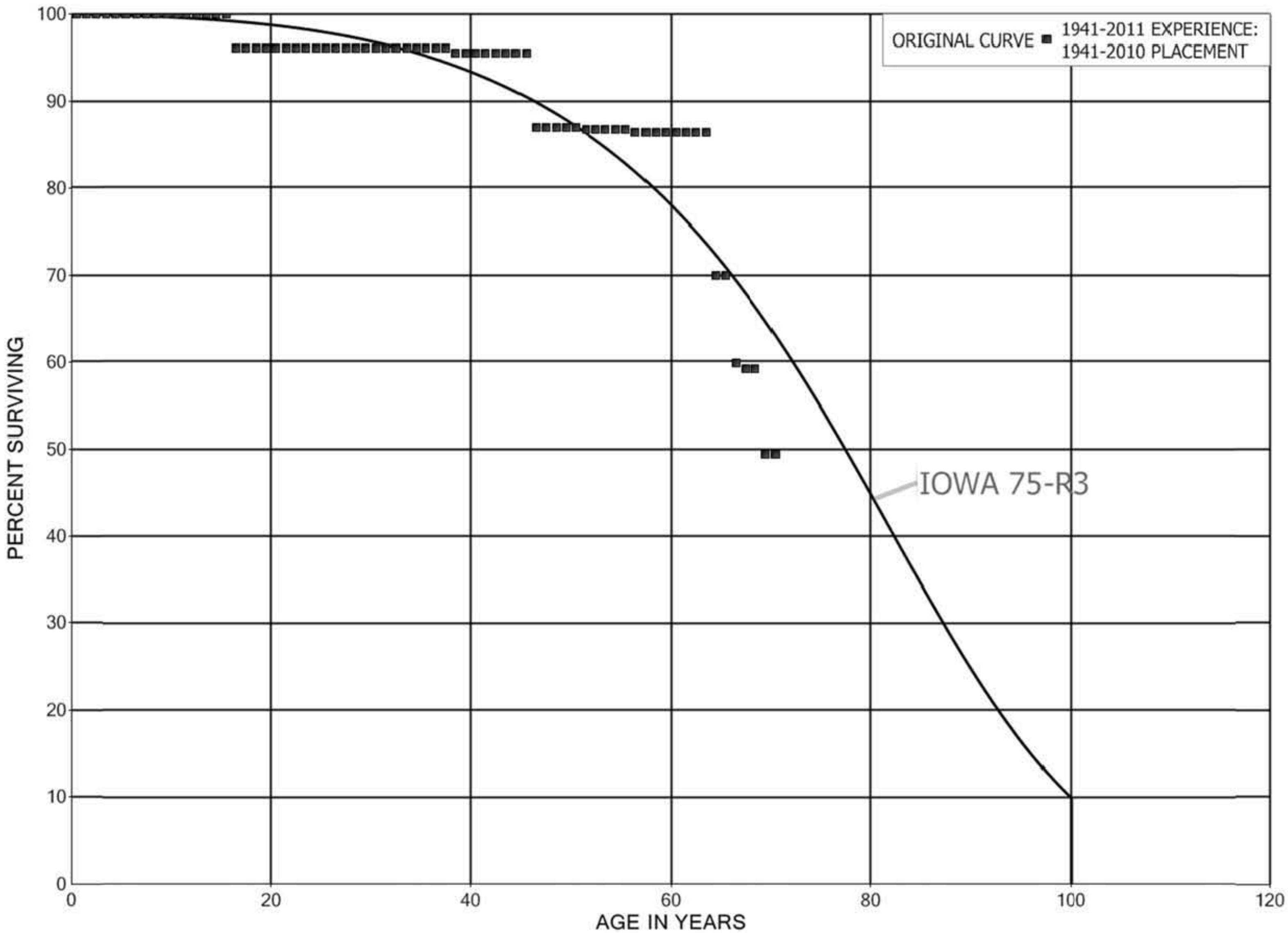
ACCOUNT 332 RESERVOIRS, DAMS AND WATERWAYS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1941-2011 EXPERIENCE BAND 1941-2011

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	6,474,694		0.0000	1.0000	98.32
40.5	6,470,974		0.0000	1.0000	98.32
41.5	6,470,974		0.0000	1.0000	98.32
42.5	6,470,974		0.0000	1.0000	98.32
43.5	6,470,974		0.0000	1.0000	98.32
44.5	6,470,974		0.0000	1.0000	98.32
45.5	6,470,974	179,747	0.0278	0.9722	98.32
46.5	6,291,227		0.0000	1.0000	95.59
47.5	6,291,227		0.0000	1.0000	95.59
48.5	6,291,227		0.0000	1.0000	95.59
49.5	6,291,227		0.0000	1.0000	95.59
50.5	6,291,227		0.0000	1.0000	95.59
51.5	6,291,227		0.0000	1.0000	95.59
52.5	6,291,227		0.0000	1.0000	95.59
53.5	6,291,227		0.0000	1.0000	95.59
54.5	6,291,227	21,938	0.0035	0.9965	95.59
55.5	6,269,289	702	0.0001	0.9999	95.26
56.5	6,268,587		0.0000	1.0000	95.25
57.5	6,268,587		0.0000	1.0000	95.25
58.5	6,268,587		0.0000	1.0000	95.25
59.5	6,268,587		0.0000	1.0000	95.25
60.5	6,268,587		0.0000	1.0000	95.25
61.5	6,039,199		0.0000	1.0000	95.25
62.5	6,039,199	2,023	0.0003	0.9997	95.25
63.5	6,037,176	58,987	0.0098	0.9902	95.22
64.5	5,978,188		0.0000	1.0000	94.29
65.5	5,978,188		0.0000	1.0000	94.29
66.5	5,978,188	44,162	0.0074	0.9926	94.29
67.5	5,933,165		0.0000	1.0000	93.59
68.5	5,933,165		0.0000	1.0000	93.59
69.5	5,933,165	15,191	0.0026	0.9974	93.59
70.5					93.35

KENTUCKY UTILITIES COMPANY
ACCOUNT 333 WATER WHEELS, TURBINES AND GENERATORS
ORIGINAL AND SMOOTH SURVIVOR CURVES



KENTUCKY UTILITIES COMPANY

ACCOUNT 333 WATER WHEELS, TURBINES AND GENERATORS

ORIGINAL LIFE TABLE

PLACEMENT BAND 1941-2010 EXPERIENCE BAND 1941-2011

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	4,658,676		0.0000	1.0000	100.00
0.5	4,658,676		0.0000	1.0000	100.00
1.5	623,273		0.0000	1.0000	100.00
2.5	623,273		0.0000	1.0000	100.00
3.5	561,114		0.0000	1.0000	100.00
4.5	561,114		0.0000	1.0000	100.00
5.5	561,114		0.0000	1.0000	100.00
6.5	559,121		0.0000	1.0000	100.00
7.5	559,121		0.0000	1.0000	100.00
8.5	559,121		0.0000	1.0000	100.00
9.5	559,121		0.0000	1.0000	100.00
10.5	559,121		0.0000	1.0000	100.00
11.5	559,121		0.0000	1.0000	100.00
12.5	559,121		0.0000	1.0000	100.00
13.5	559,121		0.0000	1.0000	100.00
14.5	534,300		0.0000	1.0000	100.00
15.5	534,300	21,000	0.0393	0.9607	100.00
16.5	513,300		0.0000	1.0000	96.07
17.5	513,300		0.0000	1.0000	96.07
18.5	513,300		0.0000	1.0000	96.07
19.5	500,887		0.0000	1.0000	96.07
20.5	500,887		0.0000	1.0000	96.07
21.5	500,887		0.0000	1.0000	96.07
22.5	500,887		0.0000	1.0000	96.07
23.5	500,887		0.0000	1.0000	96.07
24.5	500,887		0.0000	1.0000	96.07
25.5	500,887		0.0000	1.0000	96.07
26.5	500,887		0.0000	1.0000	96.07
27.5	500,887		0.0000	1.0000	96.07
28.5	500,887		0.0000	1.0000	96.07
29.5	500,887		0.0000	1.0000	96.07
30.5	500,887		0.0000	1.0000	96.07
31.5	500,887		0.0000	1.0000	96.07
32.5	500,887		0.0000	1.0000	96.07
33.5	500,887		0.0000	1.0000	96.07
34.5	500,887		0.0000	1.0000	96.07
35.5	500,887		0.0000	1.0000	96.07
36.5	500,887		0.0000	1.0000	96.07
37.5	500,887	2,963	0.0059	0.9941	96.07
38.5	497,924		0.0000	1.0000	95.50

KENTUCKY UTILITIES COMPANY

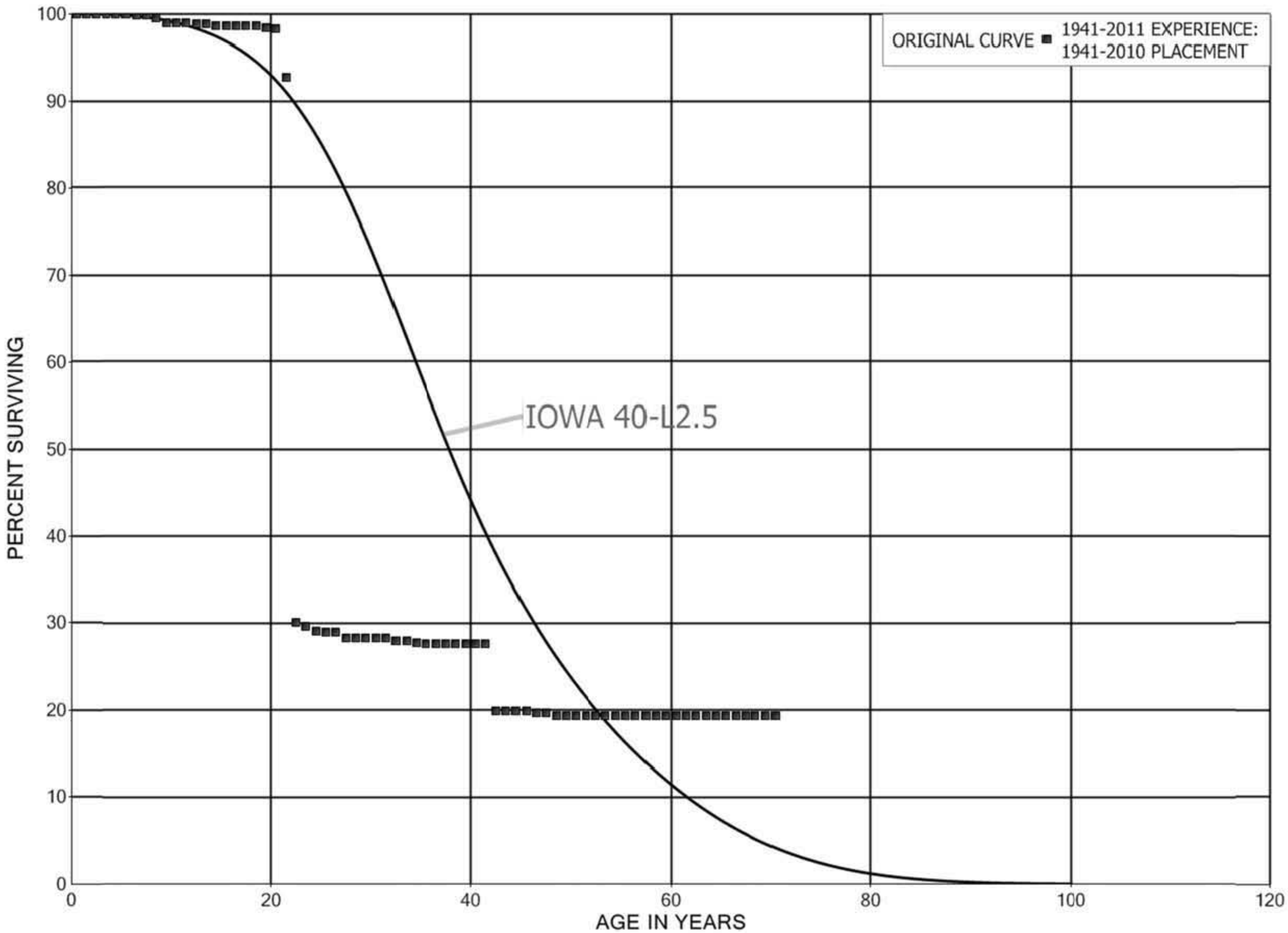
ACCOUNT 333 WATER WHEELS, TURBINES AND GENERATORS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1941-2010 EXPERIENCE BAND 1941-2011

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	497,924		0.0000	1.0000	95.50
40.5	497,924		0.0000	1.0000	95.50
41.5	497,924		0.0000	1.0000	95.50
42.5	497,924		0.0000	1.0000	95.50
43.5	497,924		0.0000	1.0000	95.50
44.5	497,924		0.0000	1.0000	95.50
45.5	497,924	44,452	0.0893	0.9107	95.50
46.5	453,473		0.0000	1.0000	86.98
47.5	453,473		0.0000	1.0000	86.98
48.5	453,441		0.0000	1.0000	86.98
49.5	440,632		0.0000	1.0000	86.98
50.5	440,632	1,109	0.0025	0.9975	86.98
51.5	439,523		0.0000	1.0000	86.76
52.5	439,523		0.0000	1.0000	86.76
53.5	435,181		0.0000	1.0000	86.76
54.5	367,656		0.0000	1.0000	86.76
55.5	367,656	1,420	0.0039	0.9961	86.76
56.5	366,236		0.0000	1.0000	86.42
57.5	366,236		0.0000	1.0000	86.42
58.5	366,236		0.0000	1.0000	86.42
59.5	366,236		0.0000	1.0000	86.42
60.5	366,236		0.0000	1.0000	86.42
61.5	366,236		0.0000	1.0000	86.42
62.5	366,236		0.0000	1.0000	86.42
63.5	366,236	69,634	0.1901	0.8099	86.42
64.5	296,602		0.0000	1.0000	69.99
65.5	296,602	43,039	0.1451	0.8549	69.99
66.5	253,563	3,022	0.0119	0.9881	59.83
67.5	250,541		0.0000	1.0000	59.12
68.5	250,541	41,413	0.1653	0.8347	59.12
69.5	209,128		0.0000	1.0000	49.35
70.5					49.35

KENTUCKY UTILITIES COMPANY
ACCOUNT 334 ACCESSORY ELECTRIC EQUIPMENT
ORIGINAL AND SMOOTH SURVIVOR CURVES



KENTUCKY UTILITIES COMPANY

ACCOUNT 334 ACCESSORY ELECTRIC EQUIPMENT

ORIGINAL LIFE TABLE

PLACEMENT BAND 1941-2010 EXPERIENCE BAND 1941-2011

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	913,471		0.0000	1.0000	100.00
0.5	913,471		0.0000	1.0000	100.00
1.5	420,506		0.0000	1.0000	100.00
2.5	420,506		0.0000	1.0000	100.00
3.5	420,506		0.0000	1.0000	100.00
4.5	420,506		0.0000	1.0000	100.00
5.5	420,506	468	0.0011	0.9989	100.00
6.5	420,038		0.0000	1.0000	99.89
7.5	420,038	1,640	0.0039	0.9961	99.89
8.5	418,398	2,360	0.0056	0.9944	99.50
9.5	416,038		0.0000	1.0000	98.94
10.5	416,038		0.0000	1.0000	98.94
11.5	416,038	300	0.0007	0.9993	98.94
12.5	415,738		0.0000	1.0000	98.87
13.5	415,738	1,016	0.0024	0.9976	98.87
14.5	414,722		0.0000	1.0000	98.62
15.5	414,722	91	0.0002	0.9998	98.62
16.5	414,631		0.0000	1.0000	98.60
17.5	414,631	13	0.0000	1.0000	98.60
18.5	414,618	1,012	0.0024	0.9976	98.60
19.5	413,606	239	0.0006	0.9994	98.36
20.5	413,367	23,560	0.0570	0.9430	98.30
21.5	389,807	263,525	0.6760	0.3240	92.70
22.5	120,779	1,600	0.0132	0.9868	30.03
23.5	119,179	2,353	0.0197	0.9803	29.63
24.5	116,826	521	0.0045	0.9955	29.05
25.5	116,305		0.0000	1.0000	28.92
26.5	116,305	2,422	0.0208	0.9792	28.92
27.5	113,883	170	0.0015	0.9985	28.32
28.5	113,713		0.0000	1.0000	28.27
29.5	113,713		0.0000	1.0000	28.27
30.5	113,713		0.0000	1.0000	28.27
31.5	113,713	1,476	0.0130	0.9870	28.27
32.5	112,237		0.0000	1.0000	27.91
33.5	112,237	614	0.0055	0.9945	27.91
34.5	111,623	689	0.0062	0.9938	27.75
35.5	110,934		0.0000	1.0000	27.58
36.5	106,839		0.0000	1.0000	27.58
37.5	103,477		0.0000	1.0000	27.58
38.5	103,477		0.0000	1.0000	27.58

KENTUCKY UTILITIES COMPANY

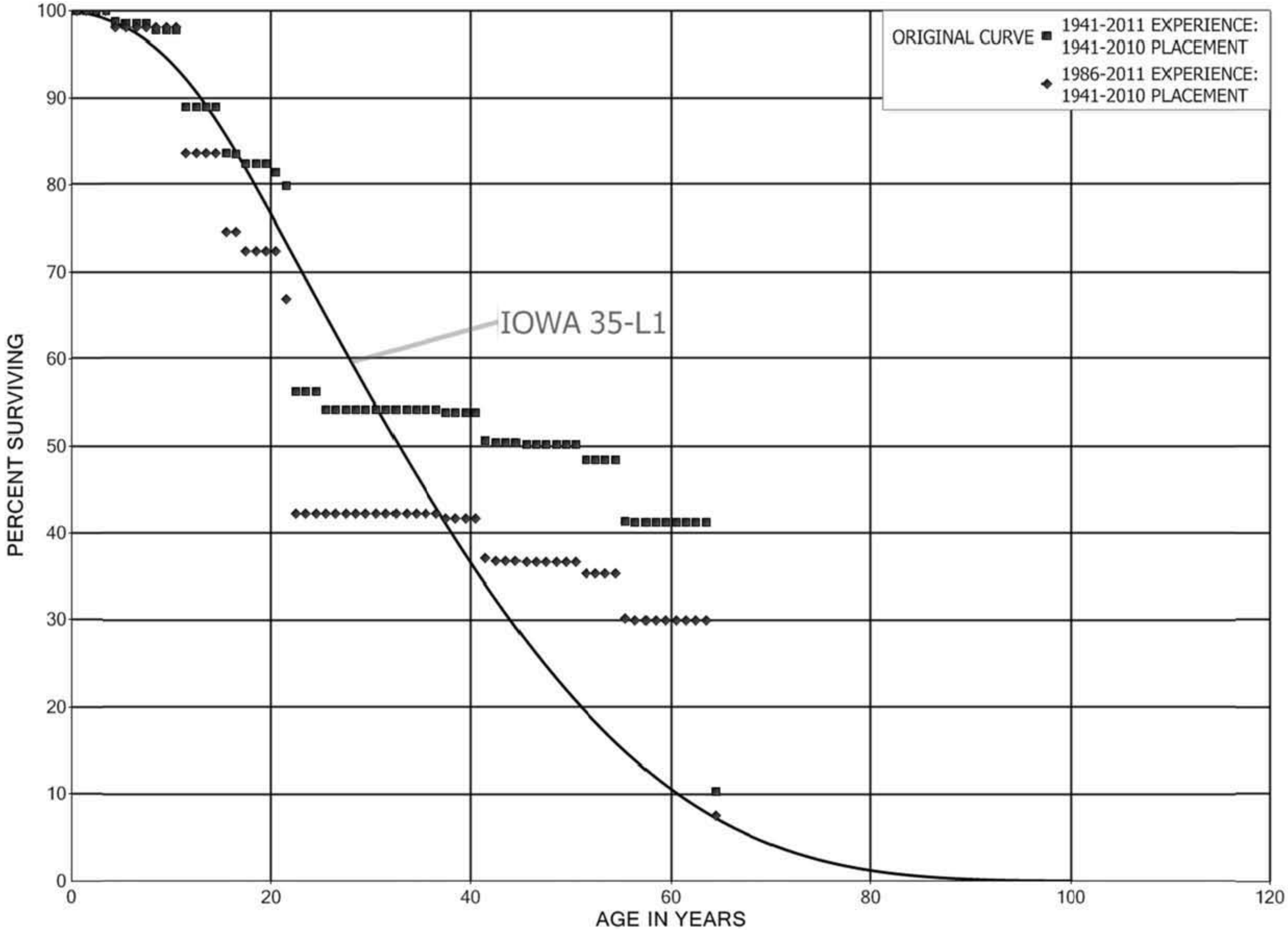
ACCOUNT 334 ACCESSORY ELECTRIC EQUIPMENT

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1941-2010 EXPERIENCE BAND 1941-2011

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	103,477		0.0000	1.0000	27.58
40.5	103,477		0.0000	1.0000	27.58
41.5	103,477	29,101	0.2812	0.7188	27.58
42.5	74,376		0.0000	1.0000	19.83
43.5	74,376		0.0000	1.0000	19.83
44.5	74,376		0.0000	1.0000	19.83
45.5	74,376	870	0.0117	0.9883	19.83
46.5	73,506	15	0.0002	0.9998	19.59
47.5	73,491	1,083	0.0147	0.9853	19.59
48.5	72,252		0.0000	1.0000	19.30
49.5	68,528		0.0000	1.0000	19.30
50.5	68,471		0.0000	1.0000	19.30
51.5	66,732		0.0000	1.0000	19.30
52.5	66,732		0.0000	1.0000	19.30
53.5	66,732		0.0000	1.0000	19.30
54.5	66,732		0.0000	1.0000	19.30
55.5	66,732		0.0000	1.0000	19.30
56.5	66,732		0.0000	1.0000	19.30
57.5	66,732		0.0000	1.0000	19.30
58.5	65,960		0.0000	1.0000	19.30
59.5	65,753		0.0000	1.0000	19.30
60.5	65,753		0.0000	1.0000	19.30
61.5	65,342		0.0000	1.0000	19.30
62.5	65,052		0.0000	1.0000	19.30
63.5	65,052		0.0000	1.0000	19.30
64.5	54,187		0.0000	1.0000	19.30
65.5	54,187		0.0000	1.0000	19.30
66.5	54,187		0.0000	1.0000	19.30
67.5	54,187		0.0000	1.0000	19.30
68.5	54,187		0.0000	1.0000	19.30
69.5	54,187		0.0000	1.0000	19.30
70.5					19.30

KENTUCKY UTILITIES COMPANY
ACCOUNT 335 MISCELLANEOUS POWER PLANT EQUIPMENT
ORIGINAL AND SMOOTH SURVIVOR CURVES



KENTUCKY UTILITIES COMPANY

ACCOUNT 335 MISCELLANEOUS POWER PLANT EQUIPMENT

ORIGINAL LIFE TABLE

PLACEMENT BAND 1941-2010 EXPERIENCE BAND 1941-2011

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	177,432		0.0000	1.0000	100.00
0.5	186,944		0.0000	1.0000	100.00
1.5	186,182		0.0000	1.0000	100.00
2.5	188,326		0.0000	1.0000	100.00
3.5	188,326	2,326	0.0124	0.9876	100.00
4.5	186,000	465	0.0025	0.9975	98.76
5.5	185,535		0.0000	1.0000	98.52
6.5	185,535		0.0000	1.0000	98.52
7.5	185,535	1,588	0.0086	0.9914	98.52
8.5	179,465		0.0000	1.0000	97.67
9.5	179,465		0.0000	1.0000	97.67
10.5	179,465	16,001	0.0892	0.9108	97.67
11.5	163,464		0.0000	1.0000	88.97
12.5	163,464	80	0.0005	0.9995	88.97
13.5	163,384	49	0.0003	0.9997	88.92
14.5	163,335	9,725	0.0595	0.9405	88.90
15.5	144,097	157	0.0011	0.9989	83.60
16.5	129,640	1,746	0.0135	0.9865	83.51
17.5	105,500		0.0000	1.0000	82.39
18.5	105,500	42	0.0004	0.9996	82.39
19.5	94,228	1,144	0.0121	0.9879	82.35
20.5	93,084	1,689	0.0181	0.9819	81.35
21.5	368,069	109,410	0.2973	0.7027	79.88
22.5	258,659		0.0000	1.0000	56.13
23.5	73,174		0.0000	1.0000	56.13
24.5	73,174	2,510	0.0343	0.9657	56.13
25.5	70,664		0.0000	1.0000	54.21
26.5	70,664		0.0000	1.0000	54.21
27.5	70,664		0.0000	1.0000	54.21
28.5	70,664		0.0000	1.0000	54.21
29.5	70,664		0.0000	1.0000	54.21
30.5	70,664		0.0000	1.0000	54.21
31.5	70,664		0.0000	1.0000	54.21
32.5	70,664		0.0000	1.0000	54.21
33.5	70,664		0.0000	1.0000	54.21
34.5	70,664		0.0000	1.0000	54.21
35.5	70,664		0.0000	1.0000	54.21
36.5	68,808	450	0.0065	0.9935	54.21
37.5	68,358		0.0000	1.0000	53.85
38.5	68,358		0.0000	1.0000	53.85

KENTUCKY UTILITIES COMPANY

ACCOUNT 335 MISCELLANEOUS POWER PLANT EQUIPMENT

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1941-2010 EXPERIENCE BAND 1941-2011

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	68,193		0.0000	1.0000	53.85
40.5	68,193	4,099	0.0601	0.9399	53.85
41.5	64,094	302	0.0047	0.9953	50.62
42.5	63,792	20	0.0003	0.9997	50.38
43.5	63,772	21	0.0003	0.9997	50.36
44.5	63,751	177	0.0028	0.9972	50.35
45.5	63,574		0.0000	1.0000	50.21
46.5	63,574		0.0000	1.0000	50.21
47.5	63,574		0.0000	1.0000	50.21
48.5	63,500	63	0.0010	0.9990	50.21
49.5	38,892		0.0000	1.0000	50.16
50.5	38,612	1,347	0.0349	0.9651	50.16
51.5	37,265		0.0000	1.0000	48.41
52.5	36,876		0.0000	1.0000	48.41
53.5	36,876		0.0000	1.0000	48.41
54.5	36,876	5,424	0.1471	0.8529	48.41
55.5	31,452	125	0.0040	0.9960	41.29
56.5	31,162		0.0000	1.0000	41.12
57.5	29,475		0.0000	1.0000	41.12
58.5	29,475		0.0000	1.0000	41.12
59.5	28,581		0.0000	1.0000	41.12
60.5	28,466		0.0000	1.0000	41.12
61.5	27,886		0.0000	1.0000	41.12
62.5	27,353		0.0000	1.0000	41.12
63.5	27,288	20,491	0.7509	0.2491	41.12
64.5	3,066		0.0000	1.0000	10.24
65.5	3,066		0.0000	1.0000	10.24
66.5	3,066		0.0000	1.0000	10.24
67.5	3,066		0.0000	1.0000	10.24
68.5	3,066		0.0000	1.0000	10.24
69.5	3,066		0.0000	1.0000	10.24
70.5					10.24

KENTUCKY UTILITIES COMPANY

ACCOUNT 335 MISCELLANEOUS POWER PLANT EQUIPMENT

ORIGINAL LIFE TABLE

PLACEMENT BAND 1941-2010 EXPERIENCE BAND 1986-2011

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	81,762		0.0000	1.0000	100.00
0.5	91,274		0.0000	1.0000	100.00
1.5	92,201		0.0000	1.0000	100.00
2.5	111,116		0.0000	1.0000	100.00
3.5	111,116	2,144	0.0193	0.9807	100.00
4.5	108,972		0.0000	1.0000	98.07
5.5	108,972		0.0000	1.0000	98.07
6.5	108,972		0.0000	1.0000	98.07
7.5	108,972		0.0000	1.0000	98.07
8.5	104,490		0.0000	1.0000	98.07
9.5	104,490		0.0000	1.0000	98.07
10.5	106,346	15,672	0.1474	0.8526	98.07
11.5	90,674		0.0000	1.0000	83.62
12.5	90,674		0.0000	1.0000	83.62
13.5	90,839		0.0000	1.0000	83.62
14.5	90,839	9,725	0.1071	0.8929	83.62
15.5	71,601		0.0000	1.0000	74.67
16.5	57,301	1,746	0.0305	0.9695	74.67
17.5	33,161		0.0000	1.0000	72.39
18.5	33,161		0.0000	1.0000	72.39
19.5	21,931		0.0000	1.0000	72.39
20.5	21,931	1,689	0.0770	0.9230	72.39
21.5	296,916	109,410	0.3685	0.6315	66.81
22.5	187,580		0.0000	1.0000	42.19
23.5	26,640		0.0000	1.0000	42.19
24.5	26,920		0.0000	1.0000	42.19
25.5	26,920		0.0000	1.0000	42.19
26.5	27,760		0.0000	1.0000	42.19
27.5	27,760		0.0000	1.0000	42.19
28.5	27,760		0.0000	1.0000	42.19
29.5	27,760		0.0000	1.0000	42.19
30.5	32,023		0.0000	1.0000	42.19
31.5	34,012		0.0000	1.0000	42.19
32.5	34,032		0.0000	1.0000	42.19
33.5	34,947		0.0000	1.0000	42.19
34.5	35,239		0.0000	1.0000	42.19
35.5	35,819		0.0000	1.0000	42.19
36.5	34,496	450	0.0130	0.9870	42.19
37.5	34,111		0.0000	1.0000	41.64
38.5	37,842		0.0000	1.0000	41.64

KENTUCKY UTILITIES COMPANY

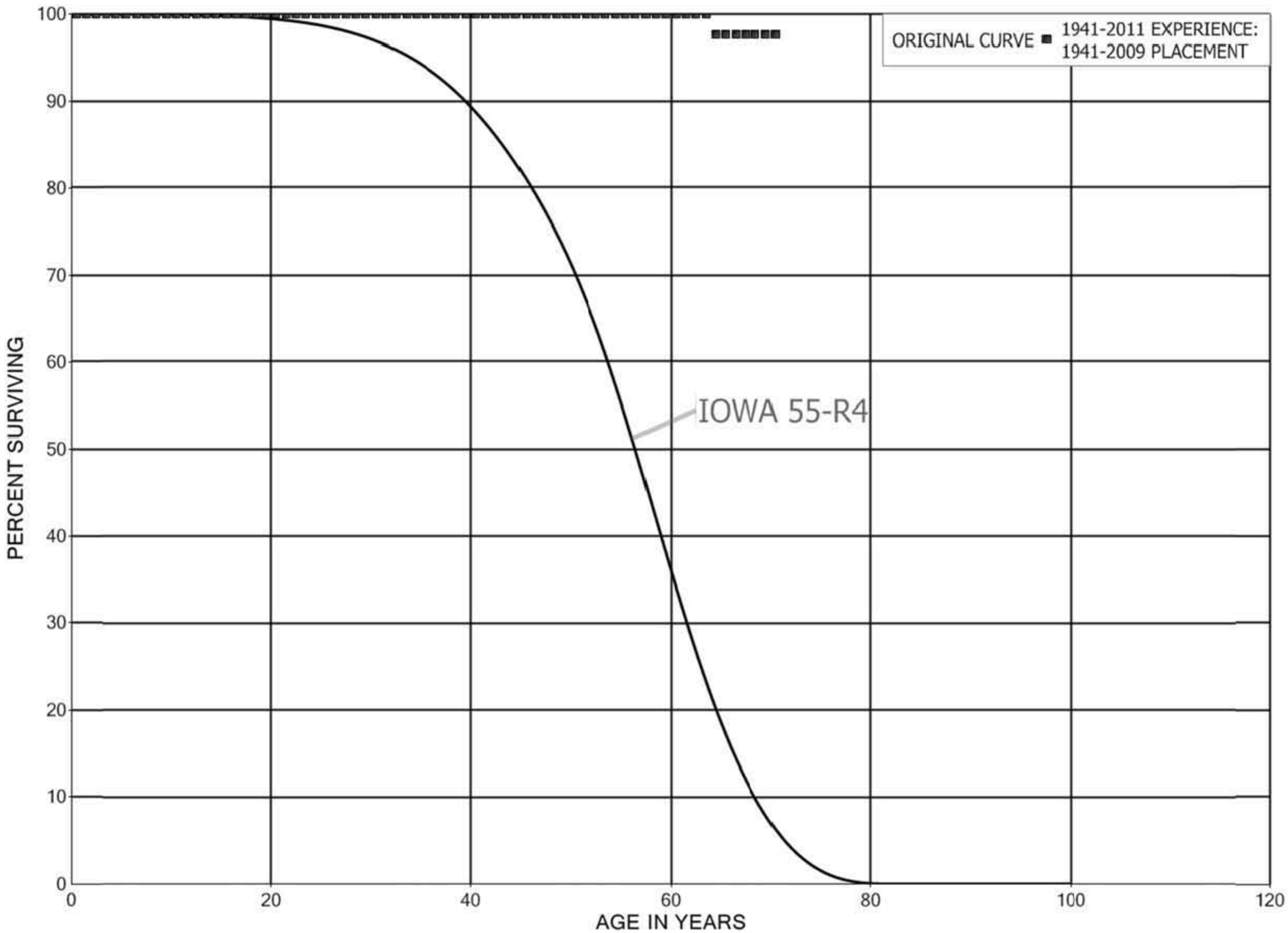
ACCOUNT 335 MISCELLANEOUS POWER PLANT EQUIPMENT

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1941-2010 EXPERIENCE BAND 1986-2011

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	37,677		0.0000	1.0000	41.64
40.5	37,677	4,099	0.1088	0.8912	41.64
41.5	33,578	302	0.0090	0.9910	37.11
42.5	33,276	20	0.0006	0.9994	36.78
43.5	33,256	21	0.0006	0.9994	36.76
44.5	63,751	177	0.0028	0.9972	36.73
45.5	63,574		0.0000	1.0000	36.63
46.5	63,574		0.0000	1.0000	36.63
47.5	63,574		0.0000	1.0000	36.63
48.5	63,500	63	0.0010	0.9990	36.63
49.5	38,892		0.0000	1.0000	36.60
50.5	38,612	1,347	0.0349	0.9651	36.60
51.5	37,265		0.0000	1.0000	35.32
52.5	36,876		0.0000	1.0000	35.32
53.5	36,876		0.0000	1.0000	35.32
54.5	36,876	5,424	0.1471	0.8529	35.32
55.5	31,452	125	0.0040	0.9960	30.12
56.5	31,162		0.0000	1.0000	30.00
57.5	29,475		0.0000	1.0000	30.00
58.5	29,475		0.0000	1.0000	30.00
59.5	28,581		0.0000	1.0000	30.00
60.5	28,466		0.0000	1.0000	30.00
61.5	27,886		0.0000	1.0000	30.00
62.5	27,353		0.0000	1.0000	30.00
63.5	27,288	20,491	0.7509	0.2491	30.00
64.5	3,066		0.0000	1.0000	7.47
65.5	3,066		0.0000	1.0000	7.47
66.5	3,066		0.0000	1.0000	7.47
67.5	3,066		0.0000	1.0000	7.47
68.5	3,066		0.0000	1.0000	7.47
69.5	3,066		0.0000	1.0000	7.47
70.5					7.47

KENTUCKY UTILITIES COMPANY
ACCOUNT 336 ROADS, RAILROADS, AND BRIDGES
ORIGINAL AND SMOOTH SURVIVOR CURVES



KENTUCKY UTILITIES COMPANY

ACCOUNT 336 ROADS, RAILROADS, AND BRIDGES

ORIGINAL LIFE TABLE

PLACEMENT BAND 1941-2009 EXPERIENCE BAND 1941-2011

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	177,529		0.0000	1.0000	100.00
0.5	177,529		0.0000	1.0000	100.00
1.5	177,529		0.0000	1.0000	100.00
2.5	48,146		0.0000	1.0000	100.00
3.5	48,146		0.0000	1.0000	100.00
4.5	48,146		0.0000	1.0000	100.00
5.5	48,146		0.0000	1.0000	100.00
6.5	48,146		0.0000	1.0000	100.00
7.5	48,146		0.0000	1.0000	100.00
8.5	48,146		0.0000	1.0000	100.00
9.5	48,146		0.0000	1.0000	100.00
10.5	48,146		0.0000	1.0000	100.00
11.5	48,146		0.0000	1.0000	100.00
12.5	48,146		0.0000	1.0000	100.00
13.5	48,146		0.0000	1.0000	100.00
14.5	48,146		0.0000	1.0000	100.00
15.5	48,146		0.0000	1.0000	100.00
16.5	48,146		0.0000	1.0000	100.00
17.5	48,146		0.0000	1.0000	100.00
18.5	48,146		0.0000	1.0000	100.00
19.5	48,146		0.0000	1.0000	100.00
20.5	48,146		0.0000	1.0000	100.00
21.5	48,146		0.0000	1.0000	100.00
22.5	48,146		0.0000	1.0000	100.00
23.5	48,146		0.0000	1.0000	100.00
24.5	48,146		0.0000	1.0000	100.00
25.5	48,146		0.0000	1.0000	100.00
26.5	48,146		0.0000	1.0000	100.00
27.5	48,146		0.0000	1.0000	100.00
28.5	48,146		0.0000	1.0000	100.00
29.5	48,146		0.0000	1.0000	100.00
30.5	48,146		0.0000	1.0000	100.00
31.5	48,146		0.0000	1.0000	100.00
32.5	48,146		0.0000	1.0000	100.00
33.5	48,146		0.0000	1.0000	100.00
34.5	48,146		0.0000	1.0000	100.00
35.5	48,146		0.0000	1.0000	100.00
36.5	48,146		0.0000	1.0000	100.00
37.5	48,146		0.0000	1.0000	100.00
38.5	48,146		0.0000	1.0000	100.00

KENTUCKY UTILITIES COMPANY

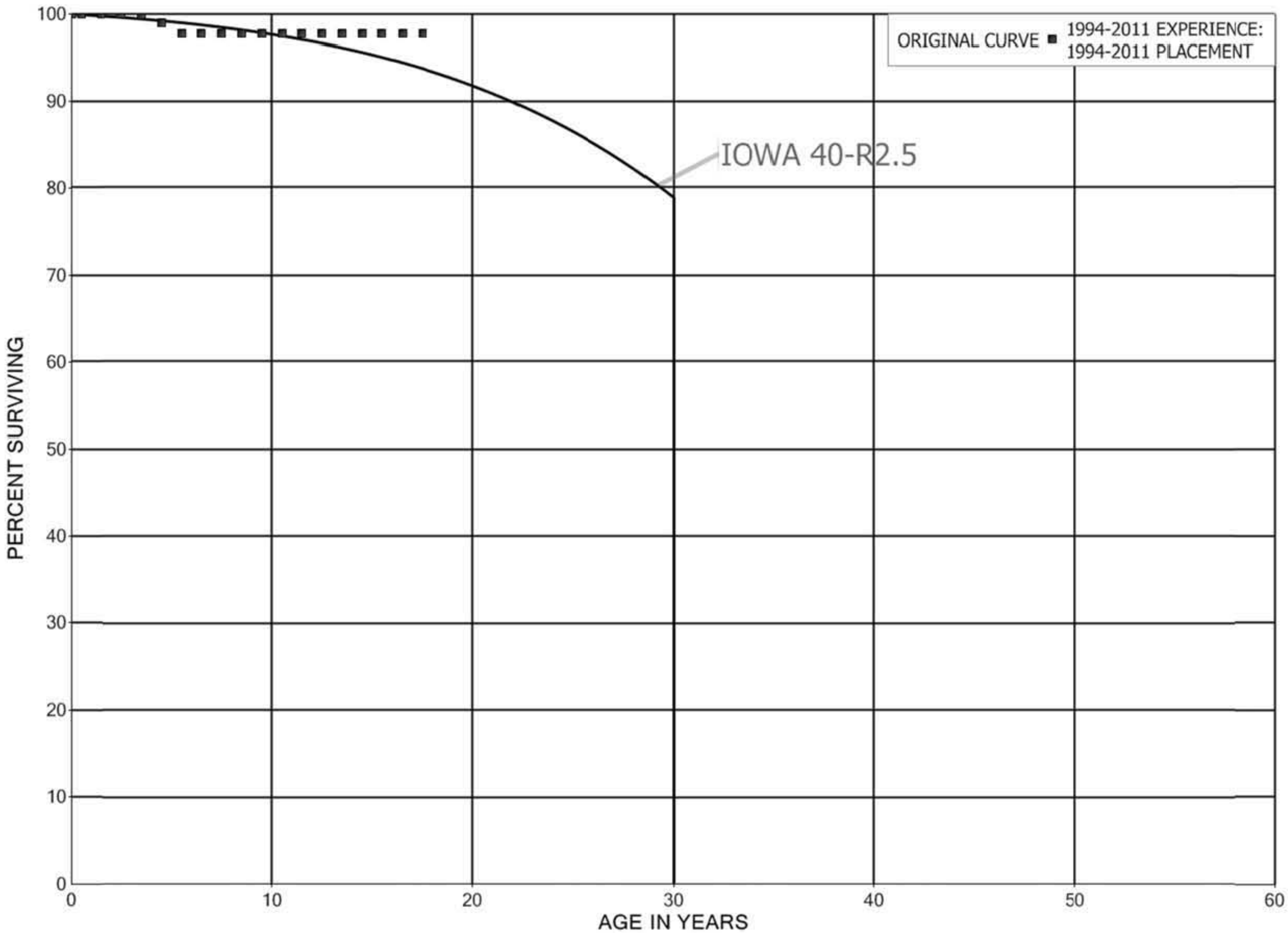
ACCOUNT 336 ROADS, RAILROADS, AND BRIDGES

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1941-2009 EXPERIENCE BAND 1941-2011

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	48,146		0.0000	1.0000	100.00
40.5	48,146		0.0000	1.0000	100.00
41.5	48,146		0.0000	1.0000	100.00
42.5	48,146		0.0000	1.0000	100.00
43.5	48,146		0.0000	1.0000	100.00
44.5	48,146		0.0000	1.0000	100.00
45.5	48,146		0.0000	1.0000	100.00
46.5	48,146		0.0000	1.0000	100.00
47.5	48,146		0.0000	1.0000	100.00
48.5	48,146		0.0000	1.0000	100.00
49.5	48,146		0.0000	1.0000	100.00
50.5	48,146		0.0000	1.0000	100.00
51.5	48,146		0.0000	1.0000	100.00
52.5	48,146		0.0000	1.0000	100.00
53.5	48,146		0.0000	1.0000	100.00
54.5	48,146		0.0000	1.0000	100.00
55.5	48,146		0.0000	1.0000	100.00
56.5	48,146		0.0000	1.0000	100.00
57.5	48,146		0.0000	1.0000	100.00
58.5	48,146		0.0000	1.0000	100.00
59.5	48,146		0.0000	1.0000	100.00
60.5	48,146		0.0000	1.0000	100.00
61.5	48,146		0.0000	1.0000	100.00
62.5	48,146		0.0000	1.0000	100.00
63.5	48,146	1,170	0.0243	0.9757	100.00
64.5	46,976		0.0000	1.0000	97.57
65.5	46,976		0.0000	1.0000	97.57
66.5	46,976		0.0000	1.0000	97.57
67.5	46,976		0.0000	1.0000	97.57
68.5	46,976		0.0000	1.0000	97.57
69.5	46,976		0.0000	1.0000	97.57
70.5					97.57

KENTUCKY UTILITIES COMPANY
ACCOUNT 341 STRUCTURES AND IMPROVEMENTS
ORIGINAL AND SMOOTH SURVIVOR CURVES



KENTUCKY UTILITIES COMPANY

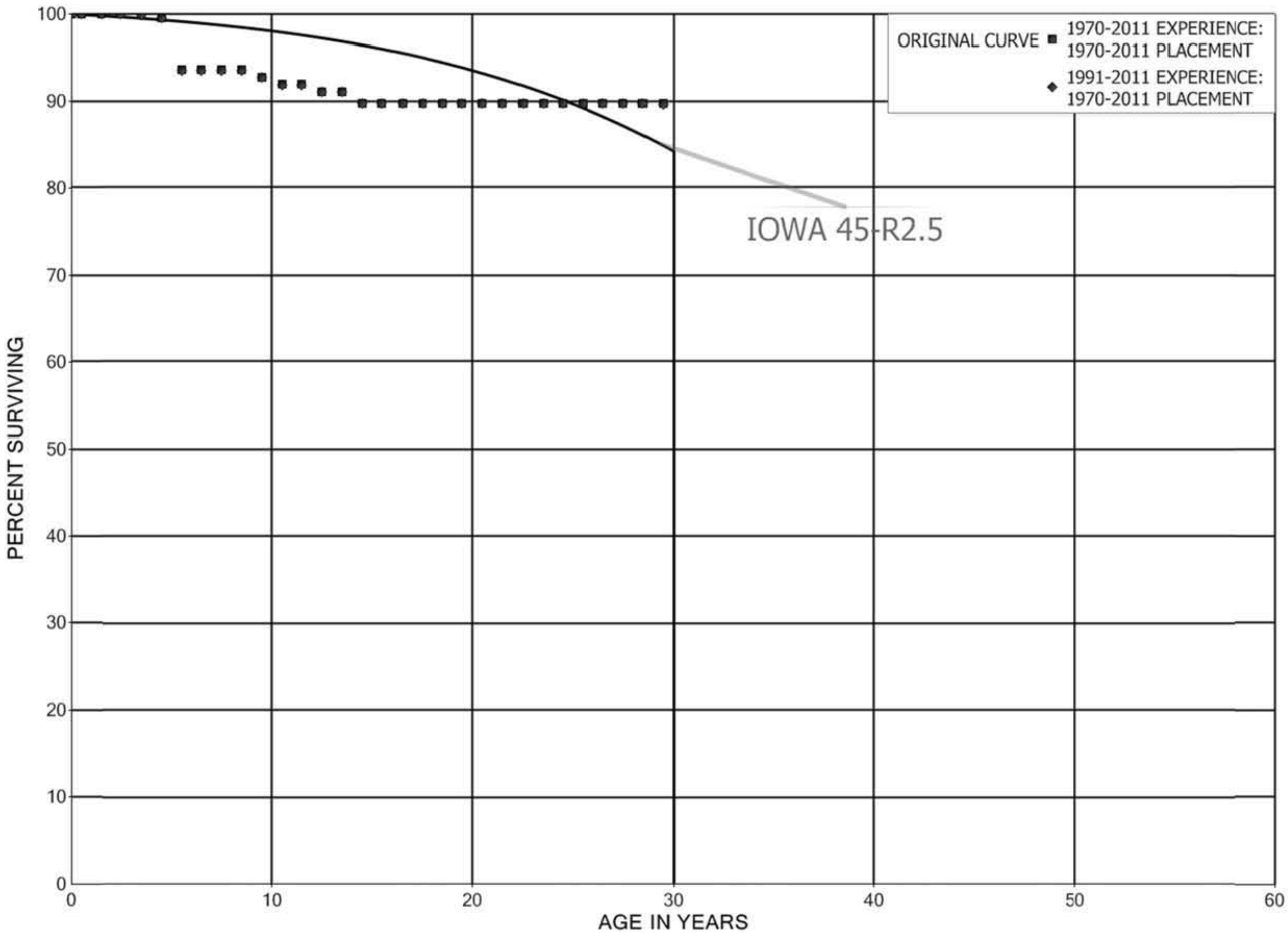
ACCOUNT 341 STRUCTURES AND IMPROVEMENTS

ORIGINAL LIFE TABLE

PLACEMENT BAND 1994-2011 EXPERIENCE BAND 1994-2011

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	36,824,236		0.0000	1.0000	100.00
0.5	36,839,858		0.0000	1.0000	100.00
1.5	36,837,335		0.0000	1.0000	100.00
2.5	36,837,335	42,413	0.0012	0.9988	100.00
3.5	36,794,922	348,269	0.0095	0.9905	99.88
4.5	36,446,653	464,499	0.0127	0.9873	98.94
5.5	35,812,799		0.0000	1.0000	97.68
6.5	35,717,419		0.0000	1.0000	97.68
7.5	21,172,433		0.0000	1.0000	97.68
8.5	21,172,433		0.0000	1.0000	97.68
9.5	14,032,746		0.0000	1.0000	97.68
10.5	11,235,292		0.0000	1.0000	97.68
11.5	10,804,077		0.0000	1.0000	97.68
12.5	10,188,686		0.0000	1.0000	97.68
13.5	9,875,661		0.0000	1.0000	97.68
14.5	8,403,598		0.0000	1.0000	97.68
15.5	6,622,106		0.0000	1.0000	97.68
16.5	2,627,085		0.0000	1.0000	97.68
17.5					97.68

KENTUCKY UTILITIES COMPANY
ACCOUNT 342 FUEL HOLDERS, PRODUCERS AND ACCESSORIES
ORIGINAL AND SMOOTH SURVIVOR CURVES



KENTUCKY UTILITIES COMPANY

ACCOUNT 342 FUEL HOLDERS, PRODUCERS AND ACCESSORIES

ORIGINAL LIFE TABLE

PLACEMENT BAND 1970-2011 EXPERIENCE BAND 1970-2011

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	24,770,897		0.0000	1.0000	100.00
0.5	24,294,358		0.0000	1.0000	100.00
1.5	22,667,608	8,061	0.0004	0.9996	100.00
2.5	22,618,040	23,300	0.0010	0.9990	99.96
3.5	22,594,740	87,378	0.0039	0.9961	99.86
4.5	22,431,208	1,329,368	0.0593	0.9407	99.48
5.5	21,095,690		0.0000	1.0000	93.58
6.5	20,707,455		0.0000	1.0000	93.58
7.5	18,362,458		0.0000	1.0000	93.58
8.5	18,325,891	164,534	0.0090	0.9910	93.58
9.5	13,205,764	111,832	0.0085	0.9915	92.74
10.5	10,559,927		0.0000	1.0000	91.95
11.5	10,559,927	96,312	0.0091	0.9909	91.95
12.5	9,904,781		0.0000	1.0000	91.12
13.5	9,897,008	145,827	0.0147	0.9853	91.12
14.5	9,509,174		0.0000	1.0000	89.77
15.5	9,284,723		0.0000	1.0000	89.77
16.5	7,965,649		0.0000	1.0000	89.77
17.5	181,132		0.0000	1.0000	89.77
18.5	181,132		0.0000	1.0000	89.77
19.5	181,132		0.0000	1.0000	89.77
20.5	181,132		0.0000	1.0000	89.77
21.5	181,132		0.0000	1.0000	89.77
22.5	181,132		0.0000	1.0000	89.77
23.5	181,132		0.0000	1.0000	89.77
24.5	181,132		0.0000	1.0000	89.77
25.5	181,132		0.0000	1.0000	89.77
26.5	181,132		0.0000	1.0000	89.77
27.5	181,132		0.0000	1.0000	89.77
28.5	181,132	142	0.0008	0.9992	89.77
29.5	180,990		0.0000	1.0000	89.70
30.5	180,990		0.0000	1.0000	89.70
31.5	180,990		0.0000	1.0000	89.70
32.5	180,990		0.0000	1.0000	89.70
33.5	180,990		0.0000	1.0000	89.70
34.5	114,454		0.0000	1.0000	89.70
35.5	114,454		0.0000	1.0000	89.70
36.5	114,454		0.0000	1.0000	89.70
37.5	114,454		0.0000	1.0000	89.70
38.5	114,209		0.0000	1.0000	89.70

KENTUCKY UTILITIES COMPANY

ACCOUNT 342 FUEL HOLDERS, PRODUCERS AND ACCESSORIES

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1970-2011 EXPERIENCE BAND 1970-2011

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	114,209		0.0000	1.0000	89.70
40.5	88,961	59,785	0.6720	0.3280	89.70
41.5					29.42

KENTUCKY UTILITIES COMPANY

ACCOUNT 342 FUEL HOLDERS, PRODUCERS AND ACCESSORIES

ORIGINAL LIFE TABLE

PLACEMENT BAND 1970-2011 EXPERIENCE BAND 1991-2011

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	24,589,766		0.0000	1.0000	100.00
0.5	24,113,226		0.0000	1.0000	100.00
1.5	22,486,476	8,061	0.0004	0.9996	100.00
2.5	22,436,908	23,300	0.0010	0.9990	99.96
3.5	22,413,608	87,378	0.0039	0.9961	99.86
4.5	22,250,076	1,329,368	0.0597	0.9403	99.47
5.5	20,914,558		0.0000	1.0000	93.53
6.5	20,526,324		0.0000	1.0000	93.53
7.5	18,181,327		0.0000	1.0000	93.53
8.5	18,144,759	164,534	0.0091	0.9909	93.53
9.5	13,024,632	111,832	0.0086	0.9914	92.68
10.5	10,378,795		0.0000	1.0000	91.88
11.5	10,378,795	96,312	0.0093	0.9907	91.88
12.5	9,723,791		0.0000	1.0000	91.03
13.5	9,782,554	145,827	0.0149	0.9851	91.03
14.5	9,394,720		0.0000	1.0000	89.67
15.5	9,170,269		0.0000	1.0000	89.67
16.5	7,851,195		0.0000	1.0000	89.67
17.5	66,923		0.0000	1.0000	89.67
18.5	66,923		0.0000	1.0000	89.67
19.5	92,171		0.0000	1.0000	89.67
20.5	181,132		0.0000	1.0000	89.67
21.5	181,132		0.0000	1.0000	89.67
22.5	181,132		0.0000	1.0000	89.67
23.5	181,132		0.0000	1.0000	89.67
24.5	181,132		0.0000	1.0000	89.67
25.5	181,132		0.0000	1.0000	89.67
26.5	181,132		0.0000	1.0000	89.67
27.5	181,132		0.0000	1.0000	89.67
28.5	181,132	142	0.0008	0.9992	89.67
29.5	180,990		0.0000	1.0000	89.60
30.5	180,990		0.0000	1.0000	89.60
31.5	180,990		0.0000	1.0000	89.60
32.5	180,990		0.0000	1.0000	89.60
33.5	180,990		0.0000	1.0000	89.60
34.5	114,454		0.0000	1.0000	89.60
35.5	114,454		0.0000	1.0000	89.60
36.5	114,454		0.0000	1.0000	89.60
37.5	114,454		0.0000	1.0000	89.60
38.5	114,209		0.0000	1.0000	89.60

KENTUCKY UTILITIES COMPANY

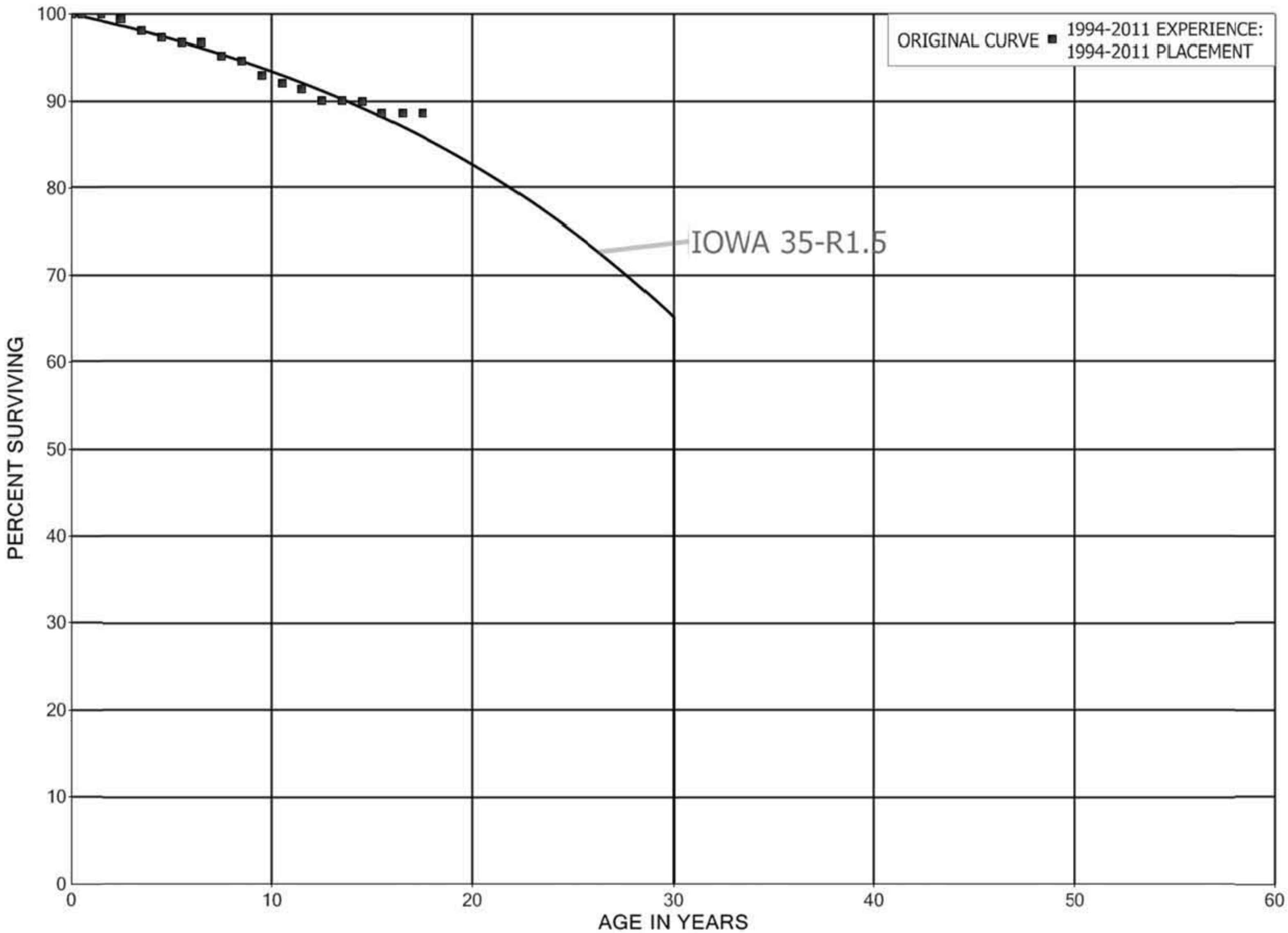
ACCOUNT 342 FUEL HOLDERS, PRODUCERS AND ACCESSORIES

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1970-2011 EXPERIENCE BAND 1991-2011

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	114,209		0.0000	1.0000	89.60
40.5	88,961	59,785	0.6720	0.3280	89.60
41.5					29.39

KENTUCKY UTILITIES COMPANY
ACCOUNT 343 PRIME MOVERS
ORIGINAL AND SMOOTH SURVIVOR CURVES



KENTUCKY UTILITIES COMPANY

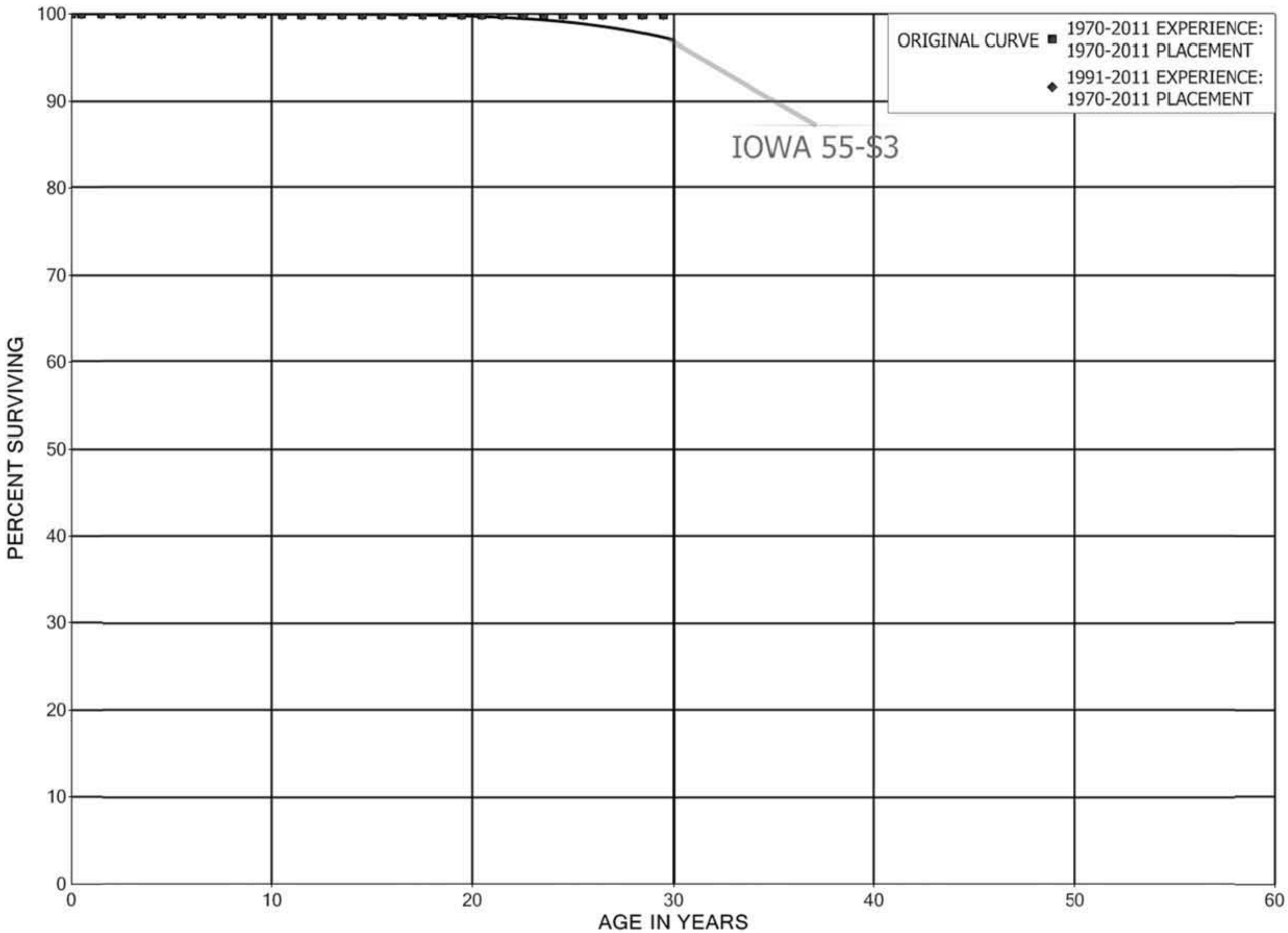
ACCOUNT 343 PRIME MOVERS

ORIGINAL LIFE TABLE

PLACEMENT BAND 1994-2011 EXPERIENCE BAND 1994-2011

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	388,313,984		0.0000	1.0000	100.00
0.5	381,089,687		0.0000	1.0000	100.00
1.5	379,831,299	2,330,051	0.0061	0.9939	100.00
2.5	371,531,007	4,819,837	0.0130	0.9870	99.39
3.5	359,000,597	3,048,432	0.0085	0.9915	98.10
4.5	345,111,921	1,814,195	0.0053	0.9947	97.26
5.5	330,134,731	60,952	0.0002	0.9998	96.75
6.5	330,008,924	5,436,760	0.0165	0.9835	96.74
7.5	234,859,638	1,425,911	0.0061	0.9939	95.14
8.5	231,899,929	3,891,416	0.0168	0.9832	94.56
9.5	168,908,447	1,719,061	0.0102	0.9898	92.98
10.5	133,293,147	893,926	0.0067	0.9933	92.03
11.5	118,139,232	1,683,634	0.0143	0.9857	91.41
12.5	71,694,368		0.0000	1.0000	90.11
13.5	65,371,451	130,906	0.0020	0.9980	90.11
14.5	61,438,277	893,966	0.0146	0.9854	89.93
15.5	42,583,571		0.0000	1.0000	88.62
16.5	14,893,196		0.0000	1.0000	88.62
17.5					88.62

KENTUCKY UTILITIES COMPANY
ACCOUNT 344 GENERATORS
ORIGINAL AND SMOOTH SURVIVOR CURVES



KENTUCKY UTILITIES COMPANY

ACCOUNT 344 GENERATORS

ORIGINAL LIFE TABLE

PLACEMENT BAND 1970-2011 EXPERIENCE BAND 1970-2011

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	59,536,530		0.0000	1.0000	100.00
0.5	59,523,256		0.0000	1.0000	100.00
1.5	59,523,256		0.0000	1.0000	100.00
2.5	59,523,256	8,870	0.0001	0.9999	100.00
3.5	59,514,386	6,511	0.0001	0.9999	99.99
4.5	59,507,875		0.0000	1.0000	99.97
5.5	59,507,875		0.0000	1.0000	99.97
6.5	59,507,875		0.0000	1.0000	99.97
7.5	47,653,665		0.0000	1.0000	99.97
8.5	47,653,665		0.0000	1.0000	99.97
9.5	40,171,864	40,984	0.0010	0.9990	99.97
10.5	31,784,949		0.0000	1.0000	99.87
11.5	31,784,949		0.0000	1.0000	99.87
12.5	24,379,209		0.0000	1.0000	99.87
13.5	24,379,209		0.0000	1.0000	99.87
14.5	24,260,098		0.0000	1.0000	99.87
15.5	19,192,169		0.0000	1.0000	99.87
16.5	9,174,912		0.0000	1.0000	99.87
17.5	3,841,744		0.0000	1.0000	99.87
18.5	3,841,744		0.0000	1.0000	99.87
19.5	3,841,744		0.0000	1.0000	99.87
20.5	3,841,744		0.0000	1.0000	99.87
21.5	3,841,744		0.0000	1.0000	99.87
22.5	3,841,744		0.0000	1.0000	99.87
23.5	3,841,744		0.0000	1.0000	99.87
24.5	3,841,744		0.0000	1.0000	99.87
25.5	3,841,744		0.0000	1.0000	99.87
26.5	3,841,744		0.0000	1.0000	99.87
27.5	3,841,744		0.0000	1.0000	99.87
28.5	3,841,744		0.0000	1.0000	99.87
29.5	3,841,744	128,839	0.0335	0.9665	99.87
30.5	3,712,905	44,894	0.0121	0.9879	96.52
31.5	3,668,011		0.0000	1.0000	95.36
32.5	3,668,011		0.0000	1.0000	95.36
33.5	3,668,011		0.0000	1.0000	95.36
34.5	3,668,011		0.0000	1.0000	95.36
35.5	3,668,011		0.0000	1.0000	95.36
36.5	3,649,514		0.0000	1.0000	95.36
37.5	3,649,514		0.0000	1.0000	95.36
38.5	3,649,514		0.0000	1.0000	95.36

KENTUCKY UTILITIES COMPANY

ACCOUNT 344 GENERATORS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1970-2011 EXPERIENCE BAND 1970-2011

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	3,649,514		0.0000	1.0000	95.36
40.5	3,502,967		0.0000	1.0000	95.36
41.5					95.36

KENTUCKY UTILITIES COMPANY

ACCOUNT 344 GENERATORS

ORIGINAL LIFE TABLE

PLACEMENT BAND 1970-2011 EXPERIENCE BAND 1991-2011

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	55,694,786		0.0000	1.0000	100.00
0.5	55,681,511		0.0000	1.0000	100.00
1.5	55,681,511		0.0000	1.0000	100.00
2.5	55,681,511	8,870	0.0002	0.9998	100.00
3.5	55,672,641	6,511	0.0001	0.9999	99.98
4.5	55,666,130		0.0000	1.0000	99.97
5.5	55,666,130		0.0000	1.0000	99.97
6.5	55,666,130		0.0000	1.0000	99.97
7.5	43,811,921		0.0000	1.0000	99.97
8.5	43,811,921		0.0000	1.0000	99.97
9.5	36,330,120	40,984	0.0011	0.9989	99.97
10.5	27,943,205		0.0000	1.0000	99.86
11.5	27,943,205		0.0000	1.0000	99.86
12.5	20,537,465		0.0000	1.0000	99.86
13.5	20,537,465		0.0000	1.0000	99.86
14.5	20,418,354		0.0000	1.0000	99.86
15.5	15,368,921		0.0000	1.0000	99.86
16.5	5,351,665		0.0000	1.0000	99.86
17.5	18,497		0.0000	1.0000	99.86
18.5	18,497		0.0000	1.0000	99.86
19.5	165,044		0.0000	1.0000	99.86
20.5	3,841,744		0.0000	1.0000	99.86
21.5	3,841,744		0.0000	1.0000	99.86
22.5	3,841,744		0.0000	1.0000	99.86
23.5	3,841,744		0.0000	1.0000	99.86
24.5	3,841,744		0.0000	1.0000	99.86
25.5	3,841,744		0.0000	1.0000	99.86
26.5	3,841,744		0.0000	1.0000	99.86
27.5	3,841,744		0.0000	1.0000	99.86
28.5	3,841,744		0.0000	1.0000	99.86
29.5	3,841,744	128,839	0.0335	0.9665	99.86
30.5	3,712,905	44,894	0.0121	0.9879	96.51
31.5	3,668,011		0.0000	1.0000	95.34
32.5	3,668,011		0.0000	1.0000	95.34
33.5	3,668,011		0.0000	1.0000	95.34
34.5	3,668,011		0.0000	1.0000	95.34
35.5	3,668,011		0.0000	1.0000	95.34
36.5	3,649,514		0.0000	1.0000	95.34
37.5	3,649,514		0.0000	1.0000	95.34
38.5	3,649,514		0.0000	1.0000	95.34

KENTUCKY UTILITIES COMPANY

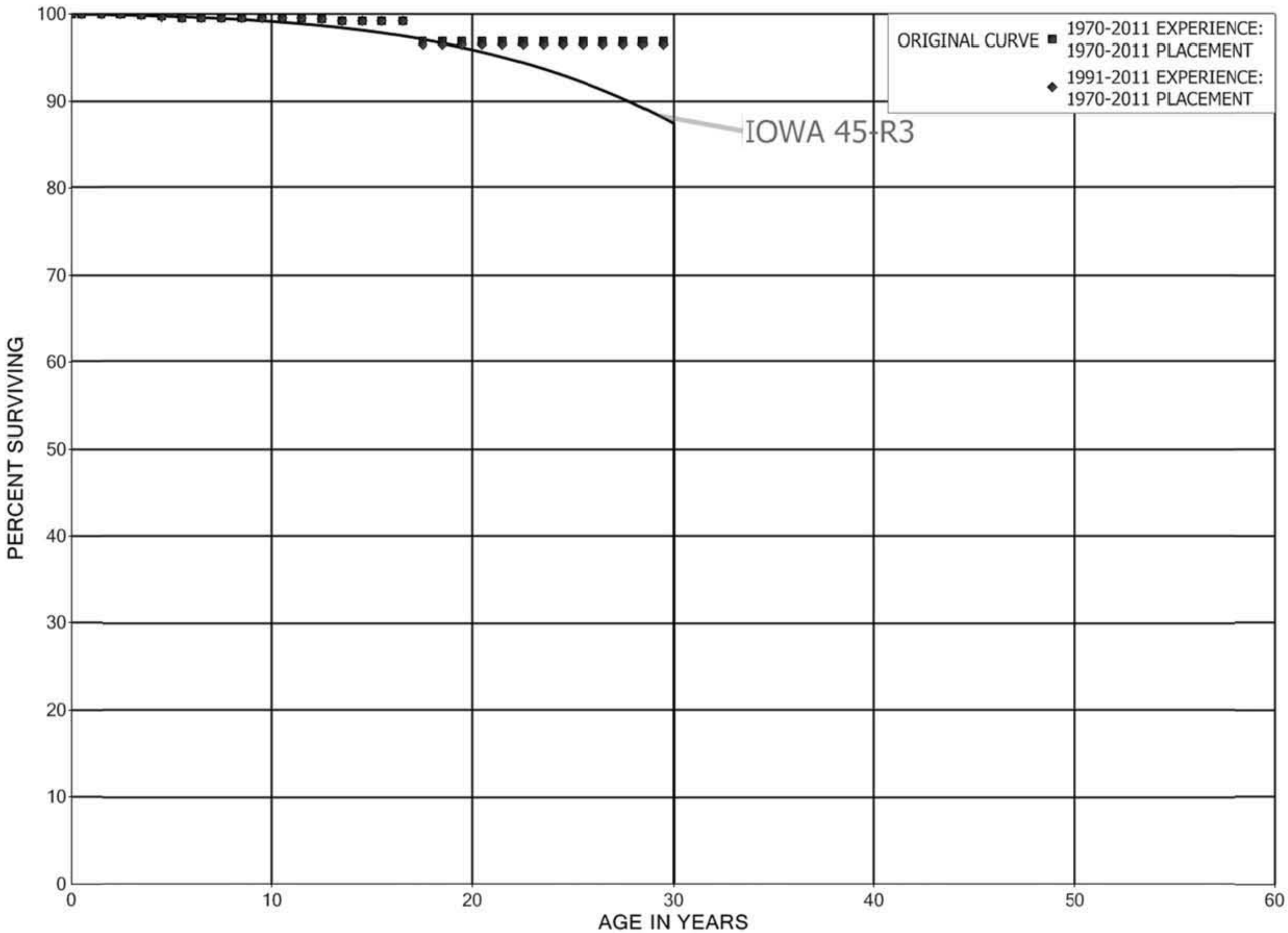
ACCOUNT 344 GENERATORS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1970-2011 EXPERIENCE BAND 1991-2011

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	3,649,514		0.0000	1.0000	95.34
40.5	3,502,967		0.0000	1.0000	95.34
41.5					95.34

KENTUCKY UTILITIES COMPANY
ACCOUNT 345 ACCESSORY ELECTRIC EQUIPMENT
ORIGINAL AND SMOOTH SURVIVOR CURVES



KENTUCKY UTILITIES COMPANY

ACCOUNT 345 ACCESSORY ELECTRIC EQUIPMENT

ORIGINAL LIFE TABLE

PLACEMENT BAND 1970-2011 EXPERIENCE BAND 1970-2011

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	33,236,790		0.0000	1.0000	100.00
0.5	32,140,089		0.0000	1.0000	100.00
1.5	32,067,667		0.0000	1.0000	100.00
2.5	31,125,850	55,908	0.0018	0.9982	100.00
3.5	31,069,942	46,720	0.0015	0.9985	99.82
4.5	30,993,053	40,633	0.0013	0.9987	99.67
5.5	34,867,686		0.0000	1.0000	99.54
6.5	34,867,686		0.0000	1.0000	99.54
7.5	20,833,668		0.0000	1.0000	99.54
8.5	21,766,668	8,080	0.0004	0.9996	99.54
9.5	15,780,949		0.0000	1.0000	99.50
10.5	12,215,623		0.0000	1.0000	99.50
11.5	12,215,623	8,145	0.0007	0.9993	99.50
12.5	8,357,048	17,431	0.0021	0.9979	99.44
13.5	9,286,343		0.0000	1.0000	99.23
14.5	9,166,669		0.0000	1.0000	99.23
15.5	7,045,559		0.0000	1.0000	99.23
16.5	4,800,546	113,226	0.0236	0.9764	99.23
17.5	2,791,933		0.0000	1.0000	96.89
18.5	603,776		0.0000	1.0000	96.89
19.5	603,776		0.0000	1.0000	96.89
20.5	603,776		0.0000	1.0000	96.89
21.5	603,776		0.0000	1.0000	96.89
22.5	603,776		0.0000	1.0000	96.89
23.5	603,776		0.0000	1.0000	96.89
24.5	603,776		0.0000	1.0000	96.89
25.5	603,776		0.0000	1.0000	96.89
26.5	603,776		0.0000	1.0000	96.89
27.5	603,776		0.0000	1.0000	96.89
28.5	603,776		0.0000	1.0000	96.89
29.5	603,776		0.0000	1.0000	96.89
30.5	603,776		0.0000	1.0000	96.89
31.5	603,776		0.0000	1.0000	96.89
32.5	603,776		0.0000	1.0000	96.89
33.5	603,776		0.0000	1.0000	96.89
34.5	603,776		0.0000	1.0000	96.89
35.5	603,776		0.0000	1.0000	96.89
36.5	603,776		0.0000	1.0000	96.89
37.5	603,776		0.0000	1.0000	96.89
38.5	600,950		0.0000	1.0000	96.89

KENTUCKY UTILITIES COMPANY

ACCOUNT 345 ACCESSORY ELECTRIC EQUIPMENT

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1970-2011 EXPERIENCE BAND 1970-2011

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	600,950		0.0000	1.0000	96.89
40.5	558,951		0.0000	1.0000	96.89
41.5					96.89

KENTUCKY UTILITIES COMPANY

ACCOUNT 345 ACCESSORY ELECTRIC EQUIPMENT

ORIGINAL LIFE TABLE

PLACEMENT BAND 1970-2011 EXPERIENCE BAND 1991-2011

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	32,633,015		0.0000	1.0000	100.00
0.5	31,536,313		0.0000	1.0000	100.00
1.5	31,463,892		0.0000	1.0000	100.00
2.5	30,522,075	55,908	0.0018	0.9982	100.00
3.5	30,466,167	46,720	0.0015	0.9985	99.82
4.5	30,389,277	40,633	0.0013	0.9987	99.66
5.5	34,263,910		0.0000	1.0000	99.53
6.5	34,263,910		0.0000	1.0000	99.53
7.5	20,229,892		0.0000	1.0000	99.53
8.5	21,162,892	8,080	0.0004	0.9996	99.53
9.5	15,177,173		0.0000	1.0000	99.49
10.5	11,611,848		0.0000	1.0000	99.49
11.5	11,611,848	8,145	0.0007	0.9993	99.49
12.5	7,753,272	17,431	0.0022	0.9978	99.42
13.5	8,682,568		0.0000	1.0000	99.20
14.5	8,562,893		0.0000	1.0000	99.20
15.5	6,441,783		0.0000	1.0000	99.20
16.5	4,196,770	113,226	0.0270	0.9730	99.20
17.5	2,190,983		0.0000	1.0000	96.52
18.5	2,826		0.0000	1.0000	96.52
19.5	44,825		0.0000	1.0000	96.52
20.5	603,776		0.0000	1.0000	96.52
21.5	603,776		0.0000	1.0000	96.52
22.5	603,776		0.0000	1.0000	96.52
23.5	603,776		0.0000	1.0000	96.52
24.5	603,776		0.0000	1.0000	96.52
25.5	603,776		0.0000	1.0000	96.52
26.5	603,776		0.0000	1.0000	96.52
27.5	603,776		0.0000	1.0000	96.52
28.5	603,776		0.0000	1.0000	96.52
29.5	603,776		0.0000	1.0000	96.52
30.5	603,776		0.0000	1.0000	96.52
31.5	603,776		0.0000	1.0000	96.52
32.5	603,776		0.0000	1.0000	96.52
33.5	603,776		0.0000	1.0000	96.52
34.5	603,776		0.0000	1.0000	96.52
35.5	603,776		0.0000	1.0000	96.52
36.5	603,776		0.0000	1.0000	96.52
37.5	603,776		0.0000	1.0000	96.52
38.5	600,950		0.0000	1.0000	96.52

KENTUCKY UTILITIES COMPANY

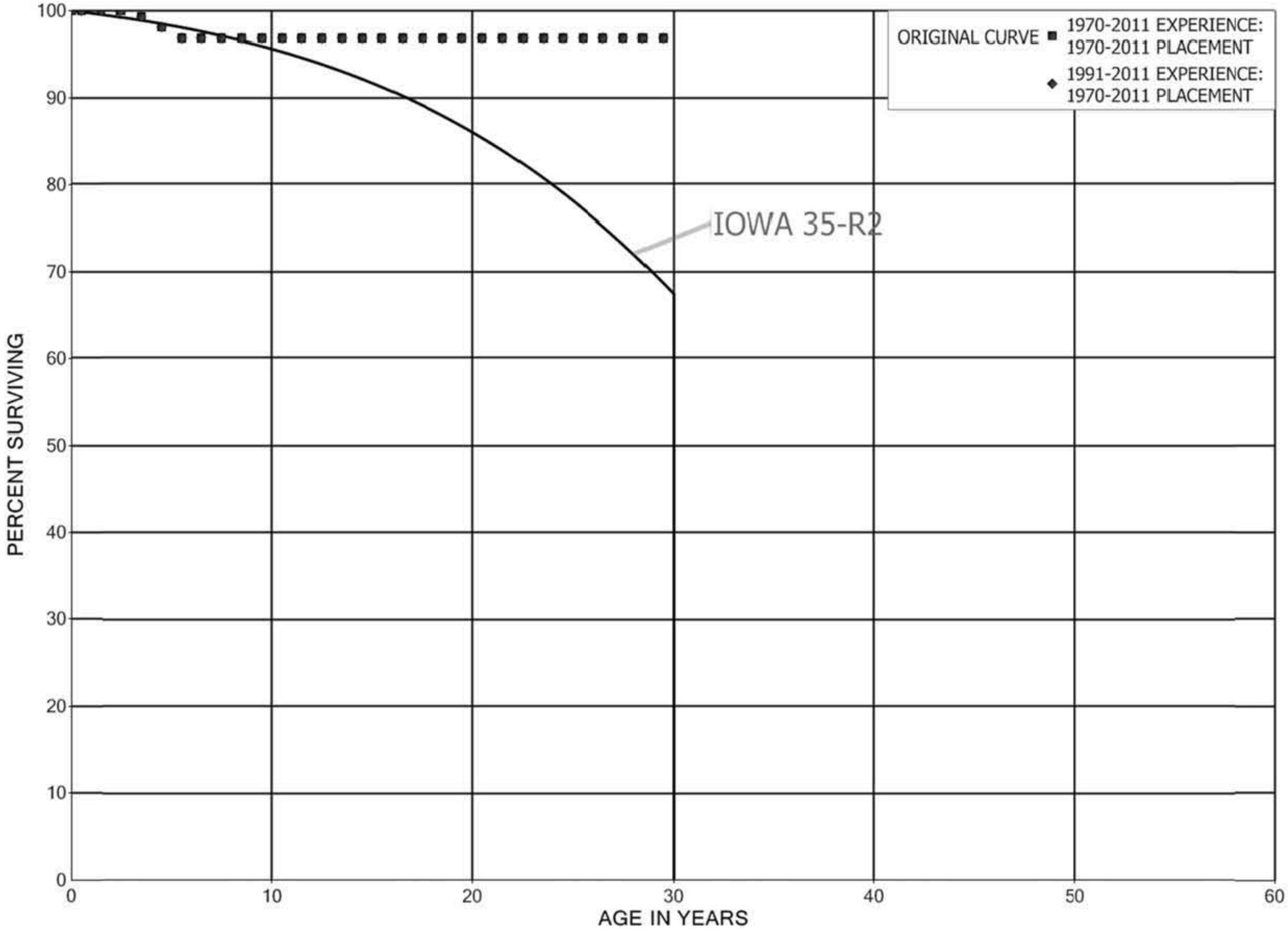
ACCOUNT 345 ACCESSORY ELECTRIC EQUIPMENT

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1970-2011 EXPERIENCE BAND 1991-2011

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	600,950		0.0000	1.0000	96.52
40.5	558,951		0.0000	1.0000	96.52
41.5					96.52

KENTUCKY UTILITIES COMPANY
ACCOUNT 346 MISCELLANEOUS POWER PLANT EQUIPMENT
ORIGINAL AND SMOOTH SURVIVOR CURVES



KENTUCKY UTILITIES COMPANY

ACCOUNT 346 MISCELLANEOUS POWER PLANT EQUIPMENT

ORIGINAL LIFE TABLE

PLACEMENT BAND 1970-2011 EXPERIENCE BAND 1970-2011

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	5,535,824	1,188	0.0002	0.9998	100.00
0.5	5,423,848		0.0000	1.0000	99.98
1.5	5,397,101	1,771	0.0003	0.9997	99.98
2.5	5,395,330	35,883	0.0067	0.9933	99.95
3.5	5,359,447	65,541	0.0122	0.9878	99.28
4.5	5,249,774	66,356	0.0126	0.9874	98.07
5.5	5,168,144		0.0000	1.0000	96.83
6.5	5,133,373		0.0000	1.0000	96.83
7.5	5,028,067		0.0000	1.0000	96.83
8.5	4,681,001		0.0000	1.0000	96.83
9.5	4,675,623		0.0000	1.0000	96.83
10.5	1,450,133		0.0000	1.0000	96.83
11.5	1,450,133		0.0000	1.0000	96.83
12.5	1,408,810		0.0000	1.0000	96.83
13.5	1,408,810		0.0000	1.0000	96.83
14.5	1,387,548		0.0000	1.0000	96.83
15.5	1,229,609		0.0000	1.0000	96.83
16.5	266,976		0.0000	1.0000	96.83
17.5	35,805		0.0000	1.0000	96.83
18.5	35,805		0.0000	1.0000	96.83
19.5	35,805		0.0000	1.0000	96.83
20.5	35,805		0.0000	1.0000	96.83
21.5	35,805		0.0000	1.0000	96.83
22.5	35,805		0.0000	1.0000	96.83
23.5	35,805		0.0000	1.0000	96.83
24.5	35,805		0.0000	1.0000	96.83
25.5	35,805		0.0000	1.0000	96.83
26.5	35,805		0.0000	1.0000	96.83
27.5	35,805		0.0000	1.0000	96.83
28.5	35,805		0.0000	1.0000	96.83
29.5	35,805		0.0000	1.0000	96.83
30.5	35,805		0.0000	1.0000	96.83
31.5	35,805		0.0000	1.0000	96.83
32.5	35,805		0.0000	1.0000	96.83
33.5	35,805		0.0000	1.0000	96.83
34.5	35,805		0.0000	1.0000	96.83
35.5	35,805		0.0000	1.0000	96.83
36.5	35,805		0.0000	1.0000	96.83
37.5	35,805		0.0000	1.0000	96.83
38.5	35,692		0.0000	1.0000	96.83

KENTUCKY UTILITIES COMPANY

ACCOUNT 346 MISCELLANEOUS POWER PLANT EQUIPMENT

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1970-2011 EXPERIENCE BAND 1970-2011

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	35,692		0.0000	1.0000	96.83
40.5	30,264		0.0000	1.0000	96.83
41.5					96.83

KENTUCKY UTILITIES COMPANY

ACCOUNT 346 MISCELLANEOUS POWER PLANT EQUIPMENT

ORIGINAL LIFE TABLE

PLACEMENT BAND 1970-2011 EXPERIENCE BAND 1991-2011

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	5,500,019	1,188	0.0002	0.9998	100.00
0.5	5,388,043		0.0000	1.0000	99.98
1.5	5,361,296	1,771	0.0003	0.9997	99.98
2.5	5,359,525	35,883	0.0067	0.9933	99.95
3.5	5,323,642	65,541	0.0123	0.9877	99.28
4.5	5,213,969	66,356	0.0127	0.9873	98.05
5.5	5,132,339		0.0000	1.0000	96.81
6.5	5,097,567		0.0000	1.0000	96.81
7.5	4,992,262		0.0000	1.0000	96.81
8.5	4,645,195		0.0000	1.0000	96.81
9.5	4,639,817		0.0000	1.0000	96.81
10.5	1,414,328		0.0000	1.0000	96.81
11.5	1,414,328		0.0000	1.0000	96.81
12.5	1,373,005		0.0000	1.0000	96.81
13.5	1,373,005		0.0000	1.0000	96.81
14.5	1,351,743		0.0000	1.0000	96.81
15.5	1,193,803		0.0000	1.0000	96.81
16.5	231,171		0.0000	1.0000	96.81
17.5	113		0.0000	1.0000	96.81
18.5	113		0.0000	1.0000	96.81
19.5	5,541		0.0000	1.0000	96.81
20.5	35,805		0.0000	1.0000	96.81
21.5	35,805		0.0000	1.0000	96.81
22.5	35,805		0.0000	1.0000	96.81
23.5	35,805		0.0000	1.0000	96.81
24.5	35,805		0.0000	1.0000	96.81
25.5	35,805		0.0000	1.0000	96.81
26.5	35,805		0.0000	1.0000	96.81
27.5	35,805		0.0000	1.0000	96.81
28.5	35,805		0.0000	1.0000	96.81
29.5	35,805		0.0000	1.0000	96.81
30.5	35,805		0.0000	1.0000	96.81
31.5	35,805		0.0000	1.0000	96.81
32.5	35,805		0.0000	1.0000	96.81
33.5	35,805		0.0000	1.0000	96.81
34.5	35,805		0.0000	1.0000	96.81
35.5	35,805		0.0000	1.0000	96.81
36.5	35,805		0.0000	1.0000	96.81
37.5	35,805		0.0000	1.0000	96.81
38.5	35,692		0.0000	1.0000	96.81

KENTUCKY UTILITIES COMPANY

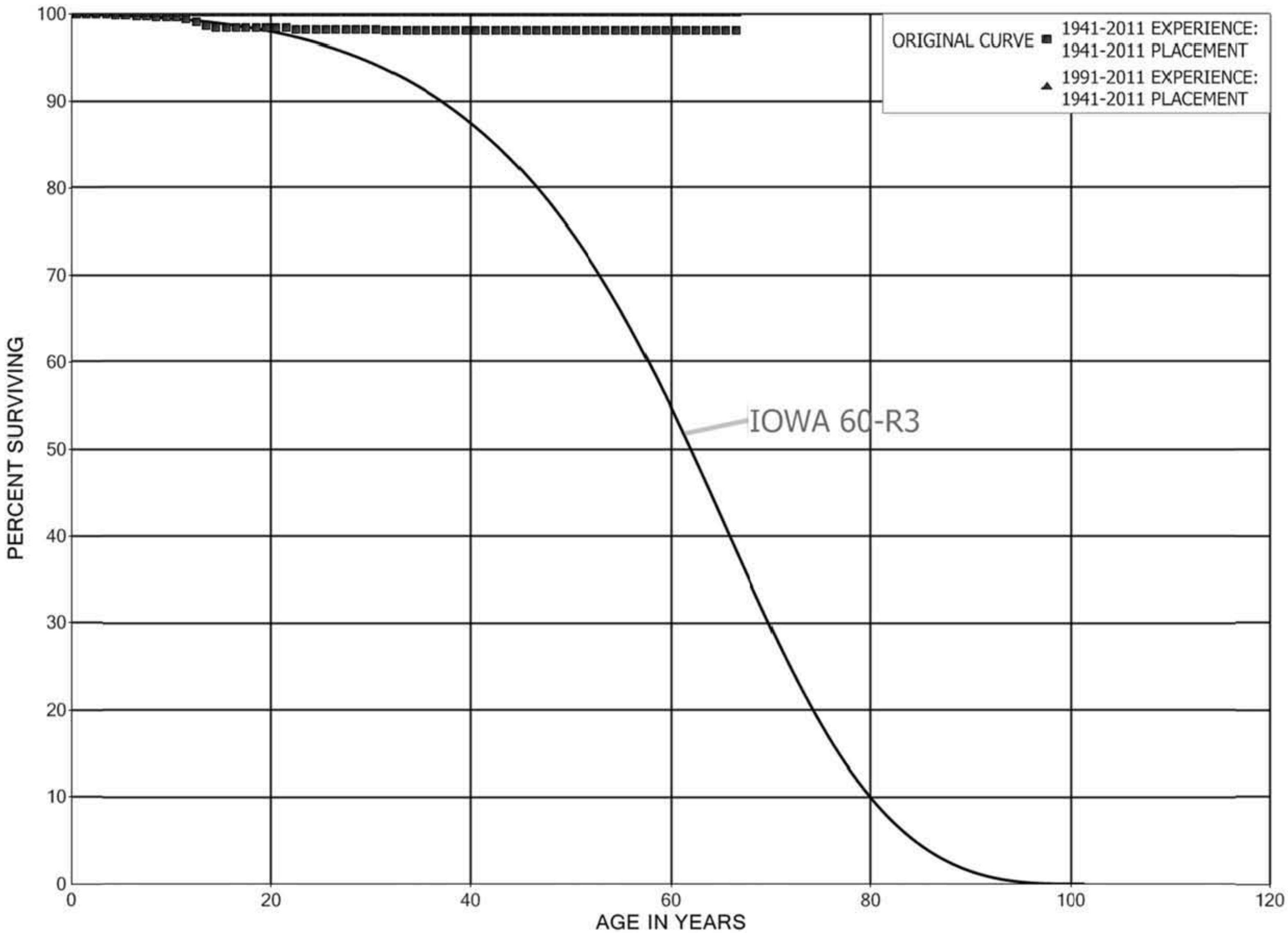
ACCOUNT 346 MISCELLANEOUS POWER PLANT EQUIPMENT

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1970-2011 EXPERIENCE BAND 1991-2011

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	35,692		0.0000	1.0000	96.81
40.5	30,264		0.0000	1.0000	96.81
41.5					96.81

KENTUCKY UTILITIES COMPANY
ACCOUNT 350.1 LAND RIGHTS
ORIGINAL AND SMOOTH SURVIVOR CURVES



KENTUCKY UTILITIES COMPANY

ACCOUNT 350.1 LAND RIGHTS

ORIGINAL LIFE TABLE

PLACEMENT BAND 1941-2011 EXPERIENCE BAND 1941-2011

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	24,341,603	1	0.0000	1.0000	100.00
0.5	24,316,780	1,233	0.0001	0.9999	100.00
1.5	24,165,597		0.0000	1.0000	99.99
2.5	23,811,760		0.0000	1.0000	99.99
3.5	23,811,760	38,734	0.0016	0.9984	99.99
4.5	23,772,940	481	0.0000	1.0000	99.83
5.5	23,772,459	34,479	0.0015	0.9985	99.83
6.5	23,737,435	3,553	0.0001	0.9999	99.69
7.5	23,733,882	10,694	0.0005	0.9995	99.67
8.5	23,373,350	3,483	0.0001	0.9999	99.63
9.5	23,368,595	40	0.0000	1.0000	99.61
10.5	23,368,555	44,006	0.0019	0.9981	99.61
11.5	23,168,410	91,664	0.0040	0.9960	99.42
12.5	22,729,422	96,578	0.0042	0.9958	99.03
13.5	22,317,425	36,417	0.0016	0.9984	98.61
14.5	22,216,853	4,272	0.0002	0.9998	98.45
15.5	22,137,184	260	0.0000	1.0000	98.43
16.5	21,722,320	2,201	0.0001	0.9999	98.43
17.5	21,635,703		0.0000	1.0000	98.42
18.5	21,587,944	14,381	0.0007	0.9993	98.42
19.5	21,517,529		0.0000	1.0000	98.35
20.5	21,208,563	2,507	0.0001	0.9999	98.35
21.5	21,080,504	33,678	0.0016	0.9984	98.34
22.5	20,921,080	1,618	0.0001	0.9999	98.18
23.5	20,794,696	1,468	0.0001	0.9999	98.18
24.5	20,188,904		0.0000	1.0000	98.17
25.5	20,019,320		0.0000	1.0000	98.17
26.5	18,640,049		0.0000	1.0000	98.17
27.5	16,418,022	1,472	0.0001	0.9999	98.17
28.5	16,101,052	1,157	0.0001	0.9999	98.16
29.5	15,240,385		0.0000	1.0000	98.15
30.5	14,667,844	14,769	0.0010	0.9990	98.15
31.5	13,894,366	306	0.0000	1.0000	98.05
32.5	13,012,208		0.0000	1.0000	98.05
33.5	12,109,922		0.0000	1.0000	98.05
34.5	11,968,740		0.0000	1.0000	98.05
35.5	11,514,099		0.0000	1.0000	98.05
36.5	11,341,297		0.0000	1.0000	98.05
37.5	10,798,351		0.0000	1.0000	98.05
38.5	9,820,313		0.0000	1.0000	98.05

KENTUCKY UTILITIES COMPANY

ACCOUNT 350.1 LAND RIGHTS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1941-2011 EXPERIENCE BAND 1941-2011

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	9,227,206		0.0000	1.0000	98.05
40.5	8,257,137		0.0000	1.0000	98.05
41.5	6,574,442		0.0000	1.0000	98.05
42.5	6,172,348	361	0.0001	0.9999	98.05
43.5	6,043,333		0.0000	1.0000	98.05
44.5	5,431,768		0.0000	1.0000	98.05
45.5	5,015,821		0.0000	1.0000	98.05
46.5	4,728,187		0.0000	1.0000	98.05
47.5	4,635,045		0.0000	1.0000	98.05
48.5	4,169,925	643	0.0002	0.9998	98.05
49.5	3,888,922		0.0000	1.0000	98.03
50.5	3,530,709		0.0000	1.0000	98.03
51.5	3,267,275		0.0000	1.0000	98.03
52.5	3,040,442		0.0000	1.0000	98.03
53.5	2,666,928		0.0000	1.0000	98.03
54.5	2,634,749		0.0000	1.0000	98.03
55.5	2,375,299		0.0000	1.0000	98.03
56.5	2,289,385		0.0000	1.0000	98.03
57.5	2,180,564		0.0000	1.0000	98.03
58.5	1,771,258		0.0000	1.0000	98.03
59.5	1,585,210		0.0000	1.0000	98.03
60.5	1,480,421		0.0000	1.0000	98.03
61.5	1,457,872		0.0000	1.0000	98.03
62.5	1,229,528		0.0000	1.0000	98.03
63.5	1,196,251		0.0000	1.0000	98.03
64.5	1,130,721		0.0000	1.0000	98.03
65.5	1,091,892		0.0000	1.0000	98.03
66.5	1,078,118		0.0000	1.0000	98.03
67.5	714,530		0.0000	1.0000	98.03
68.5	713,453		0.0000	1.0000	98.03
69.5	686,361		0.0000	1.0000	98.03
70.5					98.03

KENTUCKY UTILITIES COMPANY

ACCOUNT 350.1 LAND RIGHTS

ORIGINAL LIFE TABLE

PLACEMENT BAND 1941-2011 EXPERIENCE BAND 1991-2011

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	2,750,924	1	0.0000	1.0000	100.00
0.5	2,851,654		0.0000	1.0000	100.00
1.5	2,827,450		0.0000	1.0000	100.00
2.5	2,598,378		0.0000	1.0000	100.00
3.5	3,202,702		0.0000	1.0000	100.00
4.5	3,372,200	361	0.0001	0.9999	100.00
5.5	4,751,110		0.0000	1.0000	99.99
6.5	6,972,592		0.0000	1.0000	99.99
7.5	7,288,090		0.0000	1.0000	99.99
8.5	7,797,763		0.0000	1.0000	99.99
9.5	8,369,031		0.0000	1.0000	99.99
10.5	9,127,740		0.0000	1.0000	99.99
11.5	9,853,453		0.0000	1.0000	99.99
12.5	10,408,416		0.0000	1.0000	99.99
13.5	10,234,179		0.0000	1.0000	99.99
14.5	10,624,665		0.0000	1.0000	99.99
15.5	10,722,070		0.0000	1.0000	99.99
16.5	10,850,412		0.0000	1.0000	99.99
17.5	11,744,034		0.0000	1.0000	99.99
18.5	12,289,382		0.0000	1.0000	99.99
19.5	13,203,417		0.0000	1.0000	99.99
20.5	14,577,146		0.0000	1.0000	99.99
21.5	14,853,688		0.0000	1.0000	99.99
22.5	14,856,597		0.0000	1.0000	99.99
23.5	15,343,396		0.0000	1.0000	99.99
24.5	15,154,951		0.0000	1.0000	99.99
25.5	15,273,001		0.0000	1.0000	99.99
26.5	13,986,872		0.0000	1.0000	99.99
27.5	12,229,965		0.0000	1.0000	99.99
28.5	12,195,187		0.0000	1.0000	99.99
29.5	11,662,961		0.0000	1.0000	99.99
30.5	11,353,854		0.0000	1.0000	99.99
31.5	10,821,978		0.0000	1.0000	99.99
32.5	10,313,640		0.0000	1.0000	99.99
33.5	9,443,533		0.0000	1.0000	99.99
34.5	9,561,801		0.0000	1.0000	99.99
35.5	9,193,074		0.0000	1.0000	99.99
36.5	9,129,093		0.0000	1.0000	99.99
37.5	8,995,453		0.0000	1.0000	99.99
38.5	8,203,531		0.0000	1.0000	99.99

KENTUCKY UTILITIES COMPANY

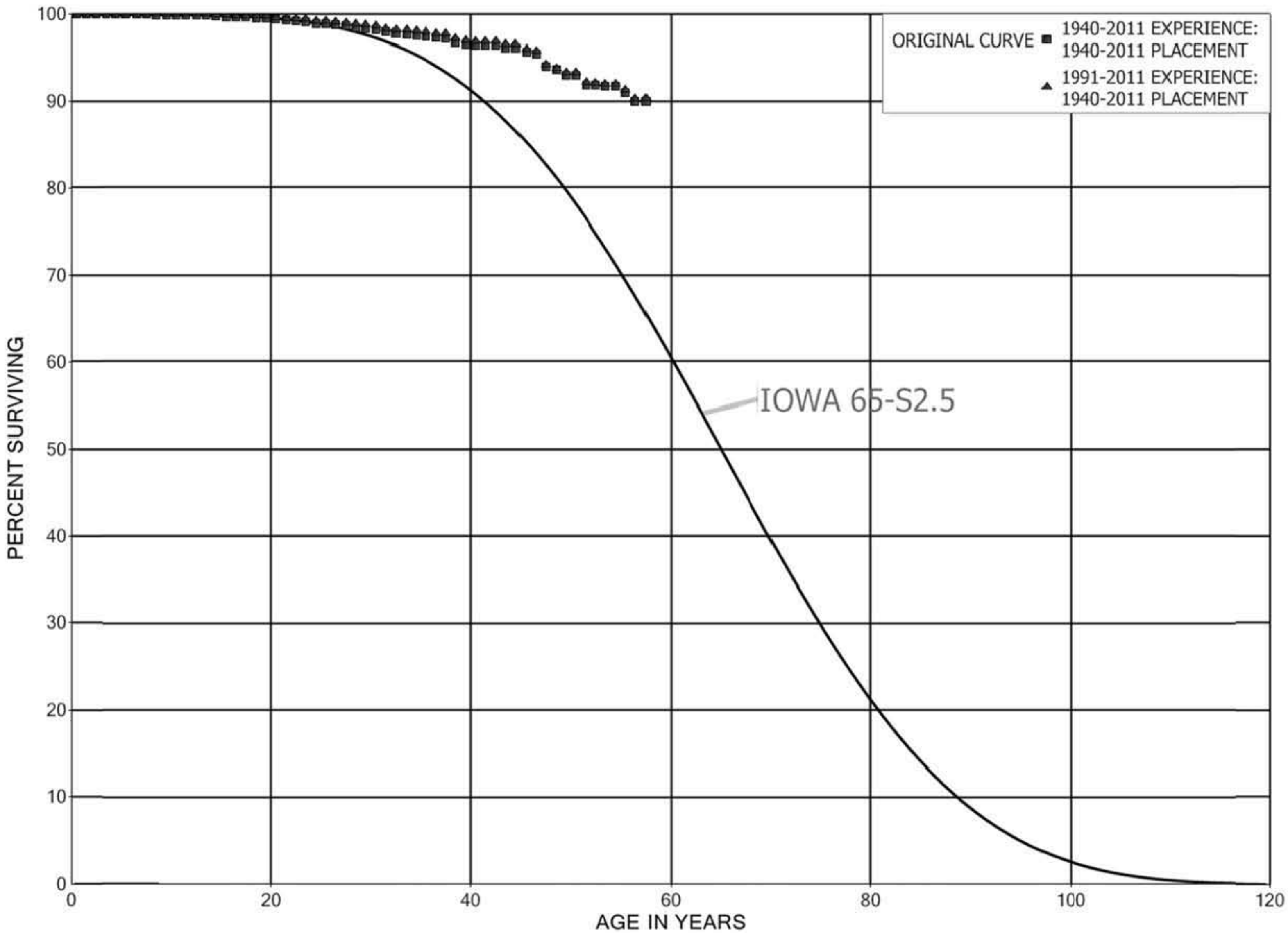
ACCOUNT 350.1 LAND RIGHTS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1941-2011 EXPERIENCE BAND 1991-2011

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	7,715,213		0.0000	1.0000	99.99
40.5	6,767,693		0.0000	1.0000	99.99
41.5	5,344,271		0.0000	1.0000	99.99
42.5	4,975,454	361	0.0001	0.9999	99.99
43.5	4,911,968		0.0000	1.0000	99.98
44.5	4,339,232		0.0000	1.0000	99.98
45.5	3,928,680		0.0000	1.0000	99.98
46.5	3,641,906		0.0000	1.0000	99.98
47.5	3,549,841		0.0000	1.0000	99.98
48.5	3,120,192		0.0000	1.0000	99.98
49.5	3,888,922		0.0000	1.0000	99.98
50.5	3,530,709		0.0000	1.0000	99.98
51.5	3,267,275		0.0000	1.0000	99.98
52.5	3,040,442		0.0000	1.0000	99.98
53.5	2,666,928		0.0000	1.0000	99.98
54.5	2,634,749		0.0000	1.0000	99.98
55.5	2,375,299		0.0000	1.0000	99.98
56.5	2,289,385		0.0000	1.0000	99.98
57.5	2,180,564		0.0000	1.0000	99.98
58.5	1,771,258		0.0000	1.0000	99.98
59.5	1,585,210		0.0000	1.0000	99.98
60.5	1,480,421		0.0000	1.0000	99.98
61.5	1,457,872		0.0000	1.0000	99.98
62.5	1,229,528		0.0000	1.0000	99.98
63.5	1,196,251		0.0000	1.0000	99.98
64.5	1,130,721		0.0000	1.0000	99.98
65.5	1,091,892		0.0000	1.0000	99.98
66.5	1,078,118		0.0000	1.0000	99.98
67.5	714,530		0.0000	1.0000	99.98
68.5	713,453		0.0000	1.0000	99.98
69.5	686,361		0.0000	1.0000	99.98
70.5					99.98

KENTUCKY UTILITIES COMPANY
ACCOUNT 352.1 STRUCTURES AND IMPROVEMENTS
ORIGINAL AND SMOOTH SURVIVOR CURVES



KENTUCKY UTILITIES COMPANY

ACCOUNT 352.1 STRUCTURES AND IMPROVEMENTS

ORIGINAL LIFE TABLE

PLACEMENT BAND 1940-2011 EXPERIENCE BAND 1940-2011

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	17,157,495		0.0000	1.0000	100.00
0.5	15,291,742	672	0.0000	1.0000	100.00
1.5	15,160,507	2,012	0.0001	0.9999	100.00
2.5	12,805,638	298	0.0000	1.0000	99.98
3.5	7,436,808		0.0000	1.0000	99.98
4.5	7,237,142	1,769	0.0002	0.9998	99.98
5.5	7,235,373		0.0000	1.0000	99.96
6.5	7,036,169	3,840	0.0005	0.9995	99.96
7.5	6,738,802	1,044	0.0002	0.9998	99.90
8.5	6,699,163	1,529	0.0002	0.9998	99.89
9.5	6,615,648	1,583	0.0002	0.9998	99.86
10.5	6,460,201	1,778	0.0003	0.9997	99.84
11.5	6,254,263	1,397	0.0002	0.9998	99.81
12.5	6,222,753	181	0.0000	1.0000	99.79
13.5	5,589,252	3,835	0.0007	0.9993	99.79
14.5	5,475,662	3,541	0.0006	0.9994	99.72
15.5	5,371,000	3,223	0.0006	0.9994	99.65
16.5	4,887,795	59	0.0000	1.0000	99.59
17.5	4,587,405	3,034	0.0007	0.9993	99.59
18.5	4,476,228	245	0.0001	0.9999	99.53
19.5	4,330,486	6,349	0.0015	0.9985	99.52
20.5	4,316,435	5,308	0.0012	0.9988	99.38
21.5	4,139,213	3,300	0.0008	0.9992	99.25
22.5	4,124,398	2,353	0.0006	0.9994	99.17
23.5	4,007,691	9,270	0.0023	0.9977	99.12
24.5	3,871,680	3,077	0.0008	0.9992	98.89
25.5	3,815,546	3,894	0.0010	0.9990	98.81
26.5	3,671,359	4,714	0.0013	0.9987	98.71
27.5	3,448,896	6,585	0.0019	0.9981	98.58
28.5	3,009,920	2,964	0.0010	0.9990	98.39
29.5	2,299,654	2,812	0.0012	0.9988	98.30
30.5	2,193,812	6,341	0.0029	0.9971	98.18
31.5	1,962,056	3,538	0.0018	0.9982	97.89
32.5	1,744,837	2,135	0.0012	0.9988	97.72
33.5	1,530,593	1,396	0.0009	0.9991	97.60
34.5	1,296,923	1,058	0.0008	0.9992	97.51
35.5	1,252,036	2,340	0.0019	0.9981	97.43
36.5	1,161,491	634	0.0005	0.9995	97.25
37.5	1,122,368	5,324	0.0047	0.9953	97.19
38.5	1,090,918	2,295	0.0021	0.9979	96.73

KENTUCKY UTILITIES COMPANY

ACCOUNT 352.1 STRUCTURES AND IMPROVEMENTS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1940-2011 EXPERIENCE BAND 1940-2011

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	889,528	957	0.0011	0.9989	96.53
40.5	762,076	132	0.0002	0.9998	96.42
41.5	688,750	132	0.0002	0.9998	96.41
42.5	644,261	1,808	0.0028	0.9972	96.39
43.5	628,652	250	0.0004	0.9996	96.12
44.5	615,535	2,808	0.0046	0.9954	96.08
45.5	561,257	1,519	0.0027	0.9973	95.64
46.5	517,922	7,693	0.0149	0.9851	95.38
47.5	464,647	1,854	0.0040	0.9960	93.97
48.5	450,948	2,981	0.0066	0.9934	93.59
49.5	435,415		0.0000	1.0000	92.97
50.5	418,246	4,921	0.0118	0.9882	92.97
51.5	376,055	118	0.0003	0.9997	91.88
52.5	338,190	513	0.0015	0.9985	91.85
53.5	286,065		0.0000	1.0000	91.71
54.5	272,225	2,120	0.0078	0.9922	91.71
55.5	233,553	2,583	0.0111	0.9889	91.00
56.5	215,514		0.0000	1.0000	89.99
57.5	169,512		0.0000	1.0000	89.99
58.5	141,370		0.0000	1.0000	89.99
59.5	139,315	1,143	0.0082	0.9918	89.99
60.5	112,026		0.0000	1.0000	89.25
61.5	89,644		0.0000	1.0000	89.25
62.5	62,042		0.0000	1.0000	89.25
63.5	60,641	2,062	0.0340	0.9660	89.25
64.5	55,356		0.0000	1.0000	86.22
65.5	55,137	1,244	0.0226	0.9774	86.22
66.5	53,893		0.0000	1.0000	84.27
67.5	53,893		0.0000	1.0000	84.27
68.5	53,893		0.0000	1.0000	84.27
69.5	53,893	1,207	0.0224	0.9776	84.27
70.5	8,529		0.0000	1.0000	82.38
71.5					82.38

KENTUCKY UTILITIES COMPANY

ACCOUNT 352.1 STRUCTURES AND IMPROVEMENTS

ORIGINAL LIFE TABLE

PLACEMENT BAND 1940-2011 EXPERIENCE BAND 1991-2011

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	12,815,687		0.0000	1.0000	100.00
0.5	11,121,847		0.0000	1.0000	100.00
1.5	11,002,800	13	0.0000	1.0000	100.00
2.5	8,764,283		0.0000	1.0000	100.00
3.5	3,522,492		0.0000	1.0000	100.00
4.5	3,384,988	1,339	0.0004	0.9996	100.00
5.5	3,523,942		0.0000	1.0000	99.96
6.5	3,542,487		0.0000	1.0000	99.96
7.5	3,681,369		0.0000	1.0000	99.96
8.5	4,348,118	840	0.0002	0.9998	99.96
9.5	4,370,140		0.0000	1.0000	99.94
10.5	4,442,533		0.0000	1.0000	99.94
11.5	4,464,132		0.0000	1.0000	99.94
12.5	4,647,286	181	0.0000	1.0000	99.94
13.5	4,246,059	3,367	0.0008	0.9992	99.94
14.5	4,178,093	529	0.0001	0.9999	99.86
15.5	4,165,876	2,845	0.0007	0.9993	99.85
16.5	3,721,537		0.0000	1.0000	99.78
17.5	3,450,163	1,873	0.0005	0.9995	99.78
18.5	3,541,670	245	0.0001	0.9999	99.72
19.5	3,524,610	5,789	0.0016	0.9984	99.72
20.5	3,587,270	4,399	0.0012	0.9988	99.55
21.5	3,458,724	1,228	0.0004	0.9996	99.43
22.5	3,462,767		0.0000	1.0000	99.39
23.5	3,361,350	6,835	0.0020	0.9980	99.39
24.5	3,282,850	2,042	0.0006	0.9994	99.19
25.5	3,270,115	2,904	0.0009	0.9991	99.13
26.5	3,174,631	3,574	0.0011	0.9989	99.04
27.5	2,965,804	2,256	0.0008	0.9992	98.93
28.5	2,549,200	2,499	0.0010	0.9990	98.86
29.5	1,858,421	2,812	0.0015	0.9985	98.76
30.5	1,789,849	6,341	0.0035	0.9965	98.61
31.5	1,595,840	1,349	0.0008	0.9992	98.26
32.5	1,433,719		0.0000	1.0000	98.18
33.5	1,236,407	994	0.0008	0.9992	98.18
34.5	1,040,212	1,058	0.0010	0.9990	98.10
35.5	1,014,584	2,340	0.0023	0.9977	98.00
36.5	972,284	634	0.0007	0.9993	97.77
37.5	968,351	4,884	0.0050	0.9950	97.71
38.5	939,395	2,295	0.0024	0.9976	97.22

KENTUCKY UTILITIES COMPANY

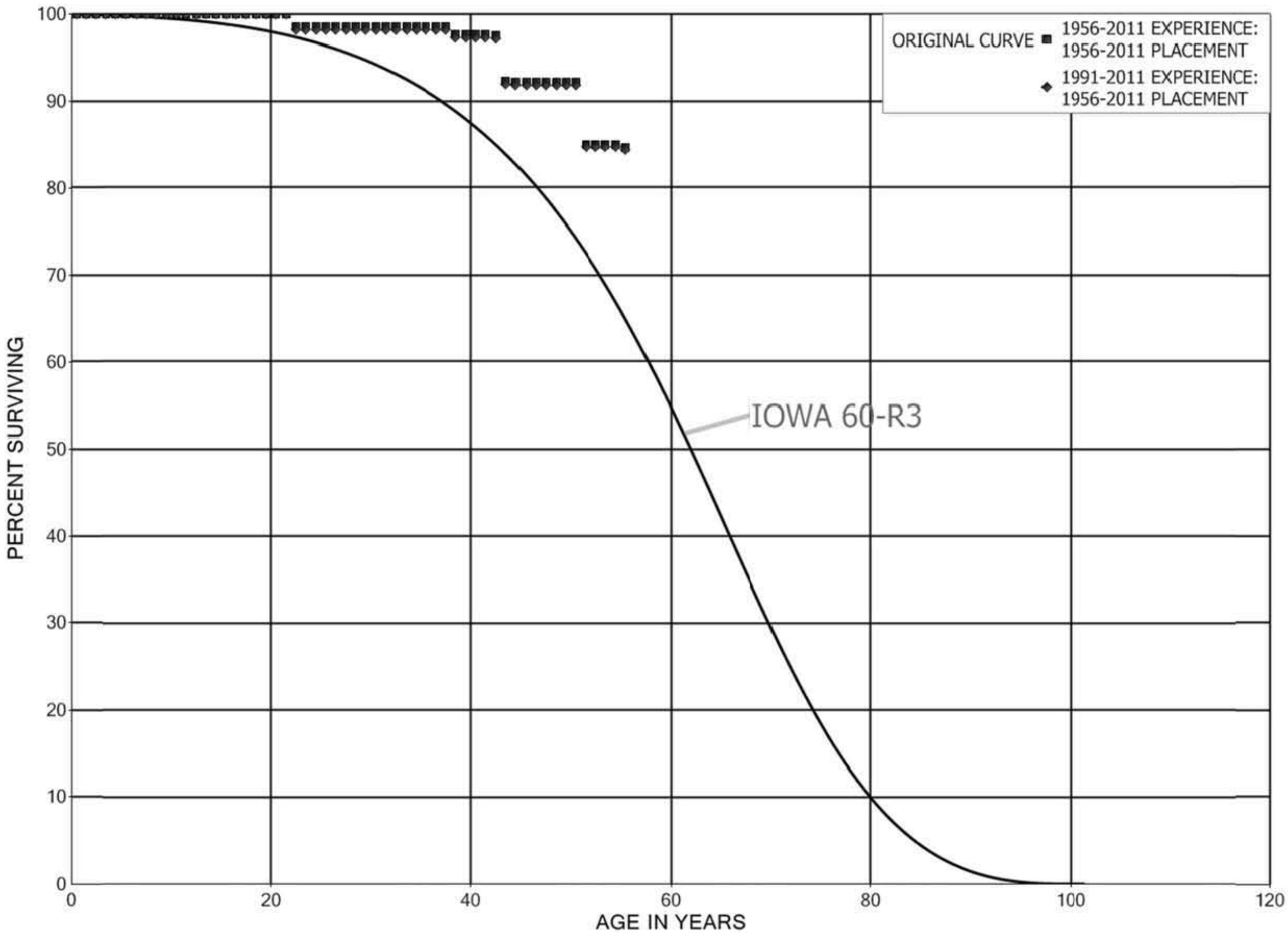
ACCOUNT 352.1 STRUCTURES AND IMPROVEMENTS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1940-2011 EXPERIENCE BAND 1991-2011

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	770,930	957	0.0012	0.9988	96.98
40.5	667,135	132	0.0002	0.9998	96.86
41.5	623,800	132	0.0002	0.9998	96.84
42.5	580,712	1,808	0.0031	0.9969	96.82
43.5	568,325	250	0.0004	0.9996	96.52
44.5	555,427	2,808	0.0051	0.9949	96.47
45.5	501,149	1,519	0.0030	0.9970	95.99
46.5	457,814	7,401	0.0162	0.9838	95.70
47.5	404,832	1,854	0.0046	0.9954	94.15
48.5	391,133	2,019	0.0052	0.9948	93.72
49.5	426,886		0.0000	1.0000	93.23
50.5	418,246	4,921	0.0118	0.9882	93.23
51.5	376,055	118	0.0003	0.9997	92.14
52.5	338,190	513	0.0015	0.9985	92.11
53.5	286,065		0.0000	1.0000	91.97
54.5	272,225	2,120	0.0078	0.9922	91.97
55.5	233,553	2,583	0.0111	0.9889	91.25
56.5	215,514		0.0000	1.0000	90.24
57.5	169,512		0.0000	1.0000	90.24
58.5	141,370		0.0000	1.0000	90.24
59.5	139,315	1,143	0.0082	0.9918	90.24
60.5	112,026		0.0000	1.0000	89.50
61.5	89,644		0.0000	1.0000	89.50
62.5	62,042		0.0000	1.0000	89.50
63.5	60,641	2,062	0.0340	0.9660	89.50
64.5	55,356		0.0000	1.0000	86.46
65.5	55,137	1,244	0.0226	0.9774	86.46
66.5	53,893		0.0000	1.0000	84.51
67.5	53,893		0.0000	1.0000	84.51
68.5	53,893		0.0000	1.0000	84.51
69.5	53,893	1,207	0.0224	0.9776	84.51
70.5	8,529		0.0000	1.0000	82.61
71.5					82.61

KENTUCKY UTILITIES COMPANY
ACCOUNT 352.2 STRUCTURES AND IMPROVEMENTS - SYS CONTROL/COM
ORIGINAL AND SMOOTH SURVIVOR CURVES



KENTUCKY UTILITIES COMPANY

ACCOUNT 352.2 STRUCTURES AND IMPROVEMENTS - SYS CONTROL/COM

ORIGINAL LIFE TABLE

PLACEMENT BAND 1956-2011 EXPERIENCE BAND 1956-2011

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	1,262,667		0.0000	1.0000	100.00
0.5	1,184,836		0.0000	1.0000	100.00
1.5	1,184,836		0.0000	1.0000	100.00
2.5	1,184,836		0.0000	1.0000	100.00
3.5	1,184,836		0.0000	1.0000	100.00
4.5	1,184,836		0.0000	1.0000	100.00
5.5	1,184,836		0.0000	1.0000	100.00
6.5	1,184,836		0.0000	1.0000	100.00
7.5	1,184,836		0.0000	1.0000	100.00
8.5	1,184,836		0.0000	1.0000	100.00
9.5	1,184,836		0.0000	1.0000	100.00
10.5	1,184,836		0.0000	1.0000	100.00
11.5	1,184,836		0.0000	1.0000	100.00
12.5	1,184,836		0.0000	1.0000	100.00
13.5	1,184,836		0.0000	1.0000	100.00
14.5	1,106,967		0.0000	1.0000	100.00
15.5	1,106,967		0.0000	1.0000	100.00
16.5	1,106,967		0.0000	1.0000	100.00
17.5	1,106,967		0.0000	1.0000	100.00
18.5	1,106,967		0.0000	1.0000	100.00
19.5	1,102,199		0.0000	1.0000	100.00
20.5	1,102,199		0.0000	1.0000	100.00
21.5	1,102,199	16,626	0.0151	0.9849	100.00
22.5	1,079,988		0.0000	1.0000	98.49
23.5	1,075,447		0.0000	1.0000	98.49
24.5	1,068,997		0.0000	1.0000	98.49
25.5	1,068,997		0.0000	1.0000	98.49
26.5	1,068,997		0.0000	1.0000	98.49
27.5	1,068,997		0.0000	1.0000	98.49
28.5	1,068,997		0.0000	1.0000	98.49
29.5	1,068,997		0.0000	1.0000	98.49
30.5	191,484		0.0000	1.0000	98.49
31.5	191,484		0.0000	1.0000	98.49
32.5	191,344		0.0000	1.0000	98.49
33.5	191,344		0.0000	1.0000	98.49
34.5	191,344		0.0000	1.0000	98.49
35.5	190,045		0.0000	1.0000	98.49
36.5	190,045		0.0000	1.0000	98.49
37.5	183,431	1,608	0.0088	0.9912	98.49
38.5	181,823		0.0000	1.0000	97.63

KENTUCKY UTILITIES COMPANY

ACCOUNT 352.2 STRUCTURES AND IMPROVEMENTS - SYS CONTROL/COM

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1956-2011 EXPERIENCE BAND 1956-2011

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	181,823		0.0000	1.0000	97.63
40.5	179,591		0.0000	1.0000	97.63
41.5	179,591	230	0.0013	0.9987	97.63
42.5	179,361	9,659	0.0539	0.9461	97.50
43.5	169,651	197	0.0012	0.9988	92.25
44.5	169,454		0.0000	1.0000	92.15
45.5	169,454		0.0000	1.0000	92.15
46.5	169,454		0.0000	1.0000	92.15
47.5	169,454		0.0000	1.0000	92.15
48.5	169,454		0.0000	1.0000	92.15
49.5	169,428		0.0000	1.0000	92.15
50.5	169,428	13,263	0.0783	0.9217	92.15
51.5	156,130		0.0000	1.0000	84.93
52.5	156,130		0.0000	1.0000	84.93
53.5	146,887		0.0000	1.0000	84.93
54.5	146,887	541	0.0037	0.9963	84.93
55.5					84.62

KENTUCKY UTILITIES COMPANY

ACCOUNT 352.2 STRUCTURES AND IMPROVEMENTS - SYS CONTROL/COM

ORIGINAL LIFE TABLE

PLACEMENT BAND 1956-2011 EXPERIENCE BAND 1991-2011

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	160,468		0.0000	1.0000	100.00
0.5	82,638		0.0000	1.0000	100.00
1.5	88,222		0.0000	1.0000	100.00
2.5	92,763		0.0000	1.0000	100.00
3.5	99,213		0.0000	1.0000	100.00
4.5	99,213		0.0000	1.0000	100.00
5.5	99,213		0.0000	1.0000	100.00
6.5	99,213		0.0000	1.0000	100.00
7.5	99,213		0.0000	1.0000	100.00
8.5	99,213		0.0000	1.0000	100.00
9.5	993,353		0.0000	1.0000	100.00
10.5	993,353		0.0000	1.0000	100.00
11.5	993,492		0.0000	1.0000	100.00
12.5	993,492		0.0000	1.0000	100.00
13.5	993,492		0.0000	1.0000	100.00
14.5	916,922		0.0000	1.0000	100.00
15.5	916,922		0.0000	1.0000	100.00
16.5	923,536		0.0000	1.0000	100.00
17.5	923,536		0.0000	1.0000	100.00
18.5	925,144		0.0000	1.0000	100.00
19.5	922,608		0.0000	1.0000	100.00
20.5	922,608		0.0000	1.0000	100.00
21.5	922,608	16,626	0.0180	0.9820	100.00
22.5	910,107		0.0000	1.0000	98.20
23.5	905,566		0.0000	1.0000	98.20
24.5	899,116		0.0000	1.0000	98.20
25.5	899,116		0.0000	1.0000	98.20
26.5	899,116		0.0000	1.0000	98.20
27.5	899,116		0.0000	1.0000	98.20
28.5	899,142		0.0000	1.0000	98.20
29.5	899,142		0.0000	1.0000	98.20
30.5	21,664		0.0000	1.0000	98.20
31.5	21,664		0.0000	1.0000	98.20
32.5	30,997		0.0000	1.0000	98.20
33.5	30,997		0.0000	1.0000	98.20
34.5	191,344		0.0000	1.0000	98.20
35.5	190,045		0.0000	1.0000	98.20
36.5	190,045		0.0000	1.0000	98.20
37.5	183,431	1,608	0.0088	0.9912	98.20
38.5	181,823		0.0000	1.0000	97.34

KENTUCKY UTILITIES COMPANY

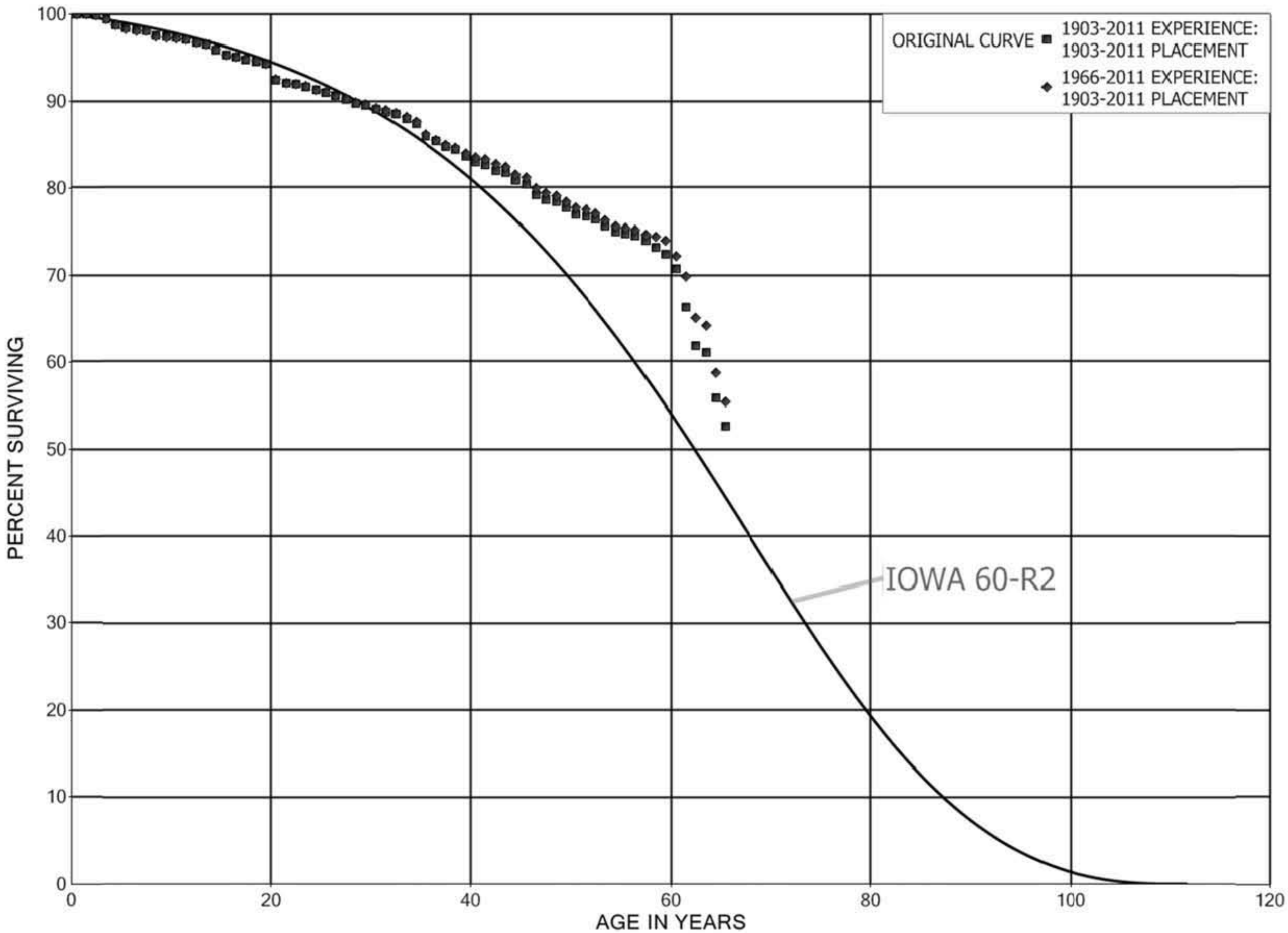
ACCOUNT 352.2 STRUCTURES AND IMPROVEMENTS - SYS CONTROL/COM

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1956-2011 EXPERIENCE BAND 1991-2011

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	181,823		0.0000	1.0000	97.34
40.5	179,591		0.0000	1.0000	97.34
41.5	179,591	230	0.0013	0.9987	97.34
42.5	179,361	9,659	0.0539	0.9461	97.21
43.5	169,651	197	0.0012	0.9988	91.98
44.5	169,454		0.0000	1.0000	91.87
45.5	169,454		0.0000	1.0000	91.87
46.5	169,454		0.0000	1.0000	91.87
47.5	169,454		0.0000	1.0000	91.87
48.5	169,454		0.0000	1.0000	91.87
49.5	169,428		0.0000	1.0000	91.87
50.5	169,428	13,263	0.0783	0.9217	91.87
51.5	156,130		0.0000	1.0000	84.68
52.5	156,130		0.0000	1.0000	84.68
53.5	146,887		0.0000	1.0000	84.68
54.5	146,887	541	0.0037	0.9963	84.68
55.5					84.37

KENTUCKY UTILITIES COMPANY
ACCOUNT 353.1 STATION EQUIPMENT
ORIGINAL AND SMOOTH SURVIVOR CURVES



KENTUCKY UTILITIES COMPANY

ACCOUNT 353.1 STATION EQUIPMENT

ORIGINAL LIFE TABLE

PLACEMENT BAND 1903-2011 EXPERIENCE BAND 1903-2011

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	237,868,416	30,785	0.0001	0.9999	100.00
0.5	226,275,327	101,546	0.0004	0.9996	99.99
1.5	206,539,441	133,440	0.0006	0.9994	99.94
2.5	195,438,139	845,462	0.0043	0.9957	99.88
3.5	187,951,203	1,302,915	0.0069	0.9931	99.45
4.5	182,289,390	708,423	0.0039	0.9961	98.76
5.5	174,341,561	406,857	0.0023	0.9977	98.37
6.5	169,876,847	89,060	0.0005	0.9995	98.14
7.5	168,110,734	1,036,894	0.0062	0.9938	98.09
8.5	150,516,043	98,527	0.0007	0.9993	97.49
9.5	142,901,626	259,240	0.0018	0.9982	97.42
10.5	141,301,054	205,228	0.0015	0.9985	97.25
11.5	137,710,705	552,522	0.0040	0.9960	97.10
12.5	136,028,238	284,574	0.0021	0.9979	96.71
13.5	130,914,291	847,353	0.0065	0.9935	96.51
14.5	125,419,045	830,664	0.0066	0.9934	95.89
15.5	122,045,962	206,134	0.0017	0.9983	95.25
16.5	116,232,288	409,194	0.0035	0.9965	95.09
17.5	114,175,710	280,974	0.0025	0.9975	94.76
18.5	111,516,806	291,319	0.0026	0.9974	94.52
19.5	103,966,852	2,062,543	0.0198	0.9802	94.28
20.5	100,961,248	392,200	0.0039	0.9961	92.41
21.5	98,885,193	118,230	0.0012	0.9988	92.05
22.5	96,328,611	324,509	0.0034	0.9966	91.94
23.5	93,158,111	388,316	0.0042	0.9958	91.63
24.5	92,175,556	285,640	0.0031	0.9969	91.25
25.5	88,874,175	379,814	0.0043	0.9957	90.96
26.5	81,530,891	383,073	0.0047	0.9953	90.57
27.5	76,560,065	344,486	0.0045	0.9955	90.15
28.5	74,616,849	191,537	0.0026	0.9974	89.74
29.5	64,155,190	289,906	0.0045	0.9955	89.51
30.5	60,528,939	239,253	0.0040	0.9960	89.11
31.5	52,517,041	175,102	0.0033	0.9967	88.76
32.5	48,487,414	258,818	0.0053	0.9947	88.46
33.5	44,722,125	274,757	0.0061	0.9939	87.99
34.5	36,423,838	626,046	0.0172	0.9828	87.45
35.5	35,257,353	246,506	0.0070	0.9930	85.94
36.5	33,656,744	233,651	0.0069	0.9931	85.34
37.5	30,827,649	144,240	0.0047	0.9953	84.75
38.5	29,590,721	262,013	0.0089	0.9911	84.35

KENTUCKY UTILITIES COMPANY

ACCOUNT 353.1 STATION EQUIPMENT

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1903-2011 EXPERIENCE BAND 1903-2011

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	27,644,770	234,205	0.0085	0.9915	83.61
40.5	24,255,491	75,767	0.0031	0.9969	82.90
41.5	21,899,096	171,824	0.0078	0.9922	82.64
42.5	18,863,559	71,694	0.0038	0.9962	81.99
43.5	18,335,896	201,265	0.0110	0.9890	81.68
44.5	17,848,526	81,372	0.0046	0.9954	80.78
45.5	16,940,784	261,139	0.0154	0.9846	80.42
46.5	15,382,342	101,596	0.0066	0.9934	79.18
47.5	14,084,137	55,445	0.0039	0.9961	78.65
48.5	13,030,600	100,944	0.0077	0.9923	78.34
49.5	12,615,104	122,542	0.0097	0.9903	77.74
50.5	11,972,153	32,851	0.0027	0.9973	76.98
51.5	11,224,884	60,835	0.0054	0.9946	76.77
52.5	10,538,841	105,643	0.0100	0.9900	76.35
53.5	10,330,986	87,859	0.0085	0.9915	75.59
54.5	8,654,978	26,874	0.0031	0.9969	74.95
55.5	6,785,122	16,544	0.0024	0.9976	74.71
56.5	5,424,241	39,292	0.0072	0.9928	74.53
57.5	4,758,923	53,269	0.0112	0.9888	73.99
58.5	2,517,920	26,673	0.0106	0.9894	73.16
59.5	1,973,321	43,860	0.0222	0.9778	72.39
60.5	1,501,784	94,810	0.0631	0.9369	70.78
61.5	719,956	49,015	0.0681	0.9319	66.31
62.5	204,660	2,590	0.0127	0.9873	61.80
63.5	182,402	15,628	0.0857	0.9143	61.01
64.5	142,455	8,038	0.0564	0.9436	55.79
65.5	110,743	124	0.0011	0.9989	52.64
66.5	93,311		0.0000	1.0000	52.58
67.5	89,744	1,412	0.0157	0.9843	52.58
68.5	80,799		0.0000	1.0000	51.75
69.5	77,613	1,051	0.0135	0.9865	51.75
70.5	39,962	0	0.0000	1.0000	51.05
71.5	39,346		0.0000	1.0000	51.05
72.5	39,346		0.0000	1.0000	51.05
73.5	39,346		0.0000	1.0000	51.05
74.5	39,346		0.0000	1.0000	51.05
75.5	39,346		0.0000	1.0000	51.05
76.5	39,346		0.0000	1.0000	51.05
77.5	39,346		0.0000	1.0000	51.05
78.5	39,346		0.0000	1.0000	51.05

KENTUCKY UTILITIES COMPANY

ACCOUNT 353.1 STATION EQUIPMENT

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1903-2011 EXPERIENCE BAND 1903-2011

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
79.5	39,346		0.0000	1.0000	51.05
80.5	39,346		0.0000	1.0000	51.05
81.5	39,346		0.0000	1.0000	51.05
82.5	21,560		0.0000	1.0000	51.05
83.5	21,560		0.0000	1.0000	51.05
84.5	21,560		0.0000	1.0000	51.05
85.5	21,560		0.0000	1.0000	51.05
86.5	21,560		0.0000	1.0000	51.05
87.5	21,560		0.0000	1.0000	51.05
88.5	21,560		0.0000	1.0000	51.05
89.5	21,560		0.0000	1.0000	51.05
90.5	21,560		0.0000	1.0000	51.05
91.5	21,560		0.0000	1.0000	51.05
92.5	21,560		0.0000	1.0000	51.05
93.5	21,560		0.0000	1.0000	51.05
94.5	21,560		0.0000	1.0000	51.05
95.5	21,560		0.0000	1.0000	51.05
96.5	21,560		0.0000	1.0000	51.05
97.5	183		0.0000	1.0000	51.05
98.5	183		0.0000	1.0000	51.05
99.5	183		0.0000	1.0000	51.05
100.5	183		0.0000	1.0000	51.05
101.5	183		0.0000	1.0000	51.05
102.5	183		0.0000	1.0000	51.05
103.5	183		0.0000	1.0000	51.05
104.5	183		0.0000	1.0000	51.05
105.5	183		0.0000	1.0000	51.05
106.5	183		0.0000	1.0000	51.05
107.5	183		0.0000	1.0000	51.05
108.5					51.05

KENTUCKY UTILITIES COMPANY

ACCOUNT 353.1 STATION EQUIPMENT

ORIGINAL LIFE TABLE

PLACEMENT BAND 1903-2011 EXPERIENCE BAND 1966-2011

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	217,174,704	21,282	0.0001	0.9999	100.00
0.5	206,977,353	92,209	0.0004	0.9996	99.99
1.5	188,810,969	117,036	0.0006	0.9994	99.95
2.5	179,034,546	812,902	0.0045	0.9955	99.88
3.5	171,968,739	1,281,951	0.0075	0.9925	99.43
4.5	166,994,442	680,113	0.0041	0.9959	98.69
5.5	159,865,680	378,192	0.0024	0.9976	98.29
6.5	156,176,870	65,042	0.0004	0.9996	98.05
7.5	155,114,650	994,143	0.0064	0.9936	98.01
8.5	139,313,631	69,520	0.0005	0.9995	97.39
9.5	133,345,383	196,169	0.0015	0.9985	97.34
10.5	133,287,505	155,664	0.0012	0.9988	97.19
11.5	131,192,085	536,079	0.0041	0.9959	97.08
12.5	131,823,753	267,083	0.0020	0.9980	96.68
13.5	126,890,933	768,438	0.0061	0.9939	96.49
14.5	122,045,728	807,908	0.0066	0.9934	95.90
15.5	119,940,489	199,959	0.0017	0.9983	95.27
16.5	114,632,029	370,583	0.0032	0.9968	95.11
17.5	112,701,888	268,136	0.0024	0.9976	94.80
18.5	110,156,859	285,871	0.0026	0.9974	94.58
19.5	102,640,526	2,046,435	0.0199	0.9801	94.33
20.5	99,668,641	390,150	0.0039	0.9961	92.45
21.5	97,598,315	107,641	0.0011	0.9989	92.09
22.5	95,099,692	316,318	0.0033	0.9967	91.99
23.5	91,948,933	383,674	0.0042	0.9958	91.68
24.5	91,187,727	276,128	0.0030	0.9970	91.30
25.5	87,899,888	366,398	0.0042	0.9958	91.02
26.5	80,570,048	361,484	0.0045	0.9955	90.64
27.5	75,620,810	322,285	0.0043	0.9957	90.24
28.5	73,699,796	184,358	0.0025	0.9975	89.85
29.5	63,245,316	280,104	0.0044	0.9956	89.63
30.5	59,628,866	221,508	0.0037	0.9963	89.23
31.5	51,634,714	161,354	0.0031	0.9969	88.90
32.5	47,618,835	248,877	0.0052	0.9948	88.62
33.5	43,863,487	249,815	0.0057	0.9943	88.16
34.5	35,590,142	606,106	0.0170	0.9830	87.66
35.5	34,443,715	246,256	0.0071	0.9929	86.16
36.5	32,861,143	223,114	0.0068	0.9932	85.55
37.5	30,049,629	142,287	0.0047	0.9953	84.97
38.5	28,814,654	216,735	0.0075	0.9925	84.56

KENTUCKY UTILITIES COMPANY

ACCOUNT 353.1 STATION EQUIPMENT

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1903-2011 EXPERIENCE BAND 1966-2011

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	26,913,981	132,205	0.0049	0.9951	83.93
40.5	23,626,702	52,592	0.0022	0.9978	83.51
41.5	21,686,601	170,036	0.0078	0.9922	83.33
42.5	18,667,392	53,754	0.0029	0.9971	82.68
43.5	18,157,669	199,242	0.0110	0.9890	82.44
44.5	17,672,322	81,372	0.0046	0.9954	81.53
45.5	16,764,580	261,137	0.0156	0.9844	81.16
46.5	15,206,139	101,596	0.0067	0.9933	79.89
47.5	13,907,934	55,445	0.0040	0.9960	79.36
48.5	12,854,397	100,944	0.0079	0.9921	79.04
49.5	12,438,901	116,035	0.0093	0.9907	78.42
50.5	11,802,458	32,851	0.0028	0.9972	77.69
51.5	11,076,566	60,835	0.0055	0.9945	77.47
52.5	10,390,523	105,643	0.0102	0.9898	77.05
53.5	10,182,668	87,859	0.0086	0.9914	76.27
54.5	8,506,660	26,874	0.0032	0.9968	75.61
55.5	6,636,804	16,544	0.0025	0.9975	75.37
56.5	5,275,923	39,292	0.0074	0.9926	75.18
57.5	4,610,605	12,627	0.0027	0.9973	74.62
58.5	2,410,245	16,651	0.0069	0.9931	74.42
59.5	1,875,668	43,860	0.0234	0.9766	73.90
60.5	1,404,131	46,142	0.0329	0.9671	72.17
61.5	719,773	49,015	0.0681	0.9319	69.80
62.5	204,660	2,590	0.0127	0.9873	65.05
63.5	182,402	15,628	0.0857	0.9143	64.23
64.5	142,455	8,038	0.0564	0.9436	58.72
65.5	110,743	124	0.0011	0.9989	55.41
66.5	93,311		0.0000	1.0000	55.35
67.5	89,744	1,412	0.0157	0.9843	55.35
68.5	80,799		0.0000	1.0000	54.48
69.5	77,613	1,051	0.0135	0.9865	54.48
70.5	39,962	0	0.0000	1.0000	53.74
71.5	39,346		0.0000	1.0000	53.74
72.5	39,346		0.0000	1.0000	53.74
73.5	39,346		0.0000	1.0000	53.74
74.5	39,346		0.0000	1.0000	53.74
75.5	39,346		0.0000	1.0000	53.74
76.5	39,346		0.0000	1.0000	53.74
77.5	39,346		0.0000	1.0000	53.74
78.5	39,346		0.0000	1.0000	53.74

KENTUCKY UTILITIES COMPANY

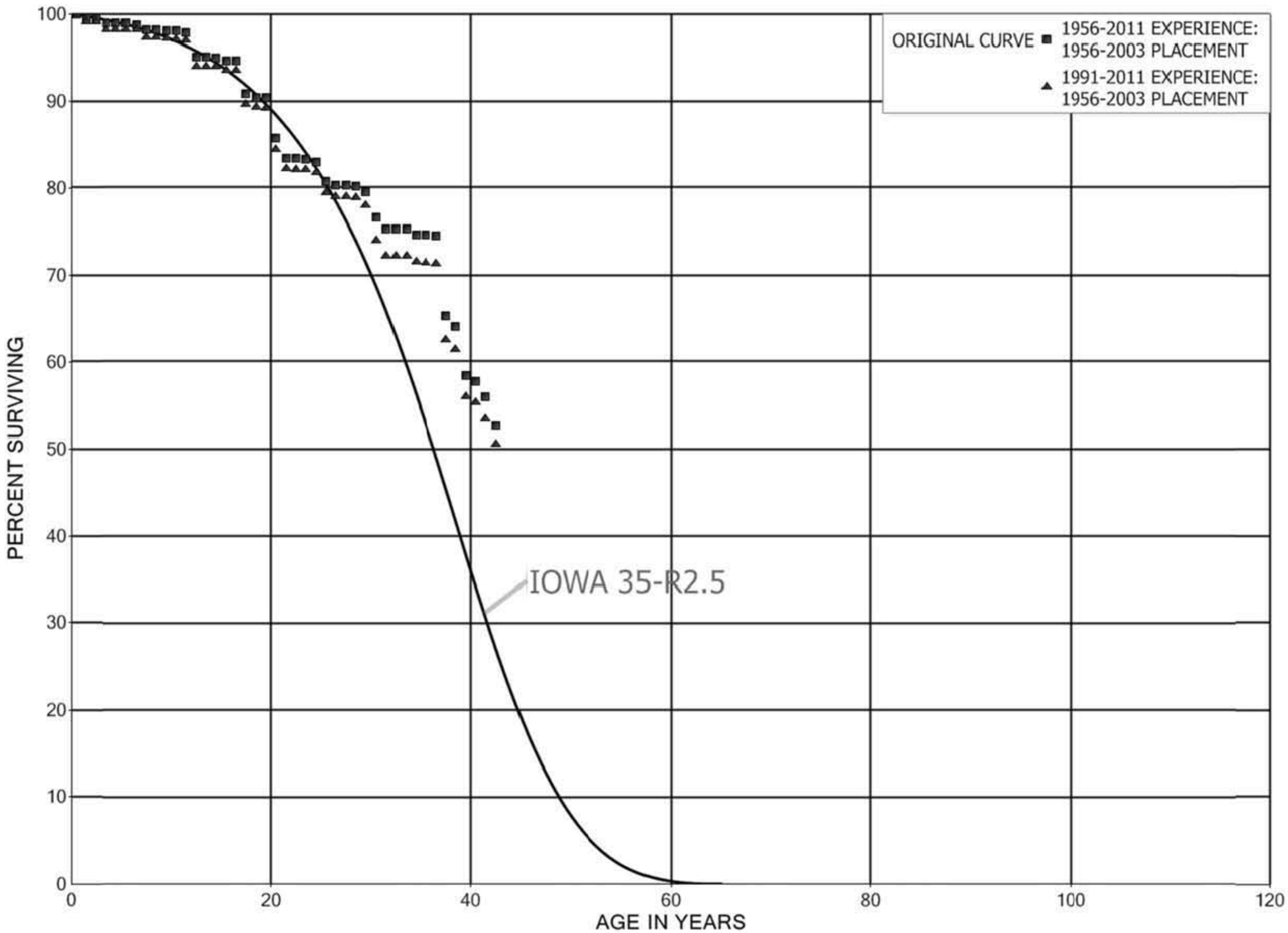
ACCOUNT 353.1 STATION EQUIPMENT

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1903-2011 EXPERIENCE BAND 1966-2011

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
79.5	39,346		0.0000	1.0000	53.74
80.5	39,346		0.0000	1.0000	53.74
81.5	39,346		0.0000	1.0000	53.74
82.5	21,560		0.0000	1.0000	53.74
83.5	21,560		0.0000	1.0000	53.74
84.5	21,560		0.0000	1.0000	53.74
85.5	21,560		0.0000	1.0000	53.74
86.5	21,560		0.0000	1.0000	53.74
87.5	21,560		0.0000	1.0000	53.74
88.5	21,560		0.0000	1.0000	53.74
89.5	21,560		0.0000	1.0000	53.74
90.5	21,560		0.0000	1.0000	53.74
91.5	21,560		0.0000	1.0000	53.74
92.5	21,560		0.0000	1.0000	53.74
93.5	21,560		0.0000	1.0000	53.74
94.5	21,560		0.0000	1.0000	53.74
95.5	21,560		0.0000	1.0000	53.74
96.5	21,560		0.0000	1.0000	53.74
97.5	183		0.0000	1.0000	53.74
98.5	183		0.0000	1.0000	53.74
99.5	183		0.0000	1.0000	53.74
100.5	183		0.0000	1.0000	53.74
101.5	183		0.0000	1.0000	53.74
102.5	183		0.0000	1.0000	53.74
103.5	183		0.0000	1.0000	53.74
104.5	183		0.0000	1.0000	53.74
105.5	183		0.0000	1.0000	53.74
106.5	183		0.0000	1.0000	53.74
107.5	183		0.0000	1.0000	53.74
108.5					53.74

KENTUCKY UTILITIES COMPANY
ACCOUNT 353.2 STATION EQUIPMENT - SYS CONTROL/COM
ORIGINAL AND SMOOTH SURVIVOR CURVES



KENTUCKY UTILITIES COMPANY

ACCOUNT 353.2 STATION EQUIPMENT - SYS CONTROL/COM

ORIGINAL LIFE TABLE

PLACEMENT BAND 1956-2003 EXPERIENCE BAND 1956-2011

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	16,685,849		0.0000	1.0000	100.00
0.5	16,634,687	87,826	0.0053	0.9947	100.00
1.5	17,481,399		0.0000	1.0000	99.47
2.5	17,490,214	85,124	0.0049	0.9951	99.47
3.5	17,405,090		0.0000	1.0000	98.99
4.5	17,405,090		0.0000	1.0000	98.99
5.5	17,395,221	37,858	0.0022	0.9978	98.99
6.5	17,357,363	104,426	0.0060	0.9940	98.77
7.5	17,252,937		0.0000	1.0000	98.18
8.5	16,842,332	19,327	0.0011	0.9989	98.18
9.5	16,413,284	5,635	0.0003	0.9997	98.07
10.5	16,268,096	29,159	0.0018	0.9982	98.03
11.5	13,257,892	373,179	0.0281	0.9719	97.86
12.5	12,566,272	4,219	0.0003	0.9997	95.10
13.5	10,888,941	7,003	0.0006	0.9994	95.07
14.5	9,655,736	38,113	0.0039	0.9961	95.01
15.5	9,521,782	1,272	0.0001	0.9999	94.63
16.5	8,580,860	342,279	0.0399	0.9601	94.62
17.5	7,178,221	33,697	0.0047	0.9953	90.85
18.5	7,137,231	569	0.0001	0.9999	90.42
19.5	6,603,707	344,038	0.0521	0.9479	90.41
20.5	6,042,240	161,094	0.0267	0.9733	85.70
21.5	5,855,438	2,646	0.0005	0.9995	83.42
22.5	5,850,115	2,830	0.0005	0.9995	83.38
23.5	5,417,335	22,217	0.0041	0.9959	83.34
24.5	5,395,118	148,646	0.0276	0.9724	83.00
25.5	5,246,472	30,057	0.0057	0.9943	80.71
26.5	5,176,545	577	0.0001	0.9999	80.25
27.5	4,563,801	1,961	0.0004	0.9996	80.24
28.5	437,681	3,981	0.0091	0.9909	80.21
29.5	432,225	15,802	0.0366	0.9634	79.48
30.5	415,406	6,928	0.0167	0.9833	76.57
31.5	369,684	160	0.0004	0.9996	75.29
32.5	364,646		0.0000	1.0000	75.26
33.5	347,268	2,737	0.0079	0.9921	75.26
34.5	342,819	388	0.0011	0.9989	74.67
35.5	324,530	212	0.0007	0.9993	74.58
36.5	166,822	20,742	0.1243	0.8757	74.53
37.5	125,146	2,218	0.0177	0.9823	65.27
38.5	122,928	10,928	0.0889	0.9111	64.11

KENTUCKY UTILITIES COMPANY

ACCOUNT 353.2 STATION EQUIPMENT - SYS CONTROL/COM

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1956-2003 EXPERIENCE BAND 1956-2011

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	111,721	1,308	0.0117	0.9883	58.41
40.5	109,818	3,386	0.0308	0.9692	57.73
41.5	106,036	6,102	0.0575	0.9425	55.95
42.5	85,400		0.0000	1.0000	52.73
43.5	85,400	3,296	0.0386	0.9614	52.73
44.5	82,105		0.0000	1.0000	50.69
45.5	81,978		0.0000	1.0000	50.69
46.5	77,347		0.0000	1.0000	50.69
47.5	76,827		0.0000	1.0000	50.69
48.5	76,809		0.0000	1.0000	50.69
49.5	76,809	135	0.0018	0.9982	50.69
50.5	76,674		0.0000	1.0000	50.60
51.5	76,674		0.0000	1.0000	50.60
52.5	76,005		0.0000	1.0000	50.60
53.5	54,819		0.0000	1.0000	50.60
54.5	50,714	3,304	0.0652	0.9348	50.60
55.5					47.31

KENTUCKY UTILITIES COMPANY

ACCOUNT 353.2 STATION EQUIPMENT - SYS CONTROL/COM

ORIGINAL LIFE TABLE

PLACEMENT BAND 1956-2003 EXPERIENCE BAND 1991-2011

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	9,205,074		0.0000	1.0000	100.00
0.5	9,180,895	87,826	0.0096	0.9904	100.00
1.5	10,158,182		0.0000	1.0000	99.04
2.5	10,355,599	85,124	0.0082	0.9918	99.04
3.5	10,272,796		0.0000	1.0000	98.23
4.5	10,310,667		0.0000	1.0000	98.23
5.5	10,808,659	7,438	0.0007	0.9993	98.23
6.5	11,414,199	104,426	0.0091	0.9909	98.16
7.5	15,835,608		0.0000	1.0000	97.26
8.5	15,434,127	19,327	0.0013	0.9987	97.26
9.5	15,009,939	5,635	0.0004	0.9996	97.14
10.5	15,206,574	29,159	0.0019	0.9981	97.11
11.5	12,210,560	373,179	0.0306	0.9694	96.92
12.5	11,536,611	3,650	0.0003	0.9997	93.96
13.5	9,861,561	3,607	0.0004	0.9996	93.93
14.5	8,652,966	36,975	0.0043	0.9957	93.89
15.5	9,111,213	1,272	0.0001	0.9999	93.49
16.5	8,390,349	342,279	0.0408	0.9592	93.48
17.5	6,987,710	33,697	0.0048	0.9952	89.67
18.5	6,949,829	569	0.0001	0.9999	89.23
19.5	6,421,642	344,038	0.0536	0.9464	89.23
20.5	5,878,072	161,094	0.0274	0.9726	84.45
21.5	5,713,462	2,646	0.0005	0.9995	82.13
22.5	5,708,389	2,830	0.0005	0.9995	82.09
23.5	5,277,570	22,217	0.0042	0.9958	82.05
24.5	5,263,028	148,646	0.0282	0.9718	81.71
25.5	5,123,109	30,057	0.0059	0.9941	79.40
26.5	5,053,702	577	0.0001	0.9999	78.93
27.5	4,440,975	1,961	0.0004	0.9996	78.92
28.5	314,856	3,981	0.0126	0.9874	78.89
29.5	309,400	15,802	0.0511	0.9489	77.89
30.5	292,581	6,928	0.0237	0.9763	73.91
31.5	251,096		0.0000	1.0000	72.16
32.5	294,248		0.0000	1.0000	72.16
33.5	282,633	2,737	0.0097	0.9903	72.16
34.5	342,819	388	0.0011	0.9989	71.46
35.5	324,530	212	0.0007	0.9993	71.38
36.5	166,822	20,742	0.1243	0.8757	71.34
37.5	125,146	2,218	0.0177	0.9823	62.47
38.5	122,928	10,928	0.0889	0.9111	61.36

KENTUCKY UTILITIES COMPANY

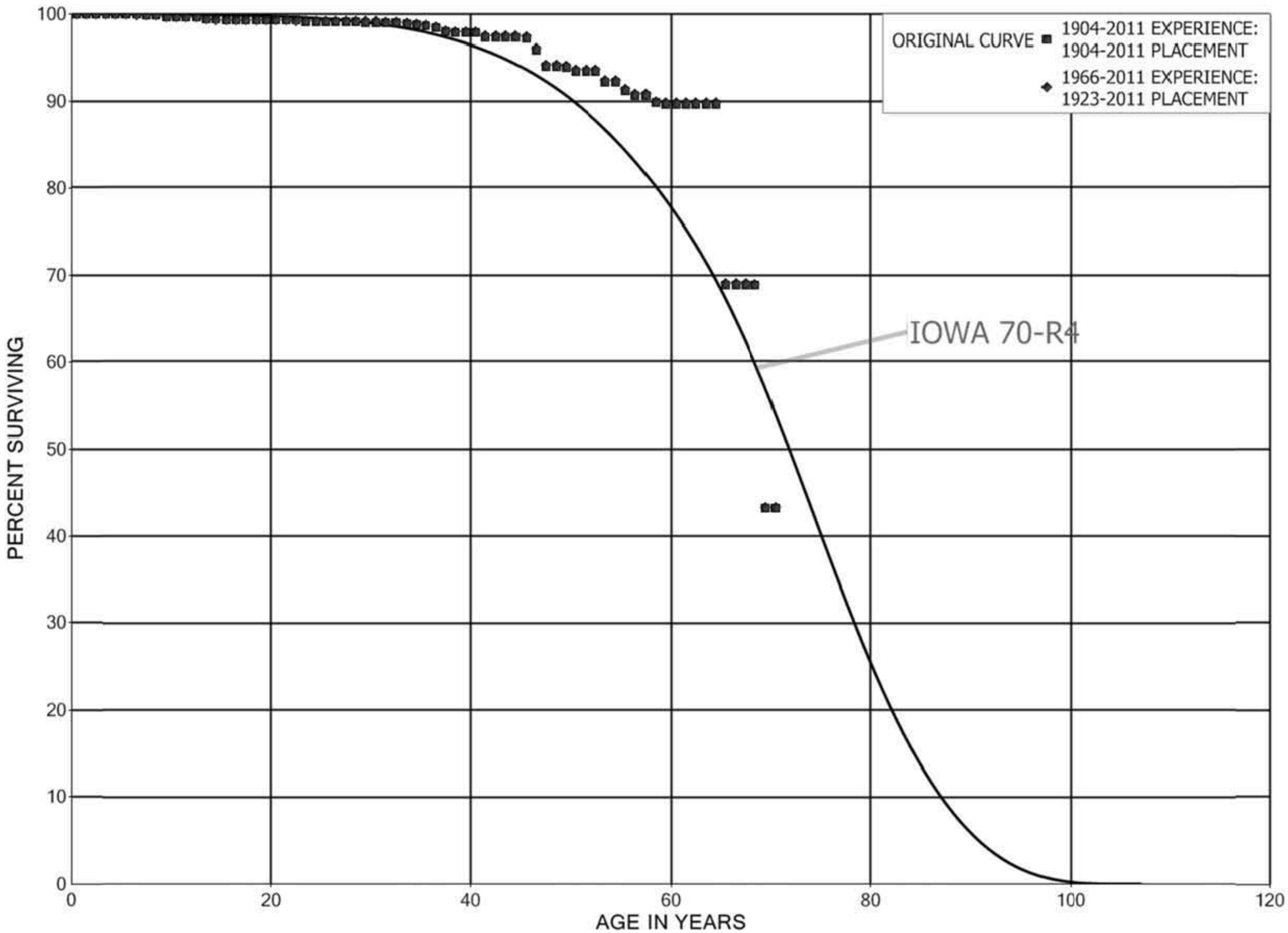
ACCOUNT 353.2 STATION EQUIPMENT - SYS CONTROL/COM

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1956-2003 EXPERIENCE BAND 1991-2011

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	111,721	1,308	0.0117	0.9883	55.91
40.5	109,818	3,386	0.0308	0.9692	55.25
41.5	106,036	6,102	0.0575	0.9425	53.55
42.5	85,400		0.0000	1.0000	50.47
43.5	85,400	3,296	0.0386	0.9614	50.47
44.5	82,105		0.0000	1.0000	48.52
45.5	81,978		0.0000	1.0000	48.52
46.5	77,347		0.0000	1.0000	48.52
47.5	76,827		0.0000	1.0000	48.52
48.5	76,809		0.0000	1.0000	48.52
49.5	76,809	135	0.0018	0.9982	48.52
50.5	76,674		0.0000	1.0000	48.43
51.5	76,674		0.0000	1.0000	48.43
52.5	76,005		0.0000	1.0000	48.43
53.5	54,819		0.0000	1.0000	48.43
54.5	50,714	3,304	0.0652	0.9348	48.43
55.5					45.28

KENTUCKY UTILITIES COMPANY
ACCOUNT 354 TOWERS AND FIXTURES
ORIGINAL AND SMOOTH SURVIVOR CURVES



KENTUCKY UTILITIES COMPANY

ACCOUNT 354 TOWERS AND FIXTURES

ORIGINAL LIFE TABLE

PLACEMENT BAND 1904-2011 EXPERIENCE BAND 1904-2011

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	97,071,713	3,849	0.0000	1.0000	100.00
0.5	96,746,791	7,496	0.0001	0.9999	100.00
1.5	65,992,502	12,672	0.0002	0.9998	99.99
2.5	64,409,819	39,786	0.0006	0.9994	99.97
3.5	64,370,033		0.0000	1.0000	99.91
4.5	64,370,033	1,280	0.0000	1.0000	99.91
5.5	64,368,753	8,526	0.0001	0.9999	99.91
6.5	64,358,623	17,863	0.0003	0.9997	99.89
7.5	63,497,875	7,904	0.0001	0.9999	99.86
8.5	61,267,077	116,385	0.0019	0.9981	99.85
9.5	60,698,499	9,921	0.0002	0.9998	99.66
10.5	60,645,960	31,530	0.0005	0.9995	99.65
11.5	60,583,582		0.0000	1.0000	99.59
12.5	60,476,882	116,798	0.0019	0.9981	99.59
13.5	60,360,084	36,307	0.0006	0.9994	99.40
14.5	58,732,192	11,221	0.0002	0.9998	99.34
15.5	58,612,872		0.0000	1.0000	99.32
16.5	58,612,872	11,213	0.0002	0.9998	99.32
17.5	58,601,659	7,066	0.0001	0.9999	99.30
18.5	58,594,593	3,393	0.0001	0.9999	99.29
19.5	58,535,412		0.0000	1.0000	99.29
20.5	58,535,412	10,354	0.0002	0.9998	99.29
21.5	58,286,783	22,318	0.0004	0.9996	99.27
22.5	56,759,598	93,753	0.0017	0.9983	99.23
23.5	56,642,148		0.0000	1.0000	99.07
24.5	54,789,115	3,651	0.0001	0.9999	99.07
25.5	52,897,269		0.0000	1.0000	99.06
26.5	48,432,399	4,643	0.0001	0.9999	99.06
27.5	38,475,226		0.0000	1.0000	99.05
28.5	38,470,864	16,006	0.0004	0.9996	99.05
29.5	31,994,300	1,881	0.0001	0.9999	99.01
30.5	31,833,994	15,553	0.0005	0.9995	99.00
31.5	19,286,149	4,765	0.0002	0.9998	98.96
32.5	19,108,674	26,301	0.0014	0.9986	98.93
33.5	13,280,462	12,839	0.0010	0.9990	98.79
34.5	12,297,553	9,002	0.0007	0.9993	98.70
35.5	11,805,080	32,297	0.0027	0.9973	98.63
36.5	11,581,341	49,331	0.0043	0.9957	98.36
37.5	11,244,110	6,741	0.0006	0.9994	97.94
38.5	10,259,746	8,203	0.0008	0.9992	97.88

KENTUCKY UTILITIES COMPANY

ACCOUNT 354 TOWERS AND FIXTURES

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1904-2011 EXPERIENCE BAND 1904-2011

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	9,979,562	763	0.0001	0.9999	97.80
40.5	8,648,705	46,872	0.0054	0.9946	97.79
41.5	6,151,599		0.0000	1.0000	97.26
42.5	5,615,105		0.0000	1.0000	97.26
43.5	5,615,105		0.0000	1.0000	97.26
44.5	5,474,609	3,349	0.0006	0.9994	97.26
45.5	5,398,702	77,541	0.0144	0.9856	97.20
46.5	5,261,636	102,475	0.0195	0.9805	95.81
47.5	5,075,369		0.0000	1.0000	93.94
48.5	4,729,440	6,281	0.0013	0.9987	93.94
49.5	4,425,271	17,763	0.0040	0.9960	93.82
50.5	3,638,131		0.0000	1.0000	93.44
51.5	3,621,786		0.0000	1.0000	93.44
52.5	3,604,007	47,252	0.0131	0.9869	93.44
53.5	2,545,050		0.0000	1.0000	92.22
54.5	2,545,050	28,851	0.0113	0.9887	92.22
55.5	2,490,832	14,449	0.0058	0.9942	91.17
56.5	2,470,652	600	0.0002	0.9998	90.64
57.5	2,463,825	22,374	0.0091	0.9909	90.62
58.5	2,390,022	3,388	0.0014	0.9986	89.80
59.5	2,386,634		0.0000	1.0000	89.67
60.5	2,366,146	1,281	0.0005	0.9995	89.67
61.5	2,364,865	908	0.0004	0.9996	89.62
62.5	994,374		0.0000	1.0000	89.59
63.5	994,374		0.0000	1.0000	89.59
64.5	994,374	230,162	0.2315	0.7685	89.59
65.5	764,212		0.0000	1.0000	68.85
66.5	764,212		0.0000	1.0000	68.85
67.5	758,811	536	0.0007	0.9993	68.85
68.5	758,275	282,246	0.3722	0.6278	68.80
69.5	474,641		0.0000	1.0000	43.19
70.5					43.19

KENTUCKY UTILITIES COMPANY

ACCOUNT 354 TOWERS AND FIXTURES

ORIGINAL LIFE TABLE

PLACEMENT BAND 1923-2011 EXPERIENCE BAND 1966-2011

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	91,327,565	3,849	0.0000	1.0000	100.00
0.5	91,068,280	7,496	0.0001	0.9999	100.00
1.5	60,411,985	12,672	0.0002	0.9998	99.99
2.5	59,312,875	39,786	0.0007	0.9993	99.97
3.5	59,569,851		0.0000	1.0000	99.90
4.5	60,417,998		0.0000	1.0000	99.90
5.5	60,434,059	6,100	0.0001	0.9999	99.90
6.5	60,449,830	17,863	0.0003	0.9997	99.89
7.5	60,673,161	7,904	0.0001	0.9999	99.86
8.5	58,442,363	116,385	0.0020	0.9980	99.85
9.5	57,901,465	9,921	0.0002	0.9998	99.65
10.5	57,854,657	31,530	0.0005	0.9995	99.63
11.5	57,792,279		0.0000	1.0000	99.58
12.5	57,762,210	116,798	0.0020	0.9980	99.58
13.5	57,645,412	36,159	0.0006	0.9994	99.38
14.5	56,040,021	11,221	0.0002	0.9998	99.31
15.5	55,933,332		0.0000	1.0000	99.29
16.5	57,364,761	11,213	0.0002	0.9998	99.29
17.5	57,359,276	7,066	0.0001	0.9999	99.27
18.5	57,356,975	3,393	0.0001	0.9999	99.26
19.5	57,297,794		0.0000	1.0000	99.26
20.5	57,297,794	10,354	0.0002	0.9998	99.26
21.5	57,049,165	22,318	0.0004	0.9996	99.24
22.5	55,521,980	7,714	0.0001	0.9999	99.20
23.5	55,498,184		0.0000	1.0000	99.19
24.5	54,754,729	3,651	0.0001	0.9999	99.19
25.5	52,862,883		0.0000	1.0000	99.18
26.5	48,398,013	3,851	0.0001	0.9999	99.18
27.5	38,441,632		0.0000	1.0000	99.17
28.5	38,437,270	16,006	0.0004	0.9996	99.17
29.5	31,960,706		0.0000	1.0000	99.13
30.5	31,802,281	15,091	0.0005	0.9995	99.13
31.5	19,254,898	4,765	0.0002	0.9998	99.08
32.5	19,077,423	26,301	0.0014	0.9986	99.06
33.5	13,249,211	12,839	0.0010	0.9990	98.92
34.5	12,266,302	8,973	0.0007	0.9993	98.83
35.5	11,773,858	32,297	0.0027	0.9973	98.75
36.5	11,550,119	49,139	0.0043	0.9957	98.48
37.5	11,213,080	6,741	0.0006	0.9994	98.06
38.5	10,228,716		0.0000	1.0000	98.00

KENTUCKY UTILITIES COMPANY

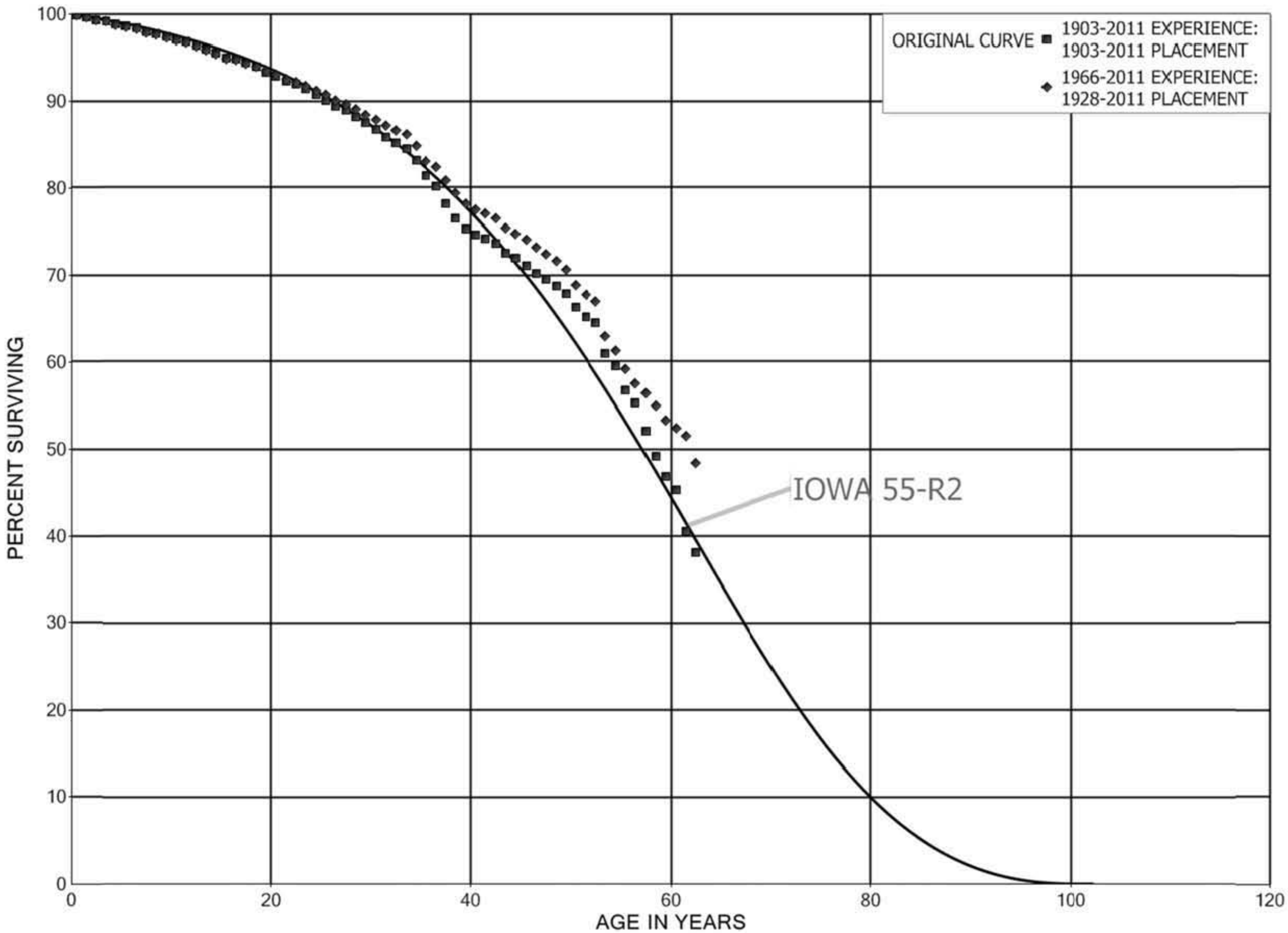
ACCOUNT 354 TOWERS AND FIXTURES

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1923-2011 EXPERIENCE BAND 1966-2011

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	9,971,345	763	0.0001	0.9999	98.00
40.5	8,640,488	46,219	0.0053	0.9947	98.00
41.5	6,147,464		0.0000	1.0000	97.47
42.5	5,613,904		0.0000	1.0000	97.47
43.5	5,613,904		0.0000	1.0000	97.47
44.5	5,473,408	3,349	0.0006	0.9994	97.47
45.5	5,397,501	77,541	0.0144	0.9856	97.41
46.5	5,260,435	102,475	0.0195	0.9805	96.01
47.5	5,074,168		0.0000	1.0000	94.14
48.5	4,728,239	6,281	0.0013	0.9987	94.14
49.5	4,424,070	17,763	0.0040	0.9960	94.02
50.5	3,636,930		0.0000	1.0000	93.64
51.5	3,620,585		0.0000	1.0000	93.64
52.5	3,602,806	47,252	0.0131	0.9869	93.64
53.5	2,543,849		0.0000	1.0000	92.41
54.5	2,543,849	28,851	0.0113	0.9887	92.41
55.5	2,489,631	14,449	0.0058	0.9942	91.36
56.5	2,469,451	600	0.0002	0.9998	90.83
57.5	2,462,624	22,374	0.0091	0.9909	90.81
58.5	2,388,821	3,388	0.0014	0.9986	89.99
59.5	2,385,433		0.0000	1.0000	89.86
60.5	2,364,945	80	0.0000	1.0000	89.86
61.5	2,364,865	908	0.0004	0.9996	89.86
62.5	994,374		0.0000	1.0000	89.82
63.5	994,374		0.0000	1.0000	89.82
64.5	994,374	230,162	0.2315	0.7685	89.82
65.5	764,212		0.0000	1.0000	69.03
66.5	764,212		0.0000	1.0000	69.03
67.5	758,811	536	0.0007	0.9993	69.03
68.5	758,275	282,246	0.3722	0.6278	68.98
69.5	474,641		0.0000	1.0000	43.31
70.5					43.31

KENTUCKY UTILITIES COMPANY
ACCOUNT 355 POLES AND FIXTURES
ORIGINAL AND SMOOTH SURVIVOR CURVES



KENTUCKY UTILITIES COMPANY

ACCOUNT 355 POLES AND FIXTURES

ORIGINAL LIFE TABLE

PLACEMENT BAND 1903-2011 EXPERIENCE BAND 1903-2011

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	165,369,083	286,182	0.0017	0.9983	100.00
0.5	157,028,830	354,142	0.0023	0.9977	99.83
1.5	128,258,507	423,251	0.0033	0.9967	99.60
2.5	112,141,657	137,284	0.0012	0.9988	99.27
3.5	110,099,172	411,421	0.0037	0.9963	99.15
4.5	101,914,291	202,713	0.0020	0.9980	98.78
5.5	98,670,300	237,696	0.0024	0.9976	98.58
6.5	91,367,098	373,591	0.0041	0.9959	98.35
7.5	89,183,299	228,381	0.0026	0.9974	97.94
8.5	82,501,108	254,818	0.0031	0.9969	97.69
9.5	80,718,145	257,390	0.0032	0.9968	97.39
10.5	76,805,791	216,030	0.0028	0.9972	97.08
11.5	75,349,700	327,597	0.0043	0.9957	96.81
12.5	71,421,774	311,696	0.0044	0.9956	96.39
13.5	68,804,456	326,565	0.0047	0.9953	95.97
14.5	65,539,519	376,464	0.0057	0.9943	95.51
15.5	61,791,465	115,616	0.0019	0.9981	94.96
16.5	58,622,749	252,062	0.0043	0.9957	94.79
17.5	56,787,867	239,202	0.0042	0.9958	94.38
18.5	55,740,719	382,206	0.0069	0.9931	93.98
19.5	52,795,387	267,745	0.0051	0.9949	93.34
20.5	50,961,371	328,336	0.0064	0.9936	92.86
21.5	48,794,406	195,139	0.0040	0.9960	92.26
22.5	46,136,314	240,595	0.0052	0.9948	91.90
23.5	43,363,548	349,172	0.0081	0.9919	91.42
24.5	42,367,423	264,960	0.0063	0.9937	90.68
25.5	38,434,410	296,298	0.0077	0.9923	90.11
26.5	36,477,548	213,319	0.0058	0.9942	89.42
27.5	33,859,578	276,989	0.0082	0.9918	88.90
28.5	32,067,407	250,259	0.0078	0.9922	88.17
29.5	30,317,725	280,646	0.0093	0.9907	87.48
30.5	27,859,989	282,057	0.0101	0.9899	86.67
31.5	26,305,614	183,583	0.0070	0.9930	85.79
32.5	24,735,300	187,464	0.0076	0.9924	85.19
33.5	23,081,348	381,385	0.0165	0.9835	84.55
34.5	21,923,649	462,787	0.0211	0.9789	83.15
35.5	19,633,412	301,794	0.0154	0.9846	81.40
36.5	18,299,091	445,067	0.0243	0.9757	80.14
37.5	16,682,732	361,214	0.0217	0.9783	78.20
38.5	13,665,607	221,564	0.0162	0.9838	76.50

KENTUCKY UTILITIES COMPANY

ACCOUNT 355 POLES AND FIXTURES

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1903-2011 EXPERIENCE BAND 1903-2011

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	12,225,314	111,163	0.0091	0.9909	75.26
40.5	11,448,382	70,278	0.0061	0.9939	74.58
41.5	10,531,831	68,374	0.0065	0.9935	74.12
42.5	8,741,030	129,062	0.0148	0.9852	73.64
43.5	8,345,032	69,393	0.0083	0.9917	72.55
44.5	7,406,814	94,483	0.0128	0.9872	71.95
45.5	6,696,878	82,178	0.0123	0.9877	71.03
46.5	5,891,000	57,599	0.0098	0.9902	70.16
47.5	5,399,020	56,668	0.0105	0.9895	69.47
48.5	4,709,722	59,142	0.0126	0.9874	68.74
49.5	4,377,821	105,116	0.0240	0.9760	67.88
50.5	3,848,868	63,712	0.0166	0.9834	66.25
51.5	3,379,804	31,164	0.0092	0.9908	65.15
52.5	2,848,774	161,357	0.0566	0.9434	64.55
53.5	2,233,737	51,530	0.0231	0.9769	60.90
54.5	2,058,516	96,330	0.0468	0.9532	59.49
55.5	1,712,246	41,532	0.0243	0.9757	56.71
56.5	1,380,938	80,419	0.0582	0.9418	55.33
57.5	1,260,480	69,916	0.0555	0.9445	52.11
58.5	795,611	37,798	0.0475	0.9525	49.22
59.5	637,882	21,059	0.0330	0.9670	46.88
60.5	446,444	47,603	0.1066	0.8934	45.33
61.5	373,359	22,795	0.0611	0.9389	40.50
62.5	263,576	4,311	0.0164	0.9836	38.03
63.5	242,029	8,314	0.0344	0.9656	37.41
64.5	160,190	7,286	0.0455	0.9545	36.12
65.5	145,184	4,775	0.0329	0.9671	34.48
66.5	135,188	3,252	0.0241	0.9759	33.34
67.5	97,600	4,308	0.0441	0.9559	32.54
68.5	83,242	2,064	0.0248	0.9752	31.11
69.5	53,991	271	0.0050	0.9950	30.33
70.5					30.18

KENTUCKY UTILITIES COMPANY

ACCOUNT 355 POLES AND FIXTURES

ORIGINAL LIFE TABLE

PLACEMENT BAND 1928-2011 EXPERIENCE BAND 1966-2011

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	152,610,872	277,976	0.0018	0.9982	100.00
0.5	145,231,488	336,661	0.0023	0.9977	99.82
1.5	117,008,473	412,318	0.0035	0.9965	99.59
2.5	101,890,761	116,791	0.0011	0.9989	99.24
3.5	100,373,995	398,213	0.0040	0.9960	99.12
4.5	92,886,551	183,437	0.0020	0.9980	98.73
5.5	90,274,265	220,361	0.0024	0.9976	98.53
6.5	83,671,493	358,153	0.0043	0.9957	98.29
7.5	82,255,620	214,689	0.0026	0.9974	97.87
8.5	75,860,995	239,988	0.0032	0.9968	97.62
9.5	74,691,110	246,297	0.0033	0.9967	97.31
10.5	71,417,518	205,194	0.0029	0.9971	96.99
11.5	70,155,555	316,936	0.0045	0.9955	96.71
12.5	67,368,938	294,952	0.0044	0.9956	96.27
13.5	65,124,314	297,334	0.0046	0.9954	95.85
14.5	62,200,302	357,991	0.0058	0.9942	95.41
15.5	58,572,693	90,069	0.0015	0.9985	94.86
16.5	55,628,610	234,337	0.0042	0.9958	94.72
17.5	54,017,048	186,025	0.0034	0.9966	94.32
18.5	53,331,261	307,519	0.0058	0.9942	93.99
19.5	50,748,675	223,850	0.0044	0.9956	93.45
20.5	48,996,852	285,468	0.0058	0.9942	93.04
21.5	46,888,108	153,918	0.0033	0.9967	92.50
22.5	44,296,505	206,411	0.0047	0.9953	92.19
23.5	41,613,543	274,827	0.0066	0.9934	91.76
24.5	40,835,924	209,412	0.0051	0.9949	91.16
25.5	36,958,459	262,867	0.0071	0.9929	90.69
26.5	35,035,028	172,502	0.0049	0.9951	90.05
27.5	32,457,875	206,238	0.0064	0.9936	89.60
28.5	30,736,455	206,008	0.0067	0.9933	89.03
29.5	29,071,735	193,030	0.0066	0.9934	88.44
30.5	26,722,583	219,735	0.0082	0.9918	87.85
31.5	25,234,469	140,156	0.0056	0.9944	87.13
32.5	23,748,331	137,472	0.0058	0.9942	86.64
33.5	22,144,371	336,697	0.0152	0.9848	86.14
34.5	21,087,786	429,077	0.0203	0.9797	84.83
35.5	18,978,140	172,525	0.0091	0.9909	83.11
36.5	17,818,063	338,681	0.0190	0.9810	82.35
37.5	16,321,935	280,785	0.0172	0.9828	80.78
38.5	13,385,239	207,084	0.0155	0.9845	79.39

KENTUCKY UTILITIES COMPANY

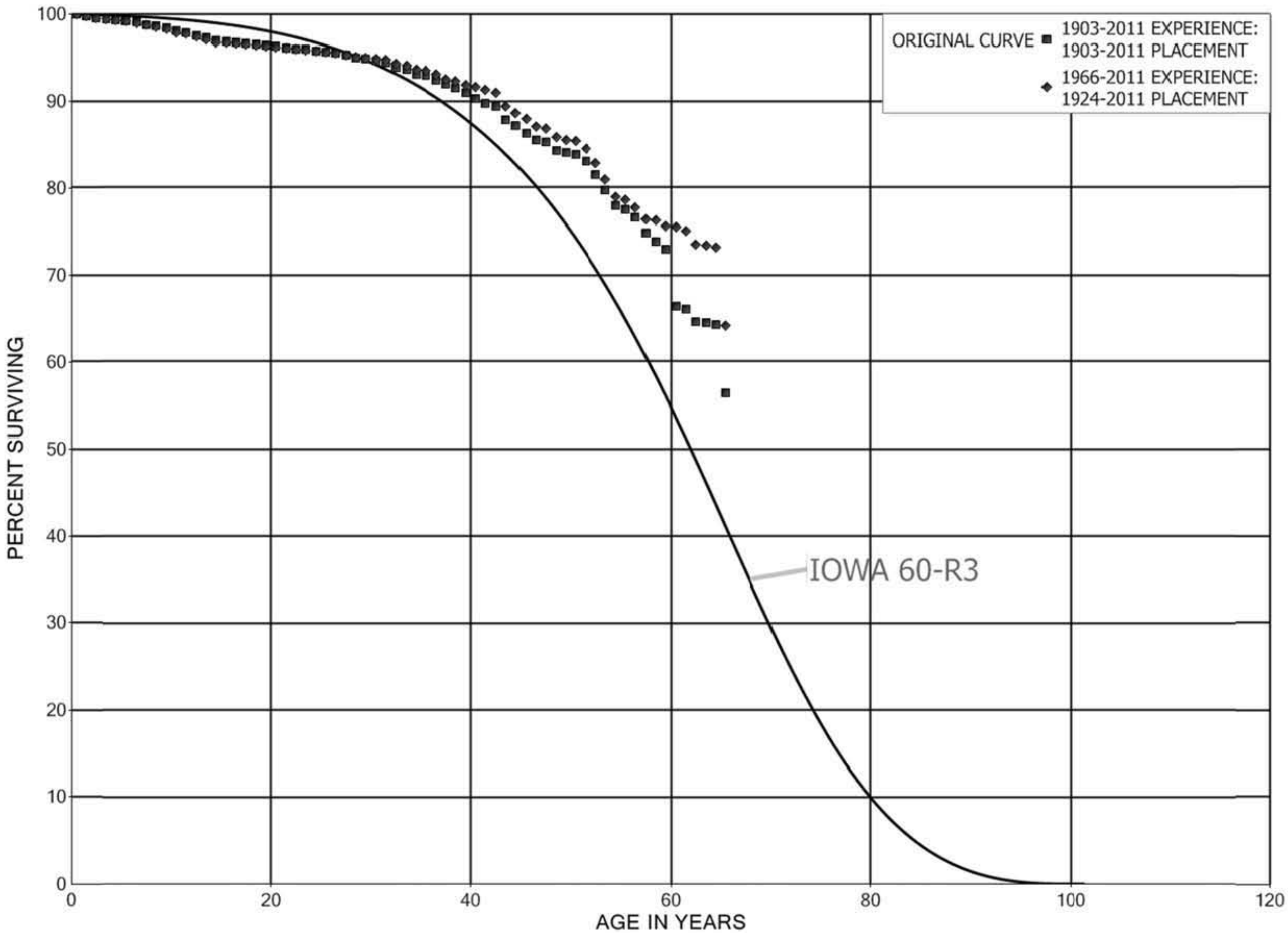
ACCOUNT 355 POLES AND FIXTURES

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1928-2011 EXPERIENCE BAND 1966-2011

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	11,959,426	101,425	0.0085	0.9915	78.17
40.5	11,192,232	69,145	0.0062	0.9938	77.50
41.5	10,276,814	62,868	0.0061	0.9939	77.02
42.5	8,491,519	127,619	0.0150	0.9850	76.55
43.5	8,096,964	67,189	0.0083	0.9917	75.40
44.5	7,160,950	66,417	0.0093	0.9907	74.78
45.5	6,479,080	82,178	0.0127	0.9873	74.08
46.5	5,673,202	57,599	0.0102	0.9898	73.14
47.5	5,181,222	56,668	0.0109	0.9891	72.40
48.5	4,491,924	59,142	0.0132	0.9868	71.61
49.5	4,160,023	105,116	0.0253	0.9747	70.67
50.5	3,631,070	63,712	0.0175	0.9825	68.88
51.5	3,162,006	31,164	0.0099	0.9901	67.67
52.5	2,630,976	161,357	0.0613	0.9387	67.01
53.5	2,015,939	51,530	0.0256	0.9744	62.90
54.5	1,840,718	65,077	0.0354	0.9646	61.29
55.5	1,525,701	41,532	0.0272	0.9728	59.12
56.5	1,194,393	23,674	0.0198	0.9802	57.51
57.5	1,130,680	27,550	0.0244	0.9756	56.37
58.5	708,177	22,085	0.0312	0.9688	55.00
59.5	566,161	9,672	0.0171	0.9829	53.28
60.5	386,110	6,096	0.0158	0.9842	52.37
61.5	373,359	22,795	0.0611	0.9389	51.55
62.5	263,576	4,311	0.0164	0.9836	48.40
63.5	242,029	8,314	0.0344	0.9656	47.61
64.5	160,190	7,286	0.0455	0.9545	45.97
65.5	145,184	4,775	0.0329	0.9671	43.88
66.5	135,188	3,252	0.0241	0.9759	42.44
67.5	97,600	4,308	0.0441	0.9559	41.42
68.5	83,242	2,064	0.0248	0.9752	39.59
69.5	53,991	271	0.0050	0.9950	38.61
70.5					38.41

KENTUCKY UTILITIES COMPANY
ACCOUNT 356 OVERHEAD CONDUCTORS AND DEVICES
ORIGINAL AND SMOOTH SURVIVOR CURVES



KENTUCKY UTILITIES COMPANY

ACCOUNT 356 OVERHEAD CONDUCTORS AND DEVICES

ORIGINAL LIFE TABLE

PLACEMENT BAND 1903-2011 EXPERIENCE BAND 1903-2011

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	175,135,576	136,238	0.0008	0.9992	100.00
0.5	169,726,893	314,855	0.0019	0.9981	99.92
1.5	149,111,910	327,111	0.0022	0.9978	99.74
2.5	143,508,380	135,342	0.0009	0.9991	99.52
3.5	142,519,077	174,117	0.0012	0.9988	99.42
4.5	140,276,434	106,502	0.0008	0.9992	99.30
5.5	138,813,737	235,658	0.0017	0.9983	99.23
6.5	135,208,807	403,708	0.0030	0.9970	99.06
7.5	133,716,964	251,164	0.0019	0.9981	98.76
8.5	129,092,695	300,057	0.0023	0.9977	98.58
9.5	127,884,022	433,669	0.0034	0.9966	98.35
10.5	124,300,764	212,086	0.0017	0.9983	98.01
11.5	122,159,331	398,219	0.0033	0.9967	97.85
12.5	120,135,360	325,577	0.0027	0.9973	97.53
13.5	118,148,745	392,616	0.0033	0.9967	97.26
14.5	116,571,395	108,651	0.0009	0.9991	96.94
15.5	114,371,323	90,763	0.0008	0.9992	96.85
16.5	111,069,672	162,677	0.0015	0.9985	96.77
17.5	109,613,605	135,258	0.0012	0.9988	96.63
18.5	109,099,056	118,835	0.0011	0.9989	96.51
19.5	106,925,610	172,772	0.0016	0.9984	96.41
20.5	105,813,010	151,583	0.0014	0.9986	96.25
21.5	104,280,865	131,246	0.0013	0.9987	96.11
22.5	103,243,282	109,946	0.0011	0.9989	95.99
23.5	101,349,560	175,208	0.0017	0.9983	95.89
24.5	93,011,710	135,119	0.0015	0.9985	95.73
25.5	87,660,312	116,770	0.0013	0.9987	95.59
26.5	83,818,978	163,167	0.0019	0.9981	95.46
27.5	76,157,083	232,621	0.0031	0.9969	95.27
28.5	74,157,425	88,324	0.0012	0.9988	94.98
29.5	67,930,542	200,518	0.0030	0.9970	94.87
30.5	63,446,178	159,957	0.0025	0.9975	94.59
31.5	51,836,444	274,218	0.0053	0.9947	94.35
32.5	49,527,943	133,913	0.0027	0.9973	93.85
33.5	43,206,255	255,629	0.0059	0.9941	93.60
34.5	41,259,659	67,652	0.0016	0.9984	93.04
35.5	38,578,354	187,293	0.0049	0.9951	92.89
36.5	36,981,181	208,877	0.0056	0.9944	92.44
37.5	35,752,637	146,566	0.0041	0.9959	91.92
38.5	32,322,270	219,259	0.0068	0.9932	91.54

KENTUCKY UTILITIES COMPANY

ACCOUNT 356 OVERHEAD CONDUCTORS AND DEVICES

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1903-2011 EXPERIENCE BAND 1903-2011

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	30,120,930	216,385	0.0072	0.9928	90.92
40.5	28,134,338	185,957	0.0066	0.9934	90.27
41.5	24,686,682	89,215	0.0036	0.9964	89.67
42.5	22,248,477	369,283	0.0166	0.9834	89.35
43.5	21,547,258	179,879	0.0083	0.9917	87.86
44.5	20,400,260	195,662	0.0096	0.9904	87.13
45.5	18,546,596	181,001	0.0098	0.9902	86.29
46.5	17,044,806	31,507	0.0018	0.9982	85.45
47.5	16,009,157	192,415	0.0120	0.9880	85.29
48.5	14,293,824	43,457	0.0030	0.9970	84.27
49.5	13,654,373	26,974	0.0020	0.9980	84.01
50.5	12,406,770	123,432	0.0099	0.9901	83.85
51.5	11,656,022	216,608	0.0186	0.9814	83.01
52.5	10,613,077	228,857	0.0216	0.9784	81.47
53.5	8,410,931	190,948	0.0227	0.9773	79.71
54.5	8,009,283	44,609	0.0056	0.9944	77.90
55.5	6,983,005	75,989	0.0109	0.9891	77.47
56.5	6,198,476	142,305	0.0230	0.9770	76.63
57.5	5,859,083	83,419	0.0142	0.9858	74.87
58.5	4,289,549	46,834	0.0109	0.9891	73.80
59.5	3,942,275	357,176	0.0906	0.9094	73.00
60.5	2,998,521	16,385	0.0055	0.9945	66.38
61.5	2,845,724	60,805	0.0214	0.9786	66.02
62.5	1,504,108	1,503	0.0010	0.9990	64.61
63.5	1,436,432	5,146	0.0036	0.9964	64.54
64.5	1,199,324	148,049	0.1234	0.8766	64.31
65.5	1,026,805	30,642	0.0298	0.9702	56.37
66.5	983,063	5,631	0.0057	0.9943	54.69
67.5	832,828	3,263	0.0039	0.9961	54.38
68.5	812,831	6,924	0.0085	0.9915	54.17
69.5	685,999	14,812	0.0216	0.9784	53.70
70.5					52.54

KENTUCKY UTILITIES COMPANY

ACCOUNT 356 OVERHEAD CONDUCTORS AND DEVICES

ORIGINAL LIFE TABLE

PLACEMENT BAND 1924-2011 EXPERIENCE BAND 1966-2011

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	151,967,390	132,867	0.0009	0.9991	100.00
0.5	148,041,805	304,468	0.0021	0.9979	99.91
1.5	128,555,586	319,015	0.0025	0.9975	99.71
2.5	124,835,637	121,874	0.0010	0.9990	99.46
3.5	124,661,263	165,934	0.0013	0.9987	99.36
4.5	123,790,740	89,048	0.0007	0.9993	99.23
5.5	123,061,239	226,363	0.0018	0.9982	99.16
6.5	120,349,673	366,367	0.0030	0.9970	98.98
7.5	121,020,253	235,301	0.0019	0.9981	98.68
8.5	116,695,202	290,385	0.0025	0.9975	98.48
9.5	116,621,261	415,677	0.0036	0.9964	98.24
10.5	114,004,202	205,916	0.0018	0.9982	97.89
11.5	112,202,142	386,419	0.0034	0.9966	97.71
12.5	112,213,490	314,243	0.0028	0.9972	97.37
13.5	110,625,777	383,822	0.0035	0.9965	97.10
14.5	109,700,895	104,134	0.0009	0.9991	96.77
15.5	107,743,102	79,573	0.0007	0.9993	96.67
16.5	105,982,293	133,946	0.0013	0.9987	96.60
17.5	104,751,322	109,182	0.0010	0.9990	96.48
18.5	104,662,141	90,957	0.0009	0.9991	96.38
19.5	102,579,977	163,450	0.0016	0.9984	96.30
20.5	101,504,448	124,302	0.0012	0.9988	96.14
21.5	100,015,206	121,280	0.0012	0.9988	96.02
22.5	99,008,287	99,126	0.0010	0.9990	95.91
23.5	97,424,231	132,507	0.0014	0.9986	95.81
24.5	90,362,223	100,487	0.0011	0.9989	95.68
25.5	85,045,457	89,812	0.0011	0.9989	95.58
26.5	81,231,081	137,321	0.0017	0.9983	95.47
27.5	73,595,032	169,857	0.0023	0.9977	95.31
28.5	71,658,138	67,196	0.0009	0.9991	95.09
29.5	65,452,383	83,799	0.0013	0.9987	95.00
30.5	61,084,738	103,053	0.0017	0.9983	94.88
31.5	49,531,908	242,599	0.0049	0.9951	94.72
32.5	47,255,026	88,540	0.0019	0.9981	94.26
33.5	40,978,711	217,844	0.0053	0.9947	94.08
34.5	39,069,900	49,498	0.0013	0.9987	93.58
35.5	36,555,889	174,405	0.0048	0.9952	93.46
36.5	35,107,423	181,036	0.0052	0.9948	93.02
37.5	34,042,009	105,000	0.0031	0.9969	92.54
38.5	30,990,605	130,358	0.0042	0.9958	92.25

KENTUCKY UTILITIES COMPANY

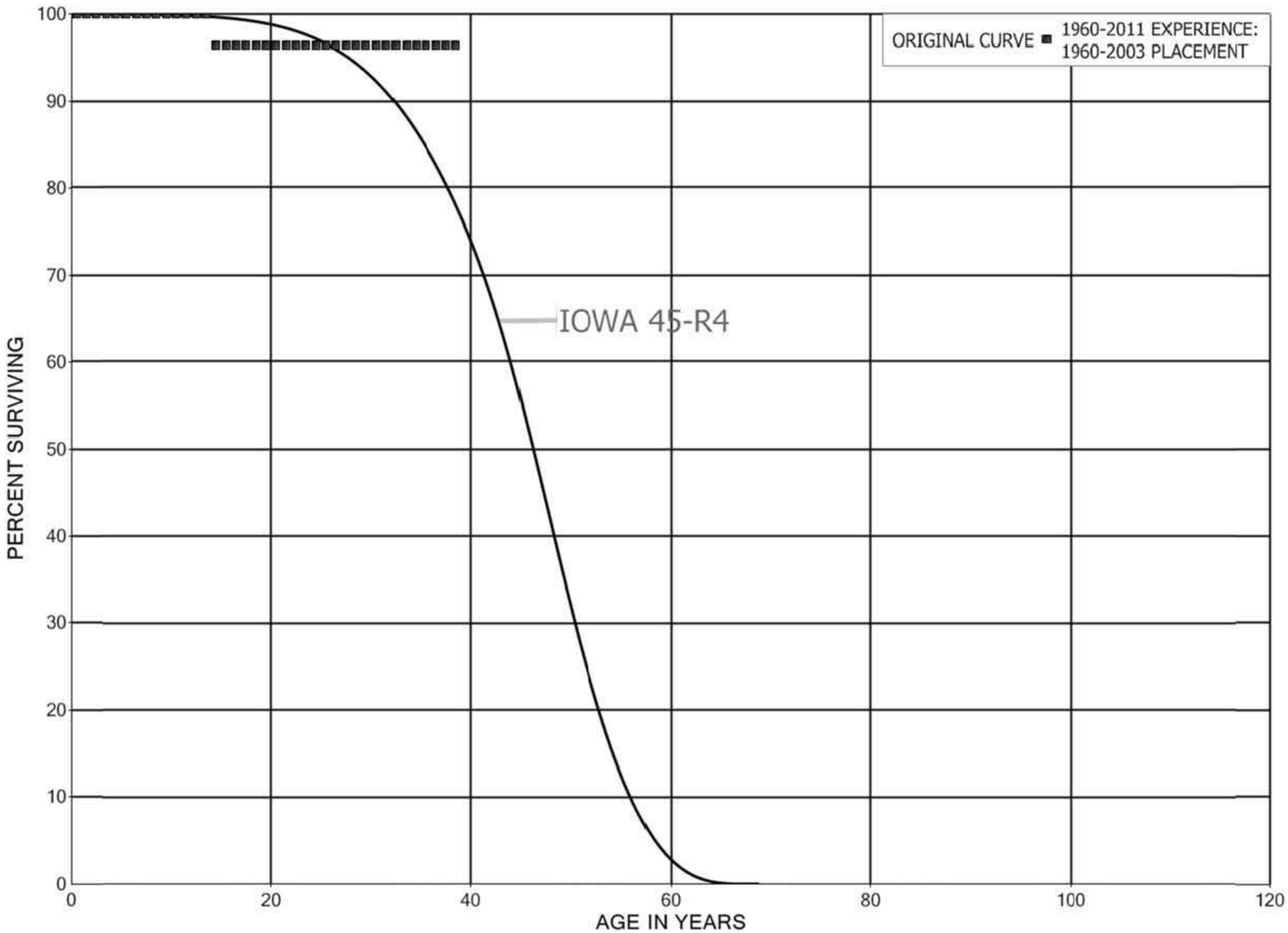
ACCOUNT 356 OVERHEAD CONDUCTORS AND DEVICES

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1924-2011 EXPERIENCE BAND 1966-2011

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	29,219,940	72,823	0.0025	0.9975	91.86
40.5	27,376,910	104,118	0.0038	0.9962	91.63
41.5	24,090,042	86,094	0.0036	0.9964	91.29
42.5	21,654,958	366,178	0.0169	0.9831	90.96
43.5	20,956,844	178,200	0.0085	0.9915	89.42
44.5	19,811,525	164,837	0.0083	0.9917	88.66
45.5	17,988,686	181,001	0.0101	0.9899	87.92
46.5	16,486,896	31,148	0.0019	0.9981	87.04
47.5	15,451,606	192,415	0.0125	0.9875	86.87
48.5	13,736,273	43,457	0.0032	0.9968	85.79
49.5	13,096,822	26,974	0.0021	0.9979	85.52
50.5	11,849,219	123,432	0.0104	0.9896	85.35
51.5	11,098,471	216,608	0.0195	0.9805	84.46
52.5	10,055,526	228,857	0.0228	0.9772	82.81
53.5	7,853,380	190,948	0.0243	0.9757	80.92
54.5	7,451,732	30,144	0.0040	0.9960	78.96
55.5	6,439,919	75,989	0.0118	0.9882	78.64
56.5	5,655,390	92,995	0.0164	0.9836	77.71
57.5	5,365,307	13,531	0.0025	0.9975	76.43
58.5	3,865,661	30,861	0.0080	0.9920	76.24
59.5	3,534,360	4,314	0.0012	0.9988	75.63
60.5	2,943,468	16,385	0.0056	0.9944	75.54
61.5	2,845,724	60,805	0.0214	0.9786	75.12
62.5	1,504,108	1,503	0.0010	0.9990	73.51
63.5	1,436,432	5,146	0.0036	0.9964	73.44
64.5	1,199,324	148,049	0.1234	0.8766	73.17
65.5	1,026,805	30,642	0.0298	0.9702	64.14
66.5	983,063	5,631	0.0057	0.9943	62.23
67.5	832,828	3,263	0.0039	0.9961	61.87
68.5	812,831	6,924	0.0085	0.9915	61.63
69.5	685,999	14,812	0.0216	0.9784	61.10
70.5					59.78

KENTUCKY UTILITIES COMPANY
ACCOUNT 357 UNDERGROUND CONDUIT
ORIGINAL AND SMOOTH SURVIVOR CURVES



KENTUCKY UTILITIES COMPANY

ACCOUNT 357 UNDERGROUND CONDUIT

ORIGINAL LIFE TABLE

PLACEMENT BAND 1960-2003 EXPERIENCE BAND 1960-2011

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	465,540		0.0000	1.0000	100.00
0.5	465,540		0.0000	1.0000	100.00
1.5	465,540		0.0000	1.0000	100.00
2.5	465,540		0.0000	1.0000	100.00
3.5	465,540		0.0000	1.0000	100.00
4.5	465,540		0.0000	1.0000	100.00
5.5	465,540		0.0000	1.0000	100.00
6.5	465,540		0.0000	1.0000	100.00
7.5	465,540		0.0000	1.0000	100.00
8.5	452,706		0.0000	1.0000	100.00
9.5	449,255		0.0000	1.0000	100.00
10.5	449,255		0.0000	1.0000	100.00
11.5	449,255		0.0000	1.0000	100.00
12.5	448,553		0.0000	1.0000	100.00
13.5	448,103	16,282	0.0363	0.9637	100.00
14.5	112,862		0.0000	1.0000	96.37
15.5	112,862		0.0000	1.0000	96.37
16.5	112,862		0.0000	1.0000	96.37
17.5	112,862		0.0000	1.0000	96.37
18.5	112,862		0.0000	1.0000	96.37
19.5	112,862		0.0000	1.0000	96.37
20.5	112,862		0.0000	1.0000	96.37
21.5	112,862		0.0000	1.0000	96.37
22.5	112,862		0.0000	1.0000	96.37
23.5	112,862		0.0000	1.0000	96.37
24.5	112,862		0.0000	1.0000	96.37
25.5	112,862		0.0000	1.0000	96.37
26.5	112,862		0.0000	1.0000	96.37
27.5	113,216		0.0000	1.0000	96.37
28.5	113,216		0.0000	1.0000	96.37
29.5	113,216		0.0000	1.0000	96.37
30.5	113,216		0.0000	1.0000	96.37
31.5	86,938		0.0000	1.0000	96.37
32.5	86,938		0.0000	1.0000	96.37
33.5	86,938		0.0000	1.0000	96.37
34.5	85,811		0.0000	1.0000	96.37
35.5	85,811		0.0000	1.0000	96.37
36.5	85,811		0.0000	1.0000	96.37
37.5	84,628		0.0000	1.0000	96.37
38.5	17,756		0.0000	1.0000	96.37

KENTUCKY UTILITIES COMPANY

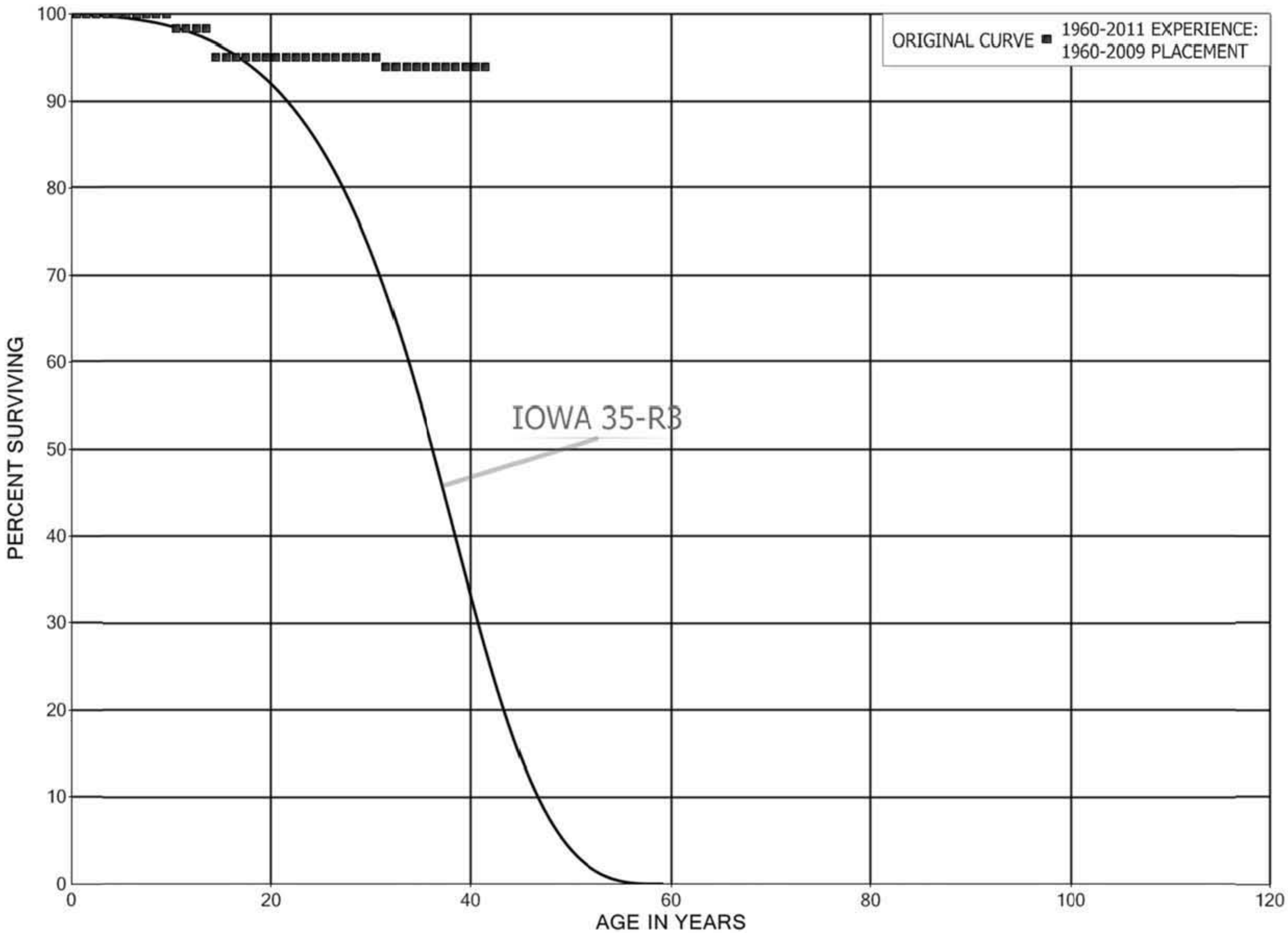
ACCOUNT 357 UNDERGROUND CONDUIT

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1960-2003 EXPERIENCE BAND 1960-2011

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	16,732		0.0000	1.0000	96.37
40.5	16,732		0.0000	1.0000	96.37
41.5	16,732		0.0000	1.0000	96.37
42.5	16,103		0.0000	1.0000	96.37
43.5	16,103		0.0000	1.0000	96.37
44.5	16,103		0.0000	1.0000	96.37
45.5	16,103		0.0000	1.0000	96.37
46.5	16,103		0.0000	1.0000	96.37
47.5	16,103		0.0000	1.0000	96.37
48.5	16,103		0.0000	1.0000	96.37
49.5					96.37

KENTUCKY UTILITIES COMPANY
ACCOUNT 358 UNDERGROUND CONDUCTORS AND DEVICES
ORIGINAL AND SMOOTH SURVIVOR CURVES



KENTUCKY UTILITIES COMPANY

ACCOUNT 358 UNDERGROUND CONDUCTORS AND DEVICES

ORIGINAL LIFE TABLE

PLACEMENT BAND 1960-2009 EXPERIENCE BAND 1960-2011

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	1,248,860		0.0000	1.0000	100.00
0.5	1,248,860		0.0000	1.0000	100.00
1.5	1,248,860		0.0000	1.0000	100.00
2.5	1,192,797		0.0000	1.0000	100.00
3.5	1,192,896		0.0000	1.0000	100.00
4.5	1,192,896		0.0000	1.0000	100.00
5.5	1,192,896		0.0000	1.0000	100.00
6.5	1,192,896		0.0000	1.0000	100.00
7.5	1,192,896		0.0000	1.0000	100.00
8.5	1,192,896		0.0000	1.0000	100.00
9.5	1,192,896	19,963	0.0167	0.9833	100.00
10.5	1,175,867		0.0000	1.0000	98.33
11.5	1,175,867		0.0000	1.0000	98.33
12.5	1,175,867		0.0000	1.0000	98.33
13.5	1,195,830	40,080	0.0335	0.9665	98.33
14.5	822,763		0.0000	1.0000	95.03
15.5	822,665		0.0000	1.0000	95.03
16.5	822,665		0.0000	1.0000	95.03
17.5	822,665		0.0000	1.0000	95.03
18.5	822,664		0.0000	1.0000	95.03
19.5	706,423		0.0000	1.0000	95.03
20.5	706,423		0.0000	1.0000	95.03
21.5	706,423		0.0000	1.0000	95.03
22.5	680,944		0.0000	1.0000	95.03
23.5	577,140		0.0000	1.0000	95.03
24.5	577,140		0.0000	1.0000	95.03
25.5	575,285		0.0000	1.0000	95.03
26.5	480,464		0.0000	1.0000	95.03
27.5	556,813		0.0000	1.0000	95.03
28.5	556,813		0.0000	1.0000	95.03
29.5	542,941		0.0000	1.0000	95.03
30.5	542,941	6,243	0.0115	0.9885	95.03
31.5	331,835		0.0000	1.0000	93.94
32.5	331,835		0.0000	1.0000	93.94
33.5	331,835		0.0000	1.0000	93.94
34.5	331,835		0.0000	1.0000	93.94
35.5	331,835		0.0000	1.0000	93.94
36.5	331,507		0.0000	1.0000	93.94
37.5	195,124		0.0000	1.0000	93.94
38.5	116,719		0.0000	1.0000	93.94

KENTUCKY UTILITIES COMPANY

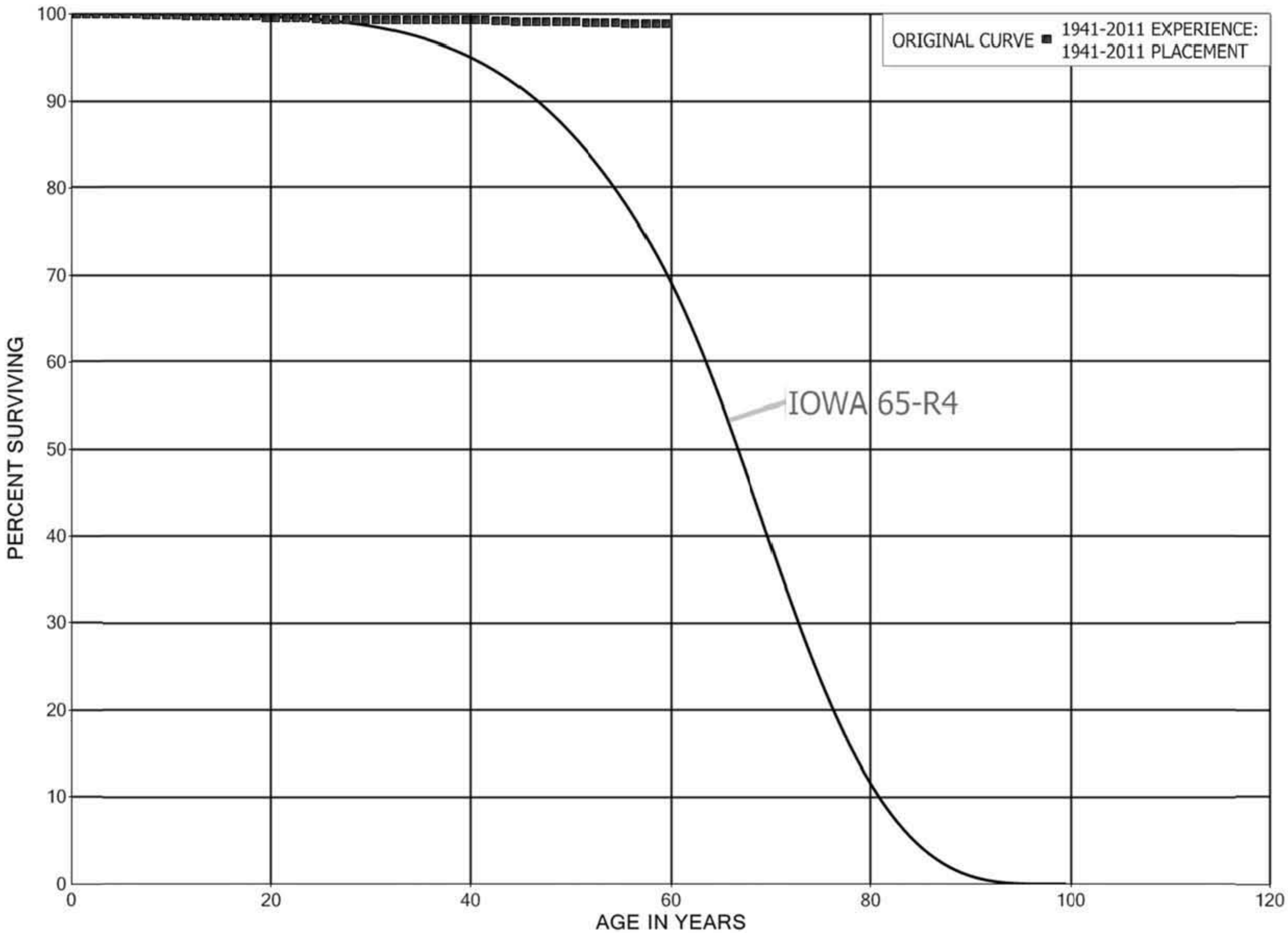
ACCOUNT 358 UNDERGROUND CONDUCTORS AND DEVICES

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1960-2009 EXPERIENCE BAND 1960-2011

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	100,843		0.0000	1.0000	93.94
40.5	100,843		0.0000	1.0000	93.94
41.5	100,843		0.0000	1.0000	93.94
42.5	13,219		0.0000	1.0000	93.94
43.5	13,219		0.0000	1.0000	93.94
44.5	13,219		0.0000	1.0000	93.94
45.5	13,219		0.0000	1.0000	93.94
46.5	13,219		0.0000	1.0000	93.94
47.5	13,219		0.0000	1.0000	93.94
48.5	13,219		0.0000	1.0000	93.94
49.5					93.94

KENTUCKY UTILITIES COMPANY
ACCOUNT 360.1 LAND RIGHTS
ORIGINAL AND SMOOTH SURVIVOR CURVES



KENTUCKY UTILITIES COMPANY

ACCOUNT 360.1 LAND RIGHTS

ORIGINAL LIFE TABLE

PLACEMENT BAND 1941-2011 EXPERIENCE BAND 1941-2011

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	1,536,457		0.0000	1.0000	100.00
0.5	1,514,174	86	0.0001	0.9999	100.00
1.5	1,507,787		0.0000	1.0000	99.99
2.5	1,449,522		0.0000	1.0000	99.99
3.5	1,449,522		0.0000	1.0000	99.99
4.5	1,449,608		0.0000	1.0000	99.99
5.5	1,449,608	700	0.0005	0.9995	99.99
6.5	1,448,908	1,928	0.0013	0.9987	99.95
7.5	1,372,617		0.0000	1.0000	99.81
8.5	1,372,504	253	0.0002	0.9998	99.81
9.5	1,373,646	29	0.0000	1.0000	99.79
10.5	1,372,217	315	0.0002	0.9998	99.79
11.5	1,452,587		0.0000	1.0000	99.77
12.5	1,424,052	318	0.0002	0.9998	99.77
13.5	1,412,700	620	0.0004	0.9996	99.75
14.5	1,311,410	262	0.0002	0.9998	99.70
15.5	1,167,786		0.0000	1.0000	99.68
16.5	1,113,042	52	0.0000	1.0000	99.68
17.5	1,089,757		0.0000	1.0000	99.68
18.5	1,051,042	1,881	0.0018	0.9982	99.68
19.5	1,044,021	190	0.0002	0.9998	99.50
20.5	1,030,850		0.0000	1.0000	99.48
21.5	992,486		0.0000	1.0000	99.48
22.5	985,136		0.0000	1.0000	99.48
23.5	980,250	1,380	0.0014	0.9986	99.48
24.5	962,604	380	0.0004	0.9996	99.34
25.5	961,445		0.0000	1.0000	99.30
26.5	927,914		0.0000	1.0000	99.30
27.5	913,244		0.0000	1.0000	99.30
28.5	913,244		0.0000	1.0000	99.30
29.5	852,076		0.0000	1.0000	99.30
30.5	850,268	52	0.0001	0.9999	99.30
31.5	839,546		0.0000	1.0000	99.30
32.5	807,660		0.0000	1.0000	99.30
33.5	789,840	213	0.0003	0.9997	99.30
34.5	774,155		0.0000	1.0000	99.27
35.5	767,950		0.0000	1.0000	99.27
36.5	740,613		0.0000	1.0000	99.27
37.5	697,148		0.0000	1.0000	99.27
38.5	688,178		0.0000	1.0000	99.27

KENTUCKY UTILITIES COMPANY

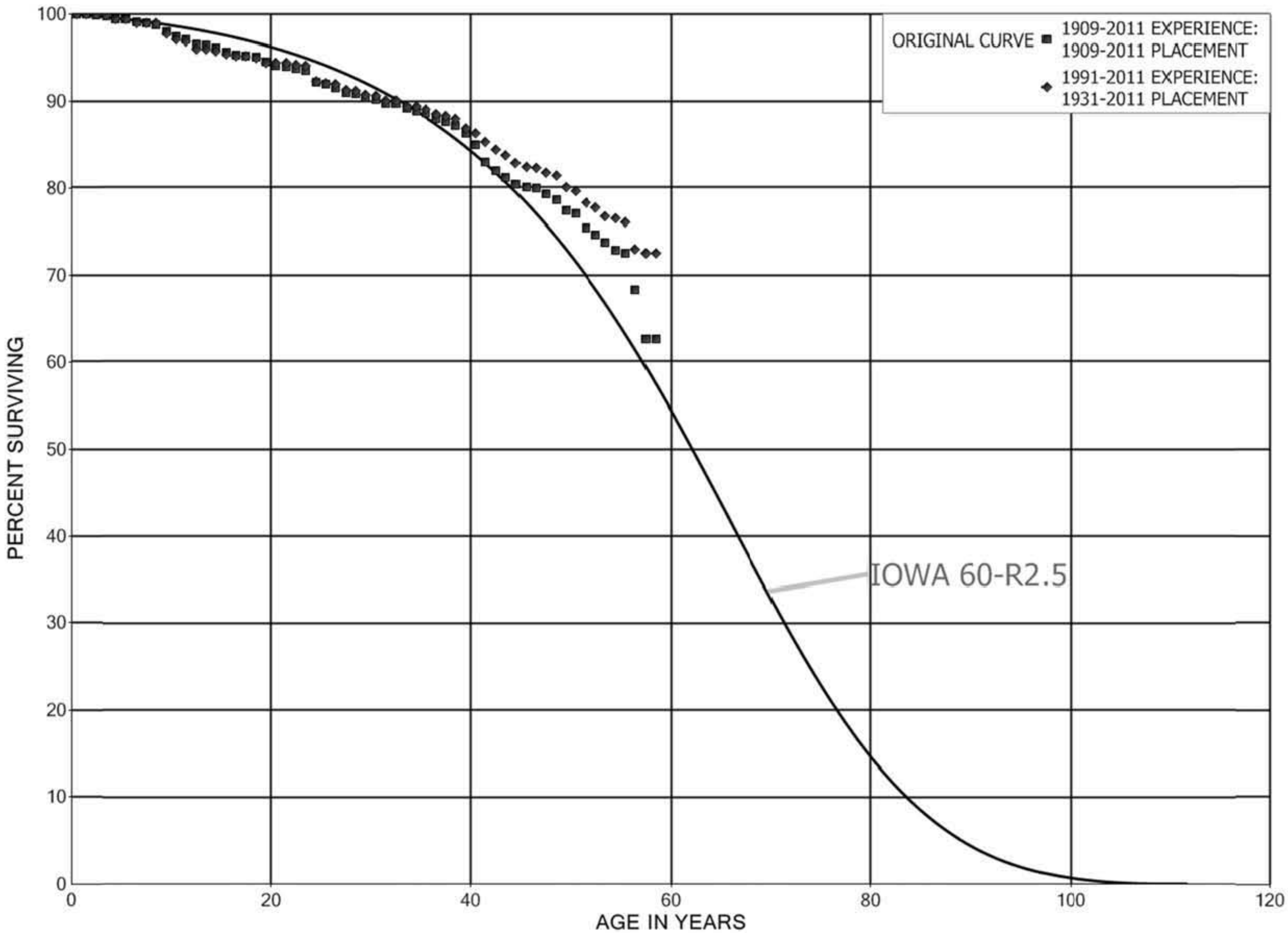
ACCOUNT 360.1 LAND RIGHTS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1941-2011 EXPERIENCE BAND 1941-2011

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	671,877	58	0.0001	0.9999	99.27
40.5	625,311	58	0.0001	0.9999	99.26
41.5	600,379	208	0.0003	0.9997	99.25
42.5	558,629		0.0000	1.0000	99.22
43.5	543,279	1,071	0.0020	0.9980	99.22
44.5	522,513		0.0000	1.0000	99.02
45.5	517,394		0.0000	1.0000	99.02
46.5	481,831		0.0000	1.0000	99.02
47.5	461,433		0.0000	1.0000	99.02
48.5	439,917		0.0000	1.0000	99.02
49.5	429,355		0.0000	1.0000	99.02
50.5	411,249	414	0.0010	0.9990	99.02
51.5	377,208		0.0000	1.0000	98.92
52.5	357,851		0.0000	1.0000	98.92
53.5	330,811		0.0000	1.0000	98.92
54.5	311,040	178	0.0006	0.9994	98.92
55.5	289,229		0.0000	1.0000	98.87
56.5	248,931		0.0000	1.0000	98.87
57.5	281,821	222	0.0008	0.9992	98.87
58.5	248,366		0.0000	1.0000	98.79
59.5	220,816		0.0000	1.0000	98.79
60.5	202,153		0.0000	1.0000	98.79
61.5	142,249		0.0000	1.0000	98.79
62.5	137,935		0.0000	1.0000	98.79
63.5	134,677		0.0000	1.0000	98.79
64.5	130,243		0.0000	1.0000	98.79
65.5	126,981		0.0000	1.0000	98.79
66.5	133,261		0.0000	1.0000	98.79
67.5	495,139		0.0000	1.0000	98.79
68.5	494,228		0.0000	1.0000	98.79
69.5	453,055		0.0000	1.0000	98.79
70.5					98.79

KENTUCKY UTILITIES COMPANY
ACCOUNT 361 STRUCTURES AND IMPROVEMENTS
ORIGINAL AND SMOOTH SURVIVOR CURVES



KENTUCKY UTILITIES COMPANY

ACCOUNT 361 STRUCTURES AND IMPROVEMENTS

ORIGINAL LIFE TABLE

PLACEMENT BAND 1909-2011 EXPERIENCE BAND 1909-2011

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	8,490,837	455	0.0001	0.9999	100.00
0.5	7,650,174	3,039	0.0004	0.9996	99.99
1.5	5,835,920	4,905	0.0008	0.9992	99.95
2.5	5,454,116	6,358	0.0012	0.9988	99.87
3.5	5,369,908	19,006	0.0035	0.9965	99.75
4.5	4,718,656	2,349	0.0005	0.9995	99.40
5.5	4,578,633	15,635	0.0034	0.9966	99.35
6.5	4,309,012	3,697	0.0009	0.9991	99.01
7.5	4,253,955	7,149	0.0017	0.9983	98.93
8.5	3,857,470	32,687	0.0085	0.9915	98.76
9.5	3,683,602	21,560	0.0059	0.9941	97.92
10.5	3,382,410	8,223	0.0024	0.9976	97.35
11.5	3,307,444	20,958	0.0063	0.9937	97.11
12.5	3,286,486	3,360	0.0010	0.9990	96.50
13.5	3,198,923	10,356	0.0032	0.9968	96.40
14.5	3,025,494	16,560	0.0055	0.9945	96.09
15.5	3,008,934	9,735	0.0032	0.9968	95.56
16.5	2,953,334	1,687	0.0006	0.9994	95.25
17.5	2,392,463	4,721	0.0020	0.9980	95.20
18.5	2,333,163	13,119	0.0056	0.9944	95.01
19.5	2,186,761	10,791	0.0049	0.9951	94.48
20.5	1,946,923	2,232	0.0011	0.9989	94.01
21.5	1,855,170	4,536	0.0024	0.9976	93.90
22.5	1,829,466	3,570	0.0020	0.9980	93.67
23.5	1,813,784	26,092	0.0144	0.9856	93.49
24.5	1,707,001	3,938	0.0023	0.9977	92.15
25.5	1,652,817	8,109	0.0049	0.9951	91.93
26.5	1,635,090	9,152	0.0056	0.9944	91.48
27.5	1,557,159	2,077	0.0013	0.9987	90.97
28.5	1,539,799	6,919	0.0045	0.9955	90.85
29.5	1,415,888	3,678	0.0026	0.9974	90.44
30.5	1,347,477	6,818	0.0051	0.9949	90.21
31.5	1,178,973	204	0.0002	0.9998	89.75
32.5	1,076,422	6,476	0.0060	0.9940	89.73
33.5	998,014	3,724	0.0037	0.9963	89.19
34.5	922,173	2,967	0.0032	0.9968	88.86
35.5	889,964	6,772	0.0076	0.9924	88.58
36.5	833,710	2,415	0.0029	0.9971	87.90
37.5	764,918	3,681	0.0048	0.9952	87.65
38.5	703,502	7,923	0.0113	0.9887	87.22

KENTUCKY UTILITIES COMPANY

ACCOUNT 361 STRUCTURES AND IMPROVEMENTS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1909-2011 EXPERIENCE BAND 1909-2011

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	654,285	9,864	0.0151	0.9849	86.24
40.5	571,621	13,235	0.0232	0.9768	84.94
41.5	542,327	6,580	0.0121	0.9879	82.98
42.5	479,972	4,334	0.0090	0.9910	81.97
43.5	438,536	4,333	0.0099	0.9901	81.23
44.5	403,955	1,745	0.0043	0.9957	80.43
45.5	381,438	530	0.0014	0.9986	80.08
46.5	346,801	2,840	0.0082	0.9918	79.97
47.5	310,524	2,646	0.0085	0.9915	79.31
48.5	266,555	4,169	0.0156	0.9844	78.64
49.5	230,335	1,160	0.0050	0.9950	77.41
50.5	209,228	4,481	0.0214	0.9786	77.02
51.5	188,162	1,853	0.0098	0.9902	75.37
52.5	175,031	2,181	0.0125	0.9875	74.63
53.5	144,072	1,635	0.0114	0.9886	73.70
54.5	127,793	568	0.0044	0.9956	72.86
55.5	105,085	6,125	0.0583	0.9417	72.53
56.5	77,779	6,491	0.0835	0.9165	68.31
57.5	54,366	34	0.0006	0.9994	62.61
58.5	54,328	523	0.0096	0.9904	62.57
59.5	48,820		0.0000	1.0000	61.97
60.5	43,615		0.0000	1.0000	61.97
61.5	30,589		0.0000	1.0000	61.97
62.5	25,504		0.0000	1.0000	61.97
63.5	22,762		0.0000	1.0000	61.97
64.5	18,120	25	0.0014	0.9986	61.97
65.5	4,425	19	0.0043	0.9957	61.88
66.5	4,350		0.0000	1.0000	61.62
67.5	2,444		0.0000	1.0000	61.62
68.5	2,444		0.0000	1.0000	61.62
69.5	2,444		0.0000	1.0000	61.62
70.5	1,445		0.0000	1.0000	61.62
71.5	1,207		0.0000	1.0000	61.62
72.5	1,207		0.0000	1.0000	61.62
73.5	1,207		0.0000	1.0000	61.62
74.5	1,207		0.0000	1.0000	61.62
75.5	1,207		0.0000	1.0000	61.62
76.5	1,207		0.0000	1.0000	61.62
77.5	1,207		0.0000	1.0000	61.62
78.5	1,207		0.0000	1.0000	61.62
79.5	1,207		0.0000	1.0000	61.62
80.5					61.62

KENTUCKY UTILITIES COMPANY

ACCOUNT 361 STRUCTURES AND IMPROVEMENTS

ORIGINAL LIFE TABLE

PLACEMENT BAND 1931-2011 EXPERIENCE BAND 1991-2011

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	6,383,777		0.0000	1.0000	100.00
0.5	5,633,225		0.0000	1.0000	100.00
1.5	3,843,196	1,348	0.0004	0.9996	100.00
2.5	3,509,408	4,166	0.0012	0.9988	99.96
3.5	3,508,084	14,717	0.0042	0.9958	99.85
4.5	2,911,349		0.0000	1.0000	99.43
5.5	2,783,741	13,946	0.0050	0.9950	99.43
6.5	2,584,586		0.0000	1.0000	98.93
7.5	2,550,156		0.0000	1.0000	98.93
8.5	2,294,949	27,414	0.0119	0.9881	98.93
9.5	2,191,546	15,516	0.0071	0.9929	97.75
10.5	2,068,423	4,150	0.0020	0.9980	97.06
11.5	2,106,212	18,612	0.0088	0.9912	96.86
12.5	2,162,455		0.0000	1.0000	96.00
13.5	2,165,890	5,116	0.0024	0.9976	96.00
14.5	2,030,696	8,292	0.0041	0.9959	95.78
15.5	2,071,099	4,457	0.0022	0.9978	95.39
16.5	2,086,720	826	0.0004	0.9996	95.18
17.5	1,608,299	2,453	0.0015	0.9985	95.14
18.5	1,601,866	10,572	0.0066	0.9934	95.00
19.5	1,544,098	459	0.0003	0.9997	94.37
20.5	1,334,110		0.0000	1.0000	94.34
21.5	1,298,092	1,595	0.0012	0.9988	94.34
22.5	1,317,096	2,426	0.0018	0.9982	94.23
23.5	1,332,425	24,332	0.0183	0.9817	94.05
24.5	1,254,293	3,659	0.0029	0.9971	92.34
25.5	1,239,744	2,315	0.0019	0.9981	92.07
26.5	1,262,026	7,918	0.0063	0.9937	91.90
27.5	1,230,331	1,503	0.0012	0.9988	91.32
28.5	1,247,896	6,372	0.0051	0.9949	91.21
29.5	1,145,412	1,245	0.0011	0.9989	90.74
30.5	1,098,035	6,615	0.0060	0.9940	90.64
31.5	942,986	204	0.0002	0.9998	90.10
32.5	871,986	6,476	0.0074	0.9926	90.08
33.5	808,428	243	0.0003	0.9997	89.41
34.5	765,675	2,902	0.0038	0.9962	89.38
35.5	764,392	4,226	0.0055	0.9945	89.04
36.5	732,632	2,415	0.0033	0.9967	88.55
37.5	664,999	2,586	0.0039	0.9961	88.26
38.5	614,769	7,531	0.0123	0.9877	87.92

KENTUCKY UTILITIES COMPANY

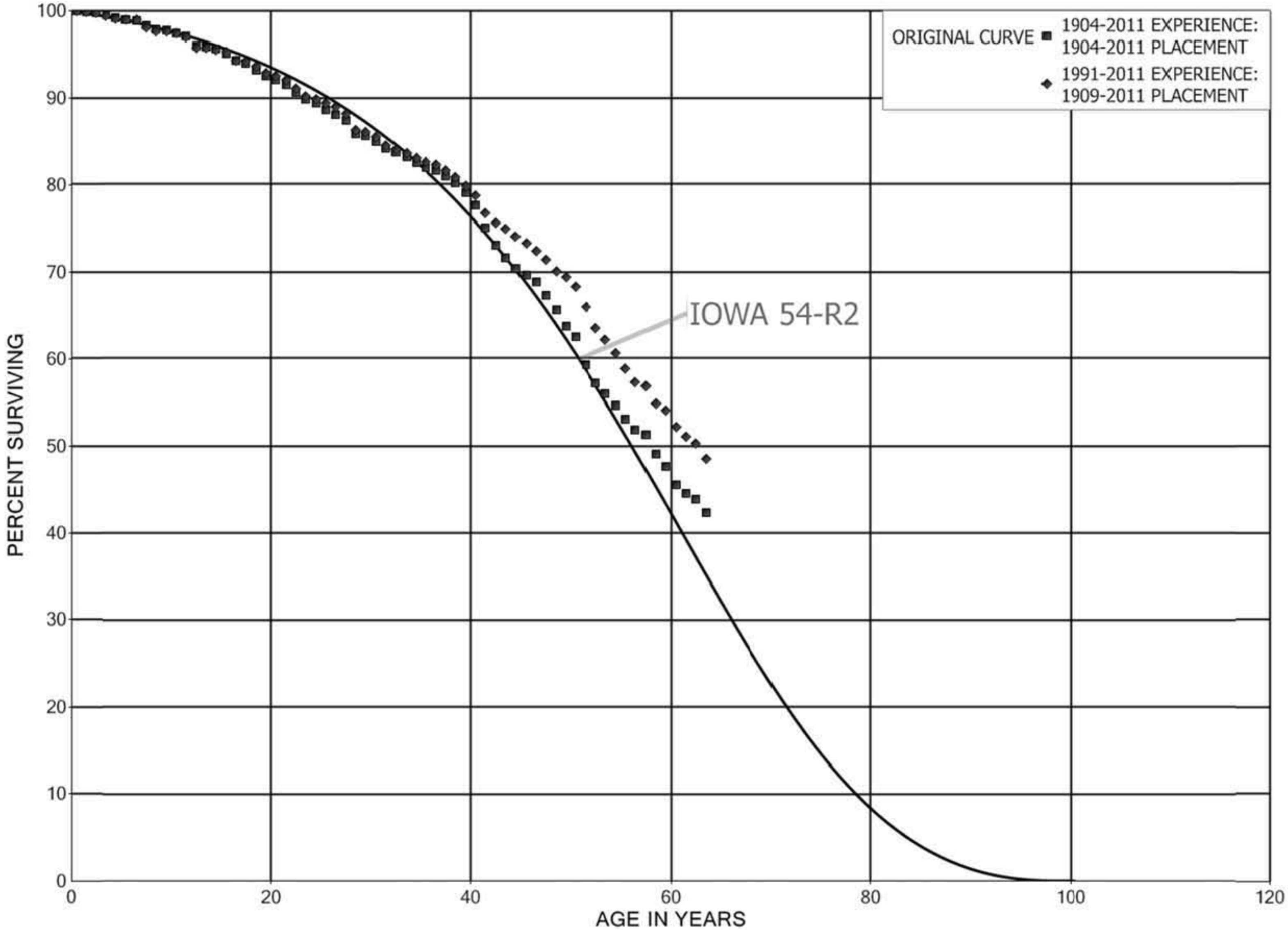
ACCOUNT 361 STRUCTURES AND IMPROVEMENTS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1931-2011 EXPERIENCE BAND 1991-2011

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	573,300	3,450	0.0060	0.9940	86.84
40.5	513,200	5,890	0.0115	0.9885	86.32
41.5	499,227	5,354	0.0107	0.9893	85.33
42.5	440,896	3,859	0.0088	0.9912	84.41
43.5	404,937	4,274	0.0106	0.9894	83.67
44.5	383,764	1,745	0.0045	0.9955	82.79
45.5	361,303	530	0.0015	0.9985	82.41
46.5	326,665	2,140	0.0066	0.9934	82.29
47.5	291,088	1,195	0.0041	0.9959	81.75
48.5	248,571	4,113	0.0165	0.9835	81.42
49.5	217,606	1,160	0.0053	0.9947	80.07
50.5	196,799	3,428	0.0174	0.9826	79.64
51.5	176,786	1,228	0.0069	0.9931	78.26
52.5	164,280	2,181	0.0133	0.9867	77.71
53.5	133,322	380	0.0029	0.9971	76.68
54.5	118,298	568	0.0048	0.9952	76.46
55.5	95,590	3,897	0.0408	0.9592	76.09
56.5	70,511	430	0.0061	0.9939	72.99
57.5	53,159	34	0.0006	0.9994	72.55
58.5	53,122	523	0.0098	0.9902	72.50
59.5	48,820		0.0000	1.0000	71.79
60.5	43,615		0.0000	1.0000	71.79
61.5	30,589		0.0000	1.0000	71.79
62.5	25,504		0.0000	1.0000	71.79
63.5	22,762		0.0000	1.0000	71.79
64.5	18,120	25	0.0014	0.9986	71.79
65.5	4,425	19	0.0043	0.9957	71.69
66.5	4,350		0.0000	1.0000	71.38
67.5	2,444		0.0000	1.0000	71.38
68.5	2,444		0.0000	1.0000	71.38
69.5	2,444		0.0000	1.0000	71.38
70.5	1,445		0.0000	1.0000	71.38
71.5	1,207		0.0000	1.0000	71.38
72.5	1,207		0.0000	1.0000	71.38
73.5	1,207		0.0000	1.0000	71.38
74.5	1,207		0.0000	1.0000	71.38
75.5	1,207		0.0000	1.0000	71.38
76.5	1,207		0.0000	1.0000	71.38
77.5	1,207		0.0000	1.0000	71.38
78.5	1,207		0.0000	1.0000	71.38
79.5	1,207		0.0000	1.0000	71.38
80.5					71.38

KENTUCKY UTILITIES COMPANY
ACCOUNT 362 STATION EQUIPMENT
ORIGINAL AND SMOOTH SURVIVOR CURVES



KENTUCKY UTILITIES COMPANY

ACCOUNT 362 STATION EQUIPMENT

ORIGINAL LIFE TABLE

PLACEMENT BAND 1904-2011 EXPERIENCE BAND 1904-2011

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	157,868,034	58,880	0.0004	0.9996	100.00
0.5	146,049,843	149,563	0.0010	0.9990	99.96
1.5	128,773,127	175,220	0.0014	0.9986	99.86
2.5	115,262,328	300,681	0.0026	0.9974	99.72
3.5	114,818,969	368,018	0.0032	0.9968	99.46
4.5	113,743,350	176,827	0.0016	0.9984	99.15
5.5	112,508,438	137,348	0.0012	0.9988	98.99
6.5	109,912,710	694,087	0.0063	0.9937	98.87
7.5	107,558,672	417,433	0.0039	0.9961	98.25
8.5	102,352,660	192,791	0.0019	0.9981	97.86
9.5	97,770,522	310,402	0.0032	0.9968	97.68
10.5	91,010,478	317,359	0.0035	0.9965	97.37
11.5	89,480,786	955,096	0.0107	0.9893	97.03
12.5	86,081,192	102,536	0.0012	0.9988	96.00
13.5	80,604,835	255,943	0.0032	0.9968	95.88
14.5	74,554,078	390,937	0.0052	0.9948	95.58
15.5	74,175,173	628,812	0.0085	0.9915	95.08
16.5	69,863,981	251,898	0.0036	0.9964	94.27
17.5	60,937,648	458,970	0.0075	0.9925	93.93
18.5	58,788,211	461,566	0.0079	0.9921	93.22
19.5	53,185,019	232,841	0.0044	0.9956	92.49
20.5	49,160,727	330,180	0.0067	0.9933	92.09
21.5	47,293,519	441,211	0.0093	0.9907	91.47
22.5	44,457,648	356,397	0.0080	0.9920	90.61
23.5	43,621,010	243,142	0.0056	0.9944	89.89
24.5	40,128,644	343,990	0.0086	0.9914	89.39
25.5	38,225,354	243,190	0.0064	0.9936	88.62
26.5	37,612,346	280,306	0.0075	0.9925	88.06
27.5	34,912,881	606,609	0.0174	0.9826	87.40
28.5	33,361,816	113,940	0.0034	0.9966	85.88
29.5	31,346,816	214,406	0.0068	0.9932	85.59
30.5	29,171,254	283,505	0.0097	0.9903	85.00
31.5	26,509,619	138,204	0.0052	0.9948	84.18
32.5	25,987,306	174,737	0.0067	0.9933	83.74
33.5	24,009,536	187,625	0.0078	0.9922	83.17
34.5	22,480,085	161,519	0.0072	0.9928	82.52
35.5	21,437,811	89,502	0.0042	0.9958	81.93
36.5	20,319,466	170,383	0.0084	0.9916	81.59
37.5	18,826,820	182,061	0.0097	0.9903	80.91
38.5	17,357,073	222,334	0.0128	0.9872	80.12

KENTUCKY UTILITIES COMPANY

ACCOUNT 362 STATION EQUIPMENT

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1904-2011 EXPERIENCE BAND 1904-2011

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	16,153,324	297,947	0.0184	0.9816	79.10
40.5	14,820,815	484,936	0.0327	0.9673	77.64
41.5	13,656,906	375,992	0.0275	0.9725	75.10
42.5	11,823,078	223,507	0.0189	0.9811	73.03
43.5	10,672,157	192,415	0.0180	0.9820	71.65
44.5	9,705,197	96,288	0.0099	0.9901	70.36
45.5	8,814,204	110,463	0.0125	0.9875	69.66
46.5	7,921,191	171,197	0.0216	0.9784	68.79
47.5	7,193,380	183,598	0.0255	0.9745	67.30
48.5	6,249,688	173,877	0.0278	0.9722	65.58
49.5	5,289,591	100,437	0.0190	0.9810	63.76
50.5	4,741,880	244,589	0.0516	0.9484	62.55
51.5	4,163,828	151,871	0.0365	0.9635	59.32
52.5	3,805,096	78,324	0.0206	0.9794	57.16
53.5	3,368,068	81,998	0.0243	0.9757	55.98
54.5	3,103,437	86,304	0.0278	0.9722	54.62
55.5	2,473,927	60,907	0.0246	0.9754	53.10
56.5	2,060,901	18,117	0.0088	0.9912	51.79
57.5	1,653,554	73,813	0.0446	0.9554	51.34
58.5	1,189,160	34,991	0.0294	0.9706	49.04
59.5	914,750	41,219	0.0451	0.9549	47.60
60.5	808,546	16,745	0.0207	0.9793	45.46
61.5	686,791	10,799	0.0157	0.9843	44.52
62.5	517,766	18,167	0.0351	0.9649	43.82
63.5	348,615	10,299	0.0295	0.9705	42.28
64.5	300,086	5,734	0.0191	0.9809	41.03
65.5	272,888	9,835	0.0360	0.9640	40.24
66.5	239,960	11,517	0.0480	0.9520	38.79
67.5	212,570	3,753	0.0177	0.9823	36.93
68.5	204,840	3,988	0.0195	0.9805	36.28
69.5	191,026	1,109	0.0058	0.9942	35.57
70.5	127,151	4,154	0.0327	0.9673	35.37
71.5	87,394	1,192	0.0136	0.9864	34.21
72.5	71,797	3,653	0.0509	0.9491	33.75
73.5	55,808		0.0000	1.0000	32.03
74.5	49,902	5,411	0.1084	0.8916	32.03
75.5	41,798		0.0000	1.0000	28.56
76.5	38,621		0.0000	1.0000	28.56
77.5	28,371	2,412	0.0850	0.9150	28.56
78.5	25,958		0.0000	1.0000	26.13

KENTUCKY UTILITIES COMPANY

ACCOUNT 362 STATION EQUIPMENT

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1904-2011 EXPERIENCE BAND 1904-2011

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
79.5	25,958		0.0000	1.0000	26.13
80.5	25,229		0.0000	1.0000	26.13
81.5	6,026		0.0000	1.0000	26.13
82.5	6,026		0.0000	1.0000	26.13
83.5	4,018		0.0000	1.0000	26.13
84.5	4,018		0.0000	1.0000	26.13
85.5	4,018		0.0000	1.0000	26.13
86.5	4,018		0.0000	1.0000	26.13
87.5	4,018		0.0000	1.0000	26.13
88.5	4,018		0.0000	1.0000	26.13
89.5	4,018		0.0000	1.0000	26.13
90.5	4,018		0.0000	1.0000	26.13
91.5	3,951		0.0000	1.0000	26.13
92.5	3,951		0.0000	1.0000	26.13
93.5	3,951		0.0000	1.0000	26.13
94.5	3,951		0.0000	1.0000	26.13
95.5	3,951		0.0000	1.0000	26.13
96.5	3,951		0.0000	1.0000	26.13
97.5	3,951		0.0000	1.0000	26.13
98.5	3,951		0.0000	1.0000	26.13
99.5	3,951		0.0000	1.0000	26.13
100.5	3,951		0.0000	1.0000	26.13
101.5	3,951	2,805	0.7100	0.2900	26.13
102.5					7.58

KENTUCKY UTILITIES COMPANY

ACCOUNT 362 STATION EQUIPMENT

ORIGINAL LIFE TABLE

PLACEMENT BAND 1909-2011 EXPERIENCE BAND 1991-2011

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	101,741,597	34,272	0.0003	0.9997	100.00
0.5	91,514,202	71,049	0.0008	0.9992	99.97
1.5	76,756,331	108,403	0.0014	0.9986	99.89
2.5	64,687,657	242,632	0.0038	0.9962	99.75
3.5	67,669,228	222,840	0.0033	0.9967	99.37
4.5	68,367,503	41,645	0.0006	0.9994	99.05
5.5	67,680,240	43,014	0.0006	0.9994	98.99
6.5	67,770,942	569,140	0.0084	0.9916	98.92
7.5	66,511,824	295,638	0.0044	0.9956	98.09
8.5	63,686,735	60,439	0.0009	0.9991	97.66
9.5	61,190,503	107,302	0.0018	0.9982	97.56
10.5	56,851,586	242,308	0.0043	0.9957	97.39
11.5	58,774,080	755,784	0.0129	0.9871	96.98
12.5	58,140,263	24,452	0.0004	0.9996	95.73
13.5	54,152,833	110,975	0.0020	0.9980	95.69
14.5	49,224,132	133,321	0.0027	0.9973	95.49
15.5	50,434,476	495,081	0.0098	0.9902	95.24
16.5	47,864,713	72,661	0.0015	0.9985	94.30
17.5	40,491,775	235,023	0.0058	0.9942	94.16
18.5	39,718,613	311,207	0.0078	0.9922	93.61
19.5	35,523,708	154,246	0.0043	0.9957	92.88
20.5	32,415,667	142,503	0.0044	0.9956	92.47
21.5	32,642,624	359,230	0.0110	0.9890	92.07
22.5	30,917,380	284,054	0.0092	0.9908	91.05
23.5	31,198,499	151,375	0.0049	0.9951	90.22
24.5	28,881,302	123,485	0.0043	0.9957	89.78
25.5	28,097,436	153,295	0.0055	0.9945	89.40
26.5	28,316,357	220,001	0.0078	0.9922	88.91
27.5	26,529,627	578,135	0.0218	0.9782	88.22
28.5	25,864,380	68,962	0.0027	0.9973	86.30
29.5	24,331,636	153,525	0.0063	0.9937	86.07
30.5	22,668,881	257,790	0.0114	0.9886	85.52
31.5	20,326,641	113,383	0.0056	0.9944	84.55
32.5	20,294,446	115,911	0.0057	0.9943	84.08
33.5	18,635,153	117,559	0.0063	0.9937	83.60
34.5	17,883,710	106,729	0.0060	0.9940	83.07
35.5	17,414,610	60,361	0.0035	0.9965	82.57
36.5	16,854,598	142,353	0.0084	0.9916	82.29
37.5	15,891,349	143,980	0.0091	0.9909	81.59
38.5	14,813,749	189,026	0.0128	0.9872	80.85

KENTUCKY UTILITIES COMPANY

ACCOUNT 362 STATION EQUIPMENT

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1909-2011 EXPERIENCE BAND 1991-2011

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	13,741,045	188,587	0.0137	0.9863	79.82
40.5	12,703,629	315,883	0.0249	0.9751	78.73
41.5	11,967,555	182,818	0.0153	0.9847	76.77
42.5	10,519,350	86,832	0.0083	0.9917	75.60
43.5	9,612,490	118,969	0.0124	0.9876	74.97
44.5	8,800,841	86,615	0.0098	0.9902	74.04
45.5	7,960,049	102,244	0.0128	0.9872	73.32
46.5	7,101,090	99,206	0.0140	0.9860	72.37
47.5	6,451,403	116,933	0.0181	0.9819	71.36
48.5	5,607,624	51,844	0.0092	0.9908	70.07
49.5	4,868,156	76,646	0.0157	0.9843	69.42
50.5	4,412,301	150,630	0.0341	0.9659	68.33
51.5	3,966,598	148,890	0.0375	0.9625	66.00
52.5	3,651,186	76,783	0.0210	0.9790	63.52
53.5	3,235,294	81,998	0.0253	0.9747	62.18
54.5	2,975,065	86,304	0.0290	0.9710	60.61
55.5	2,355,086	60,907	0.0259	0.9741	58.85
56.5	1,960,433	18,117	0.0092	0.9908	57.33
57.5	1,553,086	54,475	0.0351	0.9649	56.80
58.5	1,108,030	14,332	0.0129	0.9871	54.81
59.5	856,467	30,676	0.0358	0.9642	54.10
60.5	786,218	16,745	0.0213	0.9787	52.16
61.5	664,463	9,320	0.0140	0.9860	51.05
62.5	507,319	18,167	0.0358	0.9642	50.33
63.5	340,294	10,299	0.0303	0.9697	48.53
64.5	291,765	5,734	0.0197	0.9803	47.06
65.5	267,678	9,835	0.0367	0.9633	46.14
66.5	234,750	11,517	0.0491	0.9509	44.44
67.5	207,360	3,753	0.0181	0.9819	42.26
68.5	199,630	3,988	0.0200	0.9800	41.50
69.5	185,816	1,109	0.0060	0.9940	40.67
70.5	123,200	4,154	0.0337	0.9663	40.42
71.5	83,443	1,192	0.0143	0.9857	39.06
72.5	67,845	3,653	0.0538	0.9462	38.50
73.5	51,856		0.0000	1.0000	36.43
74.5	45,951	5,411	0.1178	0.8822	36.43
75.5	37,847		0.0000	1.0000	32.14
76.5	34,670		0.0000	1.0000	32.14
77.5	24,419	2,412	0.0988	0.9012	32.14
78.5	22,007		0.0000	1.0000	28.97

KENTUCKY UTILITIES COMPANY

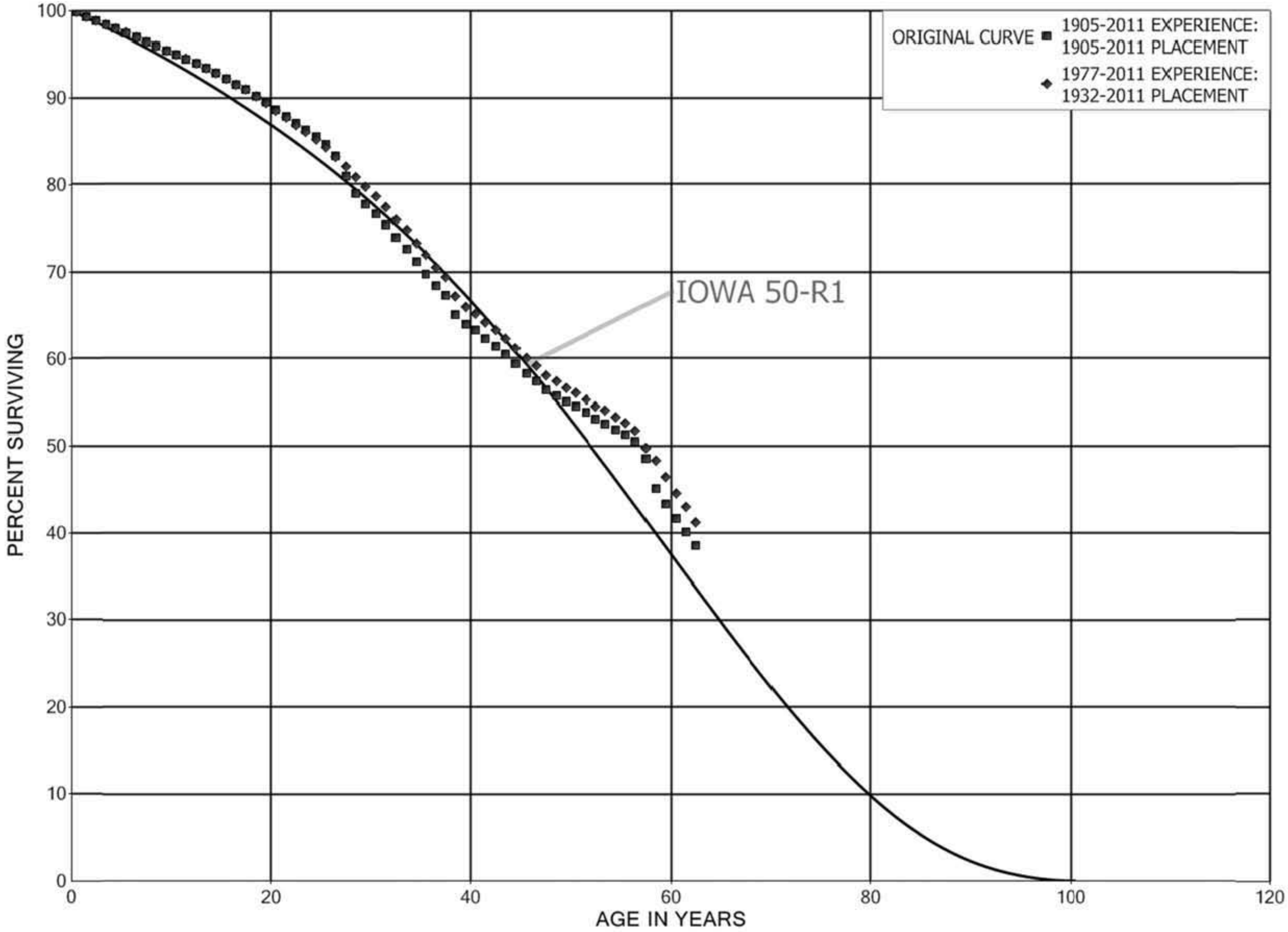
ACCOUNT 362 STATION EQUIPMENT

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1909-2011 EXPERIENCE BAND 1991-2011

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
79.5	22,007		0.0000	1.0000	28.97
80.5	21,278		0.0000	1.0000	28.97
81.5	6,026		0.0000	1.0000	28.97
82.5	6,026		0.0000	1.0000	28.97
83.5	4,018		0.0000	1.0000	28.97
84.5	4,018		0.0000	1.0000	28.97
85.5	4,018		0.0000	1.0000	28.97
86.5	4,018		0.0000	1.0000	28.97
87.5	4,018		0.0000	1.0000	28.97
88.5	4,018		0.0000	1.0000	28.97
89.5	4,018		0.0000	1.0000	28.97
90.5	4,018		0.0000	1.0000	28.97
91.5	3,951		0.0000	1.0000	28.97
92.5	3,951		0.0000	1.0000	28.97
93.5	3,951		0.0000	1.0000	28.97
94.5	3,951		0.0000	1.0000	28.97
95.5	3,951		0.0000	1.0000	28.97
96.5	3,951		0.0000	1.0000	28.97
97.5	3,951		0.0000	1.0000	28.97
98.5	3,951		0.0000	1.0000	28.97
99.5	3,951		0.0000	1.0000	28.97
100.5	3,951		0.0000	1.0000	28.97
101.5	3,951	2,805	0.7100	0.2900	28.97
102.5					8.40

KENTUCKY UTILITIES COMPANY
ACCOUNT 364 POLES, TOWERS AND FIXTURES
ORIGINAL AND SMOOTH SURVIVOR CURVES



KENTUCKY UTILITIES COMPANY

ACCOUNT 364 POLES, TOWERS AND FIXTURES

ORIGINAL LIFE TABLE

PLACEMENT BAND 1905-2011 EXPERIENCE BAND 1905-2011

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	316,000,362	625,756	0.0020	0.9980	100.00
0.5	298,221,130	1,621,085	0.0054	0.9946	99.80
1.5	281,650,242	1,276,605	0.0045	0.9955	99.26
2.5	247,046,824	1,083,742	0.0044	0.9956	98.81
3.5	222,475,873	997,159	0.0045	0.9955	98.38
4.5	217,310,447	1,097,494	0.0051	0.9949	97.94
5.5	210,050,523	1,053,782	0.0050	0.9950	97.44
6.5	204,696,863	1,138,099	0.0056	0.9944	96.95
7.5	199,297,243	1,074,789	0.0054	0.9946	96.41
8.5	187,596,943	980,970	0.0052	0.9948	95.89
9.5	179,387,555	869,309	0.0048	0.9952	95.39
10.5	172,385,706	921,334	0.0053	0.9947	94.93
11.5	164,463,649	869,655	0.0053	0.9947	94.42
12.5	156,144,976	857,902	0.0055	0.9945	93.92
13.5	147,718,982	911,478	0.0062	0.9938	93.41
14.5	138,245,895	970,452	0.0070	0.9930	92.83
15.5	129,391,598	909,809	0.0070	0.9930	92.18
16.5	119,490,406	811,328	0.0068	0.9932	91.53
17.5	110,606,750	839,338	0.0076	0.9924	90.91
18.5	103,191,899	870,501	0.0084	0.9916	90.22
19.5	95,659,687	909,078	0.0095	0.9905	89.46
20.5	89,610,633	749,683	0.0084	0.9916	88.61
21.5	83,950,865	758,924	0.0090	0.9910	87.87
22.5	78,115,707	677,507	0.0087	0.9913	87.07
23.5	72,668,666	640,893	0.0088	0.9912	86.32
24.5	67,174,118	762,202	0.0113	0.9887	85.56
25.5	61,876,566	918,685	0.0148	0.9852	84.58
26.5	57,577,034	1,627,768	0.0283	0.9717	83.33
27.5	52,989,345	1,336,381	0.0252	0.9748	80.97
28.5	47,960,085	745,245	0.0155	0.9845	78.93
29.5	44,034,142	637,280	0.0145	0.9855	77.70
30.5	40,362,726	633,134	0.0157	0.9843	76.58
31.5	37,010,237	711,684	0.0192	0.9808	75.38
32.5	33,709,795	593,107	0.0176	0.9824	73.93
33.5	31,317,637	635,646	0.0203	0.9797	72.63
34.5	28,842,061	584,780	0.0203	0.9797	71.15
35.5	26,695,693	518,639	0.0194	0.9806	69.71
36.5	24,744,254	401,891	0.0162	0.9838	68.36
37.5	22,471,064	711,679	0.0317	0.9683	67.25
38.5	19,873,239	340,455	0.0171	0.9829	65.12

KENTUCKY UTILITIES COMPANY

ACCOUNT 364 POLES, TOWERS AND FIXTURES

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1905-2011 EXPERIENCE BAND 1905-2011

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	18,107,678	206,942	0.0114	0.9886	64.00
40.5	16,471,414	257,660	0.0156	0.9844	63.27
41.5	15,365,550	223,289	0.0145	0.9855	62.28
42.5	13,925,084	203,678	0.0146	0.9854	61.38
43.5	12,614,243	230,905	0.0183	0.9817	60.48
44.5	11,394,894	201,105	0.0176	0.9824	59.37
45.5	10,253,908	154,145	0.0150	0.9850	58.32
46.5	9,254,877	162,915	0.0176	0.9824	57.45
47.5	8,241,572	102,413	0.0124	0.9876	56.44
48.5	7,347,971	90,097	0.0123	0.9877	55.73
49.5	6,710,167	66,100	0.0099	0.9901	55.05
50.5	6,059,712	77,048	0.0127	0.9873	54.51
51.5	5,878,134	83,991	0.0143	0.9857	53.82
52.5	5,302,580	48,618	0.0092	0.9908	53.05
53.5	4,886,545	65,274	0.0134	0.9866	52.56
54.5	4,285,658	46,587	0.0109	0.9891	51.86
55.5	3,806,225	62,513	0.0164	0.9836	51.29
56.5	3,473,305	134,368	0.0387	0.9613	50.45
57.5	3,243,104	230,843	0.0712	0.9288	48.50
58.5	2,847,193	110,296	0.0387	0.9613	45.05
59.5	2,159,528	85,457	0.0396	0.9604	43.30
60.5	1,577,258	57,035	0.0362	0.9638	41.59
61.5	1,008,312	39,901	0.0396	0.9604	40.08
62.5	654,179	27,740	0.0424	0.9576	38.50
63.5	449,253	8,645	0.0192	0.9808	36.87
64.5	291,909	7,745	0.0265	0.9735	36.16
65.5	190,456	7,162	0.0376	0.9624	35.20
66.5	148,287	5,916	0.0399	0.9601	33.87
67.5	167,015	10,705	0.0641	0.9359	32.52
68.5	149,202	21,613	0.1449	0.8551	30.44
69.5	121,716	18,332	0.1506	0.8494	26.03
70.5	8,602		0.0000	1.0000	22.11
71.5	8,602		0.0000	1.0000	22.11
72.5	8,602		0.0000	1.0000	22.11
73.5	8,602		0.0000	1.0000	22.11
74.5	8,602		0.0000	1.0000	22.11
75.5	8,602		0.0000	1.0000	22.11
76.5	8,602	48	0.0055	0.9945	22.11
77.5	8,554	3,045	0.3560	0.6440	21.99
78.5	5,509		0.0000	1.0000	14.16
79.5					14.16

KENTUCKY UTILITIES COMPANY

ACCOUNT 364 POLES, TOWERS AND FIXTURES

ORIGINAL LIFE TABLE

PLACEMENT BAND 1932-2011 EXPERIENCE BAND 1977-2011

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	272,359,839	515,837	0.0019	0.9981	100.00
0.5	256,958,254	1,344,590	0.0052	0.9948	99.81
1.5	242,842,082	1,059,570	0.0044	0.9956	99.29
2.5	211,002,588	937,131	0.0044	0.9956	98.86
3.5	188,998,968	837,332	0.0044	0.9956	98.42
4.5	186,127,620	952,630	0.0051	0.9949	97.98
5.5	181,156,005	912,935	0.0050	0.9950	97.48
6.5	177,691,131	999,351	0.0056	0.9944	96.99
7.5	174,209,926	942,616	0.0054	0.9946	96.44
8.5	164,344,046	867,228	0.0053	0.9947	95.92
9.5	157,668,477	744,368	0.0047	0.9953	95.41
10.5	152,065,218	810,821	0.0053	0.9947	94.96
11.5	145,687,552	789,799	0.0054	0.9946	94.46
12.5	138,771,902	784,131	0.0057	0.9943	93.94
13.5	131,638,683	839,840	0.0064	0.9936	93.41
14.5	123,269,411	881,057	0.0071	0.9929	92.82
15.5	115,478,264	805,833	0.0070	0.9930	92.15
16.5	106,520,690	721,778	0.0068	0.9932	91.51
17.5	98,584,449	779,053	0.0079	0.9921	90.89
18.5	92,132,646	807,244	0.0088	0.9912	90.17
19.5	85,539,212	825,652	0.0097	0.9903	89.38
20.5	80,389,500	695,023	0.0086	0.9914	88.52
21.5	75,525,999	746,906	0.0099	0.9901	87.76
22.5	70,196,636	677,507	0.0097	0.9903	86.89
23.5	65,385,546	633,940	0.0097	0.9903	86.05
24.5	60,614,268	664,463	0.0110	0.9890	85.21
25.5	56,052,978	736,031	0.0131	0.9869	84.28
26.5	52,705,287	721,538	0.0137	0.9863	83.17
27.5	49,508,984	711,029	0.0144	0.9856	82.04
28.5	46,029,513	630,131	0.0137	0.9863	80.86
29.5	43,085,328	604,070	0.0140	0.9860	79.75
30.5	39,805,285	601,906	0.0151	0.9849	78.63
31.5	36,554,078	690,394	0.0189	0.9811	77.44
32.5	33,292,809	502,452	0.0151	0.9849	75.98
33.5	31,001,786	633,781	0.0204	0.9796	74.83
34.5	28,532,931	546,215	0.0191	0.9809	73.30
35.5	26,524,646	518,639	0.0196	0.9804	71.90
36.5	24,577,524	401,891	0.0164	0.9836	70.49
37.5	22,306,638	711,679	0.0319	0.9681	69.34
38.5	19,709,621	340,455	0.0173	0.9827	67.13

KENTUCKY UTILITIES COMPANY

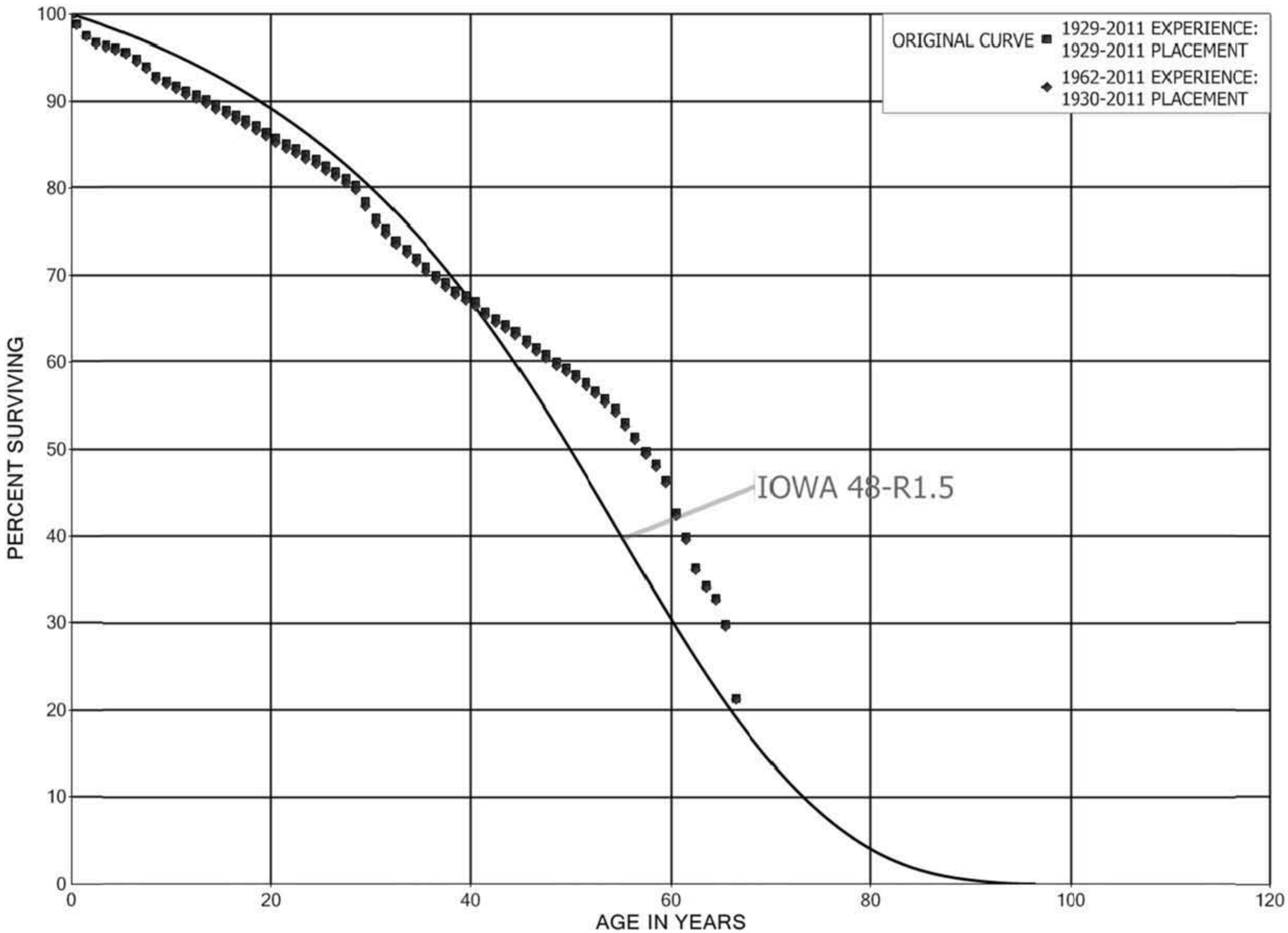
ACCOUNT 364 POLES, TOWERS AND FIXTURES

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1932-2011 EXPERIENCE BAND 1977-2011

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	17,944,195	206,942	0.0115	0.9885	65.97
40.5	16,321,901	257,660	0.0158	0.9842	65.21
41.5	15,216,122	223,289	0.0147	0.9853	64.18
42.5	13,775,656	203,678	0.0148	0.9852	63.24
43.5	12,464,816	230,905	0.0185	0.9815	62.30
44.5	11,254,433	201,105	0.0179	0.9821	61.15
45.5	10,113,447	154,145	0.0152	0.9848	60.06
46.5	9,114,416	162,915	0.0179	0.9821	59.14
47.5	8,101,111	102,413	0.0126	0.9874	58.08
48.5	7,207,510	90,097	0.0125	0.9875	57.35
49.5	6,569,706	66,100	0.0101	0.9899	56.63
50.5	5,919,251	77,048	0.0130	0.9870	56.06
51.5	5,737,673	83,991	0.0146	0.9854	55.33
52.5	5,162,119	48,618	0.0094	0.9906	54.52
53.5	4,746,084	65,274	0.0138	0.9862	54.01
54.5	4,145,197	46,587	0.0112	0.9888	53.27
55.5	3,665,764	62,513	0.0171	0.9829	52.67
56.5	3,332,844	134,368	0.0403	0.9597	51.77
57.5	3,102,643	90,382	0.0291	0.9709	49.68
58.5	2,847,193	110,296	0.0387	0.9613	48.24
59.5	2,159,528	85,457	0.0396	0.9604	46.37
60.5	1,577,258	57,035	0.0362	0.9638	44.53
61.5	1,008,312	39,901	0.0396	0.9604	42.92
62.5	654,179	27,740	0.0424	0.9576	41.22
63.5	449,253	8,645	0.0192	0.9808	39.48
64.5	291,909	7,745	0.0265	0.9735	38.72
65.5	190,456	7,162	0.0376	0.9624	37.69
66.5	148,287	5,916	0.0399	0.9601	36.27
67.5	167,015	10,705	0.0641	0.9359	34.82
68.5	149,202	21,613	0.1449	0.8551	32.59
69.5	121,716	18,332	0.1506	0.8494	27.87
70.5	8,602		0.0000	1.0000	23.67
71.5	8,602		0.0000	1.0000	23.67
72.5	8,602		0.0000	1.0000	23.67
73.5	8,602		0.0000	1.0000	23.67
74.5	8,602		0.0000	1.0000	23.67
75.5	8,602		0.0000	1.0000	23.67
76.5	8,602	48	0.0055	0.9945	23.67
77.5	8,554	3,045	0.3560	0.6440	23.54
78.5	5,509		0.0000	1.0000	15.16
79.5					15.16

KENTUCKY UTILITIES COMPANY
ACCOUNT 365 OVERHEAD CONDUCTORS AND DEVICES
ORIGINAL AND SMOOTH SURVIVOR CURVES



KENTUCKY UTILITIES COMPANY

ACCOUNT 365 OVERHEAD CONDUCTORS AND DEVICES

ORIGINAL LIFE TABLE

PLACEMENT BAND 1929-2011 EXPERIENCE BAND 1929-2011

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	314,282,764	3,733,480	0.0119	0.9881	100.00
0.5	289,219,430	3,705,946	0.0128	0.9872	98.81
1.5	272,953,893	2,291,878	0.0084	0.9916	97.55
2.5	225,538,440	791,214	0.0035	0.9965	96.73
3.5	203,650,095	686,541	0.0034	0.9966	96.39
4.5	198,518,983	929,356	0.0047	0.9953	96.06
5.5	193,485,938	1,653,287	0.0085	0.9915	95.61
6.5	190,015,632	1,586,564	0.0083	0.9917	94.80
7.5	181,064,093	2,182,512	0.0121	0.9879	94.00
8.5	175,002,485	1,082,265	0.0062	0.9938	92.87
9.5	168,046,088	960,173	0.0057	0.9943	92.30
10.5	157,980,386	1,025,337	0.0065	0.9935	91.77
11.5	152,530,067	778,211	0.0051	0.9949	91.17
12.5	146,268,681	892,669	0.0061	0.9939	90.71
13.5	140,215,251	896,419	0.0064	0.9936	90.16
14.5	132,805,352	855,231	0.0064	0.9936	89.58
15.5	125,379,255	912,523	0.0073	0.9927	89.00
16.5	116,766,490	756,235	0.0065	0.9935	88.35
17.5	109,886,587	781,805	0.0071	0.9929	87.78
18.5	104,275,932	851,280	0.0082	0.9918	87.16
19.5	98,173,355	787,797	0.0080	0.9920	86.45
20.5	92,907,367	754,296	0.0081	0.9919	85.75
21.5	87,156,609	614,934	0.0071	0.9929	85.06
22.5	80,767,359	634,276	0.0079	0.9921	84.46
23.5	75,671,659	496,933	0.0066	0.9934	83.79
24.5	71,155,707	609,488	0.0086	0.9914	83.24
25.5	66,949,132	568,878	0.0085	0.9915	82.53
26.5	63,763,036	634,857	0.0100	0.9900	81.83
27.5	60,347,232	563,041	0.0093	0.9907	81.01
28.5	56,581,188	1,291,656	0.0228	0.9772	80.26
29.5	52,202,286	1,307,287	0.0250	0.9750	78.43
30.5	47,901,465	736,284	0.0154	0.9846	76.46
31.5	44,110,908	758,134	0.0172	0.9828	75.29
32.5	40,088,498	540,603	0.0135	0.9865	73.99
33.5	36,807,269	497,794	0.0135	0.9865	72.99
34.5	34,040,260	523,937	0.0154	0.9846	72.01
35.5	31,935,421	404,406	0.0127	0.9873	70.90
36.5	29,959,449	368,938	0.0123	0.9877	70.00
37.5	27,020,242	376,009	0.0139	0.9861	69.14
38.5	24,632,991	216,770	0.0088	0.9912	68.18

KENTUCKY UTILITIES COMPANY

ACCOUNT 365 OVERHEAD CONDUCTORS AND DEVICES

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1929-2011 EXPERIENCE BAND 1929-2011

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	22,812,643	231,799	0.0102	0.9898	67.58
40.5	20,440,935	356,554	0.0174	0.9826	66.89
41.5	18,882,963	211,678	0.0112	0.9888	65.72
42.5	17,147,395	190,837	0.0111	0.9889	64.99
43.5	15,478,569	186,999	0.0121	0.9879	64.26
44.5	14,137,817	210,775	0.0149	0.9851	63.49
45.5	12,943,874	180,765	0.0140	0.9860	62.54
46.5	11,548,674	145,743	0.0126	0.9874	61.67
47.5	10,443,230	158,928	0.0152	0.9848	60.89
48.5	9,397,839	102,874	0.0109	0.9891	59.96
49.5	8,724,753	119,520	0.0137	0.9863	59.31
50.5	8,076,258	125,642	0.0156	0.9844	58.49
51.5	7,622,785	124,071	0.0163	0.9837	57.58
52.5	7,082,911	116,128	0.0164	0.9836	56.65
53.5	6,520,395	132,717	0.0204	0.9796	55.72
54.5	5,960,956	169,091	0.0284	0.9716	54.58
55.5	5,308,339	160,494	0.0302	0.9698	53.04
56.5	4,688,502	154,023	0.0329	0.9671	51.43
57.5	4,203,393	126,748	0.0302	0.9698	49.74
58.5	3,724,177	143,827	0.0386	0.9614	48.24
59.5	3,124,434	256,321	0.0820	0.9180	46.38
60.5	2,609,031	168,676	0.0647	0.9353	42.57
61.5	1,994,313	176,228	0.0884	0.9116	39.82
62.5	1,389,284	76,684	0.0552	0.9448	36.30
63.5	933,988	40,834	0.0437	0.9563	34.30
64.5	705,490	63,219	0.0896	0.9104	32.80
65.5	491,130	140,587	0.2863	0.7137	29.86
66.5	274,100	10,558	0.0385	0.9615	21.31
67.5	374,931	32,998	0.0880	0.9120	20.49
68.5	315,009	38,294	0.1216	0.8784	18.69
69.5	249,116	92,752	0.3723	0.6277	16.42
70.5					10.30

KENTUCKY UTILITIES COMPANY

ACCOUNT 365 OVERHEAD CONDUCTORS AND DEVICES

ORIGINAL LIFE TABLE

PLACEMENT BAND 1930-2011 EXPERIENCE BAND 1962-2011

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	298,426,938	3,733,480	0.0125	0.9875	100.00
0.5	274,432,451	3,705,946	0.0135	0.9865	98.75
1.5	259,230,901	2,291,878	0.0088	0.9912	97.42
2.5	212,642,583	791,214	0.0037	0.9963	96.55
3.5	191,744,244	686,541	0.0036	0.9964	96.19
4.5	187,459,042	929,356	0.0050	0.9950	95.85
5.5	183,350,327	1,653,287	0.0090	0.9910	95.38
6.5	180,809,838	1,586,564	0.0088	0.9912	94.52
7.5	172,702,640	2,182,512	0.0126	0.9874	93.69
8.5	167,644,666	1,082,265	0.0065	0.9935	92.50
9.5	161,385,799	960,173	0.0059	0.9941	91.90
10.5	151,986,090	1,025,337	0.0067	0.9933	91.36
11.5	147,212,517	778,211	0.0053	0.9947	90.74
12.5	141,627,036	892,669	0.0063	0.9937	90.26
13.5	136,044,879	896,419	0.0066	0.9934	89.69
14.5	129,345,989	855,231	0.0066	0.9934	89.10
15.5	122,493,886	912,523	0.0074	0.9926	88.51
16.5	114,201,216	756,235	0.0066	0.9934	87.85
17.5	107,433,888	781,805	0.0073	0.9927	87.27
18.5	101,927,932	851,280	0.0084	0.9916	86.64
19.5	95,952,237	787,797	0.0082	0.9918	85.91
20.5	91,591,255	754,296	0.0082	0.9918	85.21
21.5	86,026,723	614,934	0.0071	0.9929	84.51
22.5	79,829,586	634,276	0.0079	0.9921	83.90
23.5	74,930,054	496,933	0.0066	0.9934	83.24
24.5	70,551,428	609,488	0.0086	0.9914	82.68
25.5	66,473,731	568,878	0.0086	0.9914	81.97
26.5	63,368,339	634,857	0.0100	0.9900	81.27
27.5	60,007,496	563,041	0.0094	0.9906	80.45
28.5	56,298,616	1,291,656	0.0229	0.9771	79.70
29.5	51,968,359	1,307,287	0.0252	0.9748	77.87
30.5	47,773,968	736,284	0.0154	0.9846	75.91
31.5	44,108,881	758,134	0.0172	0.9828	74.74
32.5	40,088,498	540,603	0.0135	0.9865	73.46
33.5	36,807,269	497,794	0.0135	0.9865	72.47
34.5	34,040,260	523,937	0.0154	0.9846	71.49
35.5	31,935,421	404,406	0.0127	0.9873	70.39
36.5	29,959,449	368,938	0.0123	0.9877	69.49
37.5	27,020,242	376,009	0.0139	0.9861	68.64
38.5	24,632,991	216,770	0.0088	0.9912	67.68

KENTUCKY UTILITIES COMPANY

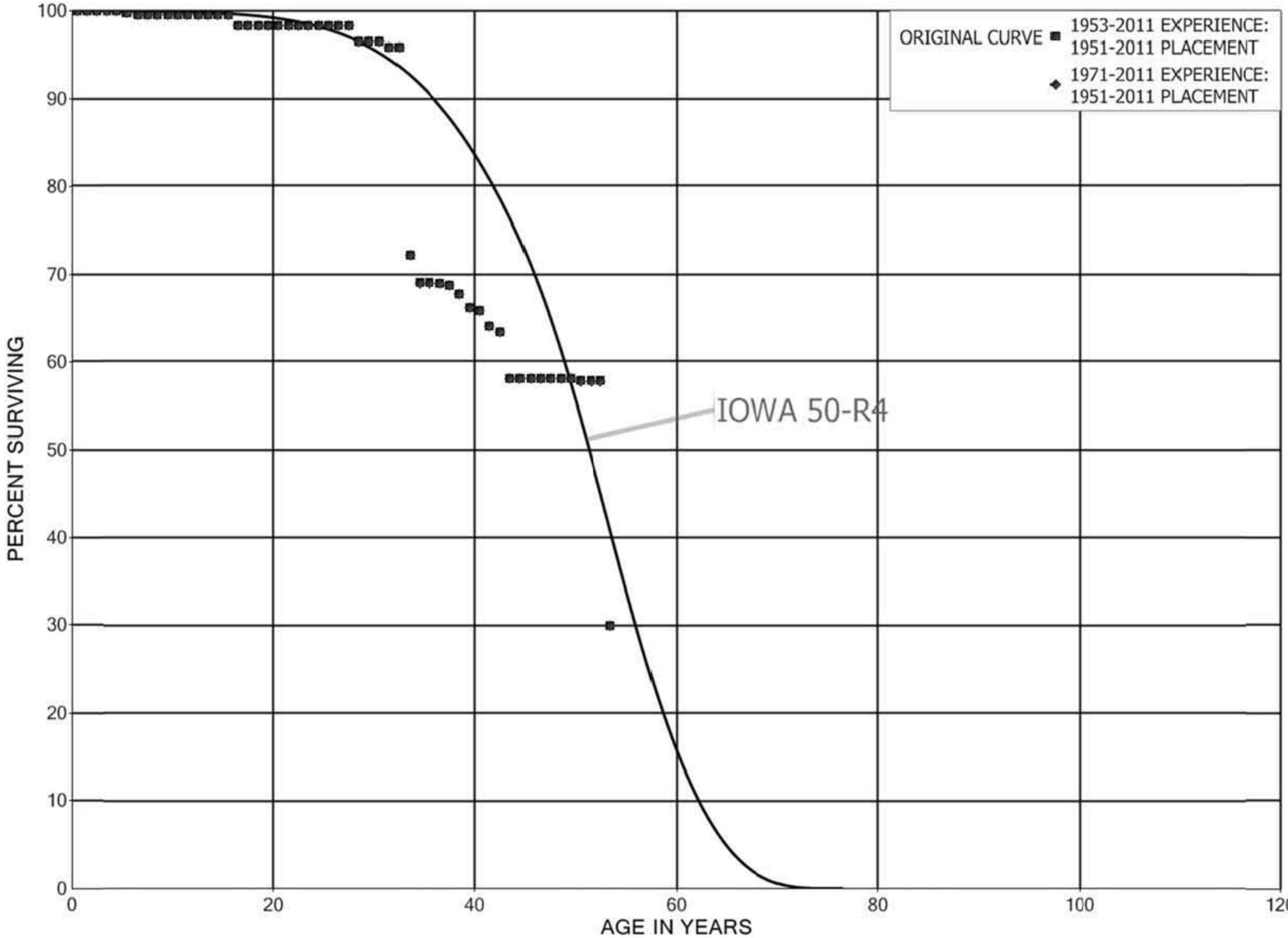
ACCOUNT 365 OVERHEAD CONDUCTORS AND DEVICES

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1930-2011 EXPERIENCE BAND 1962-2011

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	22,812,643	231,799	0.0102	0.9898	67.09
40.5	20,440,935	356,554	0.0174	0.9826	66.41
41.5	18,882,963	211,678	0.0112	0.9888	65.25
42.5	17,147,395	190,837	0.0111	0.9889	64.52
43.5	15,478,569	186,999	0.0121	0.9879	63.80
44.5	14,137,817	210,775	0.0149	0.9851	63.03
45.5	12,943,874	180,765	0.0140	0.9860	62.09
46.5	11,548,674	145,743	0.0126	0.9874	61.22
47.5	10,443,230	158,928	0.0152	0.9848	60.45
48.5	9,397,839	102,874	0.0109	0.9891	59.53
49.5	8,724,753	119,520	0.0137	0.9863	58.88
50.5	8,076,258	125,642	0.0156	0.9844	58.07
51.5	7,622,785	124,071	0.0163	0.9837	57.17
52.5	7,082,911	116,128	0.0164	0.9836	56.24
53.5	6,520,395	132,717	0.0204	0.9796	55.31
54.5	5,960,956	169,091	0.0284	0.9716	54.19
55.5	5,308,339	160,494	0.0302	0.9698	52.65
56.5	4,688,502	154,023	0.0329	0.9671	51.06
57.5	4,203,393	126,748	0.0302	0.9698	49.38
58.5	3,724,177	143,827	0.0386	0.9614	47.89
59.5	3,124,434	256,321	0.0820	0.9180	46.04
60.5	2,609,031	168,676	0.0647	0.9353	42.27
61.5	1,994,313	176,228	0.0884	0.9116	39.53
62.5	1,389,284	76,684	0.0552	0.9448	36.04
63.5	933,988	40,834	0.0437	0.9563	34.05
64.5	705,490	63,219	0.0896	0.9104	32.56
65.5	491,130	140,587	0.2863	0.7137	29.64
66.5	274,100	10,558	0.0385	0.9615	21.16
67.5	374,931	32,998	0.0880	0.9120	20.34
68.5	315,009	38,294	0.1216	0.8784	18.55
69.5	249,116	92,752	0.3723	0.6277	16.30
70.5					10.23

KENTUCKY UTILITIES COMPANY
ACCOUNT 366 UNDERGROUND CONDUIT
ORIGINAL AND SMOOTH SURVIVOR CURVES



KENTUCKY UTILITIES COMPANY

ACCOUNT 366 UNDERGROUND CONDUIT

ORIGINAL LIFE TABLE

PLACEMENT BAND 1951-2011 EXPERIENCE BAND 1953-2011

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	2,040,622	244	0.0001	0.9999	100.00
0.5	1,987,403	103	0.0001	0.9999	99.99
1.5	1,737,322	205	0.0001	0.9999	99.98
2.5	1,705,363	237	0.0001	0.9999	99.97
3.5	1,701,446		0.0000	1.0000	99.96
4.5	1,693,158	3,640	0.0021	0.9979	99.96
5.5	1,701,823	4,194	0.0025	0.9975	99.74
6.5	1,671,361		0.0000	1.0000	99.50
7.5	1,621,700		0.0000	1.0000	99.50
8.5	1,497,189		0.0000	1.0000	99.50
9.5	1,497,189		0.0000	1.0000	99.50
10.5	1,494,383		0.0000	1.0000	99.50
11.5	1,494,347		0.0000	1.0000	99.50
12.5	1,494,347		0.0000	1.0000	99.50
13.5	1,488,650		0.0000	1.0000	99.50
14.5	1,488,650		0.0000	1.0000	99.50
15.5	1,488,665	18,439	0.0124	0.9876	99.50
16.5	1,365,766		0.0000	1.0000	98.26
17.5	1,365,766		0.0000	1.0000	98.26
18.5	1,365,766		0.0000	1.0000	98.26
19.5	1,365,766		0.0000	1.0000	98.26
20.5	1,365,766		0.0000	1.0000	98.26
21.5	1,365,766		0.0000	1.0000	98.26
22.5	1,345,726		0.0000	1.0000	98.26
23.5	1,385,581		0.0000	1.0000	98.26
24.5	1,318,093		0.0000	1.0000	98.26
25.5	1,273,281		0.0000	1.0000	98.26
26.5	1,273,296		0.0000	1.0000	98.26
27.5	1,273,296	23,024	0.0181	0.9819	98.26
28.5	1,192,051		0.0000	1.0000	96.49
29.5	1,125,501		0.0000	1.0000	96.49
30.5	1,123,477	7,753	0.0069	0.9931	96.49
31.5	899,551		0.0000	1.0000	95.82
32.5	491,739	121,170	0.2464	0.7536	95.82
33.5	370,569	16,411	0.0443	0.9557	72.21
34.5	354,158		0.0000	1.0000	69.01
35.5	334,684	76	0.0002	0.9998	69.01
36.5	334,608	1,316	0.0039	0.9961	69.00
37.5	56,540	849	0.0150	0.9850	68.73
38.5	32,246	715	0.0222	0.9778	67.69

KENTUCKY UTILITIES COMPANY

ACCOUNT 366 UNDERGROUND CONDUIT

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1951-2011 EXPERIENCE BAND 1953-2011

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	31,531	172	0.0054	0.9946	66.19
40.5	31,359	828	0.0264	0.9736	65.83
41.5	30,530	345	0.0113	0.9887	64.09
42.5	30,186	2,510	0.0831	0.9169	63.37
43.5	26,606		0.0000	1.0000	58.10
44.5	23,840		0.0000	1.0000	58.10
45.5	31,456		0.0000	1.0000	58.10
46.5	31,455		0.0000	1.0000	58.10
47.5	31,470	15	0.0005	0.9995	58.10
48.5	31,455		0.0000	1.0000	58.07
49.5	31,455	153	0.0049	0.9951	58.07
50.5	31,302		0.0000	1.0000	57.79
51.5	31,302		0.0000	1.0000	57.79
52.5	31,302	15,088	0.4820	0.5180	57.79
53.5	16,214	2,826	0.1743	0.8257	29.93
54.5	13,388	96	0.0072	0.9928	24.72
55.5	13,292	9,027	0.6791	0.3209	24.54
56.5	4,266		0.0000	1.0000	7.88
57.5	4,266		0.0000	1.0000	7.88
58.5	675		0.0000	1.0000	7.88
59.5	675		0.0000	1.0000	7.88
60.5					7.88

KENTUCKY UTILITIES COMPANY

ACCOUNT 366 UNDERGROUND CONDUIT

ORIGINAL LIFE TABLE

PLACEMENT BAND 1951-2011 EXPERIENCE BAND 1971-2011

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	2,007,110	244	0.0001	0.9999	100.00
0.5	1,955,192	103	0.0001	0.9999	99.99
1.5	1,705,111	205	0.0001	0.9999	99.98
2.5	1,674,105	237	0.0001	0.9999	99.97
3.5	1,673,570		0.0000	1.0000	99.96
4.5	1,667,463	3,640	0.0022	0.9978	99.96
5.5	1,677,480	4,194	0.0025	0.9975	99.74
6.5	1,647,194		0.0000	1.0000	99.49
7.5	1,600,043		0.0000	1.0000	99.49
8.5	1,475,532		0.0000	1.0000	99.49
9.5	1,475,532		0.0000	1.0000	99.49
10.5	1,472,726		0.0000	1.0000	99.49
11.5	1,472,690		0.0000	1.0000	99.49
12.5	1,472,690		0.0000	1.0000	99.49
13.5	1,466,993		0.0000	1.0000	99.49
14.5	1,467,146		0.0000	1.0000	99.49
15.5	1,467,161	18,439	0.0126	0.9874	99.49
16.5	1,344,262		0.0000	1.0000	98.24
17.5	1,365,766		0.0000	1.0000	98.24
18.5	1,365,766		0.0000	1.0000	98.24
19.5	1,365,766		0.0000	1.0000	98.24
20.5	1,365,766		0.0000	1.0000	98.24
21.5	1,365,766		0.0000	1.0000	98.24
22.5	1,345,726		0.0000	1.0000	98.24
23.5	1,385,581		0.0000	1.0000	98.24
24.5	1,318,093		0.0000	1.0000	98.24
25.5	1,273,281		0.0000	1.0000	98.24
26.5	1,273,296		0.0000	1.0000	98.24
27.5	1,273,296	23,024	0.0181	0.9819	98.24
28.5	1,192,051		0.0000	1.0000	96.46
29.5	1,125,501		0.0000	1.0000	96.46
30.5	1,123,477	7,753	0.0069	0.9931	96.46
31.5	899,551		0.0000	1.0000	95.80
32.5	491,739	121,170	0.2464	0.7536	95.80
33.5	370,569	16,411	0.0443	0.9557	72.19
34.5	354,158		0.0000	1.0000	68.99
35.5	334,684	76	0.0002	0.9998	68.99
36.5	334,608	1,316	0.0039	0.9961	68.98
37.5	56,540	849	0.0150	0.9850	68.71
38.5	32,246	715	0.0222	0.9778	67.67

KENTUCKY UTILITIES COMPANY

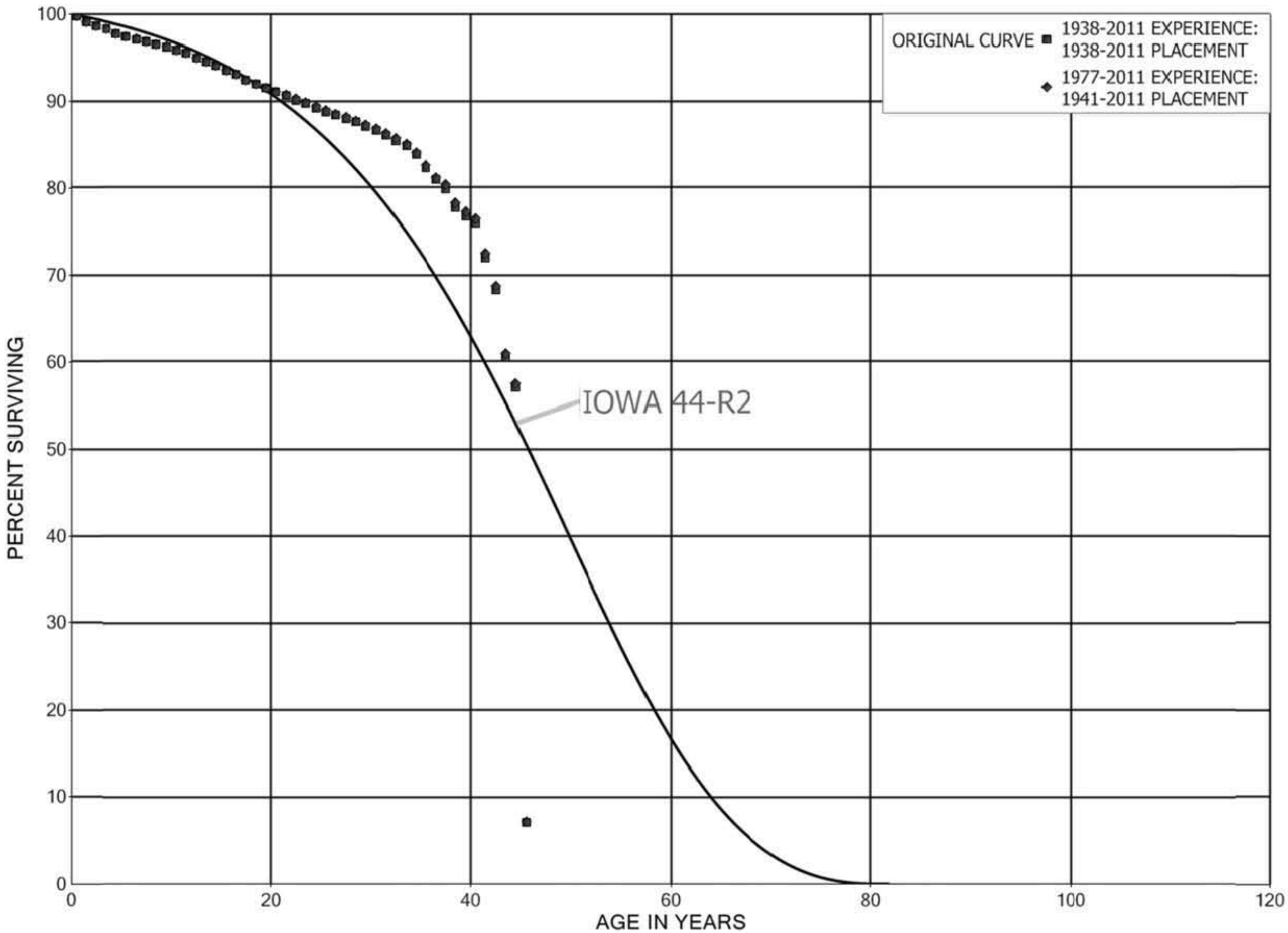
ACCOUNT 366 UNDERGROUND CONDUIT

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1951-2011 EXPERIENCE BAND 1971-2011

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	31,531	172	0.0054	0.9946	66.17
40.5	31,359	828	0.0264	0.9736	65.81
41.5	30,530	345	0.0113	0.9887	64.08
42.5	30,186	2,510	0.0831	0.9169	63.35
43.5	26,606		0.0000	1.0000	58.08
44.5	23,840		0.0000	1.0000	58.08
45.5	31,456		0.0000	1.0000	58.08
46.5	31,455		0.0000	1.0000	58.08
47.5	31,470	15	0.0005	0.9995	58.08
48.5	31,455		0.0000	1.0000	58.06
49.5	31,455	153	0.0049	0.9951	58.06
50.5	31,302		0.0000	1.0000	57.77
51.5	31,302		0.0000	1.0000	57.77
52.5	31,302	15,088	0.4820	0.5180	57.77
53.5	16,214	2,826	0.1743	0.8257	29.93
54.5	13,388	96	0.0072	0.9928	24.71
55.5	13,292	9,027	0.6791	0.3209	24.53
56.5	4,266		0.0000	1.0000	7.87
57.5	4,266		0.0000	1.0000	7.87
58.5	675		0.0000	1.0000	7.87
59.5	675		0.0000	1.0000	7.87
60.5					7.87

KENTUCKY UTILITIES COMPANY
ACCOUNT 367 UNDERGROUND CONDUCTORS AND DEVICES
ORIGINAL AND SMOOTH SURVIVOR CURVES



KENTUCKY UTILITIES COMPANY

ACCOUNT 367 UNDERGROUND CONDUCTORS AND DEVICES

ORIGINAL LIFE TABLE

PLACEMENT BAND 1938-2011 EXPERIENCE BAND 1938-2011

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	145,849,889	476,141	0.0033	0.9967	100.00
0.5	134,958,322	756,099	0.0056	0.9944	99.67
1.5	129,391,864	620,748	0.0048	0.9952	99.12
2.5	92,229,954	308,252	0.0033	0.9967	98.64
3.5	74,423,079	462,757	0.0062	0.9938	98.31
4.5	71,518,091	193,727	0.0027	0.9973	97.70
5.5	69,223,860	227,079	0.0033	0.9967	97.43
6.5	65,376,292	195,434	0.0030	0.9970	97.11
7.5	59,931,489	203,620	0.0034	0.9966	96.82
8.5	50,630,294	142,086	0.0028	0.9972	96.50
9.5	44,961,617	175,573	0.0039	0.9961	96.22
10.5	36,348,108	139,910	0.0038	0.9962	95.85
11.5	32,231,558	182,351	0.0057	0.9943	95.48
12.5	27,911,164	131,663	0.0047	0.9953	94.94
13.5	24,284,091	102,356	0.0042	0.9958	94.49
14.5	20,704,823	138,883	0.0067	0.9933	94.09
15.5	17,228,739	76,309	0.0044	0.9956	93.46
16.5	13,694,935	101,654	0.0074	0.9926	93.05
17.5	11,868,834	48,688	0.0041	0.9959	92.36
18.5	10,726,604	52,217	0.0049	0.9951	91.98
19.5	9,700,791	48,529	0.0050	0.9950	91.53
20.5	8,574,419	40,539	0.0047	0.9953	91.07
21.5	7,850,502	45,925	0.0058	0.9942	90.64
22.5	6,447,692	28,575	0.0044	0.9956	90.11
23.5	5,332,412	30,976	0.0058	0.9942	89.71
24.5	4,440,231	22,354	0.0050	0.9950	89.19
25.5	3,889,120	16,440	0.0042	0.9958	88.74
26.5	3,584,823	15,382	0.0043	0.9957	88.37
27.5	3,218,471	13,775	0.0043	0.9957	87.99
28.5	2,871,388	17,205	0.0060	0.9940	87.61
29.5	2,580,392	13,439	0.0052	0.9948	87.09
30.5	2,333,008	16,557	0.0071	0.9929	86.63
31.5	1,901,450	13,255	0.0070	0.9930	86.02
32.5	1,539,555	10,802	0.0070	0.9930	85.42
33.5	1,254,428	14,712	0.0117	0.9883	84.82
34.5	1,053,527	18,866	0.0179	0.9821	83.82
35.5	778,732	13,077	0.0168	0.9832	82.32
36.5	526,870	7,517	0.0143	0.9857	80.94
37.5	225,390	5,896	0.0262	0.9738	79.79
38.5	169,006	2,107	0.0125	0.9875	77.70

KENTUCKY UTILITIES COMPANY

ACCOUNT 367 UNDERGROUND CONDUCTORS AND DEVICES

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1938-2011 EXPERIENCE BAND 1938-2011

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	67,971	744	0.0109	0.9891	76.73
40.5	54,465	2,847	0.0523	0.9477	75.89
41.5	32,181	1,640	0.0510	0.9490	71.92
42.5	30,541	3,462	0.1134	0.8866	68.26
43.5	8,222	468	0.0569	0.9431	60.52
44.5	3,950	3,459	0.8758	0.1242	57.08
45.5	618	304	0.4913	0.5087	7.09
46.5	314	40	0.1264	0.8736	3.60
47.5	216	88	0.4094	0.5906	3.15
48.5	128		0.0000	1.0000	1.86
49.5	128		0.0000	1.0000	1.86
50.5	128		0.0000	1.0000	1.86
51.5	128		0.0000	1.0000	1.86
52.5	128		0.0000	1.0000	1.86
53.5	128		0.0000	1.0000	1.86
54.5	128		0.0000	1.0000	1.86
55.5	4,001	528	0.1320	0.8680	1.86
56.5	3,473		0.0000	1.0000	1.61
57.5	3,473	64	0.0184	0.9816	1.61
58.5	3,409	64	0.0187	0.9813	1.59
59.5	3,345		0.0000	1.0000	1.56
60.5	3,345		0.0000	1.0000	1.56
61.5	3,345		0.0000	1.0000	1.56
62.5	3,345		0.0000	1.0000	1.56
63.5	3,345		0.0000	1.0000	1.56
64.5	3,345		0.0000	1.0000	1.56
65.5	3,345	3,345	1.0000		1.56
66.5					

KENTUCKY UTILITIES COMPANY

ACCOUNT 367 UNDERGROUND CONDUCTORS AND DEVICES

ORIGINAL LIFE TABLE

PLACEMENT BAND 1941-2011 EXPERIENCE BAND 1977-2011

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	144,376,609	472,233	0.0033	0.9967	100.00
0.5	133,800,217	748,033	0.0056	0.9944	99.67
1.5	128,519,824	614,268	0.0048	0.9952	99.12
2.5	91,700,284	302,899	0.0033	0.9967	98.64
3.5	74,066,090	459,294	0.0062	0.9938	98.32
4.5	71,309,276	191,388	0.0027	0.9973	97.71
5.5	69,083,144	225,149	0.0033	0.9967	97.44
6.5	65,283,526	195,266	0.0030	0.9970	97.13
7.5	59,847,426	203,620	0.0034	0.9966	96.84
8.5	50,579,507	141,989	0.0028	0.9972	96.51
9.5	44,918,514	172,944	0.0039	0.9961	96.24
10.5	36,317,293	139,910	0.0039	0.9961	95.87
11.5	32,203,349	179,190	0.0056	0.9944	95.50
12.5	27,887,215	131,663	0.0047	0.9953	94.96
13.5	24,261,157	102,356	0.0042	0.9958	94.52
14.5	20,681,889	138,883	0.0067	0.9933	94.12
15.5	17,205,805	76,309	0.0044	0.9956	93.49
16.5	13,672,001	101,654	0.0074	0.9926	93.07
17.5	11,845,900	48,688	0.0041	0.9959	92.38
18.5	10,703,670	52,217	0.0049	0.9951	92.00
19.5	9,677,857	48,529	0.0050	0.9950	91.55
20.5	8,551,573	37,453	0.0044	0.9956	91.09
21.5	7,834,897	36,077	0.0046	0.9954	90.69
22.5	6,441,939	28,575	0.0044	0.9956	90.27
23.5	5,326,765	30,976	0.0058	0.9942	89.87
24.5	4,434,584	22,354	0.0050	0.9950	89.35
25.5	3,883,473	16,440	0.0042	0.9958	88.90
26.5	3,579,176	15,382	0.0043	0.9957	88.52
27.5	3,212,824	13,775	0.0043	0.9957	88.14
28.5	2,865,741	17,205	0.0060	0.9940	87.77
29.5	2,574,745	13,439	0.0052	0.9948	87.24
30.5	2,327,361	13,450	0.0058	0.9942	86.78
31.5	1,898,910	13,255	0.0070	0.9930	86.28
32.5	1,537,015	10,802	0.0070	0.9930	85.68
33.5	1,251,888	14,712	0.0118	0.9882	85.08
34.5	1,050,987	18,618	0.0177	0.9823	84.08
35.5	776,440	13,077	0.0168	0.9832	82.59
36.5	524,578	5,225	0.0100	0.9900	81.20
37.5	225,390	5,896	0.0262	0.9738	80.39
38.5	169,006	2,107	0.0125	0.9875	78.29

KENTUCKY UTILITIES COMPANY

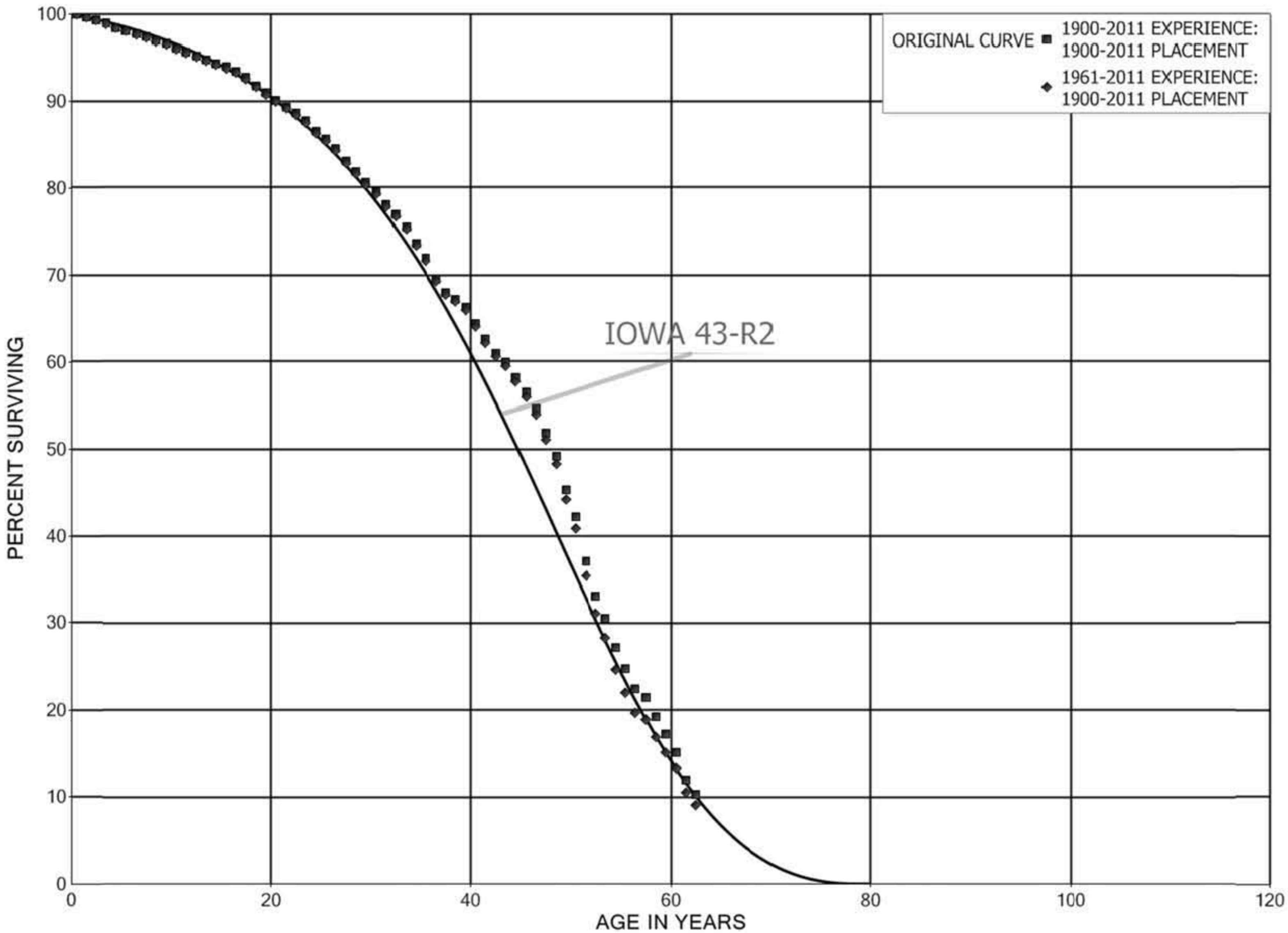
ACCOUNT 367 UNDERGROUND CONDUCTORS AND DEVICES

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1941-2011 EXPERIENCE BAND 1977-2011

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	67,971	744	0.0109	0.9891	77.31
40.5	54,465	2,847	0.0523	0.9477	76.46
41.5	32,181	1,640	0.0510	0.9490	72.47
42.5	30,541	3,462	0.1134	0.8866	68.77
43.5	8,222	468	0.0569	0.9431	60.98
44.5	3,950	3,459	0.8758	0.1242	57.51
45.5	618	304	0.4913	0.5087	7.14
46.5	314	40	0.1264	0.8736	3.63
47.5	216	88	0.4094	0.5906	3.17
48.5	128		0.0000	1.0000	1.87
49.5	128		0.0000	1.0000	1.87
50.5	128		0.0000	1.0000	1.87
51.5	128		0.0000	1.0000	1.87
52.5	128		0.0000	1.0000	1.87
53.5	128		0.0000	1.0000	1.87
54.5	128		0.0000	1.0000	1.87
55.5	4,001	528	0.1320	0.8680	1.87
56.5	3,473		0.0000	1.0000	1.63
57.5	3,473	64	0.0184	0.9816	1.63
58.5	3,409	64	0.0187	0.9813	1.60
59.5	3,345		0.0000	1.0000	1.57
60.5	3,345		0.0000	1.0000	1.57
61.5	3,345		0.0000	1.0000	1.57
62.5	3,345		0.0000	1.0000	1.57
63.5	3,345		0.0000	1.0000	1.57
64.5	3,345		0.0000	1.0000	1.57
65.5	3,345	3,345	1.0000		1.57
66.5					

KENTUCKY UTILITIES COMPANY
ACCOUNT 368 LINE TRANSFORMERS
ORIGINAL AND SMOOTH SURVIVOR CURVES



KENTUCKY UTILITIES COMPANY

ACCOUNT 368 LINE TRANSFORMERS

ORIGINAL LIFE TABLE

PLACEMENT BAND 1900-2011 EXPERIENCE BAND 1900-2011

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	320,736,564	317,485	0.0010	0.9990	100.00
0.5	315,972,575	1,000,135	0.0032	0.9968	99.90
1.5	312,828,153	786,510	0.0025	0.9975	99.58
2.5	295,799,196	1,258,393	0.0043	0.9957	99.33
3.5	285,068,507	1,337,338	0.0047	0.9953	98.91
4.5	272,378,391	987,763	0.0036	0.9964	98.45
5.5	252,817,579	1,070,140	0.0042	0.9958	98.09
6.5	251,322,293	654,178	0.0026	0.9974	97.68
7.5	246,077,689	1,199,376	0.0049	0.9951	97.42
8.5	231,716,386	907,357	0.0039	0.9961	96.95
9.5	225,171,335	1,158,104	0.0051	0.9949	96.57
10.5	213,883,325	917,686	0.0043	0.9957	96.07
11.5	203,119,351	1,042,516	0.0051	0.9949	95.66
12.5	194,936,587	858,117	0.0044	0.9956	95.17
13.5	185,090,032	866,852	0.0047	0.9953	94.75
14.5	174,884,310	708,011	0.0040	0.9960	94.30
15.5	165,402,164	932,821	0.0056	0.9944	93.92
16.5	155,109,189	1,195,532	0.0077	0.9923	93.39
17.5	144,438,125	1,410,205	0.0098	0.9902	92.67
18.5	134,435,650	1,282,266	0.0095	0.9905	91.77
19.5	126,233,235	1,110,213	0.0088	0.9912	90.89
20.5	118,991,957	1,005,192	0.0084	0.9916	90.09
21.5	111,371,480	933,101	0.0084	0.9916	89.33
22.5	103,678,113	1,033,546	0.0100	0.9900	88.58
23.5	95,871,434	1,292,931	0.0135	0.9865	87.70
24.5	88,604,749	967,826	0.0109	0.9891	86.52
25.5	81,426,385	1,054,721	0.0130	0.9870	85.57
26.5	74,931,332	1,290,498	0.0172	0.9828	84.46
27.5	69,825,925	1,018,341	0.0146	0.9854	83.01
28.5	63,328,584	913,848	0.0144	0.9856	81.80
29.5	57,518,997	816,726	0.0142	0.9858	80.62
30.5	54,525,109	952,957	0.0175	0.9825	79.47
31.5	50,463,575	751,121	0.0149	0.9851	78.09
32.5	45,087,714	840,733	0.0186	0.9814	76.92
33.5	39,604,004	957,884	0.0242	0.9758	75.49
34.5	34,229,335	805,436	0.0235	0.9765	73.66
35.5	30,949,325	1,033,551	0.0334	0.9666	71.93
36.5	28,031,629	628,633	0.0224	0.9776	69.53
37.5	23,303,960	257,119	0.0110	0.9890	67.97
38.5	19,598,755	284,638	0.0145	0.9855	67.22

KENTUCKY UTILITIES COMPANY

ACCOUNT 368 LINE TRANSFORMERS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1900-2011 EXPERIENCE BAND 1900-2011

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	17,389,274	471,321	0.0271	0.9729	66.24
40.5	15,207,419	433,636	0.0285	0.9715	64.45
41.5	12,999,345	336,699	0.0259	0.9741	62.61
42.5	11,387,889	199,820	0.0175	0.9825	60.99
43.5	10,305,229	292,369	0.0284	0.9716	59.92
44.5	8,813,362	251,541	0.0285	0.9715	58.22
45.5	7,897,356	268,551	0.0340	0.9660	56.56
46.5	6,918,695	352,089	0.0509	0.9491	54.63
47.5	6,124,086	312,184	0.0510	0.9490	51.85
48.5	5,442,379	436,055	0.0801	0.9199	49.21
49.5	4,414,326	303,421	0.0687	0.9313	45.27
50.5	3,886,868	473,390	0.1218	0.8782	42.15
51.5	3,180,307	343,834	0.1081	0.8919	37.02
52.5	2,645,799	198,016	0.0748	0.9252	33.02
53.5	2,303,234	254,995	0.1107	0.8893	30.55
54.5	1,965,307	174,625	0.0889	0.9111	27.17
55.5	1,761,540	167,933	0.0953	0.9047	24.75
56.5	1,511,961	66,504	0.0440	0.9560	22.39
57.5	1,420,400	147,949	0.1042	0.8958	21.41
58.5	1,097,086	114,244	0.1041	0.8959	19.18
59.5	916,366	110,163	0.1202	0.8798	17.18
60.5	780,945	162,942	0.2086	0.7914	15.11
61.5	589,726	83,288	0.1412	0.8588	11.96
62.5	250,383	40,737	0.1627	0.8373	10.27
63.5	193,992	18,254	0.0941	0.9059	8.60
64.5	166,668	37,706	0.2262	0.7738	7.79
65.5	115,405	38,374	0.3325	0.6675	6.03
66.5	71,850	20,825	0.2898	0.7102	4.02
67.5	48,355	16,077	0.3325	0.6675	2.86
68.5	30,487	271	0.0089	0.9911	1.91
69.5	28,782	1,305	0.0453	0.9547	1.89
70.5	437		0.0000	1.0000	1.80
71.5	437		0.0000	1.0000	1.80
72.5	437		0.0000	1.0000	1.80
73.5	437		0.0000	1.0000	1.80
74.5	437		0.0000	1.0000	1.80
75.5	437		0.0000	1.0000	1.80
76.5	437		0.0000	1.0000	1.80
77.5	437		0.0000	1.0000	1.80
78.5	437		0.0000	1.0000	1.80

KENTUCKY UTILITIES COMPANY

ACCOUNT 368 LINE TRANSFORMERS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1900-2011 EXPERIENCE BAND 1900-2011

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
79.5	437		0.0000	1.0000	1.80
80.5	437	399	0.9130	0.0870	1.80
81.5	38		0.0000	1.0000	0.16
82.5	38		0.0000	1.0000	0.16
83.5	38		0.0000	1.0000	0.16
84.5	38		0.0000	1.0000	0.16
85.5	38		0.0000	1.0000	0.16
86.5	38		0.0000	1.0000	0.16
87.5	38	38	1.0000		0.16
88.5					

KENTUCKY UTILITIES COMPANY

ACCOUNT 368 LINE TRANSFORMERS

ORIGINAL LIFE TABLE

PLACEMENT BAND 1900-2011 EXPERIENCE BAND 1961-2011

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	307,434,527	317,485	0.0010	0.9990	100.00
0.5	303,822,256	1,000,135	0.0033	0.9967	99.90
1.5	301,803,769	786,510	0.0026	0.9974	99.57
2.5	285,744,603	1,258,393	0.0044	0.9956	99.31
3.5	275,869,581	1,337,338	0.0048	0.9952	98.87
4.5	264,077,928	987,763	0.0037	0.9963	98.39
5.5	245,456,358	1,070,140	0.0044	0.9956	98.02
6.5	244,711,528	654,178	0.0027	0.9973	97.60
7.5	240,069,925	1,199,376	0.0050	0.9950	97.34
8.5	226,174,314	907,357	0.0040	0.9960	96.85
9.5	220,081,247	1,158,104	0.0053	0.9947	96.46
10.5	209,532,455	917,686	0.0044	0.9956	95.95
11.5	199,638,614	1,042,516	0.0052	0.9948	95.53
12.5	191,911,912	858,117	0.0045	0.9955	95.03
13.5	182,765,698	866,852	0.0047	0.9953	94.61
14.5	172,900,252	708,011	0.0041	0.9959	94.16
15.5	163,803,677	932,821	0.0057	0.9943	93.77
16.5	153,701,062	1,195,532	0.0078	0.9922	93.24
17.5	143,101,053	1,410,205	0.0099	0.9901	92.52
18.5	133,172,883	1,282,266	0.0096	0.9904	91.60
19.5	125,304,268	1,110,213	0.0089	0.9911	90.72
20.5	118,190,061	1,005,192	0.0085	0.9915	89.92
21.5	110,686,556	933,101	0.0084	0.9916	89.15
22.5	103,016,605	1,033,546	0.0100	0.9900	88.40
23.5	95,353,542	1,292,931	0.0136	0.9864	87.51
24.5	88,197,111	967,826	0.0110	0.9890	86.33
25.5	81,019,509	1,054,721	0.0130	0.9870	85.38
26.5	74,527,108	1,290,498	0.0173	0.9827	84.27
27.5	69,422,439	1,018,341	0.0147	0.9853	82.81
28.5	62,925,488	913,848	0.0145	0.9855	81.60
29.5	57,118,552	816,726	0.0143	0.9857	80.41
30.5	54,126,975	952,957	0.0176	0.9824	79.26
31.5	50,068,302	751,121	0.0150	0.9850	77.87
32.5	44,695,086	840,733	0.0188	0.9812	76.70
33.5	39,215,427	957,884	0.0244	0.9756	75.25
34.5	33,843,329	805,436	0.0238	0.9762	73.42
35.5	30,564,265	1,033,551	0.0338	0.9662	71.67
36.5	27,647,461	628,633	0.0227	0.9773	69.25
37.5	22,920,108	257,119	0.0112	0.9888	67.67
38.5	19,217,884	284,638	0.0148	0.9852	66.91

KENTUCKY UTILITIES COMPANY

ACCOUNT 368 LINE TRANSFORMERS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1900-2011 EXPERIENCE BAND 1961-2011

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	17,010,848	471,321	0.0277	0.9723	65.92
40.5	14,830,556	433,636	0.0292	0.9708	64.09
41.5	12,627,136	336,699	0.0267	0.9733	62.22
42.5	11,016,241	199,820	0.0181	0.9819	60.56
43.5	9,934,211	292,369	0.0294	0.9706	59.46
44.5	8,443,144	251,541	0.0298	0.9702	57.71
45.5	7,527,220	268,551	0.0357	0.9643	55.99
46.5	6,548,660	352,089	0.0538	0.9462	54.00
47.5	5,755,059	312,184	0.0542	0.9458	51.09
48.5	5,073,617	436,055	0.0859	0.9141	48.32
49.5	4,045,564	303,421	0.0750	0.9250	44.17
50.5	3,518,233	473,390	0.1346	0.8654	40.86
51.5	2,811,672	343,834	0.1223	0.8777	35.36
52.5	2,277,563	198,016	0.0869	0.9131	31.03
53.5	1,934,998	254,995	0.1318	0.8682	28.34
54.5	1,597,071	174,625	0.1093	0.8907	24.60
55.5	1,639,624	167,933	0.1024	0.8976	21.91
56.5	1,511,923	66,504	0.0440	0.9560	19.67
57.5	1,420,362	147,949	0.1042	0.8958	18.80
58.5	1,097,048	114,244	0.1041	0.8959	16.84
59.5	916,328	110,163	0.1202	0.8798	15.09
60.5	780,945	162,942	0.2086	0.7914	13.28
61.5	589,726	83,288	0.1412	0.8588	10.51
62.5	250,383	40,737	0.1627	0.8373	9.02
63.5	193,992	18,254	0.0941	0.9059	7.55
64.5	166,668	37,706	0.2262	0.7738	6.84
65.5	115,405	38,374	0.3325	0.6675	5.30
66.5	71,850	20,825	0.2898	0.7102	3.53
67.5	48,355	16,077	0.3325	0.6675	2.51
68.5	30,487	271	0.0089	0.9911	1.68
69.5	28,782	1,305	0.0453	0.9547	1.66
70.5	437		0.0000	1.0000	1.59
71.5	437		0.0000	1.0000	1.59
72.5	437		0.0000	1.0000	1.59
73.5	437		0.0000	1.0000	1.59
74.5	437		0.0000	1.0000	1.59
75.5	437		0.0000	1.0000	1.59
76.5	437		0.0000	1.0000	1.59
77.5	437		0.0000	1.0000	1.59
78.5	437		0.0000	1.0000	1.59

KENTUCKY UTILITIES COMPANY

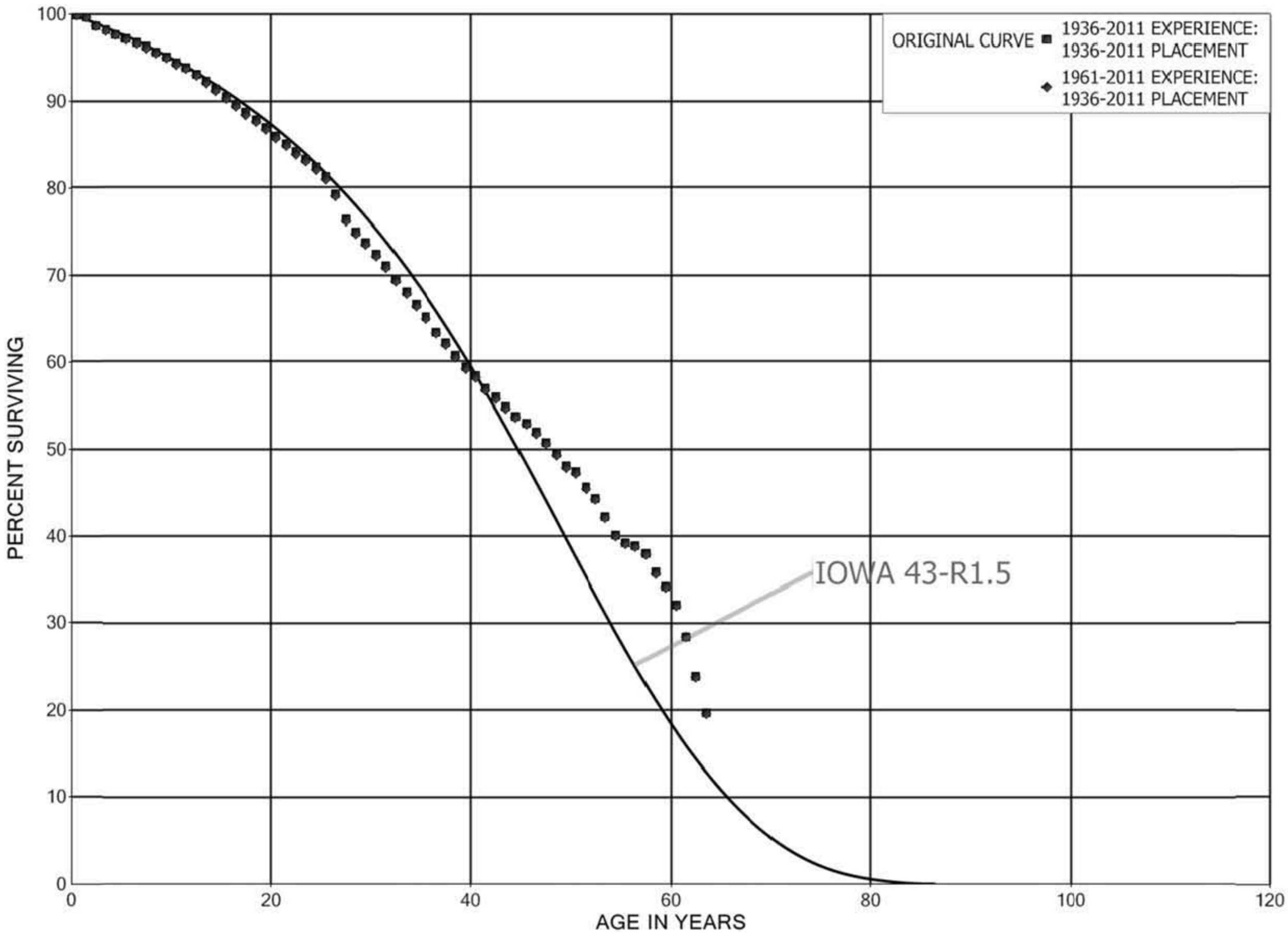
ACCOUNT 368 LINE TRANSFORMERS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1900-2011 EXPERIENCE BAND 1961-2011

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
79.5	437		0.0000	1.0000	1.59
80.5	437	399	0.9130	0.0870	1.59
81.5	38		0.0000	1.0000	0.14
82.5	38		0.0000	1.0000	0.14
83.5	38		0.0000	1.0000	0.14
84.5	38		0.0000	1.0000	0.14
85.5	38		0.0000	1.0000	0.14
86.5	38		0.0000	1.0000	0.14
87.5	38	38	1.0000		0.14
88.5					

KENTUCKY UTILITIES COMPANY
ACCOUNT 369 SERVICES
ORIGINAL AND SMOOTH SURVIVOR CURVES



KENTUCKY UTILITIES COMPANY

ACCOUNT 369 SERVICES

ORIGINAL LIFE TABLE

PLACEMENT BAND 1936-2011 EXPERIENCE BAND 1936-2011

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	106,739,868	167,629	0.0016	0.9984	100.00
0.5	100,793,020	255,385	0.0025	0.9975	99.84
1.5	96,627,222	909,036	0.0094	0.9906	99.59
2.5	95,678,330	497,946	0.0052	0.9948	98.65
3.5	93,060,720	458,965	0.0049	0.9951	98.14
4.5	92,588,277	441,857	0.0048	0.9952	97.66
5.5	92,119,924	451,397	0.0049	0.9951	97.19
6.5	91,668,527	451,471	0.0049	0.9951	96.71
7.5	91,033,888	558,993	0.0061	0.9939	96.24
8.5	89,236,636	539,193	0.0060	0.9940	95.65
9.5	85,658,401	649,474	0.0076	0.9924	95.07
10.5	82,005,306	404,841	0.0049	0.9951	94.35
11.5	78,834,558	665,272	0.0084	0.9916	93.88
12.5	73,860,045	639,637	0.0087	0.9913	93.09
13.5	67,956,246	640,534	0.0094	0.9906	92.28
14.5	62,110,075	629,449	0.0101	0.9899	91.41
15.5	56,634,955	569,449	0.0101	0.9899	90.49
16.5	51,442,490	510,925	0.0099	0.9901	89.58
17.5	47,115,377	453,201	0.0096	0.9904	88.69
18.5	43,361,381	440,611	0.0102	0.9898	87.83
19.5	40,390,064	433,793	0.0107	0.9893	86.94
20.5	37,369,868	398,281	0.0107	0.9893	86.01
21.5	34,627,057	391,877	0.0113	0.9887	85.09
22.5	31,762,045	304,714	0.0096	0.9904	84.13
23.5	29,191,511	330,300	0.0113	0.9887	83.32
24.5	27,264,407	377,319	0.0138	0.9862	82.38
25.5	24,830,358	598,497	0.0241	0.9759	81.24
26.5	22,228,066	810,545	0.0365	0.9635	79.28
27.5	19,345,932	352,866	0.0182	0.9818	76.39
28.5	16,769,877	276,208	0.0165	0.9835	75.00
29.5	15,145,375	274,879	0.0181	0.9819	73.76
30.5	13,529,484	243,622	0.0180	0.9820	72.42
31.5	12,369,370	277,415	0.0224	0.9776	71.12
32.5	10,841,164	219,558	0.0203	0.9797	69.52
33.5	9,473,976	212,959	0.0225	0.9775	68.12
34.5	8,025,167	173,563	0.0216	0.9784	66.58
35.5	6,866,322	178,599	0.0260	0.9740	65.14
36.5	6,071,785	126,478	0.0208	0.9792	63.45
37.5	5,181,432	115,228	0.0222	0.9778	62.13
38.5	4,583,407	100,367	0.0219	0.9781	60.75

KENTUCKY UTILITIES COMPANY

ACCOUNT 369 SERVICES

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1936-2011 EXPERIENCE BAND 1936-2011

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	4,068,036	71,703	0.0176	0.9824	59.42
40.5	3,628,267	88,296	0.0243	0.9757	58.37
41.5	3,374,253	62,335	0.0185	0.9815	56.95
42.5	3,075,390	60,961	0.0198	0.9802	55.90
43.5	2,832,413	52,526	0.0185	0.9815	54.79
44.5	2,535,907	37,259	0.0147	0.9853	53.77
45.5	2,305,749	46,979	0.0204	0.9796	52.98
46.5	2,137,296	47,166	0.0221	0.9779	51.90
47.5	1,904,758	48,171	0.0253	0.9747	50.76
48.5	1,683,763	49,613	0.0295	0.9705	49.47
49.5	1,475,246	20,663	0.0140	0.9860	48.02
50.5	1,282,262	47,287	0.0369	0.9631	47.34
51.5	1,191,165	34,641	0.0291	0.9709	45.60
52.5	1,004,765	46,384	0.0462	0.9538	44.27
53.5	857,707	43,542	0.0508	0.9492	42.23
54.5	697,931	16,234	0.0233	0.9767	40.08
55.5	588,040	3,955	0.0067	0.9933	39.15
56.5	557,646	13,800	0.0247	0.9753	38.89
57.5	541,474	30,635	0.0566	0.9434	37.93
58.5	492,698	21,373	0.0434	0.9566	35.78
59.5	432,628	27,175	0.0628	0.9372	34.23
60.5	382,631	43,325	0.1132	0.8868	32.08
61.5	313,850	50,931	0.1623	0.8377	28.45
62.5	232,549	41,625	0.1790	0.8210	23.83
63.5	165,614	30,025	0.1813	0.8187	19.56
64.5	135,589	7,467	0.0551	0.9449	16.02
65.5	128,122	2,767	0.0216	0.9784	15.14
66.5	125,355	1,082	0.0086	0.9914	14.81
67.5	124,273	4,874	0.0392	0.9608	14.68
68.5	119,400	93,745	0.7851	0.2149	14.11
69.5	25,655	25,655	1.0000		3.03
70.5					

KENTUCKY UTILITIES COMPANY

ACCOUNT 369 SERVICES

ORIGINAL LIFE TABLE

PLACEMENT BAND 1936-2011 EXPERIENCE BAND 1961-2011

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	102,231,657	167,629	0.0016	0.9984	100.00
0.5	96,646,605	255,385	0.0026	0.9974	99.84
1.5	92,861,875	909,036	0.0098	0.9902	99.57
2.5	92,275,161	497,946	0.0054	0.9946	98.60
3.5	90,011,005	458,965	0.0051	0.9949	98.07
4.5	89,857,213	441,857	0.0049	0.9951	97.57
5.5	89,666,068	451,397	0.0050	0.9950	97.09
6.5	89,433,685	451,471	0.0050	0.9950	96.60
7.5	88,883,126	558,993	0.0063	0.9937	96.11
8.5	87,237,306	539,193	0.0062	0.9938	95.50
9.5	83,755,130	649,474	0.0078	0.9922	94.91
10.5	80,227,093	404,841	0.0050	0.9950	94.18
11.5	77,212,542	665,272	0.0086	0.9914	93.70
12.5	72,529,772	639,637	0.0088	0.9912	92.90
13.5	66,938,685	640,534	0.0096	0.9904	92.08
14.5	61,323,276	629,449	0.0103	0.9897	91.20
15.5	55,937,113	569,449	0.0102	0.9898	90.26
16.5	50,790,356	510,925	0.0101	0.9899	89.34
17.5	46,482,633	453,201	0.0097	0.9903	88.44
18.5	42,776,547	440,611	0.0103	0.9897	87.58
19.5	40,055,130	433,793	0.0108	0.9892	86.68
20.5	37,118,452	398,281	0.0107	0.9893	85.74
21.5	34,456,908	391,877	0.0114	0.9886	84.82
22.5	31,672,142	304,714	0.0096	0.9904	83.85
23.5	29,131,131	330,300	0.0113	0.9887	83.05
24.5	27,264,407	377,319	0.0138	0.9862	82.11
25.5	24,830,358	598,497	0.0241	0.9759	80.97
26.5	22,228,066	810,545	0.0365	0.9635	79.02
27.5	19,345,932	352,866	0.0182	0.9818	76.14
28.5	16,769,877	276,208	0.0165	0.9835	74.75
29.5	15,145,375	274,879	0.0181	0.9819	73.52
30.5	13,529,484	243,622	0.0180	0.9820	72.18
31.5	12,369,370	277,415	0.0224	0.9776	70.88
32.5	10,841,164	219,558	0.0203	0.9797	69.29
33.5	9,473,976	212,959	0.0225	0.9775	67.89
34.5	8,025,167	173,563	0.0216	0.9784	66.36
35.5	6,866,322	178,599	0.0260	0.9740	64.93
36.5	6,071,785	126,478	0.0208	0.9792	63.24
37.5	5,181,432	115,228	0.0222	0.9778	61.92
38.5	4,583,407	100,367	0.0219	0.9781	60.55

KENTUCKY UTILITIES COMPANY

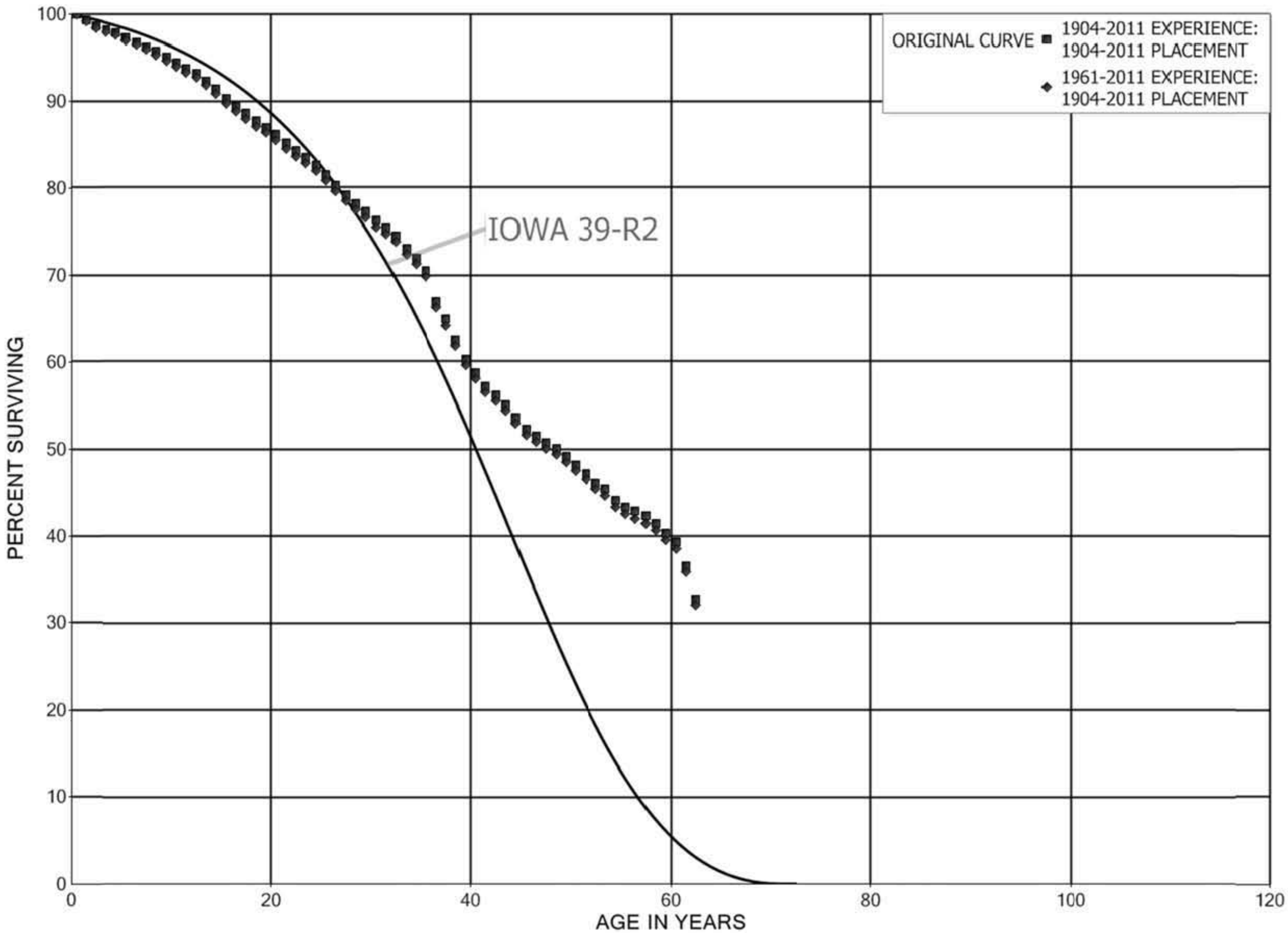
ACCOUNT 369 SERVICES

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1936-2011 EXPERIENCE BAND 1961-2011

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	4,068,036	71,703	0.0176	0.9824	59.22
40.5	3,628,267	88,296	0.0243	0.9757	58.18
41.5	3,374,253	62,335	0.0185	0.9815	56.76
42.5	3,075,390	60,961	0.0198	0.9802	55.71
43.5	2,832,413	52,526	0.0185	0.9815	54.61
44.5	2,535,907	37,259	0.0147	0.9853	53.59
45.5	2,305,749	46,979	0.0204	0.9796	52.81
46.5	2,137,296	47,166	0.0221	0.9779	51.73
47.5	1,904,758	48,171	0.0253	0.9747	50.59
48.5	1,683,763	49,613	0.0295	0.9705	49.31
49.5	1,475,246	20,663	0.0140	0.9860	47.86
50.5	1,282,262	47,287	0.0369	0.9631	47.19
51.5	1,191,165	34,641	0.0291	0.9709	45.45
52.5	1,004,765	46,384	0.0462	0.9538	44.12
53.5	857,707	43,542	0.0508	0.9492	42.09
54.5	697,931	16,234	0.0233	0.9767	39.95
55.5	588,040	3,955	0.0067	0.9933	39.02
56.5	557,646	13,800	0.0247	0.9753	38.76
57.5	541,474	30,635	0.0566	0.9434	37.80
58.5	492,698	21,373	0.0434	0.9566	35.66
59.5	432,628	27,175	0.0628	0.9372	34.11
60.5	382,631	43,325	0.1132	0.8868	31.97
61.5	313,850	50,931	0.1623	0.8377	28.35
62.5	232,549	41,625	0.1790	0.8210	23.75
63.5	165,614	30,025	0.1813	0.8187	19.50
64.5	135,589	7,467	0.0551	0.9449	15.96
65.5	128,122	2,767	0.0216	0.9784	15.09
66.5	125,355	1,082	0.0086	0.9914	14.76
67.5	124,273	4,874	0.0392	0.9608	14.63
68.5	119,400	93,745	0.7851	0.2149	14.06
69.5	25,655	25,655	1.0000		3.02
70.5					

KENTUCKY UTILITIES COMPANY
ACCOUNT 370 METERS
ORIGINAL AND SMOOTH SURVIVOR CURVES



KENTUCKY UTILITIES COMPANY

ACCOUNT 370 METERS

ORIGINAL LIFE TABLE

PLACEMENT BAND 1904-2011 EXPERIENCE BAND 1904-2011

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	87,782,475	10,093	0.0001	0.9999	100.00
0.5	87,715,896	624,504	0.0071	0.9929	99.99
1.5	85,547,397	605,693	0.0071	0.9929	99.28
2.5	82,227,807	355,291	0.0043	0.9957	98.57
3.5	81,827,216	303,922	0.0037	0.9963	98.15
4.5	80,425,697	442,090	0.0055	0.9945	97.78
5.5	76,494,044	375,962	0.0049	0.9951	97.25
6.5	75,911,145	436,184	0.0057	0.9943	96.77
7.5	74,932,221	408,409	0.0055	0.9945	96.21
8.5	72,678,099	492,303	0.0068	0.9932	95.69
9.5	70,263,804	460,344	0.0066	0.9934	95.04
10.5	67,382,851	467,467	0.0069	0.9931	94.42
11.5	64,527,128	394,714	0.0061	0.9939	93.76
12.5	62,815,959	573,099	0.0091	0.9909	93.19
13.5	59,006,467	605,556	0.0103	0.9897	92.34
14.5	55,959,978	705,489	0.0126	0.9874	91.39
15.5	53,340,100	500,203	0.0094	0.9906	90.24
16.5	50,914,845	466,761	0.0092	0.9908	89.39
17.5	48,699,779	472,795	0.0097	0.9903	88.57
18.5	46,753,495	394,280	0.0084	0.9916	87.71
19.5	43,641,158	420,277	0.0096	0.9904	86.97
20.5	41,603,094	457,212	0.0110	0.9890	86.14
21.5	39,569,830	443,178	0.0112	0.9888	85.19
22.5	37,756,544	331,334	0.0088	0.9912	84.23
23.5	36,003,827	386,514	0.0107	0.9893	83.50
24.5	34,243,888	453,046	0.0132	0.9868	82.60
25.5	32,433,324	469,846	0.0145	0.9855	81.51
26.5	30,828,447	438,613	0.0142	0.9858	80.33
27.5	29,289,112	372,684	0.0127	0.9873	79.18
28.5	27,456,580	312,903	0.0114	0.9886	78.17
29.5	26,126,330	345,430	0.0132	0.9868	77.28
30.5	25,003,105	278,422	0.0111	0.9889	76.26
31.5	23,883,375	291,109	0.0122	0.9878	75.41
32.5	21,822,841	413,125	0.0189	0.9811	74.49
33.5	19,919,206	303,262	0.0152	0.9848	73.08
34.5	17,736,408	363,682	0.0205	0.9795	71.97
35.5	16,341,199	810,957	0.0496	0.9504	70.50
36.5	14,797,130	461,856	0.0312	0.9688	67.00
37.5	12,616,692	465,010	0.0369	0.9631	64.91
38.5	11,249,769	391,513	0.0348	0.9652	62.51

KENTUCKY UTILITIES COMPANY

ACCOUNT 370 METERS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1904-2011 EXPERIENCE BAND 1904-2011

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	10,065,845	263,682	0.0262	0.9738	60.34
40.5	9,073,620	236,547	0.0261	0.9739	58.76
41.5	8,288,169	148,467	0.0179	0.9821	57.23
42.5	7,531,881	158,973	0.0211	0.9789	56.20
43.5	6,851,140	168,838	0.0246	0.9754	55.01
44.5	6,273,572	156,557	0.0250	0.9750	53.66
45.5	5,672,371	87,560	0.0154	0.9846	52.32
46.5	5,083,793	78,004	0.0153	0.9847	51.51
47.5	4,615,183	62,662	0.0136	0.9864	50.72
48.5	4,176,236	70,384	0.0169	0.9831	50.03
49.5	3,789,812	79,218	0.0209	0.9791	49.19
50.5	3,404,452	69,767	0.0205	0.9795	48.16
51.5	3,043,253	68,196	0.0224	0.9776	47.17
52.5	2,692,052	42,685	0.0159	0.9841	46.12
53.5	2,336,561	69,935	0.0299	0.9701	45.39
54.5	2,049,553	34,345	0.0168	0.9832	44.03
55.5	1,849,727	21,040	0.0114	0.9886	43.29
56.5	1,641,570	21,725	0.0132	0.9868	42.80
57.5	1,454,232	27,661	0.0190	0.9810	42.23
58.5	1,318,723	36,268	0.0275	0.9725	41.43
59.5	1,082,898	27,682	0.0256	0.9744	40.29
60.5	825,151	57,704	0.0699	0.9301	39.26
61.5	579,236	60,281	0.1041	0.8959	36.51
62.5	437,719	18,391	0.0420	0.9580	32.71
63.5	340,106	9,701	0.0285	0.9715	31.34
64.5	251,624	7,297	0.0290	0.9710	30.44
65.5	205,937	12,734	0.0618	0.9382	29.56
66.5	169,398	139	0.0008	0.9992	27.73
67.5	157,365	34,387	0.2185	0.7815	27.71
68.5	110,353	2,980	0.0270	0.9730	21.66
69.5	98,834	675	0.0068	0.9932	21.07
70.5	340		0.0000	1.0000	20.93
71.5	256		0.0000	1.0000	20.93
72.5	256		0.0000	1.0000	20.93
73.5	256		0.0000	1.0000	20.93
74.5	256		0.0000	1.0000	20.93
75.5	256		0.0000	1.0000	20.93
76.5	256		0.0000	1.0000	20.93
77.5	256		0.0000	1.0000	20.93
78.5	256		0.0000	1.0000	20.93
79.5					20.93

KENTUCKY UTILITIES COMPANY

ACCOUNT 370 METERS

ORIGINAL LIFE TABLE

PLACEMENT BAND 1904-2011 EXPERIENCE BAND 1961-2011

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	79,140,563	10,093	0.0001	0.9999	100.00
0.5	79,646,674	624,504	0.0078	0.9922	99.99
1.5	78,093,590	605,693	0.0078	0.9922	99.20
2.5	75,342,959	355,291	0.0047	0.9953	98.43
3.5	75,494,863	303,922	0.0040	0.9960	97.97
4.5	74,669,792	442,090	0.0059	0.9941	97.58
5.5	71,241,796	375,962	0.0053	0.9947	97.00
6.5	71,145,221	436,184	0.0061	0.9939	96.49
7.5	70,468,539	408,409	0.0058	0.9942	95.89
8.5	68,662,220	492,303	0.0072	0.9928	95.34
9.5	66,751,590	460,344	0.0069	0.9931	94.65
10.5	64,388,396	467,467	0.0073	0.9927	94.00
11.5	61,955,129	394,714	0.0064	0.9936	93.32
12.5	60,515,823	573,099	0.0095	0.9905	92.73
13.5	57,198,055	605,556	0.0106	0.9894	91.85
14.5	54,414,695	705,489	0.0130	0.9870	90.87
15.5	51,937,755	500,203	0.0096	0.9904	89.70
16.5	49,622,957	466,761	0.0094	0.9906	88.83
17.5	47,445,389	472,795	0.0100	0.9900	88.00
18.5	45,547,809	394,280	0.0087	0.9913	87.12
19.5	42,727,498	420,277	0.0098	0.9902	86.37
20.5	40,749,074	457,212	0.0112	0.9888	85.52
21.5	38,755,935	443,178	0.0114	0.9886	84.56
22.5	37,029,642	331,334	0.0089	0.9911	83.59
23.5	35,356,268	386,514	0.0109	0.9891	82.84
24.5	33,674,974	453,046	0.0135	0.9865	81.94
25.5	31,927,276	469,846	0.0147	0.9853	80.83
26.5	30,368,163	438,613	0.0144	0.9856	79.64
27.5	28,855,754	372,684	0.0129	0.9871	78.49
28.5	27,065,722	312,903	0.0116	0.9884	77.48
29.5	25,749,727	345,430	0.0134	0.9866	76.58
30.5	24,676,378	278,422	0.0113	0.9887	75.56
31.5	23,614,727	291,109	0.0123	0.9877	74.70
32.5	21,609,353	413,125	0.0191	0.9809	73.78
33.5	19,772,979	303,262	0.0153	0.9847	72.37
34.5	17,632,072	363,682	0.0206	0.9794	71.26
35.5	16,237,870	810,957	0.0499	0.9501	69.79
36.5	14,694,729	461,856	0.0314	0.9686	66.31
37.5	12,515,866	465,010	0.0372	0.9628	64.22
38.5	11,149,822	391,513	0.0351	0.9649	61.84

KENTUCKY UTILITIES COMPANY

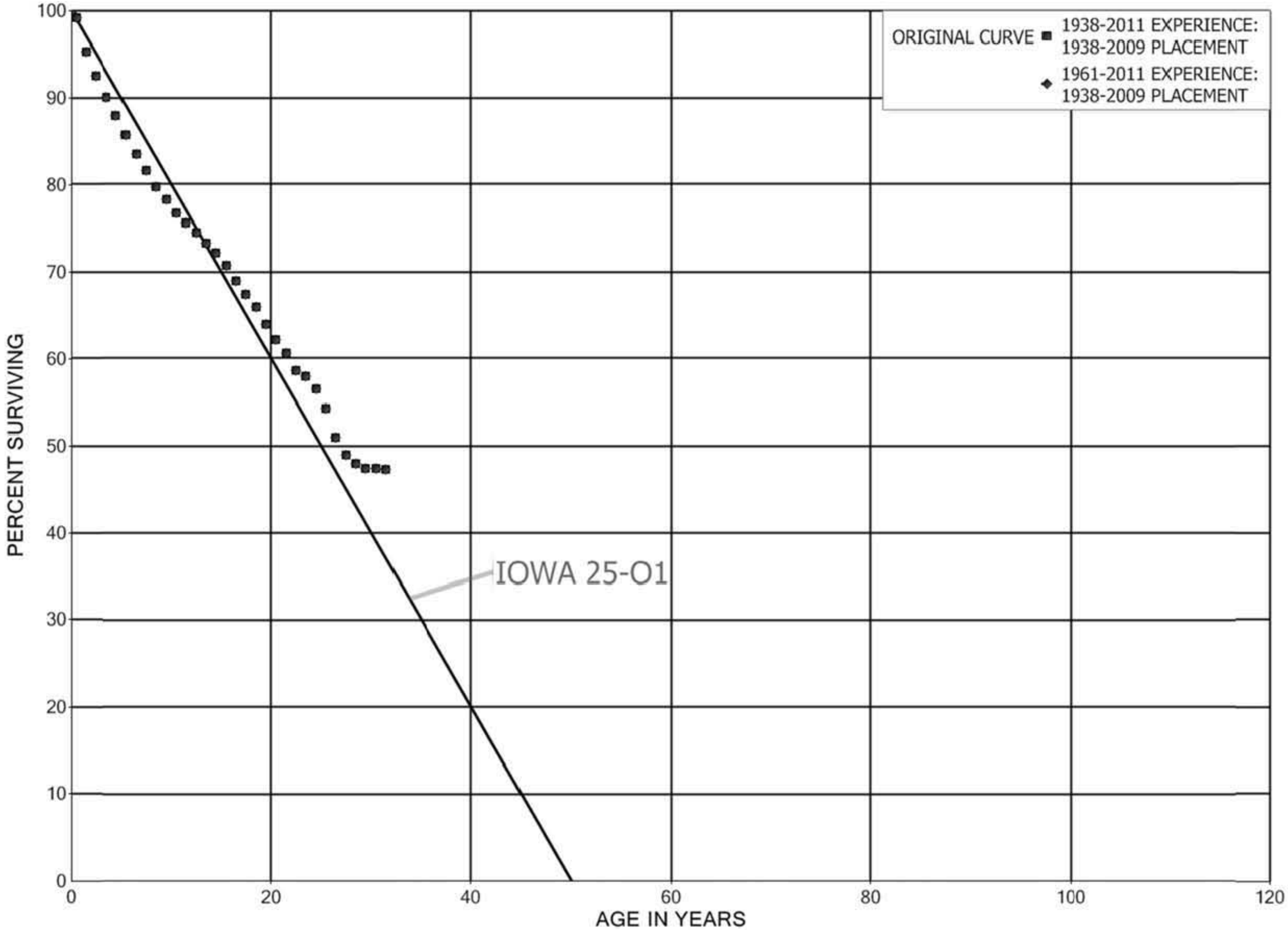
ACCOUNT 370 METERS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1904-2011 EXPERIENCE BAND 1961-2011

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	9,966,654	263,682	0.0265	0.9735	59.67
40.5	8,975,381	236,547	0.0264	0.9736	58.09
41.5	8,190,319	148,467	0.0181	0.9819	56.56
42.5	7,434,210	158,973	0.0214	0.9786	55.53
43.5	6,753,833	168,838	0.0250	0.9750	54.34
44.5	6,176,599	156,557	0.0253	0.9747	52.99
45.5	5,575,529	87,560	0.0157	0.9843	51.64
46.5	4,987,040	78,004	0.0156	0.9844	50.83
47.5	4,518,502	62,662	0.0139	0.9861	50.04
48.5	4,079,628	70,384	0.0173	0.9827	49.34
49.5	3,693,204	79,218	0.0214	0.9786	48.49
50.5	3,307,844	69,767	0.0211	0.9789	47.45
51.5	2,946,645	68,196	0.0231	0.9769	46.45
52.5	2,595,444	42,685	0.0164	0.9836	45.38
53.5	2,239,953	69,935	0.0312	0.9688	44.63
54.5	1,952,955	34,345	0.0176	0.9824	43.24
55.5	1,753,140	21,040	0.0120	0.9880	42.48
56.5	1,641,570	21,725	0.0132	0.9868	41.97
57.5	1,454,232	27,661	0.0190	0.9810	41.41
58.5	1,318,723	36,268	0.0275	0.9725	40.62
59.5	1,082,898	27,682	0.0256	0.9744	39.51
60.5	825,151	57,704	0.0699	0.9301	38.50
61.5	579,236	60,281	0.1041	0.8959	35.80
62.5	437,719	18,391	0.0420	0.9580	32.08
63.5	340,106	9,701	0.0285	0.9715	30.73
64.5	251,624	7,297	0.0290	0.9710	29.85
65.5	205,937	12,734	0.0618	0.9382	28.99
66.5	169,398	139	0.0008	0.9992	27.19
67.5	157,365	34,387	0.2185	0.7815	27.17
68.5	110,353	2,980	0.0270	0.9730	21.23
69.5	98,834	675	0.0068	0.9932	20.66
70.5	340		0.0000	1.0000	20.52
71.5	256		0.0000	1.0000	20.52
72.5	256		0.0000	1.0000	20.52
73.5	256		0.0000	1.0000	20.52
74.5	256		0.0000	1.0000	20.52
75.5	256		0.0000	1.0000	20.52
76.5	256		0.0000	1.0000	20.52
77.5	256		0.0000	1.0000	20.52
78.5	256		0.0000	1.0000	20.52
79.5					20.52

KENTUCKY UTILITIES COMPANY
ACCOUNT 371 INSTALLATIONS ON CUSTOMERS' PREMISES
ORIGINAL AND SMOOTH SURVIVOR CURVES



KENTUCKY UTILITIES COMPANY

ACCOUNT 371 INSTALLATIONS ON CUSTOMERS' PREMISES

ORIGINAL LIFE TABLE

PLACEMENT BAND 1938-2009 EXPERIENCE BAND 1938-2011

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	28,154,834	224,710	0.0080	0.9920	100.00
0.5	27,930,124	1,110,271	0.0398	0.9602	99.20
1.5	26,819,853	774,921	0.0289	0.9711	95.26
2.5	26,044,932	690,773	0.0265	0.9735	92.51
3.5	25,352,438	601,405	0.0237	0.9763	90.05
4.5	24,743,391	626,274	0.0253	0.9747	87.92
5.5	24,108,301	604,337	0.0251	0.9749	85.69
6.5	23,503,964	555,918	0.0237	0.9763	83.54
7.5	22,948,046	504,707	0.0220	0.9780	81.57
8.5	22,441,575	431,796	0.0192	0.9808	79.77
9.5	21,986,583	411,953	0.0187	0.9813	78.24
10.5	21,477,967	333,348	0.0155	0.9845	76.77
11.5	20,716,123	303,681	0.0147	0.9853	75.58
12.5	18,480,679	282,375	0.0153	0.9847	74.47
13.5	16,067,451	248,661	0.0155	0.9845	73.33
14.5	14,105,346	283,694	0.0201	0.9799	72.20
15.5	12,130,667	306,517	0.0253	0.9747	70.75
16.5	10,011,076	219,933	0.0220	0.9780	68.96
17.5	8,354,727	182,190	0.0218	0.9782	67.45
18.5	6,830,598	209,937	0.0307	0.9693	65.97
19.5	5,743,809	156,495	0.0272	0.9728	63.95
20.5	5,054,134	128,456	0.0254	0.9746	62.20
21.5	4,332,118	142,675	0.0329	0.9671	60.62
22.5	3,578,720	38,666	0.0108	0.9892	58.63
23.5	3,336,840	87,606	0.0263	0.9737	57.99
24.5	3,074,751	121,770	0.0396	0.9604	56.47
25.5	2,598,140	157,031	0.0604	0.9396	54.23
26.5	2,213,248	84,908	0.0384	0.9616	50.96
27.5	1,787,777	37,398	0.0209	0.9791	49.00
28.5	1,389,978	16,889	0.0122	0.9878	47.98
29.5	1,035,280	298	0.0003	0.9997	47.39
30.5	672,217	1,036	0.0015	0.9985	47.38
31.5	593,687	18	0.0000	1.0000	47.31
32.5	430,825	124	0.0003	0.9997	47.31
33.5	379,984	40	0.0001	0.9999	47.29
34.5	221,537	36	0.0002	0.9998	47.29
35.5	69,731		0.0000	1.0000	47.28
36.5	67,619		0.0000	1.0000	47.28
37.5	66,116		0.0000	1.0000	47.28
38.5	19,073		0.0000	1.0000	47.28

KENTUCKY UTILITIES COMPANY

ACCOUNT 371 INSTALLATIONS ON CUSTOMERS' PREMISES

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1938-2009 EXPERIENCE BAND 1938-2011

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	17,480		0.0000	1.0000	47.28
40.5	11,866		0.0000	1.0000	47.28
41.5	1,704		0.0000	1.0000	47.28
42.5	1,704		0.0000	1.0000	47.28
43.5	1,691		0.0000	1.0000	47.28
44.5	1,691		0.0000	1.0000	47.28
45.5	759		0.0000	1.0000	47.28
46.5	679	5	0.0078	0.9922	47.28
47.5	583	583	1.0000		46.91
48.5					

KENTUCKY UTILITIES COMPANY

ACCOUNT 371 INSTALLATIONS ON CUSTOMERS' PREMISES

ORIGINAL LIFE TABLE

PLACEMENT BAND 1938-2009 EXPERIENCE BAND 1961-2011

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	28,145,752	224,710	0.0080	0.9920	100.00
0.5	27,928,219	1,110,271	0.0398	0.9602	99.20
1.5	26,817,948	774,921	0.0289	0.9711	95.26
2.5	26,043,207	690,773	0.0265	0.9735	92.51
3.5	25,351,184	601,405	0.0237	0.9763	90.05
4.5	24,742,181	626,274	0.0253	0.9747	87.92
5.5	24,107,091	604,337	0.0251	0.9749	85.69
6.5	23,503,005	555,918	0.0237	0.9763	83.54
7.5	22,947,450	504,707	0.0220	0.9780	81.57
8.5	22,440,979	431,796	0.0192	0.9808	79.77
9.5	21,985,987	411,953	0.0187	0.9813	78.24
10.5	21,477,371	333,348	0.0155	0.9845	76.77
11.5	20,715,527	303,681	0.0147	0.9853	75.58
12.5	18,480,083	282,375	0.0153	0.9847	74.47
13.5	16,066,855	248,661	0.0155	0.9845	73.33
14.5	14,104,750	283,694	0.0201	0.9799	72.20
15.5	12,130,071	306,517	0.0253	0.9747	70.75
16.5	10,010,480	219,933	0.0220	0.9780	68.96
17.5	8,354,131	182,190	0.0218	0.9782	67.44
18.5	6,830,002	209,937	0.0307	0.9693	65.97
19.5	5,743,213	156,495	0.0272	0.9728	63.95
20.5	5,053,538	128,456	0.0254	0.9746	62.20
21.5	4,331,522	142,675	0.0329	0.9671	60.62
22.5	3,578,720	38,666	0.0108	0.9892	58.62
23.5	3,336,840	87,606	0.0263	0.9737	57.99
24.5	3,074,751	121,770	0.0396	0.9604	56.47
25.5	2,598,140	157,031	0.0604	0.9396	54.23
26.5	2,213,248	84,908	0.0384	0.9616	50.95
27.5	1,787,777	37,398	0.0209	0.9791	49.00
28.5	1,389,978	16,889	0.0122	0.9878	47.97
29.5	1,035,280	298	0.0003	0.9997	47.39
30.5	672,217	1,036	0.0015	0.9985	47.38
31.5	593,687	18	0.0000	1.0000	47.31
32.5	430,825	124	0.0003	0.9997	47.30
33.5	379,984	40	0.0001	0.9999	47.29
34.5	221,537	36	0.0002	0.9998	47.29
35.5	69,731		0.0000	1.0000	47.28
36.5	67,619		0.0000	1.0000	47.28
37.5	66,116		0.0000	1.0000	47.28
38.5	19,073		0.0000	1.0000	47.28

KENTUCKY UTILITIES COMPANY

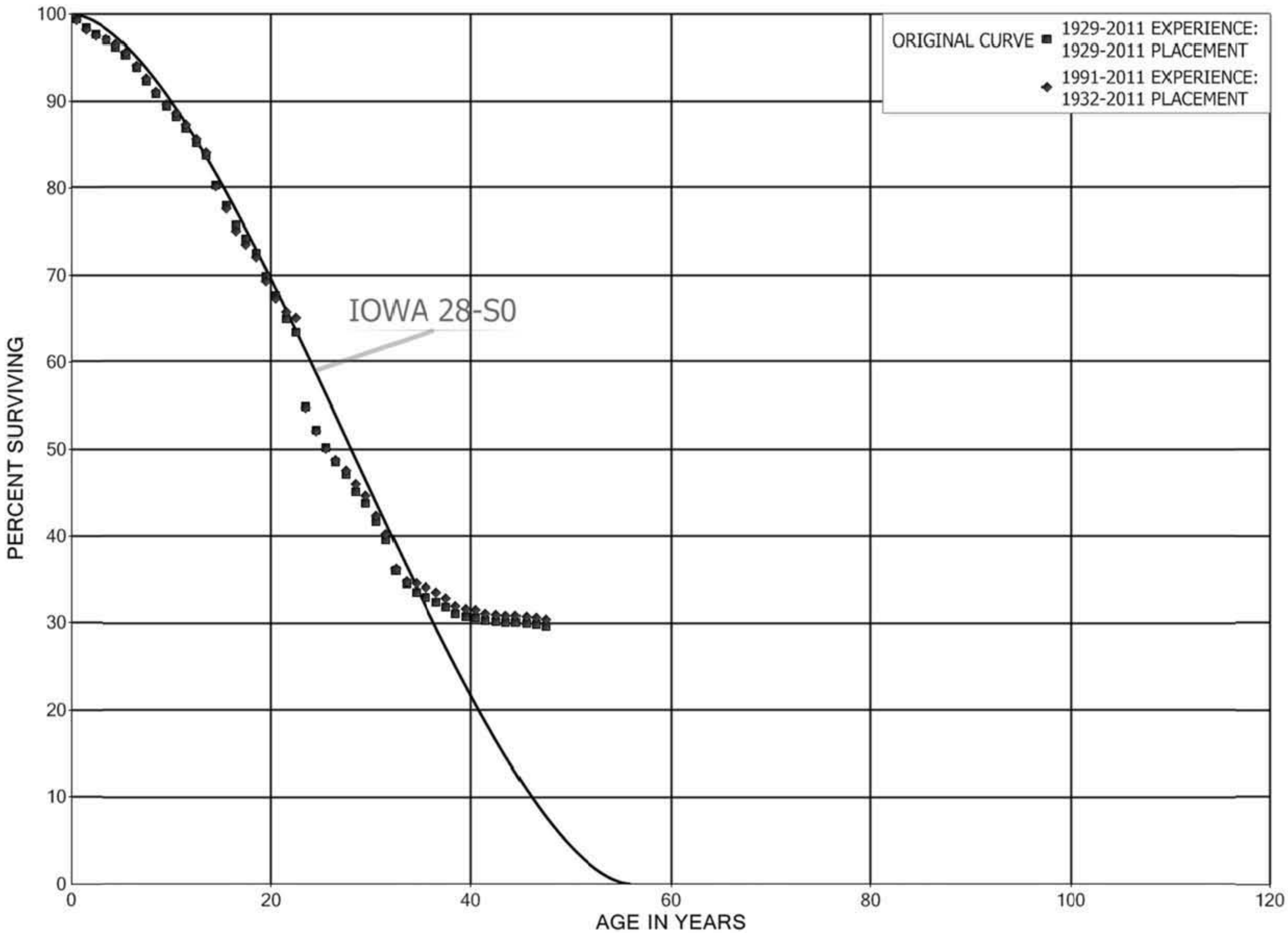
ACCOUNT 371 INSTALLATIONS ON CUSTOMERS' PREMISES

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1938-2009 EXPERIENCE BAND 1961-2011

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	17,480		0.0000	1.0000	47.28
40.5	11,866		0.0000	1.0000	47.28
41.5	1,704		0.0000	1.0000	47.28
42.5	1,704		0.0000	1.0000	47.28
43.5	1,691		0.0000	1.0000	47.28
44.5	1,691		0.0000	1.0000	47.28
45.5	759		0.0000	1.0000	47.28
46.5	679	5	0.0078	0.9922	47.28
47.5	583	583	1.0000		46.91
48.5					

KENTUCKY UTILITIES COMPANY
ACCOUNT 373 STREET LIGHTING AND SIGNAL SYSTEMS
ORIGINAL AND SMOOTH SURVIVOR CURVES



KENTUCKY UTILITIES COMPANY

ACCOUNT 373 STREET LIGHTING AND SIGNAL SYSTEMS

ORIGINAL LIFE TABLE

PLACEMENT BAND 1929-2011 EXPERIENCE BAND 1929-2011

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	104,724,091	644,356	0.0062	0.9938	100.00
0.5	96,252,648	1,008,517	0.0105	0.9895	99.38
1.5	75,916,635	550,541	0.0073	0.9927	98.34
2.5	66,780,601	505,176	0.0076	0.9924	97.63
3.5	63,451,730	446,096	0.0070	0.9930	96.89
4.5	62,959,298	627,103	0.0100	0.9900	96.21
5.5	62,014,049	955,917	0.0154	0.9846	95.25
6.5	60,660,773	954,248	0.0157	0.9843	93.78
7.5	57,628,333	938,695	0.0163	0.9837	92.31
8.5	51,266,524	802,269	0.0156	0.9844	90.80
9.5	47,452,645	657,223	0.0139	0.9861	89.38
10.5	44,255,272	682,192	0.0154	0.9846	88.15
11.5	40,503,797	752,262	0.0186	0.9814	86.79
12.5	36,452,705	642,978	0.0176	0.9824	85.18
13.5	34,583,018	1,406,733	0.0407	0.9593	83.67
14.5	31,397,437	891,051	0.0284	0.9716	80.27
15.5	28,935,427	860,081	0.0297	0.9703	77.99
16.5	27,203,348	537,694	0.0198	0.9802	75.67
17.5	24,267,326	532,092	0.0219	0.9781	74.18
18.5	22,495,601	853,372	0.0379	0.9621	72.55
19.5	20,978,943	654,317	0.0312	0.9688	69.80
20.5	19,138,307	764,175	0.0399	0.9601	67.62
21.5	17,199,909	415,761	0.0242	0.9758	64.92
22.5	15,455,965	2,077,414	0.1344	0.8656	63.35
23.5	13,033,349	639,023	0.0490	0.9510	54.84
24.5	12,315,368	466,163	0.0379	0.9621	52.15
25.5	10,834,676	362,973	0.0335	0.9665	50.17
26.5	9,515,759	290,022	0.0305	0.9695	48.49
27.5	8,183,787	332,740	0.0407	0.9593	47.02
28.5	7,614,424	224,455	0.0295	0.9705	45.10
29.5	6,821,662	342,151	0.0502	0.9498	43.77
30.5	5,366,747	265,464	0.0495	0.9505	41.58
31.5	5,034,976	449,941	0.0894	0.9106	39.52
32.5	3,918,610	159,598	0.0407	0.9593	35.99
33.5	3,566,868	107,930	0.0303	0.9697	34.52
34.5	3,289,822	46,446	0.0141	0.9859	33.48
35.5	3,122,624	54,153	0.0173	0.9827	33.01
36.5	2,909,378	53,302	0.0183	0.9817	32.43
37.5	2,578,812	66,301	0.0257	0.9743	31.84
38.5	2,338,940	18,567	0.0079	0.9921	31.02

KENTUCKY UTILITIES COMPANY

ACCOUNT 373 STREET LIGHTING AND SIGNAL SYSTEMS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1929-2011 EXPERIENCE BAND 1929-2011

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	2,250,721	8,669	0.0039	0.9961	30.78
40.5	2,059,319	25,313	0.0123	0.9877	30.66
41.5	2,007,814	8,232	0.0041	0.9959	30.28
42.5	1,807,085	6,508	0.0036	0.9964	30.16
43.5	1,651,666	2,052	0.0012	0.9988	30.05
44.5	1,455,954	2,922	0.0020	0.9980	30.01
45.5	1,144,515	4,373	0.0038	0.9962	29.95
46.5	1,079,385	7,984	0.0074	0.9926	29.84
47.5	891,076	1,673	0.0019	0.9981	29.62
48.5	753,113	1,150	0.0015	0.9985	29.56
49.5	663,817	1,677	0.0025	0.9975	29.51
50.5	585,531	845	0.0014	0.9986	29.44
51.5	514,558	760	0.0015	0.9985	29.40
52.5	458,997	1,229	0.0027	0.9973	29.35
53.5	404,363	862	0.0021	0.9979	29.28
54.5	362,836	685	0.0019	0.9981	29.21
55.5	317,524	174	0.0005	0.9995	29.16
56.5	265,115	1,098	0.0041	0.9959	29.14
57.5	230,335	530	0.0023	0.9977	29.02
58.5	202,882	914	0.0045	0.9955	28.95
59.5	192,120	455	0.0024	0.9976	28.82
60.5	180,240	262	0.0015	0.9985	28.76
61.5	172,297	99	0.0006	0.9994	28.71
62.5	162,797	212	0.0013	0.9987	28.70
63.5	146,687	6	0.0000	1.0000	28.66
64.5	137,402	64	0.0005	0.9995	28.66
65.5	132,925	6,767	0.0509	0.9491	28.65
66.5	125,264	175	0.0014	0.9986	27.19
67.5	123,972	4,838	0.0390	0.9610	27.15
68.5	118,905	5,225	0.0439	0.9561	26.09
69.5	109,413	55,964	0.5115	0.4885	24.94
70.5	3,148		0.0000	1.0000	12.18
71.5	3,148		0.0000	1.0000	12.18
72.5	3,073		0.0000	1.0000	12.18
73.5	3,073		0.0000	1.0000	12.18
74.5	3,073		0.0000	1.0000	12.18
75.5	3,073		0.0000	1.0000	12.18
76.5	3,148		0.0000	1.0000	12.18
77.5	3,148		0.0000	1.0000	12.18
78.5	3,148		0.0000	1.0000	12.18
79.5					12.18

KENTUCKY UTILITIES COMPANY

ACCOUNT 373 STREET LIGHTING AND SIGNAL SYSTEMS

ORIGINAL LIFE TABLE

PLACEMENT BAND 1932-2011 EXPERIENCE BAND 1991-2011

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	78,670,459	598,461	0.0076	0.9924	100.00
0.5	72,170,106	779,268	0.0108	0.9892	99.24
1.5	53,823,933	335,159	0.0062	0.9938	98.17
2.5	46,657,898	261,285	0.0056	0.9944	97.56
3.5	44,801,878	251,136	0.0056	0.9944	97.01
4.5	46,210,522	409,822	0.0089	0.9911	96.47
5.5	46,922,659	783,815	0.0167	0.9833	95.61
6.5	47,284,865	724,954	0.0153	0.9847	94.01
7.5	44,886,181	748,774	0.0167	0.9833	92.57
8.5	39,497,938	590,132	0.0149	0.9851	91.03
9.5	37,164,630	428,073	0.0115	0.9885	89.67
10.5	34,447,942	509,238	0.0148	0.9852	88.64
11.5	32,167,078	613,585	0.0191	0.9809	87.32
12.5	28,638,960	515,504	0.0180	0.9820	85.66
13.5	27,283,291	1,278,737	0.0469	0.9531	84.12
14.5	24,409,629	788,425	0.0323	0.9677	80.17
15.5	22,364,035	734,699	0.0329	0.9671	77.59
16.5	21,154,655	432,586	0.0204	0.9796	75.04
17.5	18,594,264	363,616	0.0196	0.9804	73.50
18.5	17,259,311	668,052	0.0387	0.9613	72.06
19.5	16,244,343	473,400	0.0291	0.9709	69.28
20.5	14,717,142	324,215	0.0220	0.9780	67.26
21.5	13,526,970	139,607	0.0103	0.9897	65.77
22.5	12,301,720	1,950,269	0.1585	0.8415	65.10
23.5	10,364,112	517,880	0.0500	0.9500	54.78
24.5	10,196,770	389,807	0.0382	0.9618	52.04
25.5	8,890,249	235,520	0.0265	0.9735	50.05
26.5	7,988,279	194,698	0.0244	0.9756	48.72
27.5	6,977,765	238,072	0.0341	0.9659	47.54
28.5	6,703,783	187,989	0.0280	0.9720	45.91
29.5	6,025,338	310,850	0.0516	0.9484	44.63
30.5	4,672,468	237,859	0.0509	0.9491	42.32
31.5	4,424,508	438,847	0.0992	0.9008	40.17
32.5	3,376,390	131,746	0.0390	0.9610	36.19
33.5	3,094,650	23,498	0.0076	0.9924	34.77
34.5	2,947,906	35,175	0.0119	0.9881	34.51
35.5	2,844,830	52,780	0.0186	0.9814	34.10
36.5	2,667,850	52,623	0.0197	0.9803	33.47
37.5	2,366,676	64,400	0.0272	0.9728	32.80
38.5	2,138,176	17,359	0.0081	0.9919	31.91

KENTUCKY UTILITIES COMPANY

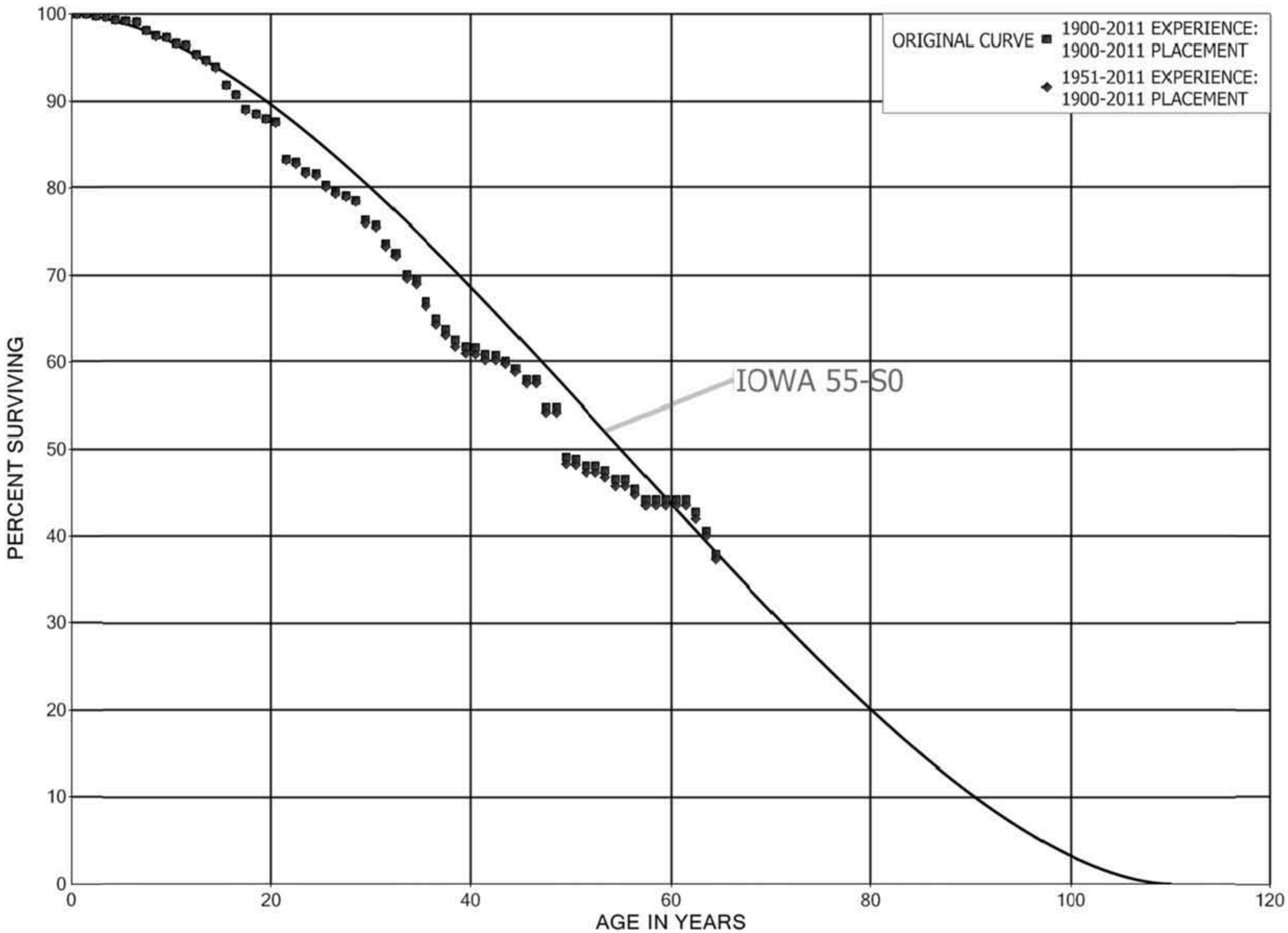
ACCOUNT 373 STREET LIGHTING AND SIGNAL SYSTEMS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1932-2011 EXPERIENCE BAND 1991-2011

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	2,063,492	8,669	0.0042	0.9958	31.65
40.5	1,879,844	24,587	0.0131	0.9869	31.52
41.5	1,839,602	8,232	0.0045	0.9955	31.11
42.5	1,655,062	6,403	0.0039	0.9961	30.97
43.5	1,509,099	1,415	0.0009	0.9991	30.85
44.5	1,318,648	2,747	0.0021	0.9979	30.82
45.5	1,008,284	4,373	0.0043	0.9957	30.76
46.5	944,334	7,148	0.0076	0.9924	30.62
47.5	757,092	1,613	0.0021	0.9979	30.39
48.5	623,485	346	0.0006	0.9994	30.33
49.5	660,668	1,677	0.0025	0.9975	30.31
50.5	582,383	845	0.0015	0.9985	30.23
51.5	511,410	760	0.0015	0.9985	30.19
52.5	455,848	1,229	0.0027	0.9973	30.14
53.5	401,215	862	0.0021	0.9979	30.06
54.5	359,762	685	0.0019	0.9981	30.00
55.5	314,451	174	0.0006	0.9994	29.94
56.5	262,042	1,098	0.0042	0.9958	29.92
57.5	227,262	530	0.0023	0.9977	29.80
58.5	202,882	914	0.0045	0.9955	29.73
59.5	192,120	455	0.0024	0.9976	29.59
60.5	180,240	262	0.0015	0.9985	29.52
61.5	172,297	99	0.0006	0.9994	29.48
62.5	162,797	212	0.0013	0.9987	29.46
63.5	146,687	6	0.0000	1.0000	29.43
64.5	137,402	64	0.0005	0.9995	29.43
65.5	132,925	6,767	0.0509	0.9491	29.41
66.5	125,264	175	0.0014	0.9986	27.91
67.5	123,972	4,838	0.0390	0.9610	27.88
68.5	118,905	5,225	0.0439	0.9561	26.79
69.5	109,413	55,964	0.5115	0.4885	25.61
70.5	3,148		0.0000	1.0000	12.51
71.5	3,148		0.0000	1.0000	12.51
72.5	3,073		0.0000	1.0000	12.51
73.5	3,073		0.0000	1.0000	12.51
74.5	3,073		0.0000	1.0000	12.51
75.5	3,073		0.0000	1.0000	12.51
76.5	3,148		0.0000	1.0000	12.51
77.5	3,148		0.0000	1.0000	12.51
78.5	3,148		0.0000	1.0000	12.51
79.5					12.51

KENTUCKY UTILITIES COMPANY
ACCOUNT 390.1 STRUCTURES AND IMPROVEMENTS - TO OWNED PROPERTY
ORIGINAL AND SMOOTH SURVIVOR CURVES



KENTUCKY UTILITIES COMPANY

ACCOUNT 390.1 STRUCTURES AND IMPROVEMENTS - TO OWNED PROPERTY

ORIGINAL LIFE TABLE

PLACEMENT BAND 1900-2011 EXPERIENCE BAND 1900-2011

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	54,612,783		0.0000	1.0000	100.00
0.5	47,989,259	848	0.0000	1.0000	100.00
1.5	47,687,050	126,392	0.0027	0.9973	100.00
2.5	45,559,251	37,612	0.0008	0.9992	99.73
3.5	41,029,070	152,919	0.0037	0.9963	99.65
4.5	39,975,658	31,271	0.0008	0.9992	99.28
5.5	38,290,204	43,893	0.0011	0.9989	99.20
6.5	35,017,803	371,715	0.0106	0.9894	99.09
7.5	33,882,327	193,356	0.0057	0.9943	98.04
8.5	32,125,965	61,436	0.0019	0.9981	97.48
9.5	31,921,718	204,653	0.0064	0.9936	97.29
10.5	30,637,948	78,828	0.0026	0.9974	96.67
11.5	30,034,024	331,367	0.0110	0.9890	96.42
12.5	29,107,180	208,101	0.0071	0.9929	95.35
13.5	28,663,117	230,373	0.0080	0.9920	94.67
14.5	28,217,817	615,736	0.0218	0.9782	93.91
15.5	26,644,317	333,753	0.0125	0.9875	91.86
16.5	23,010,773	420,969	0.0183	0.9817	90.71
17.5	21,765,398	126,109	0.0058	0.9942	89.05
18.5	21,657,987	141,160	0.0065	0.9935	88.54
19.5	20,617,825	90,620	0.0044	0.9956	87.96
20.5	20,174,094	989,850	0.0491	0.9509	87.57
21.5	18,400,928	82,194	0.0045	0.9955	83.28
22.5	11,985,280	158,193	0.0132	0.9868	82.90
23.5	11,047,328	28,641	0.0026	0.9974	81.81
24.5	11,023,816	172,923	0.0157	0.9843	81.60
25.5	10,162,463	107,421	0.0106	0.9894	80.32
26.5	8,737,348	38,685	0.0044	0.9956	79.47
27.5	8,435,255	60,892	0.0072	0.9928	79.12
28.5	7,794,361	228,505	0.0293	0.9707	78.55
29.5	7,320,209	46,812	0.0064	0.9936	76.24
30.5	5,762,785	163,542	0.0284	0.9716	75.76
31.5	5,499,512	78,745	0.0143	0.9857	73.61
32.5	5,076,186	173,725	0.0342	0.9658	72.55
33.5	4,902,275	41,716	0.0085	0.9915	70.07
34.5	4,677,566	166,541	0.0356	0.9644	69.47
35.5	4,418,397	133,436	0.0302	0.9698	67.00
36.5	4,177,705	77,195	0.0185	0.9815	64.98
37.5	4,068,883	81,506	0.0200	0.9800	63.77
38.5	3,942,236	46,808	0.0119	0.9881	62.50

KENTUCKY UTILITIES COMPANY

ACCOUNT 390.1 STRUCTURES AND IMPROVEMENTS - TO OWNED PROPERTY

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1900-2011 EXPERIENCE BAND 1900-2011

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	3,378,748	9,116	0.0027	0.9973	61.76
40.5	3,209,508	40,889	0.0127	0.9873	61.59
41.5	2,231,040	1,533	0.0007	0.9993	60.80
42.5	2,051,443	22,474	0.0110	0.9890	60.76
43.5	2,022,115	29,749	0.0147	0.9853	60.10
44.5	1,961,935	40,984	0.0209	0.9791	59.21
45.5	1,595,978	410	0.0003	0.9997	57.98
46.5	1,499,608	84,219	0.0562	0.9438	57.96
47.5	1,415,389	500	0.0004	0.9996	54.71
48.5	1,398,861	144,443	0.1033	0.8967	54.69
49.5	889,969	2,881	0.0032	0.9968	49.04
50.5	843,104	14,293	0.0170	0.9830	48.88
51.5	816,528	172	0.0002	0.9998	48.05
52.5	816,355	9,811	0.0120	0.9880	48.04
53.5	561,414	11,382	0.0203	0.9797	47.46
54.5	550,018	100	0.0002	0.9998	46.50
55.5	280,519	6,659	0.0237	0.9763	46.49
56.5	264,688	6,885	0.0260	0.9740	45.39
57.5	257,803		0.0000	1.0000	44.21
58.5	256,996		0.0000	1.0000	44.21
59.5	254,852		0.0000	1.0000	44.21
60.5	254,519	250	0.0010	0.9990	44.21
61.5	251,796	8,510	0.0338	0.9662	44.17
62.5	243,058	12,154	0.0500	0.9500	42.67
63.5	230,904	15,143	0.0656	0.9344	40.54
64.5	215,761	3,341	0.0155	0.9845	37.88
65.5	211,964	20,092	0.0948	0.9052	37.29
66.5	191,872	6,717	0.0350	0.9650	33.76
67.5	185,155	4,374	0.0236	0.9764	32.58
68.5	180,781	34,803	0.1925	0.8075	31.81
69.5	145,417		0.0000	1.0000	25.68
70.5	123,291	123,291	1.0000		25.68
71.5					

KENTUCKY UTILITIES COMPANY

ACCOUNT 390.1 STRUCTURES AND IMPROVEMENTS - TO OWNED PROPERTY

ORIGINAL LIFE TABLE

PLACEMENT BAND 1900-2011 EXPERIENCE BAND 1951-2011

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	54,130,329		0.0000	1.0000	100.00
0.5	47,516,877	848	0.0000	1.0000	100.00
1.5	47,219,968	126,392	0.0027	0.9973	100.00
2.5	45,092,368	37,612	0.0008	0.9992	99.73
3.5	40,567,495	152,919	0.0038	0.9962	99.65
4.5	39,519,772	31,271	0.0008	0.9992	99.27
5.5	37,834,317	43,893	0.0012	0.9988	99.19
6.5	34,561,916	371,715	0.0108	0.9892	99.08
7.5	33,426,441	193,356	0.0058	0.9942	98.01
8.5	31,671,106	61,436	0.0019	0.9981	97.45
9.5	31,527,416	204,653	0.0065	0.9935	97.26
10.5	30,243,646	78,828	0.0026	0.9974	96.63
11.5	29,639,722	331,367	0.0112	0.9888	96.37
12.5	28,712,878	208,101	0.0072	0.9928	95.30
13.5	28,268,815	230,373	0.0081	0.9919	94.61
14.5	27,825,174	588,236	0.0211	0.9789	93.83
15.5	26,281,174	333,753	0.0127	0.9873	91.85
16.5	22,667,711	420,969	0.0186	0.9814	90.68
17.5	21,422,336	126,109	0.0059	0.9941	89.00
18.5	21,314,925	141,160	0.0066	0.9934	88.48
19.5	20,274,763	90,620	0.0045	0.9955	87.89
20.5	19,851,670	989,850	0.0499	0.9501	87.50
21.5	18,078,954	82,194	0.0045	0.9955	83.13
22.5	11,663,306	157,793	0.0135	0.9865	82.76
23.5	10,732,516	28,641	0.0027	0.9973	81.64
24.5	10,719,166	172,923	0.0161	0.9839	81.42
25.5	9,881,128	104,221	0.0105	0.9895	80.11
26.5	8,459,213	34,480	0.0041	0.9959	79.26
27.5	8,161,325	60,892	0.0075	0.9925	78.94
28.5	7,532,714	227,055	0.0301	0.9699	78.35
29.5	7,060,012	46,812	0.0066	0.9934	75.99
30.5	5,517,236	163,542	0.0296	0.9704	75.48
31.5	5,253,963	74,873	0.0143	0.9857	73.25
32.5	4,834,509	173,725	0.0359	0.9641	72.20
33.5	4,660,598	41,716	0.0090	0.9910	69.61
34.5	4,435,889	166,541	0.0375	0.9625	68.98
35.5	4,176,720	132,136	0.0316	0.9684	66.39
36.5	3,946,788	77,195	0.0196	0.9804	64.29
37.5	3,840,016	81,506	0.0212	0.9788	63.04
38.5	3,848,887	44,550	0.0116	0.9884	61.70

KENTUCKY UTILITIES COMPANY

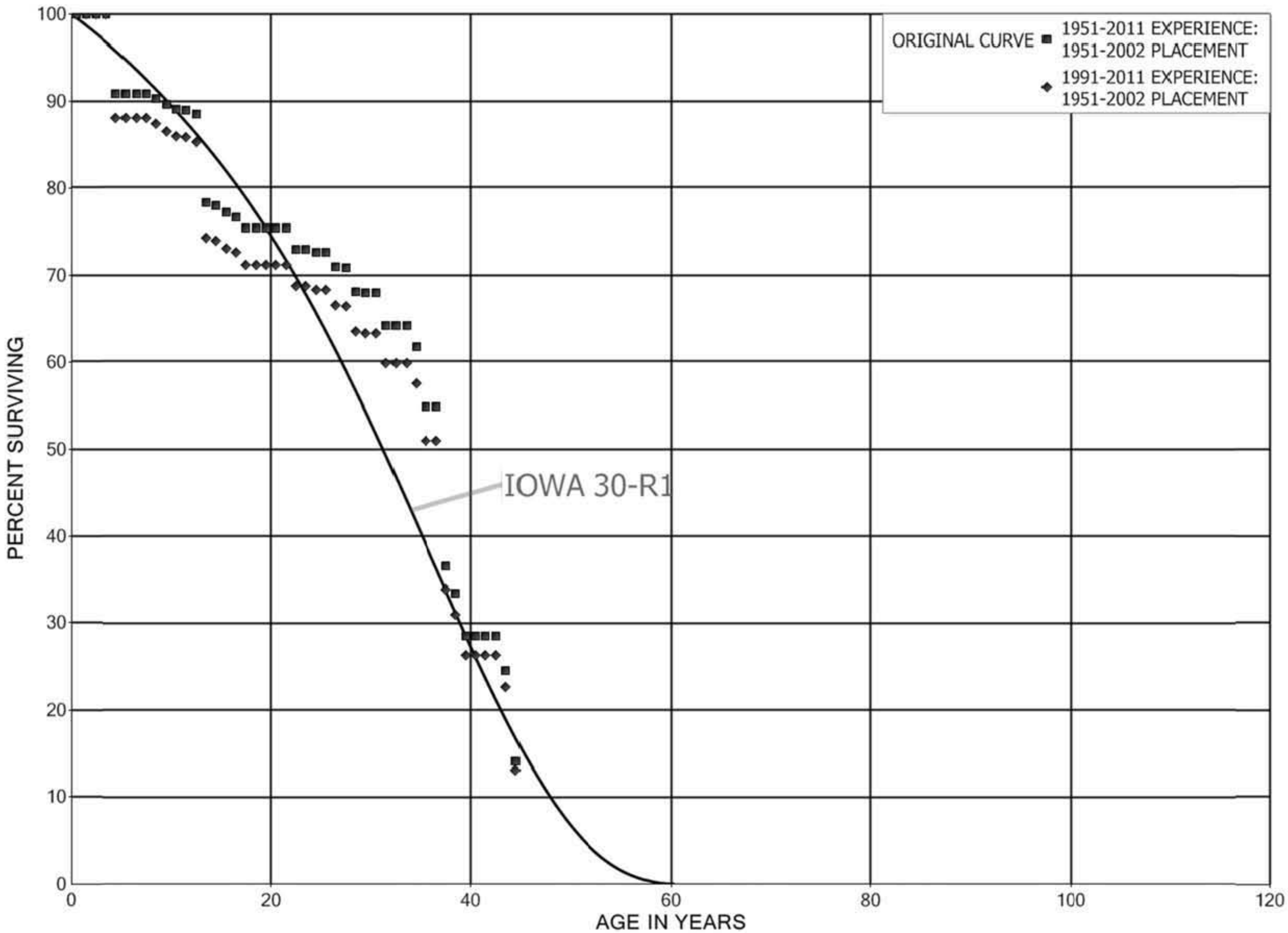
ACCOUNT 390.1 STRUCTURES AND IMPROVEMENTS - TO OWNED PROPERTY

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1900-2011 EXPERIENCE BAND 1951-2011

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	3,287,657	9,116	0.0028	0.9972	60.98
40.5	3,120,229	32,063	0.0103	0.9897	60.82
41.5	2,150,587	1,533	0.0007	0.9993	60.19
42.5	1,970,990	15,028	0.0076	0.9924	60.15
43.5	1,963,205	29,749	0.0152	0.9848	59.69
44.5	1,903,025	40,984	0.0215	0.9785	58.78
45.5	1,537,068	410	0.0003	0.9997	57.52
46.5	1,440,698	84,219	0.0585	0.9415	57.50
47.5	1,356,479	500	0.0004	0.9996	54.14
48.5	1,339,951	144,443	0.1078	0.8922	54.12
49.5	831,059	2,881	0.0035	0.9965	48.29
50.5	843,104	14,293	0.0170	0.9830	48.12
51.5	816,528	172	0.0002	0.9998	47.30
52.5	816,355	9,811	0.0120	0.9880	47.29
53.5	561,414	11,382	0.0203	0.9797	46.73
54.5	550,018	100	0.0002	0.9998	45.78
55.5	280,519	6,659	0.0237	0.9763	45.77
56.5	264,688	6,885	0.0260	0.9740	44.68
57.5	257,803		0.0000	1.0000	43.52
58.5	256,996		0.0000	1.0000	43.52
59.5	254,852		0.0000	1.0000	43.52
60.5	254,519	250	0.0010	0.9990	43.52
61.5	251,796	8,510	0.0338	0.9662	43.48
62.5	243,058	12,154	0.0500	0.9500	42.01
63.5	230,904	15,143	0.0656	0.9344	39.91
64.5	215,761	3,341	0.0155	0.9845	37.29
65.5	211,964	20,092	0.0948	0.9052	36.71
66.5	191,872	6,717	0.0350	0.9650	33.23
67.5	185,155	4,374	0.0236	0.9764	32.07
68.5	180,781	34,803	0.1925	0.8075	31.31
69.5	145,417		0.0000	1.0000	25.28
70.5	123,291	123,291	1.0000		25.28
71.5					

KENTUCKY UTILITIES COMPANY
ACCOUNT 390.2 STRUCTURES AND IMPROVEMENTS - TO LEASED PROPERTY
ORIGINAL AND SMOOTH SURVIVOR CURVES



KENTUCKY UTILITIES COMPANY

ACCOUNT 390.2 STRUCTURES AND IMPROVEMENTS - TO LEASED PROPERTY

ORIGINAL LIFE TABLE

PLACEMENT BAND 1951-2002 EXPERIENCE BAND 1951-2011

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	767,520		0.0000	1.0000	100.00
0.5	767,520		0.0000	1.0000	100.00
1.5	767,520		0.0000	1.0000	100.00
2.5	767,520		0.0000	1.0000	100.00
3.5	767,520	70,369	0.0917	0.9083	100.00
4.5	697,151		0.0000	1.0000	90.83
5.5	697,151		0.0000	1.0000	90.83
6.5	697,151		0.0000	1.0000	90.83
7.5	697,151	4,307	0.0062	0.9938	90.83
8.5	692,844	5,163	0.0075	0.9925	90.27
9.5	687,682	4,256	0.0062	0.9938	89.60
10.5	683,425	1,125	0.0016	0.9984	89.04
11.5	568,552	2,788	0.0049	0.9951	88.90
12.5	563,017	64,948	0.1154	0.8846	88.46
13.5	481,797	2,010	0.0042	0.9958	78.26
14.5	479,788	4,922	0.0103	0.9897	77.93
15.5	434,625	2,649	0.0061	0.9939	77.13
16.5	424,777	7,220	0.0170	0.9830	76.66
17.5	355,005		0.0000	1.0000	75.36
18.5	352,372		0.0000	1.0000	75.36
19.5	351,333		0.0000	1.0000	75.36
20.5	308,556		0.0000	1.0000	75.36
21.5	308,556	9,822	0.0318	0.9682	75.36
22.5	177,013		0.0000	1.0000	72.96
23.5	172,580	783	0.0045	0.9955	72.96
24.5	167,894		0.0000	1.0000	72.63
25.5	163,672	3,718	0.0227	0.9773	72.63
26.5	149,284	329	0.0022	0.9978	70.98
27.5	147,035	5,642	0.0384	0.9616	70.82
28.5	122,936	347	0.0028	0.9972	68.10
29.5	118,237		0.0000	1.0000	67.91
30.5	66,579	3,635	0.0546	0.9454	67.91
31.5	62,107		0.0000	1.0000	64.20
32.5	57,067		0.0000	1.0000	64.20
33.5	53,142	2,045	0.0385	0.9615	64.20
34.5	50,949	5,723	0.1123	0.8877	61.73
35.5	45,225		0.0000	1.0000	54.80
36.5	45,225	15,116	0.3342	0.6658	54.80
37.5	29,923	2,506	0.0837	0.9163	36.48
38.5	27,286	4,062	0.1489	0.8511	33.43

KENTUCKY UTILITIES COMPANY

ACCOUNT 390.2 STRUCTURES AND IMPROVEMENTS - TO LEASED PROPERTY

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1951-2002 EXPERIENCE BAND 1951-2011

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	23,224		0.0000	1.0000	28.45
40.5	22,060		0.0000	1.0000	28.45
41.5	21,654		0.0000	1.0000	28.45
42.5	21,654	2,997	0.1384	0.8616	28.45
43.5	18,657	7,941	0.4256	0.5744	24.51
44.5	10,250	65	0.0064	0.9936	14.08
45.5	9,562	90	0.0095	0.9905	13.99
46.5	9,471		0.0000	1.0000	13.86
47.5	9,471	683	0.0721	0.9279	13.86
48.5	8,389		0.0000	1.0000	12.86
49.5	1,183		0.0000	1.0000	12.86
50.5	1,183		0.0000	1.0000	12.86
51.5	458		0.0000	1.0000	12.86
52.5	458		0.0000	1.0000	12.86
53.5	458		0.0000	1.0000	12.86
54.5	458	285	0.6226	0.3774	12.86
55.5	173		0.0000	1.0000	4.85
56.5	173		0.0000	1.0000	4.85
57.5					4.85

KENTUCKY UTILITIES COMPANY

ACCOUNT 390.2 STRUCTURES AND IMPROVEMENTS - TO LEASED PROPERTY

ORIGINAL LIFE TABLE

PLACEMENT BAND 1951-2002 EXPERIENCE BAND 1991-2011

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	449,096		0.0000	1.0000	100.00
0.5	451,744		0.0000	1.0000	100.00
1.5	580,685		0.0000	1.0000	100.00
2.5	585,118		0.0000	1.0000	100.00
3.5	589,021	70,369	0.1195	0.8805	100.00
4.5	522,873		0.0000	1.0000	88.05
5.5	533,544		0.0000	1.0000	88.05
6.5	536,506		0.0000	1.0000	88.05
7.5	554,964	4,307	0.0078	0.9922	88.05
8.5	555,792	5,163	0.0093	0.9907	87.37
9.5	611,067	4,256	0.0070	0.9930	86.56
10.5	608,704	1,125	0.0018	0.9982	85.96
11.5	499,201	2,788	0.0056	0.9944	85.80
12.5	503,232	64,948	0.1291	0.8709	85.32
13.5	422,507	2,010	0.0048	0.9952	74.31
14.5	420,497	4,922	0.0117	0.9883	73.95
15.5	381,631	2,649	0.0069	0.9931	73.09
16.5	371,970	7,220	0.0194	0.9806	72.58
17.5	302,330		0.0000	1.0000	71.17
18.5	301,741		0.0000	1.0000	71.17
19.5	307,590		0.0000	1.0000	71.17
20.5	265,219		0.0000	1.0000	71.17
21.5	280,335	9,822	0.0350	0.9650	71.17
22.5	151,298		0.0000	1.0000	68.68
23.5	151,392	783	0.0052	0.9948	68.68
24.5	147,329		0.0000	1.0000	68.32
25.5	143,107	3,718	0.0260	0.9740	68.32
26.5	128,719	329	0.0026	0.9974	66.55
27.5	129,867	5,642	0.0434	0.9566	66.38
28.5	120,913	347	0.0029	0.9971	63.49
29.5	116,280		0.0000	1.0000	63.31
30.5	65,438	3,635	0.0555	0.9445	63.31
31.5	60,966		0.0000	1.0000	59.79
32.5	56,608		0.0000	1.0000	59.79
33.5	52,684	2,045	0.0388	0.9612	59.79
34.5	50,490	5,723	0.1134	0.8866	57.47
35.5	44,767		0.0000	1.0000	50.96
36.5	44,940	15,116	0.3364	0.6636	50.96
37.5	29,637	2,506	0.0845	0.9155	33.82
38.5	27,000	4,062	0.1504	0.8496	30.96

KENTUCKY UTILITIES COMPANY

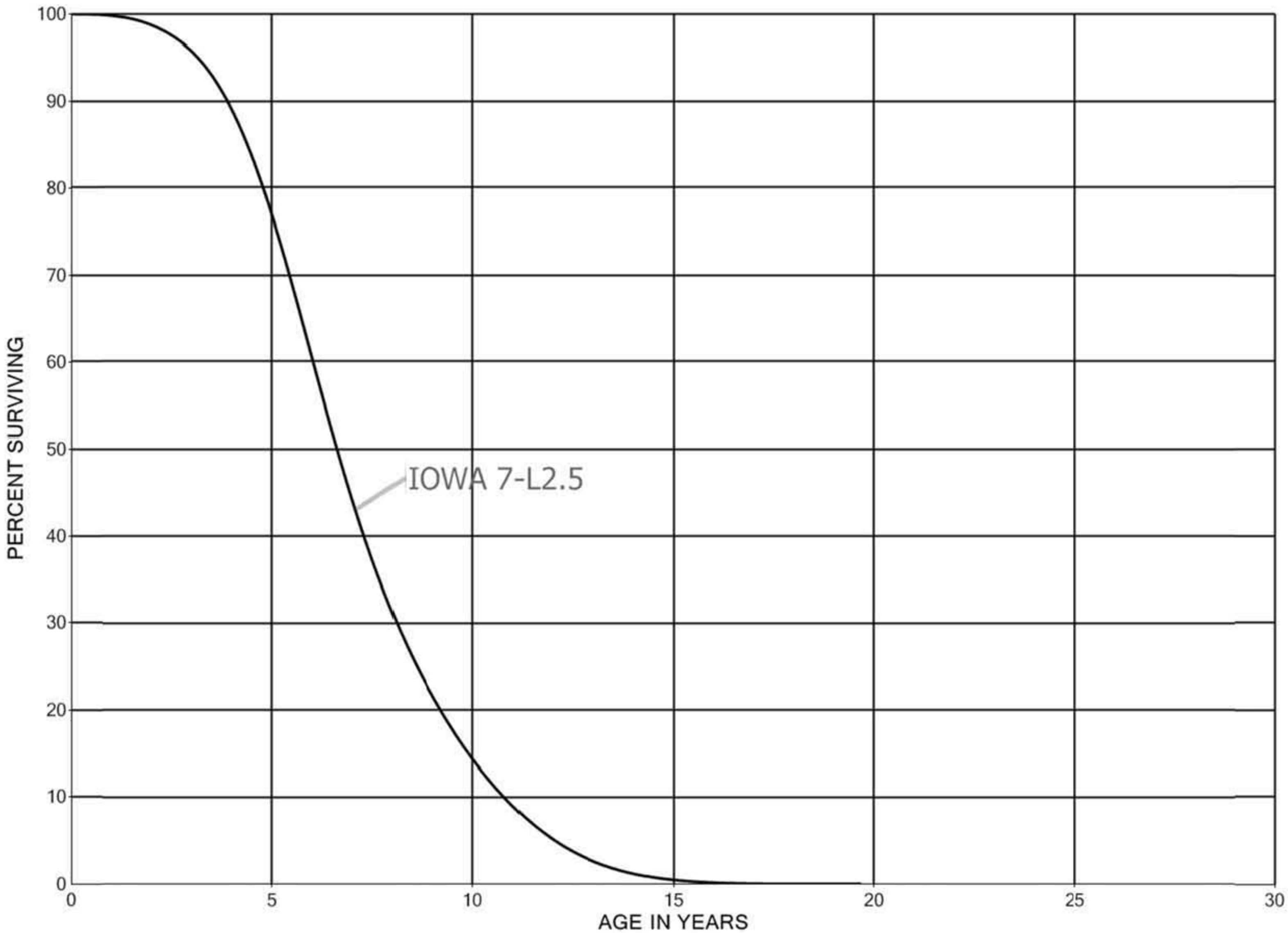
ACCOUNT 390.2 STRUCTURES AND IMPROVEMENTS - TO LEASED PROPERTY

ORIGINAL LIFE TABLE, CONT.

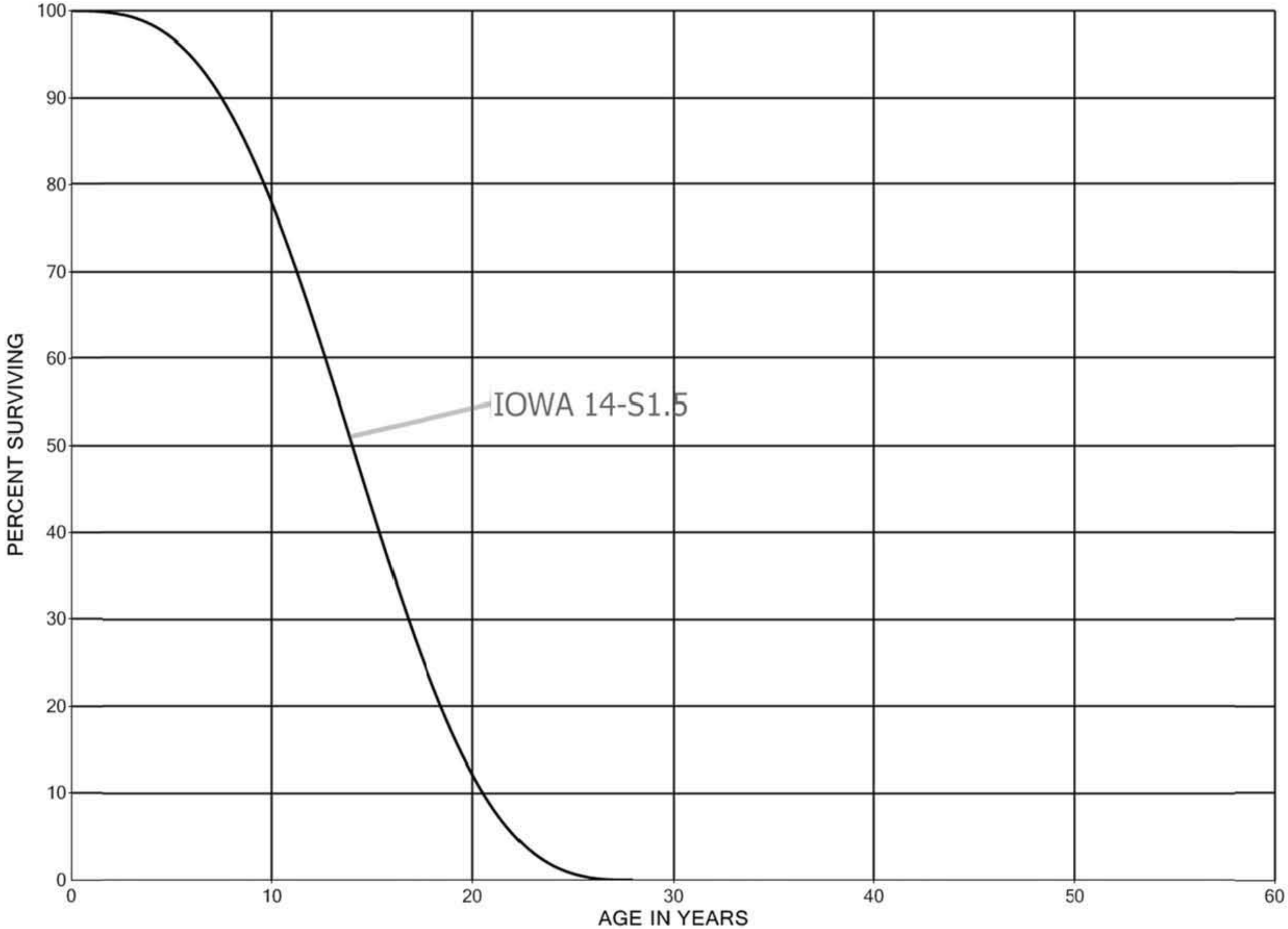
PLACEMENT BAND 1951-2002 EXPERIENCE BAND 1991-2011

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	23,224		0.0000	1.0000	26.30
40.5	22,060		0.0000	1.0000	26.30
41.5	21,654		0.0000	1.0000	26.30
42.5	21,654	2,997	0.1384	0.8616	26.30
43.5	18,657	7,941	0.4256	0.5744	22.66
44.5	10,250	65	0.0064	0.9936	13.02
45.5	9,562	90	0.0095	0.9905	12.93
46.5	9,471		0.0000	1.0000	12.81
47.5	9,471	683	0.0721	0.9279	12.81
48.5	8,389		0.0000	1.0000	11.89
49.5	1,183		0.0000	1.0000	11.89
50.5	1,183		0.0000	1.0000	11.89
51.5	458		0.0000	1.0000	11.89
52.5	458		0.0000	1.0000	11.89
53.5	458		0.0000	1.0000	11.89
54.5	458	285	0.6226	0.3774	11.89
55.5	173		0.0000	1.0000	4.49
56.5	173		0.0000	1.0000	4.49
57.5					4.49

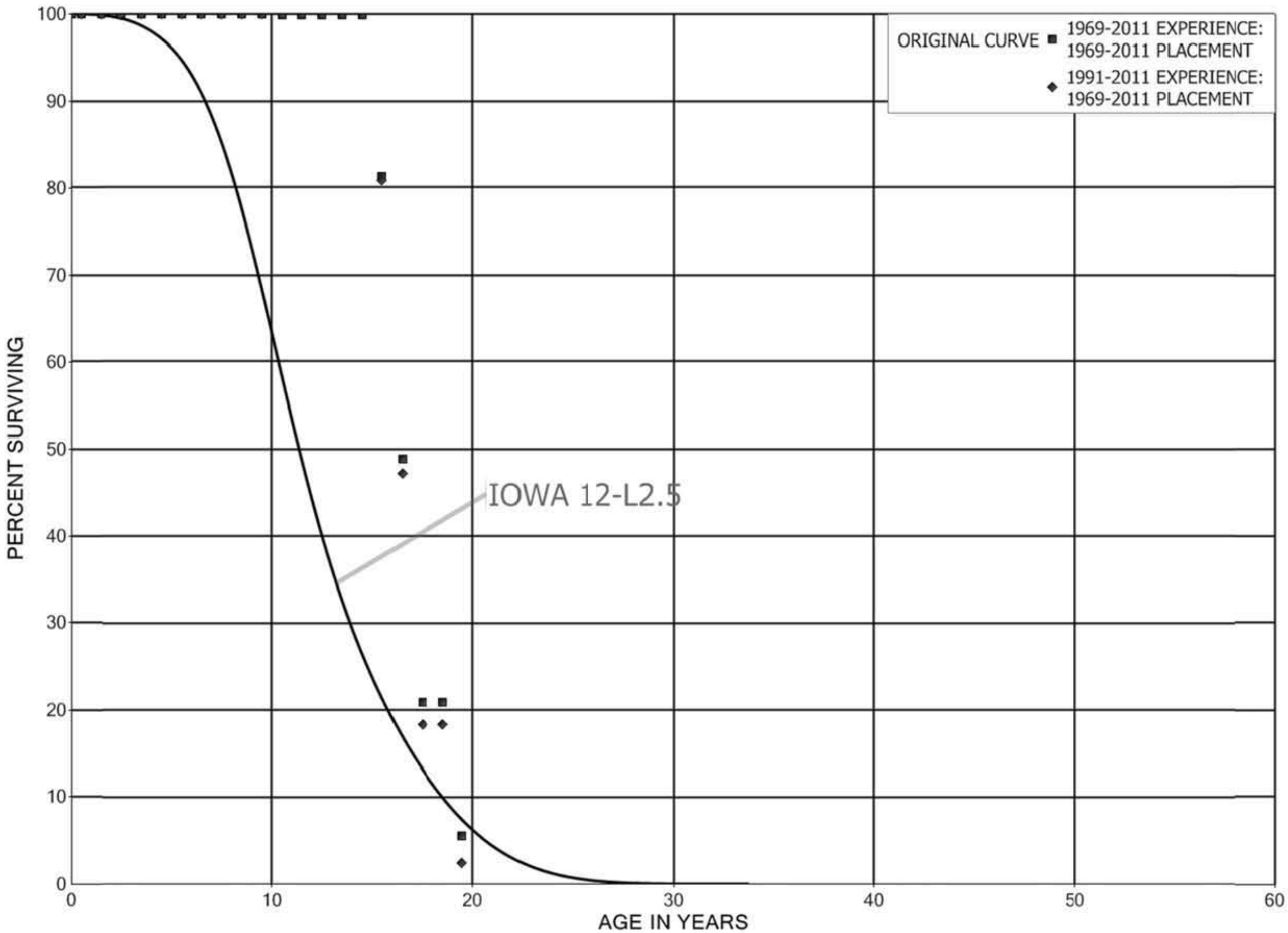
KENTUCKY UTILITIES COMPANY
ACCOUNT 392.1 TRANSPORTATION EQUIPMENT - CARS AND LIGHT TRUCKS
SMOOTH SURVIVOR CURVE



KENTUCKY UTILITIES COMPANY
ACCOUNT 392.3 TRANSPORTATION EQUIPMENT - HEAVY TRUCKS AND OTHER
SMOOTH SURVIVOR CURVE



KENTUCKY UTILITIES COMPANY
ACCOUNT 396.3 POWER OPERATED EQUIPMENT - LARGE MACHINERY
ORIGINAL AND SMOOTH SURVIVOR CURVES



KENTUCKY UTILITIES COMPANY

ACCOUNT 396.3 POWER OPERATED EQUIPMENT - LARGE MACHINERY

ORIGINAL LIFE TABLE

PLACEMENT BAND 1969-2011 EXPERIENCE BAND 1969-2011

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	1,444,100		0.0000	1.0000	100.00
0.5	1,267,250		0.0000	1.0000	100.00
1.5	565,589		0.0000	1.0000	100.00
2.5	433,217		0.0000	1.0000	100.00
3.5	433,217		0.0000	1.0000	100.00
4.5	433,217		0.0000	1.0000	100.00
5.5	433,217		0.0000	1.0000	100.00
6.5	421,909		0.0000	1.0000	100.00
7.5	325,332		0.0000	1.0000	100.00
8.5	300,509		0.0000	1.0000	100.00
9.5	300,509	367	0.0012	0.9988	100.00
10.5	300,142		0.0000	1.0000	99.88
11.5	279,311		0.0000	1.0000	99.88
12.5	275,606		0.0000	1.0000	99.88
13.5	275,606		0.0000	1.0000	99.88
14.5	269,508	50,041	0.1857	0.8143	99.88
15.5	219,467	87,816	0.4001	0.5999	81.33
16.5	131,650	75,378	0.5726	0.4274	48.79
17.5	56,272		0.0000	1.0000	20.85
18.5	56,272	41,283	0.7336	0.2664	20.85
19.5	14,989	14,025	0.9357	0.0643	5.55
20.5	964		0.0000	1.0000	0.36
21.5	964		0.0000	1.0000	0.36
22.5	964		0.0000	1.0000	0.36
23.5	964		0.0000	1.0000	0.36
24.5	964		0.0000	1.0000	0.36
25.5	964		0.0000	1.0000	0.36
26.5	964		0.0000	1.0000	0.36
27.5	964	964	1.0000		0.36
28.5					

KENTUCKY UTILITIES COMPANY

ACCOUNT 396.3 POWER OPERATED EQUIPMENT - LARGE MACHINERY

ORIGINAL LIFE TABLE

PLACEMENT BAND 1969-2011 EXPERIENCE BAND 1991-2011

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	1,281,826		0.0000	1.0000	100.00
0.5	1,134,934		0.0000	1.0000	100.00
1.5	456,244		0.0000	1.0000	100.00
2.5	323,871		0.0000	1.0000	100.00
3.5	333,385		0.0000	1.0000	100.00
4.5	333,385		0.0000	1.0000	100.00
5.5	357,455		0.0000	1.0000	100.00
6.5	346,147		0.0000	1.0000	100.00
7.5	249,570		0.0000	1.0000	100.00
8.5	224,747		0.0000	1.0000	100.00
9.5	224,747		0.0000	1.0000	100.00
10.5	224,747		0.0000	1.0000	100.00
11.5	203,916		0.0000	1.0000	100.00
12.5	243,561		0.0000	1.0000	100.00
13.5	266,890		0.0000	1.0000	100.00
14.5	260,792	50,041	0.1919	0.8081	100.00
15.5	210,751	87,816	0.4167	0.5833	80.81
16.5	122,934	75,378	0.6132	0.3868	47.14
17.5	47,556		0.0000	1.0000	18.24
18.5	47,556	41,283	0.8681	0.1319	18.24
19.5	6,273	6,273	1.0000		2.41
20.5					
21.5	964		0.0000		
22.5	964		0.0000		
23.5	964		0.0000		
24.5	964		0.0000		
25.5	964		0.0000		
26.5	964		0.0000		
27.5	964	964	1.0000		
28.5					

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NET SALVAGE STATISTICS

KENTUCKY UTILITIES COMPANY

CALCULATION OF WEIGHTED NET SALVAGE PERCENT FOR GENERATION PLANT AS OF DECEMBER 31, 2011

		Terminal Retirements			Interim Retirements			Total		Estimated
	Account	Retirements ($)	Net Salvage (%)	Net Salvage ($)	Retirements ($)	Net Salvage (%)	Net Salvage ($)	Net Salvage ($)	Total Retirements	Net Salvage (%)
	(1)	(2)	(3)	(4)=(2)x(3)	(5)	(6)	(7)=(5)x(6)	(8)=(4)+(7)	(9)=(2)+(5)	(10)=(8)/(9)
	STEAM PRODUCTION PLANT									
	BROWN GENERATING STATION									
311	STRUCTURES AND IMPROVEMENTS	68,849,852	(10)	(6,884,985)	3,042,333	(25)	760,583	7,645,568	71,892,185	(11)
312	BOILER PLANT EQUIPMENT	509,778,912	(10)	(50,977,891)	43,833,934	(30)	13,150,180	64,128,071	553,612,846	(11)
314	TURBOGENERATOR UNITS	34,988,354	(10)	(3,498,835)	14,117,591	(15)	2,117,639	5,616,474	49,105,945	(11)
315	ACCESSORY ELECTRIC EQUIPMENT	41,743,969	(10)	(4,174,397)	2,382,005	(20)	476,401	4,650,798	44,125,974	(11)
316	MISCELLANEOUS POWER PLANT EQUIPMENT	4,844,375	(10)	(484,437)	765,310	0	-	484,437	5,609,684	(11)
	TOTAL BROWN GENERATING STATION	*660,205,462*		*(66,020,546)*	*64,141,173*		*16,504,803*	*82,525,349*	*724,346,634*	*(11)*
	GHENT GENERATING STATION									
311	STRUCTURES AND IMPROVEMENTS	120,501,240	(10)	(12,050,124)	11,852,267	(25)	2,963,067	15,013,191	132,353,507	(12)
312	BOILER PLANT EQUIPMENT	1,321,271,054	(10)	(132,127,105)	171,355,455	(30)	51,406,637	183,533,742	1,492,626,510	(12)
314	TURBOGENERATOR UNITS	111,677,673	(10)	(11,167,767)	55,059,770	(15)	8,258,966	19,426,733	166,737,443	(12)
315	ACCESSORY ELECTRIC EQUIPMENT	94,779,021	(10)	(9,477,902)	13,632,245	(20)	2,726,449	12,204,351	108,411,266	(12)
316	MISCELLANEOUS POWER PLANT EQUIPMENT	12,430,337	(10)	(1,243,034)	2,456,361	0	-	1,243,034	14,886,698	(12)
	TOTAL GHENT GENERATING STATION	*1,660,659,326*		*(166,065,933)*	*254,356,098*		*65,355,118*	*231,421,050*	*1,915,015,424*	*(12)*
	GREEN RIVER GENERATING STATION									
311	STRUCTURES AND IMPROVEMENTS	10,698,728	(10)	(1,069,873)	159,527	(25)	39,882	1,109,755	10,858,255	(10)
312	BOILER PLANT EQUIPMENT	36,914,230	(10)	(3,691,423)	746,752	(30)	224,026	3,915,449	37,660,983	(10)
314	TURBOGENERATOR UNITS	14,317,850	(10)	(1,431,785)	634,829	(15)	95,224	1,527,009	14,952,679	(10)
315	ACCESSORY ELECTRIC EQUIPMENT	3,785,377	(10)	(378,538)	115,314	(20)	23,063	401,600	3,900,691	(10)
316	MISCELLANEOUS POWER PLANT EQUIPMENT	2,606,735	(10)	(260,673)	38,304	0	-	260,673	2,645,039	(10)
	TOTAL GREEN RIVER GENERATING STATION	*68,322,920*		*(6,832,292)*	*1,694,727*		*382,195*	*7,214,487*	*70,017,647*	*(10)*
	PINEVILLE GENERATING STATION									
311	STRUCTURES AND IMPROVEMENTS	16,195	(10)	(1,620)	9	(25)	2	1,622	16,204	(10)
312	BOILER PLANT EQUIPMENT	232,704	(10)	(23,270)	3,766	(30)	1,130	24,400	236,470	(10)
314	TURBOGENERATOR UNITS	-	(10)	0	-	(15)	-	-	-	(10)
315	ACCESSORY ELECTRIC EQUIPMENT	-	(10)	0	-	(20)	-	-	-	(10)
316	MISCELLANEOUS POWER PLANT EQUIPMENT	-	(10)	0	-	0	-	-	-	(10)
	TOTAL PINEVILLE GENERATING STATION	*248,900*		*(24,890)*	*3,775*		*1,132*	*26,022*	*252,675*	*(10)*
	SYSTEM LAB									
311	STRUCTURES AND IMPROVEMENTS	744,220	0	0	80,748	(25)	20,187	20,187	824,969	(1)
312	BOILER PLANT EQUIPMENT	-	0	0	-	(30)	-	-	-	(1)
314	TURBOGENERATOR UNITS	-	0	0	-	(15)	-	-	-	(1)
315	ACCESSORY ELECTRIC EQUIPMENT	-	0	0	-	(20)	-	-	-	(1)
316	MISCELLANEOUS POWER PLANT EQUIPMENT	2,394,972	0	0	368,077	0	-	-	2,763,049	(1)
	TOTAL SYSTEM LAB	*3,139,193*		*-*	*448,825*		*20,187*	*20,187*	*3,588,017*	*(1)*

KENTUCKY UTILITIES COMPANY

CALCULATION OF WEIGHTED NET SALVAGE PERCENT FOR GENERATION PLANT AS OF DECEMBER 31, 2011

Account	Terminal Retirements Retirements ($)	Terminal Retirements Net Salvage (%)	Terminal Retirements Net Salvage ($)	Interim Retirements Retirements ($)	Interim Retirements Net Salvage (%)	Interim Retirements Net Salvage ($)	Total Net Salvage ($)	Total Retirements	Estimated Net Salvage (%)
(1)	(2)	(3)	(4)=(2)x(3)	(5)	(6)	(7)=(5)x(6)	(8)=(4)+(7)	(9)=(2)+(5)	(10)=(8)/(9)
STEAM PRODUCTION PLANT (CONT.)									
TYRONE GENERATING STATION									
311 STRUCTURES AND IMPROVEMENTS	6,066,662	(10)	(606,666)	125,545	(25)	31,386	638,052	6,192,207	(10)
312 BOILER PLANT EQUIPMENT	14,040,352	(10)	(1,404,035)	374,833	(30)	112,450	1,516,485	14,415,186	(10)
314 TURBOGENERATOR UNITS	4,588,909	(10)	(458,891)	284,811	(15)	42,722	501,612	4,873,719	(10)
315 ACCESSORY ELECTRIC EQUIPMENT	2,110,076	(10)	(211,008)	70,827	(20)	14,165	225,173	2,180,903	(10)
316 MISCELLANEOUS POWER PLANT EQUIPMENT	592,490	(10)	(59,249)	10,992	0	-	59,249	603,482	(10)
TOTAL TYRONE GENERATING STATION	*27,398,488*		*(2,739,849)*	*867,009*		*200,723*	*2,940,572*	*28,265,497*	*(10)*
TRIMBLE COUNTY									
311 STRUCTURES AND IMPROVEMENTS	86,202,297	(10)	(8,620,230)	25,610,591	(25)	6,402,648	15,022,877	111,812,888	(16)
312 BOILER PLANT EQUIPMENT	352,937,892	(10)	(35,293,789)	222,956,396	(30)	66,886,919	102,180,708	575,894,288	(16)
314 TURBOGENERATOR UNITS	31,029,751	(10)	(3,102,975)	52,964,982	(15)	7,944,747	11,047,722	83,994,733	(16)
315 ACCESSORY ELECTRIC EQUIPMENT	26,315,352	(10)	(2,631,535)	16,700,474	(20)	3,340,095	5,971,630	43,015,826	(16)
316 MISCELLANEOUS POWER PLANT EQUIPMENT	2,298,460	(10)	(229,846)	1,203,987	0	-	229,846	3,502,447	(16)
TOTAL TRIMBLE COUNTY	*498,783,752*		*(49,878,375)*	*319,436,430*		*84,574,409*	*134,452,784*	*818,220,182*	*(16)*
TOTAL STEAM PRODUCTION PLANT	**2,918,758,040**		**(291,561,885)**	**640,948,036**		**167,038,567**	**458,600,452**	**3,559,706,076**	
HYDRAULIC PRODUCTION PLANT									
DIX DAM									
331 STRUCTURES AND IMPROVEMENTS	460,238	(5)	(23,012)	156,289	(5)	7,814	30,826	616,527	(6)
332 RESERVOIRS, DAMS AND WATERWAYS	19,039,829	(5)	(951,991)	2,564,141	(10)	256,414	1,208,406	21,603,970	(6)
333 WATER WHEELS, TURBINES AND GENERATORS	4,076,011	(5)	(203,801)	354,613	(20)	70,923	274,723	4,430,624	(6)
334 ACCESSORY ELECTRIC EQUIPMENT	355,642	(5)	(17,782)	222,692	0	-	17,782	578,333	(6)
335 MISCELLANEOUS POWER PLANT EQUIPMENT	77,245	(5)	(3,862)	219,779	(5)	10,989	14,851	297,024	(6)
336 ROADS, RAILROADS AND BRIDGES	124,770	(5)	(6,239)	51,589	0	-	6,239	176,360	(6)
TOTAL DIX DAM	*24,133,734*		*(1,206,687)*	*3,569,103*		*346,140*	*1,552,827*	*27,702,837*	*(6)*
TOTAL HYDRAULIC PRODUCTION PLANT	**24,133,734**		**(1,206,687)**	**3,569,103**		**346,140**	**1,552,827**	**27,702,837**	

KENTUCKY UTILITIES COMPANY

CALCULATION OF WEIGHTED NET SALVAGE PERCENT FOR GENERATION PLANT AS OF DECEMBER 31, 2011

Account (1)		Terminal Retirements: Retirements ($) (2)	Terminal Retirements: Net Salvage (%) (3)	Terminal Retirements: Net Salvage ($) (4)=(2)x(3)	Interim Retirements: Retirements ($) (5)	Interim Retirements: Net Salvage (%) (6)	Interim Retirements: Net Salvage ($) (7)=(5)x(6)	Total Net Salvage ($) (8)=(4)+(7)	Total Retirements (9)=(2)+(5)	Estimated Net Salvage (%) (10)=(8)/(9)
OTHER PRODUCTION PLANT										
	BROWN CTS									
341	STRUCTURES AND IMPROVEMENTS	9,195,757	(5)	(459,788)	2,731,546	0	-	459,788	11,927,303	(5)
342	FUEL HOLDERS, PRODUCERS AND ACCESSORIES	10,211,547	(5)	(510,577)	2,322,415	(5)	116,121	626,698	12,533,962	(5)
343	PRIME MOVERS	136,839,902	(5)	(6,841,995)	49,000,992	(5)	2,450,050	9,292,045	185,840,895	(5)
344	GENERATORS	29,442,983	(5)	(1,472,149)	1,388,038	(5)	69,402	1,541,551	30,831,020	(5)
345	ACCESSORY ELECTRIC EQUIPMENT	15,263,350	(5)	(763,168)	2,458,791	(5)	122,940	886,107	17,722,142	(5)
346	MISCELLANEOUS POWER PLANT EQUIPMENT	2,938,221	(5)	(146,911)	1,201,669	0	-	146,911	4,139,890	(5)
	TOTAL BROWN CTS	*203,891,761*		*(10,194,588)*	*59,103,452*		*2,758,512*	*12,953,100*	*262,995,213*	*(5)*
	HAEFLING CTS									
341	STRUCTURES AND IMPROVEMENTS	412,940	(5)	(20,647)	21,913	0	-	20,647	434,853	(5)
342	FUEL HOLDERS, PRODUCERS AND ACCESSORIES	479,905	(5)	(23,995)	38,800	(5)	1,940	25,935	518,705	(5)
344	GENERATORS	3,223,465	(5)	(161,173)	799,537	(5)	39,977	201,150	4,023,002	(5)
345	ACCESSORY ELECTRIC EQUIPMENT	1,211,240	(5)	(60,562)	240,717	(5)	12,036	72,598	1,451,957	(5)
346	MISCELLANEOUS POWER PLANT EQUIPMENT	13,500	(5)	(675)	22,305	0	-	675	35,805	(5)
	TOTAL HAEFLING CTS	*5,341,050*		*(267,053)*	*1,123,272*		*53,953*	*321,005*	*6,464,323*	*(5)*
	PADDY'S RUN CTS									
341	STRUCTURES AND IMPROVEMENTS	1,563,219	(5)	(78,161)	347,109	0	-	78,161	1,910,328	(5)
342	FUEL HOLDERS, PRODUCERS AND ACCESSORIES	1,730,245	(5)	(86,512)	264,856	(5)	13,243	99,755	1,995,101	(5)
343	PRIME MOVERS	12,869,763	(5)	(643,488)	4,933,601	(5)	246,680	890,168	17,803,364	(5)
344	GENERATORS	5,045,282	(5)	(252,264)	140,354	(5)	7,018	259,282	5,185,636	(5)
345	ACCESSORY ELECTRIC EQUIPMENT	2,184,168	(5)	(109,208)	272,152	(5)	13,608	122,816	2,456,320	(5)
346	MISCELLANEOUS POWER PLANT EQUIPMENT	784,628	(5)	(39,231)	304,922	0	-	39,231	1,089,550	(5)
	TOTAL PADDY'S RUN CTS	*24,177,306*		*(1,208,865)*	*6,262,993*		*280,548*	*1,489,413*	*30,440,299*	*(5)*
	TRIMBLE COUNTY CTS									
341	STRUCTURES AND IMPROVEMENTS	17,661,338	(5)	(883,067)	4,084,591	0	-	883,067	21,745,929	(5)
342	FUEL HOLDERS, PRODUCERS AND ACCESSORIES	6,528,160	(5)	(326,408)	1,171,888	(5)	58,594	385,002	7,700,048	(5)
343	PRIME MOVERS	109,263,693	(5)	(5,463,185)	45,915,081	(5)	2,295,754	7,758,939	155,178,774	(5)
344	GENERATORS	18,798,072	(5)	(939,904)	523,030	(5)	26,152	966,055	19,321,102	(5)
345	ACCESSORY ELECTRIC EQUIPMENT	20,149,294	(5)	(1,007,465)	2,587,693	(5)	129,385	1,136,849	22,736,987	(5)
346	MISCELLANEOUS POWER PLANT EQUIPMENT	75,076	(5)	(3,754)	22,620	0	-	3,754	97,696	(5)
	TOTAL TRIMBLE COUNTY CTS	*172,475,634*		*(8,623,782)*	*54,304,902*		*2,509,885*	*11,133,666*	*226,780,536*	*(5)*
TOTAL OTHER PRODUCTION PLANT		**405,885,751**		**(20,294,288)**	**120,794,620**		**5,602,897**	**25,897,185**	**526,680,370**	
GRAND TOTAL		**3,348,777,525**		**(313,062,859)**	**765,311,759**		**172,987,604**	**486,050,463**	**4,114,089,284**	

KENTUCKY UTILITIES COMPANY

ACCOUNT 311 STRUCTURES AND IMPROVEMENTS

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	COST OF REMOVAL PCT	GROSS SALVAGE REIMBURSEMENTS AMOUNT	GROSS SALVAGE REIMBURSEMENTS PCT	GROSS SALVAGE FINAL AMOUNT	GROSS SALVAGE FINAL PCT	NET SALVAGE AMOUNT	NET SALVAGE PCT
1988	6,045		0		0		0		0
1989	2,547		0		0		0		0
1990	54,378		0		0		0		0
1991									
1992									
1993									
1994									
1995	86,278	10,005	12	2,930	3		0	7,074-	8-
1996	2,936	609	21	3,210	109		0	2,601	89
1997	103,244	8,046	8		0		0	8,046-	8-
1998	32,510	16,167	50		0		0	16,167-	50-
1999	5,858-	1,967-	34		0		0	1,967	34-
2000	11,626		0		0		0		0
2001	144,193	33,335	23		0		0	33,335-	23-
2002	370,024	20,477	6	241,345	65		0	220,868	60
2003									
2004	228,612	46,180	20		0		0	46,180-	20-
2005									
2006	137,959	47,675	35		0		0	47,675-	35-
2007	2,213,101	777,334	35		0		0	777,334-	35-
2008	89,209	20,700	23		0		0	20,700-	23-
2009	145,695	45,964	32	87,350	60		0	41,386	28
2010	88,392	12,254	14		0		0	12,254-	14-
2011	681,753	435,245	64		0		0	435,245-	64-
TOTAL	4,392,646	1,472,024	34	334,836	8		0	1,137,188-	26-

THREE-YEAR MOVING AVERAGES

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	COST OF REMOVAL PCT	GROSS SALVAGE REIMBURSEMENTS AMOUNT	GROSS SALVAGE REIMBURSEMENTS PCT	GROSS SALVAGE FINAL AMOUNT	GROSS SALVAGE FINAL PCT	NET SALVAGE AMOUNT	NET SALVAGE PCT
88-90	20,990		0		0		0		0
89-91	18,975		0		0		0		0
90-92	18,126		0		0		0		0
91-93									
92-94									
93-95	28,759	3,335	12	977	3		0	2,358-	8-
94-96	29,738	3,538	12	2,047	7		0	1,491-	5-
95-97	64,153	6,220	10	2,047	3		0	4,173-	7-
96-98	46,230	8,274	18	1,070	2		0	7,204-	16-
97-99	43,299	7,415	17		0		0	7,415-	17-
98-00	12,759	4,733	37		0		0	4,733-	37-
99-01	49,987	10,456	21		0		0	10,456-	21-
00-02	175,281	17,937	10	80,448	46		0	62,511	36

KENTUCKY UTILITIES COMPANY

ACCOUNT 311 STRUCTURES AND IMPROVEMENTS

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	COST OF REMOVAL PCT	GROSS SALVAGE REIMBURSEMENTS AMOUNT	GROSS SALVAGE REIMBURSEMENTS PCT	GROSS SALVAGE FINAL AMOUNT	GROSS SALVAGE FINAL PCT	NET SALVAGE AMOUNT	NET SALVAGE PCT
THREE-YEAR MOVING AVERAGES									
01-03	171,406	17,937	10	80,448	47		0	62,511	36
02-04	199,545	22,219	11	80,448	40		0	58,229	29
03-05	76,204	15,393	20		0		0	15,393-	20-
04-06	122,191	31,285	26		0		0	31,285-	26-
05-07	783,687	275,003	35		0		0	275,003-	35-
06-08	813,423	281,903	35		0		0	281,903-	35-
07-09	816,002	281,333	34	29,117	4		0	252,216-	31-
08-10	107,766	26,306	24	29,117	27		0	2,811	3
09-11	305,280	164,488	54	29,117	10		0	135,371-	44-
FIVE-YEAR AVERAGE									
07-11	643,630	258,300	40	17,470	3		0	240,830-	37-

KENTUCKY UTILITIES COMPANY

ACCOUNT 312 BOILER PLANT EQUIPMENT

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE REIMBURSEMENTS AMOUNT	PCT	GROSS SALVAGE FINAL AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
1988	5,472,744	33,162-	1-		0	85,506	2	118,668	2
1989	140,477		0		0		0		0
1990	139,953		0		0		0		0
1991									
1992	3,381,168	126,229	4		0	2,358	0	123,871-	4-
1993	73,171	586,475	802	239,135-	327-	36,145	49	789,466-	
1994	3,105,560	1,235,481	40		0	5,496	0	1,229,984-	40-
1995	2,831,089	887,355	31	43,821	2	44,496	2	799,038-	28-
1996	2,448,557	1,372,067	56	1,220,033	50	25,699	1	126,335-	5-
1997	3,497,148	736,637	21		0	6,713	0	729,924-	21-
1998	614,620	826,172	134		0	14,906-	2-	841,078-	137-
1999	855,983	776,825	91		0	5,197	1	771,628-	90-
2000	4,074,449		0		0	20,250	0	20,250	0
2001	2,773,207	973,763	35		0	350	0	973,413-	35-
2002	1,580,022	47,752	3	842,803	53		0	795,051	50
2003	3,081,492	1,016,856	33		0		0	1,016,856-	33-
2004	2,629,000	1,220,722	46		0		0	1,220,722-	46-
2005	2,723,301	1,455,836	53		0	3,066	0	1,452,769-	53-
2006	8,467,051	5,300,625	63		0	17,365	0	5,283,260-	62-
2007	5,552,705	1,817,773	33	176,626	3	300	0	1,640,847-	30-
2008	1,602,275	654,037	41		0		0	654,037-	41-
2009	4,750,276	2,120,465	45		0	20,000	0	2,100,465-	44-
2010	8,267,108	974,238	12		0	10,802	0	963,435-	12-
2011	7,436,356	1,421,560	19		0	342,587	5	1,078,973-	15-
TOTAL	75,497,711	23,517,706	31	2,044,149	3	611,425	1	20,862,132-	28-

THREE-YEAR MOVING AVERAGES

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE REIMBURSEMENTS AMOUNT	PCT	GROSS SALVAGE FINAL AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
88-90	1,917,725	11,054-	1-		0	28,502	1	39,556	2
89-91	93,477		0		0		0		0
90-92	1,173,707	42,076	4		0	786	0	41,290-	4-
91-93	1,151,446	237,568	21	79,712-	7-	12,834	1	304,446-	26-
92-94	2,186,633	649,395	30	79,712-	4-	14,666	1	714,440-	33-
93-95	2,003,273	903,104	45	65,105-	3-	28,712	1	939,496-	47-
94-96	2,795,069	1,164,968	42	421,285	15	25,230	1	718,452-	26-
95-97	2,925,598	998,687	34	421,285	14	25,636	1	551,766-	19-
96-98	2,186,775	978,292	45	406,678	19	5,835	0	565,779-	26-
97-99	1,655,917	779,878	47		0	999-	0	780,877-	47-
98-00	1,848,351	534,332	29		0	3,514	0	530,819-	29-
99-01	2,567,880	583,529	23		0	8,599	0	574,930-	22-
00-02	2,809,226	340,505	12	280,934	10	6,867	0	52,704-	2-

KENTUCKY UTILITIES COMPANY

ACCOUNT 312 BOILER PLANT EQUIPMENT

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	COST OF REMOVAL PCT	GROSS SALVAGE REIMBURSEMENTS AMOUNT	GROSS SALVAGE REIMBURSEMENTS PCT	GROSS SALVAGE FINAL AMOUNT	GROSS SALVAGE FINAL PCT	NET SALVAGE AMOUNT	NET SALVAGE PCT
THREE-YEAR MOVING AVERAGES									
01-03	2,478,240	679,457	27	280,934	11	117	0	398,406-	16-
02-04	2,430,171	761,777	31	280,934	12		0	480,842-	20-
03-05	2,811,264	1,231,138	44		0	1,022	0	1,230,116-	44-
04-06	4,606,451	2,659,061	58		0	6,811	0	2,652,250-	58-
05-07	5,581,019	2,858,078	51	58,875	1	6,911	0	2,792,292-	50-
06-08	5,207,344	2,590,812	50	58,875	1	5,888	0	2,526,048-	49-
07-09	3,968,419	1,530,758	39	58,875	1	6,767	0	1,465,117-	37-
08-10	4,873,220	1,249,580	26		0	10,267	0	1,239,312-	25-
09-11	6,817,913	1,505,421	22		0	124,463	2	1,380,958-	20-
FIVE-YEAR AVERAGE									
07-11	5,521,744	1,397,615	25	35,325	1	74,738	1	1,287,551-	23-

KENTUCKY UTILITIES COMPANY

ACCOUNT 314 TURBOGENERATOR UNITS

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE REIMBURSEMENTS AMOUNT	PCT	GROSS SALVAGE FINAL AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
1994	1,285,265	314,381	24		0		0	314,381-	24-
1995	1,942,977	374,438	19	110,477	6		0	263,960-	14-
1996	1,313,231	452,454	34	2,403,674	183		0	1,951,220	149
1997	3,603,445	466,687	13		0		0	466,687-	13-
1998	210,345	173,846	83		0		0	173,846-	83-
1999	152,655	85,180	56		0		0	85,180-	56-
2000	32,604		0		0		0		0
2001	100,327	27,123	27		0		0	27,123-	27-
2002	405,528	42,556	10	314,790	78		0	272,234	67
2003	3,275,422	878,306	27		0	61,336	2	816,969-	25-
2004	1,624,795	449,310	28		0		0	449,310-	28-
2005	771,200	302,941	39		0		0	302,941-	39-
2006	3,934,128	1,012,073	26		0		0	1,012,073-	26-
2007	832,436	139,427	17	582,620	70		0	443,192	53
2008	3,477,445	544,686	16		0		0	544,686-	16-
2009	4,484,265	1,068,154	24	167,816	4		0	900,337-	20-
2010	133,532	18,175	14		0		0	18,175-	14-
2011	1,816,683	534,507	29		0	920,288	51	385,780	21
TOTAL	29,396,283	6,884,242	23	3,579,377	12	981,624	3	2,323,241-	8-

THREE-YEAR MOVING AVERAGES

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE REIMBURSEMENTS AMOUNT	PCT	GROSS SALVAGE FINAL AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
94-96	1,513,824	380,424	25	838,051	55		0	457,626	30
95-97	2,286,551	431,193	19	838,051	37		0	406,858	18
96-98	1,709,007	364,329	21	801,225	47		0	436,896	26
97-99	1,322,148	241,904	18		0		0	241,904-	18-
98-00	131,868	86,342	65		0		0	86,342-	65-
99-01	95,195	37,434	39		0		0	37,434-	39-
00-02	179,486	23,226	13	104,930	58		0	81,704	46
01-03	1,260,426	315,995	25	104,930	8	20,446	2	190,619-	15-
02-04	1,768,582	456,724	26	104,930	6	20,446	1	331,348-	19-
03-05	1,890,472	543,519	29		0	20,446	1	523,073-	28-
04-06	2,110,041	588,108	28		0		0	588,108-	28-
05-07	1,845,921	484,814	26	194,207	11		0	290,607-	16-
06-08	2,748,003	565,395	21	194,207	7		0	371,189-	14-
07-09	2,931,382	584,089	20	250,145	9		0	333,944-	11-

KENTUCKY UTILITIES COMPANY

ACCOUNT 314 TURBOGENERATOR UNITS

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE REIMBURSEMENTS AMOUNT	PCT	GROSS SALVAGE FINAL AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
THREE-YEAR MOVING AVERAGES									
08-10	2,698,414	543,672	20	55,939	2		0	487,733-	18-
09-11	2,144,827	540,279	25	55,939	3	306,762	14	177,578-	8-
FIVE-YEAR AVERAGE									
07-11	2,148,872	460,990	21	150,087	7	184,058	9	126,845-	6-

KENTUCKY UTILITIES COMPANY

ACCOUNT 315 ACCESSORY ELECTRIC EQUIPMENT

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE REIMBURSEMENTS AMOUNT	PCT	GROSS SALVAGE FINAL AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
1991	6,329		0		0		0		0
1992									
1993	37,232	74,358	200	396,748-			0	471,106-	
1994	9,852	977	10		0		0	977-	10-
1995	145,075	11,330	8	7,322	5		0	4,008-	3-
1996	76,925	10,741	14	124,975	162		0	114,234	149
1997	38,297	2,010	5		0		0	2,010-	5-
1998									
1999									
2000									
2001	16,118	6,569	41		0		0	6,569-	41-
2002	434		0	64,999			0	64,999	
2003	836		0		0		0		0
2004	28,226	7,603	27		0		0	7,603-	27-
2005									
2006	108,356	11,238	10		0		0	11,238-	10-
2007	195,095	358,400	184	287,143	147		0	71,257-	37-
2008	975		0		0		0		0
2009	69,407	58,030	84		0		0	58,030-	84-
2010	33,428	2,689	8		0	9,196	28	6,507	19
2011	909,711	308,869	34		0	119,912	13	188,957-	21-
TOTAL	1,676,295	852,813	51	87,691	5	129,108	8	636,014-	38-
THREE-YEAR MOVING AVERAGES									
91-93	14,520	24,786	171	132,249-	911-		0	157,035-	
92-94	15,695	25,112	160	132,249-	843-		0	157,361-	
93-95	64,053	28,888	45	129,809-	203-		0	158,697-	248-
94-96	77,284	7,682	10	44,099	57		0	36,416	47
95-97	86,766	8,027	9	44,099	51		0	36,072	42
96-98	38,407	4,250	11	41,658	108		0	37,408	97
97-99	12,766	670	5		0		0	670-	5-
98-00									
99-01	5,373	2,190	41		0		0	2,190-	41-
00-02	5,517	2,190	40	21,666	393		0	19,477	353
01-03	5,796	2,190	38	21,666	374		0	19,477	336
02-04	9,832	2,534	26	21,666	220		0	19,132	195
03-05	9,687	2,534	26		0		0	2,534-	26-
04-06	45,527	6,280	14		0		0	6,280-	14-
05-07	101,150	123,212	122	95,714	95		0	27,498-	27-
06-08	101,475	123,212	121	95,714	94		0	27,498-	27-

KENTUCKY UTILITIES COMPANY

ACCOUNT 315 ACCESSORY ELECTRIC EQUIPMENT

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE REIMBURSEMENTS AMOUNT	PCT	GROSS SALVAGE FINAL AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
THREE-YEAR MOVING AVERAGES									
07-09	88,492	138,810	157	95,714	108		0	43,096-	49-
08-10	34,603	20,240	58		0	3,065	9	17,174-	50-
09-11	337,515	123,196	37		0	43,036	13	80,160-	24-
FIVE-YEAR AVERAGE									
07-11	241,723	145,598	60	57,429	24	25,822	11	62,347-	26-

KENTUCKY UTILITIES COMPANY

ACCOUNT 316 MISCELLANEOUS POWER PLANT EQUIPMENT

SUMMARY OF BOOK SALVAGE

		COST OF REMOVAL		GROSS SALVAGE				NET SALVAGE	
				REIMBURSEMENTS		FINAL			
YEAR	REGULAR RETIREMENTS	AMOUNT	PCT	AMOUNT	PCT	AMOUNT	PCT	AMOUNT	PCT
1988	7,815		0		0	100	1	100	1
1989	20,616		0		0	4,480	22	4,480	22
1990	4,249,398		0		0	164,118	4	164,118	4
1991	4,929		0		0		0		0
1992	55,521	958	2		0		0	958-	2-
1993	11,206	383	3	5,040-	45-	42,673	381	37,251	332
1994	24,722	42	0		0	337	1	295	1
1995	52,493	70	0	112	0	6,360	12	6,402	12
1996	50,369	120	0	3,454	7	4,075	8	7,409	15
1997	244,396	219	0		0	3,617	1	3,397	1
1998	65,320	374	1		0	12,212-	19-	12,586-	19-
1999	111,838	432	0		0	5,234	5	4,802	4
2000	472		0		0		0		0
2001	25,187		0		0		0		0
2002	56,542-		0	23,399	41-		0	23,399	41-
2003									
2004	186,564	10,310	6		0		0	10,310-	6-
2005									
2006	122,613	3,804	3		0	567	0	3,237-	3-
2007	196,052	737	0		0		0	737-	0
2008	15,404		0		0		0		0
2009	39,354	1,153	3		0		0	1,153-	3-
2010	20,830	3,603	17		0		0	3,603-	17-
2011	365,962	8,495	2		0		0	8,495-	2-
TOTAL	5,814,519	30,700	1	21,925	0	219,349	4	210,574	4

THREE-YEAR MOVING AVERAGES

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	REIMBURSEMENTS AMOUNT	PCT	FINAL AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
88-90	1,425,943		0		0	56,233	4	56,233	4
89-91	1,424,981		0		0	56,199	4	56,199	4
90-92	1,436,616	319	0		0	54,706	4	54,387	4
91-93	23,885	447	2	1,680-	7-	14,224	60	12,098	51
92-94	30,483	461	2	1,680-	6-	14,337	47	12,196	40
93-95	29,474	165	1	1,643-	6-	16,457	56	14,649	50
94-96	42,528	77	0	1,188	3	3,591	8	4,702	11
95-97	115,753	137	0	1,188	1	4,684	4	5,736	5
96-98	120,028	238	0	1,151	1	1,507-	1-	593-	0
97-99	140,518	342	0		0	1,121-	1-	1,462-	1-
98-00	59,210	269	0		0	2,326-	4-	2,595-	4-
99-01	45,832	144	0		0	1,745	4	1,601	3
00-02	10,294-		0	7,800	76-		0	7,800	76-

KENTUCKY UTILITIES COMPANY

ACCOUNT 316 MISCELLANEOUS POWER PLANT EQUIPMENT

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	COST OF REMOVAL PCT	GROSS SALVAGE REIMBURSEMENTS AMOUNT	GROSS SALVAGE REIMBURSEMENTS PCT	GROSS SALVAGE FINAL AMOUNT	GROSS SALVAGE FINAL PCT	NET SALVAGE AMOUNT	NET SALVAGE PCT
THREE-YEAR MOVING AVERAGES									
01-03	10,452-		0	7,800	75-		0	7,800	75-
02-04	43,341	3,437	8	7,800	18		0	4,363	10
03-05	62,188	3,437	6		0		0	3,437-	6-
04-06	103,059	4,705	5		0	189	0	4,516-	4-
05-07	106,222	1,514	1		0	189	0	1,325-	1-
06-08	111,356	1,514	1		0	189	0	1,325-	1-
07-09	83,603	630	1		0		0	630-	1-
08-10	25,196	1,585	6		0		0	1,585-	6-
09-11	142,049	4,417	3		0		0	4,417-	3-
FIVE-YEAR AVERAGE									
07-11	127,520	2,798	2		0		0	2,798-	2-

KENTUCKY UTILITIES COMPANY

ACCOUNT 331 STRUCTURES AND IMPROVEMENTS

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	COST OF REMOVAL PCT	GROSS SALVAGE REIMBURSEMENTS AMOUNT	GROSS SALVAGE REIMBURSEMENTS PCT	GROSS SALVAGE FINAL AMOUNT	GROSS SALVAGE FINAL PCT	NET SALVAGE AMOUNT	NET SALVAGE PCT
1990	242	4,092			0		0	4,092-	
1991									
1992									
1993									
1994	5,131		0		0		0		0
1995	112		0		0		0		0
1996	19,338		0		0	23	0	23	0
1997									
1998									
1999									
2000									
2001									
2002									
2003									
2004									
2005	67,902		0		0		0		0
2006									
2007									
2008									
2009									
2010									
2011									
TOTAL	92,725	4,092	4		0	23	0	4,069-	4-
THREE-YEAR MOVING AVERAGES									
90-92	81	1,364			0		0	1,364-	
91-93									
92-94	1,710		0		0		0		0
93-95	1,748		0		0		0		0
94-96	8,194		0		0	8	0	8	0
95-97	6,483		0		0	8	0	8	0
96-98	6,446		0		0	8	0	8	0
97-99									
98-00									
99-01									
00-02									
01-03									
02-04									
03-05	22,634		0		0		0		0
04-06	22,634		0		0		0		0

KENTUCKY UTILITIES COMPANY

ACCOUNT 331 STRUCTURES AND IMPROVEMENTS

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	COST OF REMOVAL PCT	GROSS SALVAGE REIMBURSEMENTS AMOUNT	GROSS SALVAGE REIMBURSEMENTS PCT	GROSS SALVAGE FINAL AMOUNT	GROSS SALVAGE FINAL PCT	NET SALVAGE AMOUNT	NET SALVAGE PCT
THREE-YEAR MOVING AVERAGES									
05-07	22,634		0		0		0		0
06-08									
07-09									
08-10									
09-11									
FIVE-YEAR AVERAGE									
07-11									

KENTUCKY UTILITIES COMPANY

ACCOUNT 332 RESERVOIRS, DAMS AND WATERWAYS

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	COST OF REMOVAL PCT	GROSS SALVAGE REIMBURSEMENTS AMOUNT	GROSS SALVAGE REIMBURSEMENTS PCT	GROSS SALVAGE FINAL AMOUNT	GROSS SALVAGE FINAL PCT	NET SALVAGE AMOUNT	NET SALVAGE PCT
1996	25,343		0		0	30	0	30	0
1997									
1998									
1999									
2000									
2001									
2002									
2003									
2004									
2005	292,979		0		0		0		0
2006									
2007	2,023		0		0		0		0
2008	44,162	156,375	354		0		0	156,375-	354-
2009									
2010									
2011	15,191	29,260	193		0		0	29,260-	193-
TOTAL	379,697	185,635	49		0	30	0	185,605-	49-
THREE-YEAR MOVING AVERAGES									
96-98	8,448		0		0	10	0	10	0
97-99									
98-00									
99-01									
00-02									
01-03									
02-04									
03-05	97,660		0		0		0		0
04-06	97,660		0		0		0		0
05-07	98,334		0		0		0		0
06-08	15,395	52,125	339		0		0	52,125-	339-
07-09	15,395	52,125	339		0		0	52,125-	339-
08-10	14,720	52,125	354		0		0	52,125-	354-
09-11	5,064	9,753	193		0		0	9,753-	193-
FIVE-YEAR AVERAGE									
07-11	12,275	37,127	302		0		0	37,127-	302-

KENTUCKY UTILITIES COMPANY

ACCOUNT 333 WATER WHEELS, TURBINES AND GENERATORS

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	COST OF REMOVAL PCT	GROSS SALVAGE REIMBURSEMENTS AMOUNT	GROSS SALVAGE REIMBURSEMENTS PCT	GROSS SALVAGE FINAL AMOUNT	GROSS SALVAGE FINAL PCT	NET SALVAGE AMOUNT	NET SALVAGE PCT
1992	1,109		0		0		0		0
1993									
1994									
1995									
1996	2,963		0		0	3	0	3	0
1997	1,420		0		0		0		0
1998									
1999									
2000									
2001									
2002									
2003									
2004									
2005	114,085		0		0		0		0
2006									
2007	43,039	47,822	111		0		0	47,822-	111-
2008	3,022	6,931	229		0		0	6,931-	229-
2009									
2010	41,413	315,415	762		0		0	315,415-	762-
2011									
TOTAL	207,052	370,169	179		0	3	0	370,165-	179-

THREE-YEAR MOVING AVERAGES

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	COST OF REMOVAL PCT	GROSS SALVAGE REIMBURSEMENTS AMOUNT	GROSS SALVAGE REIMBURSEMENTS PCT	GROSS SALVAGE FINAL AMOUNT	GROSS SALVAGE FINAL PCT	NET SALVAGE AMOUNT	NET SALVAGE PCT
92-94	370		0		0		0		0
93-95									
94-96	988		0		0	1	0	1	0
95-97	1,461		0		0	1	0	1	0
96-98	1,461		0		0	1	0	1	0
97-99	473		0		0		0		0
98-00									
99-01									
00-02									
01-03									
02-04									
03-05	38,028		0		0		0		0
04-06	38,028		0		0		0		0
05-07	52,375	15,941	30		0		0	15,941-	30-
06-08	15,354	18,251	119		0		0	18,251-	119-
07-09	15,354	18,251	119		0		0	18,251-	119-

KENTUCKY UTILITIES COMPANY

ACCOUNT 333 WATER WHEELS, TURBINES AND GENERATORS

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	COST OF REMOVAL PCT	GROSS SALVAGE REIMBURSEMENTS AMOUNT	GROSS SALVAGE REIMBURSEMENTS PCT	GROSS SALVAGE FINAL AMOUNT	GROSS SALVAGE FINAL PCT	NET SALVAGE AMOUNT	NET SALVAGE PCT
THREE-YEAR MOVING AVERAGES									
08-10	14,812	107,449	725		0		0	107,449-	725-
09-11	13,804	105,138	762		0		0	105,138-	762-
FIVE-YEAR AVERAGE									
07-11	17,495	74,034	423		0		0	74,034-	423-

KENTUCKY UTILITIES COMPANY

ACCOUNT 334 ACCESSORY ELECTRIC EQUIPMENT

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	COST OF REMOVAL PCT	GROSS SALVAGE REIMBURSEMENTS AMOUNT	GROSS SALVAGE REIMBURSEMENTS PCT	GROSS SALVAGE FINAL AMOUNT	GROSS SALVAGE FINAL PCT	NET SALVAGE AMOUNT	NET SALVAGE PCT
1989	3,316		0		0		0		0
1990									
1991									
1992									
1993									
1994									
1995									
1996									
1997									
1998									
1999									
2000									
2001									
2002									
2003									
2004									
2005	264,486		0		0		0		0
2006									
2007									
2008									
2009									
2010	15	27	181		0		0	27-	181-
2011									
TOTAL	267,817	27	0		0		0	27-	0

THREE-YEAR MOVING AVERAGES

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	COST OF REMOVAL PCT	GROSS SALVAGE REIMBURSEMENTS AMOUNT	GROSS SALVAGE REIMBURSEMENTS PCT	GROSS SALVAGE FINAL AMOUNT	GROSS SALVAGE FINAL PCT	NET SALVAGE AMOUNT	NET SALVAGE PCT
89-91	1,105		0		0		0		0
90-92									
91-93									
92-94									
93-95									
94-96									
95-97									
96-98									
97-99									
98-00									
99-01									
00-02									
01-03									
02-04									

KENTUCKY UTILITIES COMPANY

ACCOUNT 334 ACCESSORY ELECTRIC EQUIPMENT

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	COST OF REMOVAL PCT	GROSS SALVAGE REIMBURSEMENTS AMOUNT	GROSS SALVAGE REIMBURSEMENTS PCT	GROSS SALVAGE FINAL AMOUNT	GROSS SALVAGE FINAL PCT	NET SALVAGE AMOUNT	NET SALVAGE PCT
THREE-YEAR MOVING AVERAGES									
03-05	88,162		0		0		0		0
04-06	88,162		0		0		0		0
05-07	88,162		0		0		0		0
06-08									
07-09									
08-10	5	9	181		0		0	9-	181-
09-11	5	9	181		0		0	9-	181-
FIVE-YEAR AVERAGE									
07-11	3	5	181		0		0	5-	181-

KENTUCKY UTILITIES COMPANY

ACCOUNT 335 MISCELLANEOUS POWER PLANT EQUIPMENT

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	COST OF REMOVAL PCT	GROSS SALVAGE REIMBURSEMENTS AMOUNT	GROSS SALVAGE REIMBURSEMENTS PCT	GROSS SALVAGE FINAL AMOUNT	GROSS SALVAGE FINAL PCT	NET SALVAGE AMOUNT	NET SALVAGE PCT
1990	63		0		0		0		0
1991									
1992	1,347		0		0		0		0
1993									
1994									
1995									
1996	10,618		0		0	12	0	12	0
1997									
1998									
1999									
2000									
2001									
2002									
2003									
2004									
2005	68,239		0		0		0		0
2006									
2007									
2008									
2009									
2010	92,639	6,475	7		0		0	6,475-	7-
2011									
TOTAL	172,906	6,475	4		0	12	0	6,462-	4-

THREE-YEAR MOVING AVERAGES

90-92	470		0		0		0		0
91-93	449		0		0		0		0
92-94	449		0		0		0		0
93-95									
94-96	3,539		0		0	4	0	4	0
95-97	3,539		0		0	4	0	4	0
96-98	3,539		0		0	4	0	4	0
97-99									
98-00									
99-01									
00-02									
01-03									
02-04									
03-05	22,746		0		0		0		0
04-06	22,746		0		0		0		0

KENTUCKY UTILITIES COMPANY

ACCOUNT 335 MISCELLANEOUS POWER PLANT EQUIPMENT

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	COST OF REMOVAL PCT	GROSS SALVAGE REIMBURSEMENTS AMOUNT	GROSS SALVAGE REIMBURSEMENTS PCT	GROSS SALVAGE FINAL AMOUNT	GROSS SALVAGE FINAL PCT	NET SALVAGE AMOUNT	NET SALVAGE PCT
THREE-YEAR MOVING AVERAGES									
05-07	22,746		0		0		0		0
06-08									
07-09									
08-10	30,880	2,158	7		0		0	2,158-	7-
09-11	30,880	2,158	7		0		0	2,158-	7-
FIVE-YEAR AVERAGE									
07-11	18,528	1,295	7		0		0	1,295-	7-

KENTUCKY UTILITIES COMPANY

ACCOUNT 342 FUEL HOLDERS, PRODUCERS AND ACCESSORIES

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	COST OF REMOVAL PCT	GROSS SALVAGE REIMBURSEMENTS AMOUNT	GROSS SALVAGE REIMBURSEMENTS PCT	GROSS SALVAGE FINAL AMOUNT	GROSS SALVAGE FINAL PCT	NET SALVAGE AMOUNT	NET SALVAGE PCT
2004	81,569	2,060	3		0		0	2,060-	3-
2005									
2006	11,267	715	6		0		0	715-	6-
2007	142	8,913			0		0	8,913-	
2008									
2009	30,262		0		0		0		0
2010	310,361		0		0		0		0
2011	144,830	1,252	1		0		0	1,252-	1-
TOTAL	578,432	12,940	2		0		0	12,940-	2-
THREE-YEAR MOVING AVERAGES									
04-06	30,945	925	3		0		0	925-	3-
05-07	3,803	3,209	84		0		0	3,209-	84-
06-08	3,803	3,209	84		0		0	3,209-	84-
07-09	10,135	2,971	29		0		0	2,971-	29-
08-10	113,541		0		0		0		0
09-11	161,818	417	0		0		0	417-	0
FIVE-YEAR AVERAGE									
07-11	97,119	2,033	2		0		0	2,033-	2-

KENTUCKY UTILITIES COMPANY

ACCOUNT 343 PRIME MOVERS

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	COST OF REMOVAL PCT	GROSS SALVAGE REIMBURSEMENTS AMOUNT	GROSS SALVAGE REIMBURSEMENTS PCT	GROSS SALVAGE FINAL AMOUNT	GROSS SALVAGE FINAL PCT	NET SALVAGE AMOUNT	NET SALVAGE PCT
2004	222,656		0		0		0		0
2005									
2006	7,517,883	458,920	6		0		0	458,920-	6-
2007	1,998,860	229,019	11		0		0	229,019-	11-
2008	2,244,288	55,421	2		0		0	55,421-	2-
2009	3,401,722	241,383	7		0		0	241,383-	7-
2010	991,871	25,976	3		0		0	25,976-	3-
2011	1,769,658	491,147	28		0		0	491,147-	28-
TOTAL	18,146,939	1,501,867	8		0		0	1,501,867-	8-
THREE-YEAR MOVING AVERAGES									
04-06	2,580,180	152,973	6		0		0	152,973-	6-
05-07	3,172,248	229,313	7		0		0	229,313-	7-
06-08	3,920,344	247,787	6		0		0	247,787-	6-
07-09	2,548,290	175,274	7		0		0	175,274-	7-
08-10	2,212,627	107,594	5		0		0	107,594-	5-
09-11	2,054,417	252,836	12		0		0	252,836-	12-
FIVE-YEAR AVERAGE									
07-11	2,081,280	208,589	10		0		0	208,589-	10-

KENTUCKY UTILITIES COMPANY

ACCOUNT 344 GENERATORS

SUMMARY OF BOOK SALVAGE

		COST OF REMOVAL		GROSS SALVAGE				NET SALVAGE	
				REIMBURSEMENTS		FINAL			
YEAR	REGULAR RETIREMENTS	AMOUNT	PCT	AMOUNT	PCT	AMOUNT	PCT	AMOUNT	PCT
2011	40,984	5,855	14		0		0	5,855-	14-
TOTAL	40,984	5,855	14		0		0	5,855-	14-

KENTUCKY UTILITIES COMPANY

ACCOUNT 345 ACCESSORY ELECTRIC EQUIPMENT

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	COST OF REMOVAL PCT	GROSS SALVAGE REIMBURSEMENTS AMOUNT	GROSS SALVAGE REIMBURSEMENTS PCT	GROSS SALVAGE FINAL AMOUNT	GROSS SALVAGE FINAL PCT	NET SALVAGE AMOUNT	NET SALVAGE PCT
2007	25,576	513	2		0		0	513-	2-
2008									
2009									
2010									
2011	121,306		0		0		0		0
TOTAL	146,882	513	0		0		0	513-	0
THREE-YEAR MOVING AVERAGES									
07-09	8,525	171	2		0		0	171-	2-
08-10									
09-11	40,435		0		0		0		0
FIVE-YEAR AVERAGE									
07-11	29,376	103	0		0		0	103-	0

KENTUCKY UTILITIES COMPANY

ACCOUNTS 352.1 AND 352.2 STRUCTURES AND IMPROVEMENTS

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	COST OF REMOVAL PCT	GROSS SALVAGE REIMBURSEMENTS AMOUNT	GROSS SALVAGE REIMBURSEMENTS PCT	GROSS SALVAGE FINAL AMOUNT	GROSS SALVAGE FINAL PCT	NET SALVAGE AMOUNT	NET SALVAGE PCT
1985	2,967	6,845	231		0	356	12	6,489-	219-
1986	123		0		0		0		0
1987	2,832	1,256	44		0	50	2	1,206-	43-
1988	2,848	236	8		0		0	236-	8-
1989	4,278	1,477	35		0		0	1,477-	35-
1990	2,315	1,371	59	35	2	236	10	1,100-	48-
1991	1,153	3,350	291		0	53	5	3,297-	286-
1992	3,413	1,479	43		0		0	1,479-	43-
1993	5,528	14,439	261		0	1,419	26	13,020-	236-
1994	4,241	4,195	99		0	621	15	3,574-	84-
1995	4,270	5,441	127		0	258	6	5,183-	121-
1996	6,059	7,979	132		0	1,370	23	6,609-	109-
1997	4,361	7,984	183		0	723	17	7,261-	167-
1998	8,608	45,273	526		0	5,606	65	39,667-	461-
1999									
2000	2,748		0		0		0		0
2001									
2002									
2003	21,752	1,335	6		0		0	1,335-	6-
2004	3,829	3,227	84		0		0	3,227-	84-
2005	2,062		0		0		0		0
2006	8,109	9,147	113		0		0	9,147-	113-
2007	26,842	37,817	141	23,068	86		0	14,749-	55-
2008									
2009	13,054	17,460	134		0		0	17,460-	134-
2010	9,690	29,543	305		0	13,768	142	15,775-	163-
2011	13,660	13,393	98		0		0	13,393-	98-
TOTAL	154,743	213,247	138	23,103	15	24,459	16	165,686-	107-
THREE-YEAR MOVING AVERAGES									
85-87	1,974	2,700	137		0	135	7	2,565-	130-
86-88	1,934	497	26		0	17	1	481-	25-
87-89	3,319	990	30		0	17	1	973-	29-
88-90	3,147	1,028	33	12	0	79	2	938-	30-
89-91	2,582	2,066	80	12	0	96	4	1,958-	76-
90-92	2,294	2,067	90	12	1	96	4	1,959-	85-
91-93	3,365	6,423	191		0	491	15	5,932-	176-
92-94	4,394	6,704	153		0	680	15	6,024-	137-
93-95	4,680	8,025	171		0	766	16	7,259-	155-
94-96	4,857	5,871	121		0	749	15	5,122-	105-

KENTUCKY UTILITIES COMPANY

ACCOUNTS 352.1 AND 352.2 STRUCTURES AND IMPROVEMENTS

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	COST OF REMOVAL PCT	GROSS SALVAGE REIMBURSEMENTS AMOUNT	GROSS SALVAGE REIMBURSEMENTS PCT	GROSS SALVAGE FINAL AMOUNT	GROSS SALVAGE FINAL PCT	NET SALVAGE AMOUNT	NET SALVAGE PCT
THREE-YEAR MOVING AVERAGES									
95-97	4,897	7,135	146		0	783	16	6,351-	130-
96-98	6,343	20,412	322		0	2,566	40	17,846-	281-
97-99	4,323	17,752	411		0	2,110	49	15,643-	362-
98-00	3,785	15,091	399		0	1,869	49	13,222-	349-
99-01	916		0		0		0		0
00-02	916		0		0		0		0
01-03	7,251	445	6		0		0	445-	6-
02-04	8,527	1,521	18		0		0	1,521-	18-
03-05	9,215	1,521	17		0		0	1,521-	17-
04-06	4,667	4,125	88		0		0	4,125-	88-
05-07	12,338	15,655	127	7,689	62		0	7,965-	65-
06-08	11,651	15,655	134	7,689	66		0	7,965-	68-
07-09	13,299	18,426	139	7,689	58		0	10,736-	81-
08-10	7,581	15,668	207		0	4,589	61	11,078-	146-
09-11	12,135	20,132	166		0	4,589	38	15,543-	128-
FIVE-YEAR AVERAGE									
07-11	12,649	19,643	155	4,614	36	2,754	22	12,275-	97-

KENTUCKY UTILITIES COMPANY

ACCOUNT 353.1 AND 353.2 STATION EQUIPMENT

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE REIMBURSEMENTS AMOUNT	PCT	GROSS SALVAGE FINAL AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
1985	217,959	29,125	13		0	17,298	8	11,827-	5-
1986	83,514	28,837	35	100,254	120	20,030	24	91,447	109
1987	315,181	15,504	5	297,292	94	49,454	16	331,242	105
1988	668,214	21,296	3	117,658	18	79,164	12	175,526	26
1989	140,453	21,794	16	94,849	68	16,568	12	89,623	64
1990	1,671,727	44,364	3	689,869	41	41,275	2	686,780	41
1991	49,508	9,920	20		0	17,271	35	7,351	15
1992	39,261	14,796	38	21,268	54	11,348	29	17,820	45
1993	185,130	30,467	16	233,429	126	31,681	17	234,643	127
1994	64,717	4,747	7	114,969	178	7,481	12	117,703	182
1995	1,376,276	47,725	3	297,440	22	22,617	2	272,332	20
1996	161,182	19,087	12	97,073	60	35,115	22	113,101	70
1997	505,444	39,052	8	199,073	39	36,624	7	196,645	39
1998	290,736	69,366	24	250,853	86	89,403	31	270,889	93
1999	68,667	3,876	6	4,775	7	4,258	6	5,157	8
2000	596,660	8,120	1		0		0	8,120-	1-
2001	1,974,611	1,727	0		0	40,000	2	38,273	2
2002	12,798	7,990	62		0		0	7,990-	62-
2003	352,645	45,907	13		0		0	45,907-	13-
2004	282,008	142,156	50		0	889	0	141,267-	50-
2005	59,445		0		0		0		0
2006	1,911,180	368,976	19		0	6,978	0	361,998-	19-
2007	521,200	125,767	24		0	44,862	9	80,906-	16-
2008	26,835	10,665	40		0		0	10,665-	40-
2009	2,457,817	436,836	18	1,704	0	429,547	17	5,585-	0
2010	1,196,572	104,491	9		0	76,951	6	27,539-	2-
2011	1,372,060	261,192	19		0	13,589	1	247,603-	18-
TOTAL	16,601,801	1,913,784	12	2,520,505	15	1,092,403	7	1,699,124	10

THREE-YEAR MOVING AVERAGES

85-87	205,551	24,489	12	132,515	64	28,927	14	136,954	67
86-88	355,636	21,879	6	171,735	48	49,549	14	199,405	56
87-89	374,616	19,531	5	169,933	45	48,395	13	198,797	53
88-90	826,798	29,151	4	300,792	36	45,669	6	317,310	38
89-91	620,563	25,359	4	261,573	42	25,038	4	261,251	42
90-92	586,832	23,027	4	237,046	40	23,298	4	237,317	40
91-93	91,300	18,394	20	84,899	93	20,100	22	86,605	95
92-94	96,369	16,670	17	123,222	128	16,837	17	123,389	128
93-95	542,041	27,646	5	215,279	40	20,593	4	208,226	38
94-96	534,058	23,853	4	169,827	32	21,738	4	167,712	31

KENTUCKY UTILITIES COMPANY

ACCOUNT 353.1 AND 353.2 STATION EQUIPMENT

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE REIMBURSEMENTS AMOUNT	PCT	GROSS SALVAGE FINAL AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
THREE-YEAR MOVING AVERAGES									
95-97	680,967	35,288	5	197,862	29	31,452	5	194,026	28
96-98	319,121	42,502	13	182,333	57	53,714	17	193,545	61
97-99	288,282	37,432	13	151,567	53	43,428	15	157,564	55
98-00	318,688	27,121	9	85,209	27	31,220	10	89,309	28
99-01	879,979	4,574	1	1,592	0	14,753	2	11,770	1
00-02	861,356	5,946	1		0	13,333	2	7,388	1
01-03	780,018	18,541	2		0	13,333	2	5,208-	1-
02-04	215,817	65,351	30		0	296	0	65,055-	30-
03-05	231,366	62,688	27		0	296	0	62,391-	27-
04-06	750,878	170,377	23		0	2,622	0	167,755-	22-
05-07	830,609	164,914	20		0	17,280	2	147,635-	18-
06-08	819,738	168,469	21		0	17,280	2	151,190-	18-
07-09	1,001,951	191,089	19	568	0	158,136	16	32,385-	3-
08-10	1,227,075	183,997	15	568	0	168,833	14	14,597-	1-
09-11	1,675,483	267,506	16	568	0	173,362	10	93,576-	6-
FIVE-YEAR AVERAGE									
07-11	1,114,897	187,790	17	341	0	112,990	10	74,460-	7-

KENTUCKY UTILITIES COMPANY

ACCOUNT 354 TOWERS AND FIXTURES

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	COST OF REMOVAL PCT	GROSS SALVAGE REIMBURSEMENTS AMOUNT	GROSS SALVAGE REIMBURSEMENTS PCT	GROSS SALVAGE FINAL AMOUNT	GROSS SALVAGE FINAL PCT	NET SALVAGE AMOUNT	NET SALVAGE PCT
1985	7,239	10,771	149		0	604	8	10,167-	140-
1986	18,776	6,598	35		0	14,112	75	7,514	40
1987									
1988	27,311	18-	0		0		0	18	0
1989									
1990	66,666	53,275	80	43,902	66	3,036	5	6,337-	10-
1991	47,110	22,658	48		0	25,939	55	3,281	7
1992									
1993									
1994									
1995									
1996	51,557	64,498	125	23,181	45	18,784	36	22,533-	44-
1997	114,123	198,493	174	74,125	65	30,483	27	93,885-	82-
1998									
1999	18,830	27,553	146	2,513	13	5,006	27	20,034-	106-
2000									
2001									
2002	20,206	54,410	269		0		0	54,410-	269-
2003	12,755		0	159,168			0	159,168	
2004	11,796	47,227	400		0		0	47,227-	400-
2005									
2006	256,476	103,150	40		0	41	0	103,109-	40-
2007	28,613	90,682	317	218,219	763		0	127,537	446
2008		48						48-	
2009	45,221	16,491	36	1,935	4		0	14,556-	32-
2010	388,638	189,784	49		0	4,928	1	184,855-	48-
2011	81,908	86,871	106		0		0	86,871-	106-
TOTAL	1,197,224	972,491	81	523,043	44	102,933	9	346,515-	29-

THREE-YEAR MOVING AVERAGES

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	COST OF REMOVAL PCT	GROSS SALVAGE REIMBURSEMENTS AMOUNT	GROSS SALVAGE REIMBURSEMENTS PCT	GROSS SALVAGE FINAL AMOUNT	GROSS SALVAGE FINAL PCT	NET SALVAGE AMOUNT	NET SALVAGE PCT
85-87	8,672	5,790	67		0	4,905	57	884-	10-
86-88	15,362	2,193	14		0	4,704	31	2,511	16
87-89	9,104	6-	0		0		0	6	0
88-90	31,326	17,752	57	14,634	47	1,012	3	2,106-	7-
89-91	37,925	25,311	67	14,634	39	9,658	25	1,019-	3-
90-92	37,925	25,311	67	14,634	39	9,658	25	1,019-	3-
91-93	15,703	7,553	48		0	8,646	55	1,094	7
92-94									
93-95									
94-96	17,186	21,499	125	7,727	45	6,261	36	7,511-	44-

KENTUCKY UTILITIES COMPANY

ACCOUNT 354 TOWERS AND FIXTURES

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	COST OF REMOVAL PCT	GROSS SALVAGE REIMBURSEMENTS AMOUNT	REIMBURSEMENTS PCT	GROSS SALVAGE FINAL AMOUNT	FINAL PCT	NET SALVAGE AMOUNT	NET SALVAGE PCT
THREE-YEAR MOVING AVERAGES									
95-97	55,227	87,664	159	32,435	59	16,422	30	38,806-	70-
96-98	55,227	87,664	159	32,435	59	16,422	30	38,806-	70-
97-99	44,318	75,348	170	25,546	58	11,830	27	37,973-	86-
98-00	6,277	9,184	146	838	13	1,669	27	6,678-	106-
99-01	6,277	9,184	146	838	13	1,669	27	6,678-	106-
00-02	6,735	18,137	269		0		0	18,137-	269-
01-03	10,987	18,137	165	53,056	483		0	34,919	318
02-04	14,919	33,879	227	53,056	356		0	19,177	129
03-05	8,184	15,742	192	53,056	648		0	37,314	456
04-06	89,424	50,126	56		0	14	0	50,112-	56-
05-07	95,030	64,611	68	72,740	77	14	0	8,143	9
06-08	95,030	64,627	68	72,740	77	14	0	8,127	9
07-09	24,611	35,740	145	73,385	298		0	37,644	153
08-10	144,619	68,774	48	645	0	1,643	1	66,487-	46-
09-11	171,922	97,715	57	645	0	1,643	1	95,427-	56-
FIVE-YEAR AVERAGE									
07-11	108,876	76,775	71	44,031	40	986	1	31,759-	29-

KENTUCKY UTILITIES COMPANY

ACCOUNT 355 POLES AND FIXTURES

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE REIMBURSEMENTS AMOUNT	PCT	GROSS SALVAGE FINAL AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
1985	295,387	195,597	66	124,940	42	21,727	7	48,930-	17-
1986	195,216	162,611	83	57,114	29	44,998	23	60,499-	31-
1987	457,818	338,082	74	52,789	12	51,935	11	233,358-	51-
1988	604,760	70,631	12	295,691	49	22,884-	4-	202,176	33
1989	208,004	153,267	74	116,855	56	14,916	7	21,496-	10-
1990	384,788	293,719	76	268,739	70	97,256	25	72,276	19
1991	188,629	166,567	88	187,355	99	30,560	16	51,348	27
1992	211,558	216,832	102	349,634	165	31,821	15	164,623	78
1993	143,338	275,680	192	427,869	299	35,067	24	187,256	131
1994	236,308	172,096	73	838,602	355	32,967	14	699,472	296
1995	242,108	227,169	94	304,943	126	13,950	6	91,724	38
1996	387,362	375,594	97	381,789	99	83,464	22	89,659	23
1997	220,947	297,851	135	314,587	142	34,902	16	51,637	23
1998	130,720	506,238	387	377,497	289	81,158	62	47,583-	36-
1999	357,287	405,200	113	104,511	29	56,168	16	244,521-	68-
2000	48,954		0		0		0		0
2001	289,828	186,232	64	23,452	8	2,277	1	160,503-	55-
2002	39,323	58,921	150	273,692	696	17,174	44	231,945	590
2003	311,868	120,822	39	1,078,630	346	106,620	34	1,064,428	341
2004	46,585	71,959	154		0	2,674	6	69,284-	149-
2005	4,313		0		0		0		0
2006	610,837	1,231,228	202	843,056	138	52,527	9	335,645-	55-
2007	204,555	523,135	256	778,480	381	3,453	2	258,799	127
2008	59,888	253,612	423	41,827	70	273	0	211,511-	353-
2009	845,834	1,815,589	215	362,946	43	1,867	0	1,450,775-	172-
2010	710,498	3,424,297	482		0	22,008	3	3,402,289-	479-
2011	743,968	1,668,302	224		0	2,715	0	1,665,587-	224-
TOTAL	8,180,681	13,211,231	161	7,604,998	93	819,594	10	4,786,639-	59-

THREE-YEAR MOVING AVERAGES

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE REIMBURSEMENTS AMOUNT	PCT	GROSS SALVAGE FINAL AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
85-87	316,140	232,097	73	78,281	25	39,553	13	114,262-	36-
86-88	419,265	190,441	45	135,198	32	24,683	6	30,560-	7-
87-89	423,527	187,327	44	155,112	37	14,656	3	17,559-	4-
88-90	399,184	172,539	43	227,095	57	29,763	7	84,319	21
89-91	260,474	204,518	79	190,983	73	47,577	18	34,043	13
90-92	261,658	225,706	86	268,576	103	53,212	20	96,082	37
91-93	181,175	219,693	121	321,619	178	32,483	18	134,409	74
92-94	197,068	221,536	112	538,702	273	33,285	17	350,450	178
93-95	207,251	224,982	109	523,804	253	27,328	13	326,150	157
94-96	288,593	258,286	89	508,445	176	43,460	15	293,618	102

KENTUCKY UTILITIES COMPANY

ACCOUNT 355 POLES AND FIXTURES

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	COST OF REMOVAL PCT	GROSS SALVAGE REIMBURSEMENTS AMOUNT	GROSS SALVAGE REIMBURSEMENTS PCT	GROSS SALVAGE FINAL AMOUNT	GROSS SALVAGE FINAL PCT	NET SALVAGE AMOUNT	NET SALVAGE PCT
THREE-YEAR MOVING AVERAGES									
95-97	283,472	300,205	106	333,773	118	44,105	16	77,673	27
96-98	246,343	393,228	160	357,958	145	66,508	27	31,238	13
97-99	236,318	403,097	171	265,532	112	57,409	24	80,156-	34-
98-00	178,987	303,813	170	160,669	90	45,775	26	97,368-	54-
99-01	232,023	197,144	85	42,654	18	19,482	8	135,008-	58-
00-02	126,035	81,718	65	99,048	79	6,484	5	23,814	19
01-03	213,673	121,992	57	458,591	215	42,024	20	378,623	177
02-04	132,592	83,901	63	450,774	340	42,156	32	409,030	308
03-05	120,922	64,260	53	359,543	297	36,432	30	331,715	274
04-06	220,578	434,396	197	281,019	127	18,400	8	134,976-	61-
05-07	273,235	584,788	214	540,512	198	18,660	7	25,615-	9-
06-08	291,760	669,325	229	554,455	190	18,751	6	96,119-	33-
07-09	370,092	864,112	233	394,418	107	1,865	1	467,829-	126-
08-10	538,740	1,831,166	340	134,924	25	8,050	1	1,688,192-	313-
09-11	766,767	2,302,729	300	120,982	16	8,864	1	2,172,884-	283-
FIVE-YEAR AVERAGE									
07-11	512,949	1,536,987	300	236,651	46	6,063	1	1,294,273-	252-

KENTUCKY UTILITIES COMPANY

ACCOUNT 356 OVERHEAD CONDUCTORS AND DEVICES

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	COST OF REMOVAL PCT	GROSS SALVAGE REIMBURSEMENTS AMOUNT	GROSS SALVAGE REIMBURSEMENTS PCT	GROSS SALVAGE FINAL AMOUNT	GROSS SALVAGE FINAL PCT	NET SALVAGE AMOUNT	NET SALVAGE PCT
1985	271,431	241,007	89	163,578	60	38,094	14	39,335-	14-
1986	168,572	103,081	61	24,668	15	125,859	75	47,446	28
1987	376,013	268,761	71	48,872	13	74,410	20	145,479-	39-
1988	449,663	34,559	8	243,529	54	9,064-	2-	199,906	44
1989	109,255	28,945	26	164,896	151	16,616	15	152,567	140
1990	445,041	215,298	48	410,017	92	116,469	26	311,188	70
1991	93,074	44,036	47	81,622	88	14,823	16	52,409	56
1992	115,355	88,985	77	389,835	338	31,133	27	331,983	288
1993	22,522	43,594	194	70,134	311	10,351	46	36,891	164
1994	170,373	124,874	73	630,738	370	44,653	26	550,517	323
1995	175,759	165,973	94	230,939	131	19,026	11	83,992	48
1996	416,487	406,426	98	428,232	103	168,592	40	190,398	46
1997	107,536	145,896	136	159,727	149	31,913	30	45,744	43
1998	35,818	139,602	390	107,906	301	41,778	117	10,081	28
1999	190,072	216,945	114	58,001	31	56,137	30	102,807-	54-
2000	8,372	79,307	947		0		0	79,307-	947-
2001	199,729	234,533	117	1,004	1	1,838	1	231,691-	116-
2002	32,589	88,020	270		0	7,007	22	81,013-	249-
2003	233,243	95,840	41	557,254	239	7,397	3	468,810	201
2004	13,462	8,686	65		0	4,983	37	3,703-	28-
2005	4,980		0		0		0		0
2006	904,174	1,169,323	129	1,244,318	138	119,562	13	194,558	22
2007	149,381	310,608	208	432,222	289	14,421	10	136,035	91
2008	150,704	237,948	158	177,035	117	5,651	4	55,262-	37-
2009	217,390	643,606	296	124,122	57	598	0	518,886-	239-
2010	461,935	1,867,543	404		0	4,470	1	1,863,073-	403-
2011	521,733	927,086	178		0	15,570	3	911,516-	175-
TOTAL	6,044,662	7,930,483	131	5,748,649	95	962,288	16	1,219,546-	20-

THREE-YEAR MOVING AVERAGES

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	COST OF REMOVAL PCT	GROSS SALVAGE REIMBURSEMENTS AMOUNT	GROSS SALVAGE REIMBURSEMENTS PCT	GROSS SALVAGE FINAL AMOUNT	GROSS SALVAGE FINAL PCT	NET SALVAGE AMOUNT	NET SALVAGE PCT
85-87	272,005	204,283	75	79,039	29	79,454	29	45,789-	17-
86-88	331,416	135,467	41	105,690	32	63,735	19	33,958	10
87-89	311,644	110,755	36	152,432	49	27,321	9	68,998	22
88-90	334,653	92,934	28	272,814	82	41,340	12	221,220	66
89-91	215,790	96,093	45	218,845	101	49,303	23	172,055	80
90-92	217,823	116,106	53	293,825	135	54,142	25	231,860	106
91-93	76,984	58,872	76	180,530	235	18,769	24	140,428	182
92-94	102,750	85,818	84	363,569	354	28,713	28	306,464	298
93-95	122,885	111,480	91	310,604	253	24,677	20	223,800	182
94-96	254,206	232,424	91	429,970	169	77,424	30	274,969	108

KENTUCKY UTILITIES COMPANY

ACCOUNT 356 OVERHEAD CONDUCTORS AND DEVICES

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	COST OF REMOVAL PCT	GROSS SALVAGE REIMBURSEMENTS AMOUNT	GROSS SALVAGE REIMBURSEMENTS PCT	GROSS SALVAGE FINAL AMOUNT	GROSS SALVAGE FINAL PCT	NET SALVAGE AMOUNT	NET SALVAGE PCT
THREE-YEAR MOVING AVERAGES									
95-97	233,261	239,432	103	272,966	117	73,177	31	106,712	46
96-98	186,614	230,641	124	231,955	124	80,761	43	82,074	44
97-99	111,142	167,481	151	108,544	98	43,276	39	15,661-	14-
98-00	78,087	145,285	186	55,302	71	32,638	42	57,344-	73-
99-01	132,724	176,928	133	19,668	15	19,325	15	137,935-	104-
00-02	80,230	133,953	167	335	0	2,948	4	130,670-	163-
01-03	155,187	139,464	90	186,086	120	5,414	3	52,036	34
02-04	93,098	64,182	69	185,751	200	6,462	7	128,031	138
03-05	83,895	34,842	42	185,751	221	4,127	5	155,036	185
04-06	307,539	392,670	128	414,773	135	41,515	13	63,618	21
05-07	352,845	493,310	140	558,847	158	44,661	13	110,197	31
06-08	401,419	572,626	143	617,858	154	46,545	12	91,777	23
07-09	172,491	397,387	230	244,460	142	6,890	4	146,038-	85-
08-10	276,676	916,366	331	100,386	36	3,573	1	812,407-	294-
09-11	400,353	1,146,078	286	41,374	10	6,880	2	1,097,825-	274-
FIVE-YEAR AVERAGE									
07-11	300,228	797,358	266	146,676	49	8,142	3	642,540-	214-

KENTUCKY UTILITIES COMPANY

ACCOUNT 361 STRUCTURES AND IMPROVEMENTS

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	COST OF REMOVAL PCT	GROSS SALVAGE REIMBURSEMENTS AMOUNT	GROSS SALVAGE REIMBURSEMENTS PCT	GROSS SALVAGE FINAL AMOUNT	GROSS SALVAGE FINAL PCT	NET SALVAGE AMOUNT	NET SALVAGE PCT
1985	423	23	5		0	46	11	23	5
1986	4,608	3,803	83		0	1,688	37	2,115-	46-
1987	11,848	1,210	10		0	2,266	19	1,056	9
1988	18,270	3,928	21		0	213	1	3,715-	20-
1989	98	74	76		0	164	167	90	92
1990	893	1,874	210		0	495	55	1,379-	154-
1991	11,463	2,254	20		0	2,874	25	620	5
1992	4,137	1,709	41		0	177	4	1,532-	37-
1993	9,409	2,996	32		0	2,177	23	818-	9-
1994	16,575	3,034	18		0	1,647	10	1,387-	8-
1995	9,036	2,140	24		0	2,142	24	2	0
1996	47,792	7,547	16		0	4,367	9	3,180-	7-
1997	21,041	4,138	20		0	2,482	12	1,656-	8-
1998	9,106	2,361	26		0	1,112	12	1,249-	14-
1999	3,132	526	17		0	286	9	240-	8-
2000									
2001	13,950		0		0		0		0
2002	1,055	826	78		0		0	826-	78-
2003	1,926	2,358	122		0		0	2,358-	122-
2004									
2005									
2006	9,005	2,862	32		0	94	1	2,768-	31-
2007	31,227	36,063	115		0		0	36,063-	115-
2008									
2009	25,171	10,934	43		0	1,337	5	9,597-	38-
2010	35,328	37,886	107		0		0	37,886-	107-
2011	13,807	10,031	73		0		0	10,031-	73-
TOTAL	299,301	138,577	46		0	23,569	8	115,008-	38-

THREE-YEAR MOVING AVERAGES

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	COST OF REMOVAL PCT	GROSS SALVAGE REIMBURSEMENTS AMOUNT	GROSS SALVAGE REIMBURSEMENTS PCT	GROSS SALVAGE FINAL AMOUNT	GROSS SALVAGE FINAL PCT	NET SALVAGE AMOUNT	NET SALVAGE PCT
85-87	5,626	1,679	30		0	1,333	24	345-	6-
86-88	11,575	2,980	26		0	1,389	12	1,591-	14-
87-89	10,072	1,737	17		0	881	9	856-	9-
88-90	6,420	1,959	31		0	291	5	1,668-	26-
89-91	4,151	1,401	34		0	1,178	28	223-	5-
90-92	5,498	1,946	35		0	1,182	22	764-	14-
91-93	8,336	2,320	28		0	1,743	21	577-	7-
92-94	10,040	2,580	26		0	1,334	13	1,246-	12-
93-95	11,673	2,723	23		0	1,989	17	734-	6-
94-96	24,468	4,240	17		0	2,719	11	1,522-	6-

KENTUCKY UTILITIES COMPANY

ACCOUNT 361 STRUCTURES AND IMPROVEMENTS

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	COST OF REMOVAL PCT	GROSS SALVAGE REIMBURSEMENTS AMOUNT	GROSS SALVAGE REIMBURSEMENTS PCT	GROSS SALVAGE FINAL AMOUNT	GROSS SALVAGE FINAL PCT	NET SALVAGE AMOUNT	NET SALVAGE PCT
THREE-YEAR MOVING AVERAGES									
95-97	25,956	4,608	18		0	2,997	12	1,611-	6-
96-98	25,980	4,682	18		0	2,654	10	2,028-	8-
97-99	11,093	2,342	21		0	1,293	12	1,048-	9-
98-00	4,079	962	24		0	466	11	496-	12-
99-01	5,694	176	3		0	95	2	80-	1-
00-02	5,002	275	6		0		0	275-	6-
01-03	5,644	1,061	19		0		0	1,061-	19-
02-04	994	1,061	107		0		0	1,061-	107-
03-05	642	786	122		0		0	786-	122-
04-06	3,002	954	32		0	31	1	923-	31-
05-07	13,411	12,975	97		0	31	0	12,943-	97-
06-08	13,411	12,975	97		0	31	0	12,943-	97-
07-09	18,799	15,666	83		0	446	2	15,220-	81-
08-10	20,167	16,274	81		0	446	2	15,828-	78-
09-11	24,769	19,617	79		0	446	2	19,171-	77-
FIVE-YEAR AVERAGE									
07-11	21,107	18,983	90		0	267	1	18,715-	89-

KENTUCKY UTILITIES COMPANY

ACCOUNT 362 STATION EQUIPMENT

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	COST OF REMOVAL PCT	GROSS SALVAGE REIMBURSEMENTS AMOUNT	GROSS SALVAGE REIMBURSEMENTS PCT	GROSS SALVAGE FINAL AMOUNT	GROSS SALVAGE FINAL PCT	NET SALVAGE AMOUNT	NET SALVAGE PCT
1985	326,963	14,394	4	704	0	252,702	77	239,012	73
1986	190,339	33,002	17	19,001	10	24,533	13	10,532	6
1987	285,835	21,026	7		0	226,075	79	205,049	72
1988	451,776	30,717	7	88,395	20	18,242	4	75,920	17
1989	195,083	51,602	26	88,345	45	55,356	28	92,099	47
1990	208,500	48,826	23		0	200,606	96	151,780	73
1991	165,021	39,479	24	123,276	75	35,537	22	119,334	72
1992	80,345	31,926	40	99,976	124	24,769	31	92,819	116
1993	174,354	26,006	15	55,777	32	71,285	41	101,056	58
1994	720,385	61,787	9	149,896	21	126,496	18	214,604	30
1995	167,475	18,582	11	48,206	29	70,128	42	99,752	60
1996	914,724	67,670	7	137,852	15	147,669	16	217,851	24
1997	574,447	52,925	9	84,195	15	119,715	21	150,985	26
1998	613,457	74,504	12	268,820	44	132,341	22	326,656	53
1999	179,181	14,111	8	69,306	39	28,954	16	84,149	47
2000	20,330		0		0		0		0
2001	413,104	27,584	7	3,831	1	18,337	4	5,416-	1-
2002	493,067	12,926	3		0	2,776	1	10,150-	2-
2003	73,469	25,875	35		0		0	25,875-	35-
2004	11,401	8,058	71		0	29	0	8,029-	70-
2005									
2006	2,595,376	480,902	19	11,211	0	12,249	0	457,442-	18-
2007	633,947	299,309	47	3,132-	0	20,913	3	281,529-	44-
2008	216	5,161			0		0	5,161-	
2009	738,688	446,808	60	42,219	6	17,603	2	386,986-	52-
2010	1,061,285	451,472	43		0	109,882	10	341,590-	32-
2011	416,824	353,766	85		0	29,444	7	324,322-	78-
TOTAL	11,705,592	2,698,419	23	1,287,879	11	1,745,639	15	335,099	3

THREE-YEAR MOVING AVERAGES

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	COST OF REMOVAL PCT	GROSS SALVAGE REIMBURSEMENTS AMOUNT	GROSS SALVAGE REIMBURSEMENTS PCT	GROSS SALVAGE FINAL AMOUNT	GROSS SALVAGE FINAL PCT	NET SALVAGE AMOUNT	NET SALVAGE PCT
85-87	267,712	22,807	9	6,568	2	167,770	63	151,531	57
86-88	309,317	28,248	9	35,799	12	89,617	29	97,167	31
87-89	310,898	34,448	11	58,913	19	99,891	32	124,356	40
88-90	285,120	43,715	15	58,913	21	91,401	32	106,600	37
89-91	189,535	46,636	25	70,540	37	97,166	51	121,071	64
90-92	151,289	40,077	26	74,417	49	86,971	57	121,311	80
91-93	139,907	32,470	23	93,010	66	43,864	31	104,403	75
92-94	325,028	39,906	12	101,883	31	74,183	23	136,160	42
93-95	354,071	35,458	10	84,626	24	89,303	25	138,471	39
94-96	600,861	49,346	8	111,985	19	114,764	19	177,403	30

KENTUCKY UTILITIES COMPANY

ACCOUNT 362 STATION EQUIPMENT

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE REIMBURSEMENTS AMOUNT	PCT	GROSS SALVAGE FINAL AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
THREE-YEAR MOVING AVERAGES									
95-97	552,215	46,392	8	90,084	16	112,504	20	156,196	28
96-98	700,876	65,033	9	163,622	23	133,241	19	231,831	33
97-99	455,695	47,180	10	140,774	31	93,670	21	187,263	41
98-00	270,989	29,538	11	112,709	42	53,765	20	136,935	51
99-01	204,205	13,898	7	24,379	12	15,764	8	26,244	13
00-02	308,834	13,503	4	1,277	0	7,038	2	5,189-	2-
01-03	326,547	22,128	7	1,277	0	7,038	2	13,814-	4-
02-04	192,646	15,620	8		0	935	0	14,685-	8-
03-05	28,290	11,311	40		0	10	0	11,302-	40-
04-06	868,926	162,987	19	3,737	0	4,093	0	155,157-	18-
05-07	1,076,441	260,070	24	2,693	0	11,054	1	246,323-	23-
06-08	1,076,513	261,791	24	2,693	0	11,054	1	248,044-	23-
07-09	457,617	250,426	55	13,029	3	12,839	3	224,559-	49-
08-10	600,063	301,147	50	14,073	2	42,495	7	244,579-	41-
09-11	738,932	417,349	56	14,073	2	52,310	7	350,966-	47-
FIVE-YEAR AVERAGE									
07-11	570,192	311,303	55	7,817	1	35,568	6	267,918-	47-

KENTUCKY UTILITIES COMPANY

ACCOUNT 364 POLES, TOWERS AND FIXTURES

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE REIMBURSEMENTS AMOUNT	PCT	GROSS SALVAGE FINAL AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
1985	571,087	368,139	64	161,946	28	106,240	19	99,953-	18-
1986	842,348	477,159	57	161,302	19	109,923	13	205,934-	24-
1987	755,330	593,598	79	229,120	30	126,666	17	237,812-	31-
1988	1,037,016	523,401	50	356,886	34	974,976	94	808,461	78
1989	809,610	629,908	78	494,956	61	95,316	12	39,636-	5-
1990	864,023	659,027	76	577,775	67	88,594	10	7,342	1
1991	1,982,061	697,964	35	358,660	18	882,595	45	543,291	27
1992	2,130,301	853,897	40	434,685	20	891,619	42	472,407	22
1993	1,330,114	948,478	71	774,589	58	479,512	36	305,622	23
1994	2,598,859	1,065,670	41	984,385	38	402,384	15	321,099	12
1995	1,412,233	749,106	53	739,970	52	521,426	37	512,290	36
1996	2,241,833	792,888	35	615,011	27	319,117	14	141,240	6
1997	922,869	406,495	44	246,227	27	169,584	18	9,315	1
1998	859,407	498,999	58	685,540	80	163,476	19	350,017	41
1999	841,648	316,891	38	592,607	70	119,920	14	395,637	47
2000	809,592	113,168	14		0	48,841	6	64,327-	8-
2001	662,394	193,208	29	80,169	12	34,537	5	78,502-	12-
2002	376,388	193,663	51		0	29,079	8	164,584-	44-
2003	329,129	136,497	41	257,012	78	7,183	2	127,698	39
2004	196,141	137,862	70		0	11,911	6	125,950-	64-
2005									
2006	79,289	771,184	973	502,453	634	7,660	10	261,071-	329-
2007	408,115	194,785	48	370,322	91	14,824	4	190,361	47
2008	17,166	26,923	157	12,251	71	5,049	29	9,623-	56-
2009	3,809,600	4,769,624	125	1,154,949	30	95,058	2	3,519,616-	92-
2010	1,336,949	1,207,408	90		0	65,701	5	1,141,707-	85-
2011	1,864,234	1,017,425	55		0	23,519	1	993,906-	53-
TOTAL	29,087,737	18,343,368	63	9,790,818	34	5,794,710	20	2,757,840-	9-

THREE-YEAR MOVING AVERAGES

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE REIMBURSEMENTS AMOUNT	PCT	GROSS SALVAGE FINAL AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
85-87	722,922	479,632	66	184,123	25	114,276	16	181,233-	25-
86-88	878,231	531,386	61	249,103	28	403,855	46	121,572	14
87-89	867,319	582,302	67	360,321	42	398,986	46	177,004	20
88-90	903,550	604,112	67	476,539	53	386,295	43	258,722	29
89-91	1,218,565	662,300	54	477,130	39	355,502	29	170,332	14
90-92	1,658,795	736,963	44	457,040	28	620,936	37	341,013	21
91-93	1,814,159	833,446	46	522,645	29	751,242	41	440,440	24
92-94	2,019,758	956,015	47	731,220	36	591,172	29	366,376	18
93-95	1,780,402	921,085	52	832,982	47	467,774	26	379,670	21
94-96	2,084,308	869,221	42	779,789	37	414,309	20	324,876	16

KENTUCKY UTILITIES COMPANY

ACCOUNT 364 POLES, TOWERS AND FIXTURES

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE REIMBURSEMENTS AMOUNT	PCT	GROSS SALVAGE FINAL AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
THREE-YEAR MOVING AVERAGES									
95-97	1,525,645	649,497	43	533,736	35	336,709	22	220,948	14
96-98	1,341,370	566,128	42	515,593	38	217,392	16	166,858	12
97-99	874,641	407,462	47	508,125	58	150,993	17	251,656	29
98-00	836,882	309,686	37	426,049	51	110,746	13	227,109	27
99-01	771,211	207,755	27	224,259	29	67,766	9	84,269	11
00-02	616,125	166,680	27	26,723	4	37,486	6	102,471-	17-
01-03	455,970	174,456	38	112,394	25	23,600	5	38,462-	8-
02-04	300,553	156,007	52	85,671	29	16,058	5	54,279-	18-
03-05	175,090	91,453	52	85,671	49	6,365	4	583	0
04-06	91,810	303,015	330	167,484	182	6,524	7	129,007-	141-
05-07	162,468	321,990	198	290,925	179	7,495	5	23,570-	15-
06-08	168,190	330,964	197	295,009	175	9,178	5	26,778-	16-
07-09	1,411,627	1,663,777	118	512,508	36	38,311	3	1,112,959-	79-
08-10	1,721,239	2,001,319	116	389,067	23	55,270	3	1,556,982-	90-
09-11	2,336,928	2,331,486	100	384,983	16	61,426	3	1,885,076-	81-
FIVE-YEAR AVERAGE									
07-11	1,487,213	1,443,233	97	307,505	21	40,830	3	1,094,898-	74-

KENTUCKY UTILITIES COMPANY

ACCOUNT 365 OVERHEAD CONDUCTORS AND DEVICES

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE REIMBURSEMENTS AMOUNT	PCT	GROSS SALVAGE FINAL AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
1985	413,733	392,771	95	88,257	21	174,340	42	130,174-	31-
1986	494,268	452,618	92	114,220	23	169,442	34	168,956-	34-
1987	707,438	435,605	62	89,532	13	201,963	29	144,110-	20-
1988	767,896	395,093	51	196,976	26	155,148	20	42,969-	6-
1989	679,291	511,936	75	289,737	43	228,647	34	6,448	1
1990	736,941	513,438	70	423,614	57	221,662	30	131,838	18
1991	615,033	451,911	73	197,815	32	180,149	29	73,947-	12-
1992	773,048	518,555	67	249,173	32	235,040	30	34,342-	4-
1993	850,626	735,221	86	459,874	54	310,969	37	35,623	4
1994	1,025,932	509,917	50	360,760	35	161,081	16	11,925	1
1995	1,017,289	654,067	64	494,846	49	380,889	37	221,669	22
1996	978,357	419,418	43	249,170	25	141,225	14	29,023-	3-
1997	921,889	492,192	53	228,345	25	171,787	19	92,060-	10-
1998	821,160	577,922	70	608,107	74	158,399	19	188,583	23
1999	778,038	355,076	46	508,575	65	112,417	14	265,917	34
2000	964,245	134,146	14		0	62,850	7	71,296-	7-
2001	632,267	158,791	25	107,511	17	27,771	4	23,509-	4-
2002	203,570	146,866	72	1,531	1	25,359	12	119,976-	59-
2003	502,806	181,025	36	116,131	23	15,050	3	49,844-	10-
2004	178,244	157,989	89		0	10,128	6	147,861-	83-
2005									
2006	202,377	793,547	392	233,837	116	7,261	4	552,450-	273-
2007	394,066	415,343	105	263,705	67	19,010	5	132,628-	34-
2008	43,383	37,306	86	25,826	60	9,992	23	1,487-	3-
2009	8,638,379	5,936,781	69	144,565	2	93,451	1	5,698,764-	66-
2010	5,225,221	1,814,136	35		0	148,626	3	1,665,510-	32-
2011	8,443,841	2,031,559	24		0	274,437	3	1,757,122-	21-
TOTAL	37,009,338	19,223,228	52	5,452,107	15	3,697,096	10	10,074,025-	27-

THREE-YEAR MOVING AVERAGES

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE REIMBURSEMENTS AMOUNT	PCT	GROSS SALVAGE FINAL AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
85-87	538,480	426,998	79	97,336	18	181,915	34	147,747-	27-
86-88	656,534	427,772	65	133,576	20	175,518	27	118,678-	18-
87-89	718,208	447,545	62	192,082	27	195,253	27	60,210-	8-
88-90	728,043	473,489	65	303,442	42	201,819	28	31,772	4
89-91	677,088	492,428	73	303,722	45	210,153	31	21,446	3
90-92	708,341	494,635	70	290,201	41	212,284	30	7,850	1
91-93	746,236	568,562	76	302,287	41	242,053	32	24,222-	3-
92-94	883,202	587,898	67	356,603	40	235,697	27	4,402	0
93-95	964,616	633,068	66	438,494	45	284,313	29	89,739	9
94-96	1,007,193	527,800	52	368,259	37	227,732	23	68,190	7

KENTUCKY UTILITIES COMPANY

ACCOUNT 365 OVERHEAD CONDUCTORS AND DEVICES

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	COST OF REMOVAL PCT	GROSS SALVAGE REIMBURSEMENTS AMOUNT	GROSS SALVAGE REIMBURSEMENTS PCT	GROSS SALVAGE FINAL AMOUNT	GROSS SALVAGE FINAL PCT	NET SALVAGE AMOUNT	NET SALVAGE PCT
THREE-YEAR MOVING AVERAGES									
95-97	972,512	521,892	54	324,120	33	231,301	24	33,529	3
96-98	907,135	496,511	55	361,874	40	157,137	17	22,500	2
97-99	840,362	475,063	57	448,342	53	147,534	18	120,813	14
98-00	854,481	355,715	42	372,227	44	111,222	13	127,735	15
99-01	791,517	216,004	27	205,362	26	67,679	9	57,037	7
00-02	600,027	146,601	24	36,347	6	38,660	6	71,594-	12-
01-03	446,214	162,227	36	75,058	17	22,727	5	64,443-	14-
02-04	294,873	161,960	55	39,221	13	16,846	6	105,894-	36-
03-05	227,017	113,005	50	38,710	17	8,393	4	65,902-	29-
04-06	126,874	317,179	250	77,946	61	5,796	5	233,437-	184-
05-07	198,814	402,964	203	165,847	83	8,757	4	228,359-	115-
06-08	213,275	415,399	195	174,456	82	12,088	6	228,855-	107-
07-09	3,025,276	2,129,810	70	144,699	5	40,818	1	1,944,293-	64-
08-10	4,635,661	2,596,074	56	56,797	1	84,023	2	2,455,254-	53-
09-11	7,435,814	3,260,825	44	48,188	1	172,172	2	3,040,465-	41-
FIVE-YEAR AVERAGE									
07-11	4,548,978	2,047,025	45	86,819	2	109,103	2	1,851,102-	41-

KENTUCKY UTILITIES COMPANY

ACCOUNT 366 UNDERGROUND CONDUIT

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	COST OF REMOVAL PCT	GROSS SALVAGE REIMBURSEMENTS AMOUNT	GROSS SALVAGE REIMBURSEMENTS PCT	GROSS SALVAGE FINAL AMOUNT	GROSS SALVAGE FINAL PCT	NET SALVAGE AMOUNT	NET SALVAGE PCT
1986	3,615	630	17		0	201	6	429-	12-
1987									
1988									
1989	237		0	103	43	22	9	125	53
1990									
1991									
1992									
1993									
1994									
1995									
1996									
1997	15	2	12		3		3	1-	7-
1998									
1999									
2000									
2001									
2002									
2003									
2004									
2005									
2006	20,097		0		0	1,145	6	1,145	6
2007	182,261		0	13,333	7	177	0	13,509	7
2008									
2009	25	25,952			0	3	12	25,949-	
2010	4,746	755	16		0	3	0	753-	16-
2011	18,439		0		0		0		0
TOTAL	229,435	27,339	12	13,436	6	1,551	1	12,352-	5-

THREE-YEAR MOVING AVERAGES

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	COST OF REMOVAL PCT	GROSS SALVAGE REIMBURSEMENTS AMOUNT	GROSS SALVAGE REIMBURSEMENTS PCT	GROSS SALVAGE FINAL AMOUNT	GROSS SALVAGE FINAL PCT	NET SALVAGE AMOUNT	NET SALVAGE PCT
86-88	1,205	210	17		0	67	6	143-	12-
87-89	79		0	34	43	7	9	42	53
88-90	79		0	34	43	7	9	42	53
89-91	79		0	34	43	7	9	42	53
90-92									
91-93									
92-94									
93-95									
94-96									
95-97	5	1	12		3		3		7-
96-98	5	1	12		3		3		7-

KENTUCKY UTILITIES COMPANY

ACCOUNT 366 UNDERGROUND CONDUIT

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	COST OF REMOVAL PCT	GROSS SALVAGE REIMBURSEMENTS AMOUNT	GROSS SALVAGE REIMBURSEMENTS PCT	GROSS SALVAGE FINAL AMOUNT	GROSS SALVAGE FINAL PCT	NET SALVAGE AMOUNT	NET SALVAGE PCT
THREE-YEAR MOVING AVERAGES									
97-99	5	1	12		3		3		7-
98-00									
99-01									
00-02									
01-03									
02-04									
03-05									
04-06	6,699		0		0	382	6	382	6
05-07	67,453		0	4,444	7	441	1	4,885	7
06-08	67,453		0	4,444	7	441	1	4,885	7
07-09	60,762	8,651	14	4,444	7	60	0	4,146-	7-
08-10	1,590	8,902	560		0	2	0	8,901-	560-
09-11	7,737	8,902	115		0	2	0	8,901-	115-
FIVE-YEAR AVERAGE									
07-11	41,094	5,341	13	2,667	6	36	0	2,638-	6-

KENTUCKY UTILITIES COMPANY

ACCOUNT 367 UNDERGROUND CONDUCTORS AND DEVICES

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE REIMBURSEMENTS AMOUNT	PCT	GROSS SALVAGE FINAL AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
1985	28,973	3,253	11	25,231	87	4,448	15	26,426	91
1986	46,524	7,827	17	20,433	44	5,792	12	18,398	40
1987	89,465	10,081	11	46,953	52	19,936	22	56,808	63
1988	87,088	11,885	14	51,322	59	3,342	4	42,779	49
1989	62,027	18,853	30	72,494	117	8,217	13	61,858	100
1990	51,317	9,267	18	67,295	131	15,279	30	73,307	143
1991	121,385	7,354	6	65,520	54	4,304	4	62,470	51
1992	3,940	8,736	222	16,182	411	12,461	316	19,907	505
1993	108,923	29,103	27	118,104	108	18,489	17	107,491	99
1994	119,096	18,299	15	83,993	71	8,683	7	74,377	62
1995	177,737	35,326	20	173,400	98	30,900	17	168,974	95
1996	286,239	37,933	13	146,209	51	19,185	7	127,460	45
1997	212,450	35,064	17	105,540	50	18,382	9	88,858	42
1998	217,910	47,409	22	323,650	149	19,518	9	295,758	136
1999	279,756	39,468	14	366,758	131	18,769	7	346,059	124
2000	254,398	10,987	4		0	27,478	11	16,491	6
2001	138,621	70,691	51	49,502	36	7,288	5	13,901-	10-
2002	46,298	10,315	22	31	0	3,512	8	6,772-	15-
2003	123,660	6,262	5	18,617	15	2,975	2	15,330	12
2004	11,540	10,367	90		0	2,621	23	7,746-	67-
2005									
2006	1,400	4,581	327		0	261	19	4,320-	308-
2007	27,192	26,509	97	58,982	217	680	3	33,153	122
2008									
2009	862,862	274,005	32	6,555	1	43,811	5	223,638-	26-
2010	998,897	56,448	6		0	8,891	1	47,557-	5-
2011	618,591	103,273	17		0	7,491	1	95,782-	15-
TOTAL	4,976,290	893,296	18	1,816,773	37	312,713	6	1,236,189	25

THREE-YEAR MOVING AVERAGES

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE REIMBURSEMENTS AMOUNT	PCT	GROSS SALVAGE FINAL AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
85-87	54,987	7,054	13	30,872	56	10,059	18	33,877	62
86-88	74,359	9,931	13	39,569	53	9,690	13	39,328	53
87-89	79,527	13,606	17	56,923	72	10,498	13	53,815	68
88-90	66,811	13,335	20	63,704	95	8,946	13	59,315	89
89-91	78,243	11,825	15	68,436	87	9,267	12	65,878	84
90-92	58,881	8,452	14	49,666	84	10,681	18	51,895	88
91-93	78,083	15,064	19	66,602	85	11,751	15	63,289	81
92-94	77,320	18,713	24	72,760	94	13,211	17	67,258	87
93-95	135,252	27,576	20	125,166	93	19,357	14	116,947	86
94-96	194,357	30,520	16	134,534	69	19,589	10	123,604	64

KENTUCKY UTILITIES COMPANY

ACCOUNT 367 UNDERGROUND CONDUCTORS AND DEVICES

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE REIMBURSEMENTS AMOUNT	PCT	GROSS SALVAGE FINAL AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
THREE-YEAR MOVING AVERAGES									
95-97	225,475	36,108	16	141,716	63	22,822	10	128,431	57
96-98	238,866	40,135	17	191,800	80	19,028	8	170,692	71
97-99	236,705	40,647	17	265,316	112	18,889	8	243,559	103
98-00	250,688	32,621	13	230,136	92	21,921	9	219,436	88
99-01	224,258	40,382	18	138,754	62	17,845	8	116,216	52
00-02	146,439	30,664	21	16,511	11	12,759	9	1,394-	1-
01-03	102,860	29,089	28	22,717	22	4,592	4	1,781-	2-
02-04	60,499	8,982	15	6,216	10	3,036	5	270	0
03-05	45,067	5,543	12	6,206	14	1,865	4	2,528	6
04-06	4,313	4,983	116		0	961	22	4,022-	93-
05-07	9,531	10,363	109	19,661	206	314	3	9,611	101
06-08	9,531	10,363	109	19,661	206	314	3	9,611	101
07-09	296,685	100,171	34	21,846	7	14,830	5	63,495-	21-
08-10	620,587	110,151	18	2,185	0	17,567	3	90,398-	15-
09-11	826,784	144,575	17	2,185	0	20,065	2	122,326-	15-
FIVE-YEAR AVERAGE									
07-11	501,509	92,047	18	13,107	3	12,175	2	66,765-	13-

KENTUCKY UTILITIES COMPANY

ACCOUNT 368 LINE TRANSFORMERS

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE REIMBURSEMENTS AMOUNT	PCT	GROSS SALVAGE FINAL AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
1985	896,089	142,332	16	45,004	5	157,649	18	60,321	7
1986	1,749,115	974,420	56	46,749	3	223,414	13	704,257-	40-
1987	1,032,838	145,410	14	52,688	5	154,680	15	61,958	6
1988	2,062,556	76,847	4	46,562	2	130,895	6	100,610	5
1989	1,044,857	174,951	17	157,063	15	196,514	19	178,626	17
1990	1,002,515	187,079	19	130,073	13	154,198	15	97,192	10
1991	1,195,341	149,553	13	89,709	8	105,455	9	45,611	4
1992	691,546	142,294	21	89,392	13	123,963	18	71,061	10
1993	847,976	273,889	32	99,772	12	132,418	16	41,699-	5-
1994	584,476	108,557	19	44,729	8	39,199	7	24,629-	4-
1995	765,824	184,000	24	81,073	11	122,480	16	19,554	3
1996	730,803	117,074	16	40,506	6	45,061	6	31,507-	4-
1997	2,704,437	539,566	20	145,785	5	215,265	8	178,516-	7-
1998	464,646	122,201	26	74,885	16	38,285	8	9,031-	2-
1999	594,542	101,394	17	84,579	14	36,694	6	19,878	3
2000	383,014	103,589	27		0	26,189	7	77,400-	20-
2001	2,559,948	336,354	13	21,218	1	28,713	1	286,423-	11-
2002	690,258	413,253	60	217	0	50,603	7	362,433-	53-
2003	1,188,190	400,085	34	109,497	9	21,647	2	268,941-	23-
2004	1,915,906	490,112	26		0	38,709	2	451,403-	24-
2005									
2006	4,636,662	2,000,079	43	28,687	1	131,312	3	1,840,080-	40-
2007	1,693,660	817,278-	48-	124,159	7	316,496	19	1,257,934	74
2008	140,396	106,888	76	18,155	13	610,350	435	521,616	372
2009	2,340,047	1,602,572	68	9,780	0	204,761	9	1,388,031-	59-
2010	1,705,286	158,133	9		0	273,222	16	115,089	7
2011	378,999	111,609	29		0	224,389	59	112,780	30
TOTAL	33,999,927	8,344,964	25	1,540,283	5	3,802,561	11	3,002,120-	9-

THREE-YEAR MOVING AVERAGES

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE REIMBURSEMENTS AMOUNT	PCT	GROSS SALVAGE FINAL AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
85-87	1,226,014	420,721	34	48,147	4	178,581	15	193,993-	16-
86-88	1,614,836	398,892	25	48,666	3	169,663	11	180,563-	11-
87-89	1,380,084	132,403	10	85,438	6	160,696	12	113,731	8
88-90	1,369,976	146,292	11	111,233	8	160,536	12	125,476	9
89-91	1,080,904	170,528	16	125,615	12	152,056	14	107,143	10
90-92	963,134	159,642	17	103,058	11	127,872	13	71,288	7
91-93	911,621	188,579	21	92,958	10	120,612	13	24,991	3
92-94	707,999	174,913	25	77,964	11	98,527	14	1,578	0
93-95	732,759	188,815	26	75,191	10	98,032	13	15,592-	2-
94-96	693,701	136,544	20	55,436	8	68,913	10	12,194-	2-

KENTUCKY UTILITIES COMPANY

ACCOUNT 368 LINE TRANSFORMERS

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	COST OF REMOVAL PCT	GROSS SALVAGE REIMBURSEMENTS AMOUNT	GROSS SALVAGE REIMBURSEMENTS PCT	GROSS SALVAGE FINAL AMOUNT	GROSS SALVAGE FINAL PCT	NET SALVAGE AMOUNT	NET SALVAGE PCT
THREE-YEAR MOVING AVERAGES									
95-97	1,400,355	280,213	20	89,122	6	127,602	9	63,490-	5-
96-98	1,299,962	259,614	20	87,059	7	99,537	8	73,018-	6-
97-99	1,254,542	254,387	20	101,750	8	96,748	8	55,889-	4-
98-00	480,734	109,062	23	53,155	11	33,723	7	22,184-	5-
99-01	1,179,168	180,446	15	35,266	3	30,532	3	114,648-	10-
00-02	1,211,073	284,399	23	7,145	1	35,168	3	242,085-	20-
01-03	1,479,465	383,231	26	43,644	3	33,654	2	305,932-	21-
02-04	1,264,785	434,483	34	36,571	3	36,986	3	360,926-	29-
03-05	1,034,699	296,732	29	36,499	4	20,119	2	240,115-	23-
04-06	2,184,189	830,064	38	9,562	0	56,674	3	763,828-	35-
05-07	2,110,107	394,267	19	50,949	2	149,269	7	194,049-	9-
06-08	2,156,906	429,896	20	57,000	3	352,719	16	20,177-	1-
07-09	1,391,368	297,394	21	50,698	4	377,202	27	130,506	9
08-10	1,395,243	622,531	45	9,312	1	362,778	26	250,442-	18-
09-11	1,474,777	624,105	42	3,260	0	234,124	16	386,721-	26-
FIVE-YEAR AVERAGE									
07-11	1,251,678	232,385	19	30,419	2	325,844	26	123,878	10

KENTUCKY UTILITIES COMPANY

ACCOUNT 369 SERVICES

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE REIMBURSEMENTS AMOUNT	PCT	GROSS SALVAGE FINAL AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
1985	307,193	189,913	62	2,820	1	50,161	16	136,932-	45-
1986	400,742	259,211	65	3,101	1	51,735	13	204,375-	51-
1987	383,791	138,457	36	1,058	0	51,273	13	86,126-	22-
1988	377,190	119,253	32	1,062	0	51,803	14	66,388-	18-
1989	439,585	158,123	36	4,439	1	66,296	15	87,388-	20-
1990	462,827	202,367	44	5,731	1	64,498	14	132,138-	29-
1991	425,223	210,200	49	3,620	1	55,234	13	151,346-	36-
1992	345,933	222,067	64	3,400	1	55,236	16	163,431-	47-
1993	1,401	1,094	78	108	8	289	21	697-	50-
1994	975,551	438,028	45	48,702	5	86,533	9	302,792-	31-
1995	489,073	284,068	58	33,775	7	103,451	21	146,842-	30-
1996	565,520	219,012	39	20,448	4	46,118	8	152,447-	27-
1997	579,700	279,596	48	20,385	4	61,027	11	198,184-	34-
1998	512,410	325,785	64	53,873	11	55,840	11	216,071-	42-
1999	400,211	164,999	41	37,140	9	32,668	8	95,190-	24-
2000	313,831	108,245	34		0	21,133	7	87,112-	28-
2001	114,753	41,683	36		0	7,264	6	34,419-	30-
2002	62,090	54,657	88	115,553	186	18,625	30	79,521	128
2003	52,167	15,176	29	6,009	12	516	1	8,650-	17-
2004	21,842	14,912	68		0	1,964	9	12,948-	59-
2005									
2006									
2007	3,215	251	8		0	65	2	186-	6-
2008									
2009	41,595	1,153,408		10,366	25	1,837	4	1,141,205-	
2010	5,881,960	285,012	5		0	1,168	0	283,845-	5-
2011	91,365	340,845	373		0	3,210	4	337,635-	370-
TOTAL	13,249,169	5,226,362	39	371,590	3	887,945	7	3,966,827-	30-

THREE-YEAR MOVING AVERAGES

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE REIMBURSEMENTS AMOUNT	PCT	GROSS SALVAGE FINAL AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
85-87	363,909	195,860	54	2,326	1	51,056	14	142,478-	39-
86-88	387,241	172,307	44	1,740	0	51,604	13	118,963-	31-
87-89	400,189	138,611	35	2,186	1	56,457	14	79,967-	20-
88-90	426,534	159,914	37	3,744	1	60,866	14	95,305-	22-
89-91	442,545	190,230	43	4,597	1	62,009	14	123,624-	28-
90-92	411,328	211,545	51	4,250	1	58,323	14	148,972-	36-
91-93	257,519	144,454	56	2,376	1	36,920	14	105,158-	41-
92-94	440,962	220,396	50	17,403	4	47,353	11	155,640-	35-
93-95	488,675	241,063	49	27,528	6	63,425	13	150,110-	31-
94-96	676,715	313,703	46	34,308	5	78,701	12	200,694-	30-

KENTUCKY UTILITIES COMPANY

ACCOUNT 369 SERVICES

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE REIMBURSEMENTS AMOUNT	PCT	GROSS SALVAGE FINAL AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
THREE-YEAR MOVING AVERAGES									
95-97	544,764	260,892	48	24,869	5	70,199	13	165,824-	30-
96-98	552,543	274,798	50	31,569	6	54,329	10	188,901-	34-
97-99	497,440	256,793	52	37,133	7	49,845	10	169,815-	34-
98-00	408,817	199,676	49	30,338	7	36,547	9	132,791-	32-
99-01	276,265	104,976	38	12,380	4	20,355	7	72,240-	26-
00-02	163,558	68,195	42	38,518	24	15,674	10	14,003-	9-
01-03	76,337	37,172	49	40,521	53	8,802	12	12,151	16
02-04	45,366	28,248	62	40,521	89	7,035	16	19,308	43
03-05	24,670	10,029	41	2,003	8	827	3	7,199-	29-
04-06	7,281	4,971	68		0	655	9	4,316-	59-
05-07	1,072	84	8		0	22	2	62-	6-
06-08	1,072	84	8		0	22	2	62-	6-
07-09	14,937	384,553		3,455	23	634	4	380,464-	
08-10	1,974,518	479,473	24	3,455	0	1,001	0	475,017-	24-
09-11	2,004,974	593,088	30	3,455	0	2,071	0	587,562-	29-
FIVE-YEAR AVERAGE									
07-11	1,203,627	355,903	30	2,073	0	1,256	0	352,574-	29-

KENTUCKY UTILITIES COMPANY

ACCOUNT 370 METERS

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE REIMBURSEMENTS AMOUNT	PCT	GROSS SALVAGE FINAL AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
1985	209,213	130	0	70	0	6,350	3	6,290	3
1986	140,217		0	1,643	1	415	0	2,058	1
1987	392,164	113	0	865	0	647	0	1,399	0
1988	373,675	4,471	1	2,515	1	4,055	1	2,099	1
1989	501,612	2,529	1	1,493	0	305	0	731-	0
1990	712,412	5,649	1	950	0	2,587	0	2,112-	0
1991	495,375	534	0	768	0	258	0	492	0
1992	148,022	3,236	2	4,347	3	238	0	1,349	1
1993	592,779	8,980	2	3,744	1	23,804	4	18,567	3
1994	671,459	5,850	1	2,758	0	11,580	2	8,489	1
1995	456,529	5,145	1	2,594	1	18,776	4	16,225	4
1996	860,313	6,464	1	2,560	0	13,641	2	9,736	1
1997	889,096	8,320	1	2,573	0	18,199	2	12,451	1
1998	1,012,984	12,496	1	8,764	1	21,464	2	17,731	2
1999	1,258,952	10,070	1	9,614	1	19,981	2	19,524	2
2000	591,264	7,962	1		0		0	7,962-	1-
2001									
2002	8,955		0		0		0		0
2003	1,466,018	1,532	0		0		0	1,532-	0
2004									
2005									
2006	2,446,024	15,362	1		0		0	15,362-	1-
2007	574,434	25,769	4		0		0	25,769-	4-
2008									
2009	1,162,310		0		0		0		0
2010	166,706		0		0		0		0
2011	83,939		0		0	49,178	59	49,178	59
TOTAL	15,214,452	124,612	1	45,257	0	191,478	1	112,122	1
THREE-YEAR MOVING AVERAGES									
85-87	247,198	81	0	859	0	2,471	1	3,249	1
86-88	302,019	1,528	1	1,674	1	1,706	1	1,852	1
87-89	422,484	2,371	1	1,624	0	1,669	0	922	0
88-90	529,233	4,216	1	1,653	0	2,316	0	248-	0
89-91	569,800	2,904	1	1,070	0	1,050	0	784-	0
90-92	451,936	3,140	1	2,022	0	1,028	0	90-	0
91-93	412,059	4,250	1	2,953	1	8,100	2	6,803	2
92-94	470,753	6,022	1	3,616	1	11,874	3	9,469	2
93-95	573,589	6,658	1	3,032	1	18,053	3	14,427	3
94-96	662,767	5,820	1	2,637	0	14,666	2	11,484	2

KENTUCKY UTILITIES COMPANY

ACCOUNT 370 METERS

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE REIMBURSEMENTS AMOUNT	PCT	GROSS SALVAGE FINAL AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
THREE-YEAR MOVING AVERAGES									
95-97	735,313	6,643	1	2,576	0	16,872	2	12,804	2
96-98	920,798	9,093	1	4,632	1	17,768	2	13,306	1
97-99	1,053,677	10,295	1	6,983	1	19,881	2	16,569	2
98-00	954,400	10,176	1	6,126	1	13,815	1	9,765	1
99-01	616,739	6,011	1	3,205	1	6,660	1	3,854	1
00-02	200,073	2,654	1		0		0	2,654-	1-
01-03	491,658	511	0		0		0	511-	0
02-04	491,658	511	0		0		0	511-	0
03-05	488,673	511	0		0		0	511-	0
04-06	815,341	5,121	1		0		0	5,121-	1-
05-07	1,006,819	13,710	1		0		0	13,710-	1-
06-08	1,006,819	13,710	1		0		0	13,710-	1-
07-09	578,915	8,590	1		0		0	8,590-	1-
08-10	443,005		0		0		0		0
09-11	470,985		0		0	16,393	3	16,393	3
FIVE-YEAR AVERAGE									
07-11	397,478	5,154	1		0	9,836	2	4,682	1

KENTUCKY UTILITIES COMPANY

ACCOUNT 371 INSTALLATIONS ON CUSTOMERS' PREMISES

SUMMARY OF BOOK SALVAGE

		COST OF		G R O S S	S A L V A G E			NET	
	REGULAR	REMOVAL		REIMBURSEMENTS		FINAL		SALVAGE	
YEAR	RETIREMENTS	AMOUNT	PCT	AMOUNT	PCT	AMOUNT	PCT	AMOUNT	PCT
1985	236,086	149,431	63	6,013	3	42,899	18	100,519-	43-
1986	268,717	169,600	63	9,425	4	38,447	14	121,728-	45-
1987	229,847	20,932	9	6,526	3	31,275	14	16,869	7
1988	262,863	21,093	8	949	0	45,433	17	25,289	10
1989	309,615	29,910	10	1,153	0	65,931	21	37,174	12
1990	320,943	35,677	11	765	0	70,183	22	35,271	11
1991	348,824	42,030	12	8,785	3	56,719	16	23,474	7
1992	428,381	51,052	12	12,892	3	55,800	13	17,640	4
1993	548,448	236,332	43	19,313	4	138,673	25	78,345-	14-
1994	546,944	135,529	25	12,528	2	59,395	11	63,606-	12-
1995	590,648	189,328	32	18,714	3	152,954	26	17,659-	3-
1996	631,349	134,936	21	10,473	2	63,032	10	61,430-	10-
1997	614,604	163,591	27	9,916	2	79,211	13	74,464-	12-
1998	637,825	223,795	35	30,766	5	85,095	13	107,934-	17-
1999	555,683	126,431	23	23,659	4	55,531	10	47,241-	9-
2000	120,854	24,817	21		0	45,756	38	20,939	17
2001	75,007	16,851	22		0	12,686	17	4,165-	6-
2002	34,007	11,367	33		0	8,472	25	2,895-	9-
2003	3,141		0	357	11	44	1	401	13
2004	1,028		0		0		0		0
2005									
2006	256	245	96		0	4	2	241-	94-
2007	830	17,280-		17,807			0	35,087	
2008									
2009	279	4,085			0		0	4,085-	
2010	254	83-	32-		0		0	83	32
2011	10,673	2,462	23		0	7	0	2,455-	23-
TOTAL	6,777,106	1,772,132	26	190,043	3	1,107,548	16	474,542-	7-

THREE-YEAR MOVING AVERAGES

85-87	244,883	113,321	46	7,321	3	37,540	15	68,459-	28-
86-88	253,809	70,542	28	5,633	2	38,385	15	26,523-	10-
87-89	267,442	23,978	9	2,876	1	47,546	18	26,444	10
88-90	297,807	28,893	10	956	0	60,516	20	32,578	11
89-91	326,461	35,872	11	3,568	1	64,278	20	31,973	10
90-92	366,049	42,920	12	7,481	2	60,901	17	25,462	7
91-93	441,884	109,805	25	13,663	3	83,731	19	12,410-	3-
92-94	507,924	140,971	28	14,911	3	84,623	17	41,437-	8-
93-95	562,013	187,063	33	16,852	3	117,007	21	53,204-	9-
94-96	589,647	153,264	26	13,905	2	91,794	16	47,565-	8-

KENTUCKY UTILITIES COMPANY

ACCOUNT 371 INSTALLATIONS ON CUSTOMERS' PREMISES

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE REIMBURSEMENTS AMOUNT	PCT	GROSS SALVAGE FINAL AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
THREE-YEAR MOVING AVERAGES									
95-97	612,200	162,618	27	13,035	2	98,399	16	51,184-	8-
96-98	627,926	174,107	28	17,052	3	75,779	12	81,276-	13-
97-99	602,704	171,273	28	21,447	4	73,279	12	76,546-	13-
98-00	438,121	125,015	29	18,142	4	62,127	14	44,745-	10-
99-01	250,515	56,033	22	7,886	3	37,991	15	10,156-	4-
00-02	76,623	17,678	23		0	22,305	29	4,626	6
01-03	37,385	9,406	25	119	0	7,067	19	2,220-	6-
02-04	12,725	3,789	30	119	1	2,839	22	831-	7-
03-05	1,390		0	119	9	15	1	134	10
04-06	428	82	19		0	1	0	80-	19-
05-07	362	5,678-		5,936		1	0	11,615	
06-08	362	5,678-		5,936		1	0	11,615	
07-09	370	4,398-		5,936			0	10,334	
08-10	178	1,334	750		0		0	1,334-	750-
09-11	3,735	2,155	58		0	2	0	2,153-	58-
FIVE-YEAR AVERAGE									
07-11	2,407	2,163-	90-	3,561	148	1	0	5,726	238

KENTUCKY UTILITIES COMPANY

ACCOUNT 373 STREET LIGHTING AND SIGNAL SYSTEMS

SUMMARY OF BOOK SALVAGE

		COST OF		G R O S S	S A L V A G E			NET	
	REGULAR	REMOVAL		REIMBURSEMENTS		FINAL		SALVAGE	
YEAR	RETIREMENTS	AMOUNT	PCT	AMOUNT	PCT	AMOUNT	PCT	AMOUNT	PCT
1985	301,872	73,434	24	48,991	16	92,393	31	67,950	23
1986	230,790	92,991	40	51,200	22	72,998	32	31,207	14
1987	514,814	44,409	9	176,433	34	104,654	20	236,678	46
1988	728,697	40,164	6	60,318	8	75,076	10	95,230	13
1989	253,608	45,668	18	64,537	25	69,857	28	88,726	35
1990	426,617	74,312	17	81,933	19	126,315	30	133,936	31
1991	361,654	147,907	41	84,672	23	96,301	27	33,066	9
1992	313,108	154,828	49	92,413	30	62,546	20	131	0
1993	362,396	117,366	32	113,734	31	111,278	31	107,646	30
1994	505,530	94,148	19	103,194	20	66,669	13	75,715	15
1995	421,566	101,560	24	119,041	28	132,577	31	150,058	36
1996	636,371	102,221	16	94,084	15	77,157	12	69,019	11
1997	368,090	73,636	20	52,926	14	57,612	16	36,902	10
1998	273,337	72,081	26	117,505	43	44,286	16	89,710	33
1999	787,797	134,715	17	298,933	38	95,608	12	259,826	33
2000	879,354	93,243	11		0	110,211	13	16,968	2
2001	384,843	48,268	13		0	53,491	14	5,223	1
2002	192,809	72,178	37	417	0	86,227	45	14,466	8
2003	358,374	43,857	12	31,222	9	7,911	2	4,723-	1-
2004	354,402	25,212	7		0	2,169	1	23,044-	7-
2005									
2006	2,919	8,259	283	9,077	311	319	11	1,137	39
2007	53,834	23,822	44	10,437	19	13,464	25	79	0
2008	2,020	4,550	225		0		0	4,550-	225-
2009	2,961,736	924,237	31	6,341	0	57,431	2	860,464-	29-
2010	5,076,325	771,519	15		0	56,227	1	715,293-	14-
2011	3,616,160	317,382	9		0	34,858	1	282,524-	8-
TOTAL	20,369,023	3,701,969	18	1,617,409	8	1,707,635	8	376,925-	2-

THREE-YEAR MOVING AVERAGES

85-87	349,159	70,278	20	92,208	26	90,015	26	111,945	32
86-88	491,434	59,188	12	95,984	20	84,243	17	121,038	25
87-89	499,040	43,414	9	100,429	20	83,196	17	140,211	28
88-90	469,641	53,381	11	68,929	15	90,416	19	105,964	23
89-91	347,293	89,296	26	77,047	22	97,491	28	85,243	25
90-92	367,126	125,682	34	86,339	24	95,054	26	55,711	15
91-93	345,719	140,034	41	96,940	28	90,042	26	46,948	14
92-94	393,678	122,114	31	103,113	26	80,164	20	61,164	16
93-95	429,831	104,358	24	111,990	26	103,508	24	111,139	26
94-96	521,156	99,310	19	105,439	20	92,134	18	98,264	19

KENTUCKY UTILITIES COMPANY

ACCOUNT 373 STREET LIGHTING AND SIGNAL SYSTEMS

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	COST OF REMOVAL PCT	GROSS SALVAGE REIMBURSEMENTS AMOUNT	GROSS SALVAGE REIMBURSEMENTS PCT	GROSS SALVAGE FINAL AMOUNT	GROSS SALVAGE FINAL PCT	NET SALVAGE AMOUNT	NET SALVAGE PCT
THREE-YEAR MOVING AVERAGES									
95-97	475,342	92,473	19	88,684	19	89,115	19	85,326	18
96-98	425,933	82,646	19	88,172	21	59,685	14	65,211	15
97-99	476,408	93,477	20	156,455	33	65,835	14	128,813	27
98-00	646,829	100,013	15	138,813	21	83,368	13	122,168	19
99-01	683,998	92,075	13	99,644	15	86,437	13	94,006	14
00-02	485,669	71,230	15	139	0	83,310	17	12,219	3
01-03	312,009	54,767	18	10,546	3	49,210	16	4,989	2
02-04	301,862	47,082	16	10,546	3	32,102	11	4,433-	1-
03-05	237,592	23,023	10	10,407	4	3,360	1	9,255-	4-
04-06	119,107	11,157	9	3,026	3	829	1	7,302-	6-
05-07	18,918	10,694	57	6,505	34	4,594	24	405	2
06-08	19,591	12,210	62	6,505	33	4,594	23	1,111-	6-
07-09	1,005,863	317,537	32	5,593	1	23,632	2	288,312-	29-
08-10	2,680,027	566,769	21	2,114	0	37,886	1	526,769-	20-
09-11	3,884,740	671,046	17	2,114	0	49,505	1	619,427-	16-
FIVE-YEAR AVERAGE									
07-11	2,342,015	408,302	17	3,356	0	32,396	1	372,551-	16-

KENTUCKY UTILITIES COMPANY

ACCOUNT 390.1 STRUCTURES AND IMPROVEMENTS - TO OWNED PROPERTY

SUMMARY OF BOOK SALVAGE

		COST OF		G R O S S S A L V A G E				NET	
	REGULAR	REMOVAL		REIMBURSEMENTS		FINAL		SALVAGE	
YEAR	RETIREMENTS	AMOUNT	PCT	AMOUNT	PCT	AMOUNT	PCT	AMOUNT	PCT
1985	2,780		0	6,736	242		0	6,736	242
1986	101,770	7,729	8	187,548	184		0	179,819	177
1987	98,206	344	0		0	48,102	49	47,758	49
1988	193,975	49	0	59,551	31		0	59,502	31
1989	12,034		0		0		0		0
1990	6,272	1,870	30		0		0	1,870-	30-
1991	11,957	219	2		0		0	219-	2-
1992	4,992	2,074	42		0		0	2,074-	42-
1993	6,108	7,896	129	26,412	432	54-	1-	18,461	302
1994	149,918	2,535	2	101,165	67	28,540	19	127,170	85
1995	30,624	273	1	69,152	226	34,237	112	103,116	337
1996	702,394	6,017	1	4,219	1	224,615	32	222,817	32
1997	41,337	2,761	7	209,776	507	11,792	29	218,807	529
1998	266,661	41,788	16	240,158-	90-	93,487-	35-	375,433-	141-
1999	181,729	10,208	6	6,061	3	168,645-	93-	172,792-	95-
2000	32,457		0		0		0		0
2001	764,412	2,680,595	351	2,640,441	345		0	40,154-	5-
2002									
2003	298,177	98,193	33		0		0	98,193-	33-
2004	109,166	51,759	47		0		0	51,759-	47-
2005									
2006	336,638	95,142	28		0		0	95,142-	28-
2007	2,736,942	46,921	2		0	3,000	0	43,921-	2-
2008	172	30,318			0		0	30,318-	
2009	311,229	79,642	26		0	259	0	79,383-	26-
2010	233,055	76,583	33		0		0	76,583-	33-
2011	159,687	70,870	44		0		0	70,870-	44-
TOTAL	6,792,691	3,313,787	49	3,070,903	45	88,359	1	154,526-	2-

THREE-YEAR MOVING AVERAGES

85-87	67,585	2,691	4	64,761	96	16,034	24	78,104	116
86-88	131,317	2,707	2	82,366	63	16,034	12	95,693	73
87-89	101,405	131	0	19,850	20	16,034	16	35,753	35
88-90	70,760	640	1	19,850	28		0	19,211	27
89-91	10,088	696	7		0		0	696-	7-
90-92	7,740	1,388	18		0		0	1,388-	18-
91-93	7,686	3,396	44	8,804	115	18-	0	5,389	70
92-94	53,673	4,168	8	42,526	79	9,495	18	47,853	89
93-95	62,217	3,568	6	65,576	105	20,908	34	82,916	133
94-96	294,312	2,942	1	58,179	20	95,798	33	151,035	51

KENTUCKY UTILITIES COMPANY

ACCOUNT 390.1 STRUCTURES AND IMPROVEMENTS - TO OWNED PROPERTY

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	COST OF REMOVAL PCT	GROSS SALVAGE REIMBURSEMENTS AMOUNT	GROSS SALVAGE REIMBURSEMENTS PCT	GROSS SALVAGE FINAL AMOUNT	GROSS SALVAGE FINAL PCT	NET SALVAGE AMOUNT	NET SALVAGE PCT
THREE-YEAR MOVING AVERAGES									
95-97	258,118	3,017	1	94,382	37	90,215	35	181,580	70
96-98	336,797	16,856	5	8,721-	3-	47,640	14	22,063	7
97-99	163,242	18,252	11	8,107-	5-	83,447-	51-	109,806-	67-
98-00	160,282	17,332	11	78,032-	49-	87,378-	55-	182,742-	114-
99-01	326,199	896,934	275	882,167	270	56,215-	17-	70,982-	22-
00-02	265,623	893,532	336	880,147	331		0	13,385-	5-
01-03	354,196	926,263	262	880,147	248		0	46,116-	13-
02-04	135,781	49,984	37		0		0	49,984-	37-
03-05	135,781	49,984	37		0		0	49,984-	37-
04-06	148,601	48,967	33		0		0	48,967-	33-
05-07	1,024,527	47,354	5		0	1,000	0	46,354-	5-
06-08	1,024,584	57,460	6		0	1,000	0	56,460-	6-
07-09	1,016,114	52,294	5		0	1,086	0	51,207-	5-
08-10	181,485	62,181	34		0	86	0	62,095-	34-
09-11	234,657	75,698	32		0	86	0	75,612-	32-
FIVE-YEAR AVERAGE									
07-11	688,217	60,867	9		0	652	0	60,215-	9-

KENTUCKY UTILITIES COMPANY

ACCOUNT 390.2 STRUCTURES AND IMPROVEMENTS - TO LEASED PROPERTY

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	COST OF REMOVAL PCT	GROSS SALVAGE REIMBURSEMENTS AMOUNT	GROSS SALVAGE REIMBURSEMENTS PCT	GROSS SALVAGE FINAL AMOUNT	GROSS SALVAGE FINAL PCT	NET SALVAGE AMOUNT	NET SALVAGE PCT
2001	2,662		0		0		0		0
2002									
2003	8,779		0		0		0		0
2004									
2005									
2006	224,106	22,970	10		0		0	22,970-	10-
2007									
2008									
2009									
2010									
2011									
TOTAL	235,547	22,970	10		0		0	22,970-	10-
THREE-YEAR MOVING AVERAGES									
01-03	3,814		0		0		0		0
02-04	2,926		0		0		0		0
03-05	2,926		0		0		0		0
04-06	74,702	7,657	10		0		0	7,657-	10-
05-07	74,702	7,657	10		0		0	7,657-	10-
06-08	74,702	7,657	10		0		0	7,657-	10-
07-09									
08-10									
09-11									
FIVE-YEAR AVERAGE									
07-11									

KENTUCKY UTILITIES COMPANY

ACCOUNTS 392.1 AND 392.3 TRANSPORTATION EQUIPMENT

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	COST OF REMOVAL PCT	GROSS SALVAGE REIMBURSEMENTS AMOUNT	GROSS SALVAGE REIMBURSEMENTS PCT	GROSS SALVAGE FINAL AMOUNT	GROSS SALVAGE FINAL PCT	NET SALVAGE AMOUNT	NET SALVAGE PCT
2000	17,872		0		0		0		0
2001	939,069		0		0		0		0
2002	3,936,032	75,837	2		0	112,442	3	36,605	1
2003									
2004	10,528		0		0		0		0
2005									
2006									
2007	4,934,986		0		0		0		0
2008									
2009	312,452		0		0		0		0
2010	111,742		0		0		0		0
2011	3,997,638		0		0		0		0
TOTAL	14,260,319	75,837	1		0	112,442	1	36,605	0
THREE-YEAR MOVING AVERAGES									
00-02	1,630,991	25,279	2		0	37,481	2	12,202	1
01-03	1,625,034	25,279	2		0	37,481	2	12,202	1
02-04	1,315,520	25,279	2		0	37,481	3	12,202	1
03-05	3,509		0		0		0		0
04-06	3,509		0		0		0		0
05-07	1,644,995		0		0		0		0
06-08	1,644,995		0		0		0		0
07-09	1,749,146		0		0		0		0
08-10	141,398		0		0		0		0
09-11	1,473,944		0		0		0		0
FIVE-YEAR AVERAGE									
07-11	1,871,364		0		0		0		0

KENTUCKY UTILITIES COMPANY

ACCOUNT 396.3 POWER OPERATED EQUIPMENT – LARGE MACHINERY

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	COST OF REMOVAL PCT	GROSS SALVAGE REIMBURSEMENTS AMOUNT	GROSS SALVAGE REIMBURSEMENTS PCT	GROSS SALVAGE FINAL AMOUNT	GROSS SALVAGE FINAL PCT	NET SALVAGE AMOUNT	NET SALVAGE PCT
1989	7,752		0		0		0		0
1990									
1991									
1992									
1993									
1994	19,123		0		0		0		0
1995									
1996									
1997	48,520		0		0		0		0
1998									
1999									
2000	24,071		0		0		0		0
2001									
2002									
2003									
2004	32,483		0		0		0		0
2005									
2006	29,959		0		0		0		0
2007									
2008									
2009									
2010									
2011	107,600		0		0		0		0
TOTAL	269,509		0		0		0		0
THREE-YEAR MOVING AVERAGES									
89-91	2,584		0		0		0		0
90-92									
91-93									
92-94	6,374		0		0		0		0
93-95	6,374		0		0		0		0
94-96	6,374		0		0		0		0
95-97	16,173		0		0		0		0
96-98	16,173		0		0		0		0
97-99	16,173		0		0		0		0
98-00	8,024		0		0		0		0
99-01	8,024		0		0		0		0
00-02	8,024		0		0		0		0
01-03									
02-04	10,828		0		0		0		0

KENTUCKY UTILITIES COMPANY

ACCOUNT 396.3 POWER OPERATED EQUIPMENT – LARGE MACHINERY

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	COST OF REMOVAL PCT	GROSS SALVAGE REIMBURSEMENTS AMOUNT	GROSS SALVAGE REIMBURSEMENTS PCT	GROSS SALVAGE FINAL AMOUNT	GROSS SALVAGE FINAL PCT	NET SALVAGE AMOUNT	NET SALVAGE PCT
THREE-YEAR MOVING AVERAGES									
03-05	10,828		0		0		0		0
04-06	20,814		0		0		0		0
05-07	9,986		0		0		0		0
06-08	9,986		0		0		0		0
07-09									
08-10									
09-11	35,867		0		0		0		0
FIVE-YEAR AVERAGE									
07-11	21,520		0		0		0		0

III-274 DEPRECIATION CALCULATIONS

KENTUCKY UTILITIES COMPANY

ACCOUNT 302 FRANCHISES AND CONSENTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2011

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. 20-SQUARE						
NET SALVAGE PERCENT.. 0						
1991	1,588.57	1,589	1,589			
1992	792.28	772	345	447	0.50	447
1993	6,183.50	5,720	2,556	3,628	1.50	2,419
1995	30,302.58	25,000	11,172	19,131	3.50	5,466
1996	10,457.30	8,104	3,622	6,835	4.50	1,519
1997	1,725.32	1,251	559	1,166	5.50	212
1998	2,055.48	1,387	620	1,435	6.50	221
1999	711.08	444	198	513	7.50	68
2002	585.80	278	124	462	10.50	44
2003	1,516.92	645	289	1,228	11.50	107
	55,918.83	45,190	21,074	34,845		10,503

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 3.3 18.78

KENTUCKY UTILITIES COMPANY

ACCOUNT 303 MISCELLANEOUS INTANGIBLE PLANT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2011

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. 5-SQUARE						
NET SALVAGE PERCENT.. 0						
2007	4,488,033.54	4,039,230	4,371,327	116,707	0.50	116,707
2008	864,969.59	605,479	655,260	209,710	1.50	139,807
2009	737,050.57	368,525	398,824	338,227	2.50	135,291
2010	3,390,584.53	1,017,175	1,100,805	2,289,780	3.50	654,223
2011	8,858,073.79	885,807	958,636	7,899,438	4.50	1,755,431
	18,338,712.02	6,916,216	7,484,852	10,853,860		2,801,459

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 3.9 15.28

KENTUCKY UTILITIES COMPANY

ACCOUNT 303.1 CCS SOFTWARE

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2011

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
INTERIM SURVIVOR CURVE.. SQUARE						
PROBABLE RETIREMENT YEAR.. 6-2019						
NET SALVAGE PERCENT.. 0						
2009	36,405,085.42	9,101,271	9,872,236	26,532,849	7.50	3,537,713
2010	979,128.50	163,191	177,015	802,114	7.50	106,949
2011	2,825,994.37	176,625	191,587	2,634,407	7.50	351,254
	40,210,208.29	9,441,087	10,240,838	29,969,370		3,995,916

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 7.5   9.94

KENTUCKY UTILITIES COMPANY

ACCOUNT 311 STRUCTURES AND IMPROVEMENTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2011

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
TRIMBLE COUNTY UNIT 2 INTERIM SURVIVOR CURVE.. IOWA 100-S1 PROBABLE RETIREMENT YEAR.. 6-2066 NET SALVAGE PERCENT.. -15						
1990	39,720,470.42	13,700,822	17,586,589	28,091,952	48.57	578,381
1997	449,904.13	114,902	147,490	369,900	49.95	7,405
2002	112,879.59	20,304	26,063	103,749	50.86	2,040
2003	61,493.38	10,045	12,894	57,823	51.04	1,133
2008	53,301.70	3,875	4,974	56,323	51.86	1,086
2011	65,892,531.72	717,603	921,126	74,855,285	52.30	1,431,267
	106,290,580.94	14,567,551	18,699,136	103,535,032		2,021,312
TRIMBLE COUNTY UNIT 2 SCRUBBER INTERIM SURVIVOR CURVE.. IOWA 100-S1 PROBABLE RETIREMENT YEAR.. 6-2066 NET SALVAGE PERCENT.. -15						
1990	5,522,306.98	1,904,815	2,689,746	3,660,907	48.57	75,374
	5,522,306.98	1,904,815	2,689,746	3,660,907		75,374
SYSTEM LABORATORY INTERIM SURVIVOR CURVE.. IOWA 100-S1 PROBABLE RETIREMENT YEAR.. 6-2040 NET SALVAGE PERCENT.. -1						
1989	724,776.82	326,893	551,968	180,056	27.29	6,598
1990	58,100.00	25,542	43,128	15,553	27.35	569
1994	6,176.00	2,403	4,058	2,180	27.56	79
1997	16,663.00	5,743	9,697	7,132	27.72	257
2011	19,253.00	338	571	18,875	28.28	667
	824,968.82	360,919	609,422	223,797		8,170
TYRONE UNIT 3 INTERIM SURVIVOR CURVE.. IOWA 100-S1 PROBABLE RETIREMENT YEAR.. 12-2015 NET SALVAGE PERCENT.. -10						
1947	1,752,381.00	1,808,936	1,927,619			
1948	311,618.16	321,415	342,780			
1949	38,152.92	39,320	41,968			

KENTUCKY UTILITIES COMPANY

ACCOUNT 311 STRUCTURES AND IMPROVEMENTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2011

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)

TYRONE UNIT 3
INTERIM SURVIVOR CURVE.. IOWA 100-S1
PROBABLE RETIREMENT YEAR.. 12-2015
NET SALVAGE PERCENT.. -10

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
1951	18,754.00	19,293	20,629			
1953	1,869,498.00	1,919,303	2,056,448			
1954	43,321.00	44,430	47,653			
1955	1,600.35	1,640	1,760			
1960	1,560.22	1,589	1,716			
1964	16,215.88	16,421	17,837			
1966	18.41	19	20			
1970	15,244.21	15,272	16,769			
1971	207.88	208	229			
1973	1,458.00	1,451	1,604			
1975	121.74	121	134			
1977	342,675.00	337,439	376,943			
1978	45,723.00	44,890	50,295			
1980	395,604.00	385,860	435,164			
1986	10,631.59	10,104	11,695			
1991	11,976.68	11,018	13,174			
1993	27,091.19	24,494	29,800			
1994	19,770.52	17,698	21,748			
1995	39,470.30	34,942	43,417			
1996	137,342.48	120,085	151,077			
1997	50,594.22	43,625	55,654			
2000	40,880.36	33,378	44,968			
2001	50,611.05	40,293	55,672			
2003	79,755.40	59,634	87,731			
2005	26,721.33	18,185	29,393			
2006	54,992.26	35,022	60,491			
2007	120,531.32	70,192	132,584			
2009	67,097.35	28,388	73,807			
2011	17,205.25	2,103	18,926			
	5,608,825.07	5,506,768	6,169,708			

KENTUCKY UTILITIES COMPANY

ACCOUNT 311 STRUCTURES AND IMPROVEMENTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2011

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
TYRONE UNITS 1 AND 2						
FULLY ACCRUED						
NET SALVAGE PERCENT.. -10						
1947	464,339.65	510,774	510,774			
2000	36,257.09	39,883	39,883			
2001	78,101.58	85,912	85,912			
2004	4,683.12	5,151	5,152			
	583,381.44	641,720	641,720			
GREEN RIVER UNIT 3						
INTERIM SURVIVOR CURVE.. IOWA 100-S1						
PROBABLE RETIREMENT YEAR.. 12-2015						
NET SALVAGE PERCENT.. -10						
1954	1,691,968.01	1,735,294	1,861,165			
1955	34,040.75	34,876	37,445			
1961	984.15	1,001	1,083			
1967	799.68	806	880			
1971	7,661.07	7,659	8,427			
1972	138.02	138	152			
1973	726.00	722	799			
1977	508,599.55	500,828	559,460			
1978	2,303.00	2,261	2,533			
1982	403,040.00	390,067	443,344			
1985	19,443.60	18,572	21,388			
1990	902.16	836	992			
1997	26,427.69	22,787	29,070			
2003	8,940.44	6,685	9,834			
2011	115,462.54	14,112	127,008			
	2,821,436.66	2,736,644	3,103,580			
GREEN RIVER UNIT 4						
INTERIM SURVIVOR CURVE.. IOWA 100-S1						
PROBABLE RETIREMENT YEAR.. 12-2015						
NET SALVAGE PERCENT.. -10						
1959	2,378,728.07	2,425,511	2,333,946	282,655	3.95	71,558
1960	43,581.00	44,382	42,707	5,233	3.95	1,325
1961	12,937.09	13,158	12,661	1,570	3.95	397
1969	1,917.31	1,925	1,852	257	3.96	65
1970	1,875.26	1,879	1,808	255	3.96	64

KENTUCKY UTILITIES COMPANY

ACCOUNT 311 STRUCTURES AND IMPROVEMENTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2011

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
GREEN RIVER UNIT 4						
INTERIM SURVIVOR CURVE.. IOWA 100-S1						
PROBABLE RETIREMENT YEAR.. 12-2015						
NET SALVAGE PERCENT.. -10						
1971	408.14	408	393	56	3.96	14
1972	16,184.53	16,146	15,536	2,267	3.96	572
1979	851.60	833	802	135	3.97	34
1980	83,959.86	81,892	78,801	13,555	3.97	3,414
1981	4,544.71	4,415	4,248	751	3.98	189
1982	144,849.00	140,187	134,895	24,439	3.98	6,140
1984	38,673.00	37,114	35,713	6,827	3.98	1,715
1985	40,420.00	38,608	37,151	7,311	3.98	1,837
1986	85,946.00	81,681	78,597	15,943	3.98	4,006
1987	11,321.00	10,701	10,297	2,156	3.98	542
1988	18,125.00	17,033	16,390	3,548	3.98	891
1990	13,580.00	12,588	12,113	2,825	3.99	708
1991	621,154.00	571,446	549,874	133,396	3.99	33,433
1992	453.00	413	397	101	3.99	25
1994	12,333.00	11,040	10,623	2,943	3.99	738
1995	20,344.00	18,010	17,330	5,048	3.99	1,265
1996	128,584.00	112,427	108,183	33,260	3.99	8,336
1997	164,536.00	141,871	136,515	44,474	3.99	11,146
1998	5,406.00	4,588	4,415	1,532	3.99	384
1999	23,270.12	19,396	18,664	6,933	3.99	1,738
2000	125,696.00	102,628	98,754	39,512	3.99	9,903
2003	37,909.52	28,345	27,275	14,426	4.00	3,606
2004	196,798.26	141,116	135,789	80,689	4.00	20,172
2005	188,387.38	128,207	123,367	83,859	4.00	20,965
2007	147,237.90	85,744	82,507	79,455	4.00	19,864
2009	285,502.42	120,791	116,231	197,822	4.00	49,456
2010	24.08	7	7	20	4.00	5
2011	620,517.05	75,840	72,977	609,592	4.00	152,398
	5,476,054.30	4,490,330	4,320,817	1,702,843		426,905
GREEN RIVER UNITS 1 AND 2						
FULLY ACCRUED						
NET SALVAGE PERCENT.. -10						
1950	1,667,618.05	1,834,380	1,834,380			
1951	45,085.18	49,594	49,594			
1954	29,120.73	32,033	32,033			
1960	11,239.00	12,363	12,363			
1961	219.00	241	241			

KENTUCKY UTILITIES COMPANY

ACCOUNT 311 STRUCTURES AND IMPROVEMENTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2011

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
GREEN RIVER UNITS 1 AND 2						
FULLY ACCRUED						
NET SALVAGE PERCENT.. -10						
1965	6,953.70	7,649	7,649			
1967	2,328.58	2,561	2,561			
1969	30,207.24	33,228	33,228			
1970	10,003.63	11,004	11,004			
1973	12,200.00	13,420	13,420			
1974	28.00	31	31			
1975	546,774.84	601,452	601,452			
1978	34,073.00	37,480	37,480			
1997	68,189.00	75,008	75,008			
2000	95,835.94	105,420	105,420			
2006	888.29	977	978			
	2,560,764.18	2,816,841	2,816,841			
BROWN UNIT 1						
INTERIM SURVIVOR CURVE.. IOWA 100-S1						
PROBABLE RETIREMENT YEAR.. 6-2028						
NET SALVAGE PERCENT.. -11						
1948	11,983.27	10,494	13,301			
1956	2,437,020.95	2,076,727	2,705,093			
1958	382.11	323	424			
1965	283.00	231	314			
1979	14,516.00	10,699	16,113			
1982	91,160.00	65,006	101,188			
1983	1,965.00	1,384	2,181			
1984	5,212.00	3,623	5,785			
1985	1,849.00	1,268	2,052			
1987	43,137.68	28,680	47,883			
1988	45,243.11	29,577	50,220			
1989	64,194.00	41,211	71,255			
1990	658.09	414	730			
1991	34,640.48	21,356	38,451			
1994	666,989.00	382,076	740,358			
1995	352,899.61	196,459	391,719			
1996	94,854.89	51,149	105,289			
1997	72,522.04	37,761	80,499			
1998	11,065.00	5,545	12,282			
2004	108,817.17	37,869	100,521	20,266	16.40	1,236
2005	71,616.67	22,554	59,868	19,626	16.41	1,196

KENTUCKY UTILITIES COMPANY

ACCOUNT 311 STRUCTURES AND IMPROVEMENTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2011

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
BROWN UNIT 1						
INTERIM SURVIVOR CURVE.. IOWA 100-S1						
PROBABLE RETIREMENT YEAR.. 6-2028						
NET SALVAGE PERCENT.. -11						
2006	50,453.10	14,026	37,231	18,772	16.43	1,143
2007	85,296.44	20,311	53,914	40,765	16.44	2,480
2008	436,431.15	84,791	225,073	259,365	16.45	15,767
	4,703,189.76	3,143,534	4,861,747	358,794		21,822
BROWN UNIT 2						
INTERIM SURVIVOR CURVE.. IOWA 100-S1						
PROBABLE RETIREMENT YEAR.. 6-2034						
NET SALVAGE PERCENT.. -11						
1963	1,280,411.96	971,941	1,421,257			
1965	11,653.00	8,731	12,935			
1966	10,986.00	8,175	12,194			
1967	2,142.72	1,583	2,378			
1979	24,545.95	16,182	27,246			
1980	400.00	260	444			
1983	1,964.15	1,225	2,180			
1992	96,409.90	50,009	107,015			
1997	19,477.46	8,527	21,620			
2004	43,200.52	12,057	38,999	8,953	22.27	402
2005	27,160.47	6,798	21,989	8,160	22.29	366
2007	565,018.59	105,189	340,241	286,930	22.33	12,850
2009	21,690.24	2,420	7,828	16,249	22.37	726
2010	17,628.31	1,229	3,975	15,592	22.39	696
2011	109,410.77	2,650	8,572	112,874	22.41	5,037
	2,232,100.04	1,196,976	2,028,873	448,758		20,077
BROWN UNIT 3						
INTERIM SURVIVOR CURVE.. IOWA 100-S1						
PROBABLE RETIREMENT YEAR.. 6-2035						
NET SALVAGE PERCENT.. -11						
1967	1,440.97	1,050	1,572	27	21.80	1
1968	93.83	68	102	2	21.85	
1971	7,697,492.93	5,429,252	8,128,727	415,490	21.98	18,903
1972	59,067.58	41,286	61,814	3,751	22.03	170
1973	11,995.55	8,306	12,436	879	22.07	40

KENTUCKY UTILITIES COMPANY

ACCOUNT 311 STRUCTURES AND IMPROVEMENTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2011

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
BROWN UNIT 3						
INTERIM SURVIVOR CURVE.. IOWA 100-S1						
PROBABLE RETIREMENT YEAR.. 6-2035						
NET SALVAGE PERCENT.. -11						
1974	2,999.00	2,056	3,078	251	22.12	11
1975	15,098.31	10,247	15,342	1,417	22.16	64
1977	1,211,596.00	804,354	1,204,286	140,585	22.25	6,318
1979	8,850.03	5,734	8,585	1,239	22.34	55
1980	275,262.00	176,034	263,560	41,981	22.38	1,876
1981	11,971.69	7,553	11,308	1,980	22.42	88
1983	3,928.40	2,406	3,602	758	22.50	34
1984	146,459.90	88,258	132,141	30,430	22.54	1,350
1985	58,036.00	34,385	51,482	12,938	22.58	573
1986	48,229.38	28,057	42,007	11,527	22.62	510
1987	254,194.00	145,070	217,200	64,955	22.66	2,867
1988	85,132.00	47,589	71,251	23,246	22.70	1,024
1989	477,066.00	260,932	390,670	138,873	22.74	6,107
1990	53,202.58	28,425	42,558	16,497	22.78	724
1991	68,381.00	35,621	53,332	22,571	22.82	989
1992	756,531.00	383,757	574,565	265,185	22.85	11,605
1993	84,689.00	41,714	62,455	31,550	22.89	1,378
1995	22,964.00	10,594	15,861	9,629	22.96	419
1997	251,791.96	107,433	160,850	118,639	23.03	5,151
1998	137,946.00	56,276	84,257	68,863	23.06	2,986
2001	95,860.00	33,093	49,547	56,857	23.15	2,456
2003	193,441.22	57,407	85,950	128,769	23.21	5,548
2004	122,280.23	33,049	49,481	86,250	23.24	3,711
2005	95,151.19	23,041	34,497	71,121	23.26	3,058
2007	8,016,945.98	1,437,247	2,151,860	6,746,950	23.31	289,444
2009	200,931.69	21,570	32,295	190,739	23.35	8,169
2010	423,902.15	28,378	42,488	428,044	23.37	18,316
2011	146,742.79	3,409	5,104	157,781	23.39	6,746
	21,039,674.36	9,393,651	14,064,263	9,289,776		400,691
BROWN UNITS 1, 2 AND 3 SCRUBBER						
INTERIM SURVIVOR CURVE.. IOWA 100-S1						
PROBABLE RETIREMENT YEAR.. 6-2035						
NET SALVAGE PERCENT.. -11						
2010	43,917,221.15	2,939,999	1,760,616	46,987,499	23.37	2,010,590
	43,917,221.15	2,939,999	1,760,616	46,987,499		2,010,590

KENTUCKY UTILITIES COMPANY

ACCOUNT 311 STRUCTURES AND IMPROVEMENTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2011

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
PINEVILLE UNIT 3						
FULLY ACCRUED						
NET SALVAGE PERCENT.. -10						
2007	16,204.29	17,825	17,825			
	16,204.29	17,825	17,825			
GHENT UNIT 1 SCRUBBER						
INTERIM SURVIVOR CURVE.. IOWA 100-S1						
PROBABLE RETIREMENT YEAR.. 6-2034						
NET SALVAGE PERCENT.. -12						
1997	8,449,181.47	3,732,240	6,973,308	2,489,776	22.08	112,762
2007	34,607.76	6,501	12,146	26,614	22.33	1,192
	8,483,789.23	3,738,741	6,985,454	2,516,390		113,954
GHENT UNIT 1						
INTERIM SURVIVOR CURVE.. IOWA 100-S1						
PROBABLE RETIREMENT YEAR.. 6-2034						
NET SALVAGE PERCENT.. -12						
1974	14,890,672.81	10,463,330	16,677,554			
1979	302,607.00	201,298	328,143	10,777	21.44	503
1980	27,171.00	17,847	29,093	1,339	21.48	62
1981	10,791.00	6,993	11,400	686	21.52	32
1985	107,260.53	65,361	106,547	13,585	21.67	627
1987	541,154.00	317,823	518,094	87,999	21.75	4,046
1988	97,360.62	56,066	91,395	17,649	21.78	810
1992	29,300.00	15,335	24,998	7,818	21.92	357
1994	74,968.00	36,992	60,302	23,662	21.98	1,077
1995	60,912.73	29,068	47,385	20,838	22.01	947
1996	393,716.22	181,055	295,144	145,818	22.05	6,613
1997	33,704.37	14,888	24,269	13,479	22.08	610
2003	143,388.86	44,331	72,265	88,330	22.24	3,972
2005	240,490.70	60,738	99,011	170,339	22.29	7,642
2007	240,638.23	45,203	73,687	195,828	22.33	8,770
2009	333,988.93	37,601	61,295	312,773	22.37	13,982
2010	643,507.32	45,255	73,772	646,957	22.39	28,895
2011	670,518.89	16,386	26,711	724,270	22.41	32,319
	18,842,151.21	11,655,570	18,621,064	2,482,145		111,264

KENTUCKY UTILITIES COMPANY

ACCOUNT 311 STRUCTURES AND IMPROVEMENTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2011

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
GHENT UNIT 2						
INTERIM SURVIVOR CURVE.. IOWA 100-S1						
PROBABLE RETIREMENT YEAR.. 6-2034						
NET SALVAGE PERCENT.. -12						
1977	14,940,178.05	10,172,994	13,381,079	3,351,920	21.37	156,852
1979	227,477.00	151,321	199,041	55,734	21.44	2,600
1980	88,059.38	57,840	76,080	22,546	21.48	1,050
1981	10,786.00	6,990	9,194	2,886	21.52	134
1986	385,657.47	230,879	303,687	128,249	21.71	5,907
1988	13,292.75	7,655	10,069	4,819	21.78	221
1989	11,294.78	6,365	8,372	4,278	21.82	196
1991	1,929.73	1,038	1,365	796	21.88	36
1995	27,739.56	13,238	17,413	13,656	22.01	620
1997	13,603.48	6,009	7,904	7,332	22.08	332
1998	67,159.90	28,385	37,336	37,883	22.11	1,713
2003	223,834.88	69,202	91,025	159,670	22.24	7,179
	16,011,012.98	10,751,916	14,142,566	3,789,769		176,840
GHENT UNIT 3						
INTERIM SURVIVOR CURVE.. IOWA 100-S1						
PROBABLE RETIREMENT YEAR.. 6-2037						
NET SALVAGE PERCENT.. -12						
1981	34,490,870.98	21,208,133	27,045,709	11,584,067	24.20	478,680
1982	1,235,435.00	748,187	954,127	429,560	24.25	17,714
1983	511.16	305	389	184	24.30	8
1987	2,248,542.00	1,244,879	1,587,534	930,833	24.49	38,009
1995	9,779.16	4,344	5,540	5,413	24.83	218
1996	195,780.51	83,686	106,721	112,553	24.87	4,526
2001	263,336.76	86,794	110,684	184,253	25.06	7,352
2002	234,131.24	71,779	91,536	170,691	25.10	6,800
2004	2,640,221.52	677,667	864,196	2,092,852	25.16	83,182
2005	105,410.84	24,149	30,796	87,264	25.20	3,463
2010	643,443.60	40,292	51,382	669,274	25.33	26,422
2011	109,662.90	2,375	3,029	119,794	25.35	4,726
	42,177,125.67	24,192,590	30,851,643	16,386,738		671,100

KENTUCKY UTILITIES COMPANY

ACCOUNT 311 STRUCTURES AND IMPROVEMENTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2011

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
GHENT UNIT 4 INTERIM SURVIVOR CURVE.. IOWA 100-S1 PROBABLE RETIREMENT YEAR.. 6-2038 NET SALVAGE PERCENT.. -12						
1984	17,124,092.19	9,858,956	10,976,814	8,202,169	25.24	324,967
1985	931,420.00	526,603	586,312	456,878	25.29	18,066
1986	746,643.00	414,039	460,985	375,255	25.34	14,809
1987	15,869.00	8,622	9,600	8,174	25.39	322
1988	8,118.00	4,316	4,805	4,287	25.44	169
1989	20,054.00	10,415	11,596	10,865	25.49	426
1990	23,192.76	11,757	13,090	12,886	25.53	505
1991	16,217.00	8,003	8,910	9,253	25.58	362
1992	24,302.00	11,657	12,979	14,240	25.63	556
1993	42,417.00	19,730	21,967	25,540	25.68	995
1994	11,882.00	5,348	5,954	7,353	25.72	286
1995	74,199.00	32,211	35,863	47,240	25.77	1,833
1996	80,570.00	33,639	37,453	52,785	25.81	2,045
1997	1,942,669.00	777,366	865,508	1,310,282	25.85	50,688
2001	618,493.64	198,545	221,057	471,656	26.01	18,134
2002	186,501.00	55,646	61,955	146,926	26.05	5,640
2003	189,255.91	51,949	57,839	154,127	26.09	5,908
2004	276,923.25	69,046	76,875	233,279	26.12	8,931
2005	181,861.63	40,438	45,023	158,662	26.16	6,065
2007	7,212,117.43	1,183,203	1,317,361	6,760,211	26.22	257,827
2008	265,807.80	35,025	38,996	258,708	26.25	9,856
2010	581,597.75	34,914	38,873	612,517	26.31	23,281
2011	447,887.14	9,350	10,410	491,223	26.33	18,656
	31,022,090.50	13,400,778	14,920,226	19,824,515		770,327
GHENT UNIT 2 SCRUBBER INTERIM SURVIVOR CURVE.. IOWA 100-S1 PROBABLE RETIREMENT YEAR.. 6-2034 NET SALVAGE PERCENT.. -12						
1994	15,817,337.72	7,804,882	12,919,945	4,795,473	21.98	218,174
	15,817,337.72	7,804,882	12,919,945	4,795,473		218,174
	333,950,215.30	121,262,050	160,225,192	216,002,436		7,046,600

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 30.7 2.11

KENTUCKY UTILITIES COMPANY

ACCOUNT 312 BOILER PLANT EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2011

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
TRIMBLE COUNTY UNIT 2 INTERIM SURVIVOR CURVE.. IOWA 60-R2.5 PROBABLE RETIREMENT YEAR.. 6-2066 NET SALVAGE PERCENT.. -15						
1990	31,069,801.93	11,971,428	30,293,648	5,436,625	38.68	140,554
1999	46,214.59	11,139	28,187	24,960	43.86	569
2002	278,268.17	52,539	132,950	187,059	45.31	4,128
2003	251,881.90	43,067	108,981	180,683	45.75	3,949
2004	103,726.28	15,815	40,020	79,265	46.19	1,716
2008	11,126.98	834	2,110	10,686	47.75	224
2010	84,064.47	2,772	7,015	89,660	48.44	1,851
2011	473,313,884.25	5,307,032	13,429,422	530,881,545	48.76	10,887,644
	505,158,968.57	17,404,626	44,042,332	536,890,482		11,040,635
TRIMBLE COUNTY UNIT 2 SCRUBBER INTERIM SURVIVOR CURVE.. IOWA 60-R2.5 PROBABLE RETIREMENT YEAR.. 6-2066 NET SALVAGE PERCENT.. -15						
1990	11,144,536.48	4,294,073	9,706,299	3,109,918	38.68	80,401
2003	51,829.65	8,862	20,032	39,572	45.75	865
2005	27,031.69	3,619	8,180	22,906	46.60	492
2007	131,148.15	12,468	28,183	122,638	47.38	2,588
2008	24,501.14	1,837	4,152	24,024	47.75	503
2011	59,356,272.50	665,532	1,504,365	66,755,348	48.76	1,369,060
	70,735,319.61	4,986,391	11,271,211	70,074,407		1,453,909
TYRONE UNIT 3 INTERIM SURVIVOR CURVE.. IOWA 60-R2.5 PROBABLE RETIREMENT YEAR.. 12-2015 NET SALVAGE PERCENT.. -10						
1952	11,058.16	11,330	11,080	1,084	3.70	293
1953	3,209,920.96	3,285,409	3,212,939	317,974	3.72	85,477
1972	50,809.00	50,540	49,425	6,465	3.91	1,653
1974	1,101,937.14	1,090,954	1,066,890	145,241	3.92	37,051
1975	115,788.00	114,358	111,835	15,531	3.92	3,962
1977	578,158.00	567,855	555,329	80,645	3.93	20,520
1978	87,933.00	86,117	84,217	12,509	3.93	3,183
1982	468,209.00	452,047	442,076	72,954	3.95	18,469
1984	11,342.44	10,861	10,621	1,855	3.95	470

KENTUCKY UTILITIES COMPANY

ACCOUNT 312 BOILER PLANT EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2011

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
TYRONE UNIT 3						
INTERIM SURVIVOR CURVE.. IOWA 60-R2.5						
PROBABLE RETIREMENT YEAR.. 12-2015						
NET SALVAGE PERCENT.. -10						
1988	4,596.33	4,309	4,214	842	3.96	213
1989	4,809.52	4,479	4,380	910	3.97	229
1990	19,745.79	18,263	17,860	3,860	3.97	972
1994	374,860.00	334,907	327,520	84,826	3.97	21,367
1995	898,373.89	793,316	775,817	212,394	3.98	53,365
1997	461,947.14	397,387	388,621	119,520	3.98	30,030
1998	30,461.69	25,795	25,226	8,282	3.98	2,081
1999	422,160.98	351,129	343,384	120,993	3.98	30,400
2000	10,597.60	8,633	8,443	3,215	3.98	808
2001	158,089.86	125,734	122,961	50,938	3.98	12,798
2003	1,136,972.61	848,242	829,531	421,139	3.99	105,549
2004	1,680,600.50	1,202,757	1,176,226	672,434	3.99	168,530
2005	655,927.88	445,770	435,937	285,584	3.99	71,575
2006	454,784.77	289,042	282,666	217,597	3.99	54,536
2007	856,228.46	497,646	486,669	455,182	3.99	114,081
2008	8,648.65	4,432	4,334	5,179	3.99	1,298
2009	627,450.00	265,214	259,364	430,831	3.99	107,978
2011	551,874.41	67,602	66,111	540,951	3.99	135,577
	13,993,285.78	11,354,128	11,103,677	4,288,937		1,082,465
TYRONE UNITS 1 AND 2						
FULLY ACCRUED						
NET SALVAGE PERCENT.. -10						
1947	235,381.40	258,920	258,920			
1949	56,616.00	62,278	62,278			
1951	17,049.98	18,755	18,755			
1952	16,151.00	17,766	17,766			
1955	1,738.90	1,913	1,913			
1956	21,029.61	23,133	23,133			
1973	32,257.44	35,483	35,483			
1974	3,680.00	4,048	4,048			
1979	31,164.93	34,281	34,281			
1980	76.00	84	84			
1986	6,754.70	7,430	7,430			
	421,899.96	464,091	464,090			

KENTUCKY UTILITIES COMPANY

ACCOUNT 312 BOILER PLANT EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2011

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
GREEN RIVER UNIT 3						
INTERIM SURVIVOR CURVE.. IOWA 60-R2.5						
PROBABLE RETIREMENT YEAR.. 12-2015						
NET SALVAGE PERCENT.. -10						
1954	2,990,762.32	3,058,300	2,854,810	435,029	3.73	116,630
1963	10,025.06	10,138	9,463	1,564	3.84	407
1965	4,798.72	4,837	4,515	763	3.86	198
1967	13,837.13	13,904	12,979	2,242	3.87	579
1968	10,632.95	10,664	9,954	1,742	3.88	449
1971	26,302.52	26,224	24,479	4,454	3.90	1,142
1973	1,456,912.57	1,446,110	1,349,890	252,714	3.91	64,633
1974	2,261.00	2,238	2,089	398	3.92	102
1975	277,956.09	274,522	256,256	49,496	3.92	12,627
1977	23,310.00	22,895	21,372	4,269	3.93	1,086
1978	1,847,218.00	1,809,077	1,688,706	343,233	3.93	87,337
1979	5,130.00	5,007	4,674	969	3.94	246
1980	27,370.00	26,626	24,854	5,253	3.94	1,333
1983	13,605.63	13,083	12,212	2,754	3.95	697
1984	232,275.09	222,412	207,613	47,889	3.95	12,124
1985	2,477.00	2,360	2,203	522	3.96	132
1987	4,435.78	4,183	3,905	975	3.96	246
1988	64,601.22	60,565	56,535	14,526	3.96	3,668
1989	52,783.80	49,155	45,884	12,178	3.97	3,068
1996	459,698.40	400,954	374,276	131,393	3.98	33,013
1997	92,149.00	79,271	73,997	27,367	3.98	6,876
1998	53,012.53	44,891	41,904	16,410	3.98	4,123
1999	204,868.00	170,398	159,060	66,295	3.98	16,657
2000	404,352.84	329,388	307,472	137,317	3.98	34,502
2001	317,395.51	252,435	235,639	113,496	3.98	28,517
2003	586,965.39	437,907	408,770	236,892	3.99	59,371
2004	1,660,104.16	1,188,088	1,109,036	717,078	3.99	179,719
2005	144,268.17	98,045	91,521	67,174	3.99	16,836
2007	135,499.20	78,753	73,513	75,536	3.99	18,931
2009	427,063.95	180,514	168,503	301,267	3.99	75,506
2010	130,846.99	39,135	36,531	107,401	3.99	26,918
2011	462,851.42	56,697	52,925	456,212	3.99	114,339
	12,145,770.44	10,418,776	9,725,542	3,634,805		922,012

KENTUCKY UTILITIES COMPANY

ACCOUNT 312 BOILER PLANT EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2011

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
GREEN RIVER UNIT 4						
INTERIM SURVIVOR CURVE.. IOWA 60-R2.5						
PROBABLE RETIREMENT YEAR.. 12-2015						
NET SALVAGE PERCENT.. -10						
1950	51,965.10	53,349	51,521	5,641	3.66	1,541
1958	30,292.00	30,834	29,777	3,544	3.79	935
1959	3,824,570.39	3,888,429	3,755,156	451,872	3.80	118,914
1960	1,828.00	1,856	1,792	218	3.81	57
1965	2,861.44	2,885	2,786	361	3.86	94
1967	352.56	354	342	46	3.87	12
1968	419.45	421	407	55	3.88	14
1970	185,323.48	185,170	178,823	25,032	3.89	6,435
1971	10,994.00	10,961	10,585	1,508	3.90	387
1972	12,582.00	12,515	12,086	1,754	3.91	449
1973	42.00	42	41	6	3.91	2
1974	11,163.17	11,052	10,673	1,606	3.92	410
1975	2,883,529.46	2,847,906	2,750,296	421,586	3.92	107,547
1977	1,272.00	1,249	1,206	193	3.93	49
1979	4,376.00	4,271	4,125	689	3.94	175
1980	160,968.00	156,594	151,227	25,838	3.94	6,558
1981	108,828.00	105,500	101,884	17,827	3.94	4,525
1982	388,318.00	374,914	362,064	65,086	3.95	16,477
1983	13,560.36	13,040	12,593	2,323	3.95	588
1984	715.73	685	662	126	3.95	32
1985	1,238.00	1,179	1,139	223	3.96	56
1986	299,204.00	283,666	273,944	55,181	3.96	13,935
1987	402,292.00	379,351	366,349	76,172	3.96	19,235
1988	406,724.00	381,311	368,242	79,155	3.96	19,989
1989	601.00	560	541	120	3.97	30
1991	16,932.46	15,545	15,012	3,613	3.97	910
1994	1,094,554.00	977,896	944,379	259,630	3.97	65,398
1995	4,752,884.00	4,197,072	4,053,220	1,174,952	3.98	295,214
1996	885,029.04	771,933	745,476	228,056	3.98	57,301
1997	273,588.62	235,353	227,286	73,661	3.98	18,508
1998	630,490.98	533,894	515,595	177,945	3.98	44,710
1999	299,526.11	249,129	240,590	88,888	3.98	22,334
2000	312,825.00	254,829	246,095	98,013	3.98	24,626
2001	282,516.00	224,694	216,993	93,775	3.98	23,562
2002	301,313.00	232,926	224,943	106,502	3.98	26,759
2003	862,351.24	643,360	621,309	327,277	3.99	82,024
2004	901,938.63	645,491	623,367	368,765	3.99	92,422
2005	3,599,163.11	2,445,998	2,362,163	1,596,916	3.99	400,230
2007	626,957.26	364,392	351,903	337,750	3.99	84,649
2008	30,277.36	15,516	14,984	18,321	3.99	4,592

KENTUCKY UTILITIES COMPANY

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RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2011

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
GREEN RIVER UNIT 4						
INTERIM SURVIVOR CURVE.. IOWA 60-R2.5						
PROBABLE RETIREMENT YEAR.. 12-2015						
NET SALVAGE PERCENT.. -10						
2009	327,799.66	138,556	133,807	226,773	3.99	56,835
2010	24,105.85	7,210	6,963	19,554	3.99	4,901
2011	1,139,641.78	139,602	134,817	1,118,789	3.99	280,398
	25,165,914.24	20,841,490	20,127,163	7,555,343		1,903,819
GREEN RIVER UNITS 1 AND 2						
FULLY ACCRUED						
NET SALVAGE PERCENT.. -10						
1948	254.00	279	279			
1950	30,416.47	33,458	33,458			
1953	2,440.00	2,684	2,684			
1969	9,437.83	10,382	10,382			
1970	65.48	72	72			
1971	819.30	901	901			
1972	5,264.00	5,790	5,790			
1973	640.00	704	704			
1974	28,432.00	31,275	31,275			
1975	86,592.00	95,251	95,251			
1977	91,811.76	100,993	100,993			
1978	4,567.00	5,024	5,024			
1979	65,766.00	72,343	72,343			
2000	22,792.04	25,071	25,072			
	349,297.88	384,227	384,228			
BROWN UNIT 1						
INTERIM SURVIVOR CURVE.. IOWA 60-R2.5						
PROBABLE RETIREMENT YEAR.. 6-2028						
NET SALVAGE PERCENT.. -11						
1950	38,574.00	34,884	41,285	1,532	10.85	141
1956	4,010,892.16	3,510,740	4,154,930	297,160	12.09	24,579
1957	539,284.24	469,391	555,520	43,085	12.28	3,509
1959	13,000.91	11,182	13,234	1,197	12.66	95
1965	11,524.63	9,538	11,288	1,504	13.67	110
1966	34.45	28	33	5	13.81	
1968	1,948.40	1,579	1,869	294	14.09	21

KENTUCKY UTILITIES COMPANY

ACCOUNT 312 BOILER PLANT EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2011

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)

BROWN UNIT 1
INTERIM SURVIVOR CURVE.. IOWA 60-R2.5
PROBABLE RETIREMENT YEAR.. 6-2028
NET SALVAGE PERCENT.. -11

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
1973	1,606,912.52	1,252,620	1,482,465	301,208	14.66	20,546
1974	18,694.00	14,447	17,098	3,652	14.76	247
1975	441,330.00	338,069	400,102	89,775	14.85	6,045
1977	7,170.50	5,391	6,380	1,579	15.02	105
1978	1,881.00	1,400	1,657	431	15.10	29
1983	80,244.00	56,358	66,699	22,372	15.44	1,449
1984	4,372.00	3,029	3,585	1,268	15.50	82
1985	27,185.00	18,572	21,980	8,196	15.55	527
1987	70,883.58	46,945	55,559	23,122	15.65	1,477
1988	311,788.04	202,948	240,187	105,898	15.70	6,745
1989	12,314.44	7,871	9,315	4,354	15.74	277
1990	16,976.00	10,638	12,590	6,253	15.79	396
1991	11,405,119.81	6,997,007	8,280,897	4,378,786	15.83	276,613
1992	299,803.87	179,792	212,782	120,000	15.87	7,561
1993	9,299,115.00	5,443,316	6,442,117	3,879,900	15.90	244,019
1994	821,560.00	468,076	553,964	357,968	15.94	22,457
1995	5,085.27	2,814	3,330	2,314	15.97	145
1996	597,835.99	320,544	379,361	284,237	16.00	17,765
1997	269,896.00	139,720	165,357	134,227	16.03	8,373
1999	6,580.00	3,138	3,714	3,590	16.09	223
2001	1,316,699.00	566,871	670,887	790,649	16.13	49,017
2002	13,656.00	5,518	6,531	8,628	16.16	534
2003	649,730.56	244,328	289,160	432,041	16.18	26,702
2004	1,845,220.71	638,054	755,131	1,293,064	16.20	79,819
2005	556,841.17	174,098	206,043	412,050	16.22	25,404
2006	40,236.58	11,135	13,178	31,484	16.23	1,940
2007	421,857.31	99,955	118,296	349,966	16.25	21,536
2008	2,959,357.86	571,932	676,877	2,608,011	16.27	160,296
2009	1,903,167.53	277,310	328,194	1,784,322	16.28	109,602
2010	4,550,390.06	417,813	494,478	4,556,455	16.30	279,537
2011	1,125,326.50	36,437	43,123	1,205,990	16.31	73,942
	45,302,489.09	22,593,488	26,739,197	23,546,566		1,471,865

KENTUCKY UTILITIES COMPANY

ACCOUNT 312 BOILER PLANT EQUIPMENT

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RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2011

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
BROWN UNIT 2						
INTERIM SURVIVOR CURVE.. IOWA 60-R2.5						
PROBABLE RETIREMENT YEAR.. 6-2034						
NET SALVAGE PERCENT.. -11						
1963	5,388,387.12	4,261,122	5,223,190	757,920	16.36	46,328
1964	83,935.36	65,780	80,632	12,537	16.63	754
1965	2,758.00	2,141	2,624	437	16.90	26
1966	425.52	327	401	71	17.16	4
1975	2,774,819.23	1,939,877	2,377,859	702,191	19.12	36,725
1976	55,512.07	38,349	47,007	14,611	19.29	757
1977	1,845.00	1,258	1,542	506	19.46	26
1978	24,635.42	16,593	20,339	7,006	19.61	357
1980	82,061.00	53,764	65,903	25,185	19.91	1,265
1985	3,930.00	2,377	2,914	1,449	20.52	71
1988	137,644.00	78,515	96,242	56,543	20.82	2,716
1989	106,505.00	59,420	72,836	45,385	20.91	2,170
1990	28,392.45	15,471	18,964	12,552	21.00	598
1991	382,847.00	203,441	249,374	175,587	21.08	8,330
1992	195,307.00	101,038	123,850	92,941	21.16	4,392
1993	6,219,599.00	3,124,501	3,829,945	3,073,810	21.24	144,718
1994	5,904,082.47	2,874,510	3,523,512	3,030,020	21.31	142,188
1995	532,693.34	250,630	307,217	284,073	21.38	13,287
1996	99,208.00	45,008	55,170	54,951	21.44	2,563
1998	380.00	158	194	228	21.56	11
1999	1,985,695.00	788,216	966,178	1,237,944	21.61	57,286
2002	30,185.00	9,949	12,195	21,310	21.76	979
2003	463,003.97	140,803	172,593	341,341	21.81	15,651
2004	3,336,963.09	925,674	1,134,671	2,569,358	21.85	117,591
2005	160,833.32	39,995	49,025	129,500	21.89	5,916
2007	319,765.64	59,133	72,484	282,456	21.96	12,862
2008	38,247.48	5,697	6,983	35,471	22.00	1,612
2009	5,753,897.05	636,830	780,612	5,606,213	22.03	254,481
2010	2,079,002.78	144,162	176,711	2,130,982	22.06	96,599
2011	5,764,307.83	138,845	170,193	6,228,189	22.09	281,946
	41,956,868.14	16,023,584	19,641,359	26,930,765		1,252,209
BROWN UNIT 3						
INTERIM SURVIVOR CURVE.. IOWA 60-R2.5						
PROBABLE RETIREMENT YEAR.. 6-2035						
NET SALVAGE PERCENT.. -11						
1971	26,070,360.53	18,849,121	27,118,832	1,819,268	18.90	96,258
1972	234,636.81	167,736	241,327	19,120	19.13	999

KENTUCKY UTILITIES COMPANY

ACCOUNT 312 BOILER PLANT EQUIPMENT

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YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
BROWN UNIT 3						
INTERIM SURVIVOR CURVE.. IOWA 60-R2.5						
PROBABLE RETIREMENT YEAR.. 6-2035						
NET SALVAGE PERCENT.. -11						
1973	123,362.39	87,200	125,457	11,475	19.34	593
1974	23,028.00	16,086	23,143	2,418	19.55	124
1975	413.00	285	410	48	19.75	2
1976	8,346,832.00	5,688,144	8,183,714	1,081,269	19.94	54,226
1977	300,180.00	201,956	290,561	42,639	20.12	2,119
1980	328,422.00	211,886	304,847	59,701	20.62	2,895
1981	831.05	528	760	163	20.77	8
1982	1,751,913.00	1,096,087	1,576,975	367,648	20.91	17,582
1983	208,501.00	128,308	184,601	46,835	21.05	2,225
1984	589,701.00	356,681	513,168	141,400	21.18	6,676
1985	360,811.00	214,364	308,412	92,088	21.30	4,323
1986	6,308.00	3,676	5,289	1,713	21.42	80
1987	1,349,774.00	770,909	1,109,131	389,118	21.53	18,073
1988	828,402.00	463,349	666,635	252,891	21.63	11,692
1990	704,517.47	375,938	540,874	241,140	21.83	11,046
1991	101,362.69	52,725	75,857	36,655	21.92	1,672
1992	13,222,161.14	6,688,713	9,623,265	5,053,334	22.01	229,593
1993	2,427,215.00	1,192,430	1,715,587	978,622	22.09	44,302
1994	3,077,923.00	1,464,344	2,106,798	1,309,696	22.17	59,075
1995	812,553.93	373,275	537,043	364,892	22.25	16,400
1997	4,676,406.78	1,985,589	2,856,730	2,334,081	22.39	104,247
1998	154,555.00	62,728	90,249	81,307	22.45	3,622
1999	401,832.00	155,180	223,262	222,771	22.51	9,897
2000	127,001.94	46,390	66,743	74,229	22.57	3,289
2001	346,465.53	118,953	171,141	213,435	22.62	9,436
2002	114,407.29	36,562	52,603	74,389	22.68	3,280
2003	223,577.30	65,912	94,830	153,341	22.73	6,746
2004	2,878,793.02	773,333	1,112,619	2,082,841	22.77	91,473
2005	3,924,243.63	943,577	1,357,554	2,998,356	22.82	131,392
2006	3,187,982.93	671,107	965,543	2,573,118	22.86	112,560
2007	8,078,544.98	1,439,771	2,071,445	6,895,740	22.90	301,124
2008	20,895,093.68	3,001,478	4,318,322	18,875,232	22.94	822,809
2009	245,739.33	26,194	37,686	235,085	22.97	10,234
2010	32,607,222.62	2,174,175	3,128,055	33,065,962	23.00	1,437,651
2011	3,897,315.33	90,068	129,584	4,196,436	23.04	182,137
	142,628,390.37	49,994,758	71,929,055	86,388,458		3,809,860

KENTUCKY UTILITIES COMPANY

ACCOUNT 312 BOILER PLANT EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2011

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
BROWN UNITS 1, 2 AND 3 SCRUBBER						
INTERIM SURVIVOR CURVE.. IOWA 60-R2.5						
PROBABLE RETIREMENT YEAR.. 6-2035						
NET SALVAGE PERCENT.. -11						
2010	323,513,658.34	21,571,147	18,465,634	340,634,526	23.00	14,810,197
2011	211,440.34	4,886	4,183	230,516	23.04	10,005
	323,725,098.68	21,576,033	18,469,817	340,865,043		14,820,202
PINEVILLE UNIT 3						
FULLY ACCRUED						
NET SALVAGE PERCENT.. -10						
1951	5,844.00	6,428	6,428			
1963	7,129.00	7,842	7,842			
1970	1,082.00	1,190	1,190			
1975	8,772.00	9,649	9,649			
1976	20.00	22	22			
1977	50,119.00	55,131	55,131			
1978	43,726.00	48,099	48,099			
1979	8,108.00	8,919	8,919			
1988	1,821.00	2,003	2,003			
1995	31,090.00	34,199	34,199			
1997	6,678.00	7,346	7,346			
2000	10,484.00	11,532	11,532			
2002	51,958.50	57,154	57,154			
2011	9,638.92	10,603	10,602			
	236,470.42	260,117	260,117			
GHENT UNIT 1 SCRUBBER						
INTERIM SURVIVOR CURVE.. IOWA 60-R2.5						
PROBABLE RETIREMENT YEAR.. 6-2034						
NET SALVAGE PERCENT.. -12						
1997	26,982,945.29	11,861,098	16,241,761	13,979,138	21.50	650,192
2009	116,448,621.38	13,004,423	17,807,351	112,615,105	22.03	5,111,898
2010	12,043.79	843	1,154	12,335	22.06	559
2011	759,148.82	18,450	25,264	824,983	22.09	37,346
	144,202,759.28	24,884,814	34,075,530	127,431,560		5,799,995

KENTUCKY UTILITIES COMPANY

ACCOUNT 312 BOILER PLANT EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2011

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)

GHENT UNIT 1
INTERIM SURVIVOR CURVE.. IOWA 60-R2.5
PROBABLE RETIREMENT YEAR.. 6-2034
NET SALVAGE PERCENT.. -12

1958	50,033.00	41,703	53,243	2,794	14.88	188
1974	54,473,907.25	38,885,828	49,646,465	11,364,311	18.93	600,333
1977	43,377.82	29,854	38,115	10,468	19.46	538
1979	153,844.00	103,159	131,706	40,600	19.76	2,055
1980	510,429.85	337,429	430,804	140,878	19.91	7,076
1981	6,294.00	4,101	5,236	1,813	20.04	90
1982	40,874.00	26,233	33,492	12,287	20.17	609
1983	33,169.00	20,953	26,751	10,398	20.29	512
1984	705.60	438	559	231	20.41	11
1985	3,913.34	2,389	3,050	1,333	20.52	65
1986	20,989.71	12,573	16,052	7,456	20.63	361
1987	292,500.00	171,839	219,391	108,209	20.73	5,220
1989	84,769.00	47,719	60,924	34,017	20.91	1,627
1990	63,912.00	35,140	44,864	26,717	21.00	1,272
1991	310,440.00	166,451	212,512	135,181	21.08	6,413
1992	354,903.01	185,255	236,519	160,972	21.16	7,607
1993	90,815.89	46,034	58,773	42,941	21.24	2,022
1994	610,532.00	299,927	382,924	300,872	21.31	14,119
1995	12,801,838.00	6,077,473	7,759,255	6,578,804	21.38	307,708
1996	1,281,280.85	586,513	748,815	686,219	21.44	32,006
1998	134,109.00	56,390	71,994	78,208	21.56	3,627
1999	278,194.00	111,423	142,256	169,321	21.61	7,835
2000	37,620.04	14,255	18,200	23,935	21.67	1,105
2001	5,651,052.55	2,012,995	2,570,039	3,759,140	21.72	173,073
2002	3,272,250.00	1,088,225	1,389,363	2,275,557	21.76	104,575
2003	1,573,602.15	482,854	616,471	1,145,963	21.81	52,543
2004	67,071,072.66	18,773,140	23,968,116	51,151,485	21.85	2,341,029
2005	6,533,312.05	1,639,297	2,092,930	5,224,380	21.89	238,665
2006	2,661,176.28	584,509	746,257	2,234,261	21.93	101,881
2007	1,359,443.47	253,661	323,855	1,198,722	21.96	54,587
2008	993,616.17	149,344	190,671	922,179	22.00	41,917
2009	27,951,251.25	3,121,462	3,985,245	27,320,156	22.03	1,240,134
2010	4,527,773.73	316,792	404,456	4,666,651	22.06	211,544
2011	5,512,053.79	133,965	171,036	6,002,464	22.09	271,728
	198,785,055.46	75,819,323	96,800,340	125,838,922		5,834,075

KENTUCKY UTILITIES COMPANY

ACCOUNT 312 BOILER PLANT EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2011

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)

GHENT UNIT 2
INTERIM SURVIVOR CURVE.. IOWA 60-R2.5
PROBABLE RETIREMENT YEAR.. 6-2034
NET SALVAGE PERCENT.. -12

1977	69,329,511.89	47,715,343	62,420,776	15,228,277	19.46	782,542
1978	378,364.00	257,134	336,380	87,387	19.61	4,456
1979	182,288.33	122,232	159,903	44,260	19.76	2,240
1980	41,332.94	27,324	35,745	10,548	19.91	530
1981	6,292.00	4,100	5,364	1,683	20.04	84
1982	74,950.00	48,102	62,927	21,017	20.17	1,042
1986	656,789.60	393,431	514,683	220,922	20.63	10,709
1987	847,364.00	497,813	651,234	297,813	20.73	14,366
1988	440,286.00	253,410	331,509	161,612	20.82	7,762
1989	264,599.00	148,952	194,858	101,493	20.91	4,854
1990	3,078.00	1,692	2,213	1,234	21.00	59
1991	159,055.00	85,282	111,565	66,576	21.08	3,158
1992	18,208.00	9,504	12,433	7,960	21.16	376
1994	855,071.08	420,057	549,515	408,165	21.31	19,154
1995	192,226.00	91,256	119,380	95,913	21.38	4,486
1996	1,756,502.00	804,048	1,051,848	915,434	21.44	42,697
1997	1,696,598.00	745,786	975,630	924,559	21.50	43,003
1998	31,096.00	13,075	17,105	17,723	21.56	822
1999	1,074,948.00	430,542	563,231	640,711	21.61	29,649
2000	89,346.07	33,855	44,289	55,779	21.67	2,574
2001	406,215.00	144,700	189,295	265,666	21.72	12,231
2002	5,238,048.00	1,741,974	2,278,834	3,587,779	21.76	164,880
2003	656,597.59	201,475	263,568	471,822	21.81	21,633
2004	176,216.58	49,323	64,524	132,839	21.85	6,080
2005	3,192,760.34	801,107	1,048,001	2,527,891	21.89	115,482
2006	425,029.96	93,355	122,126	353,907	21.93	16,138
2007	384,330.33	71,713	93,814	336,636	21.96	15,330
2008	179,568.29	26,990	35,308	165,808	22.00	7,537
2009	3,599,909.95	402,021	525,920	3,505,979	22.03	159,146
2010	5,195,747.63	363,528	475,564	5,343,673	22.06	242,234
2011	894,356.77	21,736	28,435	973,245	22.09	44,058
	98,446,686.35	56,020,860	73,285,978	36,974,311		1,779,312

KENTUCKY UTILITIES COMPANY

ACCOUNT 312 BOILER PLANT EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2011

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)

GHENT UNIT 3
INTERIM SURVIVOR CURVE.. IOWA 60-R2.5
PROBABLE RETIREMENT YEAR.. 6-2037
NET SALVAGE PERCENT.. -12

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
1981	137,056,787.17	85,262,040	105,216,850	48,286,751	22.17	2,178,022
1982	4,323,370.79	2,645,280	3,264,384	1,577,791	22.34	70,626
1983	175,918.00	105,792	130,552	66,476	22.50	2,954
1984	9,724,031.69	5,740,928	7,084,540	3,806,375	22.66	167,978
1985	13,041.58	7,554	9,322	5,285	22.81	232
1986	5,003.81	2,841	3,506	2,098	22.95	91
1987	1,523,545.00	846,667	1,044,822	661,549	23.09	28,651
1989	51,742.00	27,453	33,878	24,073	23.34	1,031
1990	148,350.00	76,789	94,761	71,391	23.45	3,044
1994	194,871.00	89,428	110,358	107,898	23.87	4,520
1995	694,601.50	307,611	379,605	398,349	23.96	16,626
1996	328,272.00	139,768	172,479	195,185	24.05	8,116
1997	1,620,817.00	661,374	816,163	999,152	24.13	41,407
1998	206,918.25	80,560	99,414	132,334	24.21	5,466
1999	5,607,517.20	2,074,988	2,560,620	3,719,799	24.28	153,204
2000	72,921.99	25,478	31,441	50,232	24.35	2,063
2002	602,894.00	183,861	226,892	448,349	24.48	18,315
2003	855,281.04	240,140	296,343	661,572	24.54	26,959
2004	71,794,178.90	18,303,610	22,587,405	57,822,076	24.60	2,350,491
2005	3,708,105.24	845,359	1,043,208	3,109,870	24.65	126,161
2006	1,083,127.40	215,241	265,616	947,486	24.71	38,344
2007	170,859.09	28,773	35,507	155,855	24.75	6,297
2008	34,203.02	4,631	5,715	32,593	24.80	1,314
2009	5,797,862.51	580,788	716,716	5,776,890	24.84	232,564
2010	3,722,211.44	232,582	287,016	3,881,861	24.88	156,023
2011	5,451,478.10	117,717	145,268	5,960,388	24.92	239,181
	254,967,909.72	118,847,253	146,662,379	138,901,680		5,879,680

GHENT UNIT 4
INTERIM SURVIVOR CURVE.. IOWA 60-R2.5
PROBABLE RETIREMENT YEAR.. 6-2038
NET SALVAGE PERCENT.. -12

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
1984	135,496,466.65	78,735,588	90,134,658	61,621,385	23.38	2,635,645
1986	209,125.43	116,764	133,669	100,552	23.69	4,244
1987	110,311.00	60,261	68,985	54,563	23.84	2,289
1989	864,078.80	450,196	515,374	452,394	24.12	18,756
1990	204,757.59	103,987	119,042	110,287	24.24	4,550
1991	11,877.00	5,867	6,716	6,586	24.37	270

KENTUCKY UTILITIES COMPANY

ACCOUNT 312 BOILER PLANT EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2011

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
GHENT UNIT 4						
INTERIM SURVIVOR CURVE.. IOWA 60-R2.5						
PROBABLE RETIREMENT YEAR.. 6-2038						
NET SALVAGE PERCENT.. -12						
1992	91,017.00	43,675	49,998	51,941	24.48	2,122
1994	16,651,916.58	7,482,625	8,565,934	10,084,213	24.70	408,268
1995	1,910,485.07	827,546	947,355	1,192,388	24.80	48,080
1996	704,727.26	293,570	336,072	453,222	24.89	18,209
1998	7,924.00	3,014	3,450	5,425	25.07	216
1999	1,429,371.01	515,953	590,651	1,010,245	25.15	40,169
2000	42,052.00	14,327	16,401	30,697	25.23	1,217
2001	4,451,681.00	1,421,525	1,627,329	3,358,554	25.30	132,749
2002	847,060.39	251,464	287,870	660,838	25.37	26,048
2003	2,855,608.90	779,613	892,483	2,305,799	25.44	90,637
2004	73,634,035.49	18,256,410	20,899,511	61,570,609	25.50	2,414,534
2005	4,371,863.33	967,007	1,107,007	3,789,480	25.56	148,258
2006	261,303.51	50,399	57,696	234,964	25.62	9,171
2007	728,088.85	118,625	135,799	679,660	25.67	26,477
2008	3,702,137.61	485,377	555,648	3,590,746	25.72	139,609
2009	9,060,341.84	877,664	1,004,729	9,142,854	25.77	354,787
2010	3,606,578.99	216,187	247,486	3,791,883	25.82	146,858
2011	6,603,470.88	137,564	157,480	7,238,407	25.86	279,907
	267,856,280.18	112,215,208	128,461,343	171,537,691		6,953,070
GHENT UNIT 2 SCRUBBER						
INTERIM SURVIVOR CURVE.. IOWA 60-R2.5						
PROBABLE RETIREMENT YEAR.. 6-2034						
NET SALVAGE PERCENT.. -12						
1994	57,855,387.65	28,421,714	47,867,712	16,930,322	21.31	794,478
2001	77,437.91	27,585	46,459	40,272	21.72	1,854
2002	491,092.43	163,318	275,059	274,964	21.76	12,636
2003	362,399.56	111,201	187,284	218,603	21.81	10,023
2004	556,738.99	155,831	262,450	361,098	21.85	16,526
2006	13,411.72	2,946	4,962	10,059	21.93	459
2009	33,922,043.02	3,788,251	6,380,154	31,612,534	22.03	1,434,977
	93,278,511.28	32,670,846	55,024,079	49,447,854		2,270,953

KENTUCKY UTILITIES COMPANY

ACCOUNT 312 BOILER PLANT EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2011

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
GHENT 3 SCRUBBER						
INTERIM SURVIVOR CURVE.. IOWA 60-R2.5						
PROBABLE RETIREMENT YEAR.. 6-2037						
NET SALVAGE PERCENT.. -12						
2007	118,449,945.46	19,947,350	24,643,581	108,020,358	24.75	4,364,459
2011	9,539,003.55	205,981	254,475	10,429,209	24.92	418,508
	127,988,949.01	20,153,331	24,898,056	118,449,567		4,782,967
GHENT 4 SCRUBBER						
INTERIM SURVIVOR CURVE.. IOWA 60-R2.5						
PROBABLE RETIREMENT YEAR.. 6-2038						
NET SALVAGE PERCENT.. -12						
2008	306,636,060.07	40,202,195	41,261,900	302,170,487	25.72	11,748,464
2011	464,298.43	9,672	9,927	510,087	25.86	19,725
	307,100,358.50	40,211,867	41,271,827	302,680,575		11,768,189
	2,674,446,282.96	657,125,211	834,637,320	2,171,436,966		82,825,217

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 26.2   3.10

KENTUCKY UTILITIES COMPANY

ACCOUNT 314 TURBOGENERATOR UNITS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2011

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
TRIMBLE COUNTY UNIT 2						
INTERIM SURVIVOR CURVE.. IOWA 55-S1.5						
PROBABLE RETIREMENT YEAR.. 6-2066						
NET SALVAGE PERCENT.. -15						
1990	10,495,573.59	4,475,281	9,181,764	2,888,146	33.77	85,524
2008	10,044,788.71	828,705	1,700,223	9,851,284	45.03	218,772
2011	63,454,370.46	774,968	1,589,972	71,382,554	46.60	1,531,814
	83,994,732.76	6,078,954	12,471,959	84,121,984		1,836,110
TYRONE UNIT 3						
INTERIM SURVIVOR CURVE.. IOWA 55-S1.5						
PROBABLE RETIREMENT YEAR.. 12-2015						
NET SALVAGE PERCENT.. -10						
1953	2,061,828.24	2,103,059	2,048,217	219,794	3.66	60,053
1997	302,944.98	261,080	254,272	78,968	3.98	19,841
1998	68,053.80	57,736	56,230	18,629	3.98	4,681
2004	709,334.00	509,078	495,803	284,465	3.99	71,294
2005	853,434.49	581,704	566,535	372,243	3.99	93,294
2006	76,446.76	48,736	47,465	36,626	3.99	9,179
2008	625,779.05	321,236	312,859	375,498	4.00	93,874
2009	107,692.34	45,563	44,375	74,087	4.00	18,522
	4,805,513.66	3,928,192	3,825,756	1,460,309		370,738
TYRONE UNITS 1 AND 2						
FULLY ACCRUED						
NET SALVAGE PERCENT.. -10						
1948	68,205.72	75,026	75,026			
	68,205.72	75,026	75,026			
GREEN RIVER UNIT 3						
INTERIM SURVIVOR CURVE.. IOWA 55-S1.5						
PROBABLE RETIREMENT YEAR.. 12-2015						
NET SALVAGE PERCENT.. -10						
1954	2,266,904.39	2,310,390	2,391,100	102,495	3.67	27,928
1959	1,852.62	1,879	1,945	93	3.72	25
1965	3,720.95	3,747	3,878	215	3.78	57
1970	889.30	888	919	59	3.82	15

KENTUCKY UTILITIES COMPANY

ACCOUNT 314 TURBOGENERATOR UNITS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2011

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
GREEN RIVER UNIT 3						
INTERIM SURVIVOR CURVE.. IOWA 55-S1.5						
PROBABLE RETIREMENT YEAR.. 12-2015						
NET SALVAGE PERCENT.. -10						
1984	105,301.67	100,950	104,477	11,355	3.92	2,897
1985	40,515.91	38,671	40,022	4,546	3.92	1,160
2003	1,104,882.74	826,489	855,361	360,010	3.99	90,228
2004	654,431.78	469,675	486,082	233,793	3.99	58,595
2007	196,787.96	114,481	118,480	97,987	4.00	24,497
2008	94,607.82	48,566	50,263	53,806	4.00	13,452
2011	92,298.37	11,281	11,675	89,853	4.00	22,463
	4,562,193.51	3,927,017	4,064,201	954,212		241,317
GREEN RIVER UNIT 4						
INTERIM SURVIVOR CURVE.. IOWA 55-S1.5						
PROBABLE RETIREMENT YEAR.. 12-2015						
NET SALVAGE PERCENT.. -10						
1959	2,724,813.71	2,764,165	2,997,295			
1960	656.00	665	722			
1961	6,866.47	6,950	7,553			
1972	107.97	107	117	1	3.84	
1982	7,573.80	7,321	8,027	304	3.91	78
1985	18,281.63	17,449	19,132	978	3.92	249
1995	277,398.34	245,493	269,175	35,963	3.97	9,059
1996	176,069.37	153,940	168,790	24,886	3.97	6,269
1997	4,482,276.28	3,862,853	4,235,493	695,011	3.98	174,626
2001	71,476.94	56,915	62,405	16,219	3.99	4,065
2003	138,757.24	103,795	113,808	38,825	3.99	9,731
2004	1,571,425.58	1,127,787	1,236,582	491,986	3.99	123,305
2005	330,807.10	225,479	247,230	116,657	3.99	29,237
2007	200,401.08	116,583	127,829	92,612	4.00	23,153
2011	383,574.39	46,881	51,403	370,528	4.00	92,632
	10,390,485.90	8,736,383	9,545,563	1,883,971		472,404

KENTUCKY UTILITIES COMPANY

ACCOUNT 314 TURBOGENERATOR UNITS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2011

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
BROWN UNIT 1						
INTERIM SURVIVOR CURVE.. IOWA 55-S1.5						
PROBABLE RETIREMENT YEAR.. 6-2028						
NET SALVAGE PERCENT.. -11						
1956	3,851,384.46	3,350,945	4,097,440	177,597	11.45	15,511
1959	14,882.13	12,772	15,617	902	11.86	76
1968	5,774.91	4,719	5,770	640	13.02	49
1985	11,462.31	7,965	9,739	2,984	14.87	201
1996	32,671.87	17,799	21,764	14,502	15.76	920
1997	17,942.90	9,438	11,541	8,376	15.82	529
2001	103,385.99	45,148	55,206	59,553	16.05	3,710
2004	366,604.92	128,476	157,097	249,835	16.19	15,431
2008	1,122,467.16	219,908	268,897	977,041	16.33	59,831
2009	487,229.00	71,692	87,663	453,161	16.36	27,699
2010	1,398,075.10	130,124	159,112	1,392,751	16.39	84,976
2011	100,944.20	3,313	4,051	107,997	16.41	6,581
	7,512,824.95	4,002,299	4,893,897	3,445,339		215,514
BROWN UNIT 2						
INTERIM SURVIVOR CURVE.. IOWA 55-S1.5						
PROBABLE RETIREMENT YEAR.. 6-2034						
NET SALVAGE PERCENT.. -11						
1963	4,113,866.06	3,272,230	4,566,391			
1965	26,462.00	20,739	29,373			
1985	8,768.76	5,465	9,008	725	19.19	38
1990	23,666.17	13,287	21,901	4,368	20.00	218
1994	1,497,407.00	750,232	1,236,631	425,491	20.59	20,665
1995	586,145.48	283,795	467,788	182,833	20.72	8,824
1996	32,822.53	15,304	25,226	11,207	20.86	537
1997	33,091.00	14,814	24,418	12,313	20.98	587
2002	1,508,264.00	509,016	839,027	835,146	21.54	38,772
2003	642,140.83	199,827	329,381	383,395	21.64	17,717
2004	1,221,923.10	346,286	570,794	785,541	21.73	36,150
2005	149,968.42	38,084	62,775	103,690	21.81	4,754
2006	632,295.16	140,524	231,630	470,218	21.89	21,481
2007	2,547.40	480	791	2,036	21.97	93
2009	927,175.48	104,594	172,406	856,759	22.10	38,767
2010	840,714.12	59,164	97,522	835,671	22.16	37,711
2011	52,464.36	1,282	2,113	56,122	22.21	2,527
	12,299,721.87	5,775,123	8,687,176	4,965,515		228,841

KENTUCKY UTILITIES COMPANY

ACCOUNT 314 TURBOGENERATOR UNITS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2011

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
BROWN UNIT 3						
INTERIM SURVIVOR CURVE.. IOWA 55-S1.5						
PROBABLE RETIREMENT YEAR.. 6-2035						
NET SALVAGE PERCENT.. -11						
1971	9,582,982.33	7,073,998	10,465,668	171,442	17.03	10,067
1972	28,526.97	20,849	30,845	820	17.25	48
1973	2,376.00	1,719	2,543	94	17.46	5
1984	13,467.21	8,411	12,444	2,505	19.66	127
1993	6,448.62	3,268	4,835	2,323	21.21	110
1994	191,259.00	93,812	138,791	73,507	21.37	3,440
1995	421,519.00	199,722	295,480	172,406	21.51	8,015
1997	10,588,236.43	4,629,954	6,849,813	4,903,129	21.80	224,914
1998	297,088.00	124,085	183,578	146,189	21.93	6,666
1999	68,653.00	27,251	40,317	35,888	22.06	1,627
2003	120,057.33	36,297	53,700	79,564	22.52	3,533
2004	72,895.42	20,047	29,659	51,255	22.62	2,266
2005	4,204,448.97	1,034,800	1,530,941	3,135,997	22.71	138,089
2006	1,419,771.42	305,387	451,807	1,124,140	22.80	49,304
2008	781,074.49	114,686	169,673	697,320	22.96	30,371
2009	810,823.83	88,129	130,383	769,631	23.03	33,419
2011	683,770.14	16,037	23,726	735,259	23.16	31,747
	29,293,398.16	13,798,452	20,414,202	12,101,470		543,748
GHENT UNIT 1						
INTERIM SURVIVOR CURVE.. IOWA 55-S1.5						
PROBABLE RETIREMENT YEAR.. 6-2034						
NET SALVAGE PERCENT.. -12						
1974	14,275,013.95	10,426,584	13,985,871	2,002,144	17.17	116,607
1975	131,096.54	94,726	127,062	19,766	17.37	1,138
1976	156.00	111	149	26	17.56	1
1979	21,978.00	15,146	20,316	4,299	18.12	237
1980	3,163.50	2,151	2,885	658	18.31	36
1985	156,856.25	98,638	132,310	43,369	19.19	2,260
1989	252,974.07	146,692	196,768	86,563	19.85	4,361
1992	58,228.11	31,296	41,979	23,236	20.30	1,145
1994	1,999,544.00	1,010,838	1,355,904	883,585	20.59	42,913
1996	32,637.46	15,355	20,597	15,957	20.86	765
2001	424,030.20	154,822	207,673	267,241	21.44	12,465
2002	162,462.00	55,322	74,207	107,750	21.54	5,002
2003	1,189,488.62	373,490	500,987	831,240	21.64	38,412
2004	1,385,035.03	396,047	531,244	1,019,995	21.73	46,939
2006	1,501,464.76	336,698	451,635	1,230,005	21.89	56,190

KENTUCKY UTILITIES COMPANY

ACCOUNT 314 TURBOGENERATOR UNITS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2011

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
GHENT UNIT 1						
INTERIM SURVIVOR CURVE.. IOWA 55-S1.5						
PROBABLE RETIREMENT YEAR.. 6-2034						
NET SALVAGE PERCENT.. -12						
2008	11,574,683.26	1,772,130	2,377,076	10,586,569	22.04	480,334
2009	426,823.12	48,583	65,168	412,874	22.10	18,682
2011	3,091,686.53	76,248	102,277	3,360,412	22.21	151,302
	36,687,321.40	15,054,877	20,194,109	20,895,691		978,789
GHENT UNIT 2						
INTERIM SURVIVOR CURVE.. IOWA 55-S1.5						
PROBABLE RETIREMENT YEAR.. 6-2034						
NET SALVAGE PERCENT.. -12						
1977	17,745,350.62	12,534,436	14,348,671	5,526,122	17.75	311,331
1978	4,313,274.00	3,009,775	3,445,410	1,385,457	17.94	77,227
1979	20,087.00	13,842	15,845	6,652	18.12	367
1980	2,264.00	1,539	1,762	774	18.31	42
1981	899.00	603	690	317	18.49	17
1985	156,856.24	98,638	112,915	62,764	19.19	3,271
1993	21,038.91	10,979	12,568	10,995	20.45	538
1996	2,981,619.63	1,402,788	1,605,828	1,733,586	20.86	83,106
1997	33,889.20	15,308	17,524	20,432	20.98	974
1998	64,136.87	27,696	31,705	40,129	21.10	1,902
1999	678,802.78	278,833	319,191	441,068	21.22	20,785
2002	137,999.16	46,992	53,794	100,765	21.54	4,678
2004	1,138,929.53	325,674	372,812	902,789	21.73	41,546
2005	458,645.99	117,521	134,531	379,153	21.81	17,384
2006	172,946.00	38,783	44,396	149,303	21.89	6,821
2009	2,231,560.67	254,009	290,774	2,208,574	22.10	99,935
2011	259,292.19	6,395	7,321	283,087	22.21	12,746
	30,417,591.79	18,183,811	20,815,737	13,251,966		682,670
GHENT UNIT 3						
INTERIM SURVIVOR CURVE.. IOWA 55-S1.5						
PROBABLE RETIREMENT YEAR.. 6-2037						
NET SALVAGE PERCENT.. -12						
1981	24,315,015.75	15,667,857	19,342,010	7,890,808	20.21	390,441
1982	480,015.00	304,420	375,807	161,810	20.43	7,920
1983	29,912.17	18,653	23,027	10,474	20.65	507

KENTUCKY UTILITIES COMPANY

ACCOUNT 314 TURBOGENERATOR UNITS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2011

GHENT UNIT 3
INTERIM SURVIVOR CURVE.. IOWA 55-S1.5
PROBABLE RETIREMENT YEAR.. 6-2037
NET SALVAGE PERCENT.. -12

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
1984	7,192,035.00	4,405,323	5,438,383	2,616,697	20.87	125,381
1985	156,856.24	94,268	116,374	59,305	21.09	2,812
1987	44,239.03	25,522	31,507	18,041	21.51	839
1995	2,427,276.25	1,113,735	1,374,909	1,343,641	23.04	58,318
1996	2,264.00	999	1,233	1,302	23.21	56
1999	60,118.00	22,987	28,378	38,955	23.69	1,644
2003	834,201.70	241,079	297,613	636,693	24.24	26,266
2004	943,602.66	247,183	305,148	751,687	24.37	30,845
2005	619,008.50	144,932	178,919	514,371	24.48	21,012
2006	365,407.85	74,583	92,073	317,184	24.59	12,899
2007	1,228,187.47	211,659	261,294	1,114,276	24.69	45,131
2009	1,824,052.27	185,867	229,453	1,813,485	24.88	72,889
2011	2,073,364.91	45,468	56,130	2,266,038	25.03	90,533
	42,595,556.80	22,804,535	28,152,257	19,554,767		887,493

GHENT UNIT 4
INTERIM SURVIVOR CURVE.. IOWA 55-S1.5
PROBABLE RETIREMENT YEAR.. 6-2038
NET SALVAGE PERCENT.. -12

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
1984	42,504,232.78	25,687,518	28,920,095	18,684,646	21.45	871,079
1985	236,810.00	140,387	158,054	107,174	21.68	4,943
1986	51,406.00	29,857	33,614	23,960	21.91	1,094
1987	65,193.00	37,069	41,734	31,282	22.13	1,414
1989	118,897.45	64,483	72,598	60,567	22.57	2,684
1990	12,957.34	6,846	7,708	6,805	22.79	299
1991	21,490.58	11,044	12,434	11,636	23.00	506
1993	322,179.43	155,699	175,293	185,548	23.40	7,929
1994	321,113.00	149,919	168,785	190,861	23.60	8,087
1996	33,858.00	14,632	16,473	21,448	23.97	895
2000	676.00	238	268	489	24.65	20
2003	4,624,889.04	1,301,547	1,465,337	3,714,539	25.09	148,049
2004	106,038.93	27,083	30,491	88,272	25.22	3,500
2005	951,102.73	216,328	243,551	821,684	25.35	32,414
2006	1,380,479.45	273,759	308,209	1,237,928	25.47	48,603
2007	391,047.02	65,398	73,628	364,345	25.58	14,243

KENTUCKY UTILITIES COMPANY

ACCOUNT 314 TURBOGENERATOR UNITS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2011

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
GHENT UNIT 4						
INTERIM SURVIVOR CURVE.. IOWA 55-S1.5						
PROBABLE RETIREMENT YEAR.. 6-2038						
NET SALVAGE PERCENT.. -12						
2008	399,683.45	53,538	60,275	387,370	25.69	15,079
2009	1,462,218.47	144,771	162,989	1,474,695	25.78	57,203
2011	4,032,700.47	85,364	96,106	4,420,518	25.96	170,282
	57,036,973.14	28,465,480	32,047,642	31,833,768		1,388,323
	319,664,519.66	130,830,149	165,187,525	194,468,992		7,845,947

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 24.8   2.45

KENTUCKY UTILITIES COMPANY

ACCOUNT 315 ACCESSORY ELECTRIC EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2011

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
TRIMBLE COUNTY UNIT 2						
INTERIM SURVIVOR CURVE.. IOWA 70-S3						
PROBABLE RETIREMENT YEAR.. 6-2066						
NET SALVAGE PERCENT.. -15						
1990	9,289,133.74	3,491,470	4,504,684	6,177,820	44.22	139,706
2008	28,344.56	2,055	2,651	29,945	52.03	576
2010	41,233.91	1,317	1,699	45,720	52.50	871
2011	32,241,644.59	348,532	449,675	36,628,216	52.70	695,033
	41,600,356.80	3,843,374	4,958,709	42,881,701		836,186
TRIMBLE COUNTY UNIT 2 SCRUBBER						
INTERIM SURVIVOR CURVE.. IOWA 70-S3						
PROBABLE RETIREMENT YEAR.. 6-2066						
NET SALVAGE PERCENT.. -15						
1990	1,415,469.10	532,027	653,351	974,438	44.22	22,036
	1,415,469.10	532,027	653,351	974,438		22,036
TYRONE UNIT 3						
INTERIM SURVIVOR CURVE.. IOWA 70-S3						
PROBABLE RETIREMENT YEAR.. 12-2015						
NET SALVAGE PERCENT.. -10						
1950	173,168.32	178,667	119,693	70,792	3.76	18,828
1953	503,784.00	518,397	347,286	206,877	3.79	54,585
1954	80,904.85	83,169	55,717	33,279	3.80	8,758
1960	656.22	670	449	273	3.86	71
1984	31,304.89	30,068	20,143	14,292	3.99	3,582
1991	4,218.75	3,883	2,601	2,039	4.00	510
2001	8,908.46	7,096	4,754	5,046	4.00	1,262
2003	681,738.46	509,940	341,620	408,292	4.00	102,073
2007	280,368.30	163,273	109,380	199,025	4.00	49,756
2009	296,883.70	125,606	84,146	242,426	4.00	60,606
2011	19,756.76	2,415	1,618	20,115	4.00	5,029
	2,081,692.71	1,623,184	1,087,407	1,202,455		305,060

KENTUCKY UTILITIES COMPANY

ACCOUNT 315 ACCESSORY ELECTRIC EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2011

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
TYRONE UNITS 1 AND 2						
FULLY ACCRUED						
NET SALVAGE PERCENT.. -10						
1947	8,819.64	9,702	9,702			
1948	65,636.00	72,200	72,200			
1950	9,781.78	10,760	10,760			
1951	882.57	971	971			
1953	11,577.71	12,735	12,735			
1955	306.00	337	337			
1957	185.13	204	204			
1960	935.00	1,028	1,029			
1991	1,086.89	1,196	1,196			
	99,210.72	109,133	109,132			
GREEN RIVER UNIT 3						
INTERIM SURVIVOR CURVE.. IOWA 70-S3						
PROBABLE RETIREMENT YEAR.. 12-2015						
NET SALVAGE PERCENT.. -10						
1954	444,085.25	456,512	341,283	147,210	3.80	38,739
1955	2,318.00	2,380	1,779	771	3.81	202
1960	2,013.16	2,055	1,536	678	3.86	176
1972	905.20	904	676	320	3.95	81
1995	78,347.55	69,366	51,857	34,325	4.00	8,581
1996	107,389.55	93,897	70,196	47,932	4.00	11,983
2003	44,902.89	33,587	25,109	24,284	4.00	6,071
2007	40,561.24	23,621	17,659	26,959	4.00	6,740
2011	484,839.34	59,258	44,301	489,023	4.00	122,256
	1,205,362.18	741,580	554,397	771,501		194,829
GREEN RIVER UNIT 4						
INTERIM SURVIVOR CURVE.. IOWA 70-S3						
PROBABLE RETIREMENT YEAR.. 12-2015						
NET SALVAGE PERCENT.. -10						
1950	220,263.33	227,258	178,953	63,337	3.76	16,845
1953	30,465.95	31,350	24,686	8,826	3.79	2,329
1954	388,327.03	399,194	314,342	112,817	3.80	29,689
1959	532,200.99	543,979	428,352	157,069	3.85	40,797
1972	144.40	144	113	45	3.95	11
1987	691,268.96	653,864	514,881	245,515	3.99	61,533

KENTUCKY UTILITIES COMPANY

ACCOUNT 315 ACCESSORY ELECTRIC EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
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YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
GREEN RIVER UNIT 4						
INTERIM SURVIVOR CURVE.. IOWA 70-S3						
PROBABLE RETIREMENT YEAR.. 12-2015						
NET SALVAGE PERCENT.. -10						
1991	58,482.00	53,823	42,383	21,948	4.00	5,487
1995	88,683.85	78,518	61,828	35,724	4.00	8,931
2001	33,590.00	26,756	21,069	15,880	4.00	3,970
2003	144,364.54	107,985	85,032	73,769	4.00	18,442
2005	196,537.16	133,833	105,386	110,805	4.00	27,701
2006	19,724.94	12,562	9,892	11,806	4.00	2,952
2009	79,664.81	33,705	26,541	61,091	4.00	15,273
2010	90,945.25	27,284	21,485	78,555	4.00	19,639
2011	120,665.45	14,748	11,613	121,119	4.00	30,280
	2,695,328.66	2,345,003	1,846,556	1,118,306		283,879
BROWN UNIT 1						
INTERIM SURVIVOR CURVE.. IOWA 70-S3						
PROBABLE RETIREMENT YEAR.. 6-2028						
NET SALVAGE PERCENT.. -11						
1956	965,068.08	851,260	1,071,226			
1958	178,221.03	155,613	197,825			
1963	780.00	662	866			
1965	63,901.00	53,582	70,930			
1968	2,135.00	1,754	2,370			
1979	114,770.06	85,416	127,395			
1989	1,850.00	1,189	1,987	66	16.33	4
1992	1,344.04	810	1,354	138	16.40	8
1995	1,428,056.08	793,538	1,326,126	259,016	16.45	15,746
2001	77,917.83	33,647	56,229	30,259	16.49	1,835
2006	767,016.47	212,847	355,701	495,688	16.50	30,042
2009	166,049.72	24,252	40,529	143,786	16.50	8,714
2010	19,084.61	1,765	2,950	18,234	16.50	1,105
2011	72,915.41	2,380	3,977	76,959	16.50	4,664
	3,859,109.33	2,218,715	3,259,464	1,024,147		62,118

KENTUCKY UTILITIES COMPANY

ACCOUNT 315 ACCESSORY ELECTRIC EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2011

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
BROWN UNIT 2						
INTERIM SURVIVOR CURVE.. IOWA 70-S3						
PROBABLE RETIREMENT YEAR.. 6-2034						
NET SALVAGE PERCENT.. -11						
1948	384.00	339	426			
1963	893,899.09	713,769	992,228			
1965	1,103.00	866	1,224			
1966	397.00	309	441			
1970	793.56	595	881			
1984	38,251.57	23,738	42,459			
1994	185,597.00	90,629	163,487	42,526	22.28	1,909
1995	12,605.00	5,945	10,724	3,267	22.32	146
1997	36,014.00	15,721	28,359	11,616	22.37	519
1998	22,495.00	9,392	16,942	8,027	22.39	359
2005	30,977.05	7,712	13,912	20,473	22.48	911
2010	236,396.13	16,400	29,584	232,816	22.50	10,347
2011	706,664.59	17,053	30,762	753,636	22.50	33,495
	2,165,576.99	902,468	1,331,430	1,072,360		47,686
BROWN UNIT 3						
INTERIM SURVIVOR CURVE.. IOWA 70-S3						
PROBABLE RETIREMENT YEAR.. 6-2035						
NET SALVAGE PERCENT.. -11						
1972	4,280,286.75	3,102,243	4,751,118			
1973	69,444.66	49,752	77,084			
1974	17,025.00	12,053	18,898			
1984	4,045.00	2,466	4,490			
1985	798.00	477	886			
1988	8,408.74	4,726	9,334			
1989	8,164.40	4,483	9,062			
1990	9,591.76	5,139	10,647			
1991	5,344.58	2,790	5,932			
1995	39,628.38	18,245	40,870	3,117	23.28	134
1997	778,846.00	331,050	741,575	122,944	23.35	5,265
2003	45,349.90	13,388	29,990	20,348	23.46	867
2004	18,213.04	4,897	10,970	9,247	23.46	394
2005	6,057.20	1,458	3,266	3,457	23.47	147
2007	1,652,556.67	295,017	660,858	1,173,479	23.48	49,978
2010	752,068.60	50,104	112,236	722,560	23.49	30,760
2011	901,637.20	20,847	46,699	954,119	23.50	40,601
	8,597,465.88	3,919,135	6,533,915	3,009,272		128,146

KENTUCKY UTILITIES COMPANY

ACCOUNT 315 ACCESSORY ELECTRIC EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2011

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
BROWN UNITS 1, 2 AND 3 SCRUBBER						
INTERIM SURVIVOR CURVE.. IOWA 70-S3						
PROBABLE RETIREMENT YEAR.. 6-2035						
NET SALVAGE PERCENT.. -11						
2010	29,503,821.45	1,965,609	1,205,108	31,544,134	23.49	1,342,875
	29,503,821.45	1,965,609	1,205,108	31,544,134		1,342,875
GHENT UNIT 1 SCRUBBER						
INTERIM SURVIVOR CURVE.. IOWA 70-S3						
PROBABLE RETIREMENT YEAR.. 6-2034						
NET SALVAGE PERCENT.. -12						
1997	3,016,784.27	1,328,780	1,750,477	1,628,321	22.37	72,790
2009	10,270,166.58	1,150,719	1,515,908	9,986,679	22.49	444,050
2011	5,833.85	142	187	6,347	22.50	282
	13,292,784.70	2,479,641	3,266,572	11,621,347		517,122
GHENT UNIT 1						
INTERIM SURVIVOR CURVE.. IOWA 70-S3						
PROBABLE RETIREMENT YEAR.. 6-2034						
NET SALVAGE PERCENT.. -12						
1974	6,429,953.33	4,651,912	6,644,680	556,868	20.18	27,595
1978	869,693.72	598,139	854,367	119,689	20.84	5,743
1994	911,155.00	448,936	641,249	379,244	22.28	17,022
1995	70.00	33	47	31	22.32	1
1996	15,852.00	7,268	10,381	7,373	22.35	330
2000	14,398.00	5,466	7,808	8,318	22.43	371
2004	33,927.95	9,509	13,582	24,417	22.47	1,087
2005	160,601.93	40,344	57,626	122,248	22.48	5,438
2007	83,182.55	15,533	22,187	70,977	22.49	3,156
2009	84,877.13	9,510	13,584	81,479	22.49	3,623
2011	268,831.65	6,546	9,350	291,741	22.50	12,966
	8,872,543.26	5,793,196	8,274,863	1,662,385		77,332

KENTUCKY UTILITIES COMPANY

ACCOUNT 315 ACCESSORY ELECTRIC EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2011

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
GHENT UNIT 2						
INTERIM SURVIVOR CURVE.. IOWA 70-S3						
PROBABLE RETIREMENT YEAR.. 6-2034						
NET SALVAGE PERCENT.. -12						
1977	9,908,367.02	6,905,228	8,688,396	2,408,975	20.69	116,432
1984	2,109,842.77	1,321,096	1,662,249	700,775	21.61	32,428
1989	52,698.96	29,803	37,499	21,524	22.03	977
1996	44,978.99	20,622	25,947	24,429	22.35	1,093
1997	152,868.92	67,333	84,721	86,492	22.37	3,866
2007	95,312.10	17,798	22,394	84,355	22.49	3,751
2009	292,925.23	32,821	41,297	286,780	22.49	12,751
2010	60,449.95	4,231	5,324	62,380	22.50	2,772
2011	1,140,944.59	27,781	34,955	1,242,903	22.50	55,240
	13,858,388.53	8,426,713	10,602,781	4,918,614		229,310
GHENT UNIT 3						
INTERIM SURVIVOR CURVE.. IOWA 70-S3						
PROBABLE RETIREMENT YEAR.. 6-2037						
NET SALVAGE PERCENT.. -12						
1976	639,635.42	434,055	543,642	172,749	22.74	7,597
1981	25,069,266.55	15,749,556	19,725,905	8,351,674	23.71	352,243
1982	687,842.97	424,728	531,961	238,423	23.87	9,988
1984	95,821.00	57,000	71,391	35,929	24.18	1,486
1987	68,793.51	38,438	48,143	28,906	24.56	1,177
1988	18,279.36	9,979	12,498	7,974	24.67	323
2000	4,301,009.46	1,502,511	1,881,856	2,935,275	25.37	115,699
2007	51,757.15	8,704	10,902	47,066	25.47	1,848
	30,932,405.42	18,224,971	22,826,297	11,817,997		490,361
GHENT UNIT 4						
INTERIM SURVIVOR CURVE.. IOWA 70-S3						
PROBABLE RETIREMENT YEAR.. 6-2038						
NET SALVAGE PERCENT.. -12						
1984	21,606,547.09	12,647,055	15,314,441	8,884,892	25.01	355,254
1985	48,287.00	27,696	33,537	20,544	25.16	817
1988	20,564.21	11,025	13,350	9,682	25.55	379
1991	5,683.09	2,814	3,407	2,958	25.85	114
1993	155,202.00	72,227	87,460	86,366	26.01	3,320
1994	24,278.82	10,916	13,218	13,974	26.08	536

KENTUCKY UTILITIES COMPANY

ACCOUNT 315 ACCESSORY ELECTRIC EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2011

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
GHENT UNIT 4						
INTERIM SURVIVOR CURVE.. IOWA 70-S3						
PROBABLE RETIREMENT YEAR.. 6-2038						
NET SALVAGE PERCENT.. -12						
2000	2,481,837.47	844,766	1,022,935	1,756,723	26.34	66,694
2003	42,697.44	11,643	14,099	33,723	26.41	1,277
2011	27,699.80	575	696	30,328	26.49	1,145
	24,412,796.92	13,628,717	16,503,145	10,839,188		429,536
GHENT UNIT 2 SCRUBBER						
INTERIM SURVIVOR CURVE.. IOWA 70-S3						
PROBABLE RETIREMENT YEAR.. 6-2034						
NET SALVAGE PERCENT.. -12						
2009	1,149,919.21	128,842	73,828	1,214,082	22.49	53,983
2011	5,833.85	142	81	6,453	22.50	287
	1,155,753.06	128,984	73,909	1,220,534		54,270
GHENT 3 SCRUBBER						
INTERIM SURVIVOR CURVE.. IOWA 70-S3						
PROBABLE RETIREMENT YEAR.. 6-2037						
NET SALVAGE PERCENT.. -12						
2007	11,277,366.96	1,896,492	1,975,022	10,655,629	25.47	418,360
2011	764,631.32	16,477	17,159	839,228	25.49	32,924
	12,041,998.28	1,912,969	1,992,181	11,494,857		451,284
GHENT 4 SCRUBBER						
INTERIM SURVIVOR CURVE.. IOWA 70-S3						
PROBABLE RETIREMENT YEAR.. 6-2038						
NET SALVAGE PERCENT.. -12						
2008	3,838,761.63	502,085	380,927	3,918,486	26.47	148,035
2011	5,833.83	121	92	6,442	26.49	243
	3,844,595.46	502,206	381,019	3,924,928		148,278
	201,634,659.45	69,297,625	85,460,236	141,098,164		5,620,308

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 25.1 2.79

KENTUCKY UTILITIES COMPANY

ACCOUNT 316 MISCELLANEOUS POWER PLANT EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2011

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)

TRIMBLE COUNTY UNIT 2
INTERIM SURVIVOR CURVE.. IOWA 70-R1.5
PROBABLE RETIREMENT YEAR.. 6-2066
NET SALVAGE PERCENT.. -15

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
2000	41,467.41	8,360	21,655	26,032	45.96	566
2002	26,900.64	4,606	11,931	19,005	46.42	409
2011	3,434,078.91	35,740	92,579	3,856,611	48.19	80,029
	3,502,446.96	48,706	126,166	3,901,648		81,004

SYSTEM LABORATORY
INTERIM SURVIVOR CURVE.. IOWA 70-R1.5
PROBABLE RETIREMENT YEAR.. 6-2040
NET SALVAGE PERCENT.. -1

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
1983	229.68	114	151	81	25.52	3
1984	10,283.72	4,994	6,623	3,764	25.61	147
1986	48,397.00	22,584	29,949	18,932	25.78	734
1987	100,806.00	46,043	61,059	40,755	25.86	1,576
1989	3,576.00	1,558	2,066	1,546	26.01	59
1990	39,994.08	16,983	22,522	17,872	26.08	685
1991	75,689.00	31,259	41,454	34,992	26.15	1,338
1994	4,476.87	1,681	2,229	2,292	26.34	87
1995	3,198.74	1,157	1,534	1,696	26.41	64
1996	5,552.69	1,931	2,561	3,047	26.46	115
1997	47,150.16	15,689	20,806	26,816	26.52	1,011
1998	204,188.60	64,734	85,846	120,385	26.58	4,529
1999	74,357.61	22,360	29,652	45,449	26.63	1,707
2000	730.00	207	275	463	26.68	17
2001	69,759.00	18,532	24,576	45,881	26.73	1,716
2002	370,204.00	91,285	121,056	252,850	26.78	9,442
2003	638,444.59	144,661	191,840	452,989	26.83	16,884
2004	199,225.39	40,972	54,334	146,883	26.87	5,466
2005	131,911.92	24,151	32,027	101,204	26.92	3,759
2006	31,404.52	5,012	6,647	25,072	26.96	930
2007	89,149.53	11,996	15,908	74,133	27.00	2,746
2009	230,573.11	18,376	24,369	208,510	27.08	7,700
2010	90,044.40	4,464	5,920	85,025	27.12	3,135
2011	293,702.06	5,046	6,692	289,947	27.16	10,676
	2,763,048.67	595,789	790,095	2,000,584		74,526

KENTUCKY UTILITIES COMPANY

ACCOUNT 316 MISCELLANEOUS POWER PLANT EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2011

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
TYRONE UNIT 3						
INTERIM SURVIVOR CURVE.. IOWA 70-R1.5						
PROBABLE RETIREMENT YEAR.. 12-2015						
NET SALVAGE PERCENT.. -10						
1948	34,362.68	35,227	19,801	17,998	3.85	4,675
1950	1,192.00	1,220	686	625	3.86	162
1952	3,013.00	3,078	1,730	1,584	3.87	409
1953	7,624.14	7,781	4,374	4,013	3.87	1,037
1955	3,478.00	3,542	1,991	1,835	3.88	473
1963	111.00	112	63	59	3.91	15
1970	501.00	499	280	271	3.93	69
1971	2,579.00	2,563	1,441	1,396	3.93	355
1974	1,027.00	1,014	570	560	3.94	142
1977	903.70	885	497	497	3.94	126
1981	2,877.00	2,779	1,562	1,603	3.95	406
1985	5,674.00	5,388	3,029	3,213	3.96	811
1986	9,143.00	8,638	4,856	5,202	3.96	1,314
1987	7,616.53	7,157	4,023	4,355	3.96	1,100
1988	2,681.06	2,505	1,408	1,541	3.96	389
1989	45,161.70	41,927	23,568	26,110	3.96	6,593
1990	35,070.17	32,334	18,175	20,402	3.96	5,152
1991	1,799.80	1,647	926	1,054	3.96	266
1992	14,615.41	13,265	7,456	8,621	3.96	2,177
1994	29,524.15	26,278	14,771	17,705	3.97	4,460
1995	7,264.00	6,394	3,594	4,396	3.97	1,107
1996	21.00	18	10	13	3.97	3
1997	13,683.62	11,730	6,594	8,458	3.97	2,130
1998	37,059.00	31,273	17,579	23,186	3.97	5,840
1999	51,313.00	42,526	23,904	32,540	3.97	8,196
2000	45,464.00	36,905	20,745	29,266	3.97	7,372
2001	7,144.00	5,661	3,182	4,676	3.97	1,178
2003	45,598.13	33,942	19,079	31,079	3.97	7,828
2004	29,381.73	20,985	11,796	20,524	3.97	5,170
2005	12,121.00	8,219	4,620	8,713	3.97	2,195
2006	18,101.39	11,463	6,443	13,468	3.98	3,384
2007	49,829.65	28,842	16,212	38,600	3.98	9,698
2008	5,589.34	2,850	1,602	4,546	3.98	1,142
2009	21,830.81	9,173	5,156	18,858	3.98	4,738
	553,355.01	447,820	251,724	356,967		90,112

KENTUCKY UTILITIES COMPANY

ACCOUNT 316 MISCELLANEOUS POWER PLANT EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2011

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
TYRONE UNITS 1 AND 2						
FULLY ACCRUED						
NET SALVAGE PERCENT.. -10						
1947	34,060.46	37,467	37,467			
1949	1,442.98	1,587	1,587			
1954	47.00	52	52			
1955	3,032.00	3,335	3,335			
1969	3.25	4	4			
2003	11,541.15	12,695	12,696			
	50,126.84	55,140	55,140			
GREEN RIVER UNIT 3						
INTERIM SURVIVOR CURVE.. IOWA 70-R1.5						
PROBABLE RETIREMENT YEAR.. 12-2015						
NET SALVAGE PERCENT.. -10						
1954	6,727.09	6,858	5,612	1,788	3.88	461
1957	3,175.40	3,227	2,641	852	3.89	219
1974	11,360.54	11,212	9,175	3,322	3.94	843
1976	717.85	705	577	213	3.94	54
1977	5,215.02	5,106	4,178	1,558	3.94	395
1982	7,800.00	7,507	6,143	2,437	3.95	617
1983	10,719.43	10,275	8,408	3,383	3.95	856
1984	85.00	81	66	27	3.95	7
1987	1,370.06	1,287	1,053	454	3.96	115
1988	3,153.00	2,946	2,411	1,058	3.96	267
1989	1,954.27	1,814	1,484	665	3.96	168
1999	17,320.10	14,354	11,746	7,306	3.97	1,840
2003	2,721.80	2,026	1,658	1,336	3.97	337
2004	79,826.91	57,014	46,656	41,154	3.97	10,366
	152,146.47	124,412	101,809	65,552		16,545
GREEN RIVER UNIT 4						
INTERIM SURVIVOR CURVE.. IOWA 70-R1.5						
PROBABLE RETIREMENT YEAR.. 12-2015						
NET SALVAGE PERCENT.. -10						
1941	264.00	272	203	88	3.81	23
1954	1,164.00	1,187	885	396	3.88	102
1959	72,854.61	73,849	55,041	25,099	3.90	6,436
1966	2,606.00	2,615	1,949	918	3.92	234

KENTUCKY UTILITIES COMPANY

ACCOUNT 316 MISCELLANEOUS POWER PLANT EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2011

GREEN RIVER UNIT 4
INTERIM SURVIVOR CURVE.. IOWA 70-R1.5
PROBABLE RETIREMENT YEAR.. 12-2015
NET SALVAGE PERCENT.. -10

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
1971	2,054.00	2,042	1,522	737	3.93	188
1972	2,934.00	2,910	2,169	1,059	3.93	269
1974	12,418.00	12,256	9,135	4,525	3.94	1,148
1975	11,600.00	11,420	8,512	4,248	3.94	1,078
1978	2,868.00	2,800	2,087	1,068	3.94	271
1979	48,298.75	46,985	35,019	18,110	3.95	4,585
1980	59,918.00	58,094	43,299	22,611	3.95	5,724
1981	11,740.00	11,342	8,453	4,461	3.95	1,129
1982	2,238.00	2,154	1,605	856	3.95	217
1983	25,329.00	24,279	18,096	9,766	3.95	2,472
1984	12,189.87	11,634	8,671	4,738	3.95	1,199
1985	28,478.00	27,042	20,155	11,171	3.96	2,821
1986	1,692.00	1,599	1,192	669	3.96	169
1987	201,044.00	188,927	140,812	80,337	3.96	20,287
1988	36,044.00	33,674	25,098	14,550	3.96	3,674
1989	29,093.00	27,009	20,130	11,872	3.96	2,998
1990	8,187.00	7,548	5,626	3,380	3.96	854
1991	34,288.00	31,377	23,386	14,331	3.96	3,619
1992	62,073.00	56,337	41,989	26,291	3.96	6,639
1993	15,744.00	14,161	10,555	6,764	3.96	1,708
1994	200,748.00	178,674	133,170	87,653	3.97	22,079
1995	168,648.00	148,447	110,641	74,872	3.97	18,859
1996	19,905.00	17,304	12,897	8,998	3.97	2,266
1997	499,812.00	428,465	319,345	230,448	3.97	58,047
1998	24,421.00	20,608	15,360	11,503	3.97	2,897
1999	157,287.00	130,353	97,155	75,861	3.97	19,109
2000	20,792.88	16,879	12,580	10,292	3.97	2,592
2001	143,330.76	113,584	84,657	73,007	3.97	18,390
2003	75,341.37	56,083	41,800	41,076	3.97	10,347
2004	80,190.32	57,273	42,687	45,522	3.97	11,466
2005	42,487.88	28,810	21,473	25,264	3.97	6,364
2006	17,683.49	11,198	8,346	11,106	3.98	2,790
2007	10,188.60	5,897	4,395	6,812	3.98	1,712
2009	3,399.56	1,428	1,064	2,675	3.98	672
2010	33,500.66	9,989	7,445	29,406	3.98	7,388
2011	225,287.09	27,166	20,247	227,568	3.98	57,178
	2,408,142.84	1,903,671	1,418,850	1,230,107		310,000

KENTUCKY UTILITIES COMPANY

ACCOUNT 316 MISCELLANEOUS POWER PLANT EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2011

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
GREEN RIVER UNITS 1 AND 2						
FULLY ACCRUED						
NET SALVAGE PERCENT.. -10						
1941	632.00	695	695			
1950	60,219.49	66,241	66,241			
1966	5,832.35	6,416	6,416			
1974	18,065.69	19,872	19,872			
	84,749.53	93,224	93,224			
BROWN UNIT 1						
INTERIM SURVIVOR CURVE.. IOWA 70-R1.5						
PROBABLE RETIREMENT YEAR.. 6-2028						
NET SALVAGE PERCENT.. -11						
1954	7,812.22	6,617	8,672			
1955	921.00	777	1,022			
1956	150,707.00	126,576	167,285			
1958	497.00	414	552			
1971	672.02	519	746			
1977	0.24		0			
1980	1,078.00	769	1,194	2	15.52	
1988	1,387.17	887	1,378	162	15.73	10
1990	18,405.00	11,336	17,606	2,824	15.77	179
1992	7,705.00	4,545	7,059	1,494	15.81	94
1994	9,227.37	5,172	8,033	2,210	15.85	139
1995	1,940.96	1,057	1,642	513	15.87	32
1996	2,858.88	1,508	2,342	831	15.89	52
2001	89,264.86	37,823	58,743	40,341	15.97	2,526
2003	118,172.07	43,797	68,021	63,150	16.00	3,947
2005	13,393.06	4,129	6,413	8,454	16.02	528
2007	497.91	116	180	373	16.05	23
2011	8,037.82	258	401	8,521	16.10	529
	432,577.58	246,300	351,287	128,874		8,059
BROWN UNIT 2						
INTERIM SURVIVOR CURVE.. IOWA 70-R1.5						
PROBABLE RETIREMENT YEAR.. 6-2034						
NET SALVAGE PERCENT.. -11						
1963	63,377.24	47,260	70,349			
1965	541.89	398	601			

KENTUCKY UTILITIES COMPANY

ACCOUNT 316 MISCELLANEOUS POWER PLANT EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2011

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
BROWN UNIT 2						
INTERIM SURVIVOR CURVE.. IOWA 70-R1.5						
PROBABLE RETIREMENT YEAR.. 6-2034						
NET SALVAGE PERCENT.. -11						
1968	520.36	374	578			
1969	4,400.82	3,133	4,885			
1970	555.08	392	616			
1995	3,998.73	1,837	4,439			
1996	2,858.69	1,265	3,173			
1998	5,685.52	2,316	6,311			
2000	3,709.49	1,362	4,118			
2007	21,010.50	3,801	14,773	8,549	21.62	395
	106,658.32	62,138	109,842	8,549		395
BROWN UNIT 3						
INTERIM SURVIVOR CURVE.. IOWA 70-R1.5						
PROBABLE RETIREMENT YEAR.. 6-2035						
NET SALVAGE PERCENT.. -11						
1955	1,111.17	862	1,219	15	18.87	1
1969	55,586.77	39,005	55,137	6,565	20.50	320
1970	2,634.00	1,832	2,590	334	20.59	16
1971	373,932.83	257,685	364,257	50,808	20.68	2,457
1972	20,504.00	13,994	19,782	2,978	20.77	143
1973	960.00	649	917	148	20.85	7
1974	3,179.00	2,126	3,005	523	20.94	25
1976	2,020.00	1,321	1,867	375	21.09	18
1977	40,063.51	25,902	36,614	7,856	21.17	371
1978	1,537.00	982	1,388	318	21.24	15
1980	1,594.00	992	1,402	367	21.37	17
1981	7,296.00	4,475	6,326	1,773	21.44	83
1982	900.00	544	769	230	21.50	11
1983	53,223.00	31,674	44,774	14,304	21.56	663
1984	10,688.00	6,256	8,843	3,020	21.62	140
1985	14,815.00	8,522	12,046	4,398	21.68	203
1986	146,932.00	82,986	117,307	45,787	21.73	2,107
1987	219,946.00	121,845	172,237	71,903	21.78	3,301
1988	143,323.00	77,775	109,941	49,148	21.83	2,251
1989	211,250.31	112,127	158,500	75,988	21.88	3,473
1990	328,072.94	170,041	240,366	123,795	21.93	5,645
1991	380,519.00	192,397	271,968	150,408	21.97	6,846
1992	143,407.00	70,556	99,736	59,445	22.02	2,700
1993	222,478.00	106,327	150,301	96,649	22.06	4,381

KENTUCKY UTILITIES COMPANY

ACCOUNT 316 MISCELLANEOUS POWER PLANT EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2011

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
BROWN UNIT 3						
INTERIM SURVIVOR CURVE.. IOWA 70-R1.5						
PROBABLE RETIREMENT YEAR.. 6-2035						
NET SALVAGE PERCENT.. -11						
1994	240,579.84	111,408	157,484	109,560	22.10	4,957
1995	426,920.35	191,083	270,110	203,771	22.14	9,204
1996	132,026.00	56,931	80,476	66,073	22.18	2,979
1997	247,261.54	102,409	144,763	129,697	22.21	5,840
1998	26,006.00	10,298	14,557	14,310	22.25	643
1999	73,676.00	27,778	39,266	42,514	22.28	1,908
2000	12,638.00	4,505	6,368	7,660	22.32	343
2001	61,005.75	20,450	28,908	38,809	22.35	1,736
2003	217,402.17	62,721	88,661	152,655	22.41	6,812
2004	87,825.06	23,078	32,623	64,863	22.44	2,891
2005	170,990.44	40,262	56,913	132,886	22.47	5,914
2006	93,259.29	19,220	27,169	76,349	22.50	3,393
2007	109,967.17	19,180	27,112	94,951	22.53	4,214
2008	64,285.39	9,061	12,808	58,548	22.55	2,596
2009	25,225.68	2,639	3,730	24,270	22.58	1,075
2010	510,629.45	33,271	47,031	519,768	22.61	22,988
2011	184,777.66	4,174	5,900	199,203	22.63	8,803
	5,070,448.32	2,069,343	2,925,174	2,703,024		121,490
GHENT UNIT 1 SCRUBBER						
INTERIM SURVIVOR CURVE.. IOWA 70-R1.5						
PROBABLE RETIREMENT YEAR.. 6-2034						
NET SALVAGE PERCENT.. -12						
1997	982,956.01	422,034	830,184	270,727	21.33	12,692
2000	2,454.00	909	1,788	960	21.43	45
2011	47,617.08	1,130	2,223	51,108	21.71	2,354
	1,033,027.09	424,073	834,195	322,795		15,091
GHENT UNIT 1						
INTERIM SURVIVOR CURVE.. IOWA 70-R1.5						
PROBABLE RETIREMENT YEAR.. 6-2034						
NET SALVAGE PERCENT.. -12						
1974	1,024,130.37	702,278	1,054,485	92,541	20.17	4,588
1975	85,164.91	57,795	86,780	8,604	20.24	425
1976	12,253.24	8,226	12,352	1,372	20.31	68

KENTUCKY UTILITIES COMPANY

ACCOUNT 316 MISCELLANEOUS POWER PLANT EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2011

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
GHENT UNIT 1						
INTERIM SURVIVOR CURVE.. IOWA 70-R1.5						
PROBABLE RETIREMENT YEAR.. 6-2034						
NET SALVAGE PERCENT.. -12						
1978	6,426.72	4,215	6,329	869	20.44	43
1983	4,043.88	2,475	3,716	813	20.74	39
1988	74,936.00	41,914	62,935	20,994	20.99	1,000
1989	2,178.22	1,193	1,791	648	21.03	31
1990	137,000.67	73,317	110,087	43,354	21.07	2,058
1994	52,592.00	25,196	37,832	21,071	21.23	993
1995	11,112.00	5,150	7,733	4,713	21.26	222
1996	153,652.05	68,631	103,051	69,039	21.30	3,241
1997	18,479.01	7,934	11,913	8,783	21.33	412
1998	2,709.00	1,113	1,671	1,363	21.36	64
1999	79,194.16	30,969	46,501	42,197	21.40	1,972
2000	2,880.81	1,067	1,602	1,624	21.43	76
2004	42,569.91	11,669	17,521	30,157	21.54	1,400
2006	30,770.07	6,627	9,951	24,512	21.59	1,135
2007	7,433.84	1,357	2,038	6,288	21.62	291
	1,747,526.86	1,051,126	1,578,287	378,943		18,058
GHENT UNIT 2						
INTERIM SURVIVOR CURVE.. IOWA 70-R1.5						
PROBABLE RETIREMENT YEAR.. 6-2034						
NET SALVAGE PERCENT.. -12						
1976	97,461.37	65,430	94,698	14,458	20.31	712
1977	663,118.00	440,090	636,953	105,739	20.38	5,188
1978	591,177.00	387,770	561,229	100,889	20.44	4,936
1980	2,018.11	1,290	1,867	393	20.57	19
1985	7,576.54	4,488	6,496	1,990	20.84	95
1989	51,128.40	27,992	40,513	16,750	21.03	796
1990	7,692.02	4,116	5,957	2,658	21.07	126
1991	6,857.97	3,581	5,183	2,498	21.11	118
1992	50,988.28	25,929	37,528	19,579	21.15	926
2006	15,073.78	3,246	4,698	12,185	21.59	564
2007	7,433.84	1,357	1,964	6,362	21.62	294
	1,500,525.31	965,289	1,397,086	283,502		13,774

KENTUCKY UTILITIES COMPANY

ACCOUNT 316 MISCELLANEOUS POWER PLANT EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2011

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)

GHENT UNIT 3
INTERIM SURVIVOR CURVE.. IOWA 70-R1.5
PROBABLE RETIREMENT YEAR.. 6-2037
NET SALVAGE PERCENT.. -12

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
1981	2,137,927.84	1,276,593	1,790,935	603,544	23.03	26,207
1982	220,596.00	129,706	181,965	65,103	23.10	2,818
1983	9,393.97	5,432	7,621	2,901	23.18	125
1984	599,875.00	340,982	478,364	193,496	23.25	8,322
1987	14,126.58	7,580	10,634	5,188	23.44	221
1988	8,279.00	4,347	6,098	3,174	23.50	135
1993	31,841.79	14,654	20,558	15,105	23.77	635
1994	1,429.72	637	894	708	23.82	30
2004	70,857.65	17,630	24,733	54,627	24.23	2,255
2007	56,110.00	9,232	12,952	49,892	24.33	2,051
	3,150,437.55	1,806,793	2,534,754	993,736		42,799

GHENT UNIT 4
INTERIM SURVIVOR CURVE.. IOWA 70-R1.5
PROBABLE RETIREMENT YEAR.. 6-2038
NET SALVAGE PERCENT.. -12

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
1984	1,552,539.66	866,518	926,863	811,981	24.04	33,776
1985	76,854.00	42,099	45,031	41,046	24.12	1,702
1986	71,918.00	38,628	41,318	39,230	24.19	1,622
1987	197,214.00	103,727	110,951	109,929	24.26	4,531
1988	246,937.00	127,100	135,951	140,618	24.32	5,782
1989	288,049.17	144,754	154,835	167,780	24.39	6,879
1990	248,790.00	121,954	130,447	148,198	24.45	6,061
1991	249,755.00	119,199	127,500	152,225	24.51	6,211
1992	186,806.00	86,673	92,709	116,514	24.56	4,744
1993	126,790.00	57,023	60,994	81,011	24.62	3,290
1994	96,245.00	41,889	44,806	62,988	24.67	2,553
1995	403,518.00	169,464	181,266	270,675	24.72	10,950
1996	272,256.00	109,960	117,618	187,309	24.77	7,562
1997	261,371.59	101,129	108,172	184,564	24.82	7,436
1998	36,015.00	13,297	14,223	26,114	24.87	1,050
1999	626,250.00	219,685	234,984	466,416	24.91	18,724
2000	69,931.00	23,145	24,757	53,566	24.96	2,146
2003	274,884.03	73,036	78,122	229,748	25.08	9,161
2004	272,927.50	65,871	70,458	235,220	25.12	9,364
2005	132,168.24	28,466	30,448	117,580	25.16	4,673
2006	15,073.78	2,838	3,036	13,847	25.19	550
2007	167,940.61	26,679	28,537	159,557	25.23	6,324

KENTUCKY UTILITIES COMPANY

ACCOUNT 316 MISCELLANEOUS POWER PLANT EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2011

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
GHENT UNIT 4						
INTERIM SURVIVOR CURVE.. IOWA 70-R1.5						
PROBABLE RETIREMENT YEAR.. 6-2038						
NET SALVAGE PERCENT.. -12						
2008	38,302.23	4,904	5,246	37,653	25.26	1,491
2009	82,463.42	7,789	8,331	84,028	25.30	3,321
2010	820,549.05	48,138	51,490	867,525	25.33	34,249
2011	639,633.05	13,038	13,946	702,443	25.36	27,699
	7,455,181.33	2,657,003	2,842,039	5,507,764		221,851
	30,010,398.68	12,550,827	15,409,672	17,882,045		1,013,704

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 17.6   3.38

KENTUCKY UTILITIES COMPANY

ACCOUNT 330.1 LAND RIGHTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2011

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
DIX DAM						
INTERIM SURVIVOR CURVE.. IOWA 100-R4						
PROBABLE RETIREMENT YEAR.. 6-2041						
NET SALVAGE PERCENT.. 0						
1941	879,311.47	641,159	879,311			
	879,311.47	641,159	879,311			

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 0.0 0.00

KENTUCKY UTILITIES COMPANY

ACCOUNT 331 STRUCTURES AND IMPROVEMENTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2011

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)

DIX DAM
INTERIM SURVIVOR CURVE.. IOWA 90-S2.5
PROBABLE RETIREMENT YEAR.. 6-2041
NET SALVAGE PERCENT.. -6

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
1941	265,610.35	208,967	243,522	38,025	21.68	1,754
1955	4,487.68	3,253	3,791	966	24.58	39
1961	2,999.30	2,077	2,420	759	25.68	30
1967	1,519.40	997	1,162	449	26.66	17
1975	293.52	176	205	106	27.72	4
1988	21,653.46	10,289	11,990	10,962	28.84	380
1990	54,778.00	24,719	28,807	29,258	28.95	1,011
1991	77,146.00	33,838	39,434	42,341	29.00	1,460
1992	1,037.00	441	514	585	29.05	20
2005	23,670.29	4,542	5,293	19,797	29.41	673
2007	66,025.06	9,282	10,817	59,170	29.43	2,011
2009	11,732.37	973	1,134	11,302	29.45	384
2010	75,260.09	3,865	4,504	75,272	29.46	2,555
2011	10,314.17	182	212	10,721	29.47	364
	616,526.69	303,601	353,805	299,713		10,702

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 28.0   1.74

KENTUCKY UTILITIES COMPANY

ACCOUNT 332 RESERVOIRS, DAMS AND WATERWAYS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2011

DIX DAM
INTERIM SURVIVOR CURVE.. IOWA 100-S2.5
PROBABLE RETIREMENT YEAR.. 6-2041
NET SALVAGE PERCENT.. -6

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
1941	5,917,973.92	4,581,775	5,169,531	1,103,521	23.92	46,134
1944	862.00	658	742	171	24.43	7
1950	229,388.00	169,338	191,061	52,090	25.40	2,051
1971	3,719.85	2,318	2,615	1,328	28.02	47
1990	7,354.12	3,306	3,730	4,065	29.15	139
1991	1,200,006.00	524,321	591,582	680,425	29.19	23,310
1992	370,020.00	156,888	177,014	215,207	29.22	7,365
1993	16,470.00	6,763	7,631	9,828	29.24	336
1994	10,861.26	4,306	4,858	6,655	29.27	227
2003	136,421.67	32,415	36,573	108,034	29.42	3,672
2007	1,072,820.18	150,689	170,020	967,170	29.46	32,830
2008	842,093.55	94,787	106,946	785,673	29.46	26,669
2011	11,795,979.11	208,562	235,317	12,268,421	29.48	416,161
	21,603,969.66	5,936,126	6,697,620	16,202,588		558,948

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 29.0 2.59

KENTUCKY UTILITIES COMPANY

ACCOUNT 333 WATER WHEELS, TURBINES AND GENERATORS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2011

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
DIX DAM						
INTERIM SURVIVOR CURVE.. IOWA 75-R3						
PROBABLE RETIREMENT YEAR.. 6-2041						
NET SALVAGE PERCENT.. -6						
1941	209,127.78	172,980	7,359	214,316	16.33	13,124
1957	67,525.73	49,042	2,086	69,491	22.30	3,116
1958	4,342.00	3,125	133	4,470	22.62	198
1962	12,808.80	8,883	378	13,199	23.77	555
1963	31.46	22	1	32	24.04	1
1992	12,412.14	5,296	225	12,932	28.34	456
1997	24,821.62	8,746	372	25,939	28.66	905
2005	1,992.81	384	16	2,096	29.03	72
2008	62,158.95	7,013	298	65,590	29.13	2,252
2010	4,035,403.02	207,802	8,841	4,268,687	29.18	146,288
	4,430,624.31	463,293	19,710	4,676,752		166,967

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 28.0   3.77

KENTUCKY UTILITIES COMPANY

ACCOUNT 334 ACCESSORY ELECTRIC EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2011

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
DIX DAM						
INTERIM SURVIVOR CURVE.. IOWA 40-L2.5						
PROBABLE RETIREMENT YEAR.. 6-2041						
NET SALVAGE PERCENT.. -6						
1941	54,187.00	47,042	43,512	13,927	7.24	1,924
1947	10,865.00	9,107	8,424	3,093	8.37	370
1949	290.00	240	222	85	8.78	10
1950	411.49	338	313	124	8.99	14
1952	206.57	167	154	64	9.41	7
1953	772.14	621	574	244	9.63	25
1960	1,738.80	1,329	1,229	614	11.14	55
1961	56.97	43	40	21	11.34	2
1962	3,724.00	2,806	2,595	1,352	11.54	117
1963	156.52	117	108	58	11.73	5
1974	3,361.98	2,361	2,184	1,380	13.34	103
1975	4,094.59	2,858	2,644	1,697	13.48	126
1989	5,503.19	3,113	2,879	2,954	17.56	168
2010	492,965.03	27,209	25,167	497,376	27.31	18,212
	578,333.28	97,351	90,045	522,988		21,138

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 24.7 3.65

KENTUCKY UTILITIES COMPANY

ACCOUNT 335 MISCELLANEOUS POWER PLANT EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2011

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
DIX DAM						
INTERIM SURVIVOR CURVE.. IOWA 35-L1						
PROBABLE RETIREMENT YEAR.. 6-2041						
NET SALVAGE PERCENT.. -6						
1941	3,066.11	2,562	1,494	1,756	7.41	237
1947	3,731.00	2,977	1,737	2,218	8.65	256
1948	65.00	51	30	39	8.86	4
1949	533.00	418	244	321	9.08	35
1950	580.00	452	264	351	9.29	38
1951	115.00	89	52	70	9.50	7
1952	894.00	684	399	549	9.72	56
1954	1,687.33	1,270	741	1,048	10.15	103
1955	164.19	122	71	103	10.36	10
1959	389.50	280	163	250	11.23	22
1961	279.83	198	115	181	11.66	16
1962	24,545.00	17,166	10,013	16,005	11.88	1,347
1963	74.00	51	30	49	12.10	4
1972	165.40	104	61	115	14.05	8
1975	1,855.88	1,129	659	1,309	14.69	89
1988	185,484.40	92,587	54,007	142,606	17.46	8,168
1990	1,449.67	695	405	1,131	17.87	63
1992	11,230.37	5,142	2,999	8,905	18.29	487
1994	22,393.40	9,721	5,670	18,067	18.73	965
1995	14,300.79	6,023	3,513	11,646	18.96	614
1996	9,512.12	3,873	2,259	7,824	19.21	407
2003	4,481.37	1,226	715	4,035	21.37	189
2010	10,026.50	595	347	10,281	24.11	426
	297,023.86	147,415	85,989	228,856		13,551

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 16.9 4.56

KENTUCKY UTILITIES COMPANY

ACCOUNT 336 ROADS, RAILROADS AND BRIDGES

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2011

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
DIX DAM						
INTERIM SURVIVOR CURVE.. IOWA 55-R4						
PROBABLE RETIREMENT YEAR.. 6-2041						
NET SALVAGE PERCENT.. -6						
1941	46,976.13	47,060	40,657	9,138	3.02	3,026
2009	129,383.46	10,752	9,289	127,857	29.27	4,368
	176,359.59	57,812	49,946	136,995		7,394

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 18.5   4.19

KENTUCKY UTILITIES COMPANY

ACCOUNT 340.1 LAND RIGHTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2011

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
BROWN CT GAS PIPELINE						
INTERIM SURVIVOR CURVE.. SQUARE						
PROBABLE RETIREMENT YEAR.. 6-2031						
NET SALVAGE PERCENT.. 0						
1994	167,723.31	79,328	94,686	73,037	19.50	3,745
1995	8,686.00	3,981	4,752	3,934	19.50	202
	176,409.31	83,309	99,438	76,971		3,947

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 19.5   2.24

KENTUCKY UTILITIES COMPANY

ACCOUNT 341 STRUCTURES AND IMPROVEMENTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2011

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
TRIMBLE COUNTY CT 5 INTERIM SURVIVOR CURVE.. IOWA 40-R2.5 PROBABLE RETIREMENT YEAR.. 6-2032 NET SALVAGE PERCENT.. -5						
2002	3,566,217.06	1,203,641	1,132,685	2,611,843	19.02	137,321
2004	27,551.15	7,840	7,378	21,551	19.26	1,119
2006	146,463.11	32,821	30,886	122,900	19.46	6,316
	3,740,231.32	1,244,302	1,170,949	2,756,294		144,756
TRIMBLE COUNTY CT 6 INTERIM SURVIVOR CURVE.. IOWA 40-R2.5 PROBABLE RETIREMENT YEAR.. 6-2032 NET SALVAGE PERCENT.. -5						
2002	3,564,353.91	1,203,012	1,123,903	2,618,668	19.02	137,680
2004	24,330.33	6,923	6,468	19,079	19.26	991
	3,588,684.24	1,209,935	1,130,371	2,637,747		138,671
TRIMBLE COUNTY CT 7 INTERIM SURVIVOR CURVE.. IOWA 40-R2.5 PROBABLE RETIREMENT YEAR.. 6-2034 NET SALVAGE PERCENT.. -5						
2004	3,559,154.97	950,609	909,260	2,827,853	20.90	135,304
	3,559,154.97	950,609	909,260	2,827,853		135,304
TRIMBLE COUNTY CT 8 INTERIM SURVIVOR CURVE.. IOWA 40-R2.5 PROBABLE RETIREMENT YEAR.. 6-2034 NET SALVAGE PERCENT.. -5						
2004	3,548,851.71	947,857	906,628	2,819,666	20.90	134,912
	3,548,851.71	947,857	906,628	2,819,666		134,912

KENTUCKY UTILITIES COMPANY

ACCOUNT 341 STRUCTURES AND IMPROVEMENTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2011

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
TRIMBLE COUNTY CT 9						
INTERIM SURVIVOR CURVE.. IOWA 40-R2.5						
PROBABLE RETIREMENT YEAR.. 6-2034						
NET SALVAGE PERCENT.. -5						
2004	3,655,976.41	976,469	923,545	2,915,230	20.90	139,485
	3,655,976.41	976,469	923,545	2,915,230		139,485
TRIMBLE COUNTY CT 10						
INTERIM SURVIVOR CURVE.. IOWA 40-R2.5						
PROBABLE RETIREMENT YEAR.. 6-2034						
NET SALVAGE PERCENT.. -5						
2004	3,653,029.99	975,682	922,801	2,912,880	20.90	139,372
	3,653,029.99	975,682	922,801	2,912,880		139,372
BROWN CT 5						
INTERIM SURVIVOR CURVE.. IOWA 40-R2.5						
PROBABLE RETIREMENT YEAR.. 6-2031						
NET SALVAGE PERCENT.. -5						
2001	754,032.65	280,765	264,182	527,552	18.09	29,163
2002	1,116.00	388	365	807	18.21	44
2004	19,933.20	5,864	5,518	15,412	18.42	837
	775,081.85	287,017	270,065	543,771		30,044
BROWN CT 6						
INTERIM SURVIVOR CURVE.. IOWA 40-R2.5						
PROBABLE RETIREMENT YEAR.. 6-2029						
NET SALVAGE PERCENT.. -5						
1999	133,678.33	59,039	53,187	87,175	16.24	5,368
2005	38,287.07	10,920	9,838	30,364	16.76	1,812
2006	20,848.62	5,253	4,732	17,159	16.82	1,020
	192,814.02	75,212	67,757	134,698		8,200

KENTUCKY UTILITIES COMPANY

ACCOUNT 341 STRUCTURES AND IMPROVEMENTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2011

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
BROWN CT 7						
INTERIM SURVIVOR CURVE.. IOWA 40-R2.5						
PROBABLE RETIREMENT YEAR.. 6-2029						
NET SALVAGE PERCENT.. -5						
1999	481,712.77	212,749	190,813	314,986	16.24	19,396
2002	4,117.50	1,531	1,373	2,950	16.53	178
2005	57,093.08	16,283	14,604	45,344	16.76	2,705
2006	2,042.62	515	462	1,683	16.82	100
	544,965.97	231,078	207,252	364,962		22,379
BROWN CT 8						
INTERIM SURVIVOR CURVE.. IOWA 40-R2.5						
PROBABLE RETIREMENT YEAR.. 6-2025						
NET SALVAGE PERCENT.. -5						
1994	143,346.95	85,262	84,555	65,959	12.49	5,281
1995	1,730,556.00	1,002,213	993,908	823,176	12.57	65,487
1997	120,183.00	65,437	64,895	61,297	12.72	4,819
2001	18,569.00	8,524	8,453	11,044	12.95	853
	2,012,654.95	1,161,436	1,151,811	961,477		76,440
BROWN CT 9						
INTERIM SURVIVOR CURVE.. IOWA 40-R2.5						
PROBABLE RETIREMENT YEAR.. 6-2031						
NET SALVAGE PERCENT.. -5						
1994	2,480,099.86	1,264,215	1,460,351	1,143,753	17.00	67,280
1995	512,980.00	252,768	291,984	246,645	17.19	14,348
1996	438,868.00	208,471	240,814	219,997	17.37	12,665
1997	1,190,538.00	543,453	627,767	622,298	17.54	35,479
2001	18,569.00	6,914	7,987	11,511	18.09	636
	4,641,054.86	2,275,821	2,628,903	2,244,205		130,408

KENTUCKY UTILITIES COMPANY

ACCOUNT 341 STRUCTURES AND IMPROVEMENTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2011

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
BROWN CT 10						
INTERIM SURVIVOR CURVE.. IOWA 40-R2.5						
PROBABLE RETIREMENT YEAR.. 6-2031						
NET SALVAGE PERCENT.. -5						
1995	1,751,485.20	863,034	940,079	898,980	17.19	52,297
1997	95,664.00	43,668	47,566	52,881	17.54	3,015
2001	18,569.00	6,914	7,531	11,966	18.09	661
	1,865,718.20	913,616	995,177	963,827		55,973
BROWN CT 11						
INTERIM SURVIVOR CURVE.. IOWA 40-R2.5						
PROBABLE RETIREMENT YEAR.. 6-2026						
NET SALVAGE PERCENT.. -5						
1996	1,342,623.65	731,282	715,467	694,288	13.49	51,467
1997	65,678.00	34,595	33,847	35,115	13.57	2,588
1998	313,025.00	158,987	155,549	173,128	13.64	12,693
2001	81,269.00	35,877	35,101	50,231	13.84	3,629
2004	56,158.33	20,100	19,665	39,301	14.00	2,807
2011	36,259.52	1,267	1,240	36,833	14.24	2,587
	1,895,013.50	982,108	960,868	1,028,896		75,771
HAEFLING UNITS 1, 2 AND 3						
INTERIM SURVIVOR CURVE.. IOWA 40-R2.5						
PROBABLE RETIREMENT YEAR.. 6-2020						
NET SALVAGE PERCENT.. -5						
1994	3,638.00	2,562	852	2,968	8.15	364
2000	431,215.46	259,264	86,218	366,558	8.30	44,164
	434,853.46	261,826	87,070	369,526		44,528

KENTUCKY UTILITIES COMPANY

ACCOUNT 341 STRUCTURES AND IMPROVEMENTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2011

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
PADDY'S RUN GENERATOR 13 INTERIM SURVIVOR CURVE.. IOWA 40-R2.5 PROBABLE RETIREMENT YEAR.. 6-2031 NET SALVAGE PERCENT.. -5						
2001	1,906,444.76	709,867	664,141	1,337,626	18.09	73,943
2002	3,883.00	1,351	1,264	2,813	18.21	154
	1,910,327.76	711,218	665,405	1,340,439		74,097
	36,018,413.21	13,204,186	12,997,862	24,821,471		1,350,340

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 18.4   3.75

KENTUCKY UTILITIES COMPANY

ACCOUNT 342 FUEL HOLDERS, PRODUCERS AND ACCESSORIES

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2011

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
TRIMBLE COUNTY CT 5 INTERIM SURVIVOR CURVE.. IOWA 45-R2.5 PROBABLE RETIREMENT YEAR.. 6-2032 NET SALVAGE PERCENT.. -5						
2002	237,747.79	79,616	75,588	174,047	19.39	8,976
2004	1,836.64	519	493	1,436	19.56	73
	239,584.43	80,135	76,081	175,483		9,049
TRIMBLE COUNTY CT 6 INTERIM SURVIVOR CURVE.. IOWA 45-R2.5 PROBABLE RETIREMENT YEAR.. 6-2032 NET SALVAGE PERCENT.. -5						
2002	237,623.60	79,575	75,551	173,954	19.39	8,971
2004	1,621.94	458	435	1,268	19.56	65
	239,245.54	80,033	75,986	175,222		9,036
TRIMBLE COUNTY CT GAS PIPELINE INTERIM SURVIVOR CURVE.. IOWA 45-R2.5 PROBABLE RETIREMENT YEAR.. 6-2034 NET SALVAGE PERCENT.. -5						
2002	4,474,853.28	1,411,317	1,479,697	3,218,899	21.08	152,699
2005	369,111.16	87,559	91,801	295,765	21.38	13,834
2006	6,150.29	1,277	1,339	5,119	21.47	238
	4,850,114.73	1,500,153	1,572,837	3,519,783		166,771
TRIMBLE COUNTY CT 7 INTERIM SURVIVOR CURVE.. IOWA 45-R2.5 PROBABLE RETIREMENT YEAR.. 6-2034 NET SALVAGE PERCENT.. -5						
2004	578,059.38	153,076	149,364	457,598	21.29	21,494
	578,059.38	153,076	149,364	457,598		21,494

KENTUCKY UTILITIES COMPANY

ACCOUNT 342 FUEL HOLDERS, PRODUCERS AND ACCESSORIES

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2011

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
TRIMBLE COUNTY CT 8 INTERIM SURVIVOR CURVE.. IOWA 45-R2.5 PROBABLE RETIREMENT YEAR.. 6-2034 NET SALVAGE PERCENT.. -5						
2004	576,385.74	152,633	148,931	456,274	21.29	21,431
	576,385.74	152,633	148,931	456,274		21,431
TRIMBLE COUNTY CT 9 INTERIM SURVIVOR CURVE.. IOWA 45-R2.5 PROBABLE RETIREMENT YEAR.. 6-2034 NET SALVAGE PERCENT.. -5						
2004	593,786.01	157,240	151,730	471,745	21.29	22,158
	593,786.01	157,240	151,730	471,745		22,158
TRIMBLE COUNTY CT 10 INTERIM SURVIVOR CURVE.. IOWA 45-R2.5 PROBABLE RETIREMENT YEAR.. 6-2034 NET SALVAGE PERCENT.. -5						
2004	593,307.31	157,114	152,096	470,876	21.29	22,117
2007	29,565.29	5,204	5,038	26,006	21.55	1,207
	622,872.60	162,318	157,134	496,882		23,324
BROWN CT 5 INTERIM SURVIVOR CURVE.. IOWA 45-R2.5 PROBABLE RETIREMENT YEAR.. 6-2031 NET SALVAGE PERCENT.. -5						
2001	562,558.04	207,892	116,451	474,235	18.45	25,704
2002	837.00	289	162	717	18.53	39
2010	232,392.85	17,413	9,754	234,259	19.00	12,329
	795,787.89	225,594	126,367	709,210		38,072

KENTUCKY UTILITIES COMPANY

ACCOUNT 342 FUEL HOLDERS, PRODUCERS AND ACCESSORIES

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2011

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
BROWN CT 6						
INTERIM SURVIVOR CURVE.. IOWA 45-R2.5						
PROBABLE RETIREMENT YEAR.. 6-2029						
NET SALVAGE PERCENT.. -5						
1999	89,103.45	39,106	10,822	82,736	16.57	4,993
2009	20,420.52	2,679	741	20,700	17.09	1,211
2010	232,392.75	19,294	5,339	238,673	17.12	13,941
2011	64,543.29	1,883	521	67,249	17.15	3,921
	406,460.01	62,962	17,424	409,359		24,066
BROWN CT 7						
INTERIM SURVIVOR CURVE.. IOWA 45-R2.5						
PROBABLE RETIREMENT YEAR.. 6-2029						
NET SALVAGE PERCENT.. -5						
1999	87,848.59	38,555	8,003	84,238	16.57	5,084
2009	21,086.20	2,766	574	21,566	17.09	1,262
2010	232,392.85	19,294	4,005	240,008	17.12	14,019
2011	64,543.31	1,883	391	67,380	17.15	3,929
	405,870.95	62,498	12,973	413,191		24,294
BROWN CT 8						
INTERIM SURVIVOR CURVE.. IOWA 45-R2.5						
PROBABLE RETIREMENT YEAR.. 6-2025						
NET SALVAGE PERCENT.. -5						
1995	17,785.88	10,266	6,377	12,298	12.82	959
1997	1,827.00	992	616	1,302	12.92	101
2010	232,392.85	24,435	15,178	228,834	13.30	17,206
	252,005.73	35,693	22,171	242,435		18,266
BROWN CT 9						
INTERIM SURVIVOR CURVE.. IOWA 45-R2.5						
PROBABLE RETIREMENT YEAR.. 6-2031						
NET SALVAGE PERCENT.. -5						
1994	97,042.44	48,805	50,208	51,686	17.72	2,917
1995	1,271,203.00	619,036	636,836	697,927	17.84	39,121

KENTUCKY UTILITIES COMPANY

ACCOUNT 342 FUEL HOLDERS, PRODUCERS AND ACCESSORIES

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2011

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
BROWN CT 9						
INTERIM SURVIVOR CURVE.. IOWA 45-R2.5						
PROBABLE RETIREMENT YEAR.. 6-2031						
NET SALVAGE PERCENT.. -5						
1996	198,281.39	93,178	95,857	112,338	17.96	6,255
1997	219,834.00	99,373	102,230	128,595	18.07	7,116
2010	232,392.85	17,413	17,914	226,099	19.00	11,900
	2,018,753.68	877,805	903,046	1,216,645		67,309
BROWN CT 10						
INTERIM SURVIVOR CURVE.. IOWA 45-R2.5						
PROBABLE RETIREMENT YEAR.. 6-2031						
NET SALVAGE PERCENT.. -5						
1995	30,084.96	14,650	13,261	18,328	17.84	1,027
1997	1,653.00	747	676	1,059	18.07	59
2010	232,392.85	17,413	15,762	228,250	19.00	12,013
	264,130.81	32,810	29,700	247,637		13,099
BROWN CT 11						
INTERIM SURVIVOR CURVE.. IOWA 45-R2.5						
PROBABLE RETIREMENT YEAR.. 6-2026						
NET SALVAGE PERCENT.. -5						
1996	26,169.84	14,198	10,886	16,593	13.76	1,206
1997	18,693.00	9,814	7,524	12,103	13.81	876
1998	7,567.00	3,827	2,934	5,011	13.87	361
2010	232,392.85	22,788	17,472	226,541	14.27	15,875
	284,822.69	50,627	38,816	260,248		18,318

KENTUCKY UTILITIES COMPANY

ACCOUNT 342 FUEL HOLDERS, PRODUCERS AND ACCESSORIES

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2011

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
BROWN CT GAS PIPELINE INTERIM SURVIVOR CURVE.. IOWA 45-R2.5 PROBABLE RETIREMENT YEAR.. 6-2031 NET SALVAGE PERCENT.. -5						
1994	7,687,474.69	3,866,254	4,201,333	3,870,515	17.72	218,426
1998	206.00	89	97	120	18.18	7
1999	381,882.00	157,836	171,515	229,461	18.27	12,559
2003	36,567.97	11,708	12,723	25,674	18.60	1,380
	8,106,130.66	4,035,887	4,385,668	4,125,769		232,372
HAEFLING UNITS 1, 2 AND 3 INTERIM SURVIVOR CURVE.. IOWA 45-R2.5 PROBABLE RETIREMENT YEAR.. 6-2020 NET SALVAGE PERCENT.. -5						
1970	29,175.92	25,477	16,116	14,519	6.99	2,077
1971	25,248.00	21,937	13,877	12,634	7.09	1,782
1973	245.00	211	133	124	7.27	17
1977	66,536.25	55,913	35,369	34,494	7.59	4,545
2007	46,587.71	16,877	10,676	38,241	8.41	4,547
2011	350,911.66	20,217	12,789	355,669	8.44	42,141
	518,704.54	140,632	88,960	455,680		55,109
PADDY'S RUN GENERATOR 13 INTERIM SURVIVOR CURVE.. IOWA 45-R2.5 PROBABLE RETIREMENT YEAR.. 6-2031 NET SALVAGE PERCENT.. -5						
2001	1,971,446.95	728,543	689,025	1,380,994	18.45	74,851
2002	4,531.00	1,566	1,481	3,276	18.53	177
2005	19,123.07	5,034	4,761	15,318	18.74	817
	1,995,101.02	735,143	695,267	1,399,589		75,845
	22,747,816.41	8,545,239	8,652,455	15,232,750		840,013

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 18.1   3.69

KENTUCKY UTILITIES COMPANY

ACCOUNT 343 PRIME MOVERS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2011

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
TRIMBLE COUNTY CT 5						
INTERIM SURVIVOR CURVE.. IOWA 35-R1.5						
PROBABLE RETIREMENT YEAR.. 6-2032						
NET SALVAGE PERCENT.. -5						
2002	29,834,361.10	9,791,593	9,928,548	21,397,532	17.88	1,196,730
2004	535,878.89	148,309	150,383	412,289	18.16	22,703
2006	139,712.62	30,488	30,914	115,784	18.41	6,289
2007	41,824.49	7,768	7,877	36,039	18.52	1,946
2010	35,842.85	2,518	2,553	35,082	18.83	1,863
2011	550,136.10	13,419	13,607	564,036	18.92	29,812
	31,137,756.05	9,994,095	10,133,882	22,560,762		1,259,343
TRIMBLE COUNTY CT 6						
INTERIM SURVIVOR CURVE.. IOWA 35-R1.5						
PROBABLE RETIREMENT YEAR.. 6-2032						
NET SALVAGE PERCENT.. -5						
2002	28,171,612.22	9,245,881	7,844,714	21,735,479	17.88	1,215,631
2004	615,389.01	170,314	144,504	501,655	18.16	27,624
2007	9,593.87	1,782	1,512	8,562	18.52	462
2009	15,420.35	1,730	1,468	14,724	18.73	786
2010	17,172.22	1,206	1,023	17,008	18.83	903
2011	3,201,055.57	78,079	66,247	3,294,862	18.92	174,147
	32,030,243.24	9,498,992	8,059,467	25,572,288		1,419,553
TRIMBLE COUNTY CT 7						
INTERIM SURVIVOR CURVE.. IOWA 35-R1.5						
PROBABLE RETIREMENT YEAR.. 6-2034						
NET SALVAGE PERCENT.. -5						
2004	22,365,242.81	5,814,516	6,120,153	17,363,352	19.57	887,243
2006	404,108.42	82,249	86,572	337,741	19.88	16,989
2007	4,356.44	750	789	3,785	20.03	189
2011	449,407.94	10,127	10,659	461,219	20.52	22,477
	23,223,115.61	5,907,642	6,218,174	18,166,097		926,898

KENTUCKY UTILITIES COMPANY

ACCOUNT 343 PRIME MOVERS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2011

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
TRIMBLE COUNTY CT 8 INTERIM SURVIVOR CURVE.. IOWA 35-R1.5 PROBABLE RETIREMENT YEAR.. 6-2034 NET SALVAGE PERCENT.. -5						
2004	22,269,687.19	5,789,673	6,087,843	17,295,328	19.57	883,767
2006	294,116.88	59,862	62,945	245,878	19.88	12,368
2007	4,356.44	750	789	3,786	20.03	189
2010	17,172.20	1,103	1,160	16,871	20.41	827
2011	449,407.92	10,127	10,649	461,230	20.52	22,477
	23,034,740.63	5,861,515	6,163,385	18,023,093		919,628
TRIMBLE COUNTY CT 9 INTERIM SURVIVOR CURVE.. IOWA 35-R1.5 PROBABLE RETIREMENT YEAR.. 6-2034 NET SALVAGE PERCENT.. -5						
2004	21,943,167.58	5,704,785	5,802,551	17,237,774	19.57	880,826
2006	294,378.88	59,916	60,943	248,155	19.88	12,483
2007	4,356.44	750	763	3,811	20.03	190
2009	193,712.50	19,978	20,320	183,078	20.29	9,023
2010	17,172.22	1,103	1,122	16,909	20.41	828
2011	449,407.92	10,127	10,301	461,578	20.52	22,494
	22,902,195.54	5,796,659	5,896,000	18,151,305		925,844
TRIMBLE COUNTY CT 10 INTERIM SURVIVOR CURVE.. IOWA 35-R1.5 PROBABLE RETIREMENT YEAR.. 6-2034 NET SALVAGE PERCENT.. -5						
2004	21,920,715.56	5,698,948	5,788,053	17,228,698	19.57	880,363
2006	294,703.99	59,982	60,920	248,519	19.88	12,501
2007	170,474.64	29,359	29,818	149,180	20.03	7,448
2009	15,420.35	1,590	1,615	14,577	20.29	718
2011	449,407.92	10,127	10,285	461,593	20.52	22,495
	22,850,722.46	5,800,006	5,890,691	18,102,568		923,525

KENTUCKY UTILITIES COMPANY

ACCOUNT 343 PRIME MOVERS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2011

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
BROWN CT 5 INTERIM SURVIVOR CURVE.. IOWA 35-R1.5 PROBABLE RETIREMENT YEAR.. 6-2031 NET SALVAGE PERCENT.. -5						
2001	12,179,432.18	4,410,337	4,207,294	8,581,110	17.04	503,586
2002	16,181.00	5,482	5,230	11,760	17.17	685
2003	122,530.71	38,399	36,631	92,026	17.30	5,319
2006	718,680.00	162,665	155,176	599,438	17.65	33,962
2007	23,148.35	4,461	4,256	20,050	17.75	1,130
2010	16,889.40	1,236	1,179	16,555	18.02	919
2011	1,590,074.69	40,504	38,639	1,630,939	18.10	90,107
	14,666,936.33	4,663,084	4,448,405	10,951,878		635,708
BROWN CT 6 INTERIM SURVIVOR CURVE.. IOWA 35-R1.5 PROBABLE RETIREMENT YEAR.. 6-2029 NET SALVAGE PERCENT.. -5						
1999	23,425,434.54	10,080,714	6,511,534	18,085,172	15.35	1,178,187
2002	704,287.00	254,936	164,673	574,828	15.70	36,613
2006	3,762,739.34	925,058	597,532	3,353,345	16.06	208,801
2007	28,730.96	6,040	3,901	26,266	16.14	1,627
2008	6,186,526.42	1,059,733	684,524	5,811,329	16.21	358,503
2009	154,832.01	19,894	12,850	149,723	16.28	9,197
2010	302,022.59	24,517	15,837	301,287	16.35	18,427
2011	35,576.42	1,019	658	36,697	16.41	2,236
	34,600,149.28	12,371,911	7,991,509	28,338,648		1,813,591
BROWN CT 7 INTERIM SURVIVOR CURVE.. IOWA 35-R1.5 PROBABLE RETIREMENT YEAR.. 6-2029 NET SALVAGE PERCENT.. -5						
1999	18,968,148.73	8,162,601	5,464,568	14,451,988	15.35	941,498
2001	5,754,196.00	2,222,213	1,487,692	4,554,214	15.59	292,124
2003	143,366.38	48,192	32,263	118,272	15.80	7,486
2004	35,835.80	11,054	7,400	30,227	15.89	1,902

KENTUCKY UTILITIES COMPANY

ACCOUNT 343 PRIME MOVERS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2011

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
BROWN CT 7 INTERIM SURVIVOR CURVE.. IOWA 35-R1.5 PROBABLE RETIREMENT YEAR.. 6-2029 NET SALVAGE PERCENT.. -5						
2006	3,472,462.75	853,695	571,518	3,074,568	16.06	191,443
2007	28,730.96	6,040	4,044	26,124	16.14	1,619
2009	3,254,978.30	418,227	279,988	3,137,739	16.28	192,736
	31,657,718.92	11,722,022	7,847,473	25,393,132		1,628,808
BROWN CT 8 INTERIM SURVIVOR CURVE.. IOWA 35-R1.5 PROBABLE RETIREMENT YEAR.. 6-2025 NET SALVAGE PERCENT.. -5						
1995	13,215,977.31	7,485,272	6,360,118	7,516,658	11.98	627,434
1997	989,546.00	526,671	447,504	591,519	12.16	48,645
1998	2,617,425.00	1,344,329	1,142,255	1,606,041	12.24	131,212
2006	1,654,779.20	491,249	417,407	1,320,112	12.71	103,864
2007	7,728,711.57	1,981,881	1,683,973	6,431,174	12.75	504,406
2010	20,578.26	2,121	1,802	19,805	12.86	1,540
2011	483,972.65	17,862	15,177	492,994	12.90	38,217
	26,710,989.99	11,849,385	10,068,236	17,978,303		1,455,318
BROWN CT 9 INTERIM SURVIVOR CURVE.. IOWA 35-R1.5 PROBABLE RETIREMENT YEAR.. 6-2031 NET SALVAGE PERCENT.. -5						
1994	14,893,195.84	7,407,183	8,262,641	7,375,215	15.79	467,081
1995	409,078.00	196,644	219,354	210,177	16.00	13,136
1996	472,854.00	219,049	244,347	252,150	16.20	15,565
1997	1,221,475.00	543,416	606,175	676,373	16.39	41,267
1998	3,125,155.00	1,331,630	1,485,420	1,795,992	16.56	108,454
2006	1,051,911.47	238,088	265,585	838,922	17.65	47,531
2008	1,524,046.02	238,853	266,438	1,333,810	17.84	74,765
2009	637,647.85	74,653	83,275	586,256	17.93	32,697
	23,335,363.18	10,249,516	11,433,236	13,068,895		800,496

KENTUCKY UTILITIES COMPANY

ACCOUNT 343 PRIME MOVERS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2011

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
BROWN CT 10						
INTERIM SURVIVOR CURVE.. IOWA 35-R1.5						
PROBABLE RETIREMENT YEAR.. 6-2031						
NET SALVAGE PERCENT.. -5						
1995	14,065,320.21	6,761,206	7,302,661	7,465,925	16.00	466,620
1996	3,189,002.00	1,477,304	1,595,610	1,752,842	16.20	108,200
1997	846,896.00	376,771	406,944	482,297	16.39	29,426
1999	66,608.00	27,032	29,197	40,742	16.73	2,435
2006	1,075,401.49	243,404	262,896	866,275	17.65	49,081
2010	831,538.26	60,856	65,730	807,386	18.02	44,805
	20,074,765.96	8,946,573	9,663,038	11,415,466		700,567
BROWN CT 11						
INTERIM SURVIVOR CURVE.. IOWA 35-R1.5						
PROBABLE RETIREMENT YEAR.. 6-2026						
NET SALVAGE PERCENT.. -5						
1996	14,298,883.18	7,607,957	7,007,760	8,006,067	12.83	624,011
1997	744,351.00	382,922	352,713	428,856	12.93	33,168
1998	580,337.00	287,627	264,936	344,418	13.02	26,453
1999	2,301,040.00	1,095,118	1,008,723	1,407,369	13.10	107,433
2000	14,259,988.00	6,481,357	5,970,039	9,002,949	13.18	683,077
2002	336,087.00	136,512	125,742	227,149	13.33	17,040
2003	1,267,900.75	481,223	443,259	888,037	13.39	66,321
2004	26,608.61	9,304	8,570	19,369	13.46	1,439
2007	979,775.63	238,036	219,257	809,507	13.62	59,435
	34,794,971.17	16,720,056	15,401,000	21,133,720		1,618,377
PADDY'S RUN GENERATOR 13						
INTERIM SURVIVOR CURVE.. IOWA 35-R1.5						
PROBABLE RETIREMENT YEAR.. 6-2031						
NET SALVAGE PERCENT.. -5						
2001	15,962,611.04	5,780,277	4,683,843	12,076,899	17.04	708,738
2002	37,538.00	12,718	10,306	29,109	17.17	1,695

KENTUCKY UTILITIES COMPANY

ACCOUNT 343 PRIME MOVERS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2011

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
PADDY'S RUN GENERATOR 13						
INTERIM SURVIVOR CURVE.. IOWA 35-R1.5						
PROBABLE RETIREMENT YEAR.. 6-2031						
NET SALVAGE PERCENT.. -5						
2005	64,854.57	16,702	13,534	54,563	17.54	3,111
2007	40,130.09	7,733	6,266	35,870	17.75	2,021
2009	1,698,230.31	198,820	161,107	1,622,035	17.93	90,465
	17,803,364.01	6,016,250	4,875,055	13,818,477		806,030
	358,823,032.37	125,397,706	114,089,551	262,674,632		15,833,686

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 16.6 4.41

KENTUCKY UTILITIES COMPANY

ACCOUNT 344 GENERATORS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2011

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
TRIMBLE COUNTY CT 5 INTERIM SURVIVOR CURVE.. IOWA 55-S3 PROBABLE RETIREMENT YEAR.. 6-2032 NET SALVAGE PERCENT.. -5						
2002	3,734,423.83	1,247,081	1,168,761	2,752,384	20.37	135,119
2004	28,850.68	8,137	7,626	22,667	20.42	1,110
	3,763,274.51	1,255,218	1,176,387	2,775,051		136,229
TRIMBLE COUNTY CT 6 INTERIM SURVIVOR CURVE.. IOWA 55-S3 PROBABLE RETIREMENT YEAR.. 6-2032 NET SALVAGE PERCENT.. -5						
2002	3,732,468.71	1,246,428	1,168,182	2,750,910	20.37	135,047
2004	25,477.86	7,186	6,735	20,017	20.42	980
	3,757,946.57	1,253,614	1,174,917	2,770,927		136,027
TRIMBLE COUNTY CT 7 INTERIM SURVIVOR CURVE.. IOWA 55-S3 PROBABLE RETIREMENT YEAR.. 6-2034 NET SALVAGE PERCENT.. -5						
2004	2,950,282.37	777,826	748,548	2,349,248	22.37	105,018
	2,950,282.37	777,826	748,548	2,349,248		105,018
TRIMBLE COUNTY CT 8 INTERIM SURVIVOR CURVE.. IOWA 55-S3 PROBABLE RETIREMENT YEAR.. 6-2034 NET SALVAGE PERCENT.. -5						
2004	2,937,930.22	774,569	745,414	2,339,413	22.37	104,578
	2,937,930.22	774,569	745,414	2,339,413		104,578

KENTUCKY UTILITIES COMPANY

ACCOUNT 344 GENERATORS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2011

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
TRIMBLE COUNTY CT 9 INTERIM SURVIVOR CURVE.. IOWA 55-S3 PROBABLE RETIREMENT YEAR.. 6-2034 NET SALVAGE PERCENT.. -5						
2004	2,957,520.12	779,734	741,931	2,363,465	22.37	105,653
	2,957,520.12	779,734	741,931	2,363,465		105,653
TRIMBLE COUNTY CT 10 INTERIM SURVIVOR CURVE.. IOWA 55-S3 PROBABLE RETIREMENT YEAR.. 6-2034 NET SALVAGE PERCENT.. -5						
2004	2,954,148.53	778,845	741,085	2,360,771	22.37	105,533
	2,954,148.53	778,845	741,085	2,360,771		105,533
BROWN CT 5 INTERIM SURVIVOR CURVE.. IOWA 55-S3 PROBABLE RETIREMENT YEAR.. 6-2031 NET SALVAGE PERCENT.. -5						
2001	2,786,638.61	1,028,537	931,469	1,994,502	19.37	102,969
2002	3,906.00	1,348	1,221	2,881	19.40	149
2011	67,603.05	1,775	1,607	69,376	19.49	3,560
	2,858,147.66	1,031,660	934,297	2,066,758		106,678
BROWN CT 6 INTERIM SURVIVOR CURVE.. IOWA 55-S3 PROBABLE RETIREMENT YEAR.. 6-2029 NET SALVAGE PERCENT.. -5						
1999	3,712,619.52	1,630,053	1,492,911	2,405,339	17.38	138,397
	3,712,619.52	1,630,053	1,492,911	2,405,339		138,397

KENTUCKY UTILITIES COMPANY

ACCOUNT 344 GENERATORS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2011

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
BROWN CT 7						
INTERIM SURVIVOR CURVE.. IOWA 55-S3						
PROBABLE RETIREMENT YEAR.. 6-2029						
NET SALVAGE PERCENT.. -5						
1999	3,693,120.46	1,621,492	1,452,787	2,424,990	17.38	139,528
2001	29,668.00	11,715	10,496	20,655	17.42	1,186
	3,722,788.46	1,633,207	1,463,283	2,445,645		140,714
BROWN CT 8						
INTERIM SURVIVOR CURVE.. IOWA 55-S3						
PROBABLE RETIREMENT YEAR.. 6-2025						
NET SALVAGE PERCENT.. -5						
1995	4,953,960.72	2,871,628	2,809,555	2,392,104	13.38	178,782
	4,953,960.72	2,871,628	2,809,555	2,392,104		178,782
BROWN CT 9						
INTERIM SURVIVOR CURVE.. IOWA 55-S3						
PROBABLE RETIREMENT YEAR.. 6-2031						
NET SALVAGE PERCENT.. -5						
1994	5,333,167.97	2,683,997	3,016,399	2,583,428	18.99	136,041
1995	118,873.00	57,880	65,048	59,768	19.07	3,134
	5,452,040.97	2,741,877	3,081,447	2,643,196		139,175
BROWN CT 10						
INTERIM SURVIVOR CURVE.. IOWA 55-S3						
PROBABLE RETIREMENT YEAR.. 6-2031						
NET SALVAGE PERCENT.. -5						
1995	4,944,422.71	2,407,469	2,624,840	2,566,804	19.07	134,599
	4,944,422.71	2,407,469	2,624,840	2,566,804		134,599

KENTUCKY UTILITIES COMPANY

ACCOUNT 344 GENERATORS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2011

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
BROWN CT 11						
INTERIM SURVIVOR CURVE.. IOWA 55-S3						
PROBABLE RETIREMENT YEAR.. 6-2026						
NET SALVAGE PERCENT.. -5						
1996	5,067,929.30	2,759,533	2,664,119	2,657,207	14.38	184,785
1997	119,111.00	62,750	60,580	64,486	14.40	4,478
	5,187,040.30	2,822,283	2,724,699	2,721,693		189,263
HAEFLING UNITS 1, 2 AND 3						
INTERIM SURVIVOR CURVE.. IOWA 55-S3						
PROBABLE RETIREMENT YEAR.. 6-2020						
NET SALVAGE PERCENT.. -5						
1970	3,502,967.37	3,082,813	3,146,656	531,459	7.56	70,299
1971	146,547.00	128,385	131,044	22,831	7.63	2,992
1975	18,497.00	15,884	16,213	3,209	7.87	408
2001	354,991.00	205,988	210,254	162,487	8.50	19,116
	4,023,002.37	3,433,070	3,504,167	719,985		92,815
PADDY'S RUN GENERATOR 13						
INTERIM SURVIVOR CURVE.. IOWA 55-S3						
PROBABLE RETIREMENT YEAR.. 6-2031						
NET SALVAGE PERCENT.. -5						
2001	5,174,634.11	1,909,937	1,789,075	3,644,291	19.37	188,141
2002	11,002.00	3,797	3,557	7,995	19.40	412
	5,185,636.11	1,913,734	1,792,632	3,652,286		188,553
	59,360,761.14	26,104,787	25,756,113	36,572,685		2,002,014

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 18.3 3.37

KENTUCKY UTILITIES COMPANY

ACCOUNT 345 ACCESSORY ELECTRIC EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2011

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
TRIMBLE COUNTY CT 5 INTERIM SURVIVOR CURVE.. IOWA 45-R3 PROBABLE RETIREMENT YEAR.. 6-2032 NET SALVAGE PERCENT.. -5						
2002	1,656,154.97	559,250	509,783	1,229,180	19.66	62,522
2004	12,857.15	3,661	3,337	10,163	19.83	513
2011	24,962.92	633	577	25,634	20.21	1,268
	1,693,975.04	563,544	513,697	1,264,977		64,303
TRIMBLE COUNTY CT 6 INTERIM SURVIVOR CURVE.. IOWA 45-R3 PROBABLE RETIREMENT YEAR.. 6-2032 NET SALVAGE PERCENT.. -5						
2002	4,313,237.34	1,456,494	1,034,595	3,494,304	19.66	177,737
2004	11,354.12	3,233	2,297	9,625	19.83	485
	4,324,591.46	1,459,727	1,036,892	3,503,929		178,222
TRIMBLE COUNTY CT 7 INTERIM SURVIVOR CURVE.. IOWA 45-R3 PROBABLE RETIREMENT YEAR.. 6-2034 NET SALVAGE PERCENT.. -5						
2004	3,146,235.12	840,125	791,867	2,511,679	21.61	116,228
2009	2,204.23	234	221	2,094	22.00	95
	3,148,439.35	840,359	792,088	2,513,773		116,323
TRIMBLE COUNTY CT 8 INTERIM SURVIVOR CURVE.. IOWA 45-R3 PROBABLE RETIREMENT YEAR.. 6-2034 NET SALVAGE PERCENT.. -5						
2004	3,137,127.45	837,693	789,575	2,504,408	21.61	115,891
2009	2,204.23	234	221	2,094	22.00	95
	3,139,331.68	837,927	789,796	2,506,502		115,986

KENTUCKY UTILITIES COMPANY

ACCOUNT 345 ACCESSORY ELECTRIC EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2011

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
TRIMBLE COUNTY CT 9						
INTERIM SURVIVOR CURVE.. IOWA 45-R3						
PROBABLE RETIREMENT YEAR.. 6-2034						
NET SALVAGE PERCENT.. -5						
2004	3,231,827.28	862,980	804,174	2,589,245	21.61	119,817
2009	2,204.19	234	218	2,096	22.00	95
	3,234,031.47	863,214	804,392	2,591,341		119,912
TRIMBLE COUNTY CT 10						
INTERIM SURVIVOR CURVE.. IOWA 45-R3						
PROBABLE RETIREMENT YEAR.. 6-2034						
NET SALVAGE PERCENT.. -5						
2004	7,144,489.03	1,907,761	1,450,327	6,051,386	21.61	280,027
2009	2,204.23	234	178	2,137	22.00	97
2011	49,925.08	1,136	864	51,558	22.11	2,332
	7,196,618.34	1,909,131	1,451,369	6,105,080		282,456
BROWN CT 5						
INTERIM SURVIVOR CURVE.. IOWA 45-R3						
PROBABLE RETIREMENT YEAR.. 6-2031						
NET SALVAGE PERCENT.. -5						
2001	2,262,097.84	842,556	661,447	1,713,755	18.70	91,645
2002	3,069.00	1,069	839	2,383	18.78	127
2010	11,853.65	896	703	11,743	19.22	611
	2,277,020.49	844,521	662,990	1,727,882		92,383
BROWN CT 6						
INTERIM SURVIVOR CURVE.. IOWA 45-R3						
PROBABLE RETIREMENT YEAR.. 6-2029						
NET SALVAGE PERCENT.. -5						
1999	1,930,284.42	853,951	688,962	1,337,837	16.77	79,776
2010	44,931.99	3,741	3,018	44,160	17.30	2,553
	1,975,216.41	857,692	691,980	1,381,997		82,329

KENTUCKY UTILITIES COMPANY

ACCOUNT 345 ACCESSORY ELECTRIC EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2011

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
BROWN CT 7						
INTERIM SURVIVOR CURVE.. IOWA 45-R3						
PROBABLE RETIREMENT YEAR.. 6-2029						
NET SALVAGE PERCENT.. -5						
1999	1,920,146.21	849,466	674,513	1,341,640	16.77	80,002
2010	15,635.77	1,302	1,034	15,384	17.30	889
	1,935,781.98	850,768	675,547	1,357,024		80,891
BROWN CT 8						
INTERIM SURVIVOR CURVE.. IOWA 45-R3						
PROBABLE RETIREMENT YEAR.. 6-2025						
NET SALVAGE PERCENT.. -5						
1993	1,248,083.99	763,425	647,250	663,239	12.82	51,735
1995	1,159,336.00	673,765	571,234	646,069	12.94	49,928
1997	302,783.00	165,561	140,367	177,556	13.04	13,616
2007	10,526.68	2,766	2,345	8,708	13.36	652
	2,720,729.67	1,605,517	1,361,195	1,495,571		115,931
BROWN CT 9						
INTERIM SURVIVOR CURVE.. IOWA 45-R3						
PROBABLE RETIREMENT YEAR.. 6-2031						
NET SALVAGE PERCENT.. -5						
1994	1,895,387.28	963,574	966,318	1,023,838	17.92	57,134
1995	1,463,066.43	719,489	721,538	814,681	18.06	45,110
1996	293,484.00	139,312	139,709	168,449	18.18	9,266
1997	336,423.00	153,541	153,978	199,266	18.30	10,889
2011	217,486.58	5,666	5,682	222,679	19.26	11,562
	4,205,847.29	1,981,582	1,987,226	2,428,914		133,961

KENTUCKY UTILITIES COMPANY

ACCOUNT 345 ACCESSORY ELECTRIC EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2011

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
BROWN CT 10 INTERIM SURVIVOR CURVE.. IOWA 45-R3 PROBABLE RETIREMENT YEAR.. 6-2031 NET SALVAGE PERCENT.. -5						
1993	940,073.23	492,847	474,155	512,922	17.77	28,864
1995	1,483,977.47	729,772	702,094	856,082	18.06	47,402
1997	320,442.00	146,247	140,700	195,764	18.30	10,697
	2,744,492.70	1,368,866	1,316,949	1,564,768		86,963
BROWN CT 11 INTERIM SURVIVOR CURVE.. IOWA 45-R3 PROBABLE RETIREMENT YEAR.. 6-2026 NET SALVAGE PERCENT.. -5						
1996	1,827,626.15	998,575	764,079	1,154,929	13.90	83,088
1997	35,427.00	18,732	14,333	22,865	13.95	1,639
	1,863,053.15	1,017,307	778,412	1,177,794		84,727
HAEFLING UNITS 1, 2 AND 3 INTERIM SURVIVOR CURVE.. IOWA 45-R3 PROBABLE RETIREMENT YEAR.. 6-2020 NET SALVAGE PERCENT.. -5						
1970	558,950.80	492,801	472,591	114,308	6.79	16,835
1971	41,999.00	36,824	35,314	8,785	6.92	1,270
1973	2,825.81	2,450	2,350	618	7.16	86
2007	19,643.19	7,130	6,838	13,788	8.46	1,630
2011	828,538.23	48,440	46,453	823,512	8.48	97,112
	1,451,957.03	587,645	563,545	961,010		116,933

KENTUCKY UTILITIES COMPANY

ACCOUNT 345 ACCESSORY ELECTRIC EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2011

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
PADDY'S RUN GENERATOR 13 INTERIM SURVIVOR CURVE.. IOWA 45-R3 PROBABLE RETIREMENT YEAR.. 6-2031 NET SALVAGE PERCENT.. -5						
2001	2,451,142.01	912,968	843,167	1,730,532	18.70	92,542
2002	5,178.00	1,803	1,665	3,772	18.78	201
	2,456,320.01	914,771	844,832	1,734,304		92,743
	44,367,406.07	16,502,571	14,270,910	32,314,866		1,764,063

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 18.3 3.98

KENTUCKY UTILITIES COMPANY

ACCOUNT 346 MISCELLANEOUS POWER PLANT EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2011

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
TRIMBLE COUNTY CT 5						
INTERIM SURVIVOR CURVE.. IOWA 35-R2						
PROBABLE RETIREMENT YEAR.. 6-2032						
NET SALVAGE PERCENT.. -5						
2006	15,274.16	3,424	4,753	11,285	18.75	602
2007	13,689.47	2,611	3,624	10,750	18.88	569
	28,963.63	6,035	8,377	22,035		1,171
TRIMBLE COUNTY CT 7						
INTERIM SURVIVOR CURVE.. IOWA 35-R2						
PROBABLE RETIREMENT YEAR.. 6-2034						
NET SALVAGE PERCENT.. -5						
2004	8,888.93	2,386	2,318	7,015	19.89	353
	8,888.93	2,386	2,318	7,015		353
TRIMBLE COUNTY CT 8						
INTERIM SURVIVOR CURVE.. IOWA 35-R2						
PROBABLE RETIREMENT YEAR.. 6-2034						
NET SALVAGE PERCENT.. -5						
2004	8,861.01	2,378	2,310	6,994	19.89	352
	8,861.01	2,378	2,310	6,994		352
TRIMBLE COUNTY CT 9						
INTERIM SURVIVOR CURVE.. IOWA 35-R2						
PROBABLE RETIREMENT YEAR.. 6-2034						
NET SALVAGE PERCENT.. -5						
2004	9,113.52	2,446	2,350	7,219	19.89	363
	9,113.52	2,446	2,350	7,219		363

KENTUCKY UTILITIES COMPANY

ACCOUNT 346 MISCELLANEOUS POWER PLANT EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2011

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
TRIMBLE COUNTY CT 10 INTERIM SURVIVOR CURVE.. IOWA 35-R2 PROBABLE RETIREMENT YEAR.. 6-2034 NET SALVAGE PERCENT.. -5						
2004	9,105.52	2,444	2,331	7,230	19.89	363
2010	26,747.06	1,777	1,695	26,390	20.87	1,264
2011	6,015.93	138	132	6,185	21.00	295
	41,868.51	4,359	4,157	39,805		1,922
BROWN CT 5 INTERIM SURVIVOR CURVE.. IOWA 35-R2 PROBABLE RETIREMENT YEAR.. 6-2031 NET SALVAGE PERCENT.. -5						
2001	2,082,373.17	776,554	736,460	1,450,031	17.23	84,157
2002	2,790.00	972	922	2,008	17.40	115
2003	998.32	322	305	743	17.56	42
2004	22,748.93	6,693	6,347	17,539	17.70	991
2007	30,442.19	6,026	5,715	26,249	18.08	1,452
	2,139,352.61	790,567	749,750	1,496,570		86,757
BROWN CT 6 INTERIM SURVIVOR CURVE.. IOWA 35-R2 PROBABLE RETIREMENT YEAR.. 6-2029 NET SALVAGE PERCENT.. -5						
1999	15,859.82	6,999	7,052	9,601	15.49	620
2001	2,144.00	850	856	1,395	15.77	88
2003	16,198.37	5,579	5,621	11,387	16.02	711
2005	14,757.51	4,201	4,233	11,262	16.24	693
2011	4,789.15	140	141	4,888	16.73	292
	53,748.85	17,769	17,904	38,532		2,404

KENTUCKY UTILITIES COMPANY

ACCOUNT 346 MISCELLANEOUS POWER PLANT EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2011

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
BROWN CT 7 INTERIM SURVIVOR CURVE.. IOWA 35-R2 PROBABLE RETIREMENT YEAR.. 6-2029 NET SALVAGE PERCENT.. -5						
1999	15,776.54	6,962	6,801	9,764	15.49	630
2003	19,870.85	6,844	6,686	14,179	16.02	885
	35,647.39	13,806	13,487	23,943		1,515
BROWN CT 8 INTERIM SURVIVOR CURVE.. IOWA 35-R2 PROBABLE RETIREMENT YEAR.. 6-2025 NET SALVAGE PERCENT.. -5						
1994	34,743.72	20,612	20,556	15,925	11.91	1,337
1995	185,434.00	107,045	106,752	87,953	12.03	7,311
2001	9,891.00	4,522	4,510	5,876	12.58	467
2011	55,863.61	2,074	2,068	56,588	13.10	4,320
	285,932.33	134,253	133,886	166,343		13,435
BROWN CT 9 INTERIM SURVIVOR CURVE.. IOWA 35-R2 PROBABLE RETIREMENT YEAR.. 6-2031 NET SALVAGE PERCENT.. -5						
1994	196,427.37	100,880	115,989	90,260	15.73	5,738
1995	548,710.00	271,998	312,736	263,410	15.99	16,473
1996	5,227.00	2,496	2,870	2,619	16.23	161
2001	9,891.00	3,689	4,242	6,144	17.23	357
	760,255.37	379,063	435,836	362,432		22,729

KENTUCKY UTILITIES COMPANY

ACCOUNT 346 MISCELLANEOUS POWER PLANT EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2011

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
BROWN CT 10						
INTERIM SURVIVOR CURVE.. IOWA 35-R2						
PROBABLE RETIREMENT YEAR.. 6-2031						
NET SALVAGE PERCENT.. -5						
1995	228,488.31	113,263	119,783	120,130	15.99	7,513
1996	3,144.00	1,501	1,587	1,714	16.23	106
2001	9,891.00	3,689	3,901	6,484	17.23	376
2003	32,867.56	10,586	11,195	23,316	17.56	1,328
	274,390.87	129,039	136,467	151,643		9,323
BROWN CT 11						
INTERIM SURVIVOR CURVE.. IOWA 35-R2						
PROBABLE RETIREMENT YEAR.. 6-2026						
NET SALVAGE PERCENT.. -5						
1996	149,568.53	81,286	74,475	82,572	12.89	6,406
1997	21,262.00	11,171	10,235	12,090	13.01	929
1999	9,687.00	4,703	4,309	5,862	13.22	443
2001	24,337.00	10,700	9,803	15,750	13.41	1,174
2003	277,131.30	107,072	98,101	192,887	13.57	14,214
2004	46,587.64	16,606	15,215	33,702	13.64	2,471
2005	20,014.16	6,471	5,929	15,086	13.71	1,100
2011	41,975.19	1,459	1,337	42,737	14.02	3,048
	590,562.82	239,468	219,404	400,687		29,785
HAEFLING UNITS 1, 2 AND 3						
INTERIM SURVIVOR CURVE.. IOWA 35-R2						
PROBABLE RETIREMENT YEAR.. 6-2020						
NET SALVAGE PERCENT.. -5						
1970	30,264.20	26,704	29,010	2,767	5.51	502
1971	5,428.00	4,761	5,172	527	5.66	93
1973	113.00	98	106	12	5.97	2
	35,805.20	31,563	34,289	3,306		597

KENTUCKY UTILITIES COMPANY

ACCOUNT 346 MISCELLANEOUS POWER PLANT EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2011

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)

PADDY'S RUN GENERATOR 13
INTERIM SURVIVOR CURVE.. IOWA 35-R2
PROBABLE RETIREMENT YEAR.. 6-2031
NET SALVAGE PERCENT.. -5

2001	1,086,962.03	405,348	384,083	757,227	17.23	43,948
2002	2,588.00	902	855	1,863	17.40	107
	1,089,550.03	406,250	384,938	759,090		44,055
	5,362,941.07	2,159,382	2,145,473	3,485,614		214,761

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 16.2 4.00

KENTUCKY UTILITIES COMPANY

ACCOUNT 350.1 LAND RIGHTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2011

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 60-R3						
NET SALVAGE PERCENT.. 0						
1941	686,361.06	594,849	686,361			
1942	27,091.62	23,330	27,092			
1943	1,077.00	921	1,077			
1944	860.00	731	860			
1945	5,395.00	4,552	5,395			
1946	38,829.00	32,513	38,829			
1947	65,530.00	54,444	65,530			
1948	33,277.00	27,420	33,277			
1949	228,344.00	186,557	228,344			
1950	22,549.00	18,257	22,549			
1951	104,789.00	84,059	104,789			
1952	186,048.00	147,784	186,048			
1953	409,306.00	321,784	409,306			
1954	108,821.00	84,644	108,821			
1955	85,914.00	66,082	85,914			
1956	259,450.00	197,268	258,832	618	14.38	43
1957	32,179.00	24,172	31,716	463	14.93	31
1958	373,514.00	277,084	363,557	9,957	15.49	643
1959	226,833.00	166,080	217,910	8,923	16.07	555
1960	263,434.00	190,286	249,671	13,763	16.66	826
1961	327,284.00	233,082	305,823	21,461	17.27	1,243
1962	280,359.36	196,765	258,172	22,187	17.89	1,240
1963	465,120.00	321,477	421,804	43,316	18.53	2,338
1964	93,142.00	63,367	83,143	9,999	19.18	521
1965	287,634.00	192,522	252,604	35,030	19.84	1,766
1966	415,879.00	273,719	359,142	56,737	20.51	2,766
1967	611,565.00	395,579	519,032	92,533	21.19	4,367
1968	128,655.00	81,718	107,221	21,434	21.89	979
1969	402,094.00	250,637	328,856	73,238	22.60	3,241
1970	1,682,695.00	1,028,682	1,349,714	332,981	23.32	14,279
1971	970,069.00	581,236	762,629	207,440	24.05	8,625
1972	593,107.00	348,053	456,674	136,433	24.79	5,504
1973	978,038.00	561,883	737,236	240,802	25.53	9,432
1974	542,946.00	305,043	400,241	142,705	26.29	5,428
1975	172,802.00	94,868	124,475	48,327	27.06	1,786
1976	454,641.00	243,688	319,738	134,903	27.84	4,846
1977	141,182.00	73,814	96,850	44,332	28.63	1,548
1978	902,286.00	459,868	603,384	298,902	29.42	10,160
1979	881,852.00	437,549	574,100	307,752	30.23	10,180
1980	758,709.00	366,206	480,492	278,217	31.04	8,963
1981	572,541.00	268,522	352,323	220,218	31.86	6,912
1982	859,510.00	391,223	513,316	346,194	32.69	10,590

KENTUCKY UTILITIES COMPANY

ACCOUNT 350.1 LAND RIGHTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2011

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 60-R3						
NET SALVAGE PERCENT.. 0						
1983	315,498.00	139,188	182,626	132,872	33.53	3,963
1984	2,222,027.00	948,806	1,244,910	977,117	34.38	28,421
1985	1,379,271.00	569,404	747,104	632,167	35.23	17,944
1986	169,584.00	67,579	88,669	80,915	36.09	2,242
1987	604,324.00	232,060	304,482	299,842	36.96	8,113
1988	124,766.00	46,080	60,461	64,305	37.84	1,699
1989	125,746.00	44,598	58,516	67,230	38.72	1,736
1990	125,552.00	42,666	55,981	69,571	39.61	1,756
1991	308,966.00	100,361	131,682	177,284	40.51	4,376
1992	56,034.00	17,361	22,779	33,255	41.41	803
1993	47,759.00	14,073	18,465	29,294	42.32	692
1994	84,416.00	23,580	30,939	53,477	43.24	1,237
1995	414,604.00	109,455	143,614	270,990	44.16	6,137
1996	75,397.00	18,749	24,600	50,797	45.08	1,127
1997	64,154.96	14,948	19,613	44,542	46.02	968
1998	315,419.00	68,550	89,943	225,476	46.96	4,801
1999	347,323.37	70,045	91,905	255,418	47.90	5,332
2000	70,004.00	13,009	17,069	52,935	48.85	1,084
2003	349,837.18	48,337	63,422	286,415	51.71	5,539
2005	545.00	58	76	469	53.64	9
2009	353,837.52	14,507	19,034	334,804	57.54	5,819
2010	152,130.15	3,753	4,925	147,205	58.52	2,515
2011	24,821.33	203	266	24,555	59.51	413
	23,413,728.55	12,279,688	15,953,928	7,459,801		225,538

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 33.1   0.96

KENTUCKY UTILITIES COMPANY

ACCOUNT 352.1 STRUCTURES AND IMPROVEMENTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2011

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 65-S2.5						
NET SALVAGE PERCENT.. -25						
1940	8,528.63	8,629	10,661			
1941	44,157.34	44,395	55,197			
1946	219.16	213	269	5	14.47	
1947	3,222.45	3,108	3,929	99	14.85	7
1948	1,400.50	1,340	1,694	57	15.24	4
1949	27,602.72	26,201	33,121	1,382	15.64	88
1950	22,381.88	21,069	26,634	1,343	16.05	84
1951	26,145.14	24,401	30,846	1,835	16.47	111
1952	2,055.05	1,901	2,403	166	16.91	10
1953	28,141.84	25,788	32,599	2,578	17.35	149
1954	46,002.37	41,747	52,774	4,729	17.81	266
1955	15,456.35	13,884	17,551	1,769	18.29	97
1956	36,552.43	32,496	41,079	4,612	18.77	246
1957	13,839.54	12,171	15,386	1,913	19.27	99
1958	51,612.46	44,883	56,738	7,778	19.78	393
1959	37,746.86	32,448	41,018	6,166	20.30	304
1960	37,268.81	31,650	40,010	6,576	20.84	316
1961	17,168.99	14,396	18,198	3,263	21.40	152
1962	12,553.11	10,390	13,134	2,557	21.96	116
1963	11,844.93	9,670	12,224	2,582	22.55	115
1964	45,581.34	36,684	46,373	10,604	23.15	458
1965	41,816.02	33,163	41,922	10,348	23.76	436
1966	51,469.71	40,196	50,813	13,524	24.39	554
1967	12,866.81	9,890	12,502	3,582	25.03	143
1968	13,800.95	10,433	13,189	4,062	25.69	158
1969	44,356.76	32,952	41,656	13,790	26.37	523
1970	73,194.15	53,403	67,508	23,985	27.06	886
1971	126,495.30	90,590	114,518	43,601	27.76	1,571
1972	199,094.35	139,826	176,758	72,110	28.48	2,532
1973	26,126.25	17,977	22,725	9,933	29.22	340
1974	38,488.58	25,928	32,776	15,335	29.97	512
1975	88,204.77	58,114	73,464	36,792	30.74	1,197
1976	43,828.79	28,219	35,672	19,114	31.52	606
1977	232,274.10	146,019	184,587	105,756	32.31	3,273
1978	212,108.91	129,999	164,336	100,800	33.13	3,043
1979	213,681.54	127,592	161,293	105,809	33.95	3,117
1980	225,414.87	130,958	165,548	116,221	34.79	3,341
1981	103,029.64	58,172	73,537	55,250	35.64	1,550
1982	707,302.58	387,655	490,046	394,082	36.50	10,797
1983	432,390.30	229,751	290,435	250,053	37.37	6,691
1984	217,749.69	111,972	141,547	130,640	38.26	3,415
1985	140,292.86	69,715	88,129	87,237	39.16	2,228

KENTUCKY UTILITIES COMPANY

ACCOUNT 352.1 STRUCTURES AND IMPROVEMENTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2011

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 65-S2.5						
NET SALVAGE PERCENT.. -25						
1986	53,056.45	25,447	32,168	34,153	40.06	853
1987	126,741.07	58,545	74,008	84,418	40.98	2,060
1988	114,353.09	50,777	64,189	78,752	41.91	1,879
1989	11,515.59	4,907	6,203	8,191	42.84	191
1990	171,913.94	70,154	88,684	126,208	43.78	2,883
1991	7,702.35	3,002	3,795	5,833	44.73	130
1992	145,496.77	54,030	68,301	113,570	45.69	2,486
1993	108,143.48	38,162	48,242	86,937	46.65	1,864
1994	300,330.81	100,378	126,891	248,523	47.62	5,219
1995	479,982.26	151,380	191,364	408,614	48.60	8,408
1996	105,458.55	31,292	39,557	92,266	49.57	1,861
1997	109,754.62	30,477	38,527	98,666	50.56	1,951
1998	633,320.49	163,935	207,235	584,416	51.54	11,339
1999	30,113.28	7,222	9,130	28,512	52.53	543
2000	204,160.00	45,073	56,978	198,222	53.52	3,704
2001	153,863.03	31,038	39,236	153,093	54.51	2,809
2002	81,986.71	14,963	18,915	83,568	55.51	1,505
2003	38,594.54	6,302	7,967	40,276	56.51	713
2004	293,527.04	42,334	53,516	313,393	57.50	5,450
2005	199,204.44	24,901	31,478	217,528	58.50	3,718
2007	199,665.65	17,279	21,843	227,739	60.50	3,764
2008	5,368,532.29	361,369	456,816	6,253,849	61.50	101,689
2009	2,352,857.19	113,114	142,991	2,798,080	62.50	44,769
2010	130,562.84	3,767	4,762	158,442	63.50	2,495
2011	1,865,753.20	17,935	22,672	2,309,520	64.50	35,807
	17,020,058.51	3,837,771	4,850,267	16,424,806		298,018

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 55.1 1.75

KENTUCKY UTILITIES COMPANY

ACCOUNT 352.2 STRUCTURES AND IMPROVEMENTS - SYS CONTROL/COM

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2011

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 60-R3						
NET SALVAGE PERCENT.. -25						
1956	146,345.39	139,088	170,326	12,606	14.38	877
1958	9,243.36	8,571	10,496	1,058	15.49	68
1960	35.08	32	39	5	16.66	
1962	26.03	23	28	5	17.89	
1968	50.32	40	49	14	21.89	1
1971	2,232.63	1,672	2,048	743	24.05	31
1974	6,614.02	4,645	5,688	2,580	26.29	98
1976	1,298.83	870	1,065	559	27.84	20
1979	139.70	87	107	68	30.23	2
1981	877,513.52	514,442	629,981	466,911	31.86	14,655
1987	6,449.77	3,096	3,791	4,271	36.96	116
1988	4,541.07	2,096	2,567	3,109	37.84	82
1989	5,584.75	2,476	3,032	3,949	38.72	102
1992	4,768.63	1,847	2,262	3,699	41.41	89
1997	77,868.93	22,679	27,772	69,564	46.02	1,512
2011	77,830.59	795	974	96,314	59.51	1,618
	1,220,542.62	702,459	860,225	665,453		19,271

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 34.5   1.58

KENTUCKY UTILITIES COMPANY

ACCOUNT 353.1 STATION EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2011

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 60-R2						
NET SALVAGE PERCENT.. -10						
1903	182.93	199	201			
1914	21,377.34	22,049	23,515			
1929	17,786.04	16,917	19,565			
1940	614.96	544	632	44	11.76	4
1941	36,600.24	32,114	37,316	2,944	12.14	243
1942	3,185.97	2,773	3,222	283	12.52	23
1943	7,532.50	6,503	7,556	730	12.91	57
1944	3,567.00	3,053	3,548	376	13.31	28
1945	17,308.07	14,688	17,067	1,972	13.71	144
1946	23,674.00	19,909	23,134	2,907	14.13	206
1947	24,318.71	20,259	23,541	3,210	14.56	220
1948	19,667.97	16,230	18,859	2,776	14.99	185
1949	466,281.22	380,922	442,625	70,284	15.44	4,552
1950	687,208.34	555,608	645,607	110,322	15.90	6,938
1951	427,808.96	342,274	397,717	72,873	16.36	4,454
1952	124,161.66	98,245	114,159	22,419	16.84	1,331
1953	2,185,776.20	1,710,289	1,987,327	417,027	17.32	24,078
1954	626,025.60	484,106	562,523	126,105	17.82	7,077
1955	1,333,286.59	1,018,814	1,183,845	282,770	18.32	15,435
1956	1,240,757.23	936,275	1,087,936	276,897	18.84	14,697
1957	1,595,177.56	1,188,508	1,381,026	373,669	19.36	19,301
1958	102,085.21	75,049	87,206	25,088	19.90	1,261
1959	625,322.69	453,523	526,986	160,869	20.44	7,870
1960	430,951.91	308,131	358,043	116,004	21.00	5,524
1961	524,455.70	369,603	429,472	147,429	21.56	6,838
1962	333,747.15	231,654	269,178	97,944	22.14	4,424
1963	1,000,895.92	684,075	794,884	306,102	22.72	13,473
1964	1,172,792.28	788,879	916,664	373,408	23.31	16,019
1965	1,062,368.84	702,718	816,546	352,060	23.92	14,718
1966	825,533.55	536,834	623,792	284,295	24.53	11,590
1967	286,883.75	183,294	212,985	102,587	25.15	4,079
1968	488,828.48	306,673	356,349	181,362	25.78	7,035
1969	2,850,144.76	1,755,156	2,039,461	1,095,698	26.41	41,488
1970	2,280,328.87	1,377,091	1,600,156	908,206	27.06	33,563
1971	3,155,389.73	1,867,950	2,170,526	1,300,403	27.71	46,929
1972	1,683,828.61	976,115	1,134,229	717,982	28.38	25,299
1973	1,077,738.05	611,523	710,579	474,933	29.05	16,349
1974	1,944,466.97	1,079,082	1,253,875	885,039	29.73	29,769
1975	1,355,004.17	734,819	853,847	636,658	30.42	20,929
1976	489,265.90	259,140	301,116	237,076	31.11	7,621
1977	8,033,512.04	4,151,823	4,824,348	4,012,515	31.81	126,140
1978	2,855,407.76	1,438,554	1,671,575	1,469,374	32.52	45,184

KENTUCKY UTILITIES COMPANY

ACCOUNT 353.1 STATION EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2011

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 60-R2						
NET SALVAGE PERCENT.. -10						
1979	3,854,639.79	1,891,086	2,197,410	2,042,694	33.24	61,453
1980	6,906,214.58	3,295,735	3,829,588	3,767,248	33.97	110,899
1981	3,355,635.01	1,556,468	1,808,589	1,882,610	34.70	54,254
1982	10,288,890.29	4,632,707	5,383,127	5,934,652	35.44	167,456
1983	1,598,809.56	697,901	810,949	947,742	36.19	26,188
1984	4,552,721.42	1,924,722	2,236,494	2,771,500	36.94	75,027
1985	6,969,928.88	2,849,565	3,311,146	4,355,776	37.70	115,538
1986	895,756.47	353,567	410,839	574,493	38.47	14,934
1987	600,423.96	228,409	265,407	395,059	39.25	10,065
1988	2,837,438.57	1,038,823	1,207,095	1,914,087	40.03	47,816
1989	1,763,175.69	620,308	720,787	1,218,706	40.81	29,863
1990	1,396,352.13	470,780	547,038	988,949	41.61	23,767
1991	948,808.31	305,978	355,541	688,148	42.41	16,226
1992	7,254,738.74	2,233,103	2,594,828	5,385,385	43.21	124,633
1993	2,381,585.89	697,717	810,735	1,809,009	44.02	41,095
1994	1,647,624.38	457,936	532,114	1,280,273	44.84	28,552
1995	3,727,249.19	979,197	1,137,810	2,962,164	45.67	64,860
1996	2,335,572.59	578,491	672,197	1,896,933	46.49	40,803
1997	3,955,046.34	918,706	1,067,521	3,283,030	47.33	69,365
1998	3,936,254.24	853,722	992,011	3,337,869	48.17	69,294
1999	1,113,230.00	224,301	260,634	963,919	49.01	19,668
2000	3,391,520.96	629,850	731,875	2,998,798	49.87	60,132
2001	174,996.74	29,773	34,596	157,900	50.72	3,113
2002	702,780.00	108,483	126,055	647,003	51.58	12,544
2003	13,417,061.12	1,857,096	2,157,914	12,600,853	52.45	240,245
2004	2,379,012.99	291,341	338,533	2,278,381	53.32	42,730
2005	3,362,610.06	357,570	415,490	3,283,381	54.20	60,579
2006	2,976,240.72	268,457	311,943	2,961,922	55.08	53,775
2007	2,815,160.85	208,499	242,272	2,854,405	55.96	51,008
2008	6,489,437.94	374,765	435,471	6,702,911	56.85	117,905
2009	11,138,655.26	459,470	533,896	11,718,625	57.75	202,920
2010	19,672,712.51	490,578	570,044	21,069,940	58.64	359,310
2011	11,472,251.56	94,646	109,977	12,509,500	59.55	210,067
	191,753,788.17	57,741,715	67,092,664	143,836,503		3,211,159

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 44.8   1.67

KENTUCKY UTILITIES COMPANY

ACCOUNT 353.2 STATION EQUIPMENT - SYS CONTROL/COM

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2011

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 35-R2.5						
NET SALVAGE PERCENT.. -10						
1956	47,409.75	48,470	52,151			
1957	4,105.00	4,167	4,516			
1958	21,186.00	21,360	23,305			
1959	668.56	669	735			
1963	18.00	18	20			
1964	520.00	502	572			
1965	4,631.00	4,436	5,094			
1966	126.37	120	139			
1969	14,534.00	13,439	15,987			
1970	395.87	362	435			
1971	595.00	538	654			
1972	279.00	249	307			
1974	20,933.98	18,231	23,027			
1975	157,495.54	135,131	173,245			
1976	17,902.00	15,112	19,692			
1977	1,712.00	1,420	1,883			
1978	17,378.00	14,157	19,116			
1979	4,878.00	3,896	5,366			
1980	38,794.04	30,335	42,673			
1981	1,017.00	777	1,119			
1982	1,475.00	1,101	1,622			
1983	4,124,158.41	2,999,311	4,536,574			
1984	612,168.00	433,276	673,385			
1985	39,869.71	27,417	43,857			
1988	1,170.11	730	1,287			
1989	2,677.45	1,611	2,945			
1990	23,387.00	13,539	25,726			
1991	51,555.00	28,647	56,710			
1992	424,824.23	226,041	467,307			
1993	7,293.25	3,704	8,023			
1994	1,060,360.12	512,549	1,166,396			
1995	846,562.36	388,188	931,219			
1996	69,429.47	30,069	76,372			
1997	1,379,250.62	561,795	1,517,176			
1998	1,673,112.18	637,836	1,840,423			
1999	55,607.42	19,731	61,168			
2000	2,977,919.58	977,112	3,275,712			

KENTUCKY UTILITIES COMPANY

ACCOUNT 353.2 STATION EQUIPMENT - SYS CONTROL/COM

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2011

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 35-R2.5						
NET SALVAGE PERCENT.. -10						
2001	142,678.00	42,914	156,946			
2002	355,960.00	97,329	391,556			
2003	464,366.49	114,129	510,804			
	14,668,403.51	7,430,418	16,135,244			

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 0.0 0.00

KENTUCKY UTILITIES COMPANY

ACCOUNT 354 TOWERS AND FIXTURES

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2011

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 70-R4						
NET SALVAGE PERCENT.. -25						
1941	474,641.12	508,376	593,301			
1942	1,388.00	1,475	1,735			
1948	0.10					
1949	1,369,583.00	1,360,287	1,711,979			
1951	20,488.00	19,877	25,610			
1953	51,428.51	48,664	64,286			
1955	5,731.00	5,282	7,164			
1956	23,773.61	21,608	29,717			
1958	1,011,704.75	893,550	1,264,631			
1959	17,524.00	15,246	21,744	161	21.28	8
1960	16,344.36	14,001	19,968	462	22.03	21
1961	766,432.00	646,265	921,698	36,342	22.78	1,595
1962	297,889.00	247,088	352,395	19,966	23.55	848
1963	345,884.14	282,081	402,302	30,053	24.33	1,235
1964	80,847.00	64,793	92,407	8,652	25.12	344
1965	59,524.43	46,843	66,807	7,599	25.93	293
1966	72,558.00	56,051	79,939	10,758	26.74	402
1967	140,496.00	106,477	151,857	23,763	27.56	862
1969	536,494.92	390,588	557,053	113,566	29.23	3,885
1970	2,450,234.08	1,746,221	2,490,447	572,346	30.09	19,021
1971	1,330,093.56	927,507	1,322,803	339,814	30.95	10,979
1972	272,111.12	185,522	264,590	75,549	31.82	2,374
1973	977,622.68	651,170	928,693	293,335	32.70	8,970
1974	287,865.10	187,163	266,930	92,901	33.59	2,766
1975	192,029.00	121,802	173,713	66,323	34.48	1,924
1976	483,205.00	298,639	425,917	178,089	35.39	5,032
1977	971,068.22	584,377	833,434	380,401	36.30	10,479
1978	5,801,911.00	3,396,221	4,843,663	2,408,726	37.22	64,716
1979	172,710.00	98,259	140,136	75,752	38.14	1,986
1980	12,532,292.00	6,921,898	9,871,956	5,793,409	39.07	148,283
1981	158,425.14	84,843	121,002	77,029	40.01	1,925
1982	6,460,558.00	3,351,414	4,779,760	3,295,938	40.95	80,487
1983	4,362.00	2,189	3,122	2,330	41.90	56
1984	9,911,845.74	4,803,652	6,850,931	5,538,876	42.86	129,232
1985	4,464,870.00	2,088,108	2,978,043	2,603,044	43.81	59,417
1986	1,888,194.87	850,372	1,212,794	1,147,450	44.78	25,624
1987	1,778,980.00	770,676	1,099,132	1,124,593	45.74	24,587
1988	23,697.00	9,855	14,055	15,566	46.71	333
1989	1,632,118.38	650,522	927,769	1,112,379	47.68	23,330
1990	238,275.00	90,801	129,500	168,344	48.66	3,460
1992	44,670.00	15,459	22,048	33,790	50.62	668
1994	0.01					

KENTUCKY UTILITIES COMPANY

ACCOUNT 354 TOWERS AND FIXTURES

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2011

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 70-R4						
NET SALVAGE PERCENT.. -25						
1996	108,099.00	29,804	42,506	92,618	54.56	1,698
1997	1,549,505.00	399,830	570,234	1,366,647	55.55	24,602
1999	106,700.00	23,741	33,859	99,516	57.54	1,730
2000	30,847.86	6,318	9,011	29,549	58.53	505
2001	42,618.00	7,975	11,374	41,898	59.52	704
2002	452,193.36	76,551	109,176	456,066	60.52	7,536
2003	2,222,893.40	336,602	480,059	2,298,558	61.52	37,363
2004	831,149.91	111,166	158,544	880,393	62.51	14,084
2005	1,603.60	186	265	1,740	63.51	27
2009	1,570,011.47	70,081	99,949	1,862,565	67.50	27,594
2010	30,746,792.37	823,630	1,174,656	37,258,834	68.50	543,925
2011	321,072.81	2,866	4,087	397,254	69.50	5,716
	95,353,356.62	34,453,972	48,758,751	70,432,945		1,300,626

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 54.2 1.36

KENTUCKY UTILITIES COMPANY

ACCOUNT 355 POLES AND FIXTURES

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2011

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 55-R2						
NET SALVAGE PERCENT.. -55						
1941	53,719.66	69,549	83,265			
1942	27,187.08	34,945	42,140			
1943	10,049.99	12,822	15,577			
1944	287.61	364	446			
1945	4,422.27	5,555	6,855			
1946	2,659.51	3,313	4,122			
1947	65,451.61	80,847	101,450			
1948	11,628.44	14,239	18,024			
1949	75,888.78	92,071	117,628			
1950	10,065.10	12,098	15,601			
1951	149,522.28	177,991	231,760			
1952	109,683.95	129,269	170,010			
1953	347,269.91	404,972	538,268			
1954	15,269.37	17,617	23,668			
1955	275,057.30	313,862	426,339			
1956	231,286.29	260,854	358,494			
1957	92,946.05	103,597	144,066			
1958	428,144.89	471,293	663,625			
1959	457,531.09	497,194	709,173			
1960	354,378.10	380,007	546,564	2,722	16.95	161
1961	390,263.93	412,766	593,681	11,228	17.47	643
1962	256,644.30	267,683	385,008	12,791	17.99	711
1963	616,034.45	632,982	910,418	44,435	18.54	2,397
1964	407,846.58	412,745	593,651	38,511	19.09	2,017
1965	678,898.36	676,340	972,780	79,512	19.65	4,046
1966	579,342.90	567,848	816,736	81,245	20.22	4,018
1967	853,576.22	822,695	1,183,282	139,761	20.80	6,719
1968	253,918.90	240,438	345,822	47,752	21.40	2,231
1969	1,701,803.39	1,582,677	2,276,364	361,431	22.00	16,429
1970	834,921.91	762,125	1,096,164	197,965	22.61	8,756
1971	643,471.67	576,127	828,643	168,738	23.23	7,264
1972	1,156,263.65	1,014,390	1,458,997	333,212	23.87	13,959
1973	2,635,118.22	2,264,246	3,256,664	827,769	24.51	33,773
1974	1,146,553.12	964,197	1,386,804	390,353	25.16	15,515
1975	1,021,872.73	840,340	1,208,661	375,242	25.82	14,533
1976	1,676,016.02	1,346,608	1,936,826	660,999	26.49	24,953
1977	702,432.57	550,918	792,385	296,385	27.17	10,909
1978	1,371,739.74	1,049,576	1,509,605	616,592	27.85	22,140
1979	1,356,975.77	1,011,504	1,454,846	648,466	28.55	22,713
1980	1,245,963.63	904,170	1,300,467	630,777	29.25	21,565
1981	2,146,710.96	1,514,866	2,178,831	1,148,571	29.96	38,337
1982	1,417,438.73	971,483	1,397,284	799,746	30.68	26,067

KENTUCKY UTILITIES COMPANY

ACCOUNT 355 POLES AND FIXTURES

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2011

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 55-R2						
NET SALVAGE PERCENT.. -55						
1983	1,451,029.25	964,659	1,387,469	861,626	31.41	27,432
1984	2,273,009.79	1,463,699	2,105,238	1,417,927	32.15	44,103
1985	1,590,495.28	991,038	1,425,410	1,039,858	32.89	31,616
1986	3,598,412.78	2,166,093	3,115,491	2,462,049	33.64	73,188
1987	594,825.25	345,327	496,684	425,295	34.40	12,363
1988	2,401,589.47	1,342,134	1,930,391	1,792,073	35.17	50,955
1989	2,328,353.32	1,250,681	1,798,854	1,810,094	35.94	50,364
1990	1,519,290.65	782,675	1,125,721	1,229,180	36.72	33,474
1991	1,494,925.38	736,849	1,059,810	1,257,324	37.51	33,520
1992	2,495,208.70	1,173,615	1,688,010	2,179,563	38.31	56,893
1993	713,394.29	319,465	459,486	646,275	39.11	16,525
1994	1,437,270.81	610,810	878,528	1,349,242	39.92	33,799
1995	3,003,174.50	1,207,719	1,737,062	2,917,858	40.73	71,639
1996	3,284,628.18	1,245,047	1,790,750	3,300,424	41.55	79,433
1997	2,588,398.36	920,557	1,324,037	2,687,980	42.38	63,426
1998	2,089,565.02	694,275	998,575	2,240,251	43.21	51,846
1999	3,534,447.77	1,090,693	1,568,743	3,909,651	44.05	88,755
2000	1,048,684.56	298,792	429,752	1,195,709	44.89	26,636
2001	3,428,379.94	893,707	1,285,418	4,028,571	45.75	88,056
2002	1,393,694.59	329,931	474,540	1,685,687	46.60	36,174
2003	6,378,986.32	1,355,468	1,949,569	7,937,860	47.46	167,254
2004	1,572,489.38	295,578	425,130	2,012,229	48.33	41,635
2005	6,480,706.82	1,059,255	1,523,526	8,521,570	49.20	173,203
2006	2,936,712.52	407,168	585,629	3,966,275	50.08	79,199
2007	8,318,033.57	944,667	1,358,714	11,534,238	50.97	226,295
2008	1,891,327.18	167,890	241,476	2,690,081	51.85	51,882
2009	15,594,862.24	988,878	1,422,303	22,749,733	52.75	431,275
2010	28,283,360.75	1,076,253	1,547,974	42,291,235	53.65	788,280
2011	9,117,266.78	115,598	166,264	13,965,500	54.55	256,013
	148,658,780.48	47,707,704	68,401,548	162,019,562		3,485,089

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 46.5 2.34

KENTUCKY UTILITIES COMPANY

ACCOUNT 356 OVERHEAD CONDUCTORS AND DEVICES

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2011

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 60-R3						
NET SALVAGE PERCENT.. -50						
1941	671,187.00	872,546	1,006,780			
1942	119,907.52	154,891	179,861			
1943	16,733.47	21,473	25,100			
1944	222.83	284	334			
1945	7,143.15	9,040	10,715			
1946	21,492.28	26,994	32,238			
1947	222,793.23	277,655	334,190			
1948	57,847.14	71,499	86,771			
1949	1,269,791.80	1,556,130	1,904,688			
1950	96,947.45	117,743	145,421			
1951	482,892.23	581,042	724,338			
1952	276,406.79	329,337	414,610			
1953	1,420,221.80	1,674,804	2,130,333			
1954	178,443.78	208,198	264,950	2,716	13.33	204
1955	683,623.14	788,734	1,003,733	21,702	13.85	1,567
1956	962,184.29	1,097,366	1,396,494	46,782	14.38	3,253
1957	155,307.57	174,994	222,695	10,266	14.93	688
1958	1,929,289.07	2,146,807	2,731,999	161,935	15.49	10,454
1959	789,894.61	867,506	1,103,977	80,865	16.07	5,032
1960	595,372.22	645,083	820,924	72,134	16.66	4,330
1961	1,202,682.44	1,284,772	1,634,984	169,040	17.27	9,788
1962	587,441.15	618,426	787,001	94,161	17.89	5,263
1963	1,509,747.34	1,565,238	1,991,902	272,719	18.53	14,718
1964	997,827.95	1,018,278	1,295,848	200,894	19.18	10,474
1965	1,278,682.37	1,283,791	1,633,736	284,288	19.84	14,329
1966	1,607,882.79	1,587,390	2,020,092	391,732	20.51	19,100
1967	940,268.62	912,291	1,160,970	249,433	21.19	11,771
1968	315,177.68	300,287	382,141	90,626	21.89	4,140
1969	2,295,062.14	2,145,872	2,730,809	711,784	22.60	31,495
1970	3,242,778.81	2,973,612	3,784,181	1,079,987	23.32	46,312
1971	1,753,320.97	1,575,806	2,005,351	624,630	24.05	25,972
1972	1,863,656.66	1,640,474	2,087,646	707,839	24.79	28,553
1973	3,260,665.64	2,809,879	3,575,816	1,315,182	25.53	51,515
1974	994,668.05	838,252	1,066,749	425,253	26.29	16,175
1975	1,321,177.50	1,087,990	1,384,562	597,204	27.06	22,070
1976	2,510,805.03	2,018,687	2,568,955	1,197,253	27.84	43,005
1977	1,622,348.56	1,272,319	1,619,137	814,386	28.63	28,445
1978	6,157,847.31	4,707,705	5,990,965	3,245,806	29.42	110,327
1979	2,010,113.35	1,496,037	1,903,837	1,111,333	30.23	36,763
1980	11,307,386.30	8,186,604	10,418,167	6,542,912	31.04	210,790
1981	4,249,237.05	2,989,338	3,804,193	2,569,663	31.86	80,655
1982	6,063,615.86	4,139,964	5,268,465	3,826,959	32.69	117,068

KENTUCKY UTILITIES COMPANY

ACCOUNT 356 OVERHEAD CONDUCTORS AND DEVICES

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2011

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 60-R3						
NET SALVAGE PERCENT.. -50						
1983	1,733,975.39	1,147,467	1,460,252	1,140,711	33.53	34,021
1984	7,380,496.28	4,727,208	6,015,784	5,054,960	34.38	147,032
1985	3,680,452.57	2,279,102	2,900,356	2,620,323	35.23	74,378
1986	5,172,863.43	3,092,079	3,934,940	3,824,355	36.09	105,967
1987	8,112,257.89	4,672,661	5,946,369	6,222,018	36.96	168,345
1988	1,699,354.67	941,434	1,198,057	1,350,975	37.84	35,702
1989	836,305.92	444,919	566,198	688,261	38.72	17,775
1990	1,299,516.02	662,422	842,990	1,106,284	39.61	27,929
1991	839,953.48	409,263	520,823	739,107	40.51	18,245
1992	2,016,294.55	937,063	1,192,494	1,831,948	41.41	44,239
1993	321,166.01	141,957	180,653	301,096	42.32	7,115
1994	1,175,641.59	492,588	626,861	1,136,601	43.24	26,286
1995	3,196,894.40	1,265,970	1,611,057	3,184,285	44.16	72,108
1996	2,065,997.06	770,627	980,690	2,118,306	45.08	46,990
1997	1,115,219.05	389,769	496,015	1,176,814	46.02	25,572
1998	1,629,183.94	531,106	675,879	1,767,897	46.96	37,647
1999	1,558,895.30	471,574	600,119	1,738,224	47.90	36,289
2000	1,772,654.53	494,119	628,810	2,030,172	48.85	41,559
2001	2,891,895.68	737,433	938,448	3,399,396	49.80	68,261
2002	718,425.61	166,140	211,428	866,210	50.75	17,068
2003	4,352,458.49	902,069	1,147,961	5,380,727	51.71	104,056
2004	838,350.06	153,418	195,238	1,062,287	52.68	20,165
2005	2,753,852.53	437,863	557,219	3,573,560	53.64	66,621
2006	1,460,130.15	196,395	249,930	1,940,265	54.62	35,523
2007	2,833,894.67	312,437	397,603	3,853,239	55.59	69,315
2008	835,934.12	71,886	91,481	1,162,420	56.56	20,552
2009	5,350,133.19	329,033	418,723	7,606,477	57.54	132,195
2010	20,311,467.20	751,626	956,509	29,510,692	58.52	504,284
2011	5,443,120.55	66,705	84,888	8,079,793	59.51	135,772
	160,446,879.27	86,071,471	109,283,433	131,386,886		3,105,267

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 42.3 1.94

KENTUCKY UTILITIES COMPANY

ACCOUNT 357 UNDERGROUND CONDUIT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2011

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 45-R4						
NET SALVAGE PERCENT.. 0						
1962	16,102.50	14,381	14,114	1,988	4.81	413
1969	629.49	520	510	119	7.86	15
1972	1,023.52	803	788	236	9.68	24
1973	66,872.27	51,521	50,563	16,309	10.33	1,579
1974	1,183.38	894	877	306	11.01	28
1980	26,278.29	17,291	16,970	9,308	15.39	605
1984	275.00	161	158	117	18.64	6
1997	318,959.12	101,927	100,032	218,927	30.62	7,150
1998	449.82	134	132	318	31.59	10
1999	702.00	194	190	512	32.58	16
2002	3,451.41	726	713	2,738	35.54	77
2003	12,833.46	2,416	2,371	10,462	36.53	286
	448,760.26	190,968	187,418	261,342		10,209

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 25.6   2.27

KENTUCKY UTILITIES COMPANY

ACCOUNT 358 UNDERGROUND CONDUCTORS AND DEVICES

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2011

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 35-R3						
NET SALVAGE PERCENT.. 0						
1962	13,218.53	12,324	13,219			
1969	87,624.88	77,010	87,625			
1972	15,875.19	13,512	15,875			
1973	78,405.34	65,905	78,405			
1974	136,383.31	113,120	136,383			
1980	204,862.86	152,944	204,863			
1982	13,871.63	9,889	13,872			
1984	2,212.00	1,497	2,116	96	11.32	8
1986	0.12					
1988	123,767.49	73,836	104,375	19,392	14.12	1,373
1992	116,241.00	59,117	83,568	32,673	17.20	1,900
1993	0.28					
1997	313,023.53	121,810	172,191	140,833	21.38	6,587
2009	56,063.13	3,924	5,547	50,516	32.55	1,552
	1,161,549.29	704,888	918,039	243,510		11,420

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 21.3 0.98

KENTUCKY UTILITIES COMPANY

ACCOUNT 360.1 LAND RIGHTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2011

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 65-R4						
NET SALVAGE PERCENT.. 0						
1941	453,054.53	402,244	453,055			
1942	41,173.38	36,328	41,173			
1943	911.00	798	911			
1944	850.00	740	850			
1945	2,100.00	1,814	2,100			
1946	3,262.00	2,796	3,262			
1947	4,434.00	3,769	4,434			
1948	3,258.00	2,745	3,258			
1949	4,314.00	3,601	4,314			
1950	59,904.00	49,490	59,904			
1951	18,663.00	15,258	18,663			
1952	27,550.00	22,273	27,550			
1953	33,233.00	26,556	33,233			
1954	24,267.00	19,156	24,267			
1955	40,298.35	31,408	40,298			
1956	21,633.00	16,641	21,633			
1957	19,771.00	15,005	19,771			
1958	27,040.00	20,234	27,040			
1959	19,357.00	14,279	19,357			
1960	33,627.00	24,439	33,627			
1961	18,106.00	12,958	18,106			
1962	10,562.32	7,442	10,562			
1963	21,516.00	14,916	21,516			
1964	20,398.00	13,905	20,197	201	20.69	10
1965	35,563.00	23,822	34,601	962	21.46	45
1966	5,187.00	3,413	4,957	230	22.23	10
1967	19,695.00	12,720	18,475	1,220	23.02	53
1968	15,350.00	9,727	14,128	1,222	23.81	51
1969	41,542.00	25,807	37,484	4,058	24.62	165
1970	24,874.00	15,139	21,989	2,885	25.44	113
1971	46,508.00	27,712	40,251	6,257	26.27	238
1972	16,301.00	9,500	13,798	2,503	27.12	92
1973	8,970.00	5,110	7,422	1,548	27.97	55
1974	43,465.00	24,187	35,131	8,334	28.83	289
1975	27,337.00	14,846	21,563	5,774	29.70	194
1976	6,205.00	3,286	4,773	1,432	30.58	47
1977	15,472.00	7,981	11,592	3,880	31.47	123
1978	17,820.00	8,946	12,994	4,826	32.37	149
1979	31,886.00	15,560	22,600	9,286	33.28	279
1980	10,670.00	5,056	7,344	3,326	34.20	97
1981	1,808.00	831	1,207	601	35.12	17
1982	61,168.00	27,243	39,570	21,598	36.05	599

KENTUCKY UTILITIES COMPANY

ACCOUNT 360.1 LAND RIGHTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2011

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 65-R4						
NET SALVAGE PERCENT.. 0						
1984	14,670.00	6,109	8,873	5,797	37.93	153
1985	33,531.00	13,474	19,571	13,960	38.88	359
1986	779.00	302	439	340	39.83	9
1987	16,266.00	6,058	8,799	7,467	40.79	183
1988	4,886.00	1,748	2,539	2,347	41.75	56
1989	7,350.00	2,519	3,659	3,691	42.72	86
1990	38,364.00	12,578	18,269	20,095	43.69	460
1991	12,981.00	4,062	5,900	7,081	44.66	159
1992	5,140.00	1,531	2,224	2,916	45.64	64
1993	38,715.00	10,947	15,900	22,815	46.62	489
1994	23,233.00	6,219	9,033	14,200	47.60	298
1995	54,744.00	13,829	20,086	34,658	48.58	713
1996	143,362.00	34,031	49,429	93,933	49.57	1,895
1997	100,670.04	22,364	32,483	68,187	50.56	1,349
1998	11,034.00	2,283	3,316	7,718	51.55	150
1999	28,534.63	5,470	7,945	20,590	52.54	392
2000	5,450.00	962	1,397	4,053	53.53	76
2001	1,400.00	226	328	1,072	54.53	20
2003	113.00	15	22	91	56.52	2
2004	74,362.56	8,569	12,446	61,917	57.51	1,077
2009	58,265.05	2,241	3,255	55,010	62.50	880
2010	3,796.63	88	128	3,669	63.50	58
2011	22,282.80	171	248	22,035	64.50	342
	2,039,033.29	1,155,477	1,485,249	553,784		11,896

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 46.6 0.58

KENTUCKY UTILITIES COMPANY

ACCOUNT 361 STRUCTURES AND IMPROVEMENTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2011

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)

SURVIVOR CURVE.. IOWA 60-R2.5
NET SALVAGE PERCENT.. -20

1931	1,206.50	1,266	1,263	185	7.55	25
1940	238.90	239	239	48	9.98	5
1941	998.91	993	991	208	10.29	20
1945	56.00	54	54	13	11.66	1
1946	13,669.98	13,115	13,088	3,316	12.03	276
1947	4,642.00	4,417	4,408	1,162	12.42	94
1948	2,742.00	2,587	2,582	708	12.82	55
1949	5,605.09	5,243	5,232	1,494	13.23	113
1950	13,026.82	12,073	12,048	3,584	13.66	262
1951	5,204.70	4,777	4,767	1,479	14.11	105
1952	6,107.77	5,550	5,539	1,790	14.57	123
1953	202.30	182	182	61	15.04	4
1954	17,014.22	15,133	15,102	5,315	15.53	342
1955	21,089.34	18,546	18,508	6,799	16.03	424
1956	22,140.26	19,240	19,201	7,367	16.55	445
1957	14,707.97	12,625	12,599	5,051	17.08	296
1958	28,776.87	24,391	24,342	10,190	17.62	578
1959	11,277.90	9,433	9,414	4,119	18.18	227
1960	16,948.14	13,982	13,954	6,384	18.75	340
1961	19,947.58	16,221	16,188	7,749	19.34	401
1962	32,050.80	25,685	25,633	12,828	19.93	644
1963	41,737.82	32,940	32,873	17,212	20.54	838
1964	33,527.23	26,044	25,991	14,242	21.16	673
1965	33,348.66	25,485	25,433	14,585	21.79	669
1966	20,756.17	15,592	15,560	9,347	22.44	417
1967	29,960.66	22,117	22,072	13,881	23.09	601
1968	38,874.93	28,177	28,120	18,530	23.76	780
1969	52,944.28	37,664	37,588	25,945	24.43	1,062
1970	16,417.70	11,456	11,433	8,268	25.11	329
1971	76,589.72	52,372	52,266	39,642	25.81	1,536
1972	44,762.96	29,982	29,921	23,795	26.51	898
1973	57,427.84	37,638	37,562	31,351	27.23	1,151
1974	63,434.07	40,661	40,578	35,543	27.95	1,272
1975	48,572.11	30,426	30,364	27,923	28.68	974
1976	29,417.35	17,992	17,955	17,346	29.42	590
1977	72,116.85	43,025	42,938	43,602	30.17	1,445
1978	72,775.00	42,326	42,240	45,090	30.92	1,458
1979	99,237.62	56,188	56,074	63,011	31.69	1,988
1980	161,686.25	89,057	88,876	105,148	32.46	3,239
1981	64,733.00	34,645	34,575	43,105	33.24	1,297
1982	116,877.10	60,705	60,582	79,671	34.03	2,341
1983	13,444.28	6,771	6,757	9,376	34.82	269

KENTUCKY UTILITIES COMPANY

ACCOUNT 361 STRUCTURES AND IMPROVEMENTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2011

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 60-R2.5						
NET SALVAGE PERCENT.. -20						
1984	68,778.00	33,523	33,455	49,079	35.63	1,377
1985	8,631.87	4,067	4,059	6,299	36.44	173
1986	50,245.96	22,862	22,816	37,479	37.25	1,006
1987	80,691.35	35,375	35,303	61,527	38.08	1,616
1988	11,902.67	5,021	5,011	9,272	38.91	238
1989	21,186.00	8,585	8,568	16,855	39.74	424
1990	89,521.00	34,752	34,681	72,744	40.59	1,792
1991	232,064.00	86,141	85,966	192,511	41.44	4,646
1992	133,283.06	47,182	47,086	112,854	42.30	2,668
1993	54,579.00	18,382	18,345	47,150	43.16	1,092
1994	559,184.42	178,606	178,244	492,777	44.03	11,192
1995	45,864.96	13,851	13,823	41,215	44.90	918
1997	163,072.85	43,476	43,388	152,299	46.67	3,263
1998	84,203.00	20,949	20,906	80,138	47.56	1,685
2000	66,743.00	14,216	14,187	65,905	49.35	1,335
2001	279,632.55	54,471	54,360	281,199	50.26	5,595
2002	141,181.00	24,933	24,882	144,535	51.17	2,825
2003	212,582.75	33,673	33,605	221,494	52.08	4,253
2004	15,786.36	2,210	2,206	16,738	53.00	316
2005	134,777.18	16,388	16,355	145,378	53.92	2,696
2006	137,673.95	14,180	14,151	151,058	54.85	2,754
2007	632,246.14	53,488	53,379	705,316	55.77	12,647
2008	39,332.05	2,588	2,583	44,615	56.71	787
2009	376,899.45	17,788	17,752	434,527	57.64	7,539
2010	1,753,564.78	49,808	49,707	2,054,571	58.58	35,073
2011	838,365.09	7,877	7,861	998,177	59.53	16,768
	7,658,288.09	1,791,407	1,787,771	7,402,175		153,285

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 48.3 2.00

KENTUCKY UTILITIES COMPANY

ACCOUNT 362 STATION EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2011

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 54-R2						
NET SALVAGE PERCENT.. -20						
1909	1,145.87	1,375	1,375			
1920	66.63	77	74	6	2.31	3
1928	2,008.61	2,205	2,118	292	4.59	64
1930	19,202.67	20,837	20,014	3,029	5.17	586
1931	729.35	787	756	119	5.46	22
1934	10,250.82	10,857	10,428	1,873	6.34	295
1935	3,176.82	3,344	3,212	600	6.63	90
1936	2,692.89	2,817	2,706	525	6.93	76
1937	5,905.44	6,138	5,896	1,191	7.23	165
1938	12,336.37	12,737	12,234	2,570	7.54	341
1939	14,405.80	14,777	14,193	3,094	7.84	395
1940	35,602.79	36,267	34,834	7,889	8.16	967
1941	62,766.02	63,505	60,996	14,323	8.47	1,691
1942	9,825.86	9,870	9,480	2,311	8.80	263
1943	3,934.21	3,923	3,768	953	9.13	104
1944	16,014.04	15,847	15,221	3,996	9.47	422
1945	24,186.65	23,751	22,813	6,211	9.81	633
1946	21,361.59	20,806	19,984	5,650	10.17	556
1947	38,230.64	36,931	35,472	10,405	10.53	988
1948	150,984.74	144,610	138,897	42,285	10.90	3,879
1949	158,323.42	150,301	144,363	45,625	11.28	4,045
1950	104,663.97	98,430	94,542	31,055	11.68	2,659
1951	65,110.47	60,654	58,258	19,875	12.08	1,645
1952	235,631.85	217,356	208,769	73,989	12.49	5,924
1953	390,757.58	356,807	342,711	126,198	12.91	9,775
1954	388,449.40	350,984	337,118	129,021	13.34	9,672
1955	351,941.61	314,556	302,129	120,201	13.78	8,723
1956	543,550.14	480,259	461,286	190,974	14.24	13,411
1957	180,195.96	157,372	151,155	65,080	14.70	4,427
1958	360,758.35	311,215	298,920	133,990	15.18	8,827
1959	204,854.89	174,536	167,641	78,185	15.66	4,993
1960	333,513.22	280,447	269,368	130,848	16.16	8,097
1961	446,813.77	370,659	356,016	180,161	16.67	10,807
1962	761,993.87	623,314	598,690	315,703	17.19	18,366
1963	758,265.86	611,329	587,178	322,741	17.72	18,213
1964	579,659.45	460,377	442,190	253,401	18.26	13,877
1965	786,678.43	615,006	590,710	353,304	18.82	18,773
1966	794,911.37	611,551	587,392	366,502	19.38	18,911
1967	774,410.11	585,974	562,825	366,467	19.95	18,369
1968	894,678.01	665,243	638,962	434,652	20.54	21,161
1969	1,471,507.01	1,074,848	1,032,386	733,422	21.13	34,710
1970	677,110.50	485,415	466,239	346,294	21.74	15,929

KENTUCKY UTILITIES COMPANY

ACCOUNT 362 STATION EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2011

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 54-R2						
NET SALVAGE PERCENT.. -20						
1971	1,034,896.32	727,876	699,121	542,755	22.35	24,284
1972	982,784.61	677,461	650,698	528,644	22.98	23,005
1973	1,302,968.70	879,942	845,180	718,382	23.61	30,427
1974	1,372,674.98	907,184	871,346	775,864	24.26	31,981
1975	1,028,959.18	665,160	638,883	595,868	24.91	23,921
1976	922,153.25	582,594	559,579	547,005	25.57	21,392
1977	1,341,522.75	827,564	794,871	814,956	26.24	31,058
1978	1,811,099.57	1,089,485	1,046,445	1,126,874	26.93	41,845
1979	384,923.86	225,652	216,738	245,171	27.62	8,877
1980	2,374,876.57	1,355,276	1,301,736	1,548,116	28.32	54,665
1981	1,941,729.22	1,077,869	1,035,288	1,294,787	29.02	44,617
1982	1,900,579.89	1,024,625	984,147	1,296,549	29.74	43,596
1983	950,744.40	497,350	477,702	663,191	30.46	21,773
1984	2,437,058.14	1,235,325	1,186,523	1,737,947	31.19	55,721
1985	376,935.26	184,783	177,483	274,839	31.94	8,605
1986	1,569,959.48	743,803	714,419	1,169,532	32.68	35,787
1987	3,239,155.14	1,479,931	1,421,466	2,465,520	33.44	73,730
1988	486,538.28	214,079	205,622	378,224	34.20	11,059
1989	2,378,178.19	1,005,713	965,982	1,887,832	34.97	53,984
1990	1,539,444.50	624,325	599,661	1,247,672	35.75	34,900
1991	3,787,958.43	1,469,713	1,411,652	3,133,898	36.54	85,766
1992	5,145,332.67	1,906,037	1,830,738	4,343,661	37.33	116,358
1993	1,690,676.18	596,247	572,692	1,456,119	38.13	38,188
1994	5,904,890.58	1,977,453	1,899,333	5,186,536	38.93	133,227
1995	4,025,538.84	1,275,629	1,225,235	3,605,412	39.74	90,725
1996	9,964.23	2,976	2,858	9,099	40.56	224
1997	5,809,035.24	1,627,831	1,563,523	5,407,319	41.39	130,643
1998	4,852,747.14	1,270,352	1,220,167	4,603,130	42.22	109,027
1999	2,428,768.57	590,453	567,127	2,347,395	43.06	54,515
2000	1,220,588.68	273,959	263,136	1,201,570	43.90	27,371
2001	6,572,368.98	1,351,016	1,297,644	6,589,199	44.75	147,245
2002	4,403,949.43	821,090	788,653	4,496,086	45.61	98,577
2003	4,498,378.03	752,705	722,969	4,675,085	46.47	100,604
2004	894,594.87	132,600	127,362	946,152	47.33	19,991
2005	3,333,281.56	428,873	411,930	3,588,008	48.21	74,425
2006	2,320,453.21	253,700	243,678	2,540,866	49.08	51,770
2007	2,503,125.52	224,170	215,314	2,788,437	49.97	55,802
2008	600,338.35	42,021	40,361	680,045	50.85	13,374

KENTUCKY UTILITIES COMPANY

ACCOUNT 362 STATION EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2011

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 54-R2						
NET SALVAGE PERCENT.. -20						
2009	14,314,460.85	715,780	687,503	16,489,850	51.75	318,644
2010	17,061,370.37	511,841	491,620	19,982,024	52.65	379,526
2011	8,746,819.83	87,433	83,979	10,412,205	53.55	194,439
	141,200,430.90	41,825,970	40,173,683	129,266,834		3,198,522

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 40.4   2.27

KENTUCKY UTILITIES COMPANY

ACCOUNT 364 POLES, TOWERS AND FIXTURES

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2011

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 50-R1						
NET SALVAGE PERCENT.. -45						
1932	5,508.86	6,929	7,988			
1941	94,783.00	110,745	137,435			
1942	5,872.33	6,798	8,515			
1943	7,108.39	8,153	10,307			
1944	14,805.27	16,822	21,468			
1945	36,177.96	40,697	52,458			
1946	98,731.06	109,976	143,160			
1947	156,709.01	172,739	227,228			
1948	182,646.89	199,211	264,838			
1949	325,335.95	351,067	471,737			
1950	527,428.76	562,872	764,772			
1951	517,479.33	545,951	750,345			
1952	587,022.04	612,170	851,182			
1953	212,681.31	219,140	308,388			
1954	126,596.89	128,863	183,565			
1955	285,976.48	287,446	414,666			
1956	453,191.58	449,607	657,128			
1957	566,154.56	554,288	820,924			
1958	393,241.01	379,753	570,199			
1959	534,060.96	508,463	774,388			
1960	155,042.34	145,498	224,811			
1961	621,351.90	574,452	900,960			
1962	563,957.28	513,376	817,738			
1963	808,338.23	724,352	1,162,219	9,871	19.10	517
1964	879,668.78	775,516	1,244,311	31,209	19.60	1,592
1965	890,472.67	771,871	1,238,463	52,722	20.11	2,622
1966	975,346.83	831,015	1,333,359	80,894	20.62	3,923
1967	1,003,574.54	839,932	1,347,666	107,517	21.14	5,086
1968	1,120,263.42	920,375	1,476,736	147,646	21.67	6,813
1969	1,237,836.08	997,943	1,601,194	193,668	22.20	8,724
1970	859,934.14	679,812	1,090,755	156,150	22.74	6,867
1971	1,451,595.80	1,124,392	1,804,081	300,733	23.29	12,913
1972	1,483,353.65	1,124,901	1,804,897	345,966	23.85	14,506
1973	1,933,328.36	1,434,742	2,302,035	501,291	24.41	20,536
1974	1,893,020.86	1,373,538	2,203,834	541,046	24.98	21,659
1975	1,446,884.66	1,025,914	1,646,073	451,910	25.55	17,687
1976	1,715,792.40	1,187,225	1,904,896	583,003	26.14	22,303
1977	1,915,164.32	1,292,410	2,073,665	703,323	26.73	26,312
1978	1,898,687.20	1,248,805	2,003,701	749,395	27.32	27,430
1979	2,621,744.51	1,677,995	2,692,333	1,109,197	27.93	39,713
1980	2,752,025.75	1,713,494	2,749,291	1,241,146	28.53	43,503
1981	3,069,272.37	1,855,836	2,977,678	1,472,767	29.15	50,524

KENTUCKY UTILITIES COMPANY

ACCOUNT 364 POLES, TOWERS AND FIXTURES

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2011

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 50-R1						
NET SALVAGE PERCENT.. -45						
1982	3,269,964.17	1,918,390	3,078,046	1,663,402	29.77	55,875
1983	3,765,508.89	2,140,315	3,434,123	2,025,865	30.40	66,640
1984	3,138,505.45	1,726,586	2,770,297	1,780,536	31.03	57,381
1985	3,458,283.71	1,838,320	2,949,574	2,064,937	31.67	65,202
1986	4,614,958.34	2,367,520	3,798,673	2,893,017	32.31	89,539
1987	4,910,524.27	2,426,585	3,893,442	3,226,818	32.96	97,901
1988	4,901,174.28	2,329,577	3,737,793	3,368,910	33.61	100,235
1989	5,214,786.09	2,378,829	3,816,818	3,744,622	34.27	109,268
1990	5,236,220.81	2,288,386	3,671,702	3,920,818	34.93	112,248
1991	5,211,322.07	2,176,248	3,491,778	4,064,639	35.60	114,175
1992	6,728,970.47	2,681,226	4,302,012	5,454,995	36.26	150,441
1993	6,670,923.91	2,526,546	4,053,829	5,619,011	36.94	152,112
1994	8,418,422.59	3,024,823	4,853,311	7,353,402	37.61	195,517
1995	9,150,439.53	3,107,398	4,985,803	8,282,334	38.29	216,305
1996	7,978,101.63	2,549,642	4,090,886	7,477,361	38.98	191,826
1997	8,911,617.04	2,672,237	4,287,589	8,634,256	39.66	217,707
1998	7,786,031.78	2,178,921	3,496,066	7,793,680	40.35	193,152
1999	7,513,914.61	1,952,416	3,132,641	7,762,535	41.04	189,146
2000	7,190,840.61	1,722,494	2,763,732	7,662,987	41.74	183,589
2001	6,324,507.91	1,388,419	2,227,710	6,942,826	42.43	163,630
2002	7,352,251.25	1,464,789	2,350,246	8,310,518	43.13	192,685
2003	10,672,964.92	1,906,618	3,059,158	12,416,641	43.84	283,226
2004	4,527,927.87	715,639	1,148,239	5,417,256	44.55	121,599
2005	5,014,972.04	689,358	1,106,071	6,165,638	45.26	136,227
2006	6,295,559.47	733,936	1,177,596	7,950,965	45.98	172,922
2007	4,284,118.46	409,990	657,827	5,554,145	46.70	118,932
2008	23,455,523.15	1,748,140	2,804,881	31,205,628	47.43	657,930
2009	33,278,830.47	1,775,758	2,849,193	45,405,111	48.16	942,797
2010	14,781,832.36	475,827	763,462	20,670,195	48.89	422,790
2011	21,304,757.27	228,600	366,787	30,525,111	49.63	615,054
	287,791,923.15	83,648,617	133,160,672	284,137,617		6,719,281

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 42.3   2.33

KENTUCKY UTILITIES COMPANY

ACCOUNT 365 OVERHEAD CONDUCTORS AND DEVICES

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2011

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 48-R1.5						
NET SALVAGE PERCENT.. -60						
1941	156,363.38	212,447	227,539	22,642	7.24	3,127
1942	27,599.92	37,232	39,877	4,283	7.53	569
1943	26,923.41	36,059	38,621	4,456	7.82	570
1944	32,992.81	43,858	46,974	5,814	8.12	716
1945	82,398.58	108,684	116,405	15,433	8.43	1,831
1946	154,117.89	201,690	216,018	30,571	8.74	3,498
1947	196,832.76	255,555	273,710	41,222	9.05	4,555
1948	386,937.22	498,245	533,640	85,460	9.37	9,121
1949	439,821.62	561,508	601,397	102,318	9.70	10,548
1950	485,506.01	614,487	658,140	118,670	10.03	11,832
1951	362,767.94	454,911	487,228	93,201	10.38	8,979
1952	479,949.06	596,419	638,789	129,129	10.72	12,046
1953	418,361.88	514,866	551,442	117,937	11.08	10,644
1954	349,730.39	426,089	456,358	103,211	11.45	9,014
1955	484,366.11	583,983	625,469	149,517	11.83	12,639
1956	503,545.08	600,725	643,400	162,272	12.21	13,290
1957	482,113.82	568,732	609,135	162,247	12.61	12,867
1958	490,282.06	571,834	612,457	171,994	13.01	13,220
1959	452,350.70	521,260	558,290	165,471	13.43	12,321
1960	359,775.10	409,545	438,639	137,001	13.85	9,892
1961	546,920.47	614,555	658,213	216,860	14.29	15,176
1962	578,764.93	641,660	687,243	238,781	14.74	16,200
1963	900,058.92	984,060	1,053,968	386,126	15.20	25,403
1964	966,019.57	1,041,045	1,115,001	430,630	15.67	27,481
1965	1,256,542.42	1,334,026	1,428,795	581,673	16.15	36,017
1966	1,040,889.69	1,088,071	1,165,367	500,057	16.64	30,052
1967	1,180,603.79	1,214,454	1,300,729	588,237	17.14	34,320
1968	1,494,747.06	1,512,182	1,619,607	771,988	17.65	43,739
1969	1,577,817.11	1,568,350	1,679,765	844,742	18.18	46,465
1970	1,220,338.59	1,191,460	1,276,101	676,441	18.71	36,154
1971	2,156,793.39	2,066,208	2,212,991	1,237,878	19.26	64,272
1972	1,719,614.64	1,615,860	1,730,651	1,020,732	19.81	51,526
1973	2,030,067.95	1,869,027	2,001,803	1,246,306	20.38	61,153
1974	2,590,158.38	2,334,582	2,500,430	1,643,823	20.96	78,427
1975	1,665,727.27	1,469,171	1,573,541	1,091,623	21.54	50,679
1976	1,686,320.86	1,453,609	1,556,873	1,141,240	22.14	51,547
1977	2,338,155.26	1,968,727	2,108,585	1,632,463	22.74	71,788
1978	2,772,323.34	2,276,987	2,438,744	1,996,973	23.36	85,487
1979	3,289,118.97	2,633,505	2,820,589	2,442,001	23.98	101,835
1980	3,180,003.87	2,478,266	2,654,322	2,433,684	24.62	98,850
1981	3,058,195.46	2,318,112	2,482,790	2,410,323	25.26	95,421
1982	3,166,130.86	2,331,336	2,496,954	2,568,855	25.91	99,145

KENTUCKY UTILITIES COMPANY

ACCOUNT 365 OVERHEAD CONDUCTORS AND DEVICES

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2011

SURVIVOR CURVE.. IOWA 48-R1.5
NET SALVAGE PERCENT.. -60

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
1983	3,243,362.04	2,316,850	2,481,439	2,707,940	26.57	101,917
1984	2,918,461.31	2,019,575	2,163,045	2,506,493	27.24	92,015
1985	2,665,977.80	1,785,309	1,912,137	2,353,427	27.91	84,322
1986	3,651,351.90	2,362,454	2,530,283	3,311,880	28.59	115,841
1987	4,073,366.48	2,541,781	2,722,349	3,795,037	29.28	129,612
1988	4,547,201.92	2,731,377	2,925,414	4,350,109	29.98	145,100
1989	5,851,026.73	3,375,996	3,615,826	5,745,817	30.69	187,221
1990	5,079,031.92	2,810,371	3,010,020	5,116,431	31.40	162,944
1991	4,581,529.63	2,426,671	2,599,061	4,731,386	32.11	147,349
1992	5,289,612.69	2,672,989	2,862,878	5,600,502	32.84	170,539
1993	4,886,973.66	2,350,595	2,517,581	5,301,577	33.57	157,926
1994	6,243,742.46	2,851,342	3,053,901	6,936,087	34.30	202,218
1995	7,606,923.86	3,286,191	3,519,642	8,651,436	35.04	246,902
1996	6,603,185.18	2,687,549	2,878,472	7,686,624	35.79	214,770
1997	6,543,395.05	2,499,577	2,677,147	7,792,285	36.54	213,254
1998	5,258,962.79	1,875,725	2,008,976	6,405,364	37.30	171,726
1999	5,577,547.60	1,847,998	1,979,280	6,944,796	38.06	182,470
2000	4,643,248.43	1,419,274	1,520,099	5,909,098	38.83	152,179
2001	9,360,157.88	2,620,844	2,807,029	12,169,224	39.60	307,304
2002	5,918,668.80	1,503,342	1,610,139	7,859,731	40.38	194,644
2003	3,901,416.83	889,523	952,715	5,289,552	41.16	128,512
2004	7,433,412.77	1,499,052	1,605,544	10,287,916	41.95	245,242
2005	2,366,159.88	414,854	444,325	3,341,531	42.74	78,183
2006	4,194,700.62	624,977	669,375	6,042,146	43.53	138,804
2007	4,625,920.17	565,917	606,120	6,795,352	44.33	153,290
2008	21,165,926.48	2,017,705	2,161,043	31,704,439	45.14	702,358
2009	45,203,151.57	3,089,003	3,308,446	69,016,597	45.95	1,501,993
2010	12,830,692.74	525,956	563,320	19,965,788	46.77	426,893
2011	23,232,601.08	317,450	340,001	36,832,161	47.59	773,947
	276,285,758.81	101,753,629	108,982,197	333,075,017		8,911,891

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 37.4   3.23

KENTUCKY UTILITIES COMPANY

ACCOUNT 366 UNDERGOUND CONDUIT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2011

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 50-R4						
NET SALVAGE PERCENT.. -5						
1951	675.33	657	495	214	3.70	58
1953	3,590.43	3,449	2,600	1,170	4.26	275
1963	0.09					
1965	0.92	1	1			
1966	2,181.50	1,844	1,390	901	9.74	93
1967	2,766.65	2,303	1,736	1,169	10.36	113
1968	1,069.72	876	660	463	11.00	42
1970	0.08					
1971	0.36					
1973	23,444.07	17,497	13,189	11,427	14.46	790
1974	276,752.56	202,251	152,449	138,141	15.20	9,088
1976	19,473.98	13,614	10,262	10,186	16.71	610
1979	407,636.17	264,515	199,381	228,637	19.10	11,971
1980	218,176.00	137,817	103,881	125,204	19.92	6,285
1981	15.00	9	7	9	20.76	
1982	64,154.00	38,248	28,830	38,532	21.61	1,783
1983	61,683.00	35,648	26,870	37,897	22.48	1,686
1986	44,888.00	23,425	17,657	29,475	25.15	1,172
1987	67,488.00	33,929	25,574	45,288	26.06	1,738
1989	20,092.00	9,320	7,025	14,072	27.91	504
1995	104,460.14	35,888	27,051	82,632	33.64	2,456
1998	5,763.00	1,624	1,224	4,827	36.58	132
2001	2,842.29	624	470	2,514	39.54	64
2003	124,511.19	22,173	16,713	114,024	41.52	2,746
2004	45,643.70	7,170	5,405	42,521	42.52	1,000
2005	26,268.24	3,580	2,699	24,883	43.51	572
2008	3,679.82	270	204	3,660	46.50	79
2009	31,753.72	1,667	1,256	32,085	47.50	675
2010	249,978.22	7,874	5,935	256,542	48.50	5,290
2011	52,974.97	556	419	55,205	49.50	1,115
	1,861,963.15	866,829	653,383	1,301,678		50,337

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 25.9 2.70

KENTUCKY UTILITIES COMPANY

ACCOUNT 367 UNDERGROUND CONDUCTORS AND DEVICES

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2011

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)

SURVIVOR CURVE.. IOWA 44-R2
NET SALVAGE PERCENT.. -10

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
1964	58.52	49	61	3	10.59	
1967	3,803.91	3,049	3,778	406	11.94	34
1968	18,857.70	14,893	18,455	2,288	12.41	184
1970	19,437.28	14,869	18,425	2,956	13.40	221
1971	12,761.88	9,597	11,892	2,146	13.92	154
1972	98,927.76	73,083	90,561	18,260	14.45	1,264
1973	50,488.20	36,617	45,374	10,163	14.99	678
1974	293,963.15	209,081	259,083	64,276	15.55	4,134
1975	238,785.05	166,434	206,237	56,427	16.12	3,500
1976	255,928.40	174,670	216,442	65,079	16.70	3,897
1977	186,189.14	124,282	154,004	50,804	17.30	2,937
1978	274,326.04	178,997	221,804	79,955	17.90	4,467
1979	347,715.68	221,495	274,465	108,022	18.52	5,833
1980	413,875.18	257,019	318,485	136,778	19.16	7,139
1981	233,945.65	141,537	175,385	81,955	19.80	4,139
1982	273,790.48	161,126	199,659	101,511	20.46	4,961
1983	333,308.32	190,652	236,246	130,393	21.12	6,174
1984	346,671.45	192,404	238,417	142,922	21.80	6,556
1985	291,904.98	156,971	194,511	126,584	22.49	5,628
1986	528,756.01	275,083	340,869	240,763	23.19	10,382
1987	861,205.67	432,758	536,252	411,074	23.90	17,200
1988	996,858.24	482,973	598,476	498,068	24.62	20,230
1989	1,340,438.66	624,974	774,436	700,047	25.35	27,615
1990	695,524.75	311,425	385,902	379,175	26.09	14,533
1991	1,089,988.82	467,605	579,433	619,555	26.84	23,083
1992	961,449.28	394,197	488,469	569,125	27.60	20,620
1993	1,093,542.23	427,305	529,495	673,401	28.37	23,736
1994	1,724,446.33	640,637	793,845	1,103,046	29.14	37,853
1995	3,457,495.39	1,216,164	1,507,009	2,296,236	29.93	76,720
1996	3,337,201.61	1,107,958	1,372,926	2,297,996	30.72	74,805
1997	3,477,255.42	1,084,038	1,343,285	2,481,696	31.53	78,709
1998	3,495,410.10	1,018,912	1,262,584	2,582,367	32.34	79,851
1999	4,138,043.80	1,121,393	1,389,574	3,162,274	33.16	95,364
2000	3,999,666.58	1,000,917	1,240,286	3,159,347	33.99	92,949
2001	8,355,663.15	1,917,658	2,376,265	6,814,964	34.82	195,720
2002	5,549,960.86	1,157,195	1,433,937	4,671,020	35.66	130,988
2003	9,096,461.00	1,703,340	2,110,693	7,895,414	36.51	216,253
2004	5,249,368.92	870,072	1,078,149	4,696,157	37.37	125,666
2005	3,621,603.81	522,431	647,370	3,336,394	38.23	87,272
2006	2,100,503.98	257,303	318,837	1,991,717	39.10	50,939
2007	2,442,262.11	245,438	304,134	2,382,354	39.98	59,589
2008	17,498,623.58	1,373,572	1,702,061	17,546,425	40.86	429,428

KENTUCKY UTILITIES COMPANY

ACCOUNT 367 UNDERGROUND CONDUCTORS AND DEVICES

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2011

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 44-R2						
NET SALVAGE PERCENT.. -10						
2009	36,541,161.72	2,055,587	2,547,180	37,648,098	41.75	901,751
2010	4,810,359.14	162,340	201,163	5,090,232	42.65	119,349
2011	10,462,019.39	117,729	145,884	11,362,337	43.55	260,903
	140,620,009.32	23,315,829	28,891,798	125,790,212		3,333,408

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 37.7   2.37

KENTUCKY UTILITIES COMPANY

ACCOUNT 368 LINE TRANSFORMERS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2011

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 43-R2						
NET SALVAGE PERCENT.. -15						
1941	27,040.80	29,289	31,097			
1942	1,433.77	1,542	1,649			
1943	1,791.11	1,913	2,060			
1944	2,669.42	2,830	3,070			
1945	5,181.49	5,453	5,959			
1946	13,556.11	14,161	15,590			
1947	9,070.56	9,405	10,431			
1948	15,653.65	16,109	18,002			
1949	256,054.69	261,524	294,061	402	4.81	84
1950	28,277.59	28,655	32,220	299	5.11	59
1951	25,257.55	25,399	28,559	487	5.40	90
1952	66,476.18	66,314	74,564	1,884	5.70	331
1953	175,364.63	173,482	195,065	6,604	6.01	1,099
1954	25,056.47	24,580	27,638	1,177	6.32	186
1955	81,646.20	79,416	89,296	4,597	6.63	693
1956	25,424.46	24,506	27,555	1,683	6.96	242
1957	82,931.50	79,203	89,057	6,314	7.29	866
1958	144,548.31	136,735	153,747	12,484	7.63	1,636
1959	190,675.26	178,583	200,801	18,476	7.98	2,315
1960	233,170.42	216,139	243,029	25,117	8.34	3,012
1961	224,129.14	205,539	231,111	26,638	8.71	3,058
1962	591,862.79	536,754	603,533	77,109	9.09	8,483
1963	368,924.82	330,629	371,763	52,501	9.49	5,532
1964	442,520.79	391,852	440,603	68,296	9.89	6,906
1965	710,000.93	620,729	697,956	118,545	10.31	11,498
1966	646,935.00	557,981	627,401	116,574	10.75	10,844
1967	1,199,497.30	1,020,124	1,147,040	232,382	11.20	20,748
1968	882,841.06	739,967	832,028	183,239	11.66	15,715
1969	1,274,757.16	1,052,435	1,183,371	282,600	12.13	23,298
1970	1,774,059.26	1,441,399	1,620,727	419,441	12.62	33,236
1971	1,710,534.05	1,366,456	1,536,461	430,653	13.13	32,799
1972	1,930,891.90	1,516,153	1,704,782	515,744	13.64	37,811
1973	3,418,074.34	2,634,530	2,962,299	968,486	14.18	68,299
1974	4,115,671.64	3,112,767	3,500,035	1,232,987	14.72	83,763
1975	1,876,960.75	1,391,480	1,564,598	593,907	15.28	38,868
1976	2,470,977.97	1,794,202	2,017,424	824,201	15.85	52,000
1977	4,416,056.30	3,136,815	3,527,075	1,551,390	16.44	94,367
1978	4,636,034.15	3,219,923	3,620,522	1,710,917	17.03	100,465
1979	4,620,025.72	3,133,465	3,523,308	1,789,722	17.64	101,458
1980	3,097,689.08	2,048,774	2,303,668	1,258,674	18.27	68,893
1981	2,173,836.41	1,401,126	1,575,444	924,468	18.90	48,914
1982	4,885,472.37	3,063,936	3,445,129	2,173,164	19.55	111,159

KENTUCKY UTILITIES COMPANY

ACCOUNT 368 LINE TRANSFORMERS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2011

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 43-R2						
NET SALVAGE PERCENT.. -15						
1983	5,460,039.20	3,327,894	3,741,926	2,537,119	20.21	125,538
1984	3,808,988.88	2,253,333	2,533,676	1,846,661	20.88	88,442
1985	5,424,822.25	3,110,539	3,497,530	2,741,016	21.56	127,134
1986	6,193,378.19	3,435,340	3,862,740	3,259,645	22.26	146,435
1987	5,965,119.32	3,197,050	3,594,804	3,265,083	22.96	142,207
1988	6,829,056.34	3,530,346	3,969,566	3,883,849	23.67	164,083
1989	6,754,673.08	3,360,072	3,778,108	3,989,766	24.40	163,515
1990	6,606,964.78	3,157,581	3,550,424	4,047,585	25.13	161,066
1991	6,127,599.21	2,805,589	3,154,640	3,892,099	25.88	150,390
1992	6,920,149.79	3,029,676	3,406,606	4,551,566	26.63	170,919
1993	8,592,270.25	3,584,768	4,030,759	5,850,352	27.40	213,516
1994	9,270,166.74	3,676,659	4,134,082	6,526,610	28.17	231,687
1995	9,360,154.25	3,517,087	3,954,657	6,809,520	28.95	235,217
1996	8,761,016.71	3,104,563	3,490,810	6,584,359	29.75	221,323
1997	9,339,032.12	3,109,519	3,496,383	7,243,504	30.55	237,103
1998	8,985,979.23	2,799,757	3,148,082	7,185,794	31.35	229,212
1999	7,140,702.58	2,068,226	2,325,540	5,886,268	32.17	182,974
2000	9,873,656.66	2,640,650	2,969,181	8,385,524	33.00	254,107
2001	10,106,706.55	2,478,660	2,787,037	8,835,676	33.83	261,179
2002	5,666,491.77	1,262,370	1,419,425	5,097,041	34.67	147,016
2003	13,162,697.29	2,633,099	2,960,690	12,176,412	35.52	342,804
2004	4,585,669.67	813,124	914,287	4,359,233	36.37	119,858
2005	276,780.13	42,712	48,026	270,271	37.23	7,259
2006	18,573,048.66	2,433,859	2,736,662	18,622,344	38.10	488,775
2007	11,353,223.75	1,220,625	1,372,486	11,683,721	38.98	299,736
2008	9,472,295.93	795,417	894,377	9,998,763	39.86	250,847
2009	16,236,810.41	977,123	1,098,690	17,573,642	40.75	431,255
2010	2,163,746.86	78,133	87,854	2,400,455	41.65	57,634
2011	14,180,125.36	170,736	191,977	16,115,167	42.55	378,735
	286,070,399.06	104,706,781	117,730,753	211,250,206		7,018,693

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 30.1 2.45

KENTUCKY UTILITIES COMPANY

ACCOUNT 369 SERVICES

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2011

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 43-R1.5						
NET SALVAGE PERCENT.. -30						
1948	25,310.64	28,014	32,904			
1949	30,370.57	33,348	39,482			
1950	25,456.41	27,729	33,093			
1951	22,821.88	24,652	29,668			
1952	38,696.62	41,449	50,306			
1953	18,141.67	19,262	23,584			
1954	2,372.15	2,496	3,084			
1955	26,438.90	27,560	34,371			
1956	93,657.65	96,697	121,755			
1957	116,233.47	118,810	151,104			
1958	100,674.84	101,841	130,877			
1959	151,758.43	151,910	197,286			
1960	43,810.30	43,364	56,953			
1961	172,321.06	168,587	224,017			
1962	158,903.80	153,634	206,575			
1963	172,824.37	165,003	224,672			
1964	185,371.91	174,684	240,983			
1965	121,475.03	112,930	157,918			
1966	192,898.61	176,761	250,768			
1967	243,979.74	220,325	317,174			
1968	182,016.06	161,837	236,621			
1969	236,528.23	206,945	307,487			
1970	165,717.78	142,587	215,433			
1971	368,066.44	311,126	478,486			
1972	415,004.61	344,529	539,506			
1973	482,797.08	393,220	624,013	3,623	16.06	226
1974	763,874.81	609,914	967,891	25,146	16.59	1,516
1975	615,938.26	481,737	764,483	36,237	17.13	2,115
1976	985,282.59	753,919	1,196,417	84,450	17.69	4,774
1977	1,235,848.94	924,729	1,467,481	139,123	18.25	7,623
1978	1,147,630.32	838,593	1,330,789	161,130	18.83	8,557
1979	1,250,791.01	891,665	1,415,011	211,017	19.42	10,866
1980	917,397.83	637,633	1,011,879	180,738	20.01	9,032
1981	1,340,519.98	907,011	1,439,364	303,312	20.62	14,710
1982	1,348,293.60	886,995	1,407,600	345,182	21.24	16,252
1983	2,223,190.12	1,420,218	2,253,788	636,359	21.87	29,097
1984	2,071,588.70	1,283,273	2,036,466	656,599	22.51	29,169
1985	2,003,794.87	1,201,916	1,907,358	697,575	23.16	30,120
1986	2,056,730.36	1,192,626	1,892,615	781,134	23.82	32,793
1987	1,596,803.48	893,589	1,418,064	657,781	24.49	26,859
1988	2,265,820.40	1,221,379	1,938,244	1,007,323	25.17	40,021
1989	2,473,133.92	1,282,300	2,034,921	1,180,153	25.85	45,654

KENTUCKY UTILITIES COMPANY

ACCOUNT 369 SERVICES

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2011

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 43-R1.5						
NET SALVAGE PERCENT.. -30						
1990	2,344,530.37	1,166,702	1,851,475	1,196,414	26.54	45,080
1991	2,586,403.61	1,231,552	1,954,388	1,407,937	27.25	51,667
1992	2,530,705.93	1,151,471	1,827,305	1,462,613	27.95	52,330
1993	3,300,795.00	1,430,030	2,269,359	2,021,674	28.67	70,515
1994	3,818,048.83	1,570,986	2,493,046	2,470,417	29.39	84,056
1995	4,623,015.33	1,800,151	2,856,715	3,153,205	30.12	104,688
1996	4,845,018.03	1,778,262	2,821,979	3,476,544	30.86	112,655
1997	5,205,636.47	1,794,154	2,847,198	3,920,129	31.60	124,055
1998	5,264,161.55	1,694,907	2,689,700	4,153,710	32.35	128,399
1999	4,309,241.73	1,288,463	2,044,702	3,557,312	33.11	107,439
2000	2,765,907.02	763,471	1,211,576	2,384,103	33.87	70,390
2001	3,003,620.49	760,051	1,206,148	2,698,559	34.63	77,925
2002	3,039,042.10	698,256	1,108,084	2,842,671	35.40	80,301
2003	1,238,259.63	255,304	405,150	1,204,588	36.18	33,294
2004	183,168.30	33,449	53,081	185,038	36.96	5,006
2006	26,496.15	3,573	5,670	28,775	38.54	747
2007	13,478.09	1,491	2,366	15,156	39.34	385
2008	2,119,665.10	183,273	290,842	2,464,723	40.14	61,403
2009	39,365.58	2,440	3,872	47,303	40.95	1,155
2010	3,910,902.73	145,407	230,751	4,853,423	41.77	116,194
2011	5,792,430.91	71,762	113,881	7,416,279	42.59	174,132
	89,050,180.39	36,701,952	57,697,779	58,067,456		1,811,200

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 32.1   2.03

KENTUCKY UTILITIES COMPANY

ACCOUNT 370 METERS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2011

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 39-R2						
NET SALVAGE PERCENT.. 0						
1932	256.00	256	256			
1940	84.00	83	84			
1941	97,819.19	96,565	97,819			
1942	8,538.82	8,375	8,539			
1943	12,625.18	12,298	12,625			
1944	11,893.61	11,503	11,894			
1945	23,804.91	22,859	23,805			
1946	38,389.94	36,589	38,390			
1947	78,781.05	74,519	78,781			
1948	76,136.79	71,471	76,137			
1949	84,321.08	78,527	84,321			
1950	188,211.29	173,879	187,637	574	2.97	193
1951	230,064.54	210,833	227,515	2,550	3.26	782
1952	199,557.16	181,391	195,743	3,814	3.55	1,074
1953	107,847.40	97,229	104,922	2,925	3.84	762
1954	165,612.17	148,074	159,790	5,822	4.13	1,410
1955	187,118.26	165,912	179,040	8,078	4.42	1,828
1956	162,316.18	142,671	153,960	8,356	4.72	1,770
1957	219,788.88	191,555	206,711	13,078	5.01	2,610
1958	312,806.73	270,218	291,599	21,208	5.31	3,994
1959	283,004.39	242,223	261,388	21,616	5.62	3,846
1960	291,432.36	247,120	266,673	24,759	5.93	4,175
1961	306,049.69	257,002	277,337	28,713	6.25	4,594
1962	316,040.18	262,718	283,505	32,535	6.58	4,945
1963	376,285.00	309,517	334,007	42,278	6.92	6,110
1964	390,565.30	317,760	342,902	47,663	7.27	6,556
1965	501,018.03	402,869	434,745	66,273	7.64	8,674
1966	444,644.88	353,324	381,280	63,365	8.01	7,911
1967	408,730.34	320,698	346,073	62,657	8.40	7,459
1968	521,767.27	404,036	436,005	85,762	8.80	9,746
1969	619,492.83	473,039	510,467	109,026	9.22	11,825
1970	548,903.21	413,083	445,767	103,136	9.65	10,688
1971	728,543.32	540,055	582,786	145,757	10.09	14,446
1972	789,443.56	575,891	621,457	167,987	10.55	15,923
1973	895,007.10	641,881	692,669	202,338	11.03	18,344
1974	1,713,326.22	1,207,244	1,302,765	410,561	11.52	35,639
1975	734,909.85	508,220	548,432	186,478	12.03	15,501
1976	1,031,520.34	699,587	754,941	276,579	12.55	22,038
1977	1,877,244.24	1,247,654	1,346,373	530,871	13.08	40,586
1978	1,488,771.46	968,089	1,044,687	444,084	13.64	32,557
1979	1,766,637.38	1,123,405	1,212,293	554,344	14.20	39,038
1980	845,921.58	525,343	566,910	279,012	14.78	18,878

KENTUCKY UTILITIES COMPANY

ACCOUNT 370 METERS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2011

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 39-R2						
NET SALVAGE PERCENT.. 0						
1981	770,186.96	466,456	503,364	266,823	15.38	17,349
1982	1,020,590.67	602,148	649,792	370,799	15.99	23,189
1983	1,456,791.41	836,344	902,518	554,273	16.61	33,370
1984	1,098,637.53	612,699	661,178	437,460	17.25	25,360
1985	1,115,282.93	603,402	651,145	464,138	17.90	25,929
1986	1,377,591.18	721,996	779,123	598,468	18.56	32,245
1987	1,373,677.90	696,001	751,071	622,607	19.24	32,360
1988	1,441,781.27	704,988	760,769	681,012	19.93	34,170
1989	1,346,083.46	634,046	684,214	661,869	20.63	32,083
1990	1,576,051.67	713,668	770,136	805,916	21.34	37,766
1991	1,617,787.16	702,702	758,302	859,485	22.06	38,961
1992	2,718,056.55	1,129,026	1,218,358	1,499,699	22.80	65,776
1993	1,473,489.11	584,106	630,322	843,167	23.54	35,818
1994	1,748,435.90	659,020	711,164	1,037,272	24.30	42,686
1995	1,925,051.87	688,091	742,535	1,182,517	25.06	47,187
1996	1,914,695.78	646,095	697,216	1,217,480	25.84	47,116
1997	2,924,717.57	927,662	1,001,061	1,923,657	26.63	72,236
1998	2,269,256.30	673,788	727,100	1,542,156	27.42	56,242
1999	1,799,946.00	497,055	536,384	1,263,562	28.23	44,760
2000	2,427,122.46	619,839	668,883	1,758,239	29.04	60,545
2001	2,411,718.38	564,583	609,255	1,802,463	29.87	60,344
2002	2,319,642.23	493,666	532,726	1,786,916	30.70	58,206
2003	1,931,532.62	369,464	398,697	1,532,836	31.54	48,600
2004	542,739.92	91,989	99,267	443,473	32.39	13,692
2005	292,711.66	43,157	46,572	246,140	33.25	7,403
2006	3,614,286.80	453,159	489,014	3,125,273	34.11	91,623
2007	1,151,915.79	118,440	127,811	1,024,105	34.99	29,269
2008	45,006.34	3,612	3,898	41,108	35.87	1,146
2009	2,713,896.23	156,565	168,953	2,544,943	36.75	69,250
2010	1,567,438.72	54,265	58,559	1,508,880	37.65	40,076
2011	978,001.26	11,286	12,179	965,822	38.55	25,054
	70,049,355.34	30,114,883	32,484,596	37,564,759		1,603,713

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 23.4   2.29

KENTUCKY UTILITIES COMPANY

ACCOUNT 371 INSTALLATIONS ON CUSTOMERS' PREMISES

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2011

SURVIVOR CURVE.. IOWA 25-O1
NET SALVAGE PERCENT.. -10

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
1964	90.68	95	100			
1965	80.00	82	88			
1968	12.47	12	14			
1970	10,162.00	9,278	11,178			
1971	5,339.00	4,757	5,873			
1972	1,592.19	1,384	1,751			
1973	47,043.72	39,846	51,748			
1974	1,502.79	1,240	1,653			
1975	1,694.31	1,361	1,864			
1976	149,725.69	116,936	164,698			
1977	156,448.73	118,745	172,094			
1978	45,373.00	33,440	49,910			
1979	168,188.00	120,254	185,007			
1980	83,122.22	57,604	91,434			
1981	362,765.00	243,415	399,042			
1982	337,809.00	219,238	371,590			
1983	360,401.37	225,972	396,442			
1984	340,563.00	206,041	374,619			
1985	227,861.00	132,843	250,647			
1986	354,841.00	199,066	390,325			
1987	174,483.00	94,046	191,931			
1988	203,214.19	105,062	223,536			
1989	610,722.70	302,308	671,795			
1990	593,560.00	280,754	652,916			
1991	533,180.00	240,464	586,498			
1992	876,852.53	376,170	964,538			
1993	1,341,939.00	546,169	1,463,348	12,785	15.75	812
1994	1,436,686.00	553,124	1,481,982	98,373	16.25	6,054
1995	1,813,074.65	658,146	1,763,367	231,015	16.75	13,792
1996	1,691,100.00	576,665	1,545,056	315,154	17.25	18,270
1997	1,713,444.00	546,589	1,464,473	420,315	17.75	23,680
1998	2,130,853.07	632,863	1,695,626	648,312	18.25	35,524
1999	1,931,763.00	531,235	1,423,335	701,604	18.75	37,419
2000	428,495.92	108,409	290,460	180,886	19.25	9,397
2001	96,663.00	22,329	59,826	46,503	19.75	2,355
2003	1,763.65	330	884	1,056	20.75	51
2006	8,816.12	1,067	2,859	6,839	22.25	307

KENTUCKY UTILITIES COMPANY

ACCOUNT 371 INSTALLATIONS ON CUSTOMERS' PREMISES

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2011

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 25-O1						
NET SALVAGE PERCENT.. -10						
2007	7,242.67	717	1,921	6,046	22.75	266
2008	1,721.13	133	357	1,536	23.25	66
2011	3,024.65	33	88	3,239	24.75	131
	18,253,214.45	7,308,222	17,404,873	2,673,663		148,124

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 18.1   0.81

KENTUCKY UTILITIES COMPANY

ACCOUNT 373 STREET LIGHTING AND SIGNAL SYSTEMS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2011

SURVIVOR CURVE.. IOWA 28-S0
NET SALVAGE PERCENT.. -10

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
1932	3,148.43	3,463	3,463			
1941	50,300.58	55,331	55,331			
1942	4,266.46	4,693	4,693			
1943	229.52	252	252			
1944	1,117.01	1,229	1,229			
1945	894.00	983	983			
1946	4,412.27	4,853	4,853			
1947	9,279.11	10,207	10,207			
1948	15,898.61	17,488	17,488			
1949	9,400.70	10,341	10,341			
1950	7,680.82	8,449	8,449			
1951	11,424.46	12,567	12,567			
1952	9,169.12	10,086	10,086			
1953	27,601.96	30,362	30,362			
1954	33,681.43	37,050	37,050			
1955	52,235.20	57,459	57,459			
1956	44,439.35	48,534	46,761	2,122	0.20	2,122
1957	40,665.90	43,854	42,252	2,480	0.55	2,480
1958	53,404.50	56,815	54,739	4,006	0.92	4,006
1959	54,801.19	57,504	55,403	4,878	1.29	3,781
1960	70,127.58	72,567	69,916	7,224	1.66	4,352
1961	76,608.55	78,160	75,305	8,964	2.03	4,416
1962	88,146.34	88,650	85,411	11,550	2.40	4,812
1963	136,289.75	135,033	130,100	19,819	2.78	7,129
1964	180,323.99	175,970	169,542	28,814	3.16	9,118
1965	60,757.93	58,384	56,251	10,583	3.54	2,990
1966	308,516.72	291,857	281,195	58,173	3.92	14,840
1967	193,660.27	180,235	173,651	39,375	4.31	9,136
1968	148,910.61	136,306	131,327	32,475	4.70	6,910
1969	192,496.69	173,253	166,924	44,822	5.09	8,806
1970	26,192.03	23,173	22,326	6,485	5.48	1,183
1971	182,733.77	158,796	152,995	48,012	5.88	8,165
1972	69,652.46	59,433	57,262	19,356	6.28	3,082
1973	173,570.64	145,378	140,067	50,861	6.68	7,614
1974	277,264.47	227,764	219,443	85,548	7.09	12,066
1975	159,093.37	128,126	123,445	51,558	7.50	6,874
1976	120,752.33	95,304	91,822	41,006	7.91	5,184
1977	169,129.99	130,695	125,921	60,122	8.33	7,218
1978	192,143.49	145,309	140,001	71,357	8.75	8,155
1979	666,424.02	492,987	474,978	258,088	9.17	28,145
1980	66,307.63	47,931	46,180	26,758	9.60	2,787
1981	1,112,764.79	785,577	756,879	467,162	10.03	46,576

KENTUCKY UTILITIES COMPANY

ACCOUNT 373 STREET LIGHTING AND SIGNAL SYSTEMS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2011

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 28-S0						
NET SALVAGE PERCENT.. -10						
1982	568,307.57	391,380	377,082	248,056	10.47	23,692
1983	236,622.12	158,867	153,063	107,221	10.91	9,828
1984	1,041,950.05	681,143	656,260	489,885	11.36	43,124
1985	955,943.52	608,010	585,799	465,739	11.81	39,436
1986	1,014,578.21	626,978	604,074	511,962	12.27	41,725
1987	78,957.55	47,366	45,636	41,217	12.73	3,238
1988	345,202.23	200,710	193,378	186,344	13.20	14,117
1989	1,328,182.99	747,200	719,904	741,097	13.68	54,174
1990	1,174,223.04	638,447	615,124	676,521	14.16	47,777
1991	1,186,318.09	621,717	599,005	705,945	14.66	48,155
1992	663,286.60	334,580	322,357	407,258	15.16	26,864
1993	1,239,632.89	600,473	578,537	785,059	15.67	50,099
1994	2,396,466.43	1,112,809	1,072,156	1,563,957	16.18	96,660
1995	871,998.05	386,758	372,629	586,569	16.71	35,103
1996	1,570,958.49	663,452	639,215	1,088,839	17.25	63,121
1997	1,778,848.29	712,818	686,778	1,269,955	17.80	71,346
1998	1,226,708.92	464,578	447,606	901,774	18.36	49,116
1999	3,298,829.77	1,175,449	1,132,508	2,496,205	18.93	131,865
2000	3,069,282.59	1,022,519	985,165	2,391,046	19.52	122,492
2001	2,540,150.11	785,356	756,666	2,037,499	20.13	101,217
2002	3,011,060.50	857,619	826,289	2,485,878	20.75	119,801
2003	5,426,480.70	1,409,132	1,357,654	4,611,475	21.39	215,590
2004	2,075,374.44	485,119	467,397	1,815,515	22.05	82,336
2005	397,358.63	82,266	79,261	357,833	22.73	15,743
2006	318,362.08	57,033	54,949	295,249	23.44	12,596
2007	46,120.04	6,921	6,668	44,064	24.18	1,822
2008	2,823,695.49	338,344	325,984	2,780,081	24.95	111,426
2009	8,585,493.49	755,523	727,923	8,716,120	25.76	338,359
2010	19,327,495.27	1,055,359	1,016,805	20,243,440	26.61	760,746
2011	7,831,069.36	147,647	142,253	8,471,923	27.52	307,846
	81,534,875.55	21,477,981	20,703,034	68,985,329		3,261,361

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 21.2   4.00

KENTUCKY UTILITIES COMPANY

ACCOUNT 390.1 STRUCTURES AND IMPROVEMENTS - TO OWNED PROPERTY

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2011

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 55-S0						
NET SALVAGE PERCENT.. -10						
1941	22,125.96	17,603	17,287	7,052	15.22	463
1942	561.26	442	434	183	15.63	12
1946	456.65	344	338	164	17.31	9
1949	227.20	165	162	88	18.58	5
1950	2,473.03	1,780	1,748	972	19.01	51
1951	293.27	209	205	118	19.45	6
1952	2,144.06	1,506	1,479	879	19.88	44
1953	807.17	560	550	338	20.32	17
1955	9,171.73	6,200	6,089	4,000	21.20	189
1956	269,399.17	179,744	176,517	119,822	21.64	5,537
1957	13.55	9	9	6	22.09	
1958	245,130.76	159,138	156,281	113,363	22.54	5,029
1960	12,283.57	7,751	7,612	5,900	23.45	252
1961	43,983.00	27,348	26,857	21,524	23.91	900
1962	364,449.08	223,262	219,254	181,640	24.37	7,453
1963	16,027.90	9,671	9,497	8,134	24.83	328
1965	95,961.17	56,098	55,091	50,466	25.77	1,958
1966	323,312.08	185,905	182,568	173,075	26.25	6,593
1967	30,431.42	17,206	16,897	16,578	26.73	620
1968	6,854.07	3,809	3,741	3,798	27.21	140
1969	178,064.22	97,260	95,514	100,357	27.69	3,624
1970	935,155.68	501,621	492,617	536,054	28.18	19,022
1971	160,090.55	84,304	82,791	93,309	28.67	3,255
1972	516,680.03	266,919	262,128	306,220	29.17	10,498
1973	45,140.81	22,869	22,458	27,197	29.67	917
1974	31,627.84	15,700	15,418	19,373	30.18	642
1975	107,256.45	52,148	51,212	66,770	30.69	2,176
1977	117,056.89	54,501	53,523	75,240	31.72	2,372
1979	100,121.92	44,494	43,695	66,439	32.78	2,027
1980	80,159.37	34,773	34,149	54,026	33.31	1,622
1981	1,509,679.12	638,602	627,139	1,033,508	33.85	30,532
1982	245,150.10	101,003	99,190	170,475	34.40	4,956
1983	579,395.46	232,340	228,169	409,166	34.95	11,707
1984	187,651.82	73,146	71,833	134,584	35.51	3,790
1985	1,317,694.72	498,877	489,922	959,542	36.07	26,602
1986	746,235.81	273,872	268,956	551,903	36.65	15,059
1988	779,831.49	268,110	263,297	594,518	37.81	15,724
1989	6,267,353.32	2,080,774	2,043,422	4,850,667	38.40	126,319
1990	772,856.08	247,315	242,876	607,266	39.00	15,571
1991	319,277.54	98,274	96,510	254,695	39.61	6,430
1992	897,822.50	265,221	260,460	727,145	40.23	18,075
1994	823,590.51	222,365	218,373	687,577	41.50	16,568

KENTUCKY UTILITIES COMPANY

ACCOUNT 390.1 STRUCTURES AND IMPROVEMENTS - TO OWNED PROPERTY

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2011

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 55-S0						
NET SALVAGE PERCENT.. -10						
1995	3,299,790.62	848,713	833,478	2,796,292	42.14	66,357
1996	959,486.32	234,117	229,914	825,521	42.80	19,288
1997	214,926.90	49,563	48,673	187,747	43.47	4,319
1998	231,580.56	50,252	49,350	205,389	44.15	4,652
1999	595,477.25	121,003	118,831	536,194	44.84	11,958
2000	521,854.57	98,632	96,862	477,178	45.55	10,476
2001	1,075,213.05	187,735	184,365	998,369	46.27	21,577
2002	161,504.46	25,840	25,376	152,279	47.00	3,240
2003	1,753,204.77	254,218	249,655	1,678,870	47.75	35,160
2004	317,371.37	41,132	40,394	308,715	48.52	6,363
2005	1,228,991.20	140,110	137,595	1,214,295	49.30	24,631
2006	725,794.22	70,983	69,709	728,665	50.11	14,541
2007	1,130,945.89	92,059	90,406	1,153,634	50.93	22,651
2008	4,503,806.01	290,068	284,861	4,669,326	51.78	90,176
2009	2,812,207.85	131,625	129,262	2,964,167	52.66	56,289
2010	1,405,013.30	40,183	39,462	1,506,053	53.57	28,114
2011	7,910,102.85	77,527	76,135	8,624,978	54.51	158,227
	47,011,269.52	9,826,998	9,650,596	42,061,800		945,113

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 44.5   2.01

KENTUCKY UTILITIES COMPANY

ACCOUNT 390.2 STRUCTURES AND IMPROVEMENTS - TO LEASED PROPERTY

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2011

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 30-R1						
NET SALVAGE PERCENT.. -10						
1954	172.93	184	190			
1960	725.23	723	798			
1962	7,205.33	7,025	7,926			
1963	399.36	385	439			
1966	623.09	578	685			
1967	465.41	426	512			
1970	405.94	355	447			
1971	1,164.17	1,004	1,281			
1973	131.45	110	145			
1974	186.50	153	205			
1977	148.09	114	163			
1978	3,924.94	2,968	4,317			
1979	5,040.26	3,726	5,544			
1980	837.61	605	921			
1981	51,658.03	36,405	56,824			
1982	4,351.91	2,990	4,787			
1983	18,457.70	12,345	19,779	524	11.76	45
1984	1,919.65	1,248	1,999	113	12.27	9
1985	10,670.24	6,733	10,787	950	12.79	74
1986	4,221.73	2,582	4,137	507	13.32	38
1987	3,902.50	2,309	3,699	594	13.86	43
1988	4,433.34	2,533	4,058	819	14.42	57
1989	121,720.51	66,990	107,329	26,564	14.99	1,772
1991	42,777.33	21,708	34,780	12,275	16.16	760
1992	1,038.61	504	807	335	16.76	20
1993	2,633.36	1,220	1,955	942	17.37	54
1994	62,551.31	27,545	44,131	24,675	17.99	1,372
1995	7,199.47	3,004	4,813	3,106	18.62	167
1996	40,240.41	15,847	25,389	18,875	19.26	980
1998	16,271.89	5,632	9,023	8,876	20.56	432
1999	2,747.75	885	1,418	1,605	21.22	76
2000	113,747.39	33,824	54,192	70,930	21.89	3,240
	531,973.44	262,660	413,480	171,691		9,139

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 18.8   1.72

KENTUCKY UTILITIES COMPANY

ACCOUNT 391.1 OFFICE FURNITURE AND EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2011

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. 20-SQUARE						
NET SALVAGE PERCENT.. 0						
1992	98,424.92	95,964	98,425			
1993	97,780.00	90,446	95,771	2,009	1.50	1,339
1994	146,869.00	128,510	136,076	10,793	2.50	4,317
1995	380,370.00	313,805	332,279	48,091	3.50	13,740
1996	218,919.78	169,663	179,651	39,269	4.50	8,726
1997	273,690.39	198,426	210,108	63,582	5.50	11,560
1998	217,728.76	146,967	155,619	62,110	6.50	9,555
1999	197,525.05	123,453	130,721	66,804	7.50	8,907
2000	3,589,975.52	2,064,236	2,185,762	1,404,214	8.50	165,202
2001	163,226.00	85,694	90,739	72,487	9.50	7,630
2002	188,528.48	89,551	94,823	93,705	10.50	8,924
2003	250,973.01	106,664	112,944	138,029	11.50	12,003
2004	149,260.52	55,973	59,268	89,993	12.50	7,199
2005	164,091.73	53,330	56,470	107,622	13.50	7,972
2006	99,011.55	27,228	28,831	70,181	14.50	4,840
2007	312,121.99	70,227	74,361	237,761	15.50	15,339
2008	181,323.81	31,732	33,600	147,724	16.50	8,953
2009	591,964.52	73,996	78,352	513,613	17.50	29,349
2010	56,433.78	4,233	4,482	51,952	18.50	2,808
2011	135,568.75	3,389	3,589	131,980	19.50	6,768
	7,513,787.56	3,933,487	4,161,871	3,351,917		335,131

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 10.0   4.46

KENTUCKY UTILITIES COMPANY

ACCOUNT 391.2 NON PC COMPUTER EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2011

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. 5-SQUARE						
NET SALVAGE PERCENT.. 0						
2004	1,319,347.32	1,319,347	1,319,347			
2005	1,446,806.41	1,446,806	1,446,806			
2006	836,479.79	836,480	836,480			
2007	2,250,083.47	2,025,075	1,280,895	969,188	0.50	969,188
2008	1,502,067.92	1,051,448	665,059	837,009	1.50	558,006
2009	1,037,972.62	518,986	328,267	709,706	2.50	283,882
2010	2,897,017.97	869,105	549,724	2,347,294	3.50	670,655
2011	5,966,236.85	596,624	377,375	5,588,862	4.50	1,241,969
	17,256,012.35	8,663,871	6,803,953	10,452,059		3,723,700

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 2.8   21.58

KENTUCKY UTILITIES COMPANY

ACCOUNT 391.31 PERSONAL COMPUTERS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2011

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. 4-SQUARE						
NET SALVAGE PERCENT.. 0						
2005	144,748.87	144,749	144,749			
2006	1,211,802.61	1,211,803	1,211,803			
2007	376,094.70	376,095	376,095			
2008	1,287,422.40	1,126,495	1,287,422			
2009	326,151.72	203,845	326,152			
2010	1,266,697.78	475,012	833,967	432,731	2.50	173,092
2011	1,785,453.57	223,182	391,835	1,393,619	3.50	398,177
	6,398,371.65	3,761,181	4,572,023	1,826,349		571,269

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 3.2   8.93

KENTUCKY UTILITIES COMPANY

ACCOUNT 392.1 TRANSPORTATION EQUIPMENT - CARS AND LIGHT TRUCKS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2011

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 7-L2.5						
NET SALVAGE PERCENT.. 0						
1987	29,800.99	29,801	29,801			
1988	16,057.03	16,057	16,057			
1990	42,398.59	42,399	42,399			
1992	166,353.84	163,977	166,354			
1993	29,267.84	28,181	29,268			
1995	30,733.56	28,055	30,734			
1997	241,004.34	208,985	241,004			
1998	18,749.84	15,857	18,750			
1999	322,369.42	265,265	322,369			
2000	272,220.77	216,609	272,221			
2002	42,272.12	30,919	42,272			
2004	66,854.43	44,697	66,854			
2005	25,658.90	16,458	25,659			
2006	21,485.44	12,983	21,485			
2007	48,222.98	26,178	48,223			
2008	12,992.33	5,884	12,992			
2009	100,902.22	34,162	92,121	8,781	4.63	1,897
2010	72,524.72	15,230	41,069	31,456	5.53	5,688
2011	305,221.61	21,802	58,791	246,431	6.50	37,912
	1,865,090.97	1,223,499	1,578,423	286,668		45,497

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 6.3 2.44

KENTUCKY UTILITIES COMPANY

ACCOUNT 392.3 TRANSPORTATION EQUIPMENT - HEAVY TRUCKS AND OTHER

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2011

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 14-S1.5						
NET SALVAGE PERCENT.. 0						
1980	67,377.53	67,378	67,378			
1985	95,604.34	92,941	95,604			
1986	53,393.62	50,915	53,394			
1988	110,098.03	100,975	110,098			
1989	595,889.89	535,878	595,890			
1990	1,165,710.67	1,026,653	1,165,711			
1991	939,725.77	810,175	939,726			
1992	653,977.34	550,740	653,977			
1993	1,208,412.90	993,485	1,208,413			
1994	801,985.44	642,158	801,985			
1995	1,540,632.01	1,197,287	1,540,632			
1996	1,732,022.41	1,303,970	1,732,022			
1997	1,145,122.96	831,852	1,145,123			
1998	130,736.44	91,329	130,736			
1999	990,831.73	661,737	990,832			
2000	1,537,633.77	975,306	1,512,586	25,048	5.12	4,892
2001	312,992.05	187,125	290,209	22,783	5.63	4,047
2002	49,145.22	27,451	42,573	6,572	6.18	1,063
2004	29,223.81	13,693	21,236	7,988	7.44	1,074
2009	38,375.79	6,716	10,416	27,960	11.55	2,421
2010	20,403.31	2,172	3,369	17,034	12.51	1,362
2011	882,692.60	31,521	48,885	833,808	13.50	61,764
	14,101,987.63	10,201,457	13,160,795	941,193		76,623

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 12.3   0.54

KENTUCKY UTILITIES COMPANY

ACCOUNT 393 STORES EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2011

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. 25-SQUARE						
NET SALVAGE PERCENT.. 0						
1992	4,871.57	3,800	2,800	2,072	5.50	377
1993	15,790.00	11,685	8,610	7,180	6.50	1,105
1994	69,979.00	48,985	36,094	33,885	7.50	4,518
1995	49,532.00	32,691	24,088	25,444	8.50	2,993
1996	70,779.00	43,883	32,334	38,445	9.50	4,047
1997	863.00	501	369	494	10.50	47
1998	2,667.00	1,440	1,061	1,606	11.50	140
1999	15,683.00	7,842	5,778	9,905	12.50	792
2003	102,957.32	35,005	25,793	77,164	16.50	4,677
2005	118,483.26	30,806	22,699	95,784	18.50	5,178
2007	4,390.25	790	582	3,808	20.50	186
2009	49,517.43	4,952	3,649	45,868	22.50	2,039
2011	46,281.44	926	682	45,599	24.50	1,861
	551,794.27	223,306	164,539	387,255		27,960

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 13.9   5.07

KENTUCKY UTILITIES COMPANY

ACCOUNT 394 TOOLS, SHOP AND GARAGE EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2011

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. 25-SQUARE						
NET SALVAGE PERCENT.. 0						
1991	80,015.75	65,613	58,437	21,579	4.50	4,795
1992	266,024.00	207,499	184,804	81,220	5.50	14,767
1993	51,227.00	37,908	33,762	17,465	6.50	2,687
1994	182,973.00	128,081	114,073	68,900	7.50	9,187
1995	128,983.00	85,129	75,818	53,165	8.50	6,255
1996	320,563.36	198,749	177,011	143,552	9.50	15,111
1997	275,144.00	159,584	142,130	133,014	10.50	12,668
1998	177,280.00	95,731	85,261	92,019	11.50	8,002
1999	291,566.00	145,783	129,838	161,728	12.50	12,938
2000	137,515.75	63,257	56,339	81,177	13.50	6,013
2001	113,230.00	47,557	42,356	70,874	14.50	4,888
2002	71,343.48	27,111	24,146	47,197	15.50	3,045
2003	865,094.84	294,132	261,962	603,133	16.50	36,554
2004	311,595.23	93,479	83,255	228,340	17.50	13,048
2005	203,940.80	53,025	47,226	156,715	18.50	8,471
2006	147,385.38	32,425	28,879	118,506	19.50	6,077
2007	204,061.37	36,731	32,714	171,347	20.50	8,358
2008	98,021.38	13,723	12,222	85,799	21.50	3,991
2009	845,635.90	84,564	75,315	770,321	22.50	34,236
2010	1,417,927.22	85,076	75,770	1,342,157	23.50	57,113
2011	1,459,227.98	29,185	25,993	1,433,235	24.50	58,499
	7,648,755.44	1,984,342	1,767,311	5,881,444		326,703

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 18.0 4.27

KENTUCKY UTILITIES COMPANY

ACCOUNT 396.3 POWER OPERATED EQUIPMENT - LARGE MACHINERY

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2011

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 12-L1.5						
NET SALVAGE PERCENT.. 0						
1997	6,098.00	3,816	2,773	3,325	4.49	741
1999	3,705.14	2,155	1,566	2,139	5.02	426
2000	20,831.00	11,648	8,463	12,368	5.29	2,338
2003	24,822.74	11,998	8,717	16,106	6.20	2,598
2004	96,576.68	43,621	31,693	64,884	6.58	9,861
2005	11,307.99	4,683	3,402	7,906	7.03	1,125
2009	132,372.80	25,151	18,273	114,100	9.72	11,739
2010	701,660.60	82,445	59,900	641,761	10.59	60,601
2011	176,850.49	7,074	5,140	171,710	11.52	14,905
	1,174,225.44	192,591	139,927	1,034,298		104,334

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 9.9 8.89

KENTUCKY UTILITIES COMPANY

ACCOUNT 397.1 COMMUNICATION EQUIPMENT - GENERAL ASSETS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2011

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. 10-SQUARE						
NET SALVAGE PERCENT.. 0						
1986	87,398.38	87,398	87,398			
1987	148,960.01	148,960	148,960			
1988	142,791.70	142,792	142,792			
1989	39,582.58	39,583	39,583			
1990	26,669.52	26,670	26,670			
1991	35,466.94	35,467	35,467			
1992	263,190.83	263,191	263,191			
1993	45,713.00	45,713	45,713			
1994	58,119.67	58,120	58,120			
1995	177,122.26	177,122	177,122			
1996	314,627.57	314,628	314,628			
1999	241,923.26	241,923	241,923			
2000	19,398.59	19,399	19,399			
2001	532,409.74	532,410	532,410			
2002	265,337.81	252,071	265,338			
2003	882,642.01	750,246	882,642			
2004	363,623.46	272,718	363,623			
2005	81,670.27	53,086	79,185	2,485	3.50	710
2006	152,819.64	84,051	125,373	27,447	4.50	6,099
2007	58,517.26	26,333	39,279	19,238	5.50	3,498
2008	136,482.17	47,769	71,254	65,228	6.50	10,035
2009	435,055.63	108,764	162,236	272,820	7.50	36,376
2010	4,722,083.34	708,313	1,056,545	3,665,538	8.50	431,240
2011	939,690.26	46,985	70,084	869,606	9.50	91,537
	10,171,295.90	4,483,712	5,248,935	4,922,361		579,495

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 8.5   5.70

KENTUCKY UTILITIES COMPANY

ACCOUNT 397.2 COMMUNICATION EQUIPMENT - SPECIFIC ASSETS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2011

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 25-S1						
NET SALVAGE PERCENT.. 0						
1998	67,579.67	30,114	35,253	32,327	13.86	2,332
1999	741,013.58	311,226	364,342	376,672	14.50	25,977
2000	6,884,581.53	2,709,771	3,172,241	3,712,341	15.16	244,877
2001	332,063.91	121,403	142,123	189,941	15.86	11,976
2002	490,319.06	165,139	193,323	296,996	16.58	17,913
2003	1,494,700.15	458,574	536,837	957,863	17.33	55,272
2004	618,952.82	170,336	199,407	419,546	18.12	23,154
2005	98,892.37	24,011	28,109	70,783	18.93	3,739
2006	1,267,642.26	264,177	309,263	958,379	19.79	48,427
2007	263,953.18	45,717	53,519	210,434	20.67	10,181
2008	661,845.09	90,276	105,683	556,162	21.59	25,760
2009	2,591,492.39	255,003	298,524	2,292,968	22.54	101,729
2010	2,444,774.64	145,709	170,577	2,274,198	23.51	96,733
2011	1,957,225.25	39,145	45,826	1,911,399	24.50	78,016
	19,915,035.90	4,830,601	5,655,027	14,260,009		746,086

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 19.1   3.75

KENTUCKY UTILITIES COMPANY

ACCOUNT 397.3 COMMUNICATION EQUIPMENT - FULLY ACCRUED

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2011

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
FULLY ACCRUED						
NET SALVAGE PERCENT.. 0						
2000	17,408.00	17,408	17,408			
2002	262,488.58	262,489	262,489			
2003	73,009.26	73,009	73,009			
2004	433,327.36	433,327	433,327			
	786,233.20	786,233	786,233			

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 0.0   0.00

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

APPLICATION OF KENTUCKY	**)**	
UTILITIES COMPANY FOR AN	**)**	**CASE NO. 2012-00221**
ADJUSTMENT OF ITS ELECTRIC	**)**	
RATES	**)**	

TESTIMONY OF
DANIEL K. ARBOUGH
TREASURER
KENTUCKY UTILITIES COMPANY

Filed: June 29, 2012

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

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

Q. Have you previously testified before the Commission?

A. Yes. I testified in KU's and LG&E's last base rate cases.[1] Since 2000, I have also attested to the factual representations in each of KU's financing applications filed with the Kentucky Public Service Commission ("Commission") and have appeared before Commission Staff on behalf of the Company on a regular basis. I also testified in KU's last base rate case in Virginia.[2]

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to discuss KU's cost of debt, current and target capital structures, and the effects of PPL Corporation's acquisition of KU on the Company's finances. I am also sponsoring Reference Schedule 1.14 of Blake Exhibit 1, which describes pro-forma adjustments related to pension, post-retirement, and post-employment benefit expenses; Reference Schedule 1.19 of Blake Exhibit 1, which describe pro-forma adjustments related to insurance costs of the Company; and several industry articles and assessments relevant to the topics I discuss.

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[1] Case No. 2009-00548, *In the Matter of: Application of Kentucky Utilities Company for an Adjustment of Base Rates*; Case No. 2009-00549, *In the Matter of: Application of Kentucky Utilities Company for an Adjustment of Base Rates*.

[2] Case No. PUE-2011-00013, *Application of: Kentucky Utilities Company d/b/a Old Dominion Power Company for an Adjustment of Electric Base Rates*.

Capital Structure

Q. Please explain the capital structure of KU.

A. As I testified in Case No. 2009-00548, KU is firmly committed to maintaining the financial strength of the Company. The Company has a target capital structure of the midpoint of the range for "A" rated utilities published by Standard and Poor's ("S&P"), an independent credit rating agency.

Q. What is the current target capital structure?

A. KU's current capital structure is established in accordance with the independent criteria set forth by S&P to achieve a rating in the "A" range. S&P first adopted a business risk/financial risk matrix structure in 2007. S&P's current methodology for assessing investor-owned utilities is found in an article entitled "*Key Credit Factors: Business and Financial Risks in the Investor-Owned Utilities Industry*," dated November 26, 2008, and reissued March 11, 2010, and attached as Arbough Exhibit 1. Table 1 from that article shows the relationship of S&P's assessments of the business and the financial risks for purposes of determining the credit rating of an investor-owned utility. S&P updated Table 1 in a May 27, 2009 article entitled "*Criteria Methodology: Business Risk/Financial Matrix Expanded*" which is attached as Arbough Exhibit 2. Collectively, these two publications represent S&P's current view on financial risk profile metrics for independently determining the credit ratings of investor-owned utilities.

KU's financial risk profile, according to S&P, fits the category between "Significant" and "Highly Leveraged" known as the "Aggressive" category. In other words, debt is a prominent form of capital in this financial risk profile. S&P recommends a debt to total capital range of 50% to 60% to remain in this category.

KU's target capital structure is based on achieving a rating in the "A" range rather than the current BBB. Table 1 in the same article shows KU must achieve the "Intermediate" risk profile to achieve an A rating, and a "Significant" risk profile to achieve an A- rating. To reach the Intermediate financial risk profile, KU must maintain a maximum debt/capital ratio of 45% as measured by S&P, and a maximum of 50% to achieve the "Significant" risk profile. Given S&P's assessment that the Company meets the "Excellent" business risk profile, the Company targets a debt/total capital ratio of 48% as measured by S&P.

Based on these criteria, the Company is targeting an adjusted equity to total capital ratio (including imputed debt for purchased power, leases, post-retirement benefit obligations, and other credit rating agency adjustments) of 52%, or the equivalent of a 48% adjusted debt to total capital ratio. When the credit rating agency debt adjustments set forth in S&P's November 1, 2011 report are included, the equity ratio decreases to 51.4%, as of March 31, 2012.

Q. Why do the credit rating agencies adjust the debt balances when determining the target capital structure?

A. Because the credit rating agencies view certain obligations, such as power purchase agreements and post-retirement benefit obligations as fixed obligations equivalent to debt, the Company makes corresponding adjustments when calculating the debt in the target capital structure for this purpose. Two S&P articles further explain the reasoning behind treating certain items as adjustments to the target capital structure. First, "*2008 Corporate Criteria: Ratios and Adjustments*," dated April 15, 2008, and attached as Arbough Exhibit 3, discusses twenty-two adjustments S&P considers when analyzing industrial companies. Second, "*Standard & Poor's Methodology for Imputing Debt for U.S. Utilities' Power Purchase Agreements*," dated May 7, 2007, and attached as Arbough Exhibit 4, is specific to the utility industry and recognizes that power purchase agreement fixed obligations "merit inclusion in a utility's financial metrics as though they are part of a utility's permanent capital structure."

S&P's November 2011 review of KU, attached as Arbough Exhibit 5, noted that it had imputed $183.7 million in debt to KU for the year-end 2010 financial statements. This imputed debt included $113.8 million for Postretirement Benefit Obligations, $36.9 million for "Debt—Other" (includes power purchases), $25.0 million for Operating Leases, and $8.0 million for "Debt—Accrued Interest Not Included In Reported Debt." Disregarding the impact of imputed debt could affect the Company's debt rating, resulting in a ratings downgrade and an increase in debt costs, and thereby limiting the Company's future access to attractively priced debt capital.

<u>Cost of Debt</u>

Q. Has KU prepared an exhibit showing its capitalization as of March 31, 2012?

A. Yes, Blake Exhibit 2 to the testimony of Kent Blake shows KU's capitalization at March 31, 2012, for electric operations. Blake Exhibit 2 also shows the calculation of KU's adjusted capitalization for electric operations as of March 31, 2012, for ratemaking purposes as well as the weighted average cost of capital to apply to the adjusted capitalization. Mr. Blake provides a fuller description of Blake Exhibit 2 in his testimony.

Q. Please explain how the cost of debt was calculated in Blake Exhibit 2.

A. The cost of debt shown in Blake Exhibit 2 is a weighted-average cost of debt of 3.69% as of the end of March 2012. It includes all components of interest expense for each bond, including the interest paid to the bondholders, amortization of bond issuance costs and debt discounts, credit facility costs, and credit enhancements that support each series, if applicable. The credit enhancement costs include any ongoing bond insurance fees and letter of credit fees paid to banks.

Q. How does KU's cost of debt compare to other utility companies?

A. KU monitors its cost of debt relative to a peer group of other utility companies. KU's 3.75% cost of debt (combined taxable and tax-exempt debt) is the second lowest of any utility company in the peer group for the twelve months ending March 2012, as demonstrated by Arbough Exhibit 6.

Q. How was KU's debt refinanced after the PPL Corporation acquisition?

A. In connection with the PPL Corporation acquisition, KU sought the Commission's approval in Case No. 2010-00206 to refinance approximately $1.33 billion in debt it owed to a former E.ON AG affiliate, Fidelia Corporation ("Fidelia"). Initially, KU replaced the Fidelia loans with loans from PPL Investment Corporation. The new loans were repaid on November 16, 2010, with the proceeds from the issuance of First Mortgage Bonds.

Q. Please describe the results of the refinancing transaction.

A. KU issued a total of $1.5 billion in three series of First Mortgage Bonds in accordance with the Commission's Order in Case No. 2010-00206. The first, Series A, was for $250 million and has a maturity date of November 1, 2015. The Company was able to obtain an interest rate of 1.625% for Series A. Series B was issued in the amount of $500 million and has a maturity date of November 1, 2020. The interest rate for Series B is 3.250%. Finally, Series C was issued in the amount of $750 million and has a maturity date of November 1, 2040. The interest rate for Series C is 5.125%. The proceeds of the bond issuances were used to repay existing unsecured promissory notes totaling $1.331 billion in principal, plus accrued interest. The remaining proceeds of the issuances were used to fund capital projects and for other purposes as described in the refinancing application.

The refinancing of the Fidelia loans with First Mortgage Bonds resulted in very attractive interest rates that will benefit ratepayers for many years. The weighted average interest rate on the new First Mortgage Bonds is 3.92% and the average maturity of the bonds is slightly over 19 years, whereas the Fidelia loans had a weighted average interest rate of approximately 5.50% and an average maturity of 9 years. There were no prepayment fees or penalties associated with the refinancing because it was in conjunction with the PPL Corporation acquisition.

Credit Ratings

Q. What are KU's current credit ratings?

A. Arbough Exhibit 7 shows the current credit ratings for KU and demonstrates that KU continues to retain strong credit ratings and is able to raise capital in the form of debt at very reasonable costs, but continues to target a rating in the "A" range.

Q. Has S&P issued any other rankings relevant to KU's credit rating?

A. Yes. In an article entitled "*Assessing U.S. Utility Regulatory Environments*," dated March 11, 2010, and attached as Arbough Exhibit 8, S&P ranked state regulatory commissions based upon S&P's "assessment of regulatory risk." S&P cited regulatory risk as "perhaps the most important factor in Standard & Poor's Ratings Services' analysis of a U.S. regulated, investor-owned utility's business risk." The Commission was listed as "credit supportive," placing it in the middle on a continuum from "most credit supportive" to "least credit supportive." KU believes that the Commission's balanced approach serves utility companies and ratepayers well and allows Kentucky customers to receive some of the lowest cost electricity in the United States.

<u>Access to Capital</u>

Q. Does KU have sufficient access to capital?

A. Yes. KU has authority from the Federal Energy Regulatory Commission and the Virginia State Corporation Commission to issue up to $500 million in short-term debt. KU maintains a $400 million unused revolving line of credit and a $198 million letter of credit facility. KU also has a commercial paper program with authorization to issue up to $250 million in commercial paper. The revolving line of credit serves as a backstop for any commercial paper issuances. KU presently does not have any unexercised authority to issue long-term debt, but filed for such authority and for authority to increase its revolving line of credit facility on June 6, 2012.[3]

Q. Does the existing capital structure allow KU to compete for attractively priced capital for future investments in facilities to serve customers?

A. Yes. In my opinion, KU's capital structure is appropriate and should be used for ratemaking purposes. The structure is well-balanced from the perspectives of the customers, shareholders, and the market, and provides the necessary ability to attract

[3] Case No. 2012-00232, *In the Matter of: The Application of Kentucky Utilities Company for an Order Authorizing the Issuance of Securities and the Assumption of Obligations*.

capital in public markets in the future at favorable pricing. This is particularly important given the market volatility in recent years and KU's significant upcoming capital expenditures. Maintaining strong investment grade ratings is even more important than in the recent past, as the Company, following several years of utilizing intercompany loans under E.ON AG's ownership, is once again accessing the public capital markets and issuing securities in the form of debt.

Pro Forma Adjustments

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

A. This adjustment is necessary to adjust the pension, post-retirement, and post-employment benefit expenses for the test year to the 2012 annualized cost as calculated in March 2012 by Mercer, the Company's actuarial consultant. Based on a review of Mercer's calculation of expenses and subsequent earnings on plan investments, the Company determined the net periodic expenses recorded in the test year should be adjusted to reflect the going-forward level. KU proposed a similar adjustment in Case No. 2008-00251,[4] which was resolved by a settlement approved by the Commission, while a similar adjustment was approved by the Commission in Case Nos. 2009-00548 and 2003-00434.[5]

Q. Please describe the adjustment shown on Reference Schedule 1.19 of Blake Exhibit 1 relating to Property Insurance costs.

A. Since merging its property insurance program with PPL Corporation in April 2011, the Company renews its policy on April 1 each year. The adjustment reflected on the

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[4] *In the Matter of: Application of Kentucky Utilities Company for an Adjustment of Base Rates*.
[5] *In the Matter of: An Adjustment of the Electric Rates, Terms and Conditions of Kentucky Utilities Company*.

schedule shows the change in the insurance premium from the test year to the April 1, 2012, to March 31, 2013 period based on actual renewal rates. The property insurance premium is determined by multiplying the premium rate times the estimated replacement cost of the insured facilities. Insurance costs are higher after a recent appraisal conducted by an independent third party increased the valuation of KU's property. The adjustment shown in Reference Schedule 1.19 of Blake Exhibit 1 adds the Kentucky-jurisdictional portion of the premium increase to KU's operating expenses.

Q. Does this conclude your testimony?

A. Yes, it does.

VERIFICATION

COMMONWEALTH OF KENTUCKY)
) SS:
COUNTY OF JEFFERSON)

The undersigned, **Daniel K. Arbough**, being duly sworn, deposes and says that he is Treasurer for Kentucky Utilities Company and Louisville Gas and Electric Company and an employee of LG&E and KU Services Company, and that he has personal knowledge of the matters set forth in the foregoing testimony, and that the answers contained therein are true and correct to the best of his information, knowledge and belief.

Daniel K. Arbough
Daniel K. Arbough

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 20th day of June 2012.

Notary Public (SEAL)

My Commission Expires:

July 21, 2015

APPENDIX A

Daniel K. Arbough

Treasurer
LG&E and KU Services LLC
220 West Main Street
Louisville, Kentucky 40202
(502) 627-4956

Previous Positions

E.ON U.S. LLC
Director, Corporate Finance and Treasurer — January 2001 – September 2007

LG&E Energy Corp.
Director, Corporate Finance — May 1998 – January 2001
Manager, Corporate Finance — August 1996 – May 1998

LG&E Power Inc.
Manager, Project Finance — June 1994 - August 1996

Conoco Inc., Houston, Texas
Corporate Finance, Project Finance,
and Credit Management — June 1988 - May 1994

Boise Cascade Office Products, Denver, Colorado
Inventory Management — November 1983 - September 1987

Professional/Trade Memberships

National Association of Corporate Treasurers
Association for Financial Professionals

Education

Master of Business Administration – Finance - May 1988 – GPA 3.8
University of Denver

Bachelor of Science Business Administration – General Business
June 1983 – GPA 3.9 – Graduated Summa Cum Laude
Honors Program scholarship recipient
University of Denver

Civic Activities

Louisville and Jefferson County Metropolitan Sewer District – Board of Directors
Leadership Louisville – Bingham Fellows – Class of 2012
National Center for Family Literacy – Endowment Oversight Committee Member
Louisville Central Community Centers – Past President of Board of Directors

Arbough Exhibit 1

Standard and Poor's Report: Key Credit Factors

STANDARD & POOR'S

Global Credit Portal
RatingsDirect®

March 11, 2010

Criteria | Corporates | Utilities:

Key Credit Factors: Business And Financial Risks In The Investor-Owned Utilities Industry

Primary Credit Analyst:
Todd A Shipman, CFA, New York (1) 212-438-7676; todd_shipman@standardandpoors.com

Table Of Contents

Criteria | Corporates | Utilities:

Key Credit Factors: Business And Financial Risks In The Investor-Owned Utilities Industry

(Editor's Note: Table 1 in this article is no longer current. It has been superseded by the table found in "Criteria Methodology: Business Risk/Financial Risk Matrix Expanded," published May 27, 2009, on RatingsDirect. For our latest comments on regulated utility subsidiaries, please see "Methodology: Differentiating The Issuer Credit Ratings Of A Regulated Utility Subsidiary And Its Parent," published March 11, 2010, on RatingsDirect.)

Standard & Poor's Ratings Services' analytic framework for companies in all sectors, including investor-owned utilities, is divided into two major segments: The first part is the fundamental business risk analysis. This step forms the basis and provides the industry and business contexts for the second segment of the analysis, an in-depth financial risk analysis of the company.

An integrated utility is often a part of a larger holding company structure that also owns other businesses, including unregulated power generation. This fact does not alter how we analyze the regulated utility, but it may affect the ultimate rating outcome because of any higher risk credit drag that the unregulated activities may have on the utility. Such considerations include the freedom and practice of management with respect to shifting cash resources among subsidiaries and the presence of ring-fencing mechanisms that may protect the utility.

Relationship Between Business And Financial Risks

Prior to discussing the specific risk factors we analyze within our framework, it is important to understand how we view the relationship between business and financial risks. Table 1 displays this relationship and its implications for a company's rating.

Table 1

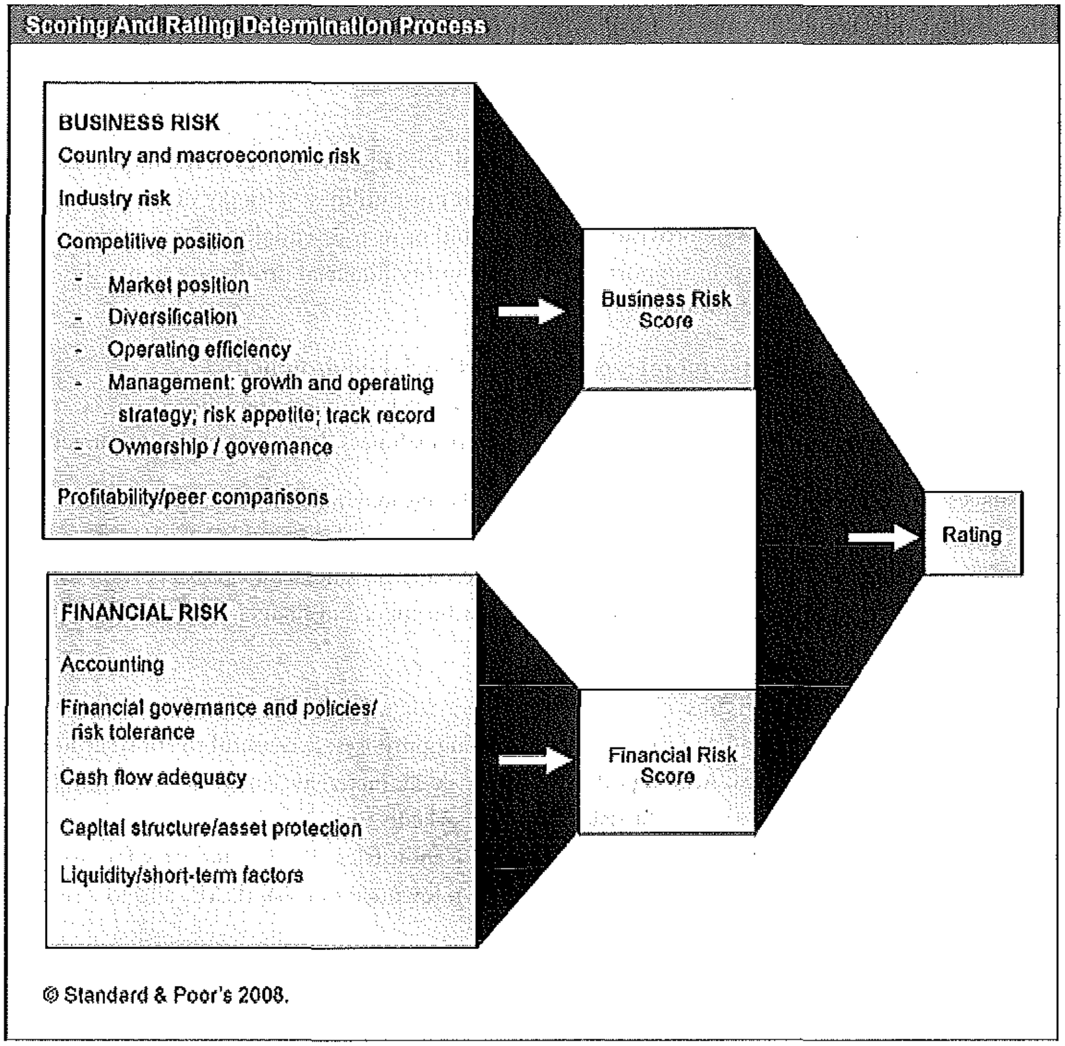
Business And Financial Risk Profile Matrix

Business Risk Profile		Financial Risk Profile: Minimal	Modest	Intermediate	Aggressive	Highly leveraged
		(AAA/AA)	(A)	(BBB)	(BB)	(B)
Excellent	(AAA/AA)	AAA	AA	A	BBB	BB
Strong	(A)	AA	A	A-	BBB-	BB-
Satisfactory	(BBB)	A	BBB+	BBB	BB+	B+
Weak	(BB)	BBB	BBB-	BB+	BB-	B
Vulnerable	(B)	BB	B+	B+	B	B-

These rating outcomes are shown for guidance purposes only. Other qualitative and quantitative rating factors may override these measures

Chart 1 summarizes the ratings process.

Chart 1



Part 1--Business Risk Analysis

Business risk is analyzed in four categories: country risk, industry risk, competitive position, and profitability. We determine a score for the overall business risk based on the scale shown in table 2.

Table 2

Business Risk Measures

Description	Rating equivalent
Excellent	AAA/AA
Strong	A
Satisfactory	BBB
Weak	BB
Vulnerable	B/CCC

Analysis of business risk factors is supported by factual data, including statistics, but ultimately involves a fair amount of subjective judgment. Understanding business risk provides a context in which to judge financial risk, which covers analysis of cash flow generation, capitalization, and liquidity. In all cases, the analysis uses historical experience to make estimates of future performance and risk.

In the U.S., regulated utilities and holding companies that are utility-focused virtually always fall in the upper range (Excellent or Strong) of business risk profiles. The defining characteristics of most utilities--a legally defined service territory generally free of significant competition, the provision of an essential or near-essential service, and the presence of regulators that have an abiding interest in supporting a healthy utility financial profile--underpin the business risk profiles of the electric, gas, and water utilities.

1. Country risk and macroeconomic factors (economic, political, and social environments)

Country risk plays a critical role in determining all ratings on companies in a given national domicile. Sovereign-related stress can have an overwhelming effect on company creditworthiness, both directly and indirectly.

Sovereign credit ratings suggest the general risk local entities face, but the ratings may not fully capture the risk applicable to the private sector. As a result, when rating a corporation, we look beyond the sovereign rating to evaluate the specific economic or country risks that may affect the entity's creditworthiness. Such risks pertain to the effect of government policies and other country risk factors on the obligor's business and financial environments, and an entity's ability to insulate itself from these risks.

2. Industry business and credit risk characteristics

In establishing a view of the degree of credit risk in a given industry for rating purposes, it is useful to consider how its risk profile compares to that of other industries. Although the industry risk characteristic categories are broadly similar across industries, the effect of these factors on credit risk can vary markedly among industries. Chart 2 illustrates how the effects of these credit-risk factors vary among some major industries. The key industry factors are scored as follows: High risk (H), medium/high risk (M/H), medium risk (M), low/medium risk (L/M), and low risk (L).

Chart 2

Key Industry Characteristics And Drivers Of Credit Risk

	Utilities regulated	Competitive power	Oil & gas downstream	Autos	Airlines
Industry dynamics and competitive environment					
Industry cyclicality	M	H	H	H	H
Ease of entry	L	M/H	H	M/H	M/H
Product cycle/obsolescence	L	L	L	H	L
Level of product quality	L	L	M	H	M
Disintermediation/substitution	L	L	L	L/M	L
Competition/commoditization	L/M	H	M	H	H
Pricing inflexibility	M	H	M	H	H
Business model stability	M	M/H	L	L/M	M
Demographic trends	L	L	M	H	L
Growth and profitability					
Growth outlook	L	M	L	M/H	L/M
Profit margin pressure/outlook	M	M/H	M	M/H	H
Earnings volatility	M	M/H	H	H	H
Operating considerations and costs					
Technological risk/change	L	L	L/M	L/M	L/M
Cost efficiency/pressures	M	H	M	H	H
Operating leverage	M/H	H	H	H	H
R&D costs	L	L	L	H	L
Energy cost sensitivity	H	H	H	H	H
Raw material cost sensitivity	H	H	H	H	L
Labor costs	M	M	M	H	H
Labor inflexibility/unrest	L	L	M	H	H
Pension costs/contingents	M	L	L/M	H	M/H
Environmental impact/costs	H	L	H	H	M/H
Marketing costs	L	L	M	H	L/M
Customer concentration	L	M	L	L	L
Supplier concentration	H	H	H	M	M
Risk management	M	H	M	M	M
Asset/plant quality and age/upkeep	M	H	H	M	M/H
Event risk sensitivity	M/H	H	H	M/H	H
Financial market volatility/sensitivity	M	M/H	L	M	M
Fashion/fad/design sensitivity	L	L	L	H	L/M
Capital and financing characteristics					
Capital intensity	H	H	H	H	H
Borrowing requirement	H	H	L/M	H	H
Interest rate sensitivity	L/M	L/M	L/M	H	L/M
Government, regulatory, and legal environments					
Regulation/deregulation	H	H	M	M/H	H
Government microeconomic and social policies	H	H	H	H	M/H
Litigiousness/legal risk	L	H	M	M	M

Industry strengths:

- Material barriers to entry because of government-granted franchises, despite deregulatory trends;
- Strategically important to national and regional economies; key pillar of the consumer and commercial economy;
- Improving management focus industry-wide on operating efficiency in recent years; and
- Cross-border growth opportunities in Europe and industrializing emerging markets.

Industry challenges/risks:

- Maturity, with a weak growth outlook in developed countries;
- Highly politicized and burdensome regulatory (i.e., rate setting and investment recovery) process; and
- Risks of "legacy cost drag" as wholesale and retail markets move toward greater deregulation.

Major global risk issues facing the utilities industry:

- Increased volatility in the regulatory environment and competitive landscape leading to greater uncertainty regarding adequacy of pricing and return on capital;
- Longer-term impact of, and ability to absorb, significant secular upturn in fuel costs, which is the industry's major operating expense;
- Ability to recover massive investment costs that will likely be necessary to replace aging industry infrastructure in a harsher cost and regulatory environment; and
- The debate over global warming will continue far beyond 2008. What the ultimate outcome will be is unclear, but growing legislation addressing carbon emissions and other greenhouse gases is probable in the near future. Utilities' ability to recover environmentally mandated costs in authorized rates and consumers' willingness to pay them could impact the industry's future credit strength.

Industry business model and risk profile in transition

Regulated utilities are in many developed countries transitioning away from quasi-monopolies toward more open competitive environments.

The level of business and credit risk associated with the investor-owned regulated utilities has historically proven in most countries to be lower (risk) than for many other industries. This has been because of the existence of government policy and related regulation that created significant barriers to entry limiting competition, and regulatory rate setting designed to provide an opportunity to achieve a specific level of profitability. The credit quality of most vertically integrated utilities in developed countries has historically been, and remains, solidly investment grade. This, to reiterate, is primarily a function of the existence of protective regulation.

The risks of, and rationale for, deregulation

The traditional protected and privileged utilities industry business model with its marked monopolistic characteristics is in many countries undergoing transition to a more competitive and open framework. This transition process, known as deregulation or liberalization, is weakening the business and credit risk profile of the industry. While the impact of these changes may prove positive in the longer term for more efficient industry players, it is important to bear in mind that economic history is littered with the vestiges of industries and enterprises that once flourished under the protection of government-created barriers and other protections. The shift is being driven by introduction in many countries of policies to encourage the entrance of new competitors and to reduce the traditional regulatory protections and privileges enjoyed by incumbents. Historically, the regulated investor-owned utilities were usually granted exclusive franchises. Because of the significant risks associated with the capital-intense nature of the utility investment, including massive sunk/fixed costs and long-term break-even horizons, governments in many countries created legal and regulatory frameworks that granted exclusivity to one operator in a given geographic area. To offset the monopolistic pricing power this exclusivity created, a system of heavy regulation was typically developed, which included the setting of pricing. The model often set pricing on a "cost-plus-basis", i.e., the margin over cost allowing for a perceived fair return to shareholders of investor-owned utilities. One major weakness of this system is that it created little incentive for utilities to efficiently manage costs. In recent years as many governments have adopted more liberal open market economic philosophies and related policies focused on the creation of greater competition—in an effort to foster improved economic growth and pricing efficiency throughout the economy—the traditional utility models in many countries have come under increasing political scrutiny and pressure.

A major public policy and political risk, as well as a credit risk, associated with deregulation of protected industries, is that existing incumbents often experience significant challenges in readjusting their management strategies, cultures, and expense basis to be able to compete effectively in the new environment.

The turmoil and bankruptcies in the U.S. in the nonregulated power marketing and trading arena between 2000 and 2002 arose subsequent to a major government initiative to deregulate the wholesale market. These failures, as well as other high-profile problems arising from deregulation elsewhere in the world, have given governments pause as to the desirability of a headlong rush into deregulation. In the U.S., for example, there is currently little impetus to carry deregulation any further.

Regulation and deregulation in the U.S.

While considerable attention has been focused on companies in states that deregulated in the late 1990s and the early part of this decade, and the related consequences of disaggregation and nonregulated generation, 27 states (plus four that formally reversed, suspended, or delayed restructuring) have retained the traditional regulated model. For utilities operating in those states, the quality of regulation and management loom considerably larger than markets, operations, and competitiveness in shaping overall financial performance. Policies and practices among state and federal regulatory bodies will be key credit determinants. Likewise, the quality of management, defined by its posture towards creditworthiness, strategic decisions, execution and consistency, and its ability to sustain a good working relationship with regulators, will be key. Importantly, however, it is virtually impossible to completely segregate each of these characteristics from the others; to some extent they are all interrelated.

Fragmentation of original model emerges in the U.S.

- Traditional regulated, vertically integrated utilities (generation, transmission, and distribution);
- Transmission and distribution;
- Diversified;
- Transmission; and
- Merchant generation.

We view a company that owns regulated generation, transmission, and distribution operations as positioned between companies with relatively low-risk transmission and distribution operations and companies with higher-risk diversified activities on the business profile spectrum. What typically distinguishes one vertically integrated utility's business profile score from another is the quality of regulation and management, which are the two leading drivers of credit quality.

Deregulation in the U.S. creates a new volatile industry subsector

The birth of large-scale, nonregulated power generators created the opportunity--and the need--for companies to market and broker power. Power marketers, independent power producers, and unregulated subsidiaries of utility companies offer power-supply alternatives to other utilities in the wholesale market as well as to large industrial customers. Power marketing operations have been formed by energy companies (many with experience in marketing natural gas), utility subsidiaries, and independents. As with the gas industry, electric power marketers expected to develop an efficient market by straddling the gulf between electricity generators and their customers, who have become "free agents" in the newly competitive environment.

Deregulation creates tiering of industry, business and credit risk profiles in Europe

The regional differences in market liberalization across Western Europe result in material variations in industry and business risk profiles for the utilities industry at the national level. The U.K. and Nordic markets, in particular, are substantially deregulated and open, and consequently present higher risks than other markets that are less open, including France and the Iberian market. Ratings therefore generally are lower in these more deregulated markets. The less-liberalized markets may face more regulatory risk going forward, particularly if efforts by the EU to advance the internal market by increasing the extent of market liberalization across the EU continue.

Legal action against companies that infringe on competition laws should be expected--particularly against those that move to prevent new entry and limit customer choice (for example, through the tying of markets and capacity hoarding) or collude with other incumbents to do so. The European Commission (EC) can fine companies that have violated antitrust laws up to 10% of their global annual turnover and, under certain conditions, impose structural remedies. Particular emphasis would be placed on increasing the effective unbundling of network and supply activities and on diminishing market concentration and barriers to entry.

The EC has publicly stated is intention to pursue, as a priority, abuses of the dominant position of vertically integrated companies (called vertical foreclosure). Behavioral remedies, such as energy release programs, are expected to be imposed by the EC for which such abuses, or collusion, are proved. The commission could also enforce structural measures when behavioral remedies are deemed insufficient.

3. Company competitive position and keys to competitive success

In analyzing a company's competitive position, we consider the following:

- Regulation;
- Markets;
- Diversification;
- Operations;
- Management, including growth strategy;
- Governance; and
- Profitability.

We are most concerned about how these elements contribute individually and in aggregate to the predictability and sustainability of financial performance, particularly cash flow generation relative to fixed obligations.

Regulation. Critical success factors include:

- Consistency and predictability of decisions;
- Support for recovery of fuel and investment costs;
- History of timely and consistent rate treatment, permitting satisfactory profit margins and timely return on investment; and
- Support for a reasonable cash return on investment.

Regulation is the most critical aspect that underlies regulated integrated utilities' creditworthiness. Regulatory decisions can profoundly affect financial performance. Our assessment of the regulatory environments in which a utility operates is guided by certain principles, most prominently consistency and predictability, as well as efficiency and timeliness. For a regulatory process to be considered supportive of credit quality, it must limit uncertainty in the recovery of a utility's investment. They must also eliminate, or at least greatly reduce, the issue of rate-case lag, especially when a utility engages in a sizable capital expenditure program.

Our evaluation encompasses the administrative, judicial, and legislative processes involved in state and national government regulation, and includes the political environment in which commissions render decisions. Regulation is assessed in terms of its ability to satisfy the particular needs of individual utilities. Rate-setting actions are reviewed case by case with regard to the potential effect on credit quality.

Evaluation of regulation focuses on the ability of regulation to provide utilities with the opportunity to generate cash flow and earnings quality and stability adequate to:

- Meet investment needs;
- Service debt and maintain a satisfactory rating profile; and
- Generate a competitive rate of return to investors.

To achieve this, regulation must allow for:

- Timely recognition of volatile cost components such as fuel and satisfactory returns on invested capital and equity;
- Ability to enter into long-term arrangements at negotiated rates without having to seek regulatory approval for each contract; and
- Ability to recover costs in new investment over a reasonable time frame.

Because the bulk of a utility's operating expenses relate to fuel and purchased power, of primary importance to rating stability is the level of support that state regulators provide to utilities for fuel cost recovery, particularly as gas and coal costs have risen. Utilities that are operating under rate moratoriums, or without access to fuel and purchased-power adjustment clauses, or face significant regulatory lag, also are subject to reduced operating margins, increased cash flow volatility, and greater demand for working capital. Companies that are granted fuel true-ups may be required to spread recovery over many years to ease the pain for the consumer. In addition to fuel cost recovery filings, regulators will have to address significant rate increase requests related to new generating capacity additions, environmental modifications, and reliability upgrades. Current cash recovery and/or return by means of construction work in progress support what would otherwise sometimes be a significant cash flow drain and reduces the utility's need to issue debt during construction.

Markets/market position. Critical success factors include:

- A healthy and growing economy;
- Growth in population and residential and commercial customer base;
- An attractive business environment;
- An above-average residential base; and
- Limited bypass risk.

The importance of diversification and size. Critical success factors include:

- Regional and cross-border market diversification (mitigates economic, demographic, and political risk concentration);
- Industrial customer diversification;
- Fuel supplier diversification;

- Retail, compared with wholesale;
- Regulatory regime diversification; and
- Generating facility diversification.

Operations (operating strategy, capability, and performance efficiency). Critical success factors include:

- Low cost structure;
- Well-maintained assets;
- Solid plant performance;
- Adequate generating reserves, and compliance with environmental standards; and
- Limited environmental exposures.

Management evaluation. Utilities are complex specialized businesses requiring experienced and successful management teams to have a strong mix of the aforementioned disciplines. Critical elements of management success include:

- Commitment to credit quality;
- Operating efficiency and cost control;
- Maintaining a competitive asset base, i.e., power plant construction project management, and plant upkeep and renovation;
- Regulatory track record, process, and relationship management;
- M&A experience in successfully identifying, executing, and integrating acquisitions;
- Credibility and strong corporate governance;
- Conservative financial policies, especially regarding non-regulated activities; and
- Ability and track record in repositioning and transforming business to not just survive, but prosper in a more open market environment.

Management is assessed for its ability to run and expand the business efficiently, while mitigating inherent business and financial risks. The evaluation also focuses on the credibility of management's strategy and projections, its operating and financial track record, and its appetite for assuming business and financial risk.

The management assessment is based on tenure, turnover, industry experience, financial track record, corporate governance, a grasp of industry issues, and knowledge of regulation, the impact of deregulation, of customers, and their needs. Management's ability and willingness to develop workable strategies to address system needs, and to execute reasonable and effective long-term plans are assessed. Management quality is also indicated by thoughtful balancing of multiple priorities; a record of credibility; and effective communication with the public, regulatory bodies, and the financial community.

We also focus on management's ability to achieve cost-effective operations and commitment to maintaining credit quality. This can be assessed by evaluating accounting and financial practices, capitalization and common dividend objectives, and the company's philosophy regarding growth and risk-taking.

4. Profitability/peer comparison

Regulated. Traditionally, the lower levels of risk in utilities because of the highly regulated environment has resulted in lower profitability and return on capital than in many other industrial sectors. In the regulated marketplace the level and margin of profitability has often primarily been a function of regulatory leeway, with the contribution of operating efficiency and revenue growth taking more of a back seat.

Deregulated/liberalized environments. In deregulated markets, cost efficiency and flexibility, and internal growth, are the major profitability drivers. The development of a robust risk management culture and infrastructure are also keys to creating stability of earnings, because the company no longer has recourse to the regulator to cover costs or losses—a recourse that usually protects from downside earnings surprises in the regulated sector.

Whether generated by the regulated or deregulated side of the business, profitability is critical for utilities because of the need to fund investment-generating capacity, maintain access to external debt and equity capital, and make acquisitions. Profit potential and stability is a critical determinant of credit protection. A company that generates higher operating margins and returns on capital also has a greater ability to fund growth internally, attract capital externally, and withstand business adversity. Earnings power ultimately attests to the value of the company's assets, as well. In fact, a company's profit performance offers a litmus test of its fundamental health and competitive position. Accordingly, the conclusions about profitability should confirm the assessment of business risk, including the degree of advantage provided by the regulatory environment.

Part 2—Financial Risk Analysis

Having evaluated a company's competitive position, operating environment, and earnings quality, our analysis proceeds to several financial categories. Financial risk is portrayed largely through quantitative means, particularly by using financial ratios.

We analyze five risk categories: accounting characteristics; financial governance/policies and risk tolerance; cash flow adequacy; capital structure and leverage; and liquidity/short-term factors. We then determine a score for overall financial risk using the following scale:

Table 3

Financial Risk Measures

Description	Rating equivalent
Minimal	AAA/AA
Modest	A
Intermediate	BBB
Aggressive	BB
Highly leveraged	B

The major goal of financial risk analysis is to determine the quality of cash resources from operations and other major sources available to service the debt and other financial liabilities, including any new debt. An integral part of this analysis is to form an understanding of the debt structure, including the mix of senior versus subordinated, fixed versus floating debt, as well as its maturity structure. It is also important to analyze and form an opinion of management's financial policy, accounting elections, and risk appetite. Using cash flow analysis as a building block, it is further necessary to establish the company's liquidity profile and flexibility. While closely interrelated, the analysis of a company's liquidity differs from that of its cash flow as it also incorporates the evaluation of other sources and uses of funds, such as committed undrawn bank facilities, as well as contingent liabilities (e.g., guarantees, triggers, regulatory issues, and legal settlements).

1. Accounting characteristics

Financial statements and related footnotes are the primary source of information about a company's financial condition and performance. The analysis begins with a review of accounting characteristics to determine whether

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ratios and statistics derived from the statements adequately measure a company's performance and position relative to those of both its direct peer group and the universe of industrial companies. This assessment is important in providing a common frame of reference and in helping the analyst determine the quality of disclosure and the reliability of the reported numbers. We focus on the following areas:

- Analytical adjustments and areas of potential concern;
- Significant transactions and notable events that have accounting implications.
- Significant accounting and financial reporting policies and the underlying assumptions.
- History of nonoperating results and extraordinary charges or adjustments and underlying accounting treatment, disclosure, and explanation.

2. Financial governance/policies and risk tolerance

The robustness of management's financial and accounting strategies and related implementation processes is a key element in credit risk evaluation. We attach great importance to management's philosophies and policies involving financial risk.

Financial policies are also important because companies with more conservative balance sheets and the credit capacity to pursue the necessary investments or acquisitions gain an advantage. Overly aggressive capital structures can leave very little capacity to absorb unexpected negative developments and will certainly leave little capacity to make future strategic investments. Companies with the credit capacity to support strategic investments will be better positioned to both evolve with industry change and to withstand inevitable downturns.

Understanding management's strategy for raising its share price, including its financial performance objectives, e.g., return on equity, can provide invaluable insight about the financial and business risk appetite.

3. Cash flow adequacy

Cash-flow analysis is one of the most critical elements of all credit rating decisions. Although there usually is a strong relationship between cash flow and profitability, many transactions and accounting entries affect one and not the other. Analysis of cash-flow patterns can reveal a level of debt-servicing capability that is either stronger or weaker than might be apparent from earnings. Focusing on the source and quality/volatility of cash flow is also important (e.g., regulated/deregulated; generation/transmission/trading).

A review of cash flow historically, as well as needs on a forward-looking basis, should take into account levels of capital expenditures for new generation plants. In periods where elevated new construction occurs in anticipation of a rise in power demand, cash outflows will be high.

It is particularly important to evaluate capital-intensive businesses, such as utility companies, on the basis of how much cash they generate and absorb. Debt service is an especially important use of cash flow.

Cash-flow ratios. Ratios show the relationship of cash flow to debt and debt service, and also to the company's needs. Because there are calls on cash flow other than repaying debt, it is important to know the extent to which those requirements will allow cash to be used for debt service or, alternatively, lead to greater need for borrowing. The most important cash flow ratios we look at for the investor-owned utilities are:

- Funds from operations (FFO)/Total debt;
- FFO/Income;
- Funds from operations/Total debt (adjusted for off-balance-sheet liabilities);

- EBITDA/Interest; and
- Net cash flow/Capital spending requirements.

4. Capital structure and leverage

For utilities, the long-term nature of capital commitments and extended breakeven periods on investment, make the type of financing required by these companies to finance these needs to be similar in many ways to the financing needs of other long-term asset-intensive businesses. Our analysts review projections of future CAPEX, debt, and FFO levels to make a determination of the likely level of leverage and debt over the medium term, and the companies' ability to sustain them. The valuation of the debt amortization scheduled is tied into projections of profitability breakeven, and the underlying assets becoming cash-flow-positive, are key components of the combined cash flow and leverage analysis.

Capitalization ratios. When analyzing a utility's balance sheet, a key element is analysis of capitalization ratios. The main factors influencing the level of debt are the level of capital expenditures, particularly construction expenditures, and the cost of debt. Companies with strong balance sheets will have more flexibility to further reduce their debt, and/or increase their dividends. The following are useful indicators of leverage:

- Total debt*/total debt + equity; and
- Total debt* + off-balance-sheet liabilities/total debt + off-balance-sheet liabilities + equity.

*Power purchase agreement-adjusted total debt. Fully adjusted, historically demonstrated, and expected to consistently continue.

Debt leverage, and interest and amortization coverage ratios are the key drivers of the financial risk score.

5. Liquidity/working capital/short-term factors:

Our liquidity analysis starts with operating cash flow and cash on hand, and then looks forward at other actual and contingent sources and uses of funds in the short term that could either provide or drain cash under given circumstances.

A key source of liquidity is bank lines. Key factors reviewed are total amount of facilities; whether they are contractually committed; facility expiration date(s); current and expected usage and estimated availability; bank group quality; evidence of support/lack of support of bank group; and covenant and trigger analysis. Financial covenant analysis is critical for speculative-grade credits. We request copies of all bank loan agreements and bond terms and conditions for rated entities, and review supplemental information provided by issuers for listing of financial covenants and stipulated compliance levels. We review covenant compliance as indicated in compliance certificates, as well as expected future compliance and covenant headroom levels. Entities that have already tripped or are expected to trip financial covenants need to be subject to special scrutiny and are reviewed for their ability to obtain waivers or modifications need to be subject to special scrutiny and are reviewed for their ability to obtain waivers or modifications to covenants. Tripping covenants can have a double negative effect on a company's liquidity. It may preclude it from borrowing further under its credit line, and may also lead to a contractual acceleration of repayment and increased interest rates.

Arbough Exhibit 2

Standard and Poor's Report: Criteria Methodology:Business Risk/Financial Risk Matrix Expanded

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Criteria Methodology: Business Risk/Financial Risk Matrix Expanded

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Criteria Methodology: Business Risk/Financial Risk Matrix Expanded

(Editor's Note: We are republishing this criteria following our periodic review completed on Dec. 8, 2010. In the original version of this article published on May 26, 2009, certain rating outcomes in the table 1 matrix were missated. A corrected version follows.

Table 1 supersedes tables 1, 2, and 3 in the following articles:

-- "Business And Financial Risks In The Global Telecommunication, Cable, And Satellite Broadcast Industry," published Jan. 27, 2009;

-- "Business And Financial Risks In The U.S. For-Profit Health Care Facilities Industry," published Jan. 21, 2009;

-- "Business And Financial Risks In The Health Care Equipment And Supply Industry," published Feb. 6, 2009;

-- "Methodology And Assumptions On Risks In The Packaging Industry," published Dec. 4, 2008;

-- "Business And Financial Risks In The Investor-Owned Utilities Industry," published Nov. 26, 2008;

-- "Business And Financial Risks In The Global Building Products And Materials Industry," published Nov. 19, 2008;

-- "Business And Financial Risks In The Commodity And Specialty Chemical Industry," published Nov. 20, 2008;

-- "Business And Financial Risks In The Oil And Gas Exploration And Production Industry," published Nov. 10, 2008;

-- "Business And Financial Risks In The U.S. Trucking Industry," published Nov. 4, 2008;

-- "Business And Financial Risks In The U.S. Gaming Industry," published Sept. 25, 2008;

-- "Business And Financial Risks In The Retail Industry," published Sept. 18, 2008; and

-- "Business And Financial Risks In The Restaurant Industry," published Dec. 4, 2008.

Table 1 also supersedes only table 1 in "Business And Financial Risks In The Global High Technology Industry," published Sept. 18, 2008.)

Standard & Poor's Ratings Services is refining its methodology for corporate ratings related to its business risk/financial risk matrix, which we published as part of "2008 Corporate Ratings Criteria" on April 15, 2008, on RatingsDirect at www.ratingsdirect.com and Standard & Poor's Web site at www.standardandpoors.com.

This article amends and supersedes the criteria as published in Corporate Ratings Criteria, page 21, and the articles listed in the "Related Articles" section at the end of this report.

This article is part of a broad series of measures announced last year to enhance our governance, analytics, dissemination of information, and investor education initiatives. These initiatives are aimed at augmenting our independence, strengthening the rating process, and increasing our transparency to better serve the global markets.

We introduced the business risk/financial risk matrix four years ago. The relationships depicted in the matrix represent an essential element of our corporate analytical methodology.

We are now expanding the matrix, by adding one category to both business and financial risks (see table 1). As a result, the matrix allows for greater differentiation regarding companies rated lower than investment grade (i.e., 'BB' and below).

Table 1

Business And Financial Risk Profile Matrix

Business Risk Profile	--Financial Risk Profile--					
	Minimal	**Modest**	**Intermediate**	**Significant**	**Aggressive**	**Highly Leveraged**
Excellent	AAA	AA	A	A-	BBB	--
Strong	AA	A	A-	BBB	BB	BB-
Satisfactory	A-	BBB+	BBB	BB+	BB-	B+
Fair	--	BBB-	BB+	BB	BB-	B
Weak	--	--	BB	BB-	B+	B-
Vulnerable	--	--	--	B+	B	CCC+

These rating outcomes are shown for guidance purposes only. Actual rating should be within one notch of indicated rating outcomes.

The rating outcomes refer to issuer credit ratings. The ratings indicated in each cell of the matrix are the midpoints of a range of likely rating possibilities. This range would ordinarily span one notch above and below the indicated rating.

Business Risk/Financial Risk Framework

Our corporate analytical methodology organizes the analytical process according to a common framework, and it divides the task into several categories so that all salient issues are considered. The first categories involve fundamental business analysis; the financial analysis categories follow.

Our ratings analysis starts with the assessment of the business and competitive profile of the company. Two companies with identical financial metrics can be rated very differently, to the extent that their business challenges and prospects differ. The categories underlying our business and financial risk assessments are:

Business risk

- Country risk
- Industry risk
- Competitive position
- Profitability/Peer group comparisons

Financial risk

- Accounting
- Financial governance and policies/risk tolerance
- Cash flow adequacy

- Capital structure/asset protection
- Liquidity/short-term factors

We do not have any predetermined weights for these categories. The significance of specific factors varies from situation to situation.

Updated Matrix

We developed the matrix to make explicit the rating outcomes that are typical for various business risk/financial risk combinations. It illustrates the relationship of business and financial risk profiles to the issuer credit rating.

We tend to weight business risk slightly more than financial risk when differentiating among investment-grade ratings. Conversely, we place slightly more weight on financial risk for speculative-grade issuers (see table 1, again). There also is a subtle compounding effect when both business risk and financial risk are aligned at extremes (i.e., excellent/minimal and vulnerable/highly leveraged.)

The new, more granular version of the matrix represents a refinement--not any change in rating criteria or standards--and, consequently, holds no implications for any changes to existing ratings. However, the expanded matrix should enhance the transparency of the analytical process.

Financial Benchmarks

Table 2

Financial Risk Indicative Ratios (Corporates)

	FFO/Debt (%)	Debt/EBITDA (x)	Debt/Capital (%)
Minimal	greater than 60	less than 1.5	less than 25
Modest	45-60	1.5-2	25-35
Intermediate	30-45	2-3	35-45
Significant	20-30	3-4	45-50
Aggressive	12-20	4-5	50-60
Highly Leveraged	less than 12	greater than 5	greater than 60

How To Use The Matrix--And Its Limitations

The rating matrix indicative outcomes are what we typically observe--but are not meant to be precise indications or guarantees of future rating opinions. Positive and negative nuances in our analysis may lead to a notch higher or lower than the outcomes indicated in the various cells of the matrix.

In certain situations there may be specific, overarching risks that are outside the standard framework, e.g., a liquidity crisis, major litigation, or large acquisition. This often is the case regarding credits at the lowest end of the credit spectrum--i.e., the 'CCC' category and lower. These ratings, by definition, reflect some impending crisis or acute vulnerability, and the balanced approach that underlies the matrix framework just does not lend itself to such situations.

Similarly, some matrix cells are blank because the underlying combinations are highly unusual--and presumably would involve complicated factors and analysis.

The following hypothetical example illustrates how the tables can be used to better understand our rating process (see tables 1 and 2).

We believe that Company ABC has a satisfactory business risk profile, typical of a low investment-grade industrial issuer. If we believed its financial risk were intermediate, the expected rating outcome should be within one notch of 'BBB'. ABC's ratios of cash flow to debt (35%) and debt leverage (total debt to EBITDA of 2.5x) are indeed characteristic of intermediate financial risk.

It might be possible for Company ABC to be upgraded to the 'A' category by, for example, reducing its debt burden to the point that financial risk is viewed as minimal. Funds from operations (FFO) to debt of more than 60% and debt to EBITDA of only 1.5x would, in most cases, indicate minimal.

Conversely, ABC may choose to become more financially aggressive--perhaps it decides to reward shareholders by borrowing to repurchase its stock. It is possible that the company may fall into the 'BB' category if we view its financial risk as significant. FFO to debt of 20% and debt to EBITDA 4x would, in our view, typify the significant financial risk category.

Still, it is essential to realize that the financial benchmarks are guidelines, neither gospel nor guarantees. They can vary in nonstandard cases: For example, if a company's financial measures exhibit very little volatility, benchmarks may be somewhat more relaxed.

Moreover, our assessment of financial risk is not as simplistic as looking at a few ratios. It encompasses:

- a view of accounting and disclosure practices;
- a view of corporate governance, financial policies, and risk tolerance;
- the degree of capital intensity, flexibility regarding capital expenditures and other cash needs, including acquisitions and shareholder distributions; and
- various aspects of liquidity--including the risk of refinancing near-term maturities.

The matrix addresses a company's standalone credit profile, and does not take account of external influences, which would pertain in the case of government-related entities or subsidiaries that in our view may benefit or suffer from affiliation with a stronger or weaker group. The matrix refers only to local-currency ratings, rather than foreign-currency ratings, which incorporate additional transfer and convertibility risks. Finally, the matrix does not apply to project finance or corporate securitizations.

Related Criteria And Research

Industrials' Business Risk/Financial Risk Matrix--A Fundamental Perspective On Corporate Ratings, April 7, 2005

Arbough Exhibit 3

Standard and Poor's Report: 2008 Corporate Criteria: Ratios & Adjustments

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2008 Corporate Criteria: Ratios And Adjustments

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2008 Corporate Criteria: Ratios And Adjustments

(Editor's Note: This criteria article, originally published on April 15, 2008, has been partially amended by "Methodology And Assumptions: Standard & Poor's Revises Key Ratios Used In Global Corporate Ratings Analysis," published Dec. 28, 2011.

This criteria article has been superseded by the following articles:

-- "Recognizing The Settlement Obligation For Foreign-Currency Hedges Of Debt Principal," published April 15, 2010;

-- "Revised Methodology For Adjusting Amounts Reported By U.K. GAAP Water Companies For Infrastructure Renewals Accounting," Jan. 27, 2010;

-- "Recognizing The Sustainable Cash Cost Of Inflation-Linked Debt For Corporates," Feb. 10, 2009;

-- "Analytical Adjustments For Captive Finance Operations," June 27, 2008; and

-- "Calculating Adjusted Debt And Interest For Corporate Issuers," June 2, 2008.

This article supersedes "Standard & Poor's Encyclopedia Of Analytical Adjustments For Corporate Entities," published July 9, 2007, "Net Debt Adjustments Reflect Asset Quality, Strategic Intent," published Feb. 22, 2007, and "Corporate Ratings Criteria 2008," published April 15, 2008. The section "Encyclopedia Of Analytical Adjustments" supersedes the article titled, "Securitization's Effect On Corporate Credit Quality," published Nov. 28, 2005.)

Ratios And Adjustments

Key ratios and glossary of terms

Table 1

Key Ratios

Ratio	Formula
Operating income before D&A to revenues	Operating income before D&A/revenues
EBIT interest coverage	EBIT/interest
EBITDA interest coverage	EBITDA/interest
FFO interest coverage	FFO plus interest paid minus operating lease adjustment to depreciation/interest*
Return on capital	EBIT/average beginning of year and end of year capital
FFO to debt	FFO/debt
FOCF to debt	FOCF/debt
Discretionary cash flow to debt	Discretionary cash flow/debt
Net cash flow to capital expenditures	Net cash flow/capital expenditures
Debt to EBITDA	Debt/EBITDA
Debt to debt plus equity	Debt/debt plus equity

Table 1

Key Ratios (cont.)
*The numerator reflects FFO before interest paid; the denominator reflects interest expense.

Table 2

Glossary Of Terms

Term	Definition
Capital	Debt plus noncurrent deferred taxes plus equity.
Capital expenditures	Funds expended to acquire or develop tangible and certain intangible assets. It includes the cost of acquisition of assets through leases and similar arrangements, and excludes capitalized costs that we expense as an analytical adjustment.
Cash flow from operations	This measure reflects cash flows from operating activities, not investment and financing activities. It includes interest received and paid, dividends received, and taxes paid in the period. Additionally, for some items such as postretirement benefit and asset retirement obligations, we include the (net) cost for the period rather than actual cash outflows, in order to separate what we view as financing of these obligations from the operating cost component.
Debt	Total short- and long-term borrowings of the company (including maturities), adjusted by adding a variety of on- and off-balance-sheet financing arrangements pursuant to our adjustment methodology, and subtracting surplus cash, where applicable. Borrowings are measured at amortized cost (including remeasurement upon change in ownership of the issuer). Foreign-currency unhedged borrowings are measured at each period-end spot rate.
Discretionary cash flow	Cash flow from operations minus capital expenditures minus dividends paid.
Dividends	Dividends paid to common and preferred shareholders and to minority interest shareholders of consolidated subsidiaries.
EBIT	A traditional view of profit that factors in capital intensity. However, it also includes interest income, the company's share of equity earnings of associates and joint ventures, and other recurring, nonoperating items.
EBITDA	Operating profits before interest income, interest expense, income taxes, D&A, and asset impairment. Excludes undistributed equity earnings of affiliates. While at times EBITDA is considered a proxy for cash earnings, changes in accounting make this increasingly an accrual-based earnings measure. The difference between EBITDA and operating income before D&A is in the adjustments we make for operating leases, exploration expense, and stock-based compensation. Exploration expense is added back to EBITDA, rather than being treated as an operating cost. The operating lease adjustment to EBITDA increases for the implicit interest component of rent expense, but not for the depreciation component. Finally, the charge to earnings for share-based compensation is reversed in calculating EBITDA.
Equity	Common equity and equity hybrids, and minority interest.
Equity hybrids	The portion of hybrid instruments attributed to equity pursuant to our methodology for classifying such securities.
FOCF	Cash flow from operations minus capital expenditures.
FFO	Operating profits from continuing operations, after tax, plus D&A, plus deferred income tax, plus other major recurring noncash items.
Interest	The gross amount of interest incurred (including amounts capitalized), adjusted for charges related to items that we add to debt; no subtraction of interest income, except where derived from assets structurally linked to a borrowing.
Net cash flow	FFO minus dividends.
Operating income before D&A	A measure of operating profitability that excludes D&A, to partially neutralize capital intensity as a factor when comparing the profitability of companies.
Revenues	Total sales and other revenues we consider to be operating.

Incorporating Adjustments Into The Analytical Process

Our analysis of financial statements begins with a review of accounting characteristics to determine whether ratios and statistics derived from the statements adequately measure a company's performance and position relative to both its direct peer group and the larger universe of industrial companies. To the extent possible, our analytical adjustments are made to better reflect reality and to minimize differences among companies.

Our approach to adjustments is meant to modify measures used in the analysis, rather than fully recast the entire set of financial statements. Further, it often may be preferable or more practical to adjust separate parts of the financial statements in different ways. For example, while stock-options expense represents a cost of doing business that must be considered as part of our profitability analysis, fully recasting the cash implications associated with their grant on operating cash flows is neither practical nor feasible, given repurchases and complexities associated with tax laws driving the deduction timing. Similarly, the analyst may prefer to derive profitability measures from LIFO-based inventory accounting--while retaining FIFO-based measures when looking at the valuation of balance sheet assets.

Certain adjustments are routine, as they apply to many of our issuers for all periods (e.g., operating lease, securitizations, and pension-related adjustments). Other adjustments are made on a specific industry basis (e.g., adjustments made to reflect asset retirement obligations of regulated utilities and volumetric production payments of oil and gas producing companies).

Beyond that, we encourage use of nonstandard adjustments that promote the objectives outlined above. Individual situations require creative application of analytical techniques--including adjustments--to capture the specific fact pattern and its nuances. For example, retail dealer stock sometimes has the characteristics of manufacturer inventory--notwithstanding its legal sale to the dealer. Subtle differences or changes in the fact pattern (such as financing terms, level of inventory relative to sales, and seasonal variations) would influence the analytical perspective.

We recognize that the use of nonstandard adjustments involves an inherent risk of inconsistency. Also, some of our constituencies want to be able to easily replicate and even anticipate our analysis--and nonstandard adjustments may frustrate that ability. However, for us, the paramount consideration is producing the best possible quality analysis. Sometimes, one must accept the tradeoffs that may be involved in its pursuit.

In many instances, sensitivity analyses and range estimates are more informative than choosing a single number. Accordingly, our analysis at times is expressed in terms of numerical ranges, multiple scenarios, or tolerance levels. Such an approach is critical when evaluating highly discretionary or potentially varied outcomes, where using exact measurement is often impossible, impractical, or even imprudent (e.g., adjusting for a major litigation where there is an equal probability of an adverse or a favorable outcome).

Similarly, in some cases, the analyst must evaluate financial information on an adjusted and an unadjusted basis. For example, most hybrid equity securities fall in a grey area that is hard to appreciate merely by making numerical adjustments. So, while we do employ a standard adjustment that splits the amounts in two, we also prefer that our analysts look at measures that treat these instruments entirely as debt--and entirely as equity.

In any event, adjustments do not always neatly allow one to gain full appreciation of financial risks and rewards. For example, a company that elects to use operating leases for its core assets must be compared with peers that purchase the same assets (e.g., retail stores), and our lease adjustment helps in this respect. But we also recognize the flexibility associated with the leases in the event of potential downsizing, and would not treat the company identically with peers that exhibit identical numbers. Likewise, in a receivable securitization, while the sale of the receivables to the securitization vehicle generally shifts some of the risks, often the predominant share remains with the issuer. Beyond adjusting to incorporate the assets and related debt of the securitization vehicles, analysts must appreciate the funding flexibility and efficiencies related to these vehicles and the limited risk transference that may pertain.

Apart from their importance to the quantitative aspects of the financial analysis, qualitative conclusions regarding the company's financial data can also influence other aspects of the analysis--including the assessment of management, financial policy, and internal controls.

Communicating our adjustments and related criteria

We traditionally have incorporated analytical adjustments to the ratings process. Our published key ratio statistics are also adjusted to reflect many of the adjustments made.

Since 2003, we have published accounting sections that outline our view of the issuer's accounting characteristics, including the underlying considerations and key adjustments made in our published industrial companies' issuer reports. The purpose is to capture in one place the major accounting issues that affect an issuer's financials, their related analytical significance, and the adjustments made; it is not intended to be a summary of every accounting policy.

We provide a reconciliation table in our credit analysis reports on corporate issuers (see "New Reconciliation Table Shows Standard & Poor's Adjustments To Company Reported Amounts," published Oct. 3, 2006, on RatingsDirect). It is a bridge between a company's reported amounts and various Standard & Poor's adjusted measures. The reconciliation table begins with company reported amounts for a range of balance sheet, earnings, and cash flow measures, then lists adjustments to each measure by topic and our total adjusted measure. Not all adjustments are included as of yet in these reconciliation tables. We are modifying our software to incorporate additional adjustments--but some adjustments may not be included, as they do not lend themselves to precision or standardization (e.g., litigation or other contingencies).

Occasionally, adjustments are based in whole or in part on nonpublic information provided to us during the rating process. Our rating analysis, evaluation, and commentary incorporate consideration of this information, but our published data refer exclusively to publicly available information.

Our criteria governing financial-statement adjustments are subject to ongoing review and occasional revisions necessary to address changes in accounting rules and in response to emerging financial products and structures--consistent with our broad objective of maintaining a dynamic criteria framework capable of addressing evolving market conditions in a timely and comprehensive manner.

When considering significant criteria changes (including ratio adjustments), we solicit public input and comments. In addition, we encourage ongoing dialogue with market participants regarding all criteria matters. We regard this dialogue as an important facet of maintaining a robust criteria framework, responsive to the needs of those who use our ratings and other market participants.

Encyclopedia Of Analytical Adjustments

The following sections outline the specific adjustments we use in analyzing industrial companies. At the end, we include our key ratios and their definitions. The list of adjustments, in alphabetical order, includes:

- Accrued Interest And Dividends
- Asset Retirement Obligations
- Capitalized Development Costs
- Capitalized Interest
- Captive Finance Operations
- Exploration Costs

- Foreign Currency Exchange Gains/Losses
- Guarantees
- Hybrid Instruments
- LIFO/FIFO: Inventory Accounting Methods
- Litigation
- Nonrecourse Debt Of Affiliates (Scope Of Consolidation)
- Nonrecurring Items/Noncore Activities
- Operating Leases
- Postretirement Employee Benefits/Deferred Compensation
- Power Purchase Agreements
- Share-Based Compensation Expense
- Stranded Costs Securitizations Of Regulated Utilities
- Surplus Cash
- Trade Receivables Securitizations
- Volumetric Production Payment
- Workers Compensation/Self Insurance

Accrued Interest And Dividends

Accrued interest that is not already included in reported debt is reclassified as debt. This adjustment allows more consistent comparisons of companies' financial obligations, by eliminating differences arising from the frequency of payments--for example, quarterly, rather than annually--or calendar dates of specific payments--for example, January 1 or December 31.

In a similar vein, accrued dividends on hybrid equity securities are treated as debt, irrespective of the extent of the securities' equity content. (Deferred amounts--whether the deferral was optional or mandatory--are also usually treated as debt, given the need to pay them in a relatively short time. Obviously, we would not include amounts that are noncumulative, which never will be paid.)

Adjustment procedures

- Balance sheet: Accrued interest and dividends accrued on hybrid securities are reclassified as debt. There is no adjustment needed to equity.
- Cash flow statement: Because the impact usually is quite limited, no adjustment is performed to FFO or operating cash flow. Annual cash flow is not affected by payment frequency or dates, except in the year a particular security is issued or retired.

Asset Retirement Obligations

We treat asset retirement obligations (AROs) as debt-like liabilities. AROs are legal commitments, assumed when commissioning or operating long-lived assets, to incur restoration and removal costs for disposing, dismantling or decommissioning those assets. Examples include the costs of plugging and dismantling on- and off-shore oil and gas facilities; decommissioning nuclear power plants and recycling or storing used nuclear fuel; and capping mining and waste-disposal sites.

These commitments are independent from the level and timing of any cash flow generated by the use of the assets. In certain instances, we expect ARO costs to be reimbursed to the entity through rates or assumed by other parties. When the asset operator's costs are reimbursed by the government or via a rate-setting process, the entity bears far different and less open-ended economic risks--and may not require debt imputation. We have tended to view AROs related to nuclear power plants of rate-regulated U.S. utilities in this light.

Several characteristics distinguish AROs from conventional debt, including timing and measurement uncertainties; tax implications; and the standing of claimants in bankruptcy.

ARO measurement involves a high degree of subjectivity and measurement imprecision. Our starting point is the reported liability amount, which may be adjusted for anticipated reimbursements, asset salvage value, and tax reductions, further adjusted for any assumptions we view as unrealistic.

Most AROs involve obligations to incur costs that may extend well into the future. Uncertainties inherent in their estimation include:

- The amount of the ultimate cost of abandonment, which will depend on the relevant country's laws and asset-specific environmental regulations at retirement; the condition of the markets for the specific assets' retirement services; possible economies of scale for the operator; and whether the activities ultimately are performed by the operator or by a third party.
- The timing of asset retirement, which is subject to assumptions that can change materially. For example, in extractive projects, future price expectations for hydrocarbon or minerals affect the economic life of the assets. For power generators, asset-retirement timing depends notably on local regulatory decisions. Their impact might be favorable (i.e., in the case of an operating license extension) or unfavorable (i.e., in the case of an early mandated closure).
- The discount rate to be used in the present value calculation. U.S. GAAP requires the use of an entity-specific discount rate. Hence, the stronger the entity's credit, the lower the discount rate--and the higher the liability. Similarly, the periodic accretion rate is lower for stronger credits, and higher for weaker credits. If nothing else, this hinders comparability across companies using U.S. GAAP, as well as IFRS-reporting companies, which use market-related rates adjusted to risk-specific factors attributable to the liability.

AROs are recorded on a pretax basis under most accounting standards. Any expected tax benefits generally are reflected as a separate deferred tax asset on the balance sheet (because the ARO-related asset is depreciated). Tax savings, when they coincide with the ARO payments (as opposed to their provisioning), reduce the net cash cost, which we factor in our analysis to the extent we expect the company to generate taxable income in the particular jurisdiction.

- The obligation, net of any dedicated retirement-fund assets, salvage value, and anticipated tax savings, is added to debt. We generally adjust for the net aggregate funding position, even if some specific obligations are underfunded and others are overfunded.
- Adjustments are made on a tax-effected basis in cases where it is likely the company will be able to use the deductions.
- The accretion of the obligation reflects the time value of money and is akin to noncash interest--similar to postretirement benefit (PRB) interest charges. Accordingly, we reclassify it (net of earnings on any dedicated funds, if applicable--but never less than zero) as interest expense for both income-statement and cash-flow statement analysis. We keep the net present value of the obligations newly incurred during the period (analogous to PRB service costs) within operating expenses. If dedicated funding is in place and the related returns are not entirely reflected in reported earnings and cash flows, the unrecognized portion of the return on these assets is

added and the recognized portion is reclassified to interest expense and operating cash flow.

- Cash payments for abandonment and contributions into dedicated funds that exceed/are less than the sum of: newly incurred obligations plus accretion of existing obligations are reclassified as repayment/incurrence of a debt obligation; this increases/decreases operating cash flow and FFO by the difference.
- For U.S. rate-regulated utilities that own nuclear power plants included in rate base, we have concluded that the decommissioning liability should not be viewed as a debt-equivalent liability. This is because of the safeguards that ensure funding sufficiency and collection of decommissioning costs in rates. Funding through customer rates and the probable nature of recovery result in a substantive liability defeasance.

Adjustment procedures

Data requirements

- The estimated asset retirement obligation (ARO), based on financial statement disclosure or analyst estimate;
- Any associated assets or funds set aside for the ARO;
- ARO interest costs, whether charged to operating or financing costs;
- New provisions (increases in liability during the period);
- Gain or loss on assets set aside for funding; and
- Cash payments for AROs.

Calculations

- Subtract assets set aside to fund asset-retirement liabilities from the ARO to create a net ARO.
- Multiply this net obligation by (1 minus the tax rate) to derive ARO adjustment for debt.
- Subtract both the gain (loss) on assets set aside from the sum of new provisions and interest costs and compare this amount with the cash payments made to arrive at the excess contribution/shortfall.
- Multiply this excess contribution/shortfall by (1 minus the tax rate) to arrive at the ARO adjustments to FFO and cash flow from operations.

Procedures

- ARO debt is added to reported debt.
- ARO interest costs (net of ARO fund earnings) are removed from operating expenses, if they are included in these, and added to interest expense.
- The ARO adjustment to FFO is added to FFO.

(Please see "Asset Retirement Obligations: How SFAS 143 Affects U.S. Utilities Owning Nuclear Plants," published March 31, 2004, and "Corporate Ratings Criteria, 2006 edition--Corporate Asset-Retirement Obligations," on RatingsDirect.)

Capitalized Development Costs

Costs relating to the conceptual formulation and design of products for sale or lease commonly are expensed on the income statement--while costs incurred subsequent to establishing the technological feasibility of these products are capitalized. The asset is then amortized over its estimated economic life.

Defining feasibility involves substantial subjectivity. Accordingly, the treatment of product or asset development costs sometimes varies substantially among companies or accounting regimes. For example, many U.S. software companies do not capitalize any software development costs (an analytically conservative approach), while others capitalize certain expenditures and amortize them over future periods.

Expensing, rather than capitalizing, can have a meaningful impact on a company's financial statements and credit metrics, making peer comparisons difficult. Automaker accounting for tooling poses similar comparability issues relating to varying capitalization policies.

While it is acceptable under the applicable accounting rules for a company to capitalize certain development costs, in order to facilitate comparability, we adjust reported financial statements. The amounts capitalized are treated as if they had been expensed. To the extent that the amortization of past capitalization equals current development spending, there is no impact on operating expenses, operating profit, or EBIT, but there is an impact on EBITDA and operating profit before depreciation.

This approach helps make companies' operating performance more transparent and comparable, regardless of their stance on capitalizing software and similar development costs. Note that with respect to energy exploration costs, we take the opposite approach (see "Adjustment For Exploration Costs"), given the objective of comparability with most companies in that industry and the pragmatic aspects of doing so.

A company's position in its product life cycle has a great effect on its current spending relative to the amortization of past capitalization of development costs. However, as a practical matter--in the absence of more accurate figures--we use the annual amortization figure reported in the financial statements as a proxy for the current year's development costs. We realize, too, that the amount amortized is not entirely comparable across companies, as the amortization period for these assets may vary. For example, in the case of software, it typically ranges from two to five years.

Adjustment procedures

Data requirements

- Amount of development costs incurred and capitalized during the period; and
- Amount of amortization of relevant capitalized costs.

Calculations

- EBITDA, operating profit before depreciation, and capital expenditures: subtract the amount of net capitalized development costs, or, alternatively, the amortization amount for that period.
- EBIT and operating profit after depreciation: subtract (or add, as the case may be) the difference between the spending and amortization in the period.
- FFO and capital expenditures: subtract the amount capitalized in the period.
- Balance sheet accounts: We do not carry through the adjustment to the cumulative asset (and equity) accounts, weighing the complexity of such adjustments against the limited impact that can be expected in most cases on amounts that are secondary to our analysis.

(Please see "Accounting Issues In The U.S. High Technology Group," published Jan. 3, 2007, on RatingsDirect.)

Capitalized Interest

We factor in capitalized interest as expense in the period when incurred. The valuation of property, plant, and equipment (PP&E) includes, under some GAAP, a cost of carry element relating to multiperiod project expenditures. Part of the rationale is that the company must factor the carrying costs when deciding on a project's economics, but this obscures the amount that actually must be paid during the period. Companies may also have significant discretion with respect to the amounts they capitalize, making comparisons difficult. Accordingly, we prefer to focus on total interest cost.

As a result, we reverse interest capitalization and include the amount as an expense. In the cash flow statement, we reclassify capitalized interest from investing to operating cash flow. This correspondingly reduces funds FFO and capital expenditure amounts. Free cash flow remains unchanged.

We do not adjust for the cumulative gross-up of PP&E resulting from interest capitalization, tax effects, or future depreciation effects. That is, we do not try to identify the portion of PP&E attributable to past interest capitalization, to reduce PP&E by the amount that would correspond to the expensed view taken on such interest capitalized in the past. It would be impractical to attempt to do so, given the lack of data available. Moreover, the more material impact tends to be to coverage and profitability measures, not to asset or equity-based ratios.

Adjustment procedures

Data requirements

- The amount of capitalized interest during the period.

Calculations

- Interest expense: add amount of capitalized interest.
- Capital expenditures, FFO, and operating cash flows: reduce by amount of capitalized interest that is reclassified as operating cash flows.

Captive Finance Operations

A captive finance operation (captive) functions primarily as an extension of a company's marketing activities. The captive facilitates the sale of goods or services by providing financing (in the form of loans or leases) to the company's dealers and/or end customers. The captive can be structured as a legally separate subsidiary, or as a distinct operating division or business line of the company. Captive finance units organized as separate subsidiaries are rated the same as their parents in the overwhelming majority of cases, meaning we view their default risk as indistinguishable from that of the parent.

Whatever the legal/organizational structure, the two businesses are not analyzed on a consolidated basis. Rather, we segregate financing activities from corporate/industrial activities and analyze each separately, reflecting the differences in business dynamics and economic characteristics, and the appropriateness of different financial measures. Our approach is to create a pro forma captive unit to enable finance company analytical techniques to be applied to the captive finance activity, and correspondingly appropriate analytical techniques to the pure industrial company.

Finance assets (e.g., loans receivable and leases)--along with appropriate amounts of financial debt and equity--are allocated to the pro forma finance company; all other assets and liabilities are included in the parent/industrial balance sheet. Similarly, only finance-related revenues and expenses are included in the pro forma finance company income statement. The debt and equity of the parents and the captives are apportioned so that both entities will reflect, in most cases, identical credit quality.

In our analytical methodology for captive finance operations, we attribute debt and equity to the pro forma finance company based on our assessment of the quality of the finance assets, taking account of factors such as underwriting standards, charge-off policy, quality of the collateral, and portfolio concentration or diversity. The adjusted financial measures are highly sensitive to assumptions we make about the leverage appropriate to the finance assets in question. We continue to refine our leverage guidelines for major finance asset types.

Adjustment procedures

Note: In almost all instances, financial statements fully consolidate majority-owned captive finance operations: Here, consolidated financial statements are assumed as the starting point. Where separate financial statements are also available for the finance unit, information from these can be used to refine the adjustment.

Data requirements

- On-balance-sheet finance receivables and leases, net;
- Finance receivables and leases sold or securitized--carried off-balance-sheet;
- Finance company revenues (if actual finance revenues are unavailable, we use 15% of total finance receivables);
- Finance company administrative expenses (if actual finance company expenses are unavailable, we use 3% of total finance receivables);
- Debt-to-equity ratio: determined to reflect our view of the "leveragability" of the captive's assets (on- and off-balance-sheet finance receivables and leases);
- Interest rate (the average rate experienced by the company); and
- Required fixed charge coverage--an interest coverage appropriate for the rating. (Often, 1.25x is used.)

Calculations

- Total finance assets: on-balance-sheet finance receivables and leases plus finance receivables and leases sold or securitized (carried off-balance-sheet).
- Finance company EBIT: finance company revenues minus noninterest expenses.
- Finance company debt: total finance assets times the debt-to-equity ratio/(1 plus the debt-to-equity ratio). This can never be more than reported consolidated debt; if so, the debt-to-equity ratio should be adjusted. (Separately, consolidated debt also is adjusted to reflect the debt equivalent of securitized assets and hybrid securities.)
- Finance company equity: total finance assets minus finance company debt.
- Finance company interest: most recent two-year finance company debt times interest rate.
- Finance company required EBIT: finance company interest times required fixed-charge coverage.
- Transfer payment: finance company EBIT minus finance company required EBIT (which can be positive or negative).
- Subtract finance company revenues from total revenues to derive adjusted industrial company revenues.
- Subtract finance company operating expenses, including depreciation, from total operating expenses to derive adjusted industrial company operating expenses.
- Industrial EBIT: adjusted revenues minus adjusted expenses plus transfer payment.
- Reduce reported interest by finance company interest, if reported captive finance company's interest is included in consolidated operating expenses; otherwise, no adjustment is required.
- Reduce reported debt (adjusted for securitized assets) by finance company debt.
- Reduce reported equity by finance company equity (after increasing total reported equity by the minority interests in the captive finance company's equity, if the captive is not fully owned, and its reported equity excludes minority interests).
- Remove the finance company's cash flows, including capital expenditures, from reported cash flows.

(Please see "Criteria: Request For Comment: Risk-Based Framework For Assessing The Capital Adequacy Of Financial Institutions," published Jan. 12, 2007; "Criteria: Captive Finance Operations," published April 17, 2007; and Finance Subsidiaries' Rating Link To Parent, in "Corporate Ratings Criteria 2006" edition, on RatingsDirect.)

Exploration Costs

Under some accounting systems, oil and gas exploration and production (E&P) companies may choose between two alternative accounting methods, full cost and successful efforts. These accounting methods differ in what costs these companies capitalize or expense. A successful-efforts-reporting company expenses the costs of unsuccessful exploration drilling (dry-hole costs) and exploration costs, such as geologic and geophysical expenditures (seismic surveys) and the costs of carrying and retaining undeveloped properties. In successful-efforts accounting, only exploratory drilling costs that result in the discovery and development of a commercial oil and gas field may be capitalized and amortized based on the field's proved reserves on a unit-of-production basis; all dry-hole expenditures are expensed as incurred. Using the full-cost accounting method, all exploration and development expenditures are capitalized and amortized over the reserves of the related pool of properties.

Another difference is the size of the cost center used to amortize capitalized costs. Successful-efforts companies use smaller cost centers, such as a particular lease or field; full-cost companies generally use larger cost centers, which may be as large as an entire country.

We view successful-efforts accounting as more appropriate, given the highly risky nature of hydrocarbon exploration. Successful-efforts accounting does not have the potential to inflate equity and smooth earnings to the same degree as full-cost accounting. In general, large companies (e.g., major integrated companies) use the successful-efforts method, while smaller companies (e.g., independent E&P companies) use the full-cost system.

However, our analysis of exploration costs requires making comparisons between companies that use different accounting methods, which can best be accomplished by adding back exploration expense to EBITDA for successful-effort companies. (While we prefer the successful efforts approach, there is no practical way to adjust full cost users to a successful efforts method.) Exploration expense usually is disclosed on the face of the income statement of successful efforts companies. This number often is referred to as EBITDAX.

Given our preference for successful efforts, we limit this adjustment to EBITDA measures--and do not carry the adjustment through to all related accounts or to other ratios. Adjusting EBITDA usually suffices for comparative purposes. And, adjusting a successful efforts company's balance sheet to reflect what it would look like if it had used the full-cost method--or vice versa--is not really feasible. (Apart from the differences as to what companies can capitalize under the two methods, the rules for asset impairment tests also differ. The full-cost impairment test, called the ceiling test, generally is easier to violate because of higher asset carrying costs and its trigger mechanism. (If the book value of assets falls below the discounted present value of cash flows, a charge may be necessary. The trigger for ordinary impairment is related to the undiscounted future cash flows.)

Adjustment procedures

Data requirements

- Exploration expenses (only applies to E&P companies using the successful-efforts method of accounting).

Calculations

- Adjustment to operating income before depreciation, depletion, and amortization to calculate EBITDA: We add exploration expense back to operating income before depreciation, depletion, and amortization in the EBITDA calculation. This increases EBITDA and operating income before depreciation and amortization by the entire amount of exploration expense.

(Please see "Credit FAQ: Exploring Standard & Poor's Oil And Gas Company Reconciliation Tables," published Feb. 12, 2007, on RatingsDirect.)

Foreign Currency Exchange Gains/Losses

Foreign currency exchange gains/losses can be related to transactions or translations:

- Transaction gains/losses arise from transactions that are denominated in a currency other than the entity's functional currency (generally the currency in which the entity principally transacts). Examples include buying and selling goods or services whose prices are denominated in a foreign currency, borrowing or lending in a foreign currency, or other contractual obligations denominated in a foreign currency. A change in the exchange rate will increase or decrease the amount of functional currency needed to settle the account between the time the transaction is recorded in the functional-currency accounts and the time it is settled, leading to exchange gains or losses. When translating the related accounts (e.g., loans receivable, accounts payable, and debt) into the reporting currency, such gains and losses are recognized in the income statement as incurred.
- Translation gains/losses occur when translating financial statements of a subsidiary from a local currency to the reporting currency of the enterprise for consolidation. Translation gains or losses are included in shareholders' equity (under U.S. GAAP, included in other comprehensive income for the period and in accumulated other comprehensive income in the owners' equity section of the balance sheet).

Foreign currency transaction gains/losses recognized in the income statement raise questions similar to those in Nonrecurring Items/Noncore Activity (see below). To present a representative view of operating performance and financial ratios, we typically adjust company income statements to exclude nonrecurring and other unusual transaction gains and losses.

Currency transaction gains and losses may be viewed as recurring or nonrecurring. We review transaction gains and losses and determine whether to adjust for them. We may adjust reported financial results for currency gains and losses that result from one-time or infrequent transactions; for example, we may adjust (or exclude) foreign currency gains or losses resulting from the infrequent purchase of a specialized capital asset payable in a foreign currency.

When the gains or losses result from recurring or ongoing transactions, we do not adjust. We consider transaction gains and losses as ongoing when the company has a history of entering into transactions denominated in foreign currencies. The purchase of inventory that is paid in a foreign currency is an example. Debt denominated in a foreign currency could also result in recurring foreign currency gains and losses that we would not adjust for.

Companies may not report currency gains or losses separately for recurring and nonrecurring transactions. Consequently, we may not make adjustments if the data are not available, or if the amount is immaterial. Our analysis must also take into account the potential for changes in actual cash flows that may be required to settle a transaction denominated in a foreign currency.

Translation gains/losses are not included in determining net income, but are included in shareholders equity (and, under U.S. GAAP, in other comprehensive income) as mentioned above. Companies generally translate assets and liabilities using the exchange rate at the balance sheet date. The income statement is translated at the exchange rate in effect at the time revenues, expenses, gains, and losses are recognized. The cash flow statement is translated using the exchange rate in effect at the time of the cash flow. As a practical matter, companies often use an average exchange rate for the reporting period for both income and cash flow statements. In addition, the cash flow statement reports the effects of exchange rate changes on cash balances held in foreign currencies on a separate line. We do not adjust the balance sheet, the income statement, or the cash flow statement for translation gains or losses included in other comprehensive income.

If a parent liquidates its investment in a foreign subsidiary (or investment), the amount of foreign currency gains or losses built up in equity are removed from equity and included in net income for the period. This amount should be excluded from income as a nonrecurring item (as would generally apply to the gain or loss resulting from the sale).

Adjustment procedures

Data requirements

- Amounts of nonrecurring (analytically determined) foreign currency exchange transaction gains and losses.

Calculations

- The amount of nonrecurring foreign currency gain or loss is added to or subtracted from operating income before and after D&A, EBITDA, and EBIT.

Guarantees

The accounting for guarantees can vary greatly. In many instances, a guarantee to support borrowings of unconsolidated affiliates or third parties is not recorded on the guarantor's consolidated balance sheet until it meets certain tests regarding probability of payment.

Alternatively, it may be recorded at the lowest amount in a range of possible outcomes or at a statistically calculated expected value (e.g., under IFRS, a contingent obligation may be measured at a probability-weighted figure of potential payment amounts). To illustrate, if the company estimates a 70% chance of having to pay nothing and a 30% chance of having to pay €1 million, then the company obligation would be measured at €300,000, an amount that has no probability of being paid.

We may take a different approach, to reflect our own assessment of the risk of ultimately being required to pay (upon the default of the other party).

We add the guaranteed amount to the guarantor's total debt, unless the other party is sufficiently creditworthy (i.e., investment grade) in its own right, or if we assess the likelihood of payment at a lower amount. (Interest is not imputed on such adjustment items, because the potential obligation may materialize far in the future, and there is no current need to service that potential obligation.)

In the case of an affiliate, we consider the possibility of support for the borrower's debt even absent a formal guarantee.

Performance guarantees are treated differently, because there should be little impact as long as the company maintains its work or product quality. Construction companies often provide performance guarantees as a condition in work contracts.

A company's track record of payments for performance guarantees could be an indicator of the amount of potential future liability. Only if the track record gives us specific reason for concern would we attempt an estimate of the liability--and add that amount to debt for ratio calculations.

Adjustment procedures

Data requirements

- Determine the value of the guarantees on and off the balance sheet to be added to debt, net of tax benefit, as applicable.

Calculations

- Debt: Add the amount of off-balance-sheet debt-equivalent; reclassify as debt the amount of on-balance-sheet liability.
- Equity: Subtract amount of off-balance-sheet debt-equivalent.

Hybrid Instruments

Hybrid instruments have some characteristics of debt, and some of common equity. The more weight the latter carries, the more equity content we attribute to the instrument. We classify corporate hybrids' equity content as minimal, intermediate, or high.

How to reflect hybrids in credit ratios is not a simple question. For many years, we did not divide the amounts involved in proportion to the equity content of the specific security, believing the resulting numbers could be misleading. As an example, a company might pay the stipulated periodic amount or defer it; under no scenario would it defer a fraction of the payment: Therefore, calculating a fixed-charge coverage ratio with a fractional amount has little intuitive meaning.

For hybrids with intermediate equity content, we instead computed financial ratios both ways--viewed alternatively, as debt and as equity. Two sets of coverage ratios were calculated--to display deferrable ongoing payments (whether technically dividends or interest) entirely as ordinary interest and, alternatively, as an equity dividend. Similarly, two sets of balance-sheet ratios were calculated for the principal amount of the hybrid instruments, displaying those amounts entirely as debt and entirely as equity.

For hybrids, analytical truth lies somewhere between these two perspectives, and analysts have been--and are--encouraged to continue viewing hybrids from all perspectives--i.e., computing ratios with the security as debt and, alternatively, as equity; to interpolate between the sets of ratios to arrive at the most meaningful depiction of an issuer's financial profile; and note and give effect to each more-equity-like or less-equity-like feature of various hybrids in the same category, although such nuances play, at most, a very subtle role in the overall rating analysis.

However, we changed our methodology in 2006 because it proved too challenging to communicate our previous, more abstract approach--and issuers, in particular, had trouble appreciating the potential impact on our view of their financial profile. Notwithstanding the issues mentioned above, we adopted the following adjustments (after adjusting convertible debt issued by IFRS reporting companies as described below):

- For hybrids in the intermediate category, we calculate ratios with outstanding amounts (excluding unpaid accrued remunerations) split 50-50: One-half of the principal is categorized as debt and one-half as equity; one-half of the period payments is treated as common dividends and one-half as interest. (There is no adjustment to taxes.) This set of ratios is used as the basic adjusted measures, and these are the ratios we publish.

- Hybrids with minimal equity content are treated entirely as debt for calculating ratios.
- Hybrids with high equity content are treated entirely as equity for calculating ratios.
- Unpaid dividends that have accrued, prior to period end, are viewed as debt--even for equity-like securities.

Convertible debt is not treated as a hybrid--unless the conversion is mandatory, or it features appropriate tenor, subordination, and deferability characteristics. While IFRS and other accounting regimes split the issued value of a convertible debt obligation between its pure debt component (the fair value of a similar debt obligation without the conversion feature), accounted for as debt, and the embedded conversion feature (the difference between the debt component and the issue price), accounted for as equity, such convertible debt generally does not attract any equity credit in our methodology. Rather, we adjust reported debt by the value of the conversion option included in shareholders' equity. Cash-based measures such as FFO continue to reflect only the actual cash cost of the convertible debt, based on the coupon rate.

Adjustment procedures

Data requirements

- Amount of hybrid instrument in the balance sheet and shareholders' equity;
- Amount of associated expense and payments in the period; and
- Amounts of accrued unpaid interest/dividends.

Calculations

- A high-equity-content hybrid reported as equity is treated as reported, as are its associated dividends. However, accrued dividends are included as debt.
- A high equity content hybrid reported as debt is removed from debt and added to equity. The associated interest charge is removed from interest expense and treated as a dividend. Additionally, interest payments are also adjusted as dividends in the FFO and operating cash flow calculations.
- An intermediate equity content hybrid reported as equity (e.g., preferred stock) has 50% of its value removed from equity and added to debt. Also, 50% of the dividend amount is removed and added to interest expense and interest paid, affecting the FFO and operating cash flow calculations.
- An intermediate equity content hybrid reported as debt has 50% of its value removed from debt and added to equity. Also, 50% of the associated interest is removed from interest expense and interest paid and added to dividends.
- A minimal equity content hybrid reported as equity is removed from equity and added to debt. Its associated dividends are added to interest expense and interest paid, thereby also reducing FFO and operating cash flow.
- A minimal equity content hybrid reported as debt is treated as reported, as is its associated interest.
- The accrued unpaid charges on hybrid instruments are categorized as debt.

Note: For optionally convertible instruments, prior to the reclassifications above, we recombine the instrument's issued amount (amortized cost) if it has been bifurcated (as described above, notably for IFRS-reporting companies). We also adjust the period's expense, where necessary and practicable, to equal the instrument's debt component multiplied by the company's refinancing rate, at the convertible's issuance date, for the equivalent nonconvertible instrument.

(Please see "Criteria: Equity Credit For Corporate Hybrid Securities," published May 8, 2006, on RatingsDirect; "Criteria: Clarification Regarding Step-Ups Used In Equity Hybrids," Aug. 9, 2007; and "Criteria: Standard &

Poor's Announces Several Refinements To Its Hybrid Capital Criteria," Oct. 30, 2007.)

LIFO/FIFO: Inventory Accounting Methods

The choice of inventory accounting methods under U.S. GAAP between FIFO, LIFO, weighted average, and specific identification can provide dramatically different results for peers that engage in the same underlying activities. This issue is more pronounced in sectors that are inventory-intensive, and in particular, where inventory prices fluctuate significantly.

The challenge of comparing peers increases on a global dimension. Similar choice of accounting options exists in generally accepted accounting standards other than U.S. GAAP--while LIFO, widely used in the U.S., is not permissible under many other accounting standards, including IFRS. Tax treatment of permissible inventory costing methods is a key driver in management's decision to elect a method, and varies significantly by jurisdiction. (For example, LIFO is permitted for tax-reporting purposes in the U.S., and those who elect LIFO for tax purposes must also use it for their financial statement reporting.)

Moreover, some companies use a combination of costing methods. For example, management may elect to use the LIFO method for a portion of inventory in which prices are expected to rise and FIFO for the balance. In other instances, inventory reported on a consolidated financial statement can include inventory balances of subsidiaries in different countries, each of which use different accounting methods.

The greatest potential disparity of financial results is between FIFO and LIFO accounting methods. In a period of rising prices, the LIFO method results in a lower income than FIFO, because the most recent costs flow into cost of goods sold on the income statement, and the oldest costs are reflected in inventory on the balance sheet. Furthermore, cash flows are temporarily improved, because current income taxes are lower as a result of the lower income. Apart from intercompany comparisons, different methods can skew the perspective of corporate performance. For example, LIFO provides a better reflection of matching costs against revenues on the income statement, but creates a balance-sheet distortion by having older costs residing in inventory. The FIFO method, on the other hand, provides a more current valuation of inventory on the balance sheet, but can significantly understate cost of goods sold in a period of rising prices, resulting in artificially overstated income.

- Balance sheet: Where significant to our analytical process or essential for peer comparability, we add back the LIFO reserve to inventory amounts on the balance sheet for companies that use the LIFO method. This enables us to reflect inventory balances at approximate current market value. (Companies that apply the LIFO method are required to disclose what the inventory valuation would be under FIFO, through an account called the LIFO reserve, which represents the cumulative effect on gross profit from the use of the LIFO method.) A corresponding adjustment, net of tax, is made to equity.
- Income statement: We do not adjust the income statement when companies use LIFO, believing the LIFO method results in costs of goods sold that are more indicative of replacement-cost values, and the best matching to revenues. While it might be desirable to adjust for those companies that use FIFO or average costs methods, the data generally are unavailable.
- When a company using the LIFO method has inventory balances that decrease over a period of time, LIFO liquidation may result. It means that older, less-recent layers of inventory are turned into cost of goods sold as a result. (These are older in terms of their accounting, not necessarily in any physical sense.) Assuming an inflationary environment, cost of goods sold is reduced, and as a result, income increases because of LIFO liquidation gains. To capture the true sustainable profitability of a company, the gains generated from LIFO

liquidation generally are excluded from our current profitability measures and ratios.
- Cash flows: We typically do not adjust the cash flows, but we consider, qualitatively, the boost to cash flows the LIFO method affords during periods of price inflation (via taxes deferred to future periods).

Adjustment procedures

Data requirements

- For the balance-sheet adjustments: LIFO reserve; and
- For the income statement adjustments: LIFO liquidation gains.

Calculations

The balance sheet adjustments affect inventory (assets) and equity.

- LIFO reserve is added to inventory (assets).
- Equity is increased by the LIFO reserve (after-tax).

The income statement adjustment affects operating income before and after D&A, and EBITDA and EBIT.

- LIFO liquidation gains are deducted from operating income when calculating operating income before and after D&A, and EBITDA and EBIT.

Litigation

We make case-by-case judgments regarding the probability of a negative outcome, the potential financial effect, and its timing, including duration of any appeals process. We also regularly obtain additional data from the company involved, on a confidential basis, to enable a more meaningful analysis of plausible scenarios. These might include any available legal opinions and research; the company's legal strategy; and the number, size, and status of claims. To assist us, we may consult legal counsel to evaluate likely scenarios. This includes in-house legal staff, external counsel, and/or industry-related counsel.

To the extent that a monetary judgment is predictable, we size the amount that will be paid and treat it as a debt-equivalent. If payment is not imminent--if, for example, there is an extended appeals process--we would estimate the time until actual payment, and discount the eventual payment amount unless interest will be added. The adjusted debt ratios are calculated including the present value of the estimated payout, on an after-tax basis. Where applicable, we subtract any expected insurance recoveries.

It usually is very challenging to size litigation outcomes. Previous cases of similar nature can serve as benchmarks. Subjective judgments regarding the merits of a case may also inform our view of possible outcomes.

Sometimes, the company's litigation reserves recorded in its financial statements can offer insight. Companies must reserve for litigation they can quantify. In practice, most companies tend to minimize legal reserves (although some companies--especially European companies--will over-reserve to enable smoothing of future earnings). Therefore, to the extent that a company does reserve, one may ordinarily conclude there is a high likelihood that required payments will be at least that amount. The company's reserve is not a reliable indicator that the ultimate liability will not exceed that amount. In any event, providing reserves is merely an accounting recognition of the liability; it doe not mean the company has put aside cash to fund the liability. We would still need to adjust the debt figures to reflect the cash impact that a payment would entail. (On the other hand, there often will be a lengthy period until payment is made, so we also consider the company's ability to generate cash in the interim.)

A class-action suit permits a large number of individual claims to be combined and tried as one lawsuit. We view class-action lawsuits as the most troublesome type for credit quality because of the potential size of awards. Class-action suits must be certified by a court to proceed to trial; however, once certified, the lawsuit often takes years to wind through the litigation process.

Outside the U.S., litigation is less significant as a credit risk than in the U.S. Typically, there is no award of punitive damages, class actions are limited, and/or trials may not come before juries that can react unpredictably to the litigation.

Because the specific financial effect of a lawsuit is difficult to quantify accurately, we may rely on analytical techniques such as calculating ranges of outcomes or performing sensitivity analysis. This can be very helpful if it allows us to conclude, for example, that the company can manage even the more dire potential outcomes without materially affecting its financial profile. Alternatively, if significant uncertainty remains, we might consider a downgrade based on a very large risk exposure.

Litigation poses several important, potentially troubling considerations beyond any direct financial consequences. We consider the potential damage to a company's reputation or ability to conduct normal business operations. For example, product liability cases sometimes result in the product's being removed from the market. Substantial litigation may require an inordinate amount of management time and create quite a distraction from running the business.

More broadly, lawsuits can affect a company's reputation and/or its ability to garner further business or raise capital. Public mistrust and a negative perception of the company's operating strategy would definitely be of concern.

Last, but not least, bonding requirements can pose a tremendous liquidity challenge, especially in jurisdictions that have no bonding caps. Bonding can tie up cash that could otherwise be invested in the business, even if it does not pose an immediate threat to solvency. (Naturally, in the case of litigation expected to benefit the company, similar adjustments apply, in reverse.)

Adjustment procedures

Data requirements

- Determine the value of the litigation exposure to be added to debt.

Calculations

- Debt: Add the amount of debt equivalent (net of tax benefit, as applicable) to debt.
- Equity: Subtract the amount of off-balance-sheet debt equivalent, net of tax.

(Please see "How Litigation Risk Affects Corporate Ratings," published Nov. 28, 2005, on RatingsDirect.)

Nonrecourse Debt Of Affiliates (Scope Of Consolidation)

In the context of corporate debt analysis, nonrecourse debt often refers to a situation in which an affiliate or subsidiary of a company borrows funds, possibly pledging its assets as collateral, while the parent company and other subsidiaries in the corporate structure have no legal obligation to perform under the borrowing agreement. If an event of default occurs, the lender's claims are limited solely to the subsidiary that borrowed the money.

Nonrecourse debt may exist for a variety of reasons. A company may want to legally isolate the bankruptcy risk of a subsidiary, for example, because the subsidiary's business prospects are more unpredictable than those of the parent. Also, nonrecourse debt may result from a particular jurisdiction's legal requirement to operate locally through a separate legal entity. In other cases, a company may own only a portion of a subsidiary, maybe even a minority interest, and the company may be unwilling to put itself on the hook to fund the obligations of the joint venture.

In nonrecourse structures, the parent company has the legal right to walk away from the troubled (or bankrupt) subsidiary. This often is a by-product of corporate law and related legal isolation doctrines related to entities structured as corporations or other limited-liability structures. Notwithstanding the theory, history has shown this often is not the way things play out. The parent company often ends up providing economic support to the subsidiary, despite the nonrecourse nature of the obligation.

In analyzing these situations, we attempt to understand the relationship between the parent and subsidiary, and make a judgment about whether the parent would be inclined to step in (and to what extent). Predicting the outcome of such a scenario is not an exact science, but we believe that considering plausible scenarios is superior to relying solely on the legal framework, and ignoring the economic relationship extant between the entities.

The relationships between the affiliated entities can vary greatly. The entity issuing the debt considered to be nonrecourse may simply represent a noncore, nonstrategic investment; if so, the parent is not burdened with the subsidiary's debt obligations.

At the other end of the spectrum, the subsidiary's operations may be characterized as an integrated business. The analysis would then fully consolidate the subsidiary's financial statements, including debt. Furthermore, the risk profile of the subsidiary's operations would be integrated with the overall business risk analysis of its parent.

Often, the subsidiary issuing the debt may not fall neatly into either category; it may lay somewhere in the middle of the spectrum. Sometimes we use a pro rata consolidation to reflect this middle ground. For example, we would apply pro rata consolidation to joint ventures between partners of comparable capacity and willingness to support for their respective strategic reasons. Even in cases that do not call for analytical consolidation, we presume there will be additional investment in the nonrecourse entity, i.e., the money the company likely would spend to provide support or bail out the unit in which it invested.

No single factor determines the analytical view of the relationship with the affiliate; rather, several factors, taken together, will lead to one characterization or another, including:

- Strategic importance--integrated lines of business or critical supplier;
- Percentage ownership (current and prospective);
- Management control;
- Shared corporate name;
- Domicile in same country;
- Common sources of capital and lending relationships;
- Financial capacity for providing support;
- Significance of amount of investment;
- Investment relative to amount of debt at the venture or project;
- Nature of any other owners (strategic or financial; financial capacity);
- Management's stated posture;

- Track record of parent company in similar circumstances;
- Nature of potential risks;
- Shared collective bargaining agreements; and
- Jurisdiction's bankruptcy-law regime.

Adjustment procedures

There is no standardized adjustment, given the multiple fact patterns and subjective nature relating to subsidiaries/projects/joint ventures. As explained above, some consolidated entities--and their liabilities--might be deconsolidated, while some nonconsolidated entities may be consolidated.

Another possible adjustment is pro rata consolidation. This approach is not used too frequently and typically applies only when both owners have similar financial profiles and motivations with respect to a joint venture.

Note that even in cases where we conclude that the liability will not ultimately be supported, we could well expect that the owner would extend partial support to the venture or subsidiary, including additional investments to attempt to rescue it. We would try to size such additional expenditures--and impute that amount as debt to the parent.

(Please see "Corporate Ratings Criteria, 2006 edition: Parent/Subsidiary Links", and "Credit FAQ: Knowing The Investors In A Company's Debt And Equity," published April 4, 2006, on RatingsDirect.)

Nonrecurring Items/Noncore Activities

We typically make adjustments to a company's reported operating income and cash flow to remove items we consider nonrecurring and include those we consider recurring, so the historical financial ratios will be more indicative of future performance. These adjustments cover items including discontinued operations; effects of natural disasters; gains or losses on asset sales and sale/leasebacks; and one-time charges for asset write-downs, restructurings, and plant shutdowns.

We review each potential nonrecurring item, and determine whether to adjust for it. Our view of these items may differ from the company's view, as presented in financial statements or footnotes.

We may view some supposedly one-time restructurings as ongoing for a particular company. Taking such a view may reflect a company's history of recurring restructuring charges, or the perceived need to address either company-specific or industrywide competitive issues (for example, the need to move facilities offshore in order to be cost competitive).

We may also view certain other items that company management characterizes as one-time items as normal operating costs: In the retail industry, we do not typically view inventory write-downs or high store pre-opening costs from a rapid expansion program as unusual items.

In a similar vein, we often distinguish between a company's core business activity and other, ancillary activities--especially if there is some question about the latter's sustainability. A manufacturer may earn money from trading activity; it may even set up its treasury operations as a profit center, but we may isolate, reclassify, and separately analyze the results of those operations.

For income derived from the sale and licensing of corporate assets, we similarly distinguish between sustainable, ongoing sales and those that are more opportunistic. Ancillary activities can distort measures of core operating performance, and peer analyses that rely on comparability of data, unless adjustments are made. An analogy can be drawn to the analytical segregation of nonhomogenous activity. Some GAAP rules may require consolidation if a company owns both manufacturing and finance subsidiaries: We would separate the two for analytical purposes.

These adjustments require an appreciation of industry-specific contexts. For example, in the high technology industry, companies dedicate substantial amounts of capital to R&D efforts and accumulate intellectual property in the form of patents, trade secrets, domain names, etc., which may be sold or licensed to complement revenues generated from core operations.

We consider revenue generated from the licensing of intellectual property to be a part of operating income, and therefore a component of EBITDA, because this arrangement allows for a relatively predictable, recurring source of revenue. However, revenue generated from the sale of intellectual property is not considered part of operating income. While there may be advantages in selling intellectual property, rather than licensing--e.g., the receipt of greater upfront proceeds or the elimination of future responsibilities--this arrangement normally is treated as nonoperating income.

In other situations, the sale of assets may be considered recurring. For example, companies that lease or rent automobiles or industrial equipment routinely and periodically dispose of these assets via auctions and/or other sales.

Adjustment procedures

Data requirements

- Amounts of income, expense, and cash flows to be reclassified (including nonrecurring items reported as operating, and recurring items not reported as operating). These amounts are judgmentally determined, based on information disclosed and our assessment.

Calculations

- Add or subtract amounts from respective measures, (e.g., revenue, operating income before and after D&A; D&A; EBIT; EBITDA; operating cash flows and FFO) to reclassify as appropriate. Because operating cash flows and FFO are post-tax measures, they also are adjusted to reflect the tax effects, where feasible.
- Beyond the standard adjustment, additional insights may be gleaned by adjusting individual line items within cost of goods sold or selling, general, and administrative (SG&A) expense, if there is sufficient data to reflect adjustments at such levels. Similarly, ancillary activities data are segregated and separately analyzed, to the extent practicable with available data.

Operating Leases

Companies commonly use leasing as a means of financing. The accounting for leases distinguishes between operating and finance leases. Finance leases (also referred to as capital leases) are accounted for in a manner similar to a debt-financed acquisition of an asset, while many operating leases are reflected in the accounts on a pay-as-you go basis. We view the accounting distinction between operating and capital leases as substantially artificial. In both cases, the lessee contracts for the use of an asset, entering into a debt-like obligation to make periodic rental payments.

Our lease adjustments seek to enhance comparability of reported results (both operating and financial) and financial obligations among companies whether they lease assets under leases accounted for as operating or financing leases, or use debt to finance asset acquisition. The operating-lease-adjustment model is intended to bring companies' financial ratios closer to the underlying economics and more comparable, by taking into consideration all financial obligations incurred, whether on or off the balance sheet. The model improves our analysis of how profitably a company employs its leased and owned assets.

Our model does not fully replicate a scenario in which a company acquired an asset and financed it with debt; rather, our adjustment is narrower in scope: It attempts to capture only the debt equivalent of a company's lease contracts in place. For example, when a company leases an asset with a 20-year productive life for five years, the adjustment picks up only the payments relating to the contracted lease period, ignoring the cost of the entire asset that would have been purchased--and depreciated--by a company that chose to buy instead of lease. We have chosen not to use alternative methodologies that capitalize the entire asset because they entail various data and interpretation challenges. In cases where the company has an economic need to use the asset for longer than the lease term, we take account of this qualitatively; however, if the lease is viewed as artificially short, and there is adequate information, such as for sale/leaseback transactions, we capitalize the entire sale amount.

Adjustment procedures

Data requirements

- Minimum lease payments: Noncancelable future lease payment stream (and residual value guarantees if not included in minimum lease payments); discount factor; annual lease-related operating expense for the most recent year; and deferred gains on sale leaseback transactions that resulted in leases accounted for as operating.
- Future-lease payment data are found in the notes to the financial statements. Annual payments for the coming five years (itemized by year) and the aggregate amount for subsequent years are provided under U.S. GAAP. Our model assumes that future payments for years beyond the fifth year approximate the fifth-year amount. Under IFRS, companies are permitted to disclose amounts payable in years two through four in a single combined amount, instead of disclosing separate amounts for each of the next five years. In this case, we assume a flat level of payments in years two through four, based on the total minimum lease payment disclosed for these three years. This approximation--caused by the limited disclosure--does not capture how future payments may decline in these years. Future lease payments are considered net of sublease rental only when the lease and sublease terms match and the sublessee is sufficiently creditworthy.
- The discount factor is determined in one of the following ways: ideally, the imputed discount rate associated with the lease would be used, but rarely is available, and unlikely to be available for all companies in an industry; use the average rate on the company's secured debt; and/or use a rate imputed from the company's total interest expense and average debt.
- Annual operating-lease-related expense is sometimes available in the notes and will be used. When the amount is not separately disclosed (e.g., when presented with contingent rent and other amounts, or incorporated with other costs), it is estimated using the average of the first projected annual payment at the end of the most recent and prior year.

Calculations

- Debt: The present value of the payment stream, determined using the discount factor, is added to debt. (Lease debt is not tax-effected because its taxes will never reflect the analytical construct underlying our adjustment. The company is, in fact, getting the tax treatment afforded to leases--assuming GAAP and tax treatment as operating lease is the same. The actual tax amounts are those included in the accounts--and generally require no adjustment.

This contrasts with PRB and ARO adjustments, which may be tax-effected. Those adjustments are based on the anticipation that tax-deductible recognition of the obligations will ultimately be required.)

- Operating income and cash flow measures: The operating-lease-related expense is apportioned to interest and depreciation components, as described below. The effect is to increase operating income measures: SG&A, by the entire amount of the expense; EBIT, by the implicit interest portion; EBITDA, by the implicit interest portion; and FFO, by the implicit depreciation portion. In addition, operating income would be adjusted to reverse gain or loss on sale/leaseback transactions.
- Interest expense: Interest expense is increased by the product of the discount rate multiplied by the average first-year projected payment for the current and previous years.
- Depreciation: Operating lease depreciation, i.e., the operating-lease-related expense amount less the calculated lease interest, is added to depreciation expense. (We deliberately calculate EBITDA without adding back the imputed depreciation component, despite the apparent definitional conflict. The cash flow characteristics of leasing do not neatly conform with the alternative of borrowing to acquire--even though our adjustment attempts to equate them. Lease payments represent ongoing cash outflows--quite different than depreciation, or even amortization of asset acquisition-related debt.)
- Capital expenditures: Capital expenditures are increased by an implied amount calculated as the year-over-year change in operating lease debt plus annual operating lease depreciation. This amount cannot be negative. Capital expenditures are also adjusted in the same fashion for capital leases.
- Property plant & equipment: Operating lease debt is added to PP&E to approximate the depreciated asset cost.

Postretirement Employee Benefits/Deferred Compensation

Defined-benefit obligations for retirees, including pensions and health care coverage (collectively referred to as PRB), and other forms of deferred compensation are financial obligations that must be paid over time, just as debt must be serviced, so we include them in debt ratios. A company may prefund the obligation or part of it (and companies often do prefund their pension obligations), which offsets the financial burden. Our objective, therefore, is to reflect the level of underfunding of defined-benefit pension obligations, as well as typically unfunded health care obligations and retiree lump-sum payment schemes, and other forms of deferred compensation. In arriving at adjusted financial measures, we must undo accounting shortcomings that affect balance sheets, cash flow statements, and income statements (under most current GAAP). The adjustments pertain to obligations already incurred, without trying to capture future levels of liability.

When PRB obligations constitute a major rating consideration, we delve more deeply into the company's particular circumstances and its benefits plans. Also, for some companies, funding and liquidity considerations surrounding retiree obligations can be much more important to the credit profile than imputing debt to the financial ratios. This situation typically pertains to speculative-grade companies that tend to have fewer available resources for cash requirements, including meeting mandated funding of PRB obligations.

We do not include in debt any amounts for defined-contribution plans, because they entail no obligations or risks to the sponsor related to past services beyond the current period's payments. We also have a slightly different position regarding multiemployer plans, not otherwise dealt with here. (See "Standard & Poor's Approach To Analyzing Employers' Participation In U.S. Multi-Employer Pension Plans," published May 30, 2006, on RatingsDirect.)

A key difference between debt and PRB obligations is the inherent measurement uncertainty, as the benefits and related assets, to the extent they are funded, are variable. Quantifying PRB obligations relies on numerous assumptions, including:

- Employee turnover rates and length of service, according to which benefits vary;
- Mortality rates and dependency status/longevity assumptions, as the employee and his/her dependents' lifespan determine how long the benefit will be paid;
- Future compensation levels, to the extent wages prior to retirement are a factor in determining the amount of the benefit;
- Health care cost inflation, use, and delivery patterns; and
- Discount rate assumptions required to calculate a present value of the future required cash outflows.

Standard financial adjustments cannot easily factor in deviations from normal assumptions on these measurement drivers. However, for some factors, the analysis can, at least, gauge the sensitivity to changes in those assumptions. For example, a rough rule of thumb is that for each percentage point increase or decrease in the discount rate, the liability decreases or increases by at least 10%, and often by 15%-20%. (The more mature the plan, or the higher the market interest rates, the lesser the impact.)

To simplify the numerical analysis, we combine all retiree benefit plan assets and liabilities, for pension, health, and other obligations, netting the positions of a company's plans in surplus against those that are in deficit.

In theory, and in the long term, companies with multiple plans should be able to curtail contributions to overfunded plans and redirect contributions to underfunded plans. In the near term, however, funding surpluses are often hard to tap--and may have adverse tax consequences if drawn--even while cash contribution requirements may be onerous on other, underfunded plans. But, if meeting near-term cash requirements is an important issue for a particular company, its credit profile likely will be driven by liquidity considerations, while debt ratio levels would be of secondary importance.

We focus on the measure of the obligation that reflects a going-concern view. For example, under U.S. GAAP for pensions, this is the projected benefit obligation (PBO), or an equivalent actuarial measure of the ultimate liability. The going-concern view of the company includes the effect of expected wage increases if the benefit attributable to past employment services is tied to employee compensation according to some formula. However, for collectively bargained labor contracts, the PBO does not take account of expected wage increases beyond the term of the existing contract.

We do not use the accumulated benefit obligation (ABO), which takes into account only the benefits payable upon plan termination at period end, or the vested benefit obligation (which is no longer disclosed under U.S. GAAP), because they reflect a shutdown value perspective, rather than an ongoing firm perspective. Similarly, in the U.K., we do not focus on the value of beneficiaries' claims based on a full buyout basis (i.e., based on the price prevailing on the annuity market, where demand is currently insufficiently covered by supply), which often considerably exceeds the amount equivalent to PBO under IFRS or U.K. GAAP. (The ABO and full buyout value are more appropriate measures in our recovery and subordination analyses.)

For other postretirement obligations--including medical liabilities, we use a measure equivalent to the pension PBO. For example, under U.S. GAAP, this is the accumulated postretirement benefit obligation (APBO).

We tax-effect our PRB adjustments--unless the related tax benefits have already been, or are unlikely to be, realized. We use the rates applicable to the company's plans, or, if this is unavailable, the current corporate rate--even while recognizing that fiscal reality may be more complex or dynamic as the company's fortunes change over time. In the typical situation, the company has credible prospects of generating sufficient future taxable income to take advantage of PRB-related deductions and reduce future tax payments. When a company's ability to generate profits is indeed dubious, we would not tax-effect. Moreover, in such cases, the company likely would be so pressured that liquidity--rather than capitalization or coverage levels--would be the overriding analytical focus.

Capital structure

We adjust capitalization for PRB effects by adjusting both debt and equity, where applicable. Debt is grossed up by the company's tax-effected unfunded PRB obligation. Equity is adjusted by the difference between the amount accrued on the corporate balance sheet and the amount of net over/underfunded obligation (net surplus/deficit), net of tax.

Companies following U.S. GAAP recently adopted SFAS 158, and record the unfunded PRB obligation on their balance sheets; companies following IFRS have the option to fully recognize actuarial gains and losses on their balance sheets. Accordingly, our equity adjustment is no longer required in many instances.

Debt is not adjusted down for net surpluses, so net overfunding (surplus) leaves debt unchanged. Equity can be adjusted up (if the net recognized asset is less than the pretax surplus) or down. We do not split the debt adjustment between short- and long-term.

Although the surplus is not treated as a cash equivalent, it nonetheless can be of value, especially to obviate future contributions. Sometimes it becomes evident that the amount is unrecoverable or cannot be used to offset future contributions. Given inconsistent accounting disclosure regarding the recoverability of surpluses, we rely on inquiries to company management.

Cash flow

We try to identify catch-up contributions made to reduce unfunded obligations, which would artificially depress reported operating cash flows. We view these contributions as akin to debt amortization, which represents a financing, rather than an operating cash flow. Specifically, cash paid (plan contributions plus benefits paid directly to beneficiaries) exceeding the sum of current-period service and net interest costs (that is, interest cost net of actual or expected returns on plan assets) is added back to FFO on a tax-effected basis. We look at actual investment returns for the period and returns normalized for potentially nonrecurring, unusually high or low performance.

Conversely, if the company is funding postretirement obligations at a level substantially below its net expense (service cost and net interest cost), we interpret this as a form of borrowing that artificially bolsters reported cash flow from operations.

In order to appropriately interpret adjusted numbers, note that our cash flow adjustment:

- Reallocates to the period certain costs (service and interest) that often differ from the cash impact in the period;
- Ignores prior service costs and other items such as curtailments, settlements and special termination benefits, and foreign-exchange variations;
- Ignores any income or charge (whether through income-statement or directly recognized into equity) that reflected the recognition of actuarial gains and losses; and
- Until early 2006, was capped at zero (no longer the case).

Income statement

In analyzing profitability (including operating profit and EBITDA), we disaggregate the benefits-cost components that may be lumped into operating income and expenses, allocate the amounts to operating and financial components, and eliminate those components we believe have no economic substance. The period's current service cost--reflecting the present value of future benefits earned by employees for services rendered during the period--is the sole item we keep as part of operating expenses.

The components, if any, that represent accounting artifacts and stem from the smoothing approach of the accounting rules--e.g., amortization of variations from previous expectations regarding plan benefits, investment performance, and actuarial experience--are eliminated from our income measures. As a result of these adjustments, pretax and after-tax income no longer match reported amounts.

Interest expense, which results from applying the discount rate to the beginning-of-period obligation to accrete the liability with the passage of time for the reporting period, is essentially a finance charge--and is reclassified as such, if reported differently.

The expected return on plan assets represents management's subjective, long-range expectation about the performance of the investment portfolio; in some accounting systems--such as U.S. GAAP--it may be applied to a smoothed, market-related value, rather than the fair-market values of the assets. We may choose instead to apply a standardized return, to gauge what multiyear average returns can be expected. We note the risks in the asset mix, but only subjectively. (In the future, we may find a way to reflect the risk profile of the portfolios in a more quantitative manner.)

Either way, the return on plan assets is netted against PRB-related interest expense up to the amount of the interest expense reported, but not beyond, as the economic benefits to be derived from such overage are limited. If, however, the actual return is negative, the full amount is treated as an addition to interest expense because the resulting economic detriment to the company is quite tangible.

Adjustment procedures

Data requirements

For the income and cash flow adjustments, amounts for the period of:

- Service cost;
- Interest cost;
- Expected return on plan assets;
- Actual return on plan assets;
- Actuarial gains/losses (amortization or immediate recognition in earnings);
- Prior service costs (amount included in earnings);
- Other amounts included in earnings (e.g., special benefits, settlements/curtailments);
- Total benefit costs; and
- The sum of employer contributions and direct payments made to participants.
- For the balance-sheet adjustments:
- PRB-related assets on the balance sheet, including intangible assets, prepaid or noncurrent assets, or any other assets;
- PRB-related liabilities on the balance sheet, including current and noncurrent liabilities;
- PRB-related deferred tax assets (or tax rate applicable to PRB costs);
- Fair value of plan assets; and
- Total plan obligations.

Note: Relevant pension and other postretirement benefit amounts are combined for all plans.

Calculations

Income-statement adjustments include adjustments to expenses and interest.

- Total PRB costs charged to operating income, less the service cost, yields the PRB adjustment to operating income. This is added to operating income before and after D&A, EBIT, and EBITDA.
- Interest cost less the expected return is PRB interest. In some cases, we may adjust expected returns to normalize it at a more realistic level. If net PRB interest is a cost, we include it in adjusted interest expense (we do not reduce interest expense if expected returns exceed interest cost). This PRB interest is added to reported interest when the net benefit costs are included in operating income. If reported interest already includes an interest component for PRBs (e.g., as may be the case under IFRS), we adjust it, if necessary, to ensure it reflects the amount of PRB interest cost. A similar calculation is made using the actual, rather than expected, return on plan assets.

The adjustment to FFO starts with a calculation of excess contributions or PRB borrowing:

- Total employer contributions (including direct payments to retirees), less service costs, less interest costs, plus expected return yields the excess contribution, if positive, or PRB borrowing, if negative. (A similar calculation is made using actual, rather than expected return.)
- The excess contribution or PRB borrowing is reduced by taxes at the rate applicable to PRB costs. That is, the amount is multiplied by (1 minus the tax rate) to create the PRB adjustment to FFO.
- The excess contribution on PRB borrowing is added or subtracted to or from FFO.

The balance-sheet adjustments affect assets, debt, and equity.

- Plan obligations less assets equals the net pension and postretirement funded status (deficit or surplus).
- The net balance sheet asset (liability) position is determined as the balance sheet assets less liabilities. For the adjustment to debt, if net pension and postretirement funded status is a surplus, debt is not adjusted. If the net pension and postretirement is a deficit, this amount is reduced by the expected tax shield, that is, the amount is multiplied by (1 minus the tax rate).
- In some jurisdictions, the tax benefit is realized in advance of funding the deficit or paying benefits, for example, when the liability is accrued for tax purposes. The expected tax shield used in our calculation only takes into account amounts that have not yet been received. The adjustment to equity also considers existing balance sheet amounts.
- Equity is adjusted for the tax-effected difference between the deficit/surplus and the net balance sheet assets/liabilities, i.e., multiplied by (1 minus the tax rate).

Unlike the adjustment to debt, the adjustment to equity can be an increase or decrease.

(Please see "Corporate Ratings Criteria, 2006 edition: Postretirement Obligations"; and "Ratings Implications Of New FASB Standard On Pensions And Other Postretirement Benefit Obligations," published Sept. 29, 2006, on RatingsDirect.)

Power Purchase Agreements

We view purchased power supply agreements (PPAs) as creating fixed, debt-like, financial obligations that represent substitutes for debt-financed capital investments in generation capacity. In a sense, a utility that has entered into a

PPA has contracted with a supplier to make the financial investment on its behalf. Consequently, by adjusting financial metrics to incorporate PPA fixed obligations, we achieve greater comparability of utilities that finance and build generation capacity and those that purchase capacity to satisfy customer needs.

PPAs do benefit utilities by shifting various risks to the suppliers, such as construction risk and most of the operating risk. The principal risk borne by a utility that relies on PPAs is the recovery of the costs of the financial obligation in rates. Differentiating the risk profiles of utilities that take divergent approaches is incorporated in our qualitative business-risk assessments.

We calculate the present value (PV) of the future stream of capacity payments under the contracts as reported in the financial statement footnotes, or as supplied directly by the company. The discount rate used is equivalent to the company's average cost of nonsecuritization debt. For U.S. companies, notes to the financial statements enumerate capacity payments for the coming five years, and a thereafter period. We often have access to company forecasts that show the detail underlying the thereafter amount; otherwise, we divide the amount reported as thereafter by the average of the capacity payments in the preceding five years to derive an approximation of annual payments after year five.

In calculating the amount we add to debt, we also consider new contracts that will commence during the forecast period. Such contracts are not reflected in the notes to the financial statements--but information regarding these contracts may be provided to us by the company.

If these contracts represent extensions of existing PPAs, they are immediately included in the PV calculation. However, a contract sometimes is executed in anticipation of incremental future needs, so the energy will not flow until some later period and there are no interim payments. In these instances, we incorporate that contract in our projections, starting in the year that energy deliveries begin under the contract, just as if the company had purchased a plant at that juncture. That way, the debt imputation is viewed in the context of all the related activity, including revenues and cash flow from the forecast demand. (Of course, the projected PPA debt is included in projected ratios. That way, the future PPA figures as a current rating factor, even if it is not included in the current-year ratio calculations.)

The calculated PV is adjusted to reflect the benefits of regulatory or legislative cost recovery mechanisms. The adjustment reduces the debt-equivalent amount by multiplying the PV by a specific risk factor that pertains to each contract. The stronger the recovery mechanisms, the smaller the risk factor. These risk factors typically range between 0% and 50%, but can be as high as 100%.

A 100% risk factor would signify that substantially all risk related to contractual obligations rests on the company, with no mitigating regulatory or legislative support. For example, an unregulated energy company that has entered into a tolling arrangement with a third-party supplier would be assigned a 100% risk factor. Conversely, a 0% risk factor indicates that the burden of the contractual payments rests solely with ratepayers. This fact pattern frequently is found among regulated utilities that act as conduits for the delivery of a third party's electricity, and essentially deliver power, collect charges, and remit revenues to the suppliers. These utilities typically have been directed to divest their generation assets; are barred from developing new generation assets; and the power supplied to their customers is sourced through a state auction or third parties that act as intermediaries between retail customers and electricity suppliers.

Intermediate degrees of recovery risk are presented by a number of regulatory and legislative mechanisms. For example, we employ a 50% risk factor in cases where regulators use a utility's rate case to establish base rates to provide for the recovery of the fixed costs created by a PPA. While we view this type of mechanism as generally supportive of credit quality, the utility still needs to obtain approval to recover costs and the prudence of PPA capacity payments in successive rate cases to ensure ongoing recovery of its fixed costs. If a regulator has established a power cost adjustment mechanism that recovers all prudent PPA costs, a risk factor of 25% is employed, because the recovery hurdle is lower than it is for a utility that must litigate time and again its right to recovery costs.

In certain jurisdictions, true-up mechanisms are more favorable and frequent than the review of base rates, but still do not amount to pure fuel adjustment clauses. Such mechanisms may be triggered by financial thresholds or passage of prescribed periods of time. In these instances, a risk factor between 25% and 50% is employed.

Legislatively created cost-recovery mechanisms are long-lasting and more resilient to change. Consequently, such mechanisms lead to risk factors between 0% and 15%, depending on the legislative provisions for cost recovery and the supply function borne by the utility. Legislative guarantees of complete and timely recovery of costs are particularly important to achieving the lowest risk factors.

We do not impute debt for supply arrangements if a utility acts merely as a conduit for the delivery of power. As an example, New Jersey's vertically integrated utility companies were transformed into pure transmission and distribution utilities. The state commission, or an appointed proxy, leads an annual auction in which suppliers bid to serve the state's retail customers, and the utilities are protected from supplier default. The state's utilities merely deliver power and collect revenues from retail customers on behalf of the suppliers. Therefore, we impute debt only to New Jersey utilities' qualifying facility and exempt wholesale generator contracts--and not for other electricity supply contracts where the utilities merely act as conduits between the winners of the regulator's supply auction and the end-user, retail customers.

We also exclude PPAs with durations of less than one year where they serve merely as gap fillers, pending either the construction of new capacity or the execution of long-term PPA contracts. These contracts are temporary--and we focus on the more permanent situation, which is factored into the forecast ratios.

Given the long-term mandate of electric utilities to meet their customers' demand for electricity, and also to enable comparison of companies with different contract lengths, we use an evergreening methodology. Evergreen treatment extends the duration of short- and intermediate-term contracts to a common length of about 12 years. To quantify the cost of the extended capacity, we use empirical data regarding the cost of developing new peaking capacity, incorporating regional differences. The cost of new capacity is translated into a dollars-per-kilowatt-year figure using a proxy weighted average cost of capital and a proxy capital recovery period.

Some PPAs are treated as operating leases for accounting purposes--based on the tenor of the PPA or the residual value of the asset upon the PPA's expiration. We accord PPA treatment to those obligations, in lieu of lease treatment, if companies identify them to us. That way, such PPAs will not be subject to a 100% risk factor for analytical purposes as though they were ordinary leases; rather, the PV of the stream of capacity payments associated with these PPAs is reduced to reflect the applicable risk factor. (PPAs treated as capital leases for accounting purposes do not fall under our PPA adjustment.)

Long-term transmission contracts can also serve in lieu of building generation, and, accordingly, fall under our PPA methodology. In some cases, these transmission contracts provide access to specific power plants, while other transmission arrangements provide access to competitive wholesale electricity markets. We view these types of transmission arrangements as extensions of the power plants to which they are connected or the markets that they serve. Accordingly, we impute debt for the fixed costs associated with such transmission contracts.

Adjustment procedures

Data requirements

- Future capacity payments obtained from the financial statement footnotes or from management;
- Discount rate: the company's cost of nonsecuritized debt; and
- Analytically determined risk factor.

Calculations

- Balance-sheet debt is increased by the PV of the stream of capacity payments multiplied by the risk factor.
- Equity is not adjusted, because the recharacterization of the PPA implies the creation of an asset, which offsets the debt.
- PP&E and total assets are increased for the implied creation of an asset equivalent to the debt.
- An implied interest expense for the imputed debt is calculated by multiplying the utility's average cost of nonsecuritized debt by the amount of imputed debt (or, average PPA imputed debt, if there is fluctuation of the level), and is added to interest expense.
- The cost amount attributed to depreciation is reclassified as capex, thereby increasing operating cash flow and FFO.
- We impute a depreciation component to PPAs. The depreciation component is derived by multiplying the relevant year's capacity payment by the risk factor and then subtracting the implied PPA-related interest for that year. Accordingly, the impact of PPAs on cash flow measures is tempered.
- Some PPA contracts refer only to a single, all-in energy price. We identify an implied capacity price within such an all-in energy price, to calculate an implied capacity payment associated with the PPA. This implied capacity payment is expressed in dollars per kilowatt year, multiplied by the number of kilowatts under contract. (In cases that exhibit markedly different capacity factors, such as wind power, the relation of capacity payment to the all-in charge is adjusted accordingly.)
- Operating income before D&A and EBITDA are increased for the imputed interest expense and imputed depreciation component, the total of which equals the entire amount paid for PPA (subject to the risk factor).
- Operating income after D&A and EBIT are increased for interest expense.

(Please see "Standard & Poor's Methodology For Imputing Debt For U.S. Utilities' Power Purchase Agreements," published May 7, 2007, and "Credit FAQ: Imputed Debt Calculation For U.S. Utilities' Power Purchase Agreements," published March 30, 2007, on RatingsDirect.)

Share-Based Compensation Expense

We view the value of equity instruments (for example, stock options and restricted shares awards) granted to employees and/or other service providers as an outlay that should be taken into account in evaluating issuers' performance and profitability. When we assess a company's ability to generate a real, all-in return on capital employed, we should not view differently companies granting equity from peers using cash as a form of compensation. Although often not representing a direct or an immediate call on a company's cash resources, these grants are made in exchange for, or in anticipation of, services to be provided: They have a real economic value and so should be considered.

In analyzing the financial aspects of equity awards granted by an issuer, we consider adjustments to:

- Normalize the value of these grants in calculating earnings and performance-based metrics. That is, certain accounting regimes mandate expensing of stock-based grants while others do not. In addition, certain practices employed by management, such as vesting acceleration and other award modifications, could meaningfully affect reported results. Accordingly, certain adjustments may be warranted for more meaningful peer and period-over-period comparisons.
- Highlight the effect that these arrangements might have over time on cash flows. That is, although most awards do not result in cash being exchanged upon grant, future cash flows are clearly affected. This occurs as a result of payments received by the company upon exercise or issuance of shares; payments made by the company for share repurchases (to mitigate earnings per share dilution); a company's practice to settle the value of equity grants in cash in lieu of shares; and tax savings generated by the favorable tax treatment generally afforded to options and other grants.
- Separately, we try to ascertain the effectiveness of a company's grants in aligning employee incentives with shareholders' and creditors' objectives.

Until recently, the major accounting regimes (e.g., IFRS, U.S. GAAP, Canadian GAAP, and Australian GAAP) did not mandate expensing of these costs. Now most require the fair value of equity-based grants (or an approximation of that value) to be included as an expense in the income statement. This amount is generally expensed over the benefiting period, i.e., the period the employee is assumed to provide services in exchange for the award. Often the vesting period is used as a proxy. Prior to the advent of IFRS and the recent mandating of expensing under U.S. GAAP for all stock-based grants, the accounting was greatly fragmented and inconsistent among companies and jurisdictions, and also varied according to the form of the award. For example, although restricted shares or stock appreciation rights may be economically equivalent to stock option grants, the accounting differed. Further, disclosures of stock-based compensation arrangements, which were lacking in the past, have vastly improved as a result of governance and transparency requirements by accounting-standard setters, securities regulators, and exchanges, providing more pertinent data on these arrangements.

Profitability analysis

Our objective is to capture compensation cost in our profitability measures--regardless of the means of payment (i.e., whether paid in cash, shares, options or other in-kind payment)--as fully and as consistently as possible.

With the recent accounting changes, most rated companies now expense the cost of equity-based grants, so the consistency of reported earnings is significantly enhanced, obviating in many cases the need to define a different common basis for analysis. However, where information enabling quantification is not available, we employ a qualitative assessment, to be conscious of the difference among peers.

Companies may, at times, modify their share-based awards, grant a one-time award (e.g., upon an acquisition), or accelerate vesting (e.g., upon a change in control or downsizing). These actions could meaningfully alter reported income and introduce discrete volatility to earnings. However, adjustments for these variants generally are not feasible as a practical matter, and are attempted only where material and the relevant information is available.

Cash flow analysis

When a company grants share-based awards, generally no cash is paid or received. Cash-flow consequences, if any, only arise when the options are exercised (e.g., as a result of payment of the exercise price and from associated tax benefits). For some other grants, such as stock appreciation rights (SARs) payable in shares and restricted share grants, no cash changes hands at all. Just as with all issuance of equity, the company's financial position is enhanced, or at least is not diminished, as a result of the grant (assuming settlement is effected with shares, and the grant/exercise is not tied to commensurate repurchases). From a cash flow standpoint, companies would gain flexibility to the extent that stock-based grants provide an alternative to cash compensation and their creditors should be better off, while their shareholders will be diluted.

Our cash-flow measures, such as FFO and operating cash flow, are not affected by share-based grants. Being a noncash item, share-based related expense will continue to be backed out on the cash flow statement. Because options and restricted share grants represent noncash events, our key cash flow ratios--FFO to total debt, EBITDA to interest, and debt to EBITDA--exclude stock option expense. Accordingly, for companies whose stock-based compensation expense (payable in shares) has been deducted, we adjust EBITDA measures by adding back the expense.

Unlike options or restricted share awards, certain other share-based arrangements are payable solely in cash (e.g., stock appreciation rights required to be settled in cash), and represent a future call on a company's cash flow. The obligations under these arrangements are treated as debt.

For tax-reporting purposes, the exercise or the point of vesting (not granting) of certain stock-based awards often generates a tax-deductible expense, regardless of whether the company has been expensing stock-option grants for financial reporting purposes. Tax credits are shown as an operating item on the cash flow statement under U.S. GAAP only to the extent they relate to the accounting expense; if the tax deduction exceeds the amount attributable to the accounting expense, such excess is a financing item. Analytically, we view tax benefits more appropriately as a financing item on the cash flow statement, because they are triggered only upon equity issuance.

To mitigate dilution caused by options and other share-related grants, companies often engage in share repurchases. Arguably, if a company regularly reverses the dilution resulting from the exercise of share-based awards through share repurchases, the related cash outlays (net of cash proceeds from the exercise) could be treated as a cash operating expense. However, we view a company's decision to repurchase its shares as a separate matter--and part of the company's overall corporate finance strategy. Accordingly, we determine the level of expected share repurchases in the context of a broader assessment of liquidity, capitalization, and financial policy.

In contrast, when an issuer enters into derivative or similar contracts to repurchase shares at a future date, we view these contracts as precursors to such purchases--and incorporate the repurchase immediately in the analysis. Still, even in the absence of such contractual arrangements, the analysis incorporates the eventual share repurchases if they are anticipated. We adjust debt by adding amounts that are anticipated as necessary to fund these transactions.

Additional considerations

For U.S. tax purposes, generally the exercise (not granting) of certain stock options results in a tax-deductible expense to the employer. However, for GAAP purposes, the company expenses the fair value of stock options, which is determined at the grant date, ratably over the related service period. As a result of the use of the grant date fair value to determine the accounting expense, rather than an exercise-date intrinsic or other value for tax deduction purposes, the book and the tax expenses will differ. Furthermore, U.S. GAAP does not allow companies to record a reduction to income tax expense on their income statements for these excess tax benefits. Instead, the tax benefit is recorded directly as an incremental increase to equity (more specifically, additional paid-in capital) and a reduction of taxes payable (i.e., never recorded in as a benefit in the income statement). Consistent with our view that the tax benefits are more financing in nature, because they relate to equity issuance, this will not give rise to an adjustment.

If the options ultimately expire unexercised, any previously recorded accounting expense (recorded based on the award's initial fair value) is not reversed under U.S. GAAP. Although in this circumstance no tax deduction would be generated at all, it would result in a deferred tax asset being recorded on the company's balance sheet over the expense recognition period (because the book expense and resulting deferred tax assets are calculated based on the initial fair value). This tax asset is reversed through earnings only upon expiration of the exercise period. This requirement can cause large deferred tax assets, unlikely to be realized, to remain on a company's balance sheet, causing artificially inflated equity balance in circumstances in which a company's fortunes are adversely changing, and its options are moving substantially out of the money (rendering both exercise and use of the tax benefit improbable). Analytically, it would be more appropriate to reverse the asset amount against equity when it becomes apparent that use of the benefits is unlikely. Adjustments for these situations are considered only in rare circumstances.

Both IFRS and U.S. GAAP now require the expensing of stock options and other share-based employee compensation. However, to facilitate the transition from the prior approach of not expensing, the transition provision allows companies to apply this approach only to grants that were made after a specific date (e.g., Nov. 7, 2002, under IFRS). As a result, costs for an increasing proportion of outstanding grants will be expensed over time. We have generally not attempted to adjust earnings measures to include the missing expenses in the early years of the transition.

Adjustment procedures

Data requirements

- Total period share-based compensation expense reflected in the financial statements. (Amounts may be available in the statements or in the notes.);
- In jurisdictions that do not require expensing of such compensation, an estimate of what would be expensed;
- Amount of deferred taxes unlikely to be realized;
- Tax cash flows included in operating that we view as financing; and
- Estimate of amounts to be used for share repurchases.

Calculations

- EBITDA: Where noncash stock compensation costs have been expensed, we reverse the expense amount.
- SG&A, Operating income before and after D&A, and EBIT: In jurisdictions where share-based compensation is not required to be expensed, the estimated amount is deducted from these profitability measures.
- Tax assets that are unlikely to be realized are subtracted from assets and equity.
- Taxes that are financing in nature are added to operating cash flow and FFO.
- Debt is increased--and equity decreased--for related share repurchases that are contractually committed or otherwise imminent.

(Please see "Analytic Implications Of Stock-Based Compensation Accounting," published March 24, 2005, and "Camouflaged Share Repurchases: The Rating Implications Of Total-Return Swaps And Similar Equity Derivatives," published Dec. 7, 2000, on RatingsDirect.)

Stranded costs securitizations of regulated utilities

For rate-regulated utilities, we remove the effects of debt related to securitization of stranded costs, to the extent that debt is serviced separately by the utilities' customers through direct inclusion in rates. Because the customers, not the utility, are responsible, by statute, for principal and interest payments, we remove the debt from the balance sheet for analytical purposes. We also remove related amounts from revenue, depreciation, and interest.

Adjustment procedures

Data requirements

- Amount of securitized debt related to stranded costs on the utility's balance sheet at period end;
- Interest expense related to securitized stranded-cost debt for the period; and
- Principal repayments on stranded-cost securitized debt during the period.
- Note: We obtain the data from the financial statements and footnotes of the utility; or separate special purpose vehicle (SPV) created for the debt securitization; or information received directly from the utility.

Calculations

- Adjustment to debt: We subtract the stranded-cost securitized debt from total debt.
- Adjustment to revenues: We remove the revenue earned from customers that is committed to paying securitized debt principal and interest from total revenues. We assume that revenue equals the sum of interest and principal payments made during the year.
- Adjustment to operating income before D&A and EBITDA: We remove the revenue earned from customers committed to paying principal and interest on securitized debt.
- Adjustment to operating income after depreciation and amortization and EBIT: We remove the revenue earned from customers committed to paying principal and interest. We also remove D&A related to the regulatory asset, which we assume equals the sum on principal payments during the period. As a result, the reduction to operating income after D&A is only for the interest portion.
- Adjustment to interest expense: We reduce interest expense by interest expense of the securitized debt.
- Operating cash flows: We reduce operating cash flows for revenues and increase for the assumed interest amount related to the securitized debt. This results in a net decrease to operating cash flows equal to the principal repayment amount.

(Please see "Securitizing Stranded Costs," published Jan. 18, 2001, on RatingsDirect.)

Surplus Cash

The credit profile of companies that have accumulated cash is, of course, enhanced by the available liquidity. But our analytical methodology regularly goes a step further, by adjusting both financial and operating ratios to reflect a company's surplus cash (that is, unless the surplus is deemed to be only temporary).

Industrial credit ratios are intended to capture the degree to which a company has leveraged its risk assets, and highly liquid financial assets often involve virtually no risk. Moreover, ratios are designed to indicate a company's ability to service and repay debt obligations from operating cash flow, and surplus cash and/or highly liquid assets are, in a sense, available to repay debt apart from ongoing cash flow generation. Accordingly, we often net surplus cash against debt and debt-like obligations--so that net debt is what figures in ratio calculations.

In some situations--only where the surplus cash is structurally linked to debt that would not be needed, were it not for the cash holdings--we also use a net interest expense when calculating the denominator of coverage ratios, such as FFO/interest, EBIT/interest, and EBITDA/interest. (Absent such linkage, we use gross interest in the denominator. Also, since interest income is differentiated from operating income, it is generally not included in the numerator.)

Further, maintenance of surplus cash distorts operational benchmarks and return on assets measures that are important for peer comparisons in some sectors, such as pharmaceuticals. Given the relatively low returns on low-risk financial assets, maintaining such assets depresses asset-related margins (even without taking into account interest expense required if the company is financing the cash with debt that otherwise would not be needed).

The key analytical considerations regarding net debt adjustments are the quality of the financial assets themselves and the company's purpose and strategies for maintaining them--although doing so involves commensurately higher levels of debt. Some of the possible strategies--and what they imply for the permanence of the surplus--are discussed below.

Virtually all companies require some cash to facilitate their operations. Retailers, restaurants, and supermarkets, for example, need cash to make change. More broadly, companies require a certain level of cash for very-near-term liquidity. We do not give any special credit or make any adjustments for cash that is merely adequate to support ongoing operations, even though the amount can sometimes be quite substantial--especially for companies that operate numerous facilities, and those that transact in diverse currencies.

Companies engage in dialogue with us to help us gauge these near-term operating liquidity needs, and our sector comparisons and reviews also target peer consistency regarding maintenance of sufficient liquidity. Apart from potential netting for surpluses, maintaining adequate liquidity is always an important rating consideration. A company with a deficient level of cash for working capital needs would be penalized in its rating assignment.

However, many companies possess still greater cash, and/or liquid, low-risk, financial resources. Several different possible purposes and strategies could apply. This is important to our analytical treatment: There are many situations in which we use net calculations and, many others where we do not, usually determined by the company's strategies. The strategies explained below are in descending order, starting with the most supportive of a net approach and concluding with a number of strategies that do not lead to a net approach.

Strategies that support net-debt treatment

- Defeasance (both legal and economic). Because the company places very high-quality assets in a trust to cover the interest and principal of a specific debt issue, this is the most obvious application of the net debt adjustment. (See "Defeasance Of Corporate Bonds May Be Gaining Popularity," published July 25, 2006, on RatingsDirect).
- Tax arbitrage. Some companies manufacture in various tax havens; retain related profits in those low-tax locales and avoid tollgate taxes by holding financial investments there; while financing and incurring tax-deductible interest expense in higher-tax rate jurisdictions. Such structural basis for maintaining cash is another solid reason for applying the net debt adjustments. (However, for analytical purposes, any "tollgate" taxes payable upon repatriation are subtracted from the cash.) The large, cash-rich U.S. pharmaceutical companies offer a good example of this tax arbitrage strategy. And, given the magnitude of this aspect of these companies' finances, profitability measures could be quite distorted without also adjusting return on asset ratios to a net basis. (See "Credit FAQ: Tax Relief On Foreign Cash And Its Special Benefit To U.S. Drug And Medical Device Firms," published Sept. 14, 2004, and "Ratings Implications Of Earnings Repatriations Under The American Jobs Creation Act," published June 26, 2006, on RatingsDirect.)
- Funding future payment of obligations--especially retiree obligations. Some companies may earmark financial

assets on their balance sheet to provide for their retiree benefit obligations. In particular, some large German corporations assert that this is their financial policy. Indeed, while these assets are not legally segregated, we would view them as offsetting the liability. Application of the net debt approach in such cases presumes that the liability itself is sufficiently debt-like to be included in our definition of adjusted debt. (U.S., U.K., and Dutch companies, among others, are forced by law to fund their pension obligations in a trust. Our pension adjustment adds back only any unfunded portion, which is equivalent to netting these financial assets against the debt-like pension liability.)

- Meet seasonal requirements. A company may choose to pre-fund its intrayear borrowing needs, by borrowing (or not repaying outstanding debt balances), holding the proceeds in cash or near-cash investments, drawing down the cash as the year progresses, and then replenishing it at period end. The company should not be penalized relative to a company that instead relies on borrowing only as the need actually materializes, thus avoiding the debt showing up on its yearend financial statements. (In both cases, there may be equal prudence, since the latter company would typically be able to rely on a revolving credit agreement.) To avoid such a distortion and promote comparability, we would use a net-debt approach. However, it would be tricky to estimate the impact on interest expense involved for this pattern, which is one reason we are reluctant to focus on net interest expense.
- Maintain access to financial markets. Very similar to the above strategy, some companies believe it is in their best interests to keep a fairly stable presence in the financial markets, especially in CP markets. They maintain market presence on a regular basis, and avoid going in and out of the markets as their cash flow patterns would dictate.

Strategies that do not support net-debt treatment

- Cyclical safety net. Some companies tend to accumulate cash during good times and hold onto it for self-preservation during expected lean years. For companies that have large ongoing capital requirements, this can be critical. The large U.S. auto companies offer a dramatic example. Similarly, high technology companies tend to operate with a large cash cushion, given the vicissitudes of the technology product life cycles. Such cash is not really an offset to debt, and net debt is not used as the basis for analysis in these instances. (Nonetheless, it is hard to forecast how much cash is appropriately dedicated to spending in future downturns. So the analyst might calculate supplementary ratios based on netting, just to gain perspective and for peer comparison purposes.)
- Reserve for investment opportunities. Cash earmarked for investment in operations--expansion or capital projects--or acquisitions does not qualify for netting against debt. The cash position is temporary, although some companies may take their time until the opportunity they seek arrives. Of course, having such cash to invest is a great positive that must not be overlooked; it figures in other aspects of the analysis: The potential additional cash flow that can be anticipated from enlarged operations is considered in financial projections, and the current availability of cash enhances liquidity.
- Awaiting return to shareholders. In the current financial environment, this situation may be the most common, at least in the U.S. Many companies that have been successful at generating surplus cash are motivated to repurchase stock or pay out special dividends. While shareholder enrichment programs may stretch out over several quarters or even a few years, the cash position of such companies is ephemeral, and should not be netted against debt.

There are many instances where the purpose may be mixed or the strategy unclear. Local business practice can then form the basis for deciding whether the cash position is likely to be long-lasting. Accordingly, companies with surplus cash that operate in the European context are regularly afforded net debt treatment, given the acceptance--even tradition--of companies operating permanently with surplus cash. (Whatever portion is deemed to be needed for operations is excluded from the adjustment.)

In contrast, North American companies operate in an environment that looks askance at cash accumulation. Shareholders expect these funds to be invested, or returned to them for reinvestment. We therefore presume that, in most cases, surplus cash will be distributed to shareholders sooner or later. Accordingly, few companies in North America are analyzed on a net-debt basis.

Some companies participate in global industries, and may be influenced, to some extent, by the behavior of cross-border peers. This could provide additional insight into what to expect in those instances.

A company's excess cash may be invested in assets of varying quality or liquidity. We tend to be fairly conservative about which assets can be used to fully offset debt. However, a diversified portfolio of assets--such as traded equities, for example--can constitute a reasonably high quality investment, and is certainly very liquid. We have sometimes taken a net approach even with respect to nonfinancial assets, when they exhibit similar critical aspects of low risk and liquidity. For example, agricultural commodity and energy trading companies hold inventory against committed orders. Netting the value of these commodities against debt allows a better picture of the true credit risks.

To the extent that asset values may be subject to decline, we would haircut the investment prior to the netting adjustment. There are situations where we would not adjust for excess cash on the balance sheet because the company has only limited access to the funds. Such exceptions include:

- Funds held at partially owned subsidiaries. Joint venture partners or minority shareholders may insist on maintaining significant liquidity at the subsidiary level, or may otherwise limit the repatriation of cash to the group's central treasury operations. Restrictive bank loan covenants at these units create similar restrictions.
- Operating subsidiaries that are regulated. These business units may be prevented from up-streaming cash to their parents, or may have to maintain substantial cash balances for regulatory reasons.
- Captive insurance subsidiaries. Although cash appears unencumbered, it usually has to be invested in line with the subsidiary's insurance status and regulations.
- Pension funding vehicles. Even pension surpluses are generally regarded as inaccessible for all practical purposes.

Adjustment procedures

Data requirements

- The amount of surplus cash is judgmentally determined, based on our assessment of liquidity available to repay debt; and
- Estimated taxes that would be subject to collection upon repatriation, if applicable.

Calculations

- Debt and cash and investments are reduced by the surplus cash amount, net of related taxes. However, the resulting debt amount may never be negative.
- If the cash and debt are structurally linked, interest expense is reduced by an amount that corresponds to earnings on the surplus cash.

(Please see "Net Debt Adjustments Reflect Asset Quality, Strategic Intent," published Feb. 22, 2007, on RatingsDirect.)

Trade Receivables Securitizations

Securitization is an important financing vehicle for many companies, often providing lower-cost, more diverse sources of funding and liquidity than otherwise available to the company. However, securitizations do not ordinarily transform the risks or the underlying economic reality of the business activity, and do not necessarily provide equity relief (i.e., that having accomplished a securitization, the issuer can retain less equity, or incur more debt, than otherwise would be the case, without any change in its credit quality).

To the extent the securitization accomplishes true risk transfer (i.e., all risks--contractual, legal, and reputational), the transaction is interpreted as an asset sale. Yet, in the much more common case, the company retains the bulk of risks related to the assets transferred, and the transaction is akin, in our view, to a secured financing. More importantly, perhaps, we do not give any benefit for securitization of assets that will be regenerated in the ordinary course of business (and financed on an ongoing basis).

Key considerations in assessing the extent of equity relief include:

- Riskiness of the securitized assets. The only risk that can be transferred is that which existed in the first place. If, as is often the case, an issuer securitizes its highest-quality or most liquid assets, that limits the extent of any meaningful equity relief.
- First-loss exposure. The issuer commonly retains the first-loss exposure, to enhance the credit protection afforded for the securitized debt. For the securitized debt to be highly rated, the extent of enhancement must be a multiple of the expected losses associated with the assets. The first-loss layer thus encompasses the preponderance of risk associated with the securitized assets, and the issuer's total realizations from the securitization will vary depending on the performance of the assets. Often, only the risk of catastrophic loss is transferred to third-party investors--risk generally of little relevance in the corporate rating analysis.
- Moral recourse. How the company would behave if losses did reach catastrophic levels. Empirical evidence suggests companies often believe they must bail out troubled financings (for example, by repurchasing problematic assets or replacing them with other assets) to preserve access to this funding source and, more broadly, to preserve their good name in the capital markets, even though they have no legal requirement to do so. Moral recourse is magnified when securitizations are a significant part of a company's financing activity, or when a company remains linked to the securitized assets by continuing in the role of servicer or operator.
- Ongoing funding needs. Even if it were contractually and legally certain that the risks related to a given pool of assets had been fully transferred and the issuer would not support failing securitizations, equity relief (or an analytical deconsolidation) still would not necessarily have been achieved. If, for whatever reason, losses related to the securitized assets rose dramatically higher than initially anticipated, and if the issuer has a recurring need to finance similar assets, future access to the securitization market would be dubious--at least economically. Future funding needs would then have to be met by other means, with the requisite equity (and the equivalent level of borrowings) to support them. Thus, even if a company separately sells the first-loss exposures, or sells the entire asset without retaining any first-loss exposure, it would not achieve equity relief.

The accounting treatment of securitizations may not be congruent with our analytical perspective, and, accordingly, adjustments to the reported financials often are necessary (especially for companies reporting under U.S. GAAP, since many securitizations remain on balance sheet under IFRS).

For transactions in which a company retains the preponderance of risks (including those related to ongoing funding needs), we calculate ratios where the outstanding amount of securitized assets are consolidated, along with the related securitized debt--regardless of the accounting treatment. If securitization is used essentially to transfer risk in full and there are no contingent or indirect liabilities, we view the transaction as the equivalent of an asset sale. When necessary, then, we recast the assets, debt, earnings and cash flows, and shareholders' equity accordingly, including adjusting for deferred tax effects and imputed interest.

Issues/limitations of adjustments

When securitizations are accounted for as sales, they commonly give rise to upfront gain/loss-on-sale effects, which represent the present value of the estimated difference between the asset yield and the securitization funding rate and other securitization-related costs. For securitizations that we are putting back on the balance sheet, it is appropriate to back out such gains and spread them out over the life of the securitizations, given the uncertainty about whether the earnings will ultimately be realized as expected and their essentially nonrecurring character. Losses that reflect the discount on sale are also backed out, to avoid double-counting the interest component of the transactions.

To impute interest, we generally have to approximate a rate, given the lack of precise information that is available. Since securitizations tend to be relatively well-secured and risk-free for the investor, we assume a rate that approximates the risk-free rate, currently 5%.

In theory, it might be desirable to fully recast the income statement, and consolidate off-balance-sheet securitizations, but as a practical matter, this is difficult to accomplish. Still, some companies have voluntarily included pro forma schedules in their public disclosures to enable such analysis.

Cash inflows or outflows related to working capital assets or liabilities, or finance receivables, are classified as operating in nature on the statement of cash flows under U.S. GAAP and IFRS. Hence, securitizations affect operating cash flow, with particularly significant effects possible in reporting periods when securitizations are initiated or mature. The reporting convention varies in line with the balance sheet classification. If the securitization is consolidated, the related borrowings are treated as a financing activity. If the securitization is not consolidated, it is as if the assets self-liquidated on an accelerated basis: No debt incurrence is identified separately, either as an operating or financing source of cash. When our analytic view is that securitizations should be consolidated (or, in rare situations, when those that are consolidated should not be), it would be desirable to recast the statement of cash flow accordingly--to smooth out the variations in operating cash flow that can result from the sale treatment of the securitization, which can give a distorted picture of recurring cash flow. Again, as a practical matter, this often can be difficult to accomplish.

Adjustment procedures

Data requirements

- Identify the period-end amount and average outstanding amount of trade receivables sold or securitized, for which an adjustment is warranted, that are not on the balance sheet.

Calculations

- Debt and receivables are increased by the amount of trade receivables sold or securitized.
- Interest expense is increased by an amount of interest imputed at the risk-free discount rate.
- Operating cash flows are adjusted to remove the proceeds from the securitization when there is an increased level of securitization--upon initiation of securitization or subsequent fluctuation in amounts securitized. Merely rolling over existing securitization requires no cash flow adjustment.

(Please see "Securitization's Effect On Corporate Credit Quality," published Nov. 28, 2005, and "Finance Company Rating Methodology: Credit Ratios To Be Analyzed On A Managed Basis," published Feb. 23, 2001, on RatingsDirect.)

Volumetric Production Payments

A volumetric production payment (VPP) is an arrangement in which an E&P company agrees to deliver a specified quantity of hydrocarbons from specific properties to a counterparty (often a financial institution) in return for a fixed amount of cash received at the beginning of the transaction. The seller often bears all of the production and development costs associated with delivering the agreed-upon volumes. The buyer receives a nonoperating interest in oil and gas properties that produce the required volumes. The security is a real interest in the producing properties that is expected to survive bankruptcy of the E&P company that sold the VPP. When the total requisite units of production are delivered, the production payment arrangement terminates and the conveyed interest reverts back to the seller.

We view production payments structured with a high level of security to production coverage as debt-like obligations, and adjust financial and operating analysis accordingly. The retention of risk in VPPs is central to our treatment of such deals as largely debt-like.

The accounting for VPPs affects the seller's financial statements and operating statistics in several ways. The VPP volumes (i.e., the amount of oil and gas required to be delivered under the agreement) are removed from the seller's reserves. Proceeds received for the VPP increase the seller's cash balances, and the seller books a deferred revenue liability--or debt--to reflect the obligation under the agreement. Revenues and costs incurred to produce the VPP volumes are included in the seller's income statement as and when the oil and gas is produced. Operating statistics calculated on a per-barrel basis will be overstated because they include both the amortization of deferred revenues and costs, but do not factor in the volumes related to the VPP. In the case of lifting costs, for example, barrels produced in the numerator are lower, while the expense in the denominator continues to include the cost of producing the VPP volumes.

When the necessary data are available, we adjust the reported results to minimize the distortion caused by accounting for a production payment. The required volumes are returned to reserves and deferred revenue is treated as debt. Similarly, the oil and gas volumes produced to meet the VPP requirements are added to the E&P company's production when calculating per-barrel sales and lifting costs. This treatment reflects the view that VPPs are conceptually similar to secured debt, rather than asset sales. The similarity pertains in typical deals, in which the reserves included in the production agreement are significantly greater than the required volumes. The seller bears the obligation to deliver the agreed-upon volumes, and retains the production and a significant amount of reserve risk, while receiving the benefit of fixing commodity prices. A VPP structured with minimal coverage would be viewed as closer to an asset sale, since the transfer of risk would be more substantial.

Adjustment procedures

Data requirements

- Amount of VPP-related deferred revenue reported on the balance sheet at period end;
- Oil and gas reserve data (related to VPPs that have been removed from reported amounts);
- Remaining quantity of oil and gas reserves removed from reported reserves at end of period (yet to be delivered); and
- Oil and gas volumes produced during the year from the VPPs.

The amount of deferred revenue related to VPPs at period end is obtained from the financial statements. Reserve quantities may come from the financial statements or from the company.

Calculations

- Adjustment to debt: We add the amount of deferred VPP revenue at period end to debt.
- Adjustment to interest expense: We impute interest expense on the adjustment to debt. The rate is that inherent in the contract, or a rate estimated by the analyst based on the company's secured borrowing rates. In either case, it is applied to the average of the current period end, and the previous period end deferred VPP revenue balance.
- We add period-end reserve volumes related to VPPs back to reported reserves.
- Similarly, we add the oil and gas volumes produced to meet the VPP requirements to the company's production and sales statistics used to calculate per-barrel selling prices and lifting costs.
- Adjustment to operating cash flow: We reclassify cash proceeds from VPPs as financing cash flows. Future cash flows will be adjusted (if practicable and data are available) upon delivery, to reflect the cash flows associated with the properties.

(Please see "Credit FAQ: Volumetric Production Payments For U.S. Oil And Gas Companies," published April 14, 2005, and "Oil And Gas Volumetric Production Payments: The Corporate Ratings Perspective," published Dec. 4, 2003, on RatingsDirect.)

Workers Compensation/Self Insurance

Workers compensation systems provide compensation for employees injured in the course of employment. While schemes differ between jurisdictions, provisions may be made for payments in lieu of wages, compensation for economic losses (past and future), reimbursement for or payment of medical and like expenses, general damages for pain and suffering, and benefits payable to the dependents of workers killed during employment. (For example, U.S. coal mining companies, under the Federal Coal Mine Health and Safety Act, are responsible for medical and disability benefits to existing and former employees and their families who are affected by pneumoconiosis, better known as black lung disease.)

Workers compensation coverage may be provided through insurance companies, and thus is not a financial concern for the company. But, in certain instances and/or industries, employers assume direct responsibility for medical treatment, lost wages, etc.

In these cases, under U.S. GAAP or IFRS, the incurred liabilities usually are recorded on the company's balance sheet as other liabilities, based on an actuarially determined present value of known and estimated claims. Accordingly, these obligations represent a call on future cash flow, distinguishing them from many other, less-certain contingencies. They are analogous to postretirement obligations, which we also add to debt.

Treating the workers compensation liability as debt affects many line items on the financial statements. Ideally, if there is sufficient disclosure available, we would adjust fully (in a manner akin to our postretirement adjustments). In practice, the data are not available, so we reclassify these obligations, adjusted for tax, as debt. Similarly, we may also treat other analogous self-insurance-type liabilities as debt.

Adjustment procedures

Data requirements

- Net amount recognized as a liability for workers compensation obligations and for self-insurance claims.

Calculations

- Add amount recognized for workers compensation obligations (net of tax) and net amount recognized for self-insurance claims (net of tax) to debt.

Arbough Exhibit 4

Standard and Poor's Report Methodology For Inputing Debt for US Utilities Power Purchase Agreements

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May 7, 2007

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Standard & Poor's Methodology For Imputing Debt For U.S. Utilities' Power Purchase Agreements

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Standard & Poor's Methodology For Imputing Debt For U.S. Utilities' Power Purchase Agreements

(Editor's Note: This criteria article was originally published on May 7, 2007. We are republishing this article following our periodic review, completed on April 26, 2011.)

For many years, Standard & Poor's Ratings Services has viewed power supply agreements (PPA) in the U.S. utility sector as creating fixed, debt-like, financial obligations that represent substitutes for debt-financed capital investments in generation capacity. In a sense, a utility that has entered into a PPA has contracted with a supplier to make the financial investment on its behalf. Consequently, PPA fixed obligations, in the form of capacity payments, merit inclusion in a utility's financial metrics as though they are part of a utility's permanent capital structure and are incorporated in our assessment of a utility's creditworthiness.

We adjust utilities' financial metrics, incorporating PPA fixed obligations, so that we can compare companies that finance and build generation capacity and those that purchase capacity to satisfy customer needs. The analytical goal of our financial adjustments for PPAs is to reflect fixed obligations in a way that depicts the credit exposure that is added by PPAs. That said, PPAs also benefit utilities that enter into contracts with suppliers because PPAs will typically shift various risks to the suppliers, such as construction risk and most of the operating risk. PPAs can also provide utilities with asset diversity that might not have been achievable through self-build. The principal risk borne by a utility that relies on PPAs is the recovery of the financial obligation in rates.

The Mechanics Of PPA Debt Imputation

A starting point for calculating the debt to be imputed for PPA-related fixed obligations can be found among the "commitments and contingencies" in the notes to a utility's financial statements. We calculate a net present value (NPV) of the stream of the outstanding contracts' capacity payments reported in the financial statements as the foundation of our financial adjustments.

The notes to the financial statements enumerate capacity payments for the five years succeeding the annual report and a "thereafter" period. While we have access to proprietary forecasts that show the detail underlying the costs that are amalgamated beyond the five-year horizon, others, for purposes of calculating an NPV, can divide the amount reported as "thereafter" by the average of the capacity payments in the preceding five years to derive an approximate tenor of the amounts combined as the sum of the obligations beyond the fifth year.

In calculating debt equivalents, we also include new contracts that will commence during the forecast period. Such contracts aren't reflected in the notes to the financial statements, but relevant information regarding these contracts are provided to us on a confidential basis. If a contract has been executed but the energy will not flow until some later period, we won't impute debt for that contract until the year that energy deliveries begin under the contract if the contract represents incremental capacity. However, to the extent that the contract will simply replace an expiring contract, we will impute debt as though the future contract is a continuation of the existing contract.

We calculate the NPV of capacity payments using a discount rate equivalent to the company's average cost of debt, net of securitization debt. Once we arrive at the NPV, we apply a risk factor, as is discussed below, to reflect the benefits of regulatory or legislative cost recovery mechanisms.

Balance sheet debt is increased by the risk-factor-adjusted NPV of the stream of capacity payments. We derive an adjusted debt-to-capitalization ratio by adding the adjusted NPV to both the numerator and the denominator of that ratio.

We calculate an implied interest expense for the imputed debt by multiplying the same utility average cost of debt used as the discount rate in the NPV calculation by the amount of imputed debt. The adjusted FFO-to-interest expense ratio is calculated by adding the implied interest expense to both the numerator and denominator of the equation. We also add implied depreciation to the equation's numerator. We calculate the adjusted FFO-to-total-debt ratio by adding imputed debt to the equation's denominator and an implied depreciation expense to its numerator.

Our adjusted cash flow credit metrics include a depreciation expense adjustment to FFO. This adjustment represents a vehicle for capturing the ownership-like attributes of the contracted asset and tempers the effects of imputation on the cash flow ratios. We derive the depreciation expense adjustment by multiplying the relevant year's capacity payment obligation by the risk factor and then subtracting the implied PPA-related interest expense for that year from the product of the risk factor times the scheduled capacity payment.

Risk Factors

The NPVs that Standard & Poor's calculates to adjust reported financial metrics to capture PPA capacity payments are multiplied by risk factors. These risk factors typically range between 0% to 50%, but can be as high as 100%. Risk factors are inversely related to the strength and availability of regulatory or legislative vehicles for the recovery of the capacity costs associated with power supply arrangements. The strongest recovery mechanisms translate into the smallest risk factors. A 100% risk factor would signify that all risk related to contractual obligations rests on the company with no mitigating regulatory or legislative support.

For example, an unregulated energy company that has entered into a tolling arrangement with a third-party supplier would be assigned a 100% risk factor. Conversely, a 0% risk factor indicates that the burden of the contractual payments rests solely with ratepayers. This type of arrangement is frequently found among regulated utilities that act as conduits for the delivery of a third party's electricity and essentially deliver power, collect charges, and remit revenues to the suppliers. These utilities have typically been directed to sell all their generation assets, are barred from developing new generation assets, and the power supplied to their customers is sourced through a state auction or third parties, leaving the utilities to act as intermediaries between retail customers and the electricity suppliers.

Intermediate degrees of recovery risk are presented by a number of regulatory and legislative mechanisms. For example, some regulators use a utility's rate case to establish base rates that provide for the recovery of the fixed costs created by PPAs. Although we see this type of mechanism as generally supportive of credit quality, the fact remains that the utility will need to litigate the right to recover costs and the prudence of PPA capacity payments in successive rate cases to ensure ongoing recovery of its fixed costs. For such a PPA, we employ a 50% risk factor. In cases where a regulator has established a power cost adjustment mechanism that recovers all prudent PPA costs, we employ a risk factor of 25% because the recovery hurdle is lower than it is for a utility that must litigate time and again its right to recover costs.

We recognize that there are certain jurisdictions that have true-up mechanisms that are more favorable and frequent than the review of base rates, but still don't amount to pure pass-through mechanisms. Some of these mechanisms are triggered when certain financial thresholds are met or after prescribed periods of time have passed. In these instances, in calculating adjusted ratios, we will employ a risk factor between the revised 25% risk factors for utilities with power cost adjustment mechanisms and 50%.

Finally, we view legislatively created cost recovery mechanisms as longer lasting and more resilient to change than regulatory cost recovery vehicles. Consequently, such mechanisms lead to risk factors between 0% and 15%, depending on the legislative provisions for cost recovery and the supply function borne by the utility. Legislative guarantees of complete and timely recovery of costs are particularly important to achieving the lowest risk factors.

Illustration Of The PPA Adjustment Methodology

The calculations of the debt equivalents, implied interest expense, depreciation expense, and adjusted financial metrics, using risk factors, are illustrated in the following example:

Example Of Power-Purchase Agreement Adjustment

($000s)	Assumption	Year 1	Year 2	Year 3	Year 4	Year 5	Thereafter
Cash from operations	2,000,000						
Funds from operations	1,500,000						
Interest expense	444,000						
Directly issued debt							
Short-term debt	600,000						
Long-term due within one year	300,000						
Long-term debt	6,500,000						
Shareholder's Equity	6,000,000						
Fixed capacity commitments	600,000	600,000	600,000	600,000	600,000	600,000	4,200,000*
NPV of fixed capacity commitments							
Using a 6.0% discount rate	5,030,306						
Application of an assumed 25% risk factor	1,257,577						
Implied interest expense¶	75,455						
Implied depreciation expense	74,545						
Unadjusted ratios							
FFO to interest (x)	4.4						
FFO to total Debt (%)	20.0						
Debt to capitalization (%)	55.0						
Ratios adjusted for debt imputation							
FFO to interest (x)§	4.0						
FFO to total debt (%)**	18.0						
Debt to capitalization (%)¶¶	59.0						

Example Of Power-Purchase Agreement Adjustment (cont.)

*Thereafter approximate years: 7. ¶The current year's implied interest is subtracted from the product of the risk factor multiplied by the current year's capacity payment. §Adds implied interest to the numerator and denominator and adds implied depreciation to FFO. **Adds implied depreciation expense to FFO and implied debt to reported debt. ¶¶Adds implied debt to both the numerator and the denominator. FFO--Funds from operations. NPV--Net present value.

Short-Term Contracts

Standard & Poor's has abandoned its historical practice of not imputing debt for contracts with terms of three years or less. However, we understand that there are some utilities that use short-term PPAs of approximately one year or less as gap fillers pending the construction of new capacity. To the extent that such short-term supply arrangements represent a nominal percentage of demand and serve the purposes described above, we will neither impute debt for such contracts nor provide evergreen treatment to such contracts.

Evergreen Treatment

The NPV of the fixed obligations associated with a portfolio of short-term or intermediate-term contracts can lead to distortions in a utility's financial profile relative to the NPV of the fixed obligations of a utility with a portfolio of PPAs that is made up of longer-term commitments. Where there is the potential for such distortions, rating committees will consider evergreen treatment of existing PPA obligations as a scenario for inclusion in the rating analysis. Evergreen treatment extends the tenor of short- and intermediate-term contracts to reflect the long-term obligation of electric utilities to meet their customers' demand for electricity.

While we have concluded that there is a limited pool of utilities whose portfolios of existing and projected PPAs don't meaningfully correspond to long-term load serving obligations, we will nevertheless apply evergreen treatment in those cases where the portfolio of existing and projected PPAs is inconsistent with long-term load-serving obligations. A blanket application of evergreen treatment is not warranted.

To provide evergreen treatment, Standard & Poor's starts by looking at the tenor of outstanding PPAs. Others can look to the "commitments and contingencies" in the notes to a utility's financial statements to derive an approximate tenor of the contracts. If we conclude that the duration of PPAs is short relative to our targeted tenor, we would then add capacity payments until the targeted tenor is achieved. Based on our analysis of several companies, we have determined that the evergreen extension of the tenor of existing contracts and anticipated contracts should extend contracts to a common length of about 12 years.

The price for the capacity that we add will be derived from new peaker entry economics. We use empirical data to establish the cost of developing new peaking capacity and reflect regional differences in our analysis. The cost of new capacity is translated into a dollars per kilowatt-year (kW-year) figure using a weighted average cost of capital for the utility and a proxy capital recovery period.

Analytical Treatment Of Contracts With All-In Energy Prices

The pricing for some PPA contracts is stated as a single, all-in energy price. Standard & Poor's considers an implied capacity price that funds the recovery of the supplier's capital investment to be subsumed within the all-in energy price. Consequently, we use a proxy capacity charge, stated in $/kW, to calculate an implied capacity payment associated with the PPA. The $/kW figure is multiplied by the number of kilowatts under contract. In cases of resources such as wind power that exhibit very low capacity factors, we will adjust the kilowatts under contract to reflect the anticipated capacity factor that the resource is expected to achieve.

We derive the proxy cost of capacity using empirical data evidencing the cost of developing new peaking capacity. We will reflect regional differences in our analysis. The cost of new capacity is translated into a $/kW figure using a weighted average cost of capital and a proxy capital recovery period. This number will be updated from time to time to reflect prevailing costs for the development and financing of the marginal unit, a combustion turbine.

Transmission Arrangements

In recent years, some utilities have entered into long-term transmission contracts in lieu of building generation. In some cases, these contracts provide access to specific power plants, while other transmission arrangements provide access to competitive wholesale electricity markets. We have concluded that these types of transmission arrangements represent extensions of the power plants to which they are connected or the markets that they serve. Irrespective of whether these transmission lines are integral to the delivery of power from a specific plant or are conduits to wholesale markets, we view these arrangements as exhibiting very strong parallels to PPAs as a substitute for investment in power plants. Consequently, we will impute debt for the fixed costs associated with long-term transmission contracts.

PPAs Treated As Leases

Several utilities have reported that their accountants dictate that certain PPAs need to be treated as leases for accounting purposes due to the tenor of the PPA or the residual value of the asset upon the PPA's expiration. We have consistently taken the position that companies should identify those capacity charges that are subject to operating lease treatment in the financial statements so that we can accord PPA treatment to those obligations, in lieu of lease treatment. That is, PPAs that receive operating lease treatment for accounting purposes won't be subject to a 100% risk factor for analytical purposes as though they were leases. Rather, the NPV of the stream of capacity payments associated with these PPAs will be reduced by the risk factor that is applied to the utility's other PPA commitments. PPAs that are treated as capital leases for accounting purposes will not receive PPA treatment because capital lease treatment indicates that the plant under contract economically "belongs" to the utility.

Evaluating The Effect Of PPAs

Though history is on the side of full cost recovery, PPAs nevertheless add financial obligations that heighten financial risk. Yet, we apply risk factors that reduce debt imputation to recognize that utilities that rely on PPAs transfer significant risks to ratepayers and suppliers.

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Arbough Exhibit 5

Standard and Poor's Report: Kentucky Utilities

STANDARD &POOR'S

Global Credit Portal®
RatingsDirect®

November 1, 2011

Kentucky Utilities Co.

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Kentucky Utilities Co.

Major Rating Factors

Strengths:

- Stable and predictable cash flows;
- Credit-supportive regulatory environment in Kentucky;
- Competitive rates; and
- Efficient operations and high customer satisfaction ratings.

Weaknesses:

- Little fuel diversity, the company's plants are virtually all coal-fired;
- Exposure to pending environmental standards; and
- Linked to parent credit quality.

Corporate Credit Rating
BBB/Stable/A-2

Rationale

Standard & Poor's Ratings Services bases its rating on vertically integrated electric utility Kentucky Utilities Co. (KU) on the consolidated credit profile of ultimate parent PPL Corp., which includes what we consider to be an excellent business risk profile and aggressive financial risk profile. (For more on business risk and financial risk, see "Business Risk/Financial Risk Matrix Expanded," published on May 27, 2009.) In the U.S., holding company PPL Corp. consists of KU and other vertically integrated utility subsidiary Louisville Gas & Electric Co. (LG&E). In addition, PPL Corp. owns transmission and distribution electric utility PPL Electric Utilities Corp. (PPLEU) and PPL Energy Supply LLC, an unregulated generation subsidiary that has 10,760 megawatts of unregulated generation capacity that consists of well-located, low-cost nuclear and coal plants that are well hedged through 2012. In the U.K., PPL Corp. owns electric distribution networks Western Power Distribution (South West) PLC, Western Power Distribution (South Wales) PLC, Western Power Distribution (West Midlands) PLC, and Western Power Distribution (East Midlands) PLC. Our rating on PPL Corp. reflects the company's mostly regulated utility strategy that will include continuous capital spending and timely cost recovery through various regulatory mechanisms.

The excellent business risk profile incorporates PPL Corp.'s strategy as a mostly regulated public utility holding company. PPL Corp.'s numerous utilities serve 10 million electric customers in the U.K., Pennsylvania, and Kentucky, and 320,000 natural gas distribution customers in Kentucky. The U.K. wires-only distribution utilities have credit-supportive U.K. regulation and no commodity risk because nonaffiliated retail suppliers procure the electricity for retail customers. We expect these U.K. operations to contribute about 30% of PPL Corp.'s consolidated cash flow. The stability of the U.K. cash flows, along with existing utility assets in Kentucky and Pennsylvania, all of which we assess as excellent, will more than offset the business risk profile of PPL Energy's merchant generation, which we assess as satisfactory, resulting in the excellent business profile overall. We expect the merchant generation business to comprise less than 25% of pro forma consolidated cash flows.

KU's consolidated business risk profile, which we consider excellent, reflects the strengths of serving electric customers scattered throughout Kentucky, including those in Lexington. The utility's strengths include relatively predictable utility operations with steady cash flows, constructive cost recovery, and relatively low rates stemming from low-cost coal-fired generation. Although most of its plants burn coal, they meet current environmental requirements, and the significant amount of capital spending needed for environmental compliance through 2015 should be recoverable through rates.

The financial risk profile for KU reflects that of PPL Corp. The consolidated financial profile, which we consider aggressive, reflects adjusted financial measures that are in line with the rating. We expect that financial measures will continue at current levels as the company incorporates full cost recovery of capital spending in operating cash flow. We expect consolidated financial measures, including ratios of debt to EBITDA, funds from operations (FFO) to total debt, and debt to capital, to remain in line with the rating. For the 12 months ended June 30, 2011, FFO to total debt was 16.5%, total debt to total capital was about 58%, and debt to EBITDA was 4.8x. After reducing cash flow from operations by capital spending and dividends, discretionary cash flow was negative $275 million, indicating a need for external funding. In addition, net cash flow (FFO after dividends) to capital spending was 101%. FFO interest coverage was 4.1x, and the company's dividend payout ratio was 50%. The consolidated adjustments for PPL Corp. include pension-related items, intermediate equity treatment of the junior subordinated notes, and high equity treatment of mandatory convertible securities.

Liquidity

The short-term rating on KU is 'A-2'. The utility's liquidity position reflects that of parent PPL Corp., which we consider adequate under Standard & Poor's liquidity methodology. (We categorize liquidity in five standard descriptors. See "Liquidity Descriptors For Global Corporate Issuers," published on Sept. 28, 2011.)

We base our liquidity assessment on the following factors and assumptions:

- We expect PPL Corp.'s liquidity sources over the next 12 months, including FFO and credit facility availability, to exceed uses by 1.2x. Uses include necessary capital spending, working capital, debt maturities, and shareholder distributions.
- Debt maturities are manageable over the next 12 months.
- We believe liquidity sources would exceed uses by 30% even if EBITDA declined 15%.
- In our assessment, PPL Corp. has good relationships with its banks, and has a good standing in the credit markets, having successfully issued debt during the recent credit crisis.

In our analysis of liquidity over the next 12 months, we assume $6.9 billion of liquidity sources, consisting of FFO and credit facility availability. We estimate liquidity uses of $5 billion for capital spending, maturing debt, working capital, and shareholder distributions.

PPL Corp.'s credit agreements include a financial covenant requiring debt to total capitalization no greater than 65% for PPL Energy Supply and 70% for the U.S. utilities. As of June 30, 2011, the company was in compliance with the covenants.

Debt maturities are manageable through 2014, with $500 million in 2011, $0 in 2012, $737 million in 2013, and $300 million in 2014. However, in 2015, $1.3 billion is due. We expect that the company will refinance many of these debt maturities.

Recovery analysis

We assign recovery ratings to first mortgage bonds (FMBs) issued by investment-grade U.S. utilities, which can result in issue ratings being notched above the corporate credit rating (CCR) on a utility depending on the CCR category and the extent of the collateral coverage. We base the investment-grade FMB recovery methodology on the ample historical record of nearly 100% recovery for secured bondholders in utility bankruptcies and on our view that the factors that supported those recoveries (limited size of the creditor class, and the durable value of utility rate-based assets during and after a reorganization, given the essential service provided and the high replacement cost) will persist in the future. Under our notching criteria, when assigning issue ratings to utility FMBs, we consider the limitations of FMB issuance under the utility's indenture relative to the value of the collateral pledged to bondholders, management's stated intentions on future FMB issuance, as well as the regulatory limitations on bond issuance. FMB ratings can exceed the CCR on a utility by up to one notch in the 'A' category, two notches in the 'BBB' category, and three notches in speculative-grade categories.

KU's FMBs benefit from a first-priority lien on substantially all of the utility's real property owned or subsequently acquired. Collateral coverage of about 1.5x supports a recovery rating of '1+' and an issue rating two notches above the CCR.

Outlook

The stable outlook on KU reflects our expectation that PPL Corp.'s management will focus on its fully regulated utilities and will not increase unregulated operations beyond current levels. The outlook also reflects our expectations that cash flow protection and debt leverage measures will be appropriate for the rating. Specifically, our baseline forecast includes FFO to total debt of around 15%, debt to EBITDA between 4x and 5x, and debt leverage to total capital under 60%, consistent with our expectations for the 'BBB' rating. Given the company's mostly regulated focus, we expect that PPL Corp. will avoid any meaningful rise in business risk by reaching constructive regulatory outcomes and limit its unregulated operations to existing levels. We could lower the ratings if PPL Corp. cannot sustain consolidated financial measures of FFO to total debt of at least 12%, debt to EBITDA below 5x, and debt leverage under 62%. This could occur if market power prices remain weak due to ongoing depressed demand. Although unlikely over the intermediate term, we could raise the ratings if the business profile further strengthens and if financial measures exceed our baseline forecast on a consistent basis, including FFO to total debt in excess of 20%, debt to EBITDA below 4x, and debt to total capital around 50%.

Related Criteria And Research

- Liquidity Descriptors For Global Corporate Issuers, Sept. 28, 2011
- Business Risk/Financial Risk Matrix Expanded, May 27, 2009
- Analytical Methodology, April 15, 2008
- Ratios And Adjustments, April 15, 2008
- Changes To Collateral Coverage Requirements For '1+' Recovery Ratings On U.S. Utility First Mortgage Bonds, Sept. 6, 2007

Table 1

PPL Corp. -- Peer Comparison*

Industry Sector: Energy

	PPL Corp.	FirstEnergy Corp.	Public Service Enterprise Group Inc.	Ameren Corp.
Rating as of Oct. 31, 2011	BBB/Stable/--	BBB-/Stable/--	BBB/Positive/A-2	BBB-/Stable/A-3

Table 1

PPL Corp. -- Peer Comparison* (cont.)

	--Average of past three fiscal years--			
(Mil. $)				
Revenues	5,285.6	13,266.0	11,995.5	7,522.3
Net income from cont. oper.	483.9	1,044.0	1,466.6	452.0
Funds from operations (FFO)	1,560.7	2,675.2	2,494.4	1,836.9
Capital expenditures	1,177.4	2,352.5	1,874.5	1,668.3
Cash and short-term investments	721.6	812.7	290.2	419.7
Debt	8,598.5	17,675.4	8,875.7	9,223.1
Preferred stock	333.3	0.0	53.3	88.7
Equity	4,776.7	8,451.0	8,533.8	7,619.0
Debt and equity	13,375.2	26,126.4	17,409.5	16,842.1
Adjusted ratios				
EBIT interest coverage (x)	2.7	2.4	6.2	3.0
FFO int. cov. (X)	4.8	3.2	6.0	4.6
FFO/debt (%)	18.2	15.1	28.1	19.9
Discretionary cash flow/debt (%)	(1.2)	(2.5)	1.0	(2.8)
Net cash flow/capex (%)	86.6	85.2	97.1	85.0
Total debt/debt plus equity (%)	64.3	67.7	51.0	54.8
Return on common equity (%)	12.7	10.9	17.5	5.6
Common dividend payout ratio (un-adj.) (%)	111.4	64.2	46.0	95.0

*Fully adjusted (including postretirement obligations).

Table 2

Kentucky Utilities Co. -- Financial Summary

Industry Sector: Electric		
	--Fiscal year ended Dec. 31--	
	2010	**2009**
Rating history	BBB+/Stable/A-2	BBB+/Stable/A-2
(Mil. $)		
Revenues	1,511.0	1,355.0
EBITDA	511.2	423.2
Operating income	366.2	290.2
Interest Expense	87.0	86.9
Net income from continuing operations	175.0	133.0
Funds from operations (FFO)	391.9	291.7
Capital expenditures	384.2	522.4
Free operating cash flow	(1.3)	(260.7)
Dividends paid	50.0	0.0
Discretionary cash flow	(51.3)	(260.7)
Debt	2,059.8	1,913.0
Preferred stock	0.0	0.0
Equity	2,691.0	1,952.0

Table 2

Kentucky Utilities Co. -- Financial Summary (cont.)		
Debt and equity	4,750.8	3,865.0
Adjusted ratios		
EBITDA margin (%)	33.8	31.2
EBITDA interest coverage (x)	5.9	4.9
EBIT interest coverage (x)	4.2	3.4
FFO int. cov. (x)	5.4	4.1
FFO/debt (%)	19.0	15.3
Free operating cash flow/debt (%)	(0.1)	(13.6)
Discretionary cash flow/debt (%)	(2.5)	(13.6)
Net cash flow/capex (%)	89.0	55.8
Debt/EBITDA (x)	4.0	4.5
Debt/debt and equity (%)	43.4	49.5
Return on capital (%)	7.7	7.2
Return on common equity (%)	7.5	7.2
Common dividend payout ratio (un-adj.) (%)	28.6	0.0

Table 3

Reconciliation Of Kentucky Utilities Co. Reported Amounts With Standard & Poor's Adjusted Amounts (Mil. $)

	--Fiscal year ended Dec. 31, 2010--									
Kentucky Utilities Co. reported amounts										
	Debt	**Shareholders' equity**	**Revenues**	**EBITDA**	**Operating income**	**Interest expense**	**Cash flow from operations**	**Cash flow from operations**	**Dividends paid**	**Capital expenditures**
Reported	1,841.0	2,691.0	1,511.0	495.0	350.0	78.0	372.0	372.0	50.0	379.0
Standard & Poor's adjustments										
Operating leases	25.0	--	--	1.2	1.2	1.2	6.3	6.3	--	5.2
Postretirement benefit obligations	113.8	--	--	15.0	15.0	6.0	4.6	4.6	--	--
Asset retirement obligations	35.1	--	--	--	--	--	--	--	--	--
Reclassification of nonoperating income (expenses)	--	--	--	--	1.0	--	--	--	--	--
Reclassification of working-capital cash flow changes	--	--	--	--	--	--	--	9.0	--	--
Debt - Accrued interest not included in reported debt	8.0	--	--	--	--	--	--	--	--	--
Debt - Other	36.9	--	--	--	--	--	--	--	--	--
Interest expense - Other	--	--	--	--	--	1.8	--	--	--	--

Table 3

Reconciliation Of Kentucky Utilities Co. Reported Amounts With Standard & Poor's Adjusted Amounts (Mil. $) (cont.)										
Total adjustments	218.8	0.0	0.0	16.2	17.2	9.0	10.9	19.9	0.0	5.2
Standard & Poor's adjusted amounts										
	Debt	Equity	Revenues	EBITDA	EBIT	Interest expense	Cash flow from operations	Funds from operations	Dividends paid	Capital expenditures
Adjusted	2,059.8	2,691.0	1,511.0	511.2	367.2	87.0	382.9	391.9	50.0	384.2

Ratings Detail (As Of November 1, 2011)	
Kentucky Utilities Co.	
Corporate Credit Rating	BBB/Stable/A-2
Senior Secured (3 Issues)	A-
Senior Secured (5 Issues)	A-/A-2
Senior Secured (2 Issues)	A-/NR
Corporate Credit Ratings History	
15-Apr-2011	BBB/Stable/A-2
02-Mar-2011	BBB/Watch Neg/A-3
27-Mar-2009	BBB+/Stable/A-2
25-Mar-2009	BBB+/Stable/NR
Business Risk Profile	Excellent
Financial Risk Profile	Aggressive
Related Entities	
LG&E and KU Energy LLC	
Issuer Credit Rating	BBB/Stable/--
Senior Unsecured (3 Issues)	BBB-
Louisville Gas & Electric Co.	
Issuer Credit Rating	BBB/Stable/A-2
Senior Secured (2 Issues)	A-
Senior Secured (11 Issues)	A-/A-2
Senior Secured (1 Issue)	A-/NR
PPL Corp.	
Issuer Credit Rating	BBB/Stable/NR
Junior Subordinated (3 Issues)	BB+
Senior Unsecured (1 Issue)	BBB-
PPL Electric Utilities Corp.	
Issuer Credit Rating	BBB/Stable/A-2
Commercial Paper	
Local Currency	A-2
Preference Stock (1 Issue)	BB+
Senior Secured (9 Issues)	A-
PPL Energy Supply LLC	
Issuer Credit Rating	BBB/Stable/A-2
Senior Unsecured (13 Issues)	BBB

Ratings Detail (As Of November 1, 2011) (cont.)	
PPL Montana LLC	
Senior Secured (1 Issue)	BBB-/Positive
PPL WEM Holdings PLC	
Issuer Credit Rating	BBB/Stable/A-2
Senior Unsecured (1 Issue)	BBB-
PPL WW Holdings Ltd.	
Issuer Credit Rating	BBB/Stable/A-2
Senior Unsecured (2 Issues)	BBB-
Western Power Distribution (East Midlands) PLC	
Issuer Credit Rating	BBB/Stable/A-2
Senior Unsecured (4 Issues)	BBB
Western Power Distribution (South Wales) PLC	
Issuer Credit Rating	BBB/Stable/A-2
Senior Unsecured (3 Issues)	BBB
Western Power Distribution (South West) PLC	
Issuer Credit Rating	BBB/Stable/A-2
Senior Unsecured (4 Issues)	BBB
Western Power Distribution (West Midlands) PLC	
Issuer Credit Rating	BBB/Stable/A-2
Senior Unsecured (3 Issues)	BBB

*Unless otherwise noted, all ratings in this report are global scale ratings. Standard & Poor's credit ratings on the global scale are comparable across countries. Standard & Poor's credit ratings on a national scale are relative to obligors or obligations within that specific country.

Arbough Exhibit 6

Utility Cost of Debt Comparision 12 Months Ending March 2012

Utilty Cost of Debt Comparison
12 Months Ending March 2012

Rank	Company	Per Public Data
1.	Duke Energy Indiana Inc.	3.67%
2.	KU	3.75%
3.	LG&E	3.96%
4.	Duke Energy Ohio	4.07%
5.	AEP Texas Central Company	4.79%
6.	Indiana Michigan Power Company	4.83%
7.	NiSource	5.18%
8.	Appalachian Power Company	5.18%
9.	PECO Energy Company	5.23%
10.	Union Electric Company	5.34%
11.	AEP Texas North Company	5.46%
12.	Pennsylvania Electric Company	5.54%
13.	Detroit Edison	5.67%
14.	Metropolitan Edison Company	5.69%
15.	Public Service Electric and Gas Company	5.74%
16.	Michigan Consolidated Gas Company	5.88%
17.	Commonwealth Edison	5.91%
18.	PPL Electric Utilities	6.14%
19.	Jersey Central Power & Light Co.	6.48%
20.	Kentucky Power Company	6.55%
21.	Ohio Power Company	6.73%
22.	Ameren Energy Generating Company	6.86%
23.	Toledo Edison Company	6.99%
24.	Ohio Edison Company	7.28%
25.	Ameren Illinois Company	7.73%

EXPLANATION OF COST OF DEBT CALCULATION

The cost of debt in the "Utility Ranking" analysis is calculated by dividing (i) the total interest expense stated within the quarterly and annual income statements for a period of 12 months by (ii) the average of (a) the beginning total current and long-term debt and (b) the ending total current and long-term debt of the 12 month period within the quarterly and annual balance sheets. Capitalized interest (if clearly identified within the financial statements) is excluded from interest expense in the calculation. Current Debt typically consists of "Long-Term Debt Due Within One Year", "Notes Payable", and "Notes Payable to Affiliates".

Arbough Exhibit 7

KU Corporate Credit Ratings

KU

Corporate Credit Ratings

	Moody's	S&P	Fitch
Issuer/ Corporate credit rating	Baa1	BBB	A-
Senior secured rating	A2	A-	A+
Short-term rating	P2	A2	F2

Arbough Exhibit 8

Standard and Poor's Report: Assessing US Utilities Regulatory Environments

STANDARD &POOR'S

Global Credit Portal
RatingsDirect®

March 11, 2010

Assessing U.S. Utility Regulatory Environments

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Assessing U.S. Utility Regulatory Environments

(Editor's Note: For our latest comments on regulated utility subsidiaries, please see "Methodology: Differentiating The Issuer Credit Ratings Of A Regulated Utility Subsidiary And Its Parent," published March 11, 2010, on RatingsDirect.)

The assessment of regulatory risk is perhaps the most important factor in Standard & Poor's Ratings Services' analysis of a U.S. regulated, investor-owned utility's business risk. Each of the other four factors we examine--markets, operations, competitiveness, and management--can affect the quality of the regulation a utility experiences, but we believe the fundamental regulatory environment in the jurisdictions in which a utility operates often influences credit quality the most. In our credit analysis, we evaluate regulatory risk on a company-specific basis. A utility management's skill in managing regulatory risk can in many cases overcome a difficult regulatory environment. Conversely, other companies can experience greater regulatory risk even with supportive regulatory regimes if management fails to devote the necessary time and resources to the important task of managing regulatory risk. Operating in a state with a regulatory structure that is conducive to maintaining credit quality will improve the chances for a utility to successfully negotiate the regulatory maze.

This commentary discusses our views on what constitutes a favorable regulatory climate. We then use those factors to create assessments of the regulatory environments in states that regulate the electric and gas utilities that we rate. (See the table at the end of this article.) Our intention is to provide a common base for our own analysis of regulatory risk and to better communicate to investors, issuers, and regulators how various elements of regulation can affect credit quality. The exercise is also expected to enhance our ability to evaluate management by highlighting instances where our opinion of a company's regulatory risk diverges significantly from the fundamental quality of the regulatory jurisdictions where it operates.

The assessments of relevant jurisdictions are based on quantitative and qualitative factors. Importantly, we make our assessments from a credit perspective. We plan to update them annually or when significant events occur that have an important impact on the regulatory climate in a particular jurisdiction. The new regulatory assessment information augments the methodology applied to regulated utilities today.

Our introduction of these regulatory assessments coincides with what we view as the increasing influence of regulatory matters on the rated utilities' risk profiles and greater credit market awareness of the importance of understanding the regulatory process. Our goal in explaining our views on regulatory practices and policies and their effect on Standard & Poor's analysis of the credit quality of utilities is to provide additional transparency to the market.

Background

State utility regulation is almost as old as credit ratings. Standard & Poor's predecessor, Standard Statistics Bureau, was formed in 1906, and the first state utility commissions, as we know them today, appeared in 1907. Regulation has always been a factor in Standard & Poor's analysis of utility ratings, but its importance to our analysis has shifted with industry trends over time.

Before the 1970s, regulators presided for the most part over stable or decreasing rates as economic growth, rising consumption, and economies of scale drove costs down. The advent of inflation, rising and volatile fuel costs, and nuclear power missteps led to higher rates and, in our view, greater regulatory influence on credit quality during the 1980s. Restructuring in the natural gas and then the electric industries marked the 1990s and the first years of the new millennium, and the importance of regulatory issues in our analysis again started to subside. In our view, we are now in another era of increasing and unstable costs and some semblance of a return to traditional utility regulation. Consequently, the quality of regulation is at the forefront of our analysis of utility creditworthiness.

We have historically focused on regulatory risk on a company-specific basis. Nothing in what follows will change that approach. Utility commissions regulate diverse industries and adopt different approaches to different types of businesses. Treatment of utilities within the same industry can vary significantly in the same jurisdiction. The quality of the regulation experienced by a company is often the product of the company's management and business strategy as much as its regulators. The regulatory climate assessments only serve as a baseline of our opinion on the fundamental attitude of a jurisdiction toward the credit quality of the utilities in that state, and they are the starting point for Standard & Poor's analysis of the regulatory risk of each rated utility. Our goal is to achieve greater consistency and continuity in utility ratings.

Assessing Regulatory Jurisdictions

We assess jurisdictions on one basic attribute--the fundamental approach to controlling utility rates--and then in three major categories. The resulting assessments are based primarily on various measures of regulatory risk that are discussed briefly below. With respect to qualitative factors, we look for long-term, historical characteristics of the jurisdiction, as well as transient regulatory and political developments.

The foundation of our opinion of the regulation in a jurisdiction is the degree to which competitive market forces are allowed to influence rates. In order of credit-friendliness, a state will rely either on full cost-based regulation for all components of the utility bill, market-based mechanisms for generation, and (more rarely) retail markets, or a hybrid of the two to control the amount charged and the terms on which that service is offered. It may surprise some to learn that we consider a hybrid setup, which in most cases exists because the transition to some sort of competition has stalled, to harbor more risk for bondholders than a system that is committed to letting market prices set a major part of the customer's bill.

The risk inherent in the market-based model is straightforward: the price for electricity can be more volatile when based on a market than when it is based on embedded costs, and regulators are apt to resist full and timely recovery when changes in generation costs are abrupt and substantial (and perhaps misunderstood). The risks in a hybrid or transitional model are less apparent, but, in our opinion, potentially more significant. First, we consider the uncertainty of the timing of reaching the end state--and what that end state will look like--to be a negative factor from a credit perspective. Second, in some cases, the hybrid model may result in a "lower-of-cost-or-market" approach that allows generation rates to reflect one or the other at different times depending on which one suits ratepayers best. A utility and its bondholders may then face a prolonged period of potential exposure to market risk (the downside) with little or no opportunity to participate in the benefits of competition (the upside of greater returns).

After identifying the fundamental regulatory paradigm, our analysis turns to factors that influence the utility's business risk climate in the jurisdiction. The factors fall into three broad categories: ratemaking, political environment, and financial stability. Broadly speaking, the ratemaking and financial stability factors influence our assessments more than the paradigm and political factors.

Ratemaking Practices And Procedures

The main, and often the most contentious, task of a regulator is to set the rates a utility may charge its customers. We analyze specific rate decisions as part of the surveillance of each utility. Our regulatory assessments focus on the jurisdiction's overall approach to setting rates and the process it uses to conduct and manage base rate filings. Practices pertaining to separate tariff clauses for large expense items are examined in the third category of the analysis (see below). In this part of the assessment, we concentrate on whether established base rates fairly reflect the cost structure of a utility and allow management an opportunity to earn a compensatory return that provides bondholders with a financial cushion that promotes credit quality.

Notably, the analysis does not revolve around "authorized" returns, but rather on actual earned returns. We note the many examples of utilities with healthy authorized returns that, we believe, have no meaningful expectation of actually earning that return because of rate case lag, expense disallowances, etc. Although, in general, the absolute level of financial returns is less important to our analysis than how that return is earned, we recognize that, all else being equal, higher earned returns translate into better credit metrics and a more comfortable equity cushion for bondholders. A regulatory approach that allows utilities the opportunity to consistently earn a reasonable return is a positive factor in our view of credit quality.

The rates of return and capital structures used to generate the revenue requirement in rate proceedings may not be the primary focus of the assessment, but those and other decisions made in the ratemaking process are still noted. We consider those decisions to be potential signals from regulators on their attitude toward credit quality. We believe that the capital structure in particular is a handy and direct indication from the regulator as to whether or not creditworthiness is an important consideration in its deliberations when setting rates. Obviously, any pronouncements from a regulator that explicitly address credit ratings or ratemaking practices that incorporate credit-minded adjustments (e.g., the use of double-leveraged capital structures or off-balance-sheet debt-like obligations) are considered in the Standard & Poor's assessment.

We analyze the issue of "regulatory lag" in a comprehensive manner and not just as a matter of the efficiency of the regulator in completing rate cases. As part of this analysis, we evaluate the timeliness of rate decisions, coupled with an evaluation of the test year. In addition, we take into account the timing of interim rates, and other practices that affect the appropriateness of rates periodically established by the regulator. We do not view the issue of regulatory lag as an intermittent concern, consequential only during times of acute inflation or rising capital spending, but as a consistent part of our credit analysis. Accordingly, in our regulatory assessments we focus on whether the regulator efficiently prosecutes rate requests and bases its decisions with respect to rate setting on the most current information.

In our view, the prevalence of rate case settlements is not necessarily an important credit consideration. Although the common assumption among market participants seems to be that a settlement must be in the best interest of a utility, we believe this assumption disregards the possibility that management will sometimes make decisions based on its effect on earnings at the expense of cash flow considerations. This does not mean we dismiss the ability of stipulations to reach a fair resolution of difficult matters that help regulators issue timely and constructive rate decisions. It just means that frequent settlements do not, in our view, directly lead to a conclusion that the regulatory environment in a state enhances credit quality.

An important policy-related issue outside of individual rate cases that falls under this part of the assessment is the regulatory oversight of large capital projects with long lead times that carry out-sized risks to a utility and its bondholders. In our opinion, practices such as legislative or regulatory recognition of the need for pre-approval of such endeavors, periodic reviews that substantively involve the regulator in the progress of the project, and rolling prudence determinations during construction can reduce the general level of risk associated with a utility committing substantial capital well in advance of the rate proceeding that results in the project being placed into rate base. Before committing to such projects, a resource-procurement process that uses objective guidelines to evaluate competing proposals to meet load obligations and keeps the regulator informed and involved in the decisions can, in our view, help to reduce the risk of subsequent disallowances. If the jurisdiction has an Integrated Resource Plan or similar mechanism that includes the participation of many parties and is used to definitively establish the need for new generation, we consider credit risk to be further diminished.

One more factor that we examine in this part of the analysis is whether a jurisdiction employs nontraditional ratemaking practices. Examples of what we may view to be potentially credit-enhancing regulatory mechanisms include weather normalization and incentive ratemaking. We believe that the beneficial effect on credit quality of a tariff clause that smooths out cash flows that can vary with outside influences like weather is self evident. The benefits of incentives incorporated into the regulatory regime may be less clear. Well-designed incentives can be at least credit neutral. A moderate amount of incentives can be credit supportive. We generally view incentive provisions (whether tied to cost control, reliability, or operational performance) as being beneficial for credit quality if they are linked to fair and objective benchmarks. Incentives that lack some or all of those features, such as a plain, long-term rate freeze, can be, in our opinion, detrimental to credit quality.

Political Insulation

The role of politics in utility regulation is often misunderstood. In most jurisdictions, legislatures created regulatory commissions and invested them with the power to set and enforce utility rates and service standards. Regardless of how a regulatory commission is statutorily organized, its function is to set and regulate rates and service standards with due regard not only for the interests of those who advance the capital needed to provide safe and reliable utility service but for other constituents as well. In this regard, bondholders should recognize that the setting of utility rates invariably reflects political as well as economic factors. Therefore, the potential for political considerations to affect utility regulation can be a key determinant when we assess a regulatory jurisdiction.

A primary factor in this part of our assessment is the method of selecting utility commissioners. In some jurisdictions, the governors appoint regulatory commissioners. In others, the same voters who pay utility bills directly elect commissioners. The regulatory risk associated with that model can sometimes be managed, but there is an inherent level of risk in elected regulatory bodies that we reflect in the assessment. Standard & Poor's also analyzes the track record of the involvement of the executive branch or the legislature in utility matters, and the relative visibility of utility issues in the political arena.

The ability of a regulator to deliver sound, fair, and timely rate decisions and set prudent regulatory policies that assist utility managers in managing business and financial risk can be affected by the overall atmosphere that it operates in. The tone can be set by the governor or legislature, the history and tradition of independence accorded to the regulatory body, and the behavior of important constituent groups that intervene in utility proceedings.

Cash Flow Support And Stability

The final set of factors in our assessment of regulatory environments is arguably the most important. The phrase "cash is king" can be overused, but it does highlight an essential part of the credit analysis. A regulatory jurisdiction that recognizes the significance of cash flow in its decision making is one that will appeal to bondholders. Generating cash is a function of the actions of utility management, but the regulator can supply (or withhold) the tools that can affect the company's essential ability to actually realize the intended level of cash flow.

The most prominent factor in this part of the analysis is the application of separate tariff provisions for major expenses such as fuel and purchased power. The timely adjustment of rates in response to changing commodity prices and other expenses that are largely out of the control of utility management is a key component of a credit-enhancing regulatory jurisdiction. We analyze the quality of special tariff mechanisms to determine their effectiveness in producing the cash flow stability they are designed to achieve. The frequency of rate adjustments, the ability to quickly react to unusual market volatility, and the control of opportunities to engage in hindsight disallowances of costs could affect the analysis almost as much as whether the tariff provisions exist at all. The record of disallowances plays a part in the regulatory assessment.

The commission's policies and oversight covering hedging activities may also be a factor in this part of the review if a utility has sought regulatory approval. For utilities that attempt to manage commodity risks, we look for a clearly-stated hedging policy and a track record of activity that conforms to that policy. The responsibility for communicating the policy and demonstrating the prudence of the hedging activity rests with the utility, but the initial response to a hedging program and the history of the regulator's treatment of the results of the program could influence our assessment.

Regulators can employ other ratemaking techniques that promote stable cash flows. We consider a commission's decisions on rate design in assessing its attitude on credit quality. For example, we take into account the relative size of the typical monthly customer charge, a decoupling mechanism that severs the direct relationship between revenues and customer usage, or other rate design features that bolster credit quality.

Especially during upswings in the capital expenditure cycle, such as we are experiencing now, a jurisdiction's willingness to support large capital projects with cash during the construction phase is an important aspect of our analysis. This is especially true for ventures with big budgets and long lead times, such as baseload coal-fired or nuclear power plants and high-voltage transmission lines that are susceptible to construction delays. Allowance of a cash return on construction work-in-progress or similar ratemaking methods historically were considered extraordinary measures for use in unusual circumstances, but in today's environment of rising construction costs and possible inflationary pressures, cash flow support could be crucial in maintaining credit quality through the spending program.

Jurisdictional Assessments

The table below shows Standard & Poor's assessments of regulatory jurisdictions. The category titles are designed to communicate one other important point regarding utility regulation and its effect on ratings. All categories are denoted as "credit-supportive". To one degree or another, all U.S. utility regulation sustains credit quality when compared with the rest of corporate ratings at Standard & Poor's. The presence of regulators, no matter where in the spectrum of our assessments, reduces business risk and generally supports all U.S. utility ratings.

Regulatory Jurisdictions For Utilities Among U.S. States

Most credit supportive	More credit supportive	Credit supportive	Less credit supportive	Least credit supportive
	Alabama	Arkansas	Louisiana	Arizona
	California	Colorado	Maine	Delaware
	Florida	Connecticut	Missouri	Dist. of Columbia
	Georgia	Hawaii	Montana	Illinois
	Indiana	Idaho	New York	Maryland
	Iowa	Kansas	Oklahoma	New Mexico
	South Carolina	Kentucky	Rhode Island	
	Wisconsin	Massachusetts	Texas	
		Michigan	Utah	
		Minnesota	Vermont	
		Mississippi	Washington	
		Nevada	West Virginia	
		New Hampshire	Wyoming	
		New Jersey		
		North Carolina		
		North Dakota		
		Ohio		
		Oregon		
		Pennsylvania		
		South Dakota		
		Virginia		

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

APPLCATION OF KENTUCKY	**)**	
UTILITIES COMPANY FOR AN	**)**	**CASE NO. 2012-00221**
ADJUSTMENT OF ITS	**)**	
ELECTRIC RATES	**)**	

TESTIMONY OF
WILLIAM E. AVERA

on behalf of

KENTUCKY UTILITIES COMPANY

Filed: June 29, 2012

DIRECT TESTIMONY OF WILLIAM E. AVERA

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I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. William E. Avera, 3907 Red River, Austin, Texas, 78751.

Q. IN WHAT CAPACITY ARE YOU EMPLOYED?

A. I am the President of FINCAP, Inc., a firm providing financial, economic, and policy consulting services to business and government.

A. Qualifications

Q. PLEASE DESCRIBE YOUR QUALIFICATIONS AND EXPERIENCE.

A. I received a B.A. degree with a major in economics from Emory University. After serving in the United States Navy, I entered the doctoral program in economics at the University of North Carolina at Chapel Hill. Upon receiving my Ph.D., I joined the faculty at the University of North Carolina and taught finance in the Graduate School of Business. I subsequently accepted a position at the University of Texas at Austin where I taught courses in financial management and investment analysis. I then went to work for International Paper Company in New York City as Manager of Financial Education, a position in which I had responsibility for all corporate education programs in finance, accounting, and economics.

In 1977, I joined the staff of the Public Utility Commission of Texas ("PUCT") as Director of the Economic Research Division. During my tenure at the PUCT, I managed a division responsible for financial analysis, cost allocation and rate design, economic and financial research, and data processing systems, and I testified in cases on a variety of financial and economic issues. Since leaving the PUCT, I have been engaged as a consultant. I have participated in a wide range of assignments involving utility-related matters on behalf of utilities, industrial customers, municipalities, and regulatory commissions. I have previously testified before the Federal Energy Regulatory Commission ("FERC"), as well as the Federal Communications Commission, the Surface Transportation Board (and its predecessor, the Interstate Commerce Commission), the Canadian Radio-Television and Telecommunications Commission, and regulatory agencies, courts, and legislative committees in over 40 states, including the Public Service Commission of the Commonwealth of Kentucky ("KPSC" or "the Commission").

In 1995, I was appointed by the PUCT to the Synchronous Interconnection Committee to advise the Texas legislature on the costs and benefits of connecting Texas to the national electric transmission grid. In addition, I served as an outside director of Georgia System Operations Corporation, the system operator for electric cooperatives in Georgia.

I have served as Lecturer in the Finance Department at the University of Texas at Austin and taught in the evening graduate program at St. Edward's University for twenty years. In addition, I have lectured on economic and regulatory topics in programs sponsored by universities and industry groups. I have taught in hundreds of educational programs for financial analysts in programs sponsored by the Association for Investment Management and Research, the Financial Analysts Review, and local financial analysts societies. These programs have been presented in Asia, Europe, and North America, including the Financial Analysts Seminar at Northwestern University. I hold the Chartered Financial Analyst (CFA®) designation and have served as Vice President for Membership of the Financial Management Association. I have also served on the Board of Directors of the North Carolina Society of Financial Analysts. I was elected Vice Chairman of the National Association of Regulatory Commissioners ("NARUC") Subcommittee on Economics and appointed to NARUC's Technical Subcommittee on the National Energy Act. I have also served as an officer of various other professional organizations and societies. A resume containing the details of my experience and qualifications is attached as Exhibit WEA-1.

B. Overview

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is to present to the KPSC my independent assessment of the fair rate of return on equity ("ROE") that Kentucky Utilities Company ("KU" or "the Company") should be authorized to earn on its investment in providing electric utility service. In addition, I also examined the reasonableness of KU's capital structure, considering both the specific risks faced by the Company, as well as other industry guidelines.

Q. PLEASE SUMMARIZE THE BASIS OF YOUR KNOWLEDGE AND CONCLUSIONS CONCERNING THE ISSUES TO WHICH YOU ARE TESTIFYING IN THIS CASE.

A. To prepare my testimony, I used information from a variety of sources that would normally be relied upon by a person in my capacity. In connection with the present filing, I considered and relied upon corporate disclosures, publicly available financial reports and filings, and other published information relating to KU. I also reviewed information relating generally to capital market conditions and specifically to investor perceptions, requirements, and expectations for utilities. These sources, coupled with my experience in the fields of finance and utility regulation, have given me a working knowledge of the issues relevant to investors' required return for KU, and they form the basis of my analyses and conclusions.

Q. WHAT IS THE PRACTICAL TEST OF THE REASONABLENESS OF THE ROE USED IN SETTING A UTILITY'S RATES?

A. The ROE compensates common equity investors for the use of their capital to finance the plant and equipment necessary to provide utility service. Investors commit capital only if they expect to earn a return on their investment commensurate with returns available from alternative investments with comparable risks. To be consistent with sound regulatory economics and the standards set forth by the Supreme Court in the *Bluefield*[1] and *Hope*[2] cases, a utility's allowed ROE should be sufficient to: (1) fairly compensate investors for capital invested in the utility, (2) enable the utility to offer a return adequate to attract new capital on reasonable terms, and (3) maintain the utility's financial integrity.

Q. HOW IS YOUR TESTIMONY ORGANIZED?

A. I first reviewed the operations and finances of KU and the current conditions in the utility industry and the capital markets. With this as a background, I conducted various well-accepted quantitative analyses to estimate the current cost of equity, including alternative applications of the discounted cash flow ("DCF") model and the Capital Asset Pricing Model ("CAPM"), an equity risk premium method ("RPM") based on allowed rates of return, as well as reference to expected earned rates of return for utilities. Based on the cost of equity estimates indicated by my analyses, KU's ROE was evaluated taking into account the specific risks and potential challenges for its jurisdictional utility operations in Kentucky, as well as other factors (*e.g.*, flotation costs) that are properly considered in setting a fair ROE for the Company.

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[1] *Bluefield Water Works & Improvement Co. v. Pub. Serv. Comm'n*, 262 U.S. 679 (1923).
[2] Fed. Power Comm'n v. Hope Natural Gas Co., 320 U.S. 591 (1944).

C. Summary of Conclusions

Q. WHAT ARE YOUR FINDINGS REGARDING THE FAIR ROE FOR KU?

A. Based on the results of my analyses and the economic requirements necessary to support continuous access to capital, I recommend an ROE for KU from the middle of my 10.3% to 11.7% reasonable range, or 11.0%. The bases for my conclusion are summarized below:

- In order to reflect the risks and prospects associated with KU's jurisdictional utility operations, my analyses focused on a proxy group of combination utilities with both gas and electric utility operations. Consistent with the fact that utilities must compete for capital with firms outside their own industry, I also referenced a proxy group of low-risk companies in the non-utility sector of the economy;
- Because investors' required return on equity is unobservable and no single method should be viewed in isolation, I applied the DCF, CAPM, and RPM, as well as the expected earnings approach, to estimate a fair ROE for KU;
- Based on the results of these analyses, and giving less weight to extremes at the high and low ends of the range, I concluded that the cost of equity for the proxy groups of utilities and non-utility companies is in the 10.1% to 11.5% range, or 10.3% to 11.7% after incorporating an adjustment to account for the impact of common equity flotation costs;
- I recommend an ROE for KU at the midpoint of my 10.3% to 11.7% range, or 11.0%; and
- Investors view existing cost recovery mechanisms as supportive of KU's financial integrity, but there is no evidence that these provisions will result in a measurable change in the Company's investment risk or ROE relative to the proxy companies;
- The reasonableness of a 11.0% ROE for KU is also supported by the need to consider the expected upward trend in capital costs and support access to capital.

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

A. My recommendation is reinforced by the following findings:

- Sensitivity to financial market and regulatory uncertainties has increased dramatically and investors recognize that constructive regulation, as demonstrated by regulatory treatment including authorized ROEs, is a key ingredient in supporting utility credit standing and financial integrity; and,

- Providing KU with the opportunity to earn a return that reflects these realities is an essential ingredient to support the Company's financial position, which ultimately benefits customers by ensuring reliable service at lower long-run costs.

Q. WHAT IS YOUR CONCLUSION AS TO THE REASONABLENESS OF THE COMPANY'S CAPITAL STRUCTURE?

A. Based on my evaluation, I concluded that a common equity ratio of 53.7% represents a reasonable basis from which to calculate KU's overall rate of return. This conclusion was based on the following findings:

- KU's common equity ratio is consistent with the range of capitalizations maintained by the firms in the proxy group of utilities and electric utility operating companies based on data at year-end 2011 and near-term expectations;
- The additional leverage implied by KU's leases and pension obligations warrant a more conservative financial posture; and,
- The requested capitalization reflects the need to support the credit standing and financial flexibility of KU as the Company seeks to fund system investments and meet the requirements of customers.

II. FUNDAMENTAL ANALYSES

Q. WHAT IS THE PURPOSE OF THIS SECTION?

A. As a predicate to subsequent quantitative analyses, this section briefly reviews the operations and finances of KU. In addition, it examines the risks and prospects for the utility industry and conditions in the capital markets and the general economy. An understanding of the fundamental factors driving the risks and prospects of electric utilities is essential in developing an informed opinion of investors' expectations and requirements that are the basis of a fair rate of return.

A. Kentucky Utilities Company

Q. BRIEFLY DESCRIBE KU.

A. Along with Louisville Gas and Electric Company ("LGE"), KU is a wholly owned subsidiary of PPL Corporation ("PPL"), which completed its acquisition of the Company from E.ON AG on November 1, 2010. Headquartered in Lexington, Kentucky, KU is principally engaged in providing regulated electric utility service. In addition to serving approximately 509,000 retail customers in central, southeastern, and western Kentucky, KU also provides service to approximately 29,000 customers in Virginia.[3]

Although KU and LGE are separate operating subsidiaries, they are operated as a single, fully integrated system. The Company's utility facilities include over 4,800 megawatts ("MW") of generating capacity. Coal-fired generating stations account for approximately 69% of KU's total generating capacity and produced approximately 98% of the electricity generated by the Company in 2011. In addition to company-owned generation, the Company purchases power under long-term contracts with various suppliers and meets a portion of its energy needs by purchases of additional supplies in the wholesale electricity markets. KU's transmission and distribution system includes approximately 20,400 miles of lines. At December 31, 2011, the Company had total assets of $6.2 billion, with annual revenues totaling approximately $1.5 billion. KU's retail electric operations are subject to the jurisdiction of the KPSC, with FERC regulating the Company's interstate transmission and wholesale operations.

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[3] KU also serves a limited number of customers in Tennessee.

Q. HOW ARE FLUCTUATIONS IN THE COMPANY'S OPERATING EXPENSES CAUSED BY VARYING ENERGY MARKET CONDITIONS ACCOMMODATED IN ITS RATES?

A. KU's retail electric rates in Kentucky contain a fuel adjustment clause ("FAC"), whereby increases and decreases in the cost of fuel for electric generation are reflected in the rates charged to retail electric customers. The KPSC requires public hearings at six-month intervals to examine past fuel adjustments, and at two-year intervals to review past operations of the fuel clause and transfer of the then current fuel adjustment charge or credit to the base charges. The Commission also requires that electric utilities, including KU, file documents relating to fuel procurement and the purchase of power and energy from other utilities.

Q. ARE THERE OTHER MECHANISMS THAT AFFECT KU'S RATES FOR UTILITY SERVICE?

A. Yes. The KPSC has approved an environmental cost recovery mechanism ("ECR") for the Company that allows for recovery of related costs required to comply with federal and state environmental statutes. KU also operates under a Demand Side Management ("DSM") rate mechanism that provides for recovery of DSM costs – including a provision to earn a return of and on capital investment for DSM programs.

Q. WHERE DOES KU OBTAIN THE CAPITAL USED TO FINANCE ITS INVESTMENT IN ELECTRIC UTILITY PLANT?

A. As a wholly-owned subsidiary, KU's common equity capital is provided through LG&E and KU Energy LLC ("LKE"). Ultimately, LKE obtains investor-supplied common equity capital solely from PPL, whose common stock is publicly traded on the New York Stock Exchange. In addition to capital supplied by PPL, KU also issues first mortgage bonds and tax-exempt debt securities in its own name.

Q. WHAT CREDIT RATINGS ARE ASSIGNED TO KU?

A. Currently, KU is assigned a corporate credit rating of "BBB" by Standard & Poor's Corporation ("S&P"). Moody's Investors Service ("Moody's") has assigned the Company an issuer rating of "Baa1", while Fitch Ratings Ltd. ("Fitch") has assigned KU an "A-" issuer default rating.

B. Risks for KU

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

A. Numerous challenges impact investors' perceptions of the relative risks inherent in the utility industry and have implications for the financial standing of the utilities themselves, including KU. Uncertain costs associated with environmental compliance, reduced demand in the wake of economic slowdown, the implications of increased conservation and renewables goals, as well as exposure to regulatory uncertainties all impact the industry's future. As Moody's noted:

> [A] sustained period of sluggish economic growth, characterized by high unemployment, could stress the sector's recovery prospects, financial performance, and credit ratings. The quality of the sector's cash flows are already showing signs of decline, partly because of higher operating costs and investments.[4]

Moody's concluded, "Regardless of whether the capital investment is required for maintenance, compliance or growth, from a credit perspective the expanded capital investment program will contribute to a more challenging business environment for utilities."[5]

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[4] Moody's Investors Service, "U.S. Electric Utilities: Uncertain Times Ahead; Strengthening Balance Sheets Now Would Protect Credit," *Special Comment* (Oct. 28, 2010).

[5] Moody's Investors Service, Moody's Investors Service, "US Regulated Electric and Gas Utilities: Stable Despite Rising Headline Rhetoric," *Industry Outlook* (Jan. 17, 2012).

Q. DOES KU ANTICIPATE THE NEED FOR ADDITIONAL CAPITAL GOING FORWARD?

A. Yes. KU will require capital investment to provide for necessary maintenance and replacements of its utility infrastructure, as well as to fund new investment in electric generation, transmission and distribution facilities. Total capital expenditures for the Company are expected to be approximately $3.1 billion over the 2012-2016 period, with Moody's noting the challenges associated with the Company's "[e]levated capital expenditure spending program," and "[l]ack of fuel diversity relating to its electric generating portfolio."[6] Support for KU's financial integrity and flexibility will be instrumental in attracting the capital necessary to fund its share of these projects in an effective manner.

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

A. Yes. In recent years utilities and their customers have had to contend with dramatic fluctuations in fuel costs due to ongoing price volatility, and investors recognize the potential for further turmoil in energy markets. In times of extreme volatility, utilities can quickly find themselves in a significant under-recovery position with respect to power costs, which can severely stress liquidity. Coal has historically provided relative stability with respect to fuel costs, but prices have experienced periods of significant volatility. The power industry and its customers have also had to contend with dramatic fluctuations in gas costs due to ongoing price volatility in the spot markets.

While current expectations for significantly lower wholesale power prices reflect weaker fundamentals affecting current load and fuel prices, investors

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[6] Moody's Investors Service, "Credit Opinion: Kentucky Utilities Co.," *Global Credit Research* (Nov, 16, 2011).

recognize the potential that such trends could quickly reverse. For example, recurring political crises in the Middle East have led to sharp increases in petroleum prices. As Moody's noted, "This view, that commodity prices remain low, could easily be proved incorrect, due to the evidence of historical volatility."[7] Moody's recently concluded that, "Should fuel and commodity costs rise, utilities will face growing underfunded fuel balances or potential rate shock issues when they seek to recover the higher costs. Liquidity profiles could become strained."[8] Fitch recently observed that market conditions will likely result in higher natural gas prices, and noted the utility industry's potential exposure to future price shocks.[9]

Q. DO THE KPSC'S ADJUSTMENT MECHANISMS PROTECT KU FROM EXPOSURE TO FLUCTUATIONS IN POWER SUPPLY COSTS?

A. To a limited extent, yes. The investment community views KU's ability to periodically adjust retail rates to accommodate fluctuations in fuel and purchased power costs as an important source of support for KU's financial integrity. Nevertheless, they also recognize that there can be a lag between the time KU actually incurs the expenditure and when it is recovered from ratepayers. As a result, KU is not insulated from the need to finance deferred power production and energy supply costs. Indeed, despite the significant investment of resources to manage energy procurement, investors are aware that the best that KU can do is to recover its actual costs. In other words, KU earns no return on fuel or purchased power costs and is exposed to disallowances in its energy procurement.

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[7] Moody's Investors Service, "U.S. Electric Utilities: Uncertain Times Ahead; Strengthening Balance Sheets Now Would Protect Credit," *Special Comment* (Oct. 28, 2010).

[8] Moody's Investors Service, "US Regulated Electric and Gas Utilities: Stable Despite Rising Headline Rhetoric," *Industry Outlook* (Jan. 17, 2012).

[9] Fitch Ratings Ltd., 2012 Outlook: Utilities, Power, and Gas," *Outlook Report* (Dec. 5, 2011).

Q. WHAT OTHER FINANCIAL PRESSURES IMPACT INVESTORS' RISK ASSESSMENT OF KU?

A. Investors are aware of the financial and regulatory pressures faced by utilities associated with rising costs and the need to undertake significant capital investments. S&P noted that cost increases and capital projects, along with uncertain load growth, were a significant challenge to the utility industry.[10] As Moody's observed:

> [W]e also see the sector's overall business risk and operating risks increasing, owing primarily to rising costs associated with upgrading and expanding the nation's trillion dollar electric infrastructure.[11]

As noted earlier, investors anticipate that KU will undertake significant electric utility capital expenditures. While providing the infrastructure necessary to meet the energy needs of customers is certainly desirable, it imposes additional financial responsibilities on the Company that are intensified during times of capital market turmoil.

Q. ARE ENVIRONMENTAL CONSIDERATIONS ALSO AFFECTING INVESTORS' EVALUATION OF ELECTRIC UTILITIES, INCLUDING KU?

A. Yes. Although KU's exposure is moderated through the ECR mechanism in Kentucky, increased environmental pressures and speculation over the potential costs associated with new regulatory mandates have also created uncertainties. Moody's noted that, "the sector is exposed to increasingly stringent environmental mandates."[12] While the momentum for carbon emissions legislation has slowed at the national level, expectations for eventual regulations continue to pose uncertainty.

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[10] Standard & Poor's Corporation, "Industry Economic And Ratings Outlook," *RatingsDirect* (Feb. 2, 2010).

[11] Moody's Investors Service, "Regulation Provides Stability As Risks Mount," *Industry Outlook* (Jan. 19, 2011).

[12] Moody's Investors Service, "Regulation Provides Stability As Risks Mount," *Industry Outlook* (Jan. 19, 2011).

Fitch recently noted that it, "expects the thrust of the EPA's agenda will continue to challenge the creditworthiness of issuers in the utility and power sector."[13] Given the significance of KU's exposure, Moody's went on to conclude that it would consider a downgrade to the Company's credit ratings if significant changes were made to the ECR mechanism.[14]

D. Impact of Capital Market Conditions

Q. WHAT ARE THE IMPLICATIONS OF RECENT CAPITAL MARKET CONDITIONS?

A. As The Value Line Investment Survey ("Value Line") recently recognized, "It has been a turbulent year for the financial markets, to say the least."[15] Investors have faced a myriad of challenges and uncertainties, including the threat of a United States government default, political brinkmanship over raising the federal debt ceiling, and S&P's subsequent downgrade of its United States sovereign debt rating.[16] The sovereign debt crisis in Europe has also dealt a harsh blow to investor confidence, and concerns over potential exposure to a Euro-zone default continues to undermine confidence in the financial and banking sector.[17] Meanwhile, speculation that the economy remains exposed to a potential "double-dip" recession persists, with unemployment remaining stubbornly high, lackluster consumer confidence, rising petroleum prices, and continued weakness plaguing the real estate sector.

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[13] Fitch Ratings Ltd., New EPA Rules: Ready or Not," *Special Report* (Mar. 1, 2012).

[14] Moody's Investors Service, "Credit Opinion: Kentucky Utilities Co.," *Global Credit Research* (Nov. 16, 2011).

[15] The Value Line Investment Survey at 541 (Dec. 9, 2011).

[16] See, e.g., Standard & Poor's Corporation, "Economic Forecast: Still Treading Water," RatingsDirect (Aug. 17, 2011).

[17] *See, e.g.*, Standard & Poor's Corporation, "U.S. Risks To The Forecast: Choppy Seas," *RatingsDirect* (Dec. 21, 2011).

Investors have had to confront ongoing volatility in share prices and stress in the credit markets,[18] and in response have repeatedly fled to the safety of United States Treasury bonds. As Fidelity Investments recently reported to investors:

> It's been quite a year, one of violent mood swings but little overall direction. We seem to be in a time warp where everything happens faster and faster. Everything seems to be correlated. There are very few places to hide, and even those places don't feel like good options anymore.[19]

Fidelity Investments concluded that, "2012 will offer more of the same, with significant ups and downs driven by three major factors: Europe, China, and the U.S."[20]

Fluctuations in the price of gold and other commodities also attest to investors' heightened concerns over prospective challenges and risks, including the overhanging threat of inflation and renewed economic turmoil. Fidelity Investments noted that, "The sovereign debt crisis in the Euro-zone remains at the epicenter of the financial markets.[21] With respect to utilities, Moody's noted the dangers to credit availability associated with exposure to European banks,[22] and concluded:

> Over the past few months, we have been reminded that global financial markets, which are still receiving extraordinary intervention benefits by sovereign governments, are exposed to turmoil. Access to the capital markets could therefore become intermittent, even for safer, more defensive sectors like the power industry.[23]

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[18] *See, e.g.,* Gongloff, Mark, "Stock Rebound Is a Crisis Flashback – Late Surge Recalls Market's Volatility at Peak of Credit Difficulties; Unusual Correlations," *Wall Street Journal* at B1 (Feb. 6, 2010); Lauricella, Tom, "Stocks Nose-Dive Amid Global Fears – Weak Outlook, Government Debt Worries Drive Dow's Biggest Point Drop Since '08," *Wall Street Journal* at A1 (Aug. 5, 2011).

[19] Fidelity Investments, "2012 markets: Expect ups and downs," *Fidelity Viewpoints* (Dec. 21, 2011).

[20] *Id.*

[21] *Id.*

[22] Moody's Investors Service, "Electric Utilities Stable But Face Increasing Regulatory Uncertainty," *Industry Outlook* (Jul. 22, 2010).

[23] Moody's Investors Service, "Regulation Provides Stability As Risks Mount," *Industry Outlook* (Jan. 19, 2011).

Uncertainties surrounding economic and capital market conditions heighten the risks faced by utilities, which, as described earlier, face a variety of operating and financial challenges.

Q. HOW DO INTEREST RATES ON LONG-TERM BONDS COMPARE WITH THOSE PROJECTED FOR THE NEXT FEW YEARS?

A. Table WEA-1 below compares current interest rates on 30-year Treasury bonds, triple-A rated corporate bonds, and double-A rated utility bonds with near-term projections from Value Line, IHS Global Insight, Blue Chip Financial Forecasts ("Blue Chip'), S&P, and the Energy Information Administration ("EIA"), which is a statistical agency of the United States Department of Energy:

TABLE WEA-1
INTEREST RATE TRENDS

	Current (a)	2012	2013	2014	2015	2016
30-Yr. Treasury						
Value Line (b)	3.1%	3.3%	3.7%	4.0%	4.5%	5.0%
IHS Global Insight (c)	3.1%	3.3%	3.8%	4.5%	5.1%	5.3%
Blue Chip (d)	3.1%	3.7%	4.2%	4.8%	5.3%	5.5%
AAA Corporate						
Value Line (b)	3.9%	4.2%	4.6%	5.0%	5.3%	5.8%
IHS Global Insight (c)	3.9%	4.2%	4.5%	5.1%	6.0%	6.2%
Blue Chip (d)	3.9%	4.3%	4.7%	5.4%	5.8%	6.2%
S&P (e)	3.9%	4.2%	4.6%	5.1%	6.0%	
AA Utility						
IHS Global Insight (c)	4.0%	4.4%	4.9%	5.6%	6.5%	6.8%
EIA (f)	4.0%	4.7%	4.8%	5.7%	6.8%	6.9%

(a) Based on monthly average bond yields for the six-month period Nov. 2011 - Apr. 2012 reported at www.credittrends.moodys.com and http://www.federalreserve.gov/releases /h15/data.htm.
(b) The Value Line Investment Survey, Forecast for the U.S. Economy (Feb. 24, 2011).
(c) IHS Global Insight, *U.S. Economic Outlook* at 25 (Dec. 2011).
(d) *Blue Chip Financial Forecasts,* Vol. 30, No. 12 (Dec. 1, 2011).
(e) Standard & Poor's Corporation, "U.S. Economic Forecast: Just Like Ol' Times," *RatingsDirect* (Jan. 12, 2012).
(f) Energy Information Administration, *Annual Energy Outlook 2012, Early Release* (Jan. 23, 2012).

As evidenced above, there is a clear consensus that the cost of permanent capital will be higher through 2016 than it is currently. As a result, current cost of capital estimates are conservative, because they are likely to understate investors' requirements at the time the rates set in this proceeding are in effect.

Q. WHAT DO THESE EVENTS IMPLY WITH RESPECT TO KU?

A. While conditions in the economy and capital markets appear to have stabilized – at least for the moment – no one knows the future of our complex global economy. Investors continue to react swiftly and negatively to any future signs of trouble in the financial system or economy, and this climate has important implications with respect to the fair ROE for KU. Given the importance of reliable utility service, it would be unwise to ignore investors' increased sensitivity to risk and future capital market trends in evaluating a fair ROE in this case.

The prospect for continued turmoil in capital markets also influences the appropriate capital structure for KU. Financial flexibility plays a crucial role in ensuring the wherewithal to meet funding needs, and utilities with higher financial leverage may be foreclosed from additional borrowing, especially during times of stress. During the credit crisis, for example, utilities were forced to draw on short-term credit lines to meet debt retirement obligations because of uncertainties regarding the availability of long-term capital,[24] while others were effectively shut out of the commercial paper market altogether. Fitch recently highlighted this exposure:

> **Capital Markets Freeze:** Significant tightening or loss of capital markets and bank access would have a deleterious affect (sic) on sector creditworthiness in the face of high capex budgets.[25]

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[24] Riddell, Kelly, "Cash-Starved Companies Scrap Dividends, Tap Credit," Pittsburgh Post-Gazette (Oct. 2, 2008).

[25] Fitch Ratings Ltd., "2012 Outlook: Utilities, Power, and Gas," *Outlook Report* (Dec. 5, 2011).

As a result, the Company's capital structure must maintain an equity "cushion" that preserves the flexibility necessary to maintain continuous access to capital, even during times of unfavorable market conditions.

III. CAPITAL MARKET ESTIMATES

Q. WHAT IS THE PURPOSE OF THIS SECTION?

A. This section presents capital market estimates of the cost of equity. First, I address the concept of the cost of common equity, along with the risk-return tradeoff principle fundamental to capital markets. Next, I describe DCF, CAPM, and RPM analyses conducted to estimate the cost of common equity for benchmark groups of comparable risk firms and evaluate expected earned rates of return for utilities. Finally, I examine flotation costs, which are properly considered in evaluating a fair ROE.

A. Economic Standards

Q. WHAT ROLE DOES THE ROE PLAY IN A UTILITY'S RATES?

A. The ROE is the cost of inducing and retaining investment in the utility's physical plant and assets. This investment is necessary to finance the asset base needed to provide utility service. Investors will commit money to a particular investment only if they expect it to produce a return commensurate with those from other investments with comparable risks. Moreover, the ROE is integral in achieving the sound regulatory objectives of rates that are sufficient to: 1) fairly compensate capital investment in the utility, 2) enable the utility to offer a return adequate to attract new capital on reasonable terms, and 3) maintain the utility's financial integrity. Meeting these objectives allows the utility to fulfill its obligation to provide reliable service while meeting the needs of customers through necessary system expansion.

Q. WHAT FUNDAMENTAL ECONOMIC PRINCIPLE UNDERLIES THE COST OF EQUITY CONCEPT?

A. The fundamental economic principle underlying the cost of equity concept is the notion that investors are risk averse. In capital markets where relatively risk-free assets are available (*e.g.*, U.S. Treasury securities), investors can be induced to hold riskier assets only if they are offered a premium, or additional return, above the rate of return on a risk-free asset. Because all assets compete with each other for investor funds, riskier assets must yield a higher expected rate of return than safer assets to induce investors to invest and hold them.

Given this risk-return tradeoff, the required rate of return (k) from an asset (i) can generally be expressed as:

$$k_i = R_f + RP_i$$

where: R_f = Risk-free rate of return, and
RP_i = Risk premium required to hold riskier asset i.

Thus, the required rate of return for a particular asset at any time is a function of: (1) the yield on risk-free assets, and (2) the asset's relative risk, with investors demanding correspondingly larger risk premiums for bearing greater risk.

Q. IS THERE EVIDENCE THAT THE RISK-RETURN TRADEOFF PRINCIPLE ACTUALLY OPERATES IN THE CAPITAL MARKETS?

A. Yes. The risk-return tradeoff can be readily documented in segments of the capital markets where required rates of return can be directly inferred from market data and where generally accepted measures of risk exist. Bond yields, for example, reflect investors' expected rates of return, and bond ratings measure the risk of individual bond issues. The observed yields on government securities, which are considered free of default risk, and bonds of various rating categories demonstrate that the risk-return tradeoff does, in fact, exist in the capital markets.

Q. DOES THE RISK-RETURN TRADEOFF OBSERVED WITH FIXED INCOME SECURITIES EXTEND TO COMMON STOCKS AND OTHER ASSETS?

A. It is generally accepted that the risk-return tradeoff evidenced with long-term debt extends to all assets. Documenting the risk-return tradeoff for assets other than fixed income securities, however, is complicated by two factors. First, there is no standard measure of risk applicable to all assets. Second, for most assets – including common stock – required rates of return cannot be directly observed. Yet there is every reason to believe that investors exhibit risk aversion in deciding whether or not to hold common stocks and other assets, just as when choosing among fixed-income securities.

Q. IS THIS RISK-RETURN TRADEOFF LIMITED TO DIFFERENCES BETWEEN FIRMS?

A. No. The risk-return tradeoff principle applies not only to investments in different firms, but also to different securities issued by the same firm. The securities issued by a utility vary considerably in risk because they have different characteristics and priorities. Long-term debt is senior among all capital in its claim on a utility's net revenues and is, therefore, the least risky. The last investors in line are common shareholders. They receive only the net revenues, if any, remaining after all other claimants have been paid. As a result, the rate of return that investors require from a utility's common stock, the most junior and riskiest of its securities, must be considerably higher than the yield offered by the utility's senior, long-term debt.

Q. WHAT DOES THE ABOVE DISCUSSION IMPLY WITH RESPECT TO ESTIMATING THE COST OF COMMON EQUITY FOR A UTILITY?

A. Although the cost of common equity cannot be observed directly, it is a function of the returns available from other investment alternatives and the risks to which the equity capital is exposed. Because it is not readily observable, the cost of common equity for a particular utility must be estimated by analyzing information about capital market conditions generally, assessing the relative risks of the company specifically, and employing various quantitative methods that focus on investors' required rates of return. These various quantitative methods typically attempt to infer investors' required rates of return from stock prices, interest rates, or other capital market data.

B. Comparable Risk Proxy Groups

Q. HOW DID YOU IMPLEMENT THESE QUANTITATIVE METHODS TO ESTIMATE THE COST OF COMMON EQUITY FOR KU?

A. Application of the DCF model and other quantitative methods to estimate the cost of common equity requires observable capital market data, such as stock prices. Moreover, even for a firm with publicly traded stock, the cost of common equity can only be estimated. As a result, applying quantitative models using observable market data only produces an estimate that inherently includes some degree of observation error. Thus, the accepted approach to increase confidence in the results is to apply the DCF model and other quantitative methods to a proxy group of publicly traded companies that investors regard as risk-comparable.

Q. WHAT SPECIFIC PROXY GROUP OF UTILITIES DID YOU RELY ON FOR YOUR ANALYSIS?

A. In order to reflect the risks and prospects associated with KU's jurisdictional utility operations, my DCF analyses focused on a reference group of other utilities composed of those companies classified by Value Line as electric utilities with: (1) both electric and gas utility operations, (2) S&P corporate credit ratings of "BBB-", "BBB", or "BBB+", (3) a Value Line Safety Rank of "2" or "3", and (4) a Value Line Financial Strength Rating of "B+" or higher. In addition, I excluded one firm because it was rated below investment grade by Moody's (CMS Energy Corporation), as well as one utility (Entergy Corporation) that otherwise would have been in the proxy group, but is not appropriate for inclusion because of current involvement in a major merger or acquisition. These criteria resulted in a proxy group composed of sixteen companies, which I will refer to as the "Combination Utility Group."

Q. WHAT OTHER PROXY GROUP DID YOU CONSIDER IN EVALUATING A FAIR ROE FOR KU?

A. Under the regulatory standards established by *Hope* and *Bluefield*, the salient criterion in establishing a meaningful benchmark to evaluate a fair ROE is relative risk, not the particular business activity or degree of regulation. With regulation taking the place of competitive market forces, required returns for utilities should be in line with those of non-utility firms of comparable risk operating under the constraints of free competition. Consistent with this accepted regulatory standard, I also applied the DCF model to a reference group of comparable risk companies in the non-utility sectors of the economy. I refer to this group as the "Non-Utility Group".

Q. DO UTILITIES HAVE TO COMPETE WITH NON-REGULATED FIRMS FOR CAPITAL?

A. Yes. The cost of capital is an opportunity cost based on the returns that investors could realize by putting their money in other alternatives. Clearly, the total capital invested in utility stocks is only the tip of the iceberg of total common stock investment, and there are a plethora of other enterprises available to investors beyond those in the utility industry. Utilities must compete for capital, not just against firms in their own industry, but with other investment opportunities of comparable risk. As the KPSC concluded, "the Commission agrees with KU that investors are always looking for the best investment opportunity and that a utility is in competition with unregulated firms."[26] Indeed, modern portfolio theory is built on the assumption that rational investors will hold a diverse portfolio of stocks, not just companies in a single industry.

Q. IS IT CONSISTENT WITH THE *BLUEFIELD* AND *HOPE* CASES TO CONSIDER REQUIRED RETURNS FOR NON-UTILITY COMPANIES?

A. Yes. The cost of equity capital in the competitive sector of the economy forms the very underpinning for utility ROEs because regulation purports to serve as a substitute for the actions of competitive markets. The Supreme Court has recognized that it is the degree of risk, not the nature of the business, which is relevant in evaluating an allowed ROE for a utility. The *Bluefield* case refers to "business undertakings attended with comparable risks and uncertainties."[27] It does not restrict consideration to other utilities. Similarly, the *Hope* case states:

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[26] *Case No. 2009-00548*, Final Order at 31.
[27] *Bluefield Water Works & Improvement Co. v. Pub. Serv. Comm'n*, 262 U.S. 679 (1923).

> By that standard the return to the equity owner should be commensurate with returns on investments in other enterprises having corresponding risks.[28]

As in the *Bluefield* decision, there is nothing to restrict "other enterprises" solely to the utility industry.

Indeed, in teaching regulatory policy I usually observe that in the early applications of the comparable earnings approach, utilities were explicitly eliminated due to a concern about circularity. In other words, soon after the *Hope* decision regulatory commissions did not want to get involved in circular logic by looking to the returns of utilities that were established by the same or similar regulatory commissions in the same geographic region. To avoid circularity, regulators looked only to the returns of non-utility companies.

Q. DOES CONSIDERATION OF THE RESULTS FOR THE NON-UTILITY GROUP MAKE THE ESTIMATION OF THE COST OF EQUITY USING THE DCF MODEL MORE RELIABLE?

A. Yes. The estimates of growth from the DCF model depend on analysts' forecasts. It is possible for utility growth rates to be distorted by short-term trends in the industry or the industry falling into favor or disfavor by analysts. The result of such distortions would be to bias the DCF estimates for utilities. For example, Value Line observed that near-term growth rates understate the longer-term expectations for gas utilities:

> Natural Gas Utility stocks have fallen near the bottom of our Industry spectrum for Timeliness. Accordingly, short-term investors would probably do best to find a group with better prospects over the coming six to 12 months. Longer-term, we expect these businesses to rebound. An

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[28] *Federal Power Comm'n v. Hope Natural Gas Co.* (320 U.S. 391, 1944).

> improved economic environment, coupled with stronger pricing, should boost results across this sector over the coming years.[29]

Because the Non-Utility Group includes low risk companies from many industries, it diversifies away any distortion that may be caused by the ebb and flow of enthusiasm for a particular sector.

Q. WHAT CRITERIA DID YOU APPLY TO DEVELOP THE NON-UTILITY GROUP?

A. My comparable risk proxy group of non-utility firms was composed of those U.S. companies followed by Value Line that: (1) pay common dividends; (2) have a Safety Rank of “1”; (3) have a Financial Strength Rating of “B++” or greater; (4) have a beta of 0.65 or less; and, (5) have investment grade credit ratings from S&P.

Q. DO THESE CRITERIA PROVIDE OBJECTIVE EVIDENCE TO EVALUATE INVESTORS’ RISK PERCEPTIONS?

A. Yes. Credit ratings are assigned by independent rating agencies for the purpose of providing investors with a broad assessment of the creditworthiness of a firm. Ratings generally extend from triple-A (the highest) to D (in default). Other symbols (*e.g.*, "A+") are used to show relative standing within a category. Because the rating agencies’ evaluation includes virtually all of the factors normally considered important in assessing a firm’s relative credit standing, corporate credit ratings provide a broad, objective measure of overall investment risk that is readily available to investors. Investment restrictions tied to credit ratings continue to influence capital flows, and credit ratings are widely cited in the investment community and referenced by investors, and also frequently used as a primary risk indicator in establishing proxy groups to estimate the cost of common equity.

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[29] The Value Line Investment Survey at 445 (Mar. 12, 2010).

While credit ratings provide the most widely referenced benchmark for investment risks, other quality rankings published by investment advisory services also provide relative assessments of risks that are considered by investors in forming their expectations for common stocks. Value Line's primary risk indicator is its Safety Rank, which ranges from "1" (Safest) to "5" (Riskiest). This overall risk measure is intended to capture the total risk of a stock, and incorporates elements of stock price stability and financial strength. Given that Value Line is perhaps the most widely available source of investment advisory information, its Safety Rank provides useful guidance regarding the risk perceptions of investors.

The Financial Strength Rating is designed as a guide to overall financial strength and creditworthiness, with the key inputs including financial leverage, business volatility measures, and company size. Value Line's Financial Strength Ratings range from "A++" (strongest) down to "C" (weakest) in nine steps. Finally, Value Line's beta measures the volatility of a security's price relative to the market as a whole. A stock that tends to respond less to market movements has a beta less than 1.00, while stocks that tend to move more than the market have betas greater than 1.00.

Q. HOW DO THE OVERALL RISKS OF YOUR PROXY GROUPS COMPARE WITH KU?

A. Table WEA-2 compares the Combination Utility Group and the Non-Utility Group with KU across four key indicators of investment risk. Because the Company does not have publicly traded common stock, the Value Line risk measures shown reflect those published for the Company's parent, PPL:

TABLE WEA-2
COMPARISON OF RISK INDICATORS

Proxy Group	S&P Credit Rating	Value Line Safety Rank	Value Line Financial Strength	Beta
Combination Utility	BBB	2	B++	0.74
Non-Utility	A	1	A+	0.66
KU	BBB	3	B++	0.65

Q. DOES THIS COMPARISON INDICATE THAT INVESTORS WOULD VIEW THE FIRMS IN YOUR PROXY GROUPS AS RISK-COMPARABLE TO KU?

A. Yes. As discussed earlier, KU, like its parent, PPL, is rated "BBB" by S&P, which is identical to the average corporate credit rating for the utilities in the Combination Utility Group. Similarly, the average Financial Strength Rating for the Combination Utility group is the same as that assigned to PPL. While PPL's Safety Rank of 3 indicated greater risk than the average for the proxy group of other utilities, its beta value is lower than the average for Combination Utility Group. Considered together, a comparison of these objective measures, which consider a broad spectrum of risks, including financial and business position, and exposure to company specific factors, indicates that investors would likely conclude that the overall investment risks for KU are comparable to those of the firms in the Combination Utility Group.

With respect to the Non-Utility Group, its average credit ratings, Quality Ranking, and Safety Rank suggest less risk than for the Combination Utility Group, with its 0.66 average beta indicating essentially identical risk. The indicators of investment risk considered in my analysis provide a sound, objective, and consistent basis to evaluate relative risks across companies and industry sectors. These measures incorporate a broad spectrum of risks, including financial and business position, the impact of regulation, relative size, and exposure to company specific factors, and they apply equally to regulated and unregulated firms. Indeed, the core idea of modern portfolio theory is that investors will diversify their holdings across multiple firms and industry groups, so that the risk of a stock is directly proportional to its beta, not the extent of competition or the freedom to set prices.

Q. DO THE BETA VALUES FOR THE NON-UTILITY GROUP ADDRESS THE CONCERNS EXPRESSED BY THE KPSC IN KU'S LAST RATE PROCEEDING?

A. Yes. The KPSC concluded in Case No. 2009-00548 that utilities must compete with non-regulated firms for capital and recognized that investors consider the opportunity costs associated with investment alternatives outside the utility industry. However, the Commission found that lower beta values for utility common stocks supported a finding that the non-utility companies were "riskier alternatives."[30] To address the KPSC's concerns, my proxy group criteria restricted the Non-Utility Group to include only firms with beta values of 0.65 or less, with the group's average beta of 0.66 being significantly lower than the 0.74 average for the Utility Group and essentially equal to the 0.65 value corresponding to KU.

C. Discounted Cash Flow Analyses

Q. HOW IS THE DCF MODEL USED TO ESTIMATE THE COST OF COMMON EQUITY?

A. DCF models attempt to replicate the market valuation process that sets the price investors are willing to pay for a share of a company's stock. The model rests on the assumption that investors evaluate the risks and expected rates of return from all securities in the capital markets. Given these expectations, the price of each stock is

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[30] *Case No. 2009-00548*, Final Order at 31.

adjusted by the market until investors are adequately compensated for the risks they bear. Therefore, we can look to the market to determine what investors believe a share of common stock is worth. By estimating the cash flows investors expect to receive from the stock in the way of future dividends and capital gains, we can calculate their required rate of return. That is, the cost of equity is the discount rate that equates the current price of a share of stock with the present value of all expected cash flows from the stock. The general form of the DCF model is expressed mathematically as follows:

$$P_0 = \frac{D_1}{(1+k_e)^1} + \frac{D_2}{(1+k_e)^2} + \cdots + \frac{D_t}{(1+k_e)^t} + \frac{P_t}{(1+k_e)^t}$$

where: P_0 = Current price per share;
P_t = Expected future price per share in period t;
D_t = Expected dividend per share in period t;
k_e = Cost of common equity.

Q. WHAT FORM OF THE DCF MODEL IS CUSTOMARILY USED TO ESTIMATE THE COST OF COMMON EQUITY IN RATE CASES?

A. Rather than developing annual estimates of cash flows into perpetuity, the DCF model can be simplified to a "constant growth" form:[31]

[31] The constant growth DCF model is dependent on a number of strict assumptions, which in practice are never met. These include a constant growth rate for both dividends and earnings; a stable dividend payout ratio; the discount rate exceeds the growth rate; a constant growth rate for book value and price; a constant earned rate of return on book value; no sales of stock at a price above or below book value; a constant price-earnings ratio; a constant discount rate (*i.e.*, no changes in risk or interest rate levels and a flat yield curve); and all of the above extend to infinity.

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

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

The cost of common equity (k_e) can be isolated by rearranging terms within the equation:

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

This constant growth form of the DCF model recognizes that the rate of return to stockholders consists of two parts: 1) dividend yield (D_1/P_0); and, 2) growth (g). In other words, investors expect to receive a portion of their total return in the form of current dividends and the remainder through price appreciation.

Q. WHAT FORM OF THE DCF MODEL DID YOU USE?

A. I applied the constant growth DCF model to estimate the cost of common equity for KU, which is the form of the model most commonly relied on to establish the cost of common equity for traditional regulated utilities and the method most often referenced by regulators.

Q. HOW IS THE CONSTANT GROWTH FORM OF THE DCF MODEL TYPICALLY USED TO ESTIMATE THE COST OF COMMON EQUITY?

A. The first step in implementing the constant growth DCF model is to determine the expected dividend yield (D_1/P_0) for the firm in question. This is usually calculated based on an estimate of dividends to be paid in the coming year divided by the current price of the stock. The second, and more controversial, step is to estimate investors' long-term growth expectations (g) for the firm. The final step is to sum the firm's dividend yield and estimated growth rate to arrive at an estimate of its cost of common equity.

Q. HOW WAS THE DIVIDEND YIELD FOR THE COMBINATION UTILITY GROUP DETERMINED?

A. Estimates of dividends to be paid by each of these utilities over the next twelve months, obtained from Value Line, served as D_1. This annual dividend was then divided by a 30-day average stock price for each utility to arrive at the expected dividend yield. The expected dividends, stock prices, and resulting dividend yields for the firms in the Combination Utility Group are presented on page 1 of Exhibit WEA-2. As shown there, dividend yields for the firms in the Combination Utility Group ranged from 3.9% to 5.5%, and averaged 4.7%.

Q. WHAT IS THE NEXT STEP IN APPLYING THE CONSTANT GROWTH DCF MODEL?

A. The next step is to evaluate long-term growth expectations, or "*g*", for the firm in question. In constant growth DCF theory, earnings, dividends, book value, and market price are all assumed to grow in lockstep, and the growth horizon of the DCF model is infinite. But implementation of the DCF model is more than just a theoretical exercise; it is an attempt to replicate the mechanism investors used to arrive at observable stock prices. A wide variety of techniques can be used to derive growth rates, but the only "*g*" that matters in applying the DCF model is the value that investors expect.

Q. ARE HISTORICAL GROWTH RATES LIKELY TO BE REPRESENTATIVE OF INVESTORS' EXPECTATIONS FOR UTILITIES?

A. No. If past trends in earnings, dividends, and book value are to be representative of investors' expectations for the future, then the historical conditions giving rise to these growth rates should be expected to continue. That is clearly not the case for utilities, where structural and industry changes have led to declining dividends, earnings pressure, and, in many cases, significant write-offs. While these conditions serve to depress historical growth measures, they are not representative of long-term expectations for the utility industry or the expectations that investors have incorporated into current market prices. As a result, historical growth measures for utilities do not currently meet the requirements of the DCF model.

Q. WHAT ARE INVESTORS MOST LIKELY TO CONSIDER IN DEVELOPING THEIR LONG-TERM GROWTH EXPECTATIONS?

A. While the DCF model is technically concerned with growth in dividend cash flows, implementation of this DCF model is solely concerned with replicating the forward-looking evaluation of real-world investors. In the case of utilities, dividend growth rates are not likely to provide a meaningful guide to investors' current growth expectations. This is because utilities have significantly altered their dividend policies in response to more accentuated business risks in the industry, with the payout ratio for utilities falling from approximately 80% historically to on the order of 60%.[32] As a result of this trend towards a more conservative payout ratio, dividend growth in the utility industry has remained largely stagnant as utilities conserve financial resources to provide a hedge against heightened uncertainties.

As payout ratios for firms in the utility industry trended downward, investors' focus has increasingly shifted from dividends to earnings as a measure of long-term growth. Future trends in earnings per share ("EPS"), which provide the source for future dividends and ultimately support share prices, play a pivotal role in determining investors' long-term growth expectations. The importance of earnings in evaluating investors' expectations and requirements is well accepted in the investment community, and surveys of analytical techniques relied on by professional analysts indicate that growth in earnings is far more influential that

[32] *See, e.g.*, The Value Line Investment Survey (Mar. 29, 1996 at 472, Mar. 9, 2012 at 540); The Value Line Investment Survey (Sep. 15, 1995 at 161, Feb. 24, 2012 at 136).

trends in dividends per share ("DPS"). Apart from Value Line, investment advisory services do not generally publish comprehensive DPS growth projections, and this scarcity of dividend growth rates relative to the abundance of earnings forecasts attests to their relative influence. The fact that securities analysts focus on EPS growth, and that dividend growth rates are not routinely published, indicates that projected EPS growth rates are likely to provide a superior indicator of the future long-term growth expected by investors.

Q. DO THE GROWTH RATE PROJECTIONS OF SECURITY ANALYSTS CONSIDER HISTORICAL TRENDS?

A. Yes. Professional security analysts study historical trends extensively in developing their projections of future earnings. Hence, to the extent there is any useful information in historical patterns, that information is incorporated into analysts' growth forecasts.

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

A. The EPS growth projections for each of the firms in the Combination Utility Group reported by Value Line, Thomson Reuters ("IBES"), and Zacks Investment Research ("Zacks") are displayed on page 2 of Exhibit WEA-2.[33]

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[33] Formerly I/B/E/S International, Inc., IBES growth rates are now compiled and published by Thomson Reuters.

Q. SOME ARGUE THAT ANALYSTS' ASSESSMENTS OF GROWTH RATES ARE BIASED. DO YOU BELIEVE THESE PROJECTIONS ARE INAPPROPRIATE FOR ESTIMATING INVESTORS' REQUIRED RETURN USING THE DCF MODEL?

A. No. In applying the DCF model to estimate the cost of common equity, the only relevant growth rate is the forward-looking expectations of investors that are captured in current stock prices. Investors, just like securities analysts and others in the investment community, do not know how the future will actually turn out. They can only make investment decisions based on their best estimate of what the future holds in the way of long-term growth for a particular stock, and securities prices are constantly adjusting to reflect their assessment of available information.

Any claims that analysts' estimates are not relied upon by investors are illogical given the reality of a competitive market for investment advice. If financial analysts' forecasts do not add value to investors' decision making, then it is irrational for investors to pay for these estimates. Similarly, those financial analysts who fail to provide reliable forecasts will lose out in competitive markets relative to those analysts whose forecasts investors find more credible. The reality that analyst estimates are routinely referenced in the financial media and in investment advisory publications (e.g., Value Line) implies that investors use them as a basis for their expectations.

The continued success of investment services such as Thompson Reuters and Value Line, and the fact that projected growth rates from such sources are widely referenced, provides strong evidence that investors give considerable weight to analysts' earnings projections in forming their expectations for future growth. While the projections of securities analysts may be proven optimistic or pessimistic in hindsight, this is irrelevant in assessing the expected growth that investors have incorporated into current stock prices, and any bias in analysts' forecasts – whether pessimistic or optimistic – is irrelevant if investors share analysts' views. Earnings growth projections of security analysts provide the most frequently referenced guide to investors' views and are widely accepted in applying the DCF model. As explained in *New Regulatory Finance*:

> Because of the dominance of institutional investors and their influence on individual investors, analysts' forecasts of long-run growth rates provide a sound basis for estimating required returns. Financial analysts exert a strong influence on the expectations of many investors who do not possess the resources to make their own forecasts, that is, they are a cause of *g* [growth]. <u>The accuracy of these forecasts in the sense of whether they turn out to be correct is not an issue here, as long as they reflect widely held expectations.</u>[34]

As the KPSC concluded:

> KU's argument concerning the appropriateness of using investors' expectations in performing a DCF analysis is more persuasive than the AG's argument that analysts' projections should be rejected in favor of historical results. The Commission agrees that analysts' projections of growth will be relatively more compelling in forming investors' forward-looking expectations than relying on historical performance…[35]

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

A. In constant growth theory, growth in book equity will be equal to the product of the earnings retention ratio (one minus the dividend payout ratio) and the earned rate of return on book equity. Furthermore, if the earned rate of return and the payout ratio are constant over time, growth in earnings and dividends will be equal to growth in book value. Despite the fact that these conditions are seldom, if ever, met in practice, this "sustainable growth" approach may provide a rough guide for

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[34] Morin, Roger A., "New Regulatory Finance," *Public Utilities Reports, Inc.* at 298 (2006) (emphasis added).
[35] *Case No. 2009-00548*, Final Order at 30-31.

evaluating a firm's growth prospects and is frequently proposed in regulatory proceedings.

Accordingly, while I believe that analysts' forecasts provide a superior and more direct guide to investors' growth expectations, I have included the "sustainable growth" approach for completeness. The sustainable growth rate is calculated by the formula, g = br+sv, where "b" is the expected retention ratio, "r" is the expected earned return on equity, "s" is the percent of common equity expected to be issued annually as new common stock, and "v" is the equity accretion rate.

Q. WHAT IS THE PURPOSE OF THE "SV" TERM?

A. Under DCF theory, the "sv" factor is a component of the growth rate designed to capture the impact of issuing new common stock at a price above, or below, book value. When a company's stock price is greater than its book value per share, the per-share contribution in excess of book value associated with new stock issues will accrue to the current shareholders. This increase to the book value of existing shareholders leads to higher expected earnings and dividends, with the "sv" factor incorporating this additional growth component.

Q. WHAT GROWTH RATE DOES THE EARNINGS RETENTION METHOD SUGGEST FOR THE COMBINATION UTILITY GROUP?

A. The sustainable, "br+sv" growth rates for each firm in the Combination Utility Group are summarized on page 2 of Exhibit WEA-2, with the underlying details being presented on Exhibit WEA-3. For each firm, the expected retention ratio (b) was calculated based on Value Line's projected dividends and earnings per share. Likewise, each firm's expected earned rate of return (r) was computed by dividing projected earnings per share by projected net book value. Because Value Line reports end-of-year book values, an adjustment factor was incorporated to compute an average rate of return over the year, consistent with the theory underlying this approach to estimating investors' growth expectations. Meanwhile, the percent of common equity expected to be issued annually as new common stock (s) was equal to the product of the projected market-to-book ratio and growth in common shares outstanding, while the equity accretion rate (v) was computed as 1 minus the inverse of the projected market-to-book ratio.

Q. WHAT COST OF COMMON EQUITY ESTIMATES WERE IMPLIED FOR THE COMBINATION UTILITY GROUP USING THE DCF MODEL?

A. After combining the dividend yields and respective growth projections for each utility, the resulting cost of common equity estimates are shown on page 3 of Exhibit WEA-2.

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

A. Yes. In applying quantitative methods to estimate the cost of equity, it is essential that the resulting values pass fundamental tests of reasonableness and economic logic. Accordingly, DCF estimates that are implausibly low or high should be eliminated when evaluating the results of this method.

Q. HOW DID YOU EVALUATE DCF ESTIMATES AT THE LOW END OF THE RANGE?

A. It is a basic economic principle that investors can be induced to hold more risky assets only if they expect to earn a return to compensate them for their risk bearing. As a result, the rate of return that investors require from a utility's common stock, the most junior and riskiest of its securities, must be considerably higher than the yield offered by senior, long-term debt. Consistent with this principle, the DCF results must be adjusted to eliminate estimates that are determined to be extreme low outliers when compared against the yields available to investors from less risky utility bonds.

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

A. S&P corporate credit ratings for the firms in the Combination Utility Group ranged from "BBB-" to "BBB+," with Moody's monthly yields on triple-B bonds averaging approximately 5.0% in May 2012.[36] It is inconceivable that investors are not requiring a substantially higher rate of return for holding common stock. Consistent with this principle, the DCF results for the Combination Utility Group must be adjusted to eliminate estimates that are determined to be extreme low outliers when compared against the yields available to investors from less risky utility bonds.

Q. HAVE SIMILAR TESTS BEEN APPLIED BY REGULATORS?

A. Yes. FERC has noted that adjustments are justified where applications of the DCF approach produce illogical results. FERC evaluates DCF results against observable yields on long-term public utility debt and has recognized that it is appropriate to eliminate estimates that do not sufficiently exceed this threshold. In a 2000 opinion establishing its current precedent for determining ROEs for electric utilities, for example, FERC noted:

> An adjustment to this data is appropriate in the case of PG&E's low-end return of 8.42 percent, which is comparable to the average Moody's "A" grade public utility bond yield of 8.06 percent, for October 1999. Because investors cannot be expected to purchase stock if debt, which has less risk than stock, yields essentially the same return, this low-end return cannot be considered reliable in this case.[37]

Similarly, FERC noted in its August 2006 decision in *Kern River Gas Transmission Company* that:

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[36] Moody's Investors Service, www.credittrends.com.

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

> [T]he 7.31 and 7.32 percent costs of equity for El Paso and Williams found by the ALJ are only 110 and 122 basis points above that average yield for public utility debt.[38]

The Commission upheld the opinion of Staff and the Administrative Law Judge that cost of equity estimates for these two proxy group companies "were too low to be credible."[39]

The practice of eliminating low-end outliers has been affirmed in numerous FERC proceedings,[40] and in its April 15, 2010 decision in *SoCal Edison*, FERC affirmed that, "it is reasonable to exclude any company whose low-end ROE fails to exceed the average bond yield by about 100 basis points or more."[41]

Q. WHAT ELSE SHOULD BE CONSIDERED IN EVALUATING DCF ESTIMATES AT THE LOW END OF THE RANGE?

A. As indicated earlier, while corporate bond yields have declined substantially from the levels reached during the height of the financial crisis, it is generally expected that long-term interest rates will rise as the economy returns to a more normal pattern of growth. As shown in Table WEA-3 below, forecasts of IHS Global Insight and the EIA imply average triple-B bond yield of approximately 6.7% over the period 2012-2016:

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[38] *Kern River Gas Transmission Company*, Opinion No. 486, 117 FERC ¶ 61,077 at P 140 & n. 227 (2006).
[39] *Id.*
[40] *See, e.g., Virginia Electric Power Co.*, 123 FERC ¶ 61,098 at P 64 (2008).
[41] *Southern California Edison Co.*, 131 FERC ¶ 61,020 at P 55 (2010) ("*SoCal Edison*").

TABLE WEA-3
IMPLIED BBB BOND YIELD

	2012-16
Projected AA Utility Yield	
IHS Global Insight (a)	5.65%
EIA (b)	5.80%
Average	5.72%
Current BBB - AA Yield Spread (c)	1.02%
Implied Triple-B Utility Yield	**6.74%**

(a) IHS Global Insight, *U.S. Economic Outlook* at 25 (Dec. 2011).
(b) Energy Information Administration, *Annual Energy Outlook 2012, Early Release* (Jan. 23, 2012).
(c) Based on monthly average bond yields from Moody's Investors Service for the six-month period Dec. 2011 - May 2012.

The increase in debt yields anticipated by IHS Global Insight and EIA is also supported by the widely-referenced Blue Chip Financial Forecasts, which projects that yields on corporate bonds will climb more than 100 basis points through the period 2012-2017.[42]

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

A. As shown on page 3 of Exhibit WEA-2, ten low-end DCF estimates ranged from 2.5% to 6.7%, with six of these values being equal to or less than the yield currently available on triple-B utility bonds. In light of the risk-return tradeoff principle and the test applied in *SoCal Edison*, it is inconceivable that investors are not requiring a substantially higher rate of return for holding common stock, which is the riskiest of a utility's securities. As a result, consistent with the test of economic logic applied

[42] *Blue Chip Financial Forecasts*, Vol. 30, No. 12 (Dec. 1, 2011).

by FERC and the upward trend expected for utility bond yields, these values provide little guidance as to the returns investors require from utility common stocks and should be excluded.

Q. IS IT ALSO APPROPRIATE TO EVALUATE ESTIMATES AT THE HIGH END OF THE RANGE OF DCF RESULTS?

A. Yes. It is just as important to eliminate high-end outliers as low-end outliers. This is also consistent with the precedent adopted by FERC, which has established that estimates found to be "extreme outliers" should be disregarded in interpreting the results of the DCF model.[43] Under FERC's test, cost of equity estimates of 17.7% or greater are considered extreme outliers, as are estimates based on growth rates of 13.3% or higher.

Q. IS THERE A BASIS TO EXCLUDE DCF ESTIMATES AT THE HIGH END OF THE RANGE FOR THE COMBINATION UTILITY GROUP?

A. No. The upper end of the DCF range for the Combination Utility Group was set by a cost of equity estimates of 15.2%. While this cost of equity estimate may exceed the majority of the remaining estimates, low-end estimates of approximately 7.5% are assuredly far below investors' required rate of return. This high-end estimate also falls far below the thresholds established by FERC. Taken together and considered along with the balance of the DCF estimates, these values provide a reasonable basis on which to evaluate investors' required rate of return.

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[43] See, *e.g.*, *ISO New England, Inc.*, 109 FERC ¶ 61,147 at P 205 (2004).

Q. WHAT COST OF COMMON EQUITY ESTIMATES ARE IMPLIED BY YOUR DCF RESULTS FOR THE COMBINATION UTILITY GROUP?

A. As shown on page 3 of Exhibit WEA-2 and summarized in Table WEA-4, below, after eliminating illogical low-end values, application of the constant growth DCF model resulted in the following cost of equity estimates:

TABLE WEA-4
DCF RESULTS – COMBINATION UTILITY GROUP

	Cost of Equity	
Growth Rate	**Average**	**Midpoint**
Value Line	10.0%	11.0%
IBES	10.2%	11.9%
Zacks	9.4%	9.6%
br + sv	9.0%	9.2%

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

A. I applied the DCF model to the Non-Utility Group in exactly the same manner described earlier for the Combination Utility Group. The results of my DCF analysis for the Non-Utility Group are presented in Exhibit WEA-4, with the sustainable, "br+sv" growth rates being developed on Exhibit WEA-5.

I noted earlier that values that are implausibly low or high should be eliminated when evaluating the results of any quantitative method used to estimate the cost of equity. As highlighted on page 3 of Exhibit WEA-4, in addition to illogical low-end values, various DCF estimates for the firms in the Non-Utility Group exceeded 17.0%. I determined that, when compared with the balance of the remaining estimates, these values could be considered implausible and should be excluded.

As shown on page 3 of Exhibit WEA-4 and summarized in Table WEA-5, below, after eliminating illogical low- and high-end values, application of the constant growth DCF model resulted in cost of common equity estimates ranging from 10.9% to 13.2%:

TABLE WEA-5
DCF RESULTS – NON-UTILITY GROUP

	Cost of Equity	
Growth Rate	**Average**	**Midpoint**
Value Line	12.2%	12.6%
IBES	10.9%	10.9%
Zacks	11.7%	12.2%
br + sv	13.2%	12.1%

As discussed earlier, reference to the Non-Utility Group is consistent with established regulatory principles. Required returns for utilities should be in line with those of non-utility firms of comparable risk operating under the constraints of free competition.

Q. HOW CAN YOU RECONCILE THESE DCF RESULTS FOR THE NON-UTILITY GROUP AGAINST THE SIGNIFICANTLY LOWER ESTIMATES PRODUCED FOR YOUR COMPARABLE-RISK GROUP OF UTILITIES?

A. First, it is important to be clear that the higher DCF results for the Non-Utility Group cannot be attributed to risk differences. As I documented earlier, the risks that investors associate with the group of non-utility firms - as measured by S&P's credit ratings and Value Line's Safety Rank, Financial Strength, and Beta – are lower than the risks investors associate with the Combination Utility Group. The objective evidence provided by these observable risk measures rules out a conclusion that the higher non-utility DCF estimates are associated with higher investment risk.

Rather, the divergence between the DCF results for these groups of utility and non-utility firms can be attributed to the fact that DCF estimates invariably depart from the returns that investors actually require because their expectations may not be captured by the inputs to the model, particularly the assumed growth rate. Because the actual cost of equity is unobservable, and DCF results inherently incorporate a degree of error, the cost of equity estimates for the Non-Utility Group provide an important benchmark in evaluating a fair ROE for KU. There is no basis to conclude that DCF results for a group of utilities would be inherently more reliable than those for firms in the competitive sector, and the divergence between the DCF estimates for the groups of utilities and the Non-Utility Group suggests that both should be considered to ensure a balanced end-result.

D. Capital Asset Pricing Model

Q. PLEASE DESCRIBE THE CAPM.

A. The CAPM is a theory of market equilibrium that measures risk using the beta coefficient. Assuming investors are fully diversified, the relevant risk of an individual asset (*e.g.*, common stock) is its volatility relative to the market as a whole, with beta reflecting the tendency of a stock's price to follow changes in the market. The CAPM is mathematically expressed as:

$$R_j = R_f + \beta_j(R_m - R_f)$$

where:
R_j = required rate of return for stock j;
R_f = risk-free rate;
R_m = expected return on the market portfolio; and,
β_j = beta, or systematic risk, for stock j.

Like the DCF model, the CAPM is an *ex-ante,* or forward-looking model based on expectations of the future. As a result, in order to produce a meaningful estimate of investors' required rate of return, the CAPM must be applied using estimates that reflect the expectations of actual investors in the market, not with backward-looking, historical data.

Q. HOW DID YOU APPLY THE CAPM TO ESTIMATE THE COST OF COMMON EQUITY?

A. Application of the CAPM to the Combination Utility Group based on a forward-looking estimate for investors' required rate of return from common stocks is presented on Exhibit WEA-6. In order to capture the expectations of today's investors in current capital markets, the expected market rate of return was estimated by conducting a DCF analysis on the dividend paying firms in the S&P 500.

The dividend yield for each firm was obtained from Value Line, and the growth rate was equal to the consensus earnings growth projections for each firm published by IBES, with each firm's dividend yield and growth rate being weighted by its proportionate share of total market value. Based on the weighted average of the projections for the 382 individual firms, current estimates imply an average growth rate over the next five years of 10.8%. Combining this average growth rate with a year-ahead dividend yield of 2.5% results in a current cost of common equity estimate for the market as a whole (R_m) of approximately 13.3%. Subtracting a 2.9% risk-free rate based on the average yield on 30-year Treasury bonds produced a market equity risk premium of 10.4%.

Q. WHAT WAS THE SOURCE OF THE BETA VALUES YOU USED TO APPLY THE CAPM?

A. I relied on the beta values reported by Value Line, which in my experience is the most widely referenced source for beta in regulatory proceedings. As noted in *New Regulatory Finance*:

> Value Line is the largest and most widely circulated independent investment advisory service, and influences the expectations of a large number of institutional and individual investors. … Value Line betas are computed on a theoretically sound basis using a broadly based market index, and they are adjusted for the regression tendency of betas to converge to 1.00.[44]

Q. WHAT ELSE SHOULD BE CONSIDERED IN APPLYING THE CAPM?

A. As explained by Morningstar:

> One of the most remarkable discoveries of modern finance is that of a relationship between firm size and return. The relationship cuts across the entire size spectrum but is most evident among smaller companies, which have higher returns on average than larger ones.[45]

Empirical research indicates that the CAPM does not fully account for observed differences in rates of return attributable to firm size, necessitating a modification to account for this size effect. As explained below, this adjustment to incorporate the increment of investors' required return that is related to firm size is specific to the CAPM model. I am not proposing to apply a general size risk premium in arriving at a fair ROE for KU; rather, this adjustment merely corrects for an observed inability of the CAPM to fully reflect the risks perceived by investors.

According to the CAPM, the expected return on a security should consist of the riskless rate, plus a premium to compensate for the systematic risk of the particular security. The degree of systematic risk is represented by the beta coefficient. The need for the size adjustment arises because differences in investors' required rates of return that are related to firm size are not fully captured by beta. To account for this, Morningstar has developed size premiums that need to be added to the theoretical CAPM cost of equity estimates to account for the level of a firm's

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[44] Morin, Roger A., "New Regulatory Finance," *Public Utilities Reports* at 71 (2006).

[45] *Morningstar*, "Ibbotson SBBI 2012 Valuation Yearbook," at p. 85.

market capitalization in determining the CAPM cost of equity.[46] These premiums correspond to the size deciles of publicly traded common stocks, and range from a premium of 6.1% for a company in the first decile (market capitalization less than $207 million), to a reduction of 38 basis points for firms in the tenth decile (market capitalization between $15.5 billion and $354.4 billion). Accordingly, my CAPM analyses incorporated an adjustment to recognize the impact of size distinctions, as measured by the average market capitalization for the Combination Utility Group, that are not captured by the beta value, but which are acknowledged by empirical research.

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

A. The average market capitalization of the Combination Utility Group is $8.2 billion. Based on data from Morningstar, this means that the theoretical CAPM cost of equity estimate must be increased by 78 basis points to account for the group's relative size. As shown on page 1 of Exhibit WEA-6, adjusting the 10.6% theoretical CAPM result to incorporate this size adjustment results in an average indicated cost of common equity of 11.4%.

Q. IS IT APPROPRIATE TO CONSIDER ANTICIPATED CAPITAL MARKET CHANGES IN APPLYING THE CAPM?

A. Yes. As discussed earlier, there is widespread consensus that interest rates will increase materially as the economy continues to strengthen. As a result, current bond yields are likely to understate capital market requirements at the time the outcome of this proceeding becomes effective. Accordingly, in addition to the use

[46] *Id.* at Table C-1.

of current bond yields, I also applied the CAPM based on the forecasted long-term Treasury bond yields developed based on projections published by Value Line, IHS Global Insight and Blue Chip.

Q. WHAT COST OF EQUITY WAS PRODUCED BY THE CAPM AFTER INCORPORATING FORECASTED BOND YIELDS?

A. As shown on page 2 of Exhibit WEA-6, incorporating a forecasted Treasury bond yield for 2012-2016 implied a cost of equity of approximately 11.0% for the Combination Utility Group, or 11.8% after adjusting for the impact of relative size.

Q. SHOULD THE CAPM APPROACH BE APPLIED USING HISTORICAL RATES OF RETURN?

A. No. While investors undoubtedly consider historical information as one facet in their evaluation of future expectations, the cost of capital is a forward-looking concept. Because the CAPM is focused solely on the perceptions of today's capital market investors, it should not be applied using historical rates of return. The CAPM cost of common equity estimate is calibrated from investors' required risk premium between Treasury bonds and common stocks. In response to heightened uncertainties, investors have repeatedly sought a safe haven in U.S. government bonds and this "flight to safety" has pushed Treasury yields significantly lower while yield spreads for corporate debt have widened. This distortion not only impacts the absolute level of the CAPM cost of equity estimate, but it affects estimated risk premiums. Economic logic would suggest that investors' required risk premium for common stocks over Treasury bonds has also increased.

Meanwhile, backward-looking approaches incorrectly assume that investors' assessment of the required risk premium between Treasury bonds and common stocks is constant, and equal to some historical average. At no time in recent history has the fallacy of this assumption been demonstrated more concretely than it is today. This incongruity between investors' current expectations and historical risk premiums is particularly relevant during periods of heightened uncertainty and rapidly changing capital market conditions, such as those experienced recently. As the Staff of the Florida Public Service Commission concluded:

> [R]ecognizing the impact the Federal Government's unprecedented intervention in the capital markets has had on the yields on long-term Treasury bonds, staff believes models that relate the investor-required return on equity to the yield on government securities, such as the CAPM approach, produce less reliable estimates of the ROE at this time.[47]

Q. HAS THE FEDERAL RESERVE CONTINUED TO PURSUE A POLICY OF ACTIVELY MANAGING LONG-TERM GOVERNMENT BOND YIELDS?

A. Yes. In September 2011, the Federal Reserve announced "Operation Twist," involving the exchange of short-term Treasury instruments for longer-term government bonds, in an effort to put downward pressure on long-term interest rates. The ongoing potential for renewed turmoil in the capital markets has been seen repeatedly, with common stock prices exhibiting the dramatic volatility that is indicative of heightened sensitivity to risk.

Nowhere has this been more evident than in the market for Treasury bonds, with yields being pushed significantly lower due to a global "flight to safety" in the face of rising political, economic, and capital market risks. In turn, this has led to a dramatic increase in risk premiums, as illustrated by the spreads between triple-B utility bond yields and 30-year Treasuries shown in Figure WEA-1, below:

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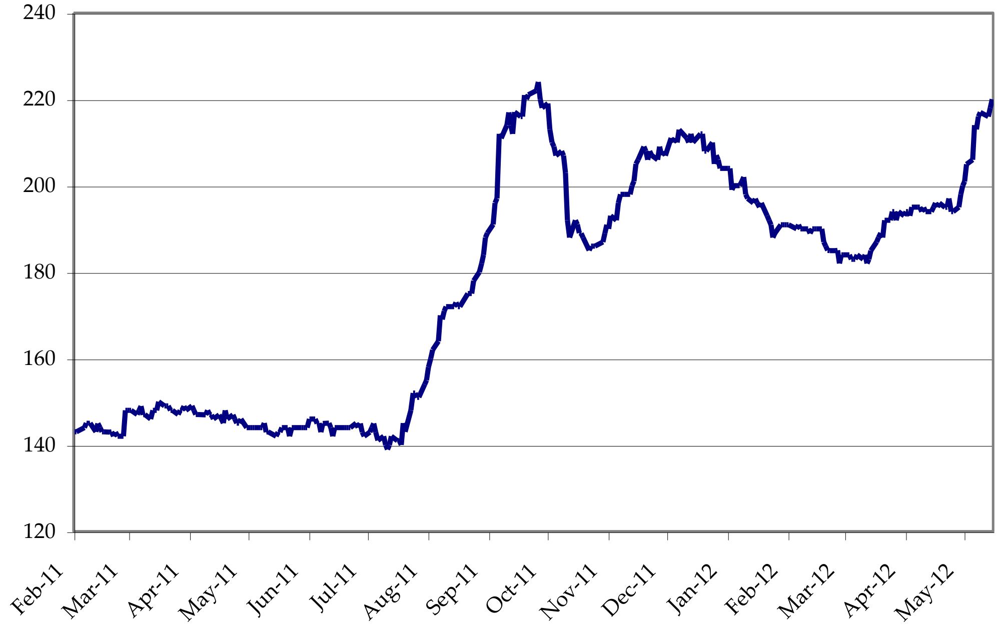
[47] *Staff Recommendation for Docket No. 080677-E1 - Petition for increase in rates by Florida Power & Light Company*, at p. 280 (Dec. 23, 2009).

FIGURE WEA-1
YIELD SPREAD (BASIS POINTS) – BBB UTILITY – 30-YR. TREASURY



This increase in the yield spread indicates that the additional compensation investors demand to take on higher risks has increased. As S&P observed:

> Standard & Poor's U.S. speculative-grade composite spread, which measures the extra yield above U.S. Treasury bonds that investors demand to hold the bonds of riskier companies, widened by 63% to 781 basis points (bps) from April 18, 2011, to Sept. 30, 2011. This sharp expansion reflected the bond market's increasing aversion to credit risk in an uncertain and riskier environment. … During periods of stress, correlations frequently increase among risky asset classes such as the relationship between the return on speculative-grade bonds and the return from equities.[48]

Equity risk premiums cannot be observed directly, but because common stock investors are the last in line with respect to their claim on a utility's cash flows, higher yield spreads imply an even steeper increase in the additional return required

[48] Standard & Poor's Corporation, "Recent Expansion In Credit Spreads Shows Bond Market Stress, But Less Severe Than During The Financial Crisis," *RatingsDirect* (Oct. 11, 2011).

from an investment in common equity. In short, heightened capital market and economic uncertainties, and the increase in risk premiums demanded by investors, further undermine any reliance on historical studies to apply the CAPM.

E. Risk Premium Method

Q. BRIEFLY DESCRIBE THE RPM.

A. The RPM extends the risk-return tradeoff observed with bonds to estimate investors' required rate of return on common stocks. The cost of equity is estimated by first determining the additional return investors require to forgo the relative safety of bonds and to bear the greater risks associated with common stock, and by then adding this equity risk premium to the current yield on bonds. Like the DCF model, the RPM is capital market oriented. However, unlike DCF models, which indirectly impute the cost of equity, risk premium methods directly estimate investors' required rate of return by adding an equity risk premium to observable bond yields.

Q. HOW DID YOU IMPLEMENT THE RPM?

A. I based my estimates of equity risk premiums for utilities on surveys of previously authorized rates of return on common equity. Authorized returns presumably reflect regulatory commissions' best estimates of the cost of equity, however determined, at the time they issued their final order. Such returns should represent a balanced and impartial outcome that considers the need to maintain a utility's financial integrity and ability to attract capital. Moreover, allowed returns are an important consideration for investors and have the potential to influence other observable investment parameters, including credit ratings and borrowing costs. Thus, these data provide a logical and frequently referenced basis for estimating equity risk premiums for regulated utilities.

Q. IS IT CIRCULAR TO CONSIDER RISK PREMIUMS BASED ON AUTHORIZED RETURNS IN ASSESSING A FAIR ROE FOR KU?

A. No. In establishing authorized returns, regulators typically consider the results of alternative market-based approaches, including the DCF model. Because allowed risk premiums consider objective market data (*e.g.*, stock prices dividends, beta, and interest rates), and are not based strictly on past actions of other regulators, this mitigates concerns over any potential for circularity.

Q. HOW DID YOU IMPLEMENT THE RPM USING SURVEYS OF ALLOWED RATES OF RETURN?

A. Surveys of previously authorized rates of return on common equity are frequently referenced as the basis for estimating equity risk premiums. The rates of return on common equity authorized utilities by regulatory commissions across the U.S. are compiled by Regulatory Research Associates and published in its *Regulatory Focus* report. In Exhibit WEA-7, the average yield on public utility bonds is subtracted from the average allowed rate of return on common equity for electric utilities to calculate equity risk premiums for each year between 1974 and 2011.[49] As shown on page 3 of Exhibit WEA-7, over this period, these equity risk premiums for electric averaged 3.41%, and the yield on public utility bonds averaged 8.91%.

Q. IS THERE ANY CAPITAL MARKET RELATIONSHIP THAT MUST BE CONSIDERED WHEN IMPLEMENTING THE RISK PREMIUM METHOD?

A. Yes. There is considerable evidence that the magnitude of equity risk premiums is not constant and that equity risk premiums tend to move inversely with interest

[49] My analysis encompasses the entire period for which published data is available.

rates.[50] In other words, when interest rate levels are relatively high, equity risk premiums narrow, and when interest rates are relatively low, equity risk premiums widen. The implication of this inverse relationship is that the cost of equity does not move as much as, or in lockstep with, interest rates. Accordingly, for a 1 % increase or decrease in interest rates, the cost of equity may only rise or fall, say, 50 basis points. Therefore, when implementing the risk premium method, adjustments may be required to incorporate this inverse relationship if current interest rate levels have diverged from the average interest rate level represented in the data set.

Finally, it is important to recognize that the historical focus of risk premium studies almost certainly ensures that they fail to fully capture the significantly greater risks that investors now associate with providing utility service. As a result, they are likely to understate the cost of equity for a firm operating in today's utility industry.

Q. WHAT COST OF EQUITY IS IMPLIED BY THE RPM USING SURVEYS OF ALLOWED RATES OF RETURN ON EQUITY?

A. Based on the regression output between the interest rates and equity risk premiums displayed on page 4 of Exhibit WEA-7, the equity risk premium for electric utilities increased approximately 41 basis points for each percentage point drop in the yield on average public utility bonds. As illustrated on page 1 of Exhibit WEA-7, with the average yield on public utility bonds in May 2012 being 4.36%, this implied a current equity risk premium of 5.28% for electric utilities. Adding this equity risk premium to the average yield on triple-B utility bonds of 4.97% implies a current cost of equity for KU of approximately 10.3%.

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[50] *See, e.g.,* Brigham, E.F., Shome, D.K., and Vinson, S.R., "The Risk Premium Approach to Measuring a Utility's Cost of Equity," *Financial Management* (Spring 1985); Harris, R.S., and Marston, F.C., "Estimating Shareholder Risk Premia Using Analysts' Growth Forecasts," *Financial Management* (Summer 1992).

Q. WHAT COST OF EQUITY WAS PRODUCED BY THE RPM AFTER INCORPORATING FORECASTED BOND YIELDS?

A. As shown on page 2 of Exhibit WEA-7, incorporating a forecasted yield for 2012-2016 and adjusting for changes in interest rates since the study period implied an equity risk premium of 4.54% for electric utilities. Adding this equity risk premium to the implied average yield on triple-B public utility bonds for 2012-2016 of 6.74% resulted in an implied cost of equity of approximately 11.3%.

F. Expected Earnings Approach

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

A. As I noted earlier, I also evaluated the cost of common equity using the expected earnings method. Reference to rates of return available from alternative investments of comparable risk can provide an important benchmark in assessing the return necessary to assure confidence in the financial integrity of a firm and its ability to attract capital. This expected earnings approach is consistent with the economic underpinnings for a fair rate of return established by the U.S. Supreme Court in *Bluefield* and *Hope*. Moreover, it avoids the complexities and limitations of capital market methods and instead focuses on the returns earned on book equity, which are readily available to investors.

Q. WHAT ECONOMIC PREMISE UNDERLIES THE EXPECTED EARNINGS APPROACH?

A. The simple, but powerful concept underlying the expected earnings approach is that investors compare each investment alternative with the next best opportunity. If the utility is unable to offer a return similar to that available from other opportunities of comparable risk, investors will become unwilling to supply the capital on reasonable terms. For existing investors, denying the utility an opportunity to earn what is available from other similar risk alternatives prevents them from earning their opportunity cost of capital. In this situation the government is effectively taking the value of investors' capital without adequate compensation. The expected earnings approach is consistent with the economic rationale underpinning established regulatory standards, which specifies a methodology to determine an ROE benchmark based on earned rates of return for a peer group of other regional utilities.

Q. HOW IS THE COMPARISON OF OPPORTUNITY COSTS TYPICALLY IMPLEMENTED?

A. The traditional comparable earnings test identifies a group of companies that are believed to be comparable in risk to the utility. The actual earnings of those companies on the book value of their investment are then compared to the allowed return of the utility. While the traditional comparable earnings test is implemented using historical data taken from the accounting records, it is also common to use projections of returns on book investment, such as those published by recognized investment advisory publications (*e.g.*, Value Line). Because these returns on book value equity are analogous to the allowed return on a utility's rate base, this measure of opportunity costs results in a direct, "apples to apples" comparison.

Moreover, regulators do not set the returns that investors earn in the capital markets – they can only establish the allowed return on the value of a utility's investment, as reflected on its accounting records. As a result, the expected earnings approach provides a direct guide to ensure that the allowed ROE is similar to what other utilities of comparable risk will earn on invested capital. This opportunity cost test does not require theoretical models to indirectly infer investors' perceptions from stock prices or other market data. As long as the proxy companies are similar in risk, their expected earned returns on invested capital provide a direct benchmark for investors' opportunity costs that is independent of fluctuating stock prices, market-to-book ratios, debates over DCF growth rates, or the limitations inherent in any theoretical model of investor behavior.

Q. WHAT RATES OF RETURN ON EQUITY ARE INDICATED FOR UTILITIES BASED ON THE EXPECTED EARNINGS APPROACH?

A. For the firms in the Combination Utility Group specifically, the returns on common equity projected by Value Line over its three-to-five year forecast horizon are shown on Exhibit WEA-8.

Consistent with the rationale underlying the development of the br+sv growth rates, these year-end values were converted to average returns using the same adjustment factors discussed earlier and developed on Exhibits WEA-3. As shown on Exhibit WEA-8, Value Line's projections for the Combination Utility Group suggested an average ROE of 10.4%.

G. Flotation Costs

Q. WHAT OTHER CONSIDERATIONS ARE RELEVANT IN DETERMINING THE ROE FOR KU?

A. The common equity used to finance the investment in utility assets is provided from either the sale of stock in the capital markets or from retained earnings not paid out as dividends. When equity is raised through the sale of common stock, there are costs associated with "floating" the new equity securities. These flotation costs include services such as legal, accounting, and printing, as well as the fees and discounts paid to compensate brokers for selling the stock to the public. Also, some argue that the "market pressure" from the additional supply of common stock and other market factors may further reduce the amount of funds a utility nets when it issues common equity.

Q. IS THERE AN ESTABLISHED MECHANISM FOR A UTILITY TO RECOGNIZE EQUITY ISSUANCE COSTS?

A. No. While debt flotation costs are recorded on the books of the utility, amortized over the life of the issue, and thus increase the effective cost of debt capital, there is no similar accounting treatment to ensure that equity flotation costs are recorded and ultimately recognized. No rate of return is authorized on flotation costs necessarily incurred to obtain a portion of the equity capital used to finance plant. In other words, equity flotation costs are not included in a utility's rate base because neither that portion of the gross proceeds from the sale of common stock used to pay flotation costs is available to invest in plant and equipment, nor are flotation costs capitalized as an intangible asset. Unless some provision is made to recognize these issuance costs, a utility's revenue requirements will not fully reflect all of the costs incurred for the use of investors' funds. Because there is no accounting convention to accumulate the flotation costs associated with equity issues, they must be accounted for indirectly, with an upward adjustment to the cost of equity being the most appropriate mechanism. For example, the Washington Utilities and Transportation Commission concluded that a flotation cost adjustment of 25 basis points should be included in the allowed return on equity:

> The Commission also agrees with both Dr. Avera and Dr. Lurito that a 25 basis point markup for flotation costs should be made. This amount compensates the Company for costs incurred from past issues of common stock. Flotation costs incurred in connection with a sale of common stock are not included in a utility's rate base because the portion of gross

> proceeds that is used to pay these costs is not available to invest in plant and equipment.[51]

Q. HAS THE KPSC ROUTINELY APPROVED A FLOTATION COST ADJUSTMENT FOR KU?

A. I am aware that the KPSC has not routinely approved a flotation cost adjustment for KU in past proceedings. Nevertheless, the evidence in this case provides a sound theoretical and practical basis to include consideration of flotation costs for KU. First, an adjustment for flotation costs associated with past equity issues is appropriate, even when the utility is not contemplating any new sales of common stock. The need for a flotation cost adjustment to compensate for past equity issues has been recognized in the financial literature.

In a *Public Utilities Fortnightly* article, for example, Brigham, Aberwald, and Gapenski demonstrated that even if no further stock issues are contemplated, a flotation cost adjustment in all future years is required to keep shareholders whole, and that the flotation cost adjustment must consider total equity, including retained earnings.[52] Similarly, *New Regulatory Finance* contains the following discussion:

> Another controversy is whether the flotation cost allowance should still be applied when the utility is not contemplating an imminent common stock issue. Some argue that flotation costs are real and should be recognized in calculating the fair rate of return on equity, but only at the time when the expenses are incurred. In other words, the flotation cost allowance should not continue indefinitely, but should be made in the year in which the sale of securities occurs, with no need for continuing compensation in future years. This argument implies that the company has already been compensated for these costs and/or the initial contributed capital was obtained freely, devoid of any flotation costs, which is an unlikely assumption, and certainly not applicable to most utilities. … The flotation cost adjustment cannot be strictly forward-

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[51] *Third Supplemental Order*, Washington Utilities and Transportation Commission, Docket No. UE-991606, et al., p. 95 (September 2000).

[52] Brigham, E.F., Aberwald, D.A., and Gapenski, L.C., "Common Equity Flotation Costs and Rate Making," *Public Utilities Fortnightly,* May, 2, 1985.

> looking unless all past flotation costs associated with past issues have been recovered.[53]

The following example demonstrates that investors will not have the opportunity to earn their required rate of return (*i.e.*, dividend yield plus expected growth) unless an allowance for past flotation costs is included in the allowed rate of return on equity. Assume a utility sells $10 worth of common stock at the beginning of year 1. If the utility incurs flotation costs of $0.48 (5% of the net proceeds), then only $9.52 is available to invest in rate base. Assume that common shareholders' required rate of return is 11.5%, the expected dividend in year 1 is $0.50 (*i.e.*, a dividend yield of 5 percent), and that growth is expected to be 6.5% annually. As developed below, if the allowed rate of return on common equity is only equal to the utility's 11.5% "bare bones" cost of equity, common stockholders will not earn their required rate of return on their $10 investment, since growth will really only be 6.25%, instead of 6.5%:

TABLE WEA-6
NO FLOTATION COST ADJUSTMENT

Year	Common Stock	Retained Earnings	Total Equity	Market Price	M/B Ratio	Allowed ROE	Earnings Per Share	Dividends Per Share	Payout Ratio
1	$ 9.52	$ -	$ 9.52	$ 10.00	1.050	11.50%	$ 1.09	$ 0.50	45.7%
2	$ 9.52	$ 0.59	$ 10.11	$ 10.62	1.050	11.50%	$ 1.16	$ 0.53	45.7%
3	$ 9.52	$ 0.63	$ 10.75	$ 11.29	1.050	11.50%	$ 1.24	$ 0.56	45.7%
Growth			**6.25%**	**6.25%**			**6.25%**	**6.25%**	

The reason that investors never really earn 11.5% on their investment in the above example is that the $0.48 in flotation costs initially incurred to raise the common stock is not treated like debt issuance costs (*i.e.*, amortized into interest expense and therefore increasing the embedded cost of debt), nor is it included as an asset in rate base.

[53] Morin, Roger A., "New Regulatory Finance," *Public Utilities Reports, Inc.* (2006) at 335.

Including a flotation cost adjustment allows investors to be fully compensated for the impact of these costs. One commonly referenced method for calculating the flotation cost adjustment is to multiply the dividend yield by a flotation cost percentage. Thus, with a 5% dividend yield and a 5% flotation cost percentage, the flotation cost adjustment in the above example would be approximately 25 basis points. As shown below, by allowing a rate of return on common equity of 11.75% (an 11.5% cost of equity plus a 25 basis point flotation cost adjustment), investors earn their 11.5% required rate of return, since actual growth is now equal to 6.5%:

TABLE WEA-7
INCLUDING FLOTATION COST ADJUSTMENT

Year	Common Stock	Retained Earnings	Total Equity	Market Price	M/B Ratio	Allowed ROE	Earnings Per Share	Dividends Per Share	Payout Ratio
1	$ 9.52	$ -	$ 9.52	$ 10.00	1.050	11.75%	$ 1.12	$ 0.50	44.7%
2	$ 9.52	$ 0.62	$ 10.14	$ 10.65	1.050	11.75%	$ 1.19	$ 0.53	44.7%
3	$ 9.52	$ 0.66	$ 10.80	$ 11.34	1.050	11.75%	$ 1.27	$ 0.57	44.7%
Growth			**6.50%**	**6.50%**			**6.50%**	**6.50%**	

The only way for investors to be fully compensated for issuance costs is to include an ongoing adjustment to account for past flotation costs when setting the return on common equity. This is the case regardless of whether or not the utility is expected to issue additional shares of common stock in the future.

Q. DOES THE FACT THAT UTILITY STOCK PRICES GENERALLY EXCEED BOOK VALUE UNDERMINE THE NEED TO CONSIDER FLOTATION COSTS?

A. No. While utility stocks continue to trade at prices that exceed book value, this says nothing about the need to recognize the impact of legitimate costs of issuing common stock when establishing a fair rate of return. Investors determine the price they are willing to pay for a share of common stock based on their assessment of expected cash flows and relative risks. The fact that the market price of a utility's common stock exceeds book value doesn't change the fact that investors must be granted an opportunity to earn their required rate of return on *all* invested capital, including that portion paid out as issuance expenses. As I demonstrated in the example above, this can only occur if an upward adjustment to the ROE is made to account for flotation costs.

The only purpose of the flotation cost adjustment is to allow the utility an opportunity to recover a reasonable and necessary expense associated with raising equity capital. As discussed earlier, these costs are directly analogous to debt issuance expenses that are routinely recovered from ratepayers. A flotation cost adjustment does not constitute any form of "windfall" for investors; rather, it merely recognizes a legitimate cost of raising capital that is invested in the facilities used to serve customers.

Q. WILL ADDITIONAL EQUITY CAPITAL BE REQUIRED TO SUPPORT KU?

A. Yes. Additional equity will be instrumental in financing the sizeable investment in utility infrastructure contemplated for the Company. Moody's observed that the substantial magnitude of future capital spending will be likely to strain KU's balance sheet and will require new common equity capital.[54] Moody's noted that the rating profile of PPL and its subsidiaries was supported by a "conservative financing approach," which has included the sale of more than $4.8 billion of common stock and more than $2.0 billion of convertible equity units.[55]

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[54] Moody's Investors Service, "Credit Opinion: Kentucky Utilities Co.," *Global Credit Research* (Nov. 16, 2011).

[55] Moody's Investors Service, "Credit Opinion: PPL Corporation," *Global Credit Research* (Mar. 30, 2012).

In addition to the theoretical justification for recovering flotation costs associated with past sales of common stock, PPL will also be incurring flotation costs associated with ongoing sales of new shares. Moody's noted that "capital spending for the rate regulated businesses is expected to show material increases," with "$6.3 billion of capital expected to be spent at the Kentucky utilities [over the next five years] including about $3 billion for environmental capital projects."[56] In order to meet these commitments while maintaining a balanced mix of long-term capital sources, PPL anticipates the sale of significant amounts of new common stock. On April 9, 2012, PPL filed a Prospectus Supplement with the Securities and Exchange Commission governing the sale of new common shares with a gross offering price of up to approximately $315 million, with the proceeds to be used in part, "to make capital contributions to our subsidiaries."[57]

Q. WHAT IS THE MAGNITUDE OF THE ADJUSTMENT TO THE "BARE BONES" COST OF EQUITY TO ACCOUNT FOR ISSUANCE COSTS?

A. There are any number of ways in which a flotation cost adjustment can be calculated, and the adjustment can range from just a few basis points to more than a full percent. One of the most common methods used to account for flotation costs in regulatory proceedings is to apply an average flotation-cost percentage to a utility's dividend yield. Based on a review of the finance literature, *New Regulatory Finance* concluded:

> The flotation cost allowance requires an estimated adjustment to the return on equity of approximately 5% to 10%, depending on the size and risk of the issue.[58]

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[56] *Id.*

[57] PPL Corporation, *Preliminary Prospectus Supplement*, (Apr. 9, 2012).

[58] Roger A. Morin, "New Regulatory Finance," *Public Utilities Reports, Inc.* at 323 (2006).

Alternatively, a study of data from Morgan Stanley regarding issuance costs associated with utility common stock issuances suggests an average flotation cost percentage of 3.6%.[59] With respect to shares sold under PPL's current offering, underwriting discounts, commission, and direct expenses are estimated at approximately 2.6% of gross proceeds.[60]

Issuance costs are a legitimate consideration in setting the ROE for a utility, and applying these expense percentages to a representative dividend yield for the Combination Utility Group of 4.7% implies a flotation cost adjustment on the order of 12 to 47 basis points. I recommend a flotation cost adjustment of 20 basis points, which falls approximately in the middle of this range.

IV. ROE FOR KENTUCKY UTILITIES COMPANY

Q. WHAT IS THE PURPOSE OF THIS SECTION?

A. In addition to presenting my conclusions regarding a fair ROE for KU, this section also discusses the relationship between ROE and preservation of a utility's financial integrity and the ability to attract capital. In addition, I evaluate the reasonableness of KU's requested capital structure and examine the implications of cost adjustment mechanisms for the Company's ROE.

A. Implications for Financial Integrity

Q. WHY IS IT IMPORTANT TO ALLOW KU AN ADEQUATE ROE?

A. Given the importance of the utility industry to the economy and society, it is essential to maintain reliable and economical service to all consumers. While the

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[59] *Application of Yankee Gas Services Company for a Rate Increase*, DPUC Docket No. 04-06-01, Direct Testimony of George J. Eckenroth (Jul. 2, 2004) at Exhibit GJE-11.1. Updating the results presented by Mr. Eckenroth through April 2005 also resulted in an average flotation cost percentage of 3.6%.

[60] PPL Corporation, *Preliminary Prospectus Supplement* (Apr. 4, 2012).

Company remains committed to providing reliable electric service, a utility's ability to fulfill its mandate can be compromised if it lacks the necessary financial wherewithal or is unable to earn a return sufficient to attract capital.

As documented earlier, the major rating agencies have warned of exposure to uncertainties associated with political and regulatory developments, especially in view of the pressures associated with ongoing capital expenditure requirements, uncertain environmental compliance costs, and the potential for continued energy price volatility. Investors understand just how swiftly unforeseen circumstances can lead to deterioration in a utility's financial condition, and stakeholders have discovered first hand how difficult and complex it can be to remedy the situation after the fact. Investors' increased reticence to supply additional capital during times of crisis highlights the need to preserve financial flexibility and the importance of allowing an adequate ROE.

Q. WHAT ROLE DOES REGULATION PLAY IN ENSURING THAT KU HAS ACCESS TO CAPITAL UNDER REASONABLE TERMS AND ON A SUSTAINABLE BASIS?

A. Considering investors' heightened awareness of the risks associated with the utility industry and the damage that results when a utility's financial flexibility is compromised, the continuation of supportive regulation remains crucial to the Company's access to capital. Investors recognize that regulation has its own risks, and that constructive regulation is a key ingredient in supporting utility credit ratings and financial integrity, particularly during times of adverse conditions.

Fitch concluded, "[G]iven the lingering rate of unemployment and voter concerns about the economy, there could well be pockets of adverse rate decisions, and those companies with little financial cushion could suffer adverse effects." [61] Moody's has also emphasized the need for regulatory support, concluding:

> For the longer term, however, we are becoming increasingly concerned about possible changes to our fundamental assumptions about regulatory risk, particularly the prospect of a more adversarial political (and therefore regulatory) environment. A prolonged recessionary climate with high unemployment, or an intense period of inflation, could make cost recovery more uncertain.[62]

More recently, Moody's observed that, "A much larger risk lies in the potential for political intervention, which we see as a more unpredictable and severe event risk, accompanied by material unintended consequences."[63] Similarly, S&P concluded, "the quality of regulation is at the forefront of our analysis of utility creditworthiness."[64]

Q. IS IT REASONABLE TO CONSIDER THE IMPACT OF KU'S EXPOSURE TO ATTRITION?

A. Yes. Investors are concerned with what they can expect in the future, not what they might expect in theory if a historical test year were to repeat. To be fair to investors and to benefit customers, a regulated utility must have a <u>reasonable opportunity to actually earn</u> a return that will maintain financial integrity, facilitate capital attraction, and compensate for risk. In other words, it is the end result in the future that determines whether or not the *Hope* and *Bluefield* standards are met. S&P observed that its risk analysis focuses on the utility's ability to consistently <u>earn</u> a reasonable return:

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[61] Fitch Ratings Ltd., "U.S. Utilities, Power and Gas 2010 Outlook," *Global Power North America Special Report* (Dec. 4, 2009).

[62] Moody's Investors Service, "U.S. Regulated Electric Utilities, Six-Month Update," *Industry Outlook* (July 2009).

[63] Moody's Investors Service, "US Regulated Electric and Gas Utilities: Stable Despite Rising Headline Rhetoric," *Industry Outlook* (Jan. 17, 2012).

[64] Standard & Poor's Corporation, "Assessing U.S. Utility Regulatory Environments," *RatingsDirect* (Nov. 7, 2008).

> Notably, the analysis does not revolve around "authorized" returns, but rather on actual earned returns. We note the many examples of utilities with healthy authorized returns that, we believe, have no meaningful expectation of actually earning that return because of rate case lag, expense disallowances, etc.[65]

Similarly, Moody's concluded, "we evaluate the framework and mechanisms that allow a utility to recover its costs and investments and earn allowed returns. We are less concerned with the official allowed return on equity, instead focusing on the earned returns and cash flows."[66]

As documented in the testimony of Mr. Kent Blake, the effects of regulatory lag have denied KU an opportunity to actually earn its allowed ROE in the past, and increasing capital expenditures that fall outside the provisions of the ECR mechanism, coupled with anemic sales growth and sharp declines in off-system sales, will challenge KU going forward. Given the Company's inability to earn its authorized ROE in the past and the dynamics faced by KU, there is every reason to believe that attrition will result in under-earning the allowed ROE if the impact of regulatory lag and rising capital requirements are ignored.

In real world capital markets, investors have many competing places to put their money. If the capital dedicated to public utility service does not have an opportunity to earn a return commensurate with that available from alternatives of equivalent risk in the capital markets, investors are not being adequately compensated for the use of their money and bearing risk. KU's ROE should consider the past record of earnings attrition and future prospects for regulatory lag

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[65] Standard & Poor's Corporation, "Assessing U.S. Utility Regulatory Environments," *RatingsDirect* (Nov. 7, 2008).

[66] Moody's Investors Service, "Electric Utilities Face Challenges Beyond Near-Term," *Industry Outlook* (Jan. 2010).

that pressure KU's credit standing and undermine the Company's ability to attract capital on reasonable terms.

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

A. Yes. Providing a return that is both commensurate with those available from investments of corresponding risk and sufficient to maintain KU's ability to attract capital, even under duress, is consistent with the economic requirements embodied in the U.S. Supreme Court's *Bluefield* and *Hope* decisions; but it is also in customers' best interests. Ultimately, it is customers and the service area economy that enjoy the benefits that come from ensuring that the utility has the financial wherewithal to take whatever actions are required to ensure a reliable energy supply. By the same token, customers also bear a significant burden when the ability of the utility to attract capital is impaired and service quality is compromised.

B. Capital Structure

Q. IS AN EVALUATION OF THE CAPITAL STRUCTURE MAINTAINED BY A UTILITY RELEVANT IN ASSESSING ITS RETURN ON EQUITY?

A. Yes. Other things equal, a higher debt ratio, or lower common equity ratio, translates into increased financial risk for all investors. A greater amount of debt means more investors have a senior claim on available cash flow, thereby reducing the certainty that each will receive his contractual payments. This increases the risks to which lenders are exposed, and they require correspondingly higher rates of interest. From common shareholders' standpoint, a higher debt ratio means that there are proportionately more investors ahead of them, thereby increasing the uncertainty as to the amount of cash flow, if any, that will remain.

Q. WHAT COMMON EQUITY RATIO IS IMPLICIT IN KU'S REQUESTED CAPITAL STRUCTURE?

A. The Company's capital structure is discussed in the testimony of Daniel K. Arbough. As summarized there, common equity as a percent of the capital sources used to compute the overall rate of return for KU was 53.7%.

Q. HOW CAN THE COMPANY'S REQUESTED CAPITAL STRUCTURE BE EVALUATED?

A. It is generally accepted that the norms established by comparable firms provide one valid benchmark against which to evaluate the reasonableness of a utility's capital structure. The capital structure maintained by other electric utilities should reflect their collective efforts to finance themselves so as to minimize capital costs while preserving their financial integrity and ability to attract capital. Moreover, these industry capital structures should also incorporate the requirements of investors (both debt and equity), as well as the influence of regulators.

Q. WHAT CAPITALIZATION RATIOS ARE MAINTAINED BY OTHER UTILITY OPERATING COMPANIES?

A. Exhibit WEA-9 displays capital structure data at year-end 2011 for the group of electric utility operating companies owned by the firms in the Combination Utility Group used to estimate the cost of equity. As shown there, common equity ratios for these utilities ranged from 47.5% to 61.8% and averaged 53.8%.

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

A. As shown on Exhibit WEA-10, for the firms in the Combination Utility Group, common equity ratios at December 31, 2011 ranged between 38.1% and 60.9% and averaged 49.9% of long-term capital, with Value Line projecting an average common equity ratio for 2015-2017 in the range of 43.0% to 60.0%, and averaging 50.5%.

Q. WHAT IMPLICATION DOES THE INCREASING RISK OF THE UTILITY INDUSTRY HAVE FOR THE CAPITAL STRUCTURE MAINTAINED BY KU?

A. As discussed earlier, utilities are facing energy market volatility, rising cost structures, the need to finance significant capital investment plans, uncertainties over accommodating future environmental mandates, and ongoing regulatory risks. Coupled with the ongoing turmoil in capital markets, these considerations warrant a stronger balance sheet to deal with an increasingly uncertain environment. A more conservative financial profile, in the form of a higher common equity ratio, is consistent with increasing uncertainties and the need to maintain the continuous access to capital that is required to fund operations and necessary system investment, even during times of adverse capital market conditions.

Moody's has warned investors of the risks associated with debt leverage and fixed obligations and affirmed that it expects regulated utilities to strengthen their balance sheets in order "to prepare for more challenging business conditions."[67] Similarly, S&P noted that, "we generally consider a debt to capital level of 50% or greater to be aggressive or highly leveraged for utilities."[68] Fitch affirmed that equity issuances are needed if regulated utilities are to maintain a balanced capital mix.[69]

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[67] Moody's Investors Service, "U.S. Electric Utilities: Uncertain Times Ahead; Strengthening Balance Sheets Now Would Protect Credit," *Special Comment* (Oct. 28, 2010).

[68] Standard & Poor's Corporation, "Ratings Roundup: U.S. Electric Utility Sector Maintained Strong Credit Quality In A Gloomy 2009," *RatingsDirect* (Jan. 26, 2010).

[69] Fitch Ratings Ltd., "2012 Outlook: Utilities, Power, and Gas," *Outlook Report* (Dec. 5, 2011).

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

A. Depending on their specific attributes, contractual agreements or other obligations that require the utility to make specified payments may be treated as debt in evaluating a utility's financial risk. For example, because power purchase agreements, leases, and postretirement benefit obligations typically obligate the utility to make specified minimum contractual payments akin to those associated with traditional debt financing, investors consider a portion of these commitments as debt in evaluating total financial risks. Because investors consider the debt impact of such fixed obligations in assessing a utility's financial position, they imply greater risk and reduced financial flexibility. In order to offset the debt equivalent associated with off-balance sheet obligations, the utility must rebalance its capital structure by increasing its common equity in order to restore its effective capitalization ratios to previous levels.[70]

These commitments have been repeatedly cited by major bond rating agencies in connection with assessments of utility financial risks,[71] with S&P adjusting KU's reported debt amounts upward to include debt equivalents associated with leases and postretirement benefit obligations.[72] Unless the Company takes action to offset this additional financial risk by maintaining a higher equity ratio, the resulting leverage will weaken KU's creditworthiness and imply greater risk.

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[70] The capital structure ratios presented earlier do not include imputed debt associated with power purchase agreements or the impact of other off-balance sheet obligations.

[71] See, *e.g.*, Standard & Poor's Corporation, "Implications Of Operating Leases On Analysis Of U.S. Electric Utilities," *RatingsDirect* (Jan. 15, 2008)

[72] Standard & Poor's Corporation, "Kentucky Utilities Co.," *RatingsDirect* (Nov. 1, 2011).

Q. WHAT DID YOU CONCLUDE REGARDING THE REASONABLENESS OF KU'S REQUESTED CAPITAL STRUCTURE?

A. Based on my evaluation, I concluded that the 53.7% common equity ratio requested by KU represents a reasonable mix of capital sources from which to calculate the Company's overall rate of return. Although this common equity ratio is somewhat higher than the historical and projected averages maintained by the Combination Utility Group, it is well within the range of individual results, consistent with the capitalization maintained by other utility operating companies, and reflects the trend towards lower financial leverage necessary to accommodate higher expected capital expenditures in the industry.

While industry averages provide one benchmark for comparison, each firm must select its capitalization based on the risks and prospects it faces, as well as its specific needs to access the capital markets. Financial flexibility plays a crucial role in ensuring the wherewithal to meet the needs of customers, and utilities with higher leverage may be foreclosed from additional borrowing, especially during times of stress. KU's proposed capital structure is consistent with industry benchmarks and reflects the Company's ongoing efforts to maintain its credit standing and support access to capital on reasonable terms. The reasonableness of the Company's capital structure is reinforced by the ongoing uncertainties associated with the utility industry and the importance of supporting continued system investment, even during times of adverse industry or market conditions.

C. Impact of Trackers

Q. DOES THE FACT THAT KU OPERATES UNDER CERTAIN RATE ADJUSTMENT MECHANISMS WARRANT ANY ADJUSTMENT IN YOUR EVALUATION OF A FAIR ROE?

A. No. Investors recognize that KU is exposed to significant risks associated with energy price volatility and rising costs and concerns over these risks have become increasingly pronounced in the industry. The KPSC's rate adjustment mechanisms are a valuable means of mitigating those risks, but they do not eliminate them. In addition, investors also recognize that the increased scrutiny associated with trackers exposes the Company to increased risk for retroactive reviews and disallowances. While the adjustment mechanisms approved for KU partially attenuate exposure to attrition in an era of rising costs, this leveling of the playing field only serves to address factors that could otherwise impair KU's opportunity to earn its authorized return, as required by established regulatory standards.

Reflective of this industry trend, the companies in the Combination Utility Group operate under a wide variety of cost adjustment mechanisms, which range from riders to recover bad debt expense and post-retirement employee benefit costs to revenue decoupling and adjustment clauses designed to address the rising costs of environmental compliance measures. Similarly, the firms in the Non-Utility Group also have the ability to alter prices in response to rising production costs, with the added flexibility to withdraw from the market altogether. As a result, the mitigation in risks associated with utilities' ability to attenuate the risk of cost recovery is already reflected in the cost of equity range determined earlier, and no separate adjustment to KU's ROE is necessary or warranted.

D. Return on Equity Range Recommendation

Q. PLEASE SUMMARIZE THE RESULTS OF YOUR ANALYSES.

A. The cost of common equity estimates produced by the various capital market oriented analyses described in my testimony are summarized in Table WEA-8, below:

TABLE WEA-8
SUMMARY OF QUANTITATIVE RESULTS

	Combination Utility		Non-Utility	
DCF	**Average**	**Midpoint**	**Average**	**Midpoint**
Value Line	10.0%	11.0%	12.2%	12.6%
IBES	10.2%	11.9%	10.9%	10.9%
Zacks	9.4%	9.6%	11.7%	12.2%
br + sv	9.0%	9.2%	13.2%	12.1%
CAPM - Current Bond Yield				
Unadjusted	10.6%			
Size Adjusted	11.4%			
CAPM - Projected Bond Yield				
Unadjusted	11.0%			
Size Adjusted	11.8%			
Utility Risk Premium				
Current Bond Yields	10.3%			
Projected Bond Yields	11.3%			
Expected Earnings	10.4%	10.6%		

Q. BASED ON THE RESULTS FOR THE COMBINATION UTILITY GROUP, WHAT IS YOUR CONCLUSION REGARDING A FAIR ROE RANGE?

A. Considering the relative strengths and weaknesses inherent in each method, and conservatively giving less emphasis to the upper- and lower-most boundaries of the range of results for the two groups of utilities, I concluded that the cost of common equity is in the 10.1% to 11.5% range. After incorporating an adjustment for flotation costs of 20 basis points to my “bare bones” cost of equity range, I concluded that my analyses indicate a fair ROE in the 10.3% to 11.7% range, with a midpoint of 11.0%.

Q. HOW WERE THE DCF ESTIMATES FOR THE NON-UTILITY GROUP CONSIDERED IN ARRIVING AT YOUR RECOMMENDED ROE RANGE?

A. As discussed earlier in my testimony, DCF estimates for the Non-Utility Group provide a useful benchmark because investors evaluate the required rate of return from utility investments against other opportunities available in the capital markets. The purpose of regulation is to serve as a substitute for the actions of competitive markets, and expected returns for non-utility companies form the basis for the regulatory standards underlying a fair ROE.

The DCF results for the Non-Utility Group were considerably higher than those implied for the proxy group of utilities, even though objective evidence demonstrates that the investment risks of the unregulated companies are lower.[73] Moreover, there is no basis to conclude that DCF results for a group of utilities would be inherently more reliable than those for firms in the competitive sector. In fact, considering the prominence of the 12 non-utility companies, the diversification afforded by considering multiple industries, and the scrutiny that analysts' afford to these paragons of American industry, the DCF results for the Non-Utility Group provide compelling evidence that suggests a downward bias in the utility DCF results. I considered this downward bias in evaluating my recommended ROE range from within the results produced for the Combination Utility Group.

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[73] As indicated earlier, my selection criteria were specifically designed to result in a conservative, low-risk group of non-utility firms. These companies do not reflect the market as a whole; instead, they represent the pinnacle of corporate America.

Q. WHAT THEN IS YOUR CONCLUSION AS TO A FAIR ROE FOR KU?

A. Considering capital market expectations, the potential exposures faced by KU, and the economic requirements necessary to maintain financial integrity and support additional capital investment even under adverse circumstances, it is my opinion that the 11.0% midpoint of my recommended 10.3% to 11.7% range represents a fair and reasonable ROE for KU. My conclusion is supported by the need to consider the potential exposures faced by KU and the economic requirements necessary to maintain financial integrity and support access to capital even under adverse circumstances.

Apart from the results of the quantitative methods summarized above, it is crucial to recognize the importance of supporting the Company's financial position so that KU remains prepared to respond to unforeseen events that may materialize in the future. Recent challenges in the economic and financial market environment highlight the imperative of maintaining the Company's financial strength in attracting the capital needed to secure reliable service at a lower cost for customers. The reasonableness of my recommended ROE is reinforced by the expected upward trend in long-term capital costs and the ongoing uncertainties faced by KU related to future emissions legislation. Coupled with the need to provide an ROE that supports KU's credit standing while funding necessary system investments, these considerations indicate that an ROE from the middle of my recommended range is reasonable.

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

A. Yes.

VERIFICATION

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

The undersigned, **William E. Avera**, being duly sworn, deposes and says he is President of FINCAP, Inc., that he has personal knowledge of the matters set forth in the foregoing testimony and exhibits, and the answers contained therein are true and correct to the best of his information, knowledge and belief.

____
William E. Avera

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 20th day of June 2012.

______________________________(SEAL)
Notary Public

My Commission Expires:

1/10/2015

ADRIEN MCKENZIE
Notary Public
STATE OF TEXAS
My Comm. Exp. Jan. 10, 2015

EXHIBIT WEA-1

<u>QUALIFICATIONS OF WILLIAM E. AVERA</u>

WILLIAM E. AVERA

FINCAP, INC.
Financial Concepts and Applications
Economic and Financial Counsel

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Austin, Texas 78751
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Summary of Qualifications

Ph.D. in economics and finance; Chartered Financial Analyst (CFA ®) designation; extensive expert witness testimony before courts, alternative dispute resolution panels, regulatory agencies and legislative committees; lectured in executive education programs around the world on ethics, investment analysis, and regulation; undergraduate and graduate teaching in business and economics; appointed to leadership positions in government, industry, academia, and the military.

Employment

Principal, FINCAP, Inc. (Sep. 1979 to present)	Financial, economic and policy consulting to business and government. Perform business and public policy research, cost/benefit analyses and financial modeling, valuation of businesses (almost 200 entities valued), estimation of damages, statistical and industry studies. Provide strategy advice and educational services in public and private sectors, and serve as expert witness before regulatory agencies, legislative committees, arbitration panels, and courts.
Director, Economic Research Division, Public Utility Commission of Texas (Dec. 1977 to Aug. 1979)	Responsible for research and testimony preparation on rate of return, rate structure, and econometric analysis dealing with energy, telecommunications, water and sewer utilities. Testified in major rate cases and appeared before legislative committees and served as Chief Economist for agency. Administered state and federal grant funds. Communicated frequently with political leaders and representatives from consumer groups, media, and investment community.
Manager, Financial Education, International Paper Company New York City (Feb. 1977 to Nov. 1977)	Directed corporate education programs in accounting, finance, and economics. Developed course materials, recruited and trained instructors, liaison within the company and with academic institutions. Prepared operating budget and designed financial controls for corporate professional development program.

Lecturer in Finance,
The University of Texas at Austin
(Sep. 1979 to May 1981)
Assistant Professor of Finance,
(Sep. 1975 to May 1977)

Taught graduate and undergraduate courses in financial management and investment theory. Conducted research in business and public policy. Named Outstanding Graduate Business Professor and received various administrative appointments.

Assistant Professor of Business,
University of North Carolina at Chapel Hill
(Sep. 1972 to Jul. 1975)

Taught in BBA, MBA, and Ph.D. programs. Created project course in finance, Financial Management for Women, and participated in developing Small Business Management sequence. Organized the North Carolina Institute for Investment Research, a group of financial institutions that supported academic research. Faculty advisor to the Media Board, which funds student publications and broadcast stations.

Education

Ph.D., Economics and Finance,
University of North Carolina at Chapel Hill
(Jan. 1969 to Aug. 1972)

Elective courses included financial management, public finance, monetary theory, and econometrics. Awarded the Stonier Fellowship by the American Bankers' Association and University Teaching Fellowship. Taught statistics, macroeconomics, and microeconomics.

Dissertation: *The Geometric Mean Strategy as a Theory of Multiperiod Portfolio Choice*

B.A., Economics,
Emory University, Atlanta, Georgia
(Sep. 1961 to Jun. 1965)

Active in extracurricular activities, president of the Barkley Forum (debate team), Emory Religious Association, and Delta Tau Delta chapter. Individual awards and team championships at national collegiate debate tournaments.

Professional Associations

Received Chartered Financial Analyst (CFA) designation in 1977; Vice President for Membership, Financial Management Association; President, Austin Chapter of Planning Executives Institute; Board of Directors, North Carolina Society of Financial Analysts; Candidate Curriculum Committee, Association for Investment Management and Research; Executive Committee of Southern Finance Association; Vice Chair, Staff Subcommittee on Economics and National Association of Regulatory Utility Commissioners (NARUC); Appointed to NARUC Technical Subcommittee on the National Energy Act.

Teaching in Executive Education Programs

University-Sponsored Programs: Central Michigan University, Duke University, Louisiana State University, National Defense University, National University of Singapore, Texas A&M University, University of Kansas, University of North Carolina, University of Texas.

Business and Government-Sponsored Programs: Advanced Seminar on Earnings Regulation, American Public Welfare Association, Association for Investment Management and Research, Congressional Fellows Program, Cost of Capital Workshop, Electricity Consumers Resource Council, Financial Analysts Association of Indonesia, Financial Analysts Review, Financial Analysts Seminar at Northwestern University, Governor's Executive Development Program of Texas, Louisiana Association of Business and Industry, National Association of Purchasing Management, National Association of Tire Dealers, Planning Executives Institute, School of Banking of the South, State of Wisconsin Investment Board, Stock Exchange of Thailand, Texas Association of State Sponsored Computer Centers, Texas Bankers' Association, Texas Bar Association, Texas Savings and Loan League, Texas Society of CPAs, Tokyo Association of Foreign Banks, Union Bank of Switzerland, U.S. Department of State, U.S. Navy, U.S. Veterans Administration, in addition to Texas state agencies and major corporations.

Presented papers for Mills B. Lane Lecture Series at the University of Georgia and Heubner Lectures at the University of Pennsylvania. Taught graduate courses in finance and economics for evening program at St. Edward's University in Austin from January 1979 through 1998.

Expert Witness Testimony

Testified in over 300 cases before regulatory agencies addressing cost of capital, regulatory policy, rate design, and other economic and financial issues.

Federal Agencies: Federal Communications Commission, Federal Energy Regulatory Commission, Surface Transportation Board, Interstate Commerce Commission, and the Canadian Radio-Television and Telecommunications Commission.

State Regulatory Agencies: Alaska, Arizona, Arkansas, California, Colorado, Connecticut, Delaware, Florida, Georgia, Hawaii, Idaho, Illinois, Indiana, Iowa, Kansas, Kentucky, Maryland, Michigan, Missouri, Nevada, New Mexico, Montana, Nebraska, North Carolina, Ohio, Oklahoma, Oregon, Pennsylvania, South Carolina, South Dakota, Texas, Utah, Virginia, Washington, West Virginia, Wisconsin, and Wyoming.

Testified in 42 cases before federal and state courts, arbitration panels, and alternative dispute tribunals (89 depositions given) regarding damages, valuation, antitrust liability, fiduciary duties, and other economic and financial issues.

Board Positions and Other Professional Activities

Co-chair, Synchronous Interconnection Committee established by Texas Legislature to study interconnection of Texas with national grid; Audit Committee and Outside Director, Georgia System Operations Corporation (electric system operator for member-owned electric cooperatives in Georgia); Chairman, Board of Print Depot, Inc. and FINCAP, Inc.; Appointed by Hays County Commission to Citizens Advisory Committee of Habitat Conservation Plan, Operator of AAA Ranch, a certified organic producer of agricultural products; Appointed to Organic Livestock

Advisory Committee by Texas Agricultural Commissioner; Appointed by Texas Railroad Commissioners to study group for *The UP/SP Merger: An Assessment of the Impacts on the State of Texas; A*ppointed by Hawaii Public Utilities Commission to team reviewing affiliate relationships of Hawaiian Electric Industries; Chairman, Energy Task Force, Greater Austin-San Antonio Corridor Council; Consultant to Public Utility Commission of Texas on cogeneration policy and other matters; Consultant to Public Service Commission of New Mexico on cogeneration policy; Evaluator of Energy Research Grant Proposals for Texas Higher Education Coordinating Board.

Community Activities

Treasurer, Dripping Springs Presbyterian Church; Board of Directors, Sustainable Food Center; Chair, Board of Deacons, Finance Committee, and Elder, Central Presbyterian Church of Austin; Founding Member, Orange-Chatham County (N.C.) Legal Aid Screening Committee.

Military

Captain, U.S. Naval Reserve (retired after 28 years service); Commanding Officer, Naval Special Warfare Engineering (SEAL) Support Unit; Officer-in-Charge of SWIFT patrol boat in Vietnam; Enlisted service as weather analyst (advanced to second class petty officer).

Bibliography

Monographs

“Economic Perspectives on Texas Water Resources,” with Robert M. Avera and Felipe Chacon in *Essentials of Texas Water Resources*, Mary K. Sahs, ed. State Bar of Texas (2012).

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

“Definition of Industry Ethics and Development of a Code” and “Applying Ethics in the Real World,” in *Good Ethics: The Essential Element of a Firm’s Success*, Association for Investment Management and Research (1994)

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

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

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

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

Articles

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

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

"The Energy Crisis and the Homeowner: The Grief Process," *Texas Business Review* (Jan.–Feb. 1980); reprinted in *The Energy Picture: Problems and Prospects*, J. E. Pluta, ed., Bureau of Business Research (1980)

"Use of IFPS at the Public Utility Commission of Texas," *Proceedings of the IFPS Users Group Annual Meeting* (1979)

"Production Capacity Allocation: Conversion, CWIP, and One-Armed Economics," *Proceedings of the NARUC Biennial Regulatory Information Conference* (1978)

"Some Thoughts on the Rate of Return to Public Utility Companies," with Bruce H. Fairchild in *Proceedings of the NARUC Biennial Regulatory Information Conference* (1978)

"A New Capital Budgeting Measure: The Integration of Time, Liquidity, and Uncertainty," with David Cordell in *Proceedings of the Southwestern Finance Association* (1977)

"Usefulness of Current Values to Investors and Creditors," in *Inflation Accounting/Indexing and Stock Behavior* (1977)

"Consumer Expectations and the Economy," *Texas Business Review* (Nov. 1976)

"Portfolio Performance Evaluation and Long-run Capital Growth," with Henry A. Latané in *Proceedings of the Eastern Finance Association* (1973)

Book reviews in *Journal of Finance* and *Financial Review*. Abstracts for *CFA Digest*. Articles in *Carolina Financial Times*.

Selected Papers and Presentations

"Economic Perspective on Water Marketing in Texas," 2009 Water Law Institute, The University of Texas School of Law, Austin, TX (Dec. 2009).

"Estimating Utility Cost of Equity in Financial Turmoil," SNL EXNET 15th Annual FERC Briefing, Washington, D.C. (Mar. 2009)

"The Who, What, When, How, and Why of Ethics," San Antonio Financial Analysts Society (Jan. 16, 2002). Similar presentation given to the Austin Society of Financial Analysts (Jan. 17, 2002)

"Ethics for Financial Analysts," Sponsored by Canadian Council of Financial Analysts: delivered in Calgary, Edmonton, Regina, and Winnipeg, June 1997. Similar presentations given to Austin Society of Financial Analysts (Mar. 1994), San Antonio Society of Financial Analysts (Nov. 1985), and St. Louis Society of Financial Analysts (Feb. 1986)

"Cost of Capital for Multi-Divisional Corporations," Financial Management Association, New Orleans, Louisiana (Oct. 1996)

"Ethics and the Treasury Function," Government Treasurers Organization of Texas, Corpus Christi, Texas (Jun. 1996)

"A Cooperative Future," Iowa Association of Electric Cooperatives, Des Moines (December 1995). Similar presentations given to National G & T Conference, Irving, Texas (June 1995), Kentucky Association of Electric Cooperatives Annual Meeting, Louisville (Nov. 1994), Virginia, Maryland, and Delaware Association of Electric Cooperatives Annual Meeting, Richmond (July 1994), and Carolina Electric Cooperatives Annual Meeting, Raleigh (Mar. 1994)

"Information Superhighway Warnings: Speed Bumps on Wall Street and Detours from the Economy," Texas Society of Certified Public Accountants Natural Gas, Telecommunications and Electric Industries Conference, Austin (Apr. 1995)

"Economic/Wall Street Outlook," Carolinas Council of the Institute of Management Accountants, Myrtle Beach, South Carolina (May 1994). Similar presentation given to Bell Operating Company Accounting Witness Conference, Santa Fe, New Mexico (Apr. 1993)

"Regulatory Developments in Telecommunications," Regional Holding Company Financial and Accounting Conference, San Antonio (Sep. 1993)

"Estimating the Cost of Capital During the 1990s: Issues and Directions," The National Society of Rate of Return Analysts, Washington, D.C. (May 1992)

"Making Utility Regulation Work at the Public Utility Commission of Texas," Center for Legal and Regulatory Studies, University of Texas, Austin (June 1991)

"Can Regulation Compete for the Hearts and Minds of Industrial Customers," Emerging Issues of Competition in the Electric Utility Industry Conference, Austin (May 1988)

"The Role of Utilities in Fostering New Energy Technologies," Emerging Energy Technologies in Texas Conference, Austin (Mar. 1988)

"The Regulators' Perspective," Bellcore Economic Analysis Conference, San Antonio (Nov. 1987)

"Public Utility Commissions and the Nuclear Plant Contractor," Construction Litigation Superconference, Laguna Beach, California (Dec. 1986)

"Development of Cogeneration Policies in Texas," University of Georgia Fifth Annual Public Utilities Conference, Atlanta (Sep. 1985)

"Wheeling for Power Sales," Energy Bureau Cogeneration Conference, Houston (Nov. 1985).

"Asymmetric Discounting of Information and Relative Liquidity: Some Empirical Evidence for Common Stocks" (with John Groth and Kerry Cooper), Southern Finance Association, New Orleans (Nov. 1982)

"Used and Useful Planning Models," Planning Executive Institute, 27th Corporate Planning Conference, Los Angeles (Nov. 1979)

"Staff Input to Commission Rate of Return Decisions," The National Society of Rate of Return Analysts, New York (Oct. 1979)

""Discounted Cash Life: A New Measure of the Time Dimension in Capital Budgeting," with David Cordell, Southern Finance Association, New Orleans (Nov. 1978)

"The Relative Value of Statistics of Ex Post Common Stock Distributions to Explain Variance," with Charles G. Martin, Southern Finance Association, Atlanta (Nov. 1977)

"An ANOVA Representation of Common Stock Returns as a Framework for the Allocation of Portfolio Management Effort," with Charles G. Martin, Financial Management Association, Montreal (Oct. 1976)

"A Growth-Optimal Portfolio Selection Model with Finite Horizon," with Henry A. Latané, American Finance Association, San Francisco (Dec. 1974)

"An Optimal Approach to the Finance Decision," with Henry A. Latané, Southern Finance Association, Atlanta (Nov. 1974)

"A Pragmatic Approach to the Capital Structure Decision Based on Long-Run Growth," with Henry A. Latané, Financial Management Association, San Diego (Oct. 1974)

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

DCF MODEL - COMBINATION UTILITY GROUP

DIVIDEND YIELD

	Company	(a) Price	(b) Dividends	Yield
1	ALLETE	$ 40.83	$ 1.85	4.5%
2	Alliant Energy	$ 43.71	$ 1.83	4.2%
3	Ameren Corp.	$ 32.08	$ 1.63	5.1%
4	Avista Corp.	$ 25.71	$ 1.18	4.6%
5	Black Hills Corp.	$ 32.99	$ 1.49	4.5%
6	DTE Energy Co.	$ 55.31	$ 2.44	4.4%
7	Empire District Elec	$ 20.14	$ 1.00	5.0%
8	Exelon Corp.	$ 38.48	$ 2.10	5.5%
9	Northwestern Corp.	$ 34.92	$ 1.49	4.3%
10	PG&E Corp.	$ 43.28	$ 1.82	4.2%
11	PPL Corp.	$ 27.45	$ 1.44	5.2%
12	Pub Sv Enterprise Grp	$ 30.35	$ 1.42	4.7%
13	SCANA Corp.	$ 45.25	$ 1.98	4.4%
14	Sempra Energy	$ 62.52	$ 2.43	3.9%
15	TECO Energy	$ 17.61	$ 0.89	5.1%
16	UIL Holdings	$ 34.06	$ 1.73	5.1%
	Average			**4.7%**

(a) Average of closing prices for 30 trading days ended May 4, 2012.
(b) The Value Line Investment Survey, Summary & Index (May 4, 2012).

GROWTH RATES

		(a)	(b)	(c)	(d)
		Earnings Growth			br+sv
	Company	V Line	IBES	Zacks	Growth
1	ALLETE	6.5%	5.0%	5.0%	4.1%
2	Alliant Energy	6.5%	6.4%	6.2%	4.8%
3	Ameren Corp.	-0.5%	-2.3%	4.0%	2.7%
4	Avista Corp.	5.5%	4.0%	4.7%	3.9%
5	Black Hills Corp.	7.0%	6.0%	6.0%	3.0%
6	DTE Energy Co.	5.0%	4.3%	4.4%	3.8%
7	Empire District Elec	6.0%	10.2%	NA	3.1%
8	Exelon Corp.	-3.0%	-10.2%	0.0%	3.7%
9	Northwestern Corp.	5.0%	5.0%	5.0%	4.3%
10	PG&E Corp.	4.5%	1.5%	4.6%	5.3%
11	PPL Corp.	5.0%	-1.0%	NA	5.7%
12	Pub Sv Enterprise Grp	0.0%	1.7%	2.0%	6.0%
13	SCANA Corp.	3.5%	6.7%	4.0%	5.2%
14	Sempra Energy	4.5%	7.1%	7.0%	6.0%
15	TECO Energy	9.0%	4.1%	3.7%	5.3%
16	UIL Holdings	3.0%	4.1%	4.0%	2.5%

(a) The Value Line Investment Survey (Feb. 24, Mar. 23, & May 4, 2012).
(b) www.finance.yahoo.com (Retrieved May 17, 2012).
(c) www.zacks.com (retrieved May 17, 2012).
(d) See Exhibit WEA-3.

DCF MODEL - COMBINATION UTILITY GROUP

DCF COST OF EQUITY ESTIMATES

		(a)	(a)	(a)	(a)
		Earnings Growth			br+sv
	Company	**V Line**	**IBES**	**Zacks**	**Growth**
1	ALLETE	11.0%	9.5%	9.5%	8.6%
2	Alliant Energy	10.7%	10.5%	10.4%	9.0%
3	Ameren Corp.	4.6%	2.8%	9.1%	7.8%
4	Avista Corp.	10.1%	8.6%	9.3%	8.5%
5	Black Hills Corp.	11.5%	10.5%	10.5%	7.5%
6	DTE Energy Co.	9.4%	8.7%	8.8%	8.2%
7	Empire District Elec	11.0%	15.2%	NA	8.0%
8	Exelon Corp.	2.5%	-4.7%	5.5%	9.2%
9	Northwestern Corp.	9.3%	9.3%	9.3%	8.6%
10	PG&E Corp.	8.7%	5.7%	8.8%	9.5%
11	PPL Corp.	10.2%	4.3%	NA	11.0%
12	Pub Sv Enterprise Grp	4.7%	6.3%	6.7%	10.7%
13	SCANA Corp.	7.9%	11.1%	8.4%	9.6%
14	Sempra Energy	8.4%	10.9%	10.9%	9.9%
15	TECO Energy	14.1%	9.2%	8.8%	10.4%
16	UIL Holdings	8.1%	9.2%	9.1%	7.5%
	Average (b)	**10.0%**	**10.2%**	**9.4%**	**9.0%**
	Midpoint (c)	**11.0%**	**11.9%**	**9.6%**	**9.2%**

(a) Sum of dividend yield (page 1) and respective growth rate (page 2).
(b) Excludes highlighted figures.
(c) Average of low and high values.

DCF MODEL - COMBINATION UTILITY GROUP

BR+SV GROWTH RATE

		(a)	(a)	(a)			(b)	(c)		(d)	(e)		
		------------- 2016 -------------					Adjustment			--------- "sv" Factor --------			
	Company	**EPS**	**DPS**	**BVPS**	**b**	**r**	**Factor**	**Adjusted r**	**br**	**s**	**v**	**sv**	**br + sv**
1	ALLETE	$3.25	$2.00	$34.50	38.5%	9.4%	1.0257	9.7%	3.7%	0.0191	0.1882	0.36%	**4.1%**
2	Alliant Energy	$3.60	$2.20	$32.35	38.9%	11.1%	1.0216	11.4%	4.4%	0.0129	0.3189	0.41%	**4.8%**
3	Ameren Corp.	$2.75	$1.80	$36.25	34.5%	7.6%	1.0158	7.7%	2.7%	0.0104	0.0333	0.03%	**2.7%**
4	Avista Corp.	$2.25	$1.40	$24.00	37.8%	9.4%	1.0235	9.6%	3.6%	0.0150	0.2000	0.30%	**3.9%**
5	Black Hills Corp.	$2.50	$1.60	$31.00	36.0%	8.1%	1.0145	8.2%	2.9%	0.0051	0.0462	0.02%	**3.0%**
6	DTE Energy Co.	$4.50	$2.80	$49.25	37.8%	9.1%	1.0244	9.4%	3.5%	0.0165	0.1792	0.29%	**3.8%**
7	Empire District Elec	$1.75	$1.20	$18.75	31.4%	9.3%	1.0157	9.5%	3.0%	0.0070	0.1477	0.10%	**3.1%**
8	Exelon Corp.	$3.25	$2.10	$25.00	35.4%	13.0%	1.0084	13.1%	4.6%	(0.0193)	0.4737	-0.91%	**3.7%**
9	Northwestern Corp.	$3.00	$1.80	$29.00	40.0%	10.3%	1.0214	10.6%	4.2%	0.0037	0.2267	0.08%	**4.3%**
10	PG&E Corp.	$3.75	$2.00	$36.00	46.7%	10.4%	1.0254	10.7%	5.0%	0.0135	0.2000	0.27%	**5.3%**
11	PPL Corp.	$2.75	$1.70	$24.75	38.2%	11.1%	1.0426	11.6%	4.4%	0.0378	0.3400	1.28%	**5.7%**
12	Pub Sv Enterprise Grp	$3.00	$1.45	$26.50	51.7%	11.3%	1.0274	11.6%	6.0%	-	0.2429	0.00%	**6.0%**
13	SCANA Corp.	$3.75	$2.15	$39.00	42.7%	9.6%	1.0468	10.1%	4.3%	0.0516	0.1789	0.92%	**5.2%**
14	Sempra Energy	$5.75	$2.80	$52.00	51.3%	11.1%	1.0262	11.3%	5.8%	0.0072	0.3067	0.22%	**6.0%**
15	TECO Energy	$1.75	$1.10	$13.25	37.1%	13.2%	1.0250	13.5%	5.0%	0.0076	0.3977	0.30%	**5.3%**
16	UIL Holdings	$2.40	$1.73	$27.50	27.9%	8.7%	1.0139	8.8%	2.5%	-	0.3125	0.00%	**2.5%**

DCF MODEL - COMBINATION UTILITY GROUP

BR+SV GROWTH RATE

		(a)	(a)	(f)	(a)	(a)	(f)	(g)	(a)	(a)		(h)	(a)	(a)	(g)
		-------------- 2011 -------------			-------------- 2016 -------------			Chg	-------- 2016 Price --------				---- Common Shares ----		
	Company	Eq Ratio	Tot Cap	Com Eq	Eq Ratio	Tot Cap	Com Eq	Equity	High	Low	Avg.	M/B	2011	2016	Growth
1	ALLETE	55.7%	$1,937	$1,079	60.0%	$2,325	$1,395	5.3%	$50.00	$35.00	$42.50	1.232	37.50	40.50	1.55%
2	Alliant Energy	50.9%	$5,921	$3,014	49.5%	$7,555	$3,740	4.4%	$55.00	$40.00	$47.50	1.468	111.02	116.00	0.88%
3	Ameren Corp.	53.7%	$14,738	$7,914	55.5%	$16,700	$9,269	3.2%	$45.00	$30.00	$37.50	1.034	242.60	255.00	1.00%
4	Avista Corp.	48.6%	$2,440	$1,186	48.0%	$3,125	$1,500	4.8%	$35.00	$25.00	$30.00	1.250	58.42	62.00	1.20%
5	Black Hills Corp.	48.6%	$2,490	$1,210	49.5%	$2,825	$1,398	2.9%	$40.00	$25.00	$32.50	1.048	43.92	45.00	0.49%
6	DTE Energy Co.	49.4%	$14,196	$7,013	50.0%	$17,900	$8,950	5.0%	$70.00	$50.00	$60.00	1.218	169.25	181.00	1.35%
7	Empire District Elec	50.1%	$1,386	$694	50.0%	$1,625	$813	3.2%	$25.00	$19.00	$22.00	1.173	41.98	43.25	0.60%
8	Exelon Corp.	54.0%	$26,661	$14,397	50.5%	$31,000	$15,655	1.7%	$55.00	$40.00	$47.50	1.900	663.00	630.00	-1.02%
9	Northwestern Corp.	47.8%	$1,797	$859	57.5%	$1,850	$1,064	4.4%	$45.00	$30.00	$37.50	1.293	36.28	36.80	0.29%
10	PG&E Corp.	50.2%	$24,119	$12,108	50.5%	$30,900	$15,605	5.2%	$55.00	$35.00	$45.00	1.250	412.26	435.00	1.08%
11	PPL Corp.	37.1%	$29,018	$10,766	47.5%	$34,700	$16,483	8.9%	$45.00	$30.00	$37.50	1.515	588.00	665.00	2.49%
12	Pub Sv Enterprise Grp	55.5%	$18,375	$10,198	55.0%	$24,400	$13,420	5.6%	$40.00	$30.00	$35.00	1.321	505.90	505.90	0.00%
13	SCANA Corp.	45.7%	$8,511	$3,890	48.0%	$12,950	$6,216	9.8%	$55.00	$40.00	$47.50	1.218	130.00	160.00	4.24%
14	Sempra Energy	49.2%	$20,015	$9,847	48.5%	$26,400	$12,804	5.4%	$85.00	$65.00	$75.00	1.442	239.93	246.00	0.50%
15	TECO Energy	45.8%	$4,954	$2,269	44.5%	$6,550	$2,915	5.1%	$25.00	$19.00	$22.00	1.660	216.00	221.00	0.46%
16	UIL Holdings	42.0%	$2,850	$1,197	43.0%	$3,200	$1,376	2.8%	$45.00	$35.00	$40.00	1.455	50.00	50.00	0.00%

(a) The Value Line Investment Survey (Feb. 24, Mar. 23, & May 4, 2012).
(b) Computed using the formula 2*(1+5-Yr. Change in Equity)/(2+5 Yr. Change in Equity).
(c) Product of average year-end "r" for 2016 and Adjustment Factor.
(d) Product of change in common shares outstanding and M/B Ratio.
(e) Computed as 1 - B/M Ratio.
(f) Product of total capital and equity ratio.
(g) Five-year rate of change.
(h) Average of High and Low expected market prices divided by 2016 BVPS.

DIVIDEND YIELD

	Company	(a) Price	(b) Dividends	Yield
1	Abbott Labs.	$ 56.68	$ 2.04	3.6%
2	Bard (C.R.)	$ 94.21	$ 0.76	0.8%
3	Church & Dwight	$ 47.75	$ 0.96	2.0%
4	Coca-Cola	$ 69.06	$ 2.04	3.0%
5	Colgate-Palmolive	$ 93.04	$ 2.32	2.5%
6	Gen'l Mills	$ 38.77	$ 1.28	3.3%
7	Kellogg	$ 51.92	$ 1.72	3.3%
8	Kimberly-Clark	$ 72.03	$ 2.96	4.1%
9	McCormick & Co.	$ 50.72	$ 1.24	2.4%
10	PepsiCo, Inc.	$ 63.76	$ 2.18	3.4%
11	Procter & Gamble	$ 65.82	$ 2.10	3.2%
12	Wal-Mart Stores	$ 60.49	$ 1.59	2.6%
	Average			**2.9%**

(a) Average of closing prices for 30 trading days ended Mar. 16, 2012.
(b) The Value Line Investment Survey, *Summary & Index* (Mar. 16, 2012).

GROWTH RATES

		(a)	(b)	(c)	(d)
		Earnings Growth			br+sv
	Company	**V Line**	**IBES**	**Zacks**	**Growth**
1	Abbott Labs.	8.5%	8.3%	7.5%	18.6%
2	Bard (C.R.)	8.5%	8.5%	10.4%	19.8%
3	Church & Dwight	10.5%	10.5%	11.8%	12.5%
4	Coca-Cola	10.0%	6.4%	8.0%	12.4%
5	Colgate-Palmolive	11.0%	8.8%	8.8%	11.0%
6	Gen'l Mills	8.5%	7.6%	8.0%	9.0%
7	Kellogg	7.5%	8.0%	8.8%	12.4%
8	Kimberly-Clark	7.0%	6.1%	6.5%	11.3%
9	McCormick & Co.	13.5%	8.4%	9.0%	18.0%
10	PepsiCo, Inc.	8.5%	6.2%	8.0%	11.2%
11	Procter & Gamble	10.0%	8.5%	8.8%	5.9%
12	Wal-Mart Stores	8.5%	9.1%	10.6%	5.8%

(a) The Value Line Investment Survey (retrieved Mar. 16, 2012).
(b) www.finance.yahoo.com (retrieved Mar. 16, 2012).
(c) www.zacks.com (retrieved Mar. 16, 2012).
(d) See Exhibit WEA-5.

DCF COST OF EQUITY ESTIMATES

		(a)	(a)	(a)	(a)
		Earnings Growth			**br+sv**
	Company	**V Line**	**IBES**	**Zacks**	**Growth**
1	Abbott Labs.	12.1%	11.9%	11.1%	22.2%
2	Bard (C.R.)	9.3%	9.3%	11.2%	20.6%
3	Church & Dwight	12.5%	12.5%	13.8%	14.5%
4	Coca-Cola	13.0%	9.3%	11.0%	15.4%
5	Colgate-Palmolive	13.5%	11.2%	11.3%	13.5%
6	Gen'l Mills	11.8%	10.9%	11.3%	12.3%
7	Kellogg	10.8%	11.3%	12.1%	15.7%
8	Kimberly-Clark	11.1%	10.2%	10.6%	15.5%
9	McCormick & Co.	15.9%	10.8%	11.4%	20.4%
10	PepsiCo, Inc.	11.9%	9.6%	11.4%	14.6%
11	Procter & Gamble	13.2%	11.7%	12.0%	9.1%
12	Wal-Mart Stores	11.1%	11.7%	13.2%	8.4%
	Average (b)	**12.2%**	**10.9%**	**11.7%**	**13.2%**
	Midpoint (c)	**12.6%**	**10.9%**	**12.2%**	**12.1%**

(a) Sum of dividend yield (page 1) and respective growth rate (page 2).
(b) Excludes highlighted figures.

BR+SV GROWTH RATE

		(a)	(a)	(a)			(b)	(c)		(d)	(e)		
		----------- 2016 ----------					Adjust.			--------- "sv" Factor --------			
	Company	**EPS**	**DPS**	**BVPS**	**b**	**r**	**Factor**	**Adj. r**	**br**	**s**	**v**	**sv**	**br + sv**
1	Abbott Labs.	$6.00	$2.20	$20.50	63.3%	29.3%	1.0341	30.3%	19.2%	(0.0068)	0.7722	-0.53%	**18.6%**
2	Bard (C.R.)	$9.00	$0.94	$36.75	89.6%	24.5%	1.0553	25.8%	23.1%	(0.0429)	0.7738	-3.32%	**19.8%**
3	Church & Dwight	$3.10	$0.72	$19.70	76.8%	15.7%	1.0403	16.4%	12.6%	(0.0015)	0.6248	-0.09%	**12.5%**
4	Coca-Cola	$4.90	$2.15	$9.10	56.1%	53.8%	1.0318	55.6%	31.2%	(0.2109)	0.8897	-18.77%	**12.4%**
5	Colgate-Palmolive	$7.60	$3.40	$11.00	55.3%	69.1%	1.0574	73.1%	40.4%	(0.3167)	0.9267	-29.34%	**11.0%**
6	Gen'l Mills	$3.40	$1.60	$14.30	52.9%	23.8%	1.0478	24.9%	13.2%	(0.0561)	0.7400	-4.15%	**9.0%**
7	Kellogg	$4.90	$2.15	$9.10	56.1%	53.8%	1.0318	55.6%	31.2%	(0.2109)	0.8897	-18.77%	**12.4%**
8	Kimberly-Clark	$6.50	$3.00	$21.25	53.8%	30.6%	1.0298	31.5%	17.0%	(0.0724)	0.7763	-5.62%	**11.3%**
9	McCormick & Co.	$5.05	$1.72	$23.10	65.9%	21.9%	1.0778	23.6%	15.5%	0.0314	0.7690	2.42%	**18.0%**
10	PepsiCo, Inc.	$5.95	$2.36	$25.40	60.3%	23.4%	1.0573	24.8%	14.9%	(0.0484)	0.7838	-3.79%	**11.2%**
11	Procter & Gamble	$5.95	$3.00	$32.85	49.6%	18.1%	1.0333	18.7%	9.3%	(0.0507)	0.6715	-3.40%	**5.9%**
12	Wal-Mart Stores	$6.00	$2.20	$26.30	63.3%	22.8%	1.0108	23.1%	14.6%	(0.1257)	0.6994	-8.79%	**5.8%**

DCF MODEL - NON-UTILITY GROUP

BR+SV GROWTH RATE

		(a)	(a)	(f)	(a)	(a)		(g)	(a)	(a)	(f)
		---- Common Equity ----			---------- 2016 Price ---------				----- Common Shares -----		
	Company	2011	2016	Chg.	High	Low	Avg.	M/B	2011	2016	Growth
1	Abbott Labs.	$22,388	$31,500	7.1%	$100.00	$80.00	$90.00	4.390	1,547.00	1,535.00	-0.16%
2	Bard (C.R.)	$1,690	$2,940	11.7%	$180.00	$145.00	$162.50	4.422	84.00	80.00	-0.97%
3	Church & Dwight	$1,871	$2,800	8.4%	$60.00	$45.00	$52.50	2.665	142.40	142.00	-0.06%
4	Coca-Cola	$2,158	$2,965	6.6%	$90.00	$75.00	$82.50	9.066	365.60	325.00	-2.33%
5	Colgate-Palmolive	$2,675	$4,750	12.2%	$165.00	$135.00	$150.00	13.636	494.85	440.00	-2.32%
6	Gen'l Mills	$5,403	$8,720	10.0%	$60.00	$50.00	$55.00	3.846	656.50	610.00	-1.46%
7	Kellogg	$2,158	$2,965	6.6%	$90.00	$75.00	$82.50	9.066	365.60	325.00	-2.33%
8	Kimberly-Clark	$5,917	$7,975	6.2%	$105.00	$85.00	$95.00	4.471	406.90	375.00	-1.62%
9	McCormick & Co.	$1,463	$3,190	16.9%	$110.00	$90.00	$100.00	4.329	133.10	138.00	0.73%
10	PepsiCo, Inc.	$21,476	$38,125	12.2%	$130.00	$105.00	$117.50	4.626	1,581.00	1,500.00	-1.05%
11	Procter & Gamble	$61,439	$85,700	6.9%	$110.00	$90.00	$100.00	3.044	2,838.50	2,610.00	-1.66%
12	Wal-Mart Stores	$68,542	$76,360	2.2%	$95.00	$80.00	$87.50	3.327	3,516.00	2,900.00	-3.78%

(a) The Value Line Investment Survey (retrieved Mar. 16, 2012).
(b) Computed using the formula 2*(1+5-Yr. Change in Equity)/(2+5 Yr. Change in Equity).
(c) Product of year-end "r" for 2016 and Adjustment Factor.
(d) Product of change in common shares outstanding and M/B Ratio.
(e) Computed as 1 - B/M Ratio.
(f) Five-year rate of change.
(g) Average of High and Low expected market prices divided by 2016 BVPS.

CAPM - CURRENT BOND YIELD **Exhibit WEA-6**

COMBINATION UTILITY GROUP

Market Rate of Return		
Dividend Yield (a)	2.5%	
Growth Rate (b)	10.8%	
Market Return (c)		13.3%
Less: Risk-Free Rate (d)		
Long-term Treasury Bond Yield		2.9%
Market Risk Premium (e)		10.4%
Utility Proxy Group Beta (f)		0.74
Risk Premium (g)		7.7%
Plus: Risk-free Rate (d)		
Long-term Treasury Bond Yield		2.9%
Unadjusted CAPM (h)		10.6%
Size Adjustment (i)		0.78%
Implied Cost of Equity (j)		**11.4%**

(a) Weighted average dividend yield for the dividend paying firms in the S&P 500 from www.valueline.com (retrieved Apr. 17, 2012).
(b) Weighted average of IBES earnings growth rates for the dividend paying firms in the S&P 500 (retrieved May 8, 2012).
(c) (a) + (b)
(d) Average yield on 30-year Treasury bonds for May 2012 from the Federal Reserve Board at http://www.federalreserve.gov/releases/h15/data/Monthly/H15_TCMNOM_Y20.txt.
(e) (c) - (d).
(f) www.valueline.com (retrieved May 2, 2012).
(g) (e) x (f).
(h) (d) + (g).
(i) *Morningstar* , "2012 Ibbotson SBBI Valuation Yearbook," at Appendix C, Table C-1 (2012).
(j) (h) + (i).

CAPM - PROJECTED BOND YIELD

COMBINATION UTILITY GROUP

Market Rate of Return		
Dividend Yield (a)	2.5%	
Growth Rate (b)	10.8%	
Market Return (c)		13.3%
Less: Risk-Free Rate (d)		
Projected Long-term Treasury Bond Yield		4.4%
Market Risk Premium (e)		8.9%
Utility Proxy Group Beta (f)		0.74
Risk Premium (g)		6.5%
Plus: Risk-free Rate (d)		
Projected Long-term Treasury Bond Yield		4.4%
Unadjusted CAPM (h)		11.0%
Size Adjustment (i)		0.78%
Implied Cost of Equity (j)		**11.8%**

(a) Weighted average dividend yield for the dividend paying firms in the S&P 500 from www.valueline.com (retrieved Apr. 17, 2012).
(b) Weighted average of IBES earnings growth rates for the dividend paying firms in the S&P 500 (retrieved May 8, 2012).
(c) (a) + (b)
(d) Average projected 30-year Treasury bond yield for 2012-2016 based on data from the Value Line Investment Survey, *Forecast for the U.S. Economy* (Feb. 24, 2012), IHS Global Insight, *U.S. Economic Outlook* at 25 (Dec. 2011), Blue Chip Financial Forecasts, Vol. 30, No. 12 (Dec. 1, 2011).
(e) (c) - (d).
(f) www.valueline.com (retrieved May 2, 2012).
(g) (e) x (f).
(h) (d) + (g).
(i) *Morningstar* , "2012 Ibbotson SBBI Valuation Yearbook," at Appendix C, Table C-1 (2012).
(j) (h) + (i).

ELECTRIC UTILITY RISK PREMIUM

CURRENT BOND YIELDS

Current Equity Risk Premium

(a)	Avg. Yield over Study Period	8.91%
(b)	May 2012 Average Utility Bond Yield	4.36%
	Change in Bond Yield	-4.55%
(c)	Risk Premium/Interest Rate Relationship	-0.4114
	Adjustment to Average Risk Premium	1.87%
(a)	Average Risk Premium over Study Period	3.41%
	Adjusted Risk Premium	**5.28%**

Implied Cost of Equity

(b)	May 2012 BBB Utility Bond Yield	4.97%
	Adjusted Equity Risk Premium	5.28%
	Risk Premium Cost of Equity	**10.25%**

(a) Exhibit WEA-7, page 3.
(b) Moody's Investors Service, www.creditrends.com.
(c) Exhibit WEA-7, page 4.

PROJECTED BOND YIELDS

Current Equity Risk Premium

(a)	Avg. Yield over Study Period	8.91%
(b)	Projected Average Utility Bond Yield	6.16%
	Change in Bond Yield	-2.75%
(c)	Risk Premium/Interest Rate Relationship	-0.4114
	Adjustment to Average Risk Premium	1.13%
(a)	Average Risk Premium over Study Period	3.41%
	Adjusted Risk Premium	**4.54%**

Implied Cost of Equity

(b)	Projected BBB Utility Bond Yield	6.74%
	Adjusted Equity Risk Premium	4.54%
	Risk Premium Cost of Equity	**11.28%**

(a) Exhibit WEA-7, page 3.
(b) Projected yields on utility bonds for 2012-16 based on data from IHS Global Insight, *U.S. Economic Outlook* at 25 (Dec. 2011), Energy Information Administration, *Annual Energy Outlook 2012, Early Release* (Jan. 23, 2012), and Moody's Investors Service at www.credittrends.com.
(c) Exhibit WEA-7, page 4.

AUTHORIZED RETURNS

Year	(a) Allowed ROE	(b) Average Utility Bond Yield	Risk Premium
1974	13.10%	9.27%	3.83%
1975	13.20%	9.88%	3.32%
1976	13.10%	9.17%	3.93%
1977	13.30%	8.58%	4.72%
1978	13.20%	9.22%	3.98%
1979	13.50%	10.39%	3.11%
1980	14.23%	13.15%	1.08%
1981	15.22%	15.62%	-0.40%
1982	15.78%	15.33%	0.45%
1983	15.36%	13.31%	2.05%
1984	15.32%	14.03%	1.29%
1985	15.20%	12.29%	2.91%
1986	13.93%	9.46%	4.47%
1987	12.99%	9.98%	3.01%
1988	12.79%	10.45%	2.34%
1989	12.97%	9.66%	3.31%
1990	12.70%	9.76%	2.94%
1991	12.55%	9.21%	3.34%
1992	12.09%	8.57%	3.52%
1993	11.41%	7.56%	3.85%
1994	11.34%	8.30%	3.04%
1995	11.55%	7.91%	3.64%
1996	11.39%	7.74%	3.65%
1997	11.40%	7.63%	3.77%
1998	11.66%	7.00%	4.66%
1999	10.77%	7.55%	3.22%
2000	11.43%	8.09%	3.34%
2001	11.09%	7.72%	3.37%
2002	11.16%	7.53%	3.63%
2003	10.97%	6.61%	4.36%
2004	10.75%	6.20%	4.55%
2005	10.54%	5.67%	4.87%
2006	10.36%	6.08%	4.28%
2007	10.36%	6.11%	4.25%
2008	10.46%	6.65%	3.81%
2009	10.48%	6.28%	4.20%
2010	10.34%	5.56%	4.78%
2011	10.22%	5.13%	5.09%
Average	12.32%	8.91%	3.41%

(a) Major Rate Case Decisions, Regulatory Focus, Regulatory Research Associates; *UtilityScope Regulatory Service* , Argus.

(b) Moody's Investors Service.

REGRESSION RESULTS

SUMMARY OUTPUT

Regression Statistics	
Multiple R	0.9062018
R Square	0.8212016
Adjusted R Square	0.816235
Standard Error	0.005182
Observations	38

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	0.004439957	0.00444	165.344	5.054E-15
Residual	36	0.000966702	2.7E-05		
Total	37	0.005406659			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
Intercept	0.0707625	0.00297293	23.8023	1.3E-23	0.06473308	0.07679183	0.064733085	0.07679183
X Variable 1	-0.411449	0.031997942	-12.8586	5.1E-15	-0.4763441	-0.3465546	-0.47634415	-0.34655465

EXPECTED EARNINGS APPROACH

COMBINATION UTILITY GROUP

		(a)	(b)	(c)
	Company	**Expected Return on Common Equity**	**Adjustment Factor**	**Adjusted Return on Common Equity**
1	ALLETE	9.5%	1.025678	9.7%
2	Alliant Energy	11.0%	1.021575	11.2%
3	Ameren Corp.	7.5%	1.015794	7.6%
4	Avista Corp.	9.0%	1.023501	9.2%
5	Black Hills Corp.	8.5%	1.014469	8.6%
6	DTE Energy Co.	9.0%	1.024386	9.2%
7	Empire District Elec	9.5%	1.015693	9.6%
8	Exelon Corp.	13.5%	1.008377	13.6%
9	Northwestern Corp.	10.5%	1.021374	10.7%
10	PG&E Corp.	10.5%	1.025366	10.8%
11	PPL Corp.	11.0%	1.042568	11.5%
12	Pub Sv Enterprise Grp	11.5%	1.027447	11.8%
13	SCANA Corp.	9.5%	1.04685	9.9%
14	Sempra Energy	11.0%	1.026249	11.3%
15	TECO Energy	13.0%	1.025044	13.3%
16	UIL Holdings	8.5%	1.013935	8.6%
	Average (d)			**10.4%**
	Midpoint (e)			**10.6%**

(a) The Value Line Investment Survey (Feb. 24, Mar. 23, & May 4, 2012).
(b) Adjustment to convert year-end return to an average rate of return from Exhibit WEA-3.
(c) (a) x (b).
(d) Excludes highlighted figures.
(e) Average of low and high values.

CAPITAL STRUCTURE | **Exhibit WEA-9**

UTILITY OPERATING COS.

		At Fiscal Year-End 2011 (a)		
	Company	**Debt**	**Preferred**	**Common Equity**
1	Ameren Illinois Co.	40.3%	1.5%	58.2%
2	Black Hills Power	45.1%	0.0%	54.9%
3	Cheyenne Light Fuel & Power	41.8%	0.0%	58.2%
4	Commonweath Edison Co.	44.6%	0.0%	55.4%
5	Detroit Edison Co.	52.5%	0.0%	47.5%
6	Interstate Power & Light	46.0%	5.1%	49.0%
7	Pacific Gas & Electric Co.	48.1%	1.1%	50.8%
8	PECO Energy Co.	39.5%	1.7%	58.8%
9	PPL Electric Utilities Corp.	44.7%	6.5%	48.8%
10	Pub Service Electric & Gas Co.	47.9%	0.0%	52.1%
11	San Diego Gas & Electric	51.5%	0.0%	48.5%
12	South Carolina Electric & Gas	46.2%	0.0%	53.8%
13	Southern California Gas Co.	37.6%	0.6%	61.8%
14	Superior Water, Light & Power Co.	40.1%	0.0%	59.9%
15	Tampa Electric Co.	48.0%	0.0%	52.0%
16	Union Electric Co.	49.5%	1.0%	49.5%
17	Wisconsin Power & Light	41.9%	2.3%	55.8%
	Average	**45.0%**	**1.2%**	**53.8%**

(a) Company Form 10-K and Annual Reports, FERC Form 1 Annual Reports.

CAPITAL STRUCTURE

COMBINATION UTILITY GROUP

		At Fiscal Year-End 2011 (a)			Value Line Projected (b)		
	Company	**Debt**	**Preferred**	**Common Equity**	**Debt**	**Other**	**Common Equity**
1	ALLETE	44.4%	0.0%	55.6%	40.0%	0.0%	60.0%
2	Alliant Energy	45.7%	3.5%	50.9%	47.5%	3.0%	49.5%
3	Ameren Corp.	45.9%	0.0%	54.1%	43.5%	1.0%	55.5%
4	Avista Corp.	48.7%	2.1%	49.1%	52.0%	0.0%	48.0%
5	Black Hills Corp.	39.1%	0.0%	60.9%	50.5%	0.0%	49.5%
6	DTE Energy Co.	50.6%	0.0%	49.4%	50.0%	0.0%	50.0%
7	Empire District Elec	50.0%	0.0%	50.0%	50.0%	0.0%	50.0%
8	Exelon Corp.	46.6%	0.3%	53.1%	49.0%	0.5%	50.5%
9	Northwestern Corp.	51.4%	0.0%	48.6%	42.5%	0.0%	57.5%
10	PG&E Corp.	48.9%	1.0%	50.1%	48.5%	1.0%	50.5%
11	PPL Corp.	61.9%	0.0%	38.1%	52.0%	0.5%	47.5%
12	Pub Sv Enterprise Grp	40.9%	0.0%	59.1%	45.0%	0.0%	55.0%
13	SCANA Corp.	54.5%	0.0%	45.5%	52.0%	0.0%	48.0%
14	Sempra Energy	50.4%	0.1%	49.5%	51.5%	0.0%	48.5%
15	TECO Energy	57.3%	0.0%	42.7%	55.5%	0.0%	44.5%
16	UIL Holdings	58.8%	0.0%	41.2%	57.0%	0.0%	43.0%
	Average	**49.7%**	**0.4%**	**49.9%**	**49.2%**	**0.4%**	**50.5%**

(a) Company Form 10-K and Annual Reports.
(b) The Value Line Investment Survey (Feb. 24, Mar. 23, & May 4, 2012).

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

APPLICATION OF KENTUCKY	**)**	
UTILITIES COMPANY FOR AN	**)**	**CASE NO. 2012-00221**
ADJUSTMENT OF ITS	**)**	
ELECTRIC RATES	**)**	

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

Filed: June 29, 2012

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

A. My name is Lonnie E. Bellar. I am the Vice President, State Regulation and Rates for Kentucky Utilities Company ("KU" or "Company") and Louisville Gas and Electric Company ("LG&E"). I am employed by LG&E and KU Services Company, which provides services to KU and LG&E (collectively "the Companies"). My business address is 220 West Main Street, Louisville, Kentucky, 40202. A complete statement of my education and work experience is attached to this testimony as Appendix A.

Q. Have you previously testified before the Kentucky Public Service Commission?

A. Yes. I have testified before the Commission numerous times, including the Companies' most recent base rate cases,[1] and most recently in the Companies' application for Certificates of Public Convenience and Necessity to purchase existing generating units and to build a new natural-gas combined cycle generating facility.[2]

Q. What are the purposes of your testimony?

A. The purposes of my testimony are: (1) to support certain exhibits required by the Commission's regulations; (2) to present the revenue effects and the bill impacts to the average residential customer; (3) to present KU's recommendation for the allocation of the proposed increases in revenues among the customer classes based on the results of the Company's cost of service study prepared by Robert M. Conroy in this case; (4) to explain the relationship of KU's various cost-recovery mechanisms to

[1] *In the Matter of: Application of Kentucky Utilities Company for an Adjustment of Its Base Rates*, Case No. 2009-00548; *In the Matter of: Application of Louisville Gas and Electric Company for an Adjustment of Its Electric and Gas Base Rates*, Case No. 2009-00549.

[2] *In the Matter of: Joint Application of Louisville Gas and Electric Company and Kentucky Utilities Company for a Certificate of Public Convenience and Necessity and Site Compatibility Certificate for the Construction of a Combined Cycle Combustion Turbine at the Cane Run Generating Station and the Purchase of Existing Simple Cycle Combustion Turbine Facilities from Bluegrass Generation Company, LLC in LaGrange, Kentucky*, Case No. 2011-00375.

its base rates; (5) to explain certain pro forma adjustments to which the testimony of Kent W. Blake refers; (6) to discuss proposed changes to KU's Curtailable Service Riders ("CSRs"); and (7) to describe the various ways the Companies pursue energy-efficiency initiatives and provide customers ways to "go green."

Q. Are you supporting the schedules that are required by Commission regulations 807 KAR 5:001?

A. Yes, the table of contents to KU's filing requirements lists the schedules I am sponsoring. Although I am sponsoring KU's proposed tariff and proposed tariff changes, Mr. Conroy's testimony will address issues of rate design, as well as changes to the terms and conditions of KU's electric service.

Revenue Effect

Q. What are the revenue effects 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 adjustments is $82,432,892 for electric operations.

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

A. The average monthly residential electric bill increase due to the proposed electric base rates will be 8.03%, or approximately $7.41, for a residential customer using an average of 1,178 kWh of electricity.

Revenue Allocation

Q. Has KU analyzed how the proposed increase in revenue should be allocated among its customers?

A. Yes. Mr. Conroy and the State Regulation and Rates group conducted a fully allocated, embedded cost of service study. The study was also time-differentiated.

Q. What methodology did KU use in its cost of service study?

A. KU used the modified Base-Intermediate-Peak methodology that the Commission has followed for years. The details of that study are presented in the testimony of Mr. Conroy. The summary of the results of that study, reflecting the pro forma rate of return for the principal rate schedules, is set forth below:

Bellar Table I – Pro Forma Electric Rates of Return

Customer Class	**KU Electric Actual**
Residential – Rate RS	3.97%
General Service Rate – Rate GS	8.72%
All Electric Schools – Rate AES	7.25%
Power Service – Rate PS	
- Secondary	10.51%
- Primary	8.52%
Time-of-Day Secondary – Rate TODS	5.83%
Time-of-Day Primary – Rate TODP	5.89%
Retail Transmission Service – Rate RTS	6.06%
Fluctuating Load Service – Rate FLS	-1.59%
Lighting	7.13%
Total Kentucky Jurisdiction	6.02%

Based on the actual class rates of return, Mr. Conroy prepared a revenue allocation that, while increasing revenues across all the electric rate classes, also reduced some inter-class subsidies and capped certain classes at a maximum rate of return. The details of the KU electric revenue allocation are contained in Mr. Conroy's testimony. The overall results are shown below:

Bellar Table II

Pro Forma Electric Rates of Return as Adjusted for Proposed Increase

Customer Class	**KU Electric Proposed**
Residential – Rate RS	5.62%
General Service Rate – Rate GS	10.10%
All Electric Schools – Rate AES	8.86%
Power Service – Rate PS	
- Secondary	11.15%
- Primary	10.19%
Time-of-Day Secondary – Rate TODS	7.63%
Time-of-Day Primary – Rate TODP	7.58%
Retail Transmission Service – Rate RTS	7.82%
Fluctuating Load Service – Rate FLS	6.13%
Lighting	8.05%
Total Kentucky Jurisdiction	7.59%

Q. Following the results of the electric cost of service study, what ratemaking concepts did KU employ to develop the electric rates for this proceeding?

A. The foremost principle of proper rate design is cost causation. Therefore, KU crafted unit charges to reflect the cost of service study as nearly as practicable so customer charges would be more reflective of customer-related costs, demand charges would be more reflective of demand-related costs, and energy-commodities charges would be more reflective of energy-commodity-related costs. Also, KU sought to simplify rate design wherever feasible.

<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 assessed separately from base rates.

Q. Do ratemaking mechanisms such as the fuel adjustment clause, environmental cost recovery mechanism, and demand-side management cost recovery mechanism have any effect on the base rate increase KU is requesting?

A. No. As presented in the testimony of Mr. Blake and discussed in Mr. Conroy's testimony, the impact of those mechanisms has been removed from the calculation of KU's operating revenues and expenses for the test year ended March 31, 2012. The mechanisms, and the costs and revenues associated with them, therefore have no effect on the calculation of the revenue deficiency and corresponding base rate increase that KU is requesting in this case. In addition, by removing these items from the calculation of net operating income in the Application, there is no double recovery of these costs or double counting of these revenues.

Pro Forma Adjustments

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

A. Consistent with prior rate cases, unbilled revenues were removed from test-year operating revenues. The Commission determined a similar adjustment to be reasonable in Case Nos. 2003-00434 and 2009-00548. KU proposed a similar adjustment in Case No. 2008-00251, which was resolved by a settlement approved by the Commission.

Q. Please explain the adjustment to operating revenues concerning off-system sales margins shown in Reference Schedule 1.09 of Blake Exhibit 1.

A. For the reasons discussed in Paul Thompson's testimony, KU is facing significantly declining off-system sales margins and cannot reasonably expect to achieve the amount of off-system sales margins in the test year going forward. Clear evidence of this phenomenon can be seen in Reference Schedule 1.09 of Blake Exhibit 1, which compares test-year off-system sales margins to an annualized amount of such margins based on the first three months' results from 2012 (the last three months of the test year). The comparison, based on known and measurable changes during the test year, shows that KU's off-system sales margins are in steep decline. This proposed adjustment therefore removes from test-year off-system sales margins the difference between the test-year results and the annualized amount of such margins based on the first three months' results from 2012. KU will update this adjustment upon request to include post-test-year data.

Q. Please explain the adjustment to operating expenses concerning the SPP-to-TranServ ITO expenses shown in Reference Schedule 1.20 of Blake Exhibit 1.

A. KU currently has embedded in its electric base rates its share of the cost of Independent Transmission Operator ("ITO") services performed for the Companies by the Southwest Power Pool, Inc. ("SPP"). On January 31, 2012, the Companies filed an application with the Commission in Case No. 2012-00031 for approval of the transfer of nearly all of the ITO functions currently performed by SPP to TranServ International, Inc. ("TranServ") and its subcontractor MAPPCOR. KU's share of the expected annual cost of ITO services from TranServ and MAPPCOR is less than the amount currently embedded in KU's base electric rates. The Commission issued an order on May 11, 2012, approving the transfer from SPP to TranServ and MAPPCOR to be effective as of September 1, 2012, well before any changes to base rates resulting from this proceeding will be decided by this Commission or placed into effect. The time for appealing or seeking rehearing of the May 11 order has now passed. Therefore, the adjustment to operating expenses shown in Reference Schedule 1.20 of Blake Exhibit 1 reflects the reduction in annual operating expenses that will result from this transfer.

Q. Please explain the adjustment to operating expenses concerning the amortization of the general management audit regulatory asset shown in Reference Schedule 1.22 of Blake Exhibit 1.

A. In its July 30, 2010 Orders in the Companies' most recent rate cases, the Commission ordered a general management audit to be conducted of the Companies.[3] Consistent with KRS 278.255(3), the Companies paid the cost of the audit.

KRS 278.255(3) entitles the Companies to recover the cost of the audit through base rates as part of their cost of service. Based on that authority, the Companies created a regulatory asset for each utility in the amount of each utility's share of the management audit's cost, and now propose to amortize each asset over three years. The Commission found a similar adjustment and amortization period to be reasonable in Case No. 2003-00434.[4]

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

A. This adjustment to operating expenses is necessary to include the expenses incurred in conjunction with this base rate case and to remove the appropriate amounts of annualized amortization for expenses incurred in the two most recent base rate cases,

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[3] *In the Matter of: Application of Kentucky Utilities Company for an Adjustment of Base Rates,* Case No. 2009-00548, Order at 35 (July 30, 2010); *In the Matter of: Application of Louisville Gas and Electric Company for an Adjustment of Electric and Gas Base Rates*, Case No. 2009-00549, Order at 37 (July 30, 2010).

[4] *In the Matter of: Adjustment of the Electric Rates, Terms and Conditions of Kentucky Utilities Company*, Case No. 2003-00434, Order Appx. F (June 30, 2004).

Case Nos. 2009-00548 and 2008-00251. KU estimates the total electric rate case expense, including publishing public notice, to be $2,030,000. KU proposes to amortize this expense over 3 years at a rate of $676,667 per year. This estimate was used only for the purpose of calculating the revenue requirement at the time of filing KU's Application. KU requests recovery of its actual expenses in this proceeding in accordance with Commission policy, and requests that it be allowed to provide the Commission monthly updates to reflect its actual rate case expenses through Commission requests for information. The adjustment thus will be trued-up as actual expenditures are incurred. This adjustment also accounts for amortizations of KU's two most recent base rate case costs and is consistent with a similar adjustment in the revenue requirements analysis performed and found reasonable by the Commission in the Company's most recent base rate case, Case No. 2009-00548, and in Case Nos. 2008-00251, and 2003-00434.

Proposed Changes to Curtailable Service Riders

Q. Please summarize the changes KU proposes to make to its current Curtailable Service Riders CSR10 and CSR30.

A. KU proposes to reduce the credits available under both riders to reflect more accurately the value CSR customers provide under the riders. For CSR10, KU proposes to reduce the credit to $2.80 kVA/month for primary-level customers and $2.75 kVA/month for transmission-level customers. For CSR30, in recognition of the lower value associated with a 30-minute notice compared to a 10-minute notice, KU proposes a credit of $2.30 kVA/month for primary-level customers and $2.25 kVA/month for transmission-level customers. Additionally, KU proposes to remove the current restrictions on when KU can require physical curtailment, which will increase the value of the riders to KU and its non-CSR customers. Even with these modifications in place, KU's two CSR options should still be attractive to its large industrial customers.

Q. How are KU's CSRs currently structured?

A. The Commission approved KU's and LG&E's current CSRs in their most recent rate cases, Case Nos. 2009-00548 and 2009-00549, as part of the stipulation and recommendation reached in the cases. Each of the Companies has two CSRs, which are structured as shown in the table below.

		Interruption (hrs.)		Credit $/kW Month	
	Min. Notice	Physical	Buy Through	Trans.	Primary
CSR 10	10	100	275	5.4	5.5
CSR 30	30	100	250	4.3	4.4

KU may request a buy-through interruption without restriction, but may request physical curtailment only in the event of a "system reliability event," defined to be any condition or occurrence: 1) that impairs KU and LG&E's ability to maintain service to contractually committed system load; 2) where KU and LG&E's ability to meet their compliance obligations with NERC reliability standards cannot otherwise be achieved; or 3) that KU and LG&E reasonably anticipate will last more than six hours and could require KU and LG&E to call upon automatic reserve sharing at some point during the event. The constraint on when KU may use physical curtailment significantly reduces the value of the CSRs to KU and its non-CSR customers.

KU currently has just three CSR customers, all on CSR10. LG&E has just two CSR customers, one on CSR10 and the other on CSR30.

Q. Why does KU propose to change its existing CSRs?

A. Although the credits KU currently provides under its CSRs are less than the estimated cost of a combustion turbine ("CT") in today's marketplace, they are still too high in view of the significant limitations on the use of CSR and the availability of only 100 hours of physical interruption.

By way of comparison, from the time the new CSRs went into effect in August 2010 through the end of the test year (March 31, 2012), the Companies used their large-frame CTs extensively, accumulating an average of 948 operating hours per unit from an average of 126 starts. This equates to an annual average of 598 operating hours per unit and 80 starts. Over the same period, the Companies operated their five 100 MW CTs on an annual average basis of 95 hours per unit and 21 starts. Thus, the average annual usage of the Companies' 14 modern CTs is 643 hours and 59 starts. This value far exceeds the operational limitations in the CSR tariff. Moreover, existing CSR customers can terminate their CSR contracts with only six months' notice and new customers have a minimum contract term of just one year, further differentiating this resource from a physical resource. It is therefore unreasonable to use the fully loaded cost of a CT for the calculation of the value for CSR, and suggests a markedly lower value for CSR curtailment would be appropriate.

Fortunately, determining what would be a more appropriate CSR value does not have to occur in a vacuum; recent data are available to review in determining what would be a reasonable base CSR credit. For example, the purchase price of Bluegrass CTs the Companies recently negotiated, and the most recent PJM demand-response auction. The purchase price for the Bluegrass CTs was $222/kW, which, using a 10% carrying cost, would yield a CSR-equivalent value of $1.85/kW-month. The most recent PJM demand response auction generated a $3.83/kW-month result for 2014-15. Values in the auction were considerably less in 2012-13 at $0.50/kW-month and $0.84/kW-month for 2013-14. Based on these data, offering a transmission-level credit of $2.75/kVA-month and a primary-level credit of $2.80/kVA-month for CSR10 strikes a reasonable balance between capacity-market prices and the desire to encourage demand response.

But to justify even this reduced CSR credit requires removing the restriction on the circumstances under which KU can use physical curtailment. Although increasing the number of hours of physical curtailment available would increase the value of the CSRs to KU and its non-CSR customers, KU's CSR customers have expressed a strong desire to limit the hours of physical interruption to no more than 100 hours. KU therefore proposes to eliminate the current "system reliability event" restriction on its ability to request physical curtailment of CSR customers' loads. The physical assets KU controls have no such restriction. Thus, to justify even a reduced CSR credit of $2.75/kVA-month, KU proposes to remove the current restriction.

Q. What will be the effect of changing the CSRs as KU proposes?

A. The result of changing the CSRs as KU proposes will be to bring the amount of the CSR credits more in line with the actual economic value CSR customers provide. This approach should still provide CSR customers with a healthy incentive to participate in the program while ensuring non-CSR customers receive a fair value for the credits they provide.

Programs to Encourage Conservation and Green Energy

Q. What steps have the Companies taken to encourage energy conservation and to permit customers to "go green"?

A. The Companies have taken numerous steps to encourage energy conservation and to permit customers to "go green." First and foremost, the Companies are the clear leaders in Demand-Side Management and Energy Efficiency ("DSM-EE") programs in Kentucky, having been involved in such programs for almost twenty years and recently expanding and reconfiguring their DSM-EE portfolio. Second, the Companies have several different tariff structures to permit customers who wish to self-generate with renewable or other kinds of generation to do so while still receiving service from the Companies. Third, the Companies offer a Green Energy Rider and Low-Emission Vehicle ("LEV") Rate for customers who desire to "go green" by encouraging lower carbon emissions. Fourth and finally, the Companies' personnel involved in these matters periodically consult with their counterparts throughout the PPL family of companies to share best practices and to further our goal to continue to improve and expand the Companies' DSM-EE, "green," and related offerings to our customers, all in a manner consistent with our commitment and obligation to provide lowest-reasonable-cost service safely and reliably to all customers.

Q. Please describe briefly the Companies' leadership in DSM-EE programs in Kentucky.

A. The Companies have long had an impressive portfolio of cost-effective DSM-EE programs, and the Companies have expanded and improved their portfolio of DSM-EE programs to include numerous residential and commercial offerings. They are currently in the process of implementing the portfolio changes the Commission approved in Case No. 2011-00134. The Companies' current and soon-to-be-implemented DSM-EE program offerings provide customers a wide array of options for reducing their electric demand and energy usage, from the long-standing residential and commercial load-control programs to residential and commercial energy-efficiency rebate programs Through the end of the test year, the Companies' DSM-EE programs produced cumulative energy savings of over 900,000 MWh, gas savings of over 15 million Ccf, and a cumulative demand reduction of 226 MW. For large industrial customers, the Companies provide CSR options to compensate such customers for the value of being able to interrupt their service—in other words, to decrease their demand—at times of peak need, which is a form of demand-side management. Therefore, the Companies are currently providing and continue to work to provide conservation-minded customers plentiful options to achieve their conservation and bill-reduction goals.

Q. What options are available for customers who desire to self-generate?

A. The Companies offer three tariff options for customers who desire to self-generate: Net Metering Service (Rider NMS), Small Capacity Cogeneration Qualifying Facilities (Rider SQF), and Large Capacity Cogeneration Qualifying Facilities (Rider LQF). These options permit customers who self-generate on their own property to do so while remaining connected to the Companies' facilities to provide any additional energy such customers may need. All three of the tariff options provide a means of compensating customers who self-generate beyond their own energy requirements.

Q. Please describe further the tariff options the Companies provide for customers who desire to "go green."

A. The Companies provide two explicitly "green" tariff options to customers. The first is the Green Energy Rider. The Green Energy Rider enables customers to contribute funds to be used to purchase Renewable Energy Certificates, which directly support renewable energy sources as they produce verifiable amounts of energy. It is an entirely voluntary program in which over one thousand customers participate.

The second "green" option the Companies offer is the Low-Emission Vehicle rate. The LEV rate is available to residential customers who invest in battery-powered vehicles or natural-gas-powered vehicles that use the electricity supplied under Rate LEV to power natural-gas filling stations at their residences. The time-differentiated rates offered under Rate LEV enable participating customers to enjoy reduced off-peak rates during hours when it is most likely they will need the energy to charge or power the fueling of their cars.

Q. How is the Companies' approach to these conservation and "green" programs and tariff options consistent with the Companies' commitment to providing low-cost service?

A. The Companies' foremost responsibility is to provide lowest-reasonable-cost service safely and reliably to all customers. Therefore, where programs, such as the Companies' DSM-EE programs, are part of a lowest-reasonable-cost solution to providing service to all customers, the Companies proudly take ownership of them. That is also true of the renewable resources, as the Companies have demonstrated by their work to refurbish the Ohio Falls hydroelectric facility.

But as the Companies demonstrated conclusively in their most recent IRP and generation CPCN cases, fossil-fueled generation remains the least-reasonable-cost means of providing the capacity and energy their customers need and desire. Moreover, it appears that will continue to be the case for decades to come. But that is all the more reason for the Companies to provide their customers options to encourage or even generate "green" energy; it enables customers to achieve their goals while the Companies continue to fulfill their mandate to all customers.

<u>Administrative Case No. 2008-00408</u>

Q. The Commission's October 6, 2011 Order in Administrative Case No. 2008-00408 states, "In each rate case, the subject electric utility shall fully explain its consideration of cost-effective energy efficiency resources and the impact of such resources on its test year."[5] Although the order is not binding on the Companies because the Commission has granted rehearing in that proceeding, how has KU considered such resources, and what impact have they had on KU's test year?

A. During the test year, the Companies filed an application seeking revisions to, and an expansion of, their current DSM-EE offerings in Case No. 2011-00134.[6] The Commission approved the Companies' application on November 9, 2011.[7] (Rather than recite at length the contents of that application and the testimony that accompanied it, I respectfully refer the Commission to the record of that proceeding.) As the electric utilities offering the most extensive DSM-EE programs in the

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[5] *In the Matter of: Consideration of the New Federal Standards of the Energy Independent and Security Act of 2007*, Case No. 2008-00408, Order at 24 (Oct. 6, 2011).

[6] *In the Matter of: Joint Application of Louisville Gas and Electric Company and Kentucky Utilities Company for Review, Modification, and Continuation of Existing, and Addition of New Demand-Side Management and Energy Efficiency*, Case No. 2011-00134, Application (April 14, 2011).

Commonwealth, the Companies are not just considering such programs, but are successfully implementing them on a large scale. Indeed, in its final order in Case No. 2011-00375, the Commission "recognize[d] that the ICF Report indicated that the Joint Applicants' DSM portfolio contained many elements of best practices, including cost effectiveness, broad targeting, and flexible design."[8]

Also, the Companies consider and evaluate such programs in their Integrated Resource Planning, and assume that such programs will deliver the forecasted results when making generation investment decisions, as the Companies demonstrated in their recent application for additional generating resources in Case No. 2011-00375.

Through the end of the test year, KU's DSM-EE programs achieved a total demand reduction of 90 MW, and in the test year alone produced energy savings of over 100,000 MWh.

Finally, in accordance with the Commission's May 3, 2012 Order in Case No. 2011-00375, the Companies issued a request for proposals for a vendor to conduct a DSM-EE potential and market-characterization study to determine what additional DSM-EE potential may exist for the Companies' service territory. The Companies are currently reviewing the proposals and expect to select a vendor in July. The Companies look forward to receiving the results of the study and to providing it to the Commission.

Q. Does this conclude your testimony?

A. Yes.

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[7] *In the Matter of: Joint Application of Louisville Gas and Electric Company and Kentucky Utilities Company for Review, Modification, and Continuation of Existing, and Addition of New Demand-Side Management and Energy Efficiency*, Case No. 2011-00134, Order (Nov. 9, 2011).
[8] *Id.* at 18.

VERIFICATION

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

The undersigned, **Lonnie E. Bellar**, being duly sworn, deposes and says that he is Vice President, State Regulation and Rates for Louisville Gas and Electric Company and Kentucky Utilities Company and an employee of LG&E and KU Services Company, and that he has personal knowledge of the matters set forth in the foregoing testimony, and that the answers contained therein are true and correct to the best of his information, knowledge and belief.

Lonnie E Bellar
Lonnie E. Bellar

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 20th day of June 2012.

Joan A. Henry (SEAL)
Notary Public

My Commission Expires:

July 21, 2015

APPENDIX A

Lonnie E. Bellar
LG&E and KU Energy LLC
220 West Main Street
Louisville, Kentucky 40202

<u>Education</u>

Bachelors in Electrical Engineering;
University of Kentucky, May 1987
Bachelors in Engineering Arts;
Georgetown College, May 1987
E.ON Academy, Intercultural Effectiveness Program: 2002-2003
E.ON Finance, Harvard Business School: 2003
E.ON Executive Pool: 2003-2007
E.ON Executive Program, Harvard Business School: 2006
E.ON Academy, Personal Awareness and Impact: 2006

<u>Professional Experience</u>

E.ON U.S. LLC

Vice President, State Regulation and Rates	Aug. 2007 – Present
Director, Transmission	Sept. 2006 – Aug. 2007
Director, Financial Planning and Controlling	April 2005 – Sept. 2006
General Manager, Cane Run, Ohio Falls and Combustion Turbines	Feb. 2003 – April 2005
Director, Generation Services	Feb. 2000 – Feb. 2003
Manager, Generation Systems Planning	Sept. 1998 – Feb. 2000
Group Leader, Generation Planning and Sales Support	May 1998 – Sept. 1998

Kentucky Utilities Company

Manager, Generation Planning	Sept. 1995 – May 1998
Supervisor, Generation Planning	Jan. 1993 – Sept. 1995
Technical Engineer I, II and Senior, Generation System Planning	May 1987 – Jan. 1993

<u>Professional Memberships</u>

IEEE

<u>Civic Activities</u>

E.ON U.S. Power of One Co-Chair – 2007
Louisville Science Center – Board of Directors – 2008 – Present
Chairman of Louisville Science Center Board beginning June 2012
Metro United Way Campaign – 2008
UK College of Engineering Advisory Board – 2009 – Present

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

APPLICATION OF KENTUCKY	**)**	
UTILITIES COMPANY FOR AN	**)**	**CASE NO. 2012-00221**
ADJUSTMENT OF ITS	**)**	
ELECTRIC RATES	**)**	

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

Filed: June 29, 2012

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Conroy Exhibit R2 – Residential Electric Unit Cost
Conroy Exhibit R3 – Reconstruction of Electric Billing Determinants
Conroy Exhibit R4 – Summary of Electric Revenue Increase
Conroy Exhibit R5 – Electric Revenue Increase by Rate Schedule
Conroy Exhibit R6 – Summary of Increases to Miscellaneous Charges

Miscellaneous Service Charges & Deposits
Conroy Exhibit M1 – Excess Facilities Charge Cost Support
Conroy Exhibit M2 – Redundant Capacity Charge Cost Support
Conroy Exhibit M3 – Supplemental and Standby Service Cost Support
Conroy Exhibit M4 – Cable TV Attachment Charges
Conroy Exhibit M5 – Meter Test Charge Cost Support
Conroy Exhibit M6 – Disconnect/Reconnect Charge Cost Support
Conroy Exhibit M7 – Meter Relay Pulse Charge Cost Support
Conroy Exhibit M8 – Customer Deposit Requirements

I. INTRODUCTION

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

A. My name is Robert M. Conroy. I am the Director of Rates for Kentucky Utilities Company ("KU" or "the Company") and Louisville Gas and Electric Company ("LG&E"). I am employed by LG&E and KU Services Company, which provides services to LG&E and KU (collectively "the Companies"). My business address is 220 West Main Street, Louisville, Kentucky. A statement of my professional history and education is attached to this testimony as Appendix A.

Q. Have you previously testified before this Commission?

A. Yes, I have testified before the Commission numerous times, including KU's two most recent base rate cases,[1] and most recently in the KU 2011 environmental cost recovery ("ECR") proceeding.[2]

Q. What are the purposes of your testimony?

A. The purposes of my testimony are: (1) to support certain exhibits identified below which are required by the Commission's regulations; (2) to explain certain proposed pro forma adjustments; (3) to sponsor the fully allocated class cost of service study based on KU's embedded cost of providing electric service for the 12 months ended March 31, 2012; (4) to describe the proposed allocation of the revenue increases for KU's electric operations and the proposed rates; and (5) to discuss and explain the various tariff changes KU proposes.

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[1] *In the Matter of: Application of Kentucky Utilities Company for an Adjustment of Base Rates*, Case No. 2008-00251; *In the Matter of: Application of Kentucky Utilities Company for an Adjustment of Base Rates,* Case No. 2009-00548.

[2] *In the Matter of: The Application of Kentucky Utilities Company for Certificates of Public Convenience and Necessity and Approval of Its 2011 Compliance Plan for Recovery by Environmental Surcharge,* Case No. 2011-00161.

Q. Are you supporting certain information required by Commission regulation 807 KAR 5:001, Section 10(6)(a)-(v) and Section 10(7)(e)?

A. Yes, I am sponsoring the following schedules for the corresponding filing requirements:

• New Rates Effect – Overall Revenues	Section 10(6)(d)	Tab 23
• Average Customer Class Bill Impact	Section 10(6)(e)	Tab 24
• Analysis of Customer Bills	Section 10(6)(g)	Tab 26
• Cost of Service Study	Section 10(6)(u)	Tab 40
• Period-End Customer Additions	Section 10(7)(e)	Tab 46

II. PRO FORMA ADJUSTMENTS

Q. Please explain the adjustment to operating expenses and revenues to eliminate the mismatch between fuel costs and fuel cost recovery through the Fuel Adjustment Clause ("FAC") shown in Reference Schedule 1.01 of Blake Exhibit 1.

A. Consistent with past Commission practice, the mismatch between fuel costs and fuel cost recovery through KU's FAC has been eliminated. These over- and under-recoveries were taken directly from KU's monthly FAC filings. The Commission determined a similar adjustment to be reasonable in Case Nos. 2003-00434 and 2009-00548, and KU proposed such an adjustment in Case No. 2008-00251, which was resolved by a settlement approved by the Commission.

Q. Please explain the adjustment to operating revenues to reflect the roll-in of the FAC for a full year shown in Reference Schedule 1.02 of Blake Exhibit 1.

A. The Commission's May 31, 2011 Order in Case No. 2010-00492 authorized the roll-in of the FAC into base rates effective with the July 2011 billing cycle.[3] Test-year revenues have been adjusted to reflect the rolled-in level of base rates and FAC billings for a full year. Conroy Exhibit P1 shows the impact on base rate revenues of the FAC roll-ins for a full year. Conroy Exhibit P2 shows the impact on FAC billings of reflecting the new base fuel cost (Fb/Sb) for a full year. The Commission determined a similar adjustment to be reasonable in Case Nos. 2003-00434 and 2009-00548. KU proposed a similar adjustment in Case No. 2008-00251, which was resolved by a settlement approved by the Commission.

Q. Please explain the adjustment to operating revenues and expenses to reflect changes to the FAC calculations shown in Reference Schedule 1.03 of Blake Exhibit 1.

A. KU is seeking to correct a long-standing mismatch in the calculation of its monthly FAC billing factors. KU provides electric service to customers in multiple jurisdictions, and recovers its fuel expense through approved recovery mechanisms in each jurisdiction. Specific to its Kentucky retail business, KU calculates its retail FAC billing factor, consistent with Commission regulation 807 KAR 5:056, using *total company* fuel expense, generation, and sales. The per kWh cost of fuel, adjusted by the retail base fuel component, is then billed to KU's Kentucky retail customers only, ensuring that appropriate cost recovery occurs.

The mismatch in the monthly FAC calculations that KU is seeking to correct relates to the inclusion of system losses as a component of sales. KU currently

[3] *In the Matter of: An Examination of the Application of the Fuel Adjustment Clause of Kentucky Utilities Company from November 1, 2008 through October 31, 2010*, Case No. 2010-00492 (Order dated May 31, 2011).

includes only the portion of losses calculated to occur on the Kentucky jurisdiction portion of its electric system. KU does not jurisdictionalize any of the components of its FAC calculation *except* system losses, and by including only a portion of its losses in the FAC calculations, KU is misstating its recoverable fuel expense. KU proposes to implement the use of total system losses in the FAC monthly calculation with the expense month coinciding with the implementation of new base rates in this proceeding, thereby ensuring that there is no inadvertent opportunity for over- or under-recovery of FAC-eligible fuel expenses. Supporting calculations to adjust for the inclusion of Total System losses is shown in Conroy Exhibit P3.

Q. Please explain the adjustment to operating expenses and revenues to eliminate ECR revenues and expenses shown in Reference Schedule 1.04 of Blake Exhibit 1.

A. Consistent with the Commission's practice of eliminating the revenues and expenses associated with full-cost-recovery trackers, an adjustment was made to eliminate ECR revenues and expenses during the test year that will continue to be included in the ECR mechanism after the implementation of new base rates as shown in Reference Schedule 1.04 of Blake Exhibit 1. The ECR surcharge provides for full recovery of approved environmental costs that qualify for the surcharge.

Q. Did KU make changes to the methodology used to eliminate ECR revenues from the test period?

A. Yes. As a result of the Commission's Order in Case No. 2009-00310 approving the use of the revenue requirement method for calculating the monthly ECR billing factor, KU is removing all ECR revenues collected in the environmental surcharge and in base rates.[4] The removal of ECR revenues from base rates is necessary to ensure base revenues reflect only base rate components and costs are recovered through the appropriate rate-making mechanism.

Q Please explain why it is necessary to eliminate all ECR revenues from the test period.

A. Prior to the Commission's Order in Case No. 2009-00310, KU used a percentage method called the Base-Current methodology to calculate the monthly ECR billing factors. The calculation to determine the Monthly Environmental Surcharge Factor ("MESF") was established by subtracting the Base Environmental Surcharge Factor ("BESF") from the Current Environmental Surcharge Factor ("CESF"). All three factors were based on a percentage of a 12-month historical revenue calculation.

The CESF was the net jurisdictional E(m) divided by the 12-month average retail revenues (excluding ECR revenues). The BESF was the ECR annual revenue requirement currently included in base rates divided by 12-month base rate revenues (basic service charges, energy charges and demand charges) for the period immediately preceding the effective date of the roll-in adjustment to base rates. The MESF was the arithmetic difference between CESF and BESF and was the billing factor applied to retail bills. However, the CESF and BESF were determined using different 12-month historical revenues in the denominator.

In Case No. 2009-00310, KU proposed, and the Commission approved, the use of the revenue requirement method for calculating the monthly ECR billing factor. Through continued process improvements and modifications to the billing

[4] *In the Matter of: An Examination By The Public Service Commission of the Environmental Surcharge Mechanism of Kentucky Utilities Company for the Two-Year Billing Period Ending April 30, 2009*, Case No. 2009-00310 (Order dated December 2, 2009).

system, KU can identify the amount of ECR revenue collected through base rates in a given month prior to the filing of the ECR monthly billing factor for the expense month. To determine the monthly ECR billing factor, the Net Jurisdictional Revenue Requirement for the environmental projects is reduced by the actual ECR revenue collected through base rates to arrive at the Net Jurisdictional Revenue Requirement to be collected through the monthly ECR billing factor. Therefore, the ECR billing factor revenues are directly impacted by the revenues collected through bases rates for the ECR roll-in. Thus, it is necessary to remove all revenues associated with the total ECR revenue requirement from revenues when determining the revenue requirement for the establishment of new base rates. As previously stated, this will ensure that base rate revenues only reflect base rate components.

Q. Is KU proposing to eliminate from the ECR mechanism the 2005 and 2006 ECR Plans?

A. Yes. In Case Nos. 2003-00434 and 2009-00548, KU proposed, and the Commission approved, the elimination of the 1994 ECR Plan, and the 2001 and 2003 ECR Plans, respectively, from the ECR mechanism. In a similar manner, KU is proposing in this proceeding to eliminate its 2005 and 2006 ECR Plans (with the exception of Project 22 discussed below) from its monthly ECR filings on a going-forward basis because the projects in those plans are now complete and in service, the costs of the projects in those plans are already included in base rates through a series of "roll-ins," and eliminating the two plans will simplify the oversight and administration of the ECR mechanism. As a result of eliminating the 2005 and 2006 ECR Plans in Reference Schedule 1.04 of Blake Exhibit 1, only the revenues and operating expenses associated with KU's 2009, 2011, and subsequent ECR Plans that will continue to be part of the ECR mechanism are eliminated in this adjustment. KU proposes to recover the revenue requirements for the environmental compliance rate base associated with the 2005 and 2006 Plans through base rates, and proposes to continue to recover the revenue requirements of the remaining environmental compliance rate base through its monthly ECR mechanism (both the roll-in component and the monthly billing factor component). Upon approval of new base rates, KU will continue to use the approved ES Forms in the monthly ECR filings but exclude the costs associated with the 2005 and 2006 Plan projects in the expense month associated with the change in base rates until the next 2-year review, at which time the ES Forms will be modified to reflect the elimination of the 2005 and 2006 Plans. Conroy Exhibit P4 shows the supporting data and calculations of the revenue requirement and expenses associated with the 2005 and 2006 ECR Plans that are included in Reference Schedule 1.04 of Blake Exhibit 1.

Q. Please describe KU's proposal concerning the treatment of emission allowance expenses, inventory, and sales currently being recovered through the environmental surcharge mechanism.

A. KU currently recovers through the environmental surcharge mechanism as part of Project 22 (2005 Plan) the costs related to the use of emission allowances less the annual emission allowance expense of $58,346 included in current base rates. Additionally, KU earns a return on the emission allowance inventory less the allowance inventory of $69,415 included in current base rates, and includes the total proceeds from the sale of emission allowances less allowance sales proceeds baseline of $286,166 included in current base rates.

KU is proposing to separate Project 22 from the 2005 Plan to maintain the current treatment of emission allowance expenses, inventory, and sales currently being recovered through the environmental surcharge mechanism and remove the base rate baseline amounts from the monthly calculations. The amounts in the base rate baselines related to emission allowances were established based on the test year in Case No. 2003-00434. Due to the uncertainty of future environmental regulation, it is more appropriate to include emission allowances in a separate tracking mechanism like the environmental surcharge mechanism than in base rates. The emission allowance base rate baseline amounts are included in the 2005-2006 Plans Revenues and Expenses in Reference Schedule 1.04 of Blake Exhibit 1. The total amounts related to emission allowances are included the Net Revenues and Expenses in Reference Schedule 1.04 of Blake Exhibit 1.

Q. Are there other adjustments necessary for the elimination of the 2005 and 2006 ECR Plans previously discussed?

A. Yes. As discussed in the testimony of Mr. Blake, KU's capitalization as of March 31, 2012, is adjusted to remove the environmental compliance rate base associated with the ECR mechanism. This adjustment, shown in Column 12 of Blake Exhibit 2, includes only the environmental compliance rate base associated with the ECR Plans that will continue to be included in the ECR monthly filings and the remaining amount associated with the roll-in recently approved in Case No. 2011-00231.[5] It does not include the environmental compliance rate base associated with the 2005 and 2006 ECR Plans.

Q. Please explain the adjustment to operating revenues shown in Reference Schedule 1.05, which concerns off-system sales revenues related to the ECR calculation.

A. In the determination of the monthly ECR surcharge, a portion of KU's environmental compliance costs are allocated to off-system sales, including intercompany sales, through the jurisdictional allocation ratio. But by including off-system and intercompany sales revenues in test-year operating results, these revenues are credited to jurisdictional customers. Moreover, because total ECR expenses are removed through the adjustment in Reference Schedule 1.04, the expenses associated with off-system and intercompany sales are understated. This results in an overstatement of margins from off-system and intercompany sales and a mismatch of the revenues and expenses related to the off-system and intercompany sales portion of the allocated environmental surcharge monthly revenue requirement. KU has included in this adjustment a reduction to revenues associated with ECR-related off-system and intercompany sales revenues. KU performed the adjustment in a manner generally consistent with the methodology used in Case No. 2009-00548; however, an adjustment (shown on page 2 of 2 in Reference Schedule 1.05 of Blake Exhibit 1) was made to the ECR revenue requirements to reflect the elimination of the 2005 and 2006 Plans, as previously discussed.

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[5] *In the Matter of: An Examination by the Public Service Commission of the Environmental Surcharge Mechanism of Kentucky Utilities Company for the Two-Year Billing Period Ending April 30, 2011*, Case No. 2011-00231, Order January 31, 2012.

Q. Please explain the adjustment to operating revenues and expenses shown in Reference Schedule 1.10, which annualizes year-end customers.

A. The numbers of customers served at the end of the test period for the rate classes differed from the average number of customers for the 13-month period including the test year. Prior practice has been to multiply the differences between the number of customers served at year-end and the average number for each rate class during the 13-month period 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 basic service charges, energy charges, demand charges and minimum bills calculated net of base ECR). This approach is reasonable when applied to rate classes with large numbers of customers and relatively low average per customer usage, i.e., homogenous groups of customers such as Residential and General Services. However, the average usage and average cost methods can cause inaccurate results when applied to rate classes with smaller numbers of customers and larger average usage, particularly rate classes with wide ranges of electricity usage. For example, if KU applied the average usage methodology to its analysis of the RTS class, the resulting calculation would indicate a net decrease of one customer and a corresponding decrease in revenue of approximately $188,000. To verify this result, KU undertook a detailed analysis of the RTS class, found that four customers left the KU system and five customers joined the system during the test year, for a net change in customer count of positive one. Because this result is the opposite of what the average usage method would indicate, KU elected to analyze the customers in the three largest-usage rate classes: Rate RTS, Rate TODP and Rate TODS. For customers that were determined to have left the system during the test-year, KU removed the revenue received (adjusted to current rates net of base ECR) from the test year revenue and from the total for the rate class. For customers that joined the KU system during the test year, KU annualized each customer's actual usage and calculated incremental revenue at current rates net of base ECR, which was added to test year revenues and to the total revenue for the rate class. These calculations are detailed on pages 3-5 of Conroy Exhibit P5, and the results of the calculations are included in Conroy Exhibit R4 (Summary of Electric Revenue Increase) and Conroy Exhibit R5 (Electric Revenue Increase by Rate Schedule). Base ECR was removed from current rates to ensure that the revenue adjustments for year-end customers were calculated on a consistent basis with the total revenue requirement and cost of service study, both of which are net of all ECR revenues and costs.

As discussed in more detail below, several KU customers changed rates during the test year. To ensure that the calculations of the year-end customer adjustment accurately reflected the rate schedule that customers are currently on, the total customer count, energy consumption, and revenues were adjusted to reflect annual usage on the current rate net of base ECR for the entire test year. These calculations are detailed on pages 7 and 8 of Conroy Exhibit P5 and are included in Conroy Exhibit R4 (Summary of Electric Revenue Increase) and Conroy Exhibit R5 (Electric Revenue Increase by Rate Schedule).

The change in operating expenses associated with serving the change in customers and volumes was calculated by applying an operating ratio to the revenue adjustment. Consistent with the Commission's practice, the operating ratio 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 net of base ECR.

The detailed calculations of the electric year-end customer adjustment to revenues and expenses are contained in Conroy Exhibit P5, pages 1 and 2.

Q. Please explain the adjustment to operating revenues shown in Reference Schedule 1.11, which concerns customer rate switching and billing adjustments for electric customers.

A. KU must adjust its operating revenues to account for billing adjustments and customer rate switching related to a number of customers. Detail of the customers switching rates is more fully shown in Conroy Exhibit P6 and the detail of the other billing adjustments is shown in Conroy Exhibit P7. The Commission determined a similar adjustment to be reasonable in Case Nos. 2003-00434 and 2009-00548. KU proposed a similar adjustment in Case No. 2008-00251, which was resolved by a settlement approved by the Commission.

KU identified the customers that switched rate schedules during the test year, tracking the rate schedule each customer switched from and to. All customers switching to a particular rate schedule were grouped together and analyzed. First, test-year usage was re-billed at current rates net of base ECR to reflect the FAC and ECR roll-ins and the proposed elimination of the 2005 and 2006 ECR Plans. Then, test-year usage was recalculated as if each customer had been on the new rate schedule for the entire year. The revenue adjustment for rate switching is the net difference between the two calculations. The calculations are summarized in Conroy

Exhibit P6. Page 1 of the exhibit presents the revenue calculations for the rate schedule that customers left (or switched from). Page 2 of the exhibit presents the revenue calculations for the rate schedule that customers switched to, and presents the net difference in the calculations.

In October 2011, KU made a billing cycle adjustment to its six largest accounts to improve the accuracy of the calculation of unbilled revenues. Specifically, these six accounts were being billed on Cycle 1, which means that electric consumption was delivered entirely in one month, but included in revenue in the subsequent month. In other words, for a customer billed on Cycle 1, all electricity delivered and used in April is included in May revenues because the customer is billed on the first billing cycle in May. In contrast, customers billed on Cycle 20 are billed on the last billing cycle in April, so April revenue reflects April consumption. KU determined that billing its six largest accounts on Cycle 20 would remove uncertainty and volatility from its unbilled revenue calculations, and implemented the change in October 2011. The change was completely transparent to the customers, and the customers did not receive an additional bill as a result of the change. However, KU's test year revenues reflect 13 months of billing data during the test year. If the six accounts had been on billing Cycle 20 for the entire test year, the first month's data in the test year, billed on April's Cycle 1, would have been billed on March Cycle 20 and been excluded from the test year. Therefore, KU removed the April 2011 billing data from its test year revenues. The details of this adjustment are presented on Conroy Exhibit P7.

III. COST OF SERVICE STUDY

Q. Did you prepare a cost of service study for KU's electric operations based on financial and operating results for the 12 months ended March 31, 2012?

A. Yes. I supervised the preparation of a jurisdictional, fully allocated, time-differentiated, embedded cost of service study for electric operations. The cost of service study corresponds to the pro forma financial exhibits included in the testimony of Mr. Blake. 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 jurisdictional 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. Are the models used to perform the cost of service study consistent with prior base rate case proceedings?

A. Yes. KU continues to use the same spreadsheet models developed and utilized in the prior base rate proceedings to perform the cost of service study.

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 preceded by a jurisdictional separation study that allocated KU's total financial results to its four regulated jurisdictions – Kentucky retail customers, Virginia retail customers, Tennessee retail customers, and Federal Energy Regulatory Commission ("FERC") wholesale customers. Additionally, the Kentucky-jurisdictional cost of service was 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 jurisdictionally assigned (jurisdictionalized); (2) costs were functionally assigned (functionalized) to the major functional groups; (3) costs were then classified as energy-related, demand-related, or customer-related; (4) costs were assigned to the costing periods; and then (5) costs were allocated to the rate classes. Steps two through five are depicted in the following diagram, which assumes jurisdictional costs as the starting point (Figure 1).

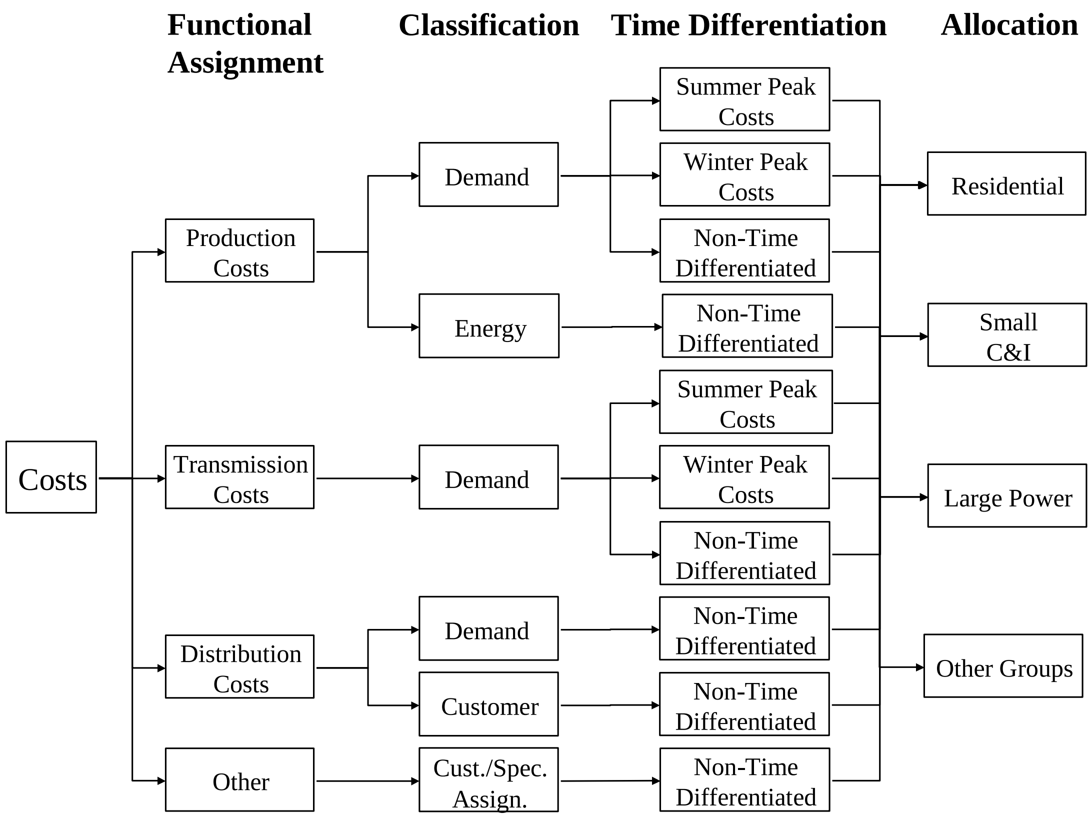

Figure 1

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. How were costs time differentiated in the study?

A. Consistent with prior studies, the modified Base-Intermediate-Peak ("BIP") methodology was used to assign production and transmission costs to each costing period.[6] 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 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 or winter peak periods or assigned as non-time-differentiated. Base costs were assigned as non-time-differentiated. Intermediate costs were assigned to the winter peak period. Peak costs were assigned to the summer peak period.

Q. In 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 to determine the percentages of production and transmission fixed cost assigned to the costing periods. Since the two systems are planned and operated jointly it is 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

[6] In Case No. 90-158, 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 December 21, 1990, at 58.)

periods and allocation factors using the combined KU and LG&E load in the cost of service study does not result in any shifting in booked expenses of one 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 Conroy Exhibit C1 shows the application of the modified BIP methodology. Using this methodology, 32.39% of KU's production and transmission fixed costs were assigned to the winter peak period, 33.26% to the summer peak period, and 34.35% 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 jurisdictional separation, functional assignment, time-differentiation and classification steps of the electric cost of service study?

A. Yes. Conroy Exhibit C2 shows the results of KU's jurisdictional separation and Conroy Exhibit C3 shows the results of the next 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 electric cost of service study:

- **E01** – Production energy costs and the energy cost component of purchased power costs were allocated on the basis of the kWh sales to each class of customers during the test year.
- **PPBDA** – The base demand cost components of production and transmission fixed costs were allocated on the basis each class's average annual demands, or the loss adjusted energy delivered divided by the hours

in the test period.

- **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.
- **NCPL** and **NCPS** – The demand cost component of distribution Poles and Lines (NCPL) and distribution Substations (NCPS) is allocated on the basis of the maximum class demands for primary and secondary voltage customers.
- **SICD** – The demand cost component of distribution fixed costs is allocated on the basis of the sum of individual customer demands for secondary voltage customers.
- **C02** – Distribution services costs were specifically assigned by relating the costs associated with various types of service installations for customers taking service at secondary voltage.
- **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.

- **C04 –** O&M expenses related to outdoor lighting costs are directly assigned to the Lighting rate class.
- **C05 –** O&M expenses related to meter reading and customer billing costs are allocated on the basis of weighted average customers.
- **C06 –** O&M expenses related to marketing and economic development costs are allocated on the basis of average customers.
- **YECust04** – Plant costs associated with lighting systems were specifically assigned to the lighting class of customers based on the lighting customers taking service at the end of the test period.
- **YECust05 and YECust06** – Plant costs associated with meter reading, billing costs and customer service expenses were allocated on the basis of a customer weighting factor based on discussions with KU’s meter reading, billing, and customer service departments and applied to the number of customers in each class at the end of the test period.
- **Cust07 –** O&M expenses related to distribution secondary line costs are allocated on the basis of average secondary customers.

- **Cust08 –** O&M expenses related to distribution primary line costs are allocated on the basis of average primary customers.
- **YECust07** – The customer-related Plant cost component of line transformers and secondary voltage conductor is allocated on the basis of the year-end number of secondary customers.
- **YECust08** – The customer-related Plant cost component of primary voltage conductor is allocated on the basis of the year-end number of primary customers.

Q. How are functionally assigned and classified costs allocated to the customer classes in the cost of service study?

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 accounting costs to simultaneously assign costs to the functional groups and classify costs. Therefore, in the portion of the model included in Conroy Exhibit C3, 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 Conroy Exhibit C3. 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 cash working capital on the same basis as total operation and maintenance expenses less purchased power. (See Conroy Exhibit C3, 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 "Functional Vector" and refers to a vector identified elsewhere in the analysis by the column labeled "Name."

Once the accounting costs 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.

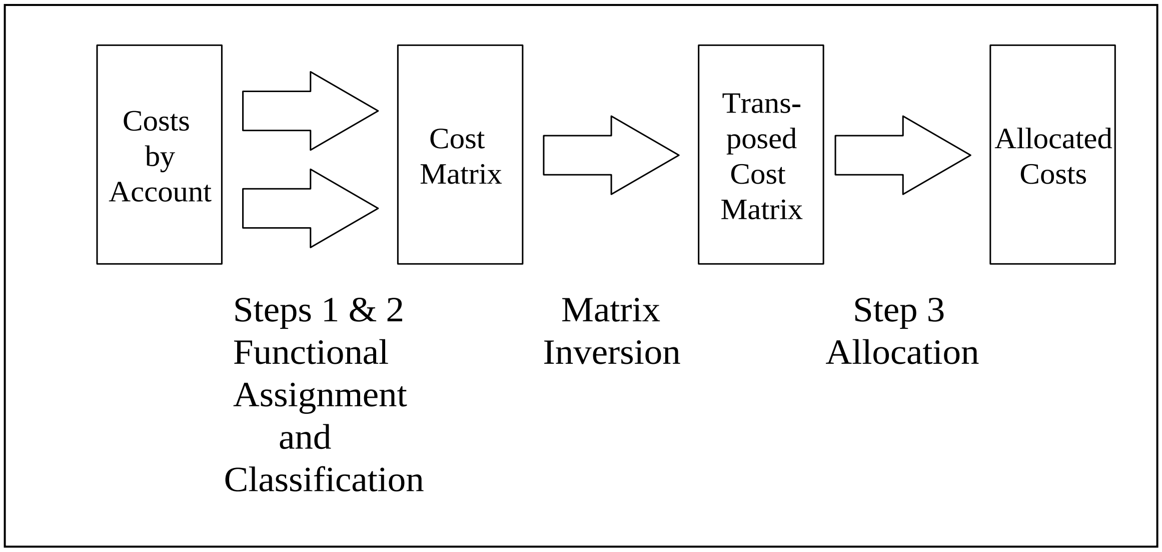

Figure 2

The results of the class allocation step of the cost of service study are included in Conroy Exhibit C4. The costs shown in the column labeled "Total System" in Conroy Exhibit C4 were carried forward *from* the functionally assigned and classified costs shown in Conroy Exhibit C3. The column labeled "Ref" in Conroy Exhibit C4 provides a reference to the results included in Conroy Exhibit C3, in the column labeled "Name".

Q. What methodology was used to classify distribution plant?

A. Consistent with the prior base rate proceedings, the "zero-intercept" methodology was used to determine the customer components of overhead conductors, underground conductors, and line transformers.

As explained in prior proceedings, the theory behind the zero-intercept methodology is that there is a linear relationship between the unit cost ($/ft or $/transformer) of conductors 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.

The feet of conductor and number of transformers on KU's system are not uniformly distributed over all sizes of wire and transformer. For this reason, it was necessary to use a weighted regression analysis in the determination of the zero intercept. Without performing a weighted regression analysis all types of conductor and transformers would have the same impact on the analysis, even though the quantity of conductor and transformers are not the same for each size and type.

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 LG&E's cost of service studies (both electric and gas) submitted in 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 The Union Light, Heat and Power Company in Case No. 2001-00092, which utilized a zero-intercept methodology, to be reasonable. In addition, KU has utilized the zero-intercept methodology when preparing the cost of service studies in Case Nos. 2003-00434, 2008-00251, and 2009-00548.

Q. Have you prepared exhibits showing the results of the zero-intercept analysis?

A. Yes. For overhead conductors the zero-intercept analysis is contained in Conroy Exhibit C5. For underground conductors the analysis is included in Conroy Exhibit C6. Finally, for line transformers the analysis is included in Conroy Exhibit C7.

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. Blake's 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 - RS	3.97%	5.62%
General Service - GS	8.72%	10.10%
All Electric Schools – AES	7.25%	8.86%
Power Service – Rate PS		
- Secondary	10.51%	11.15%
- Primary	8.52%	10.19%
Time of Day Secondary – TODS	5.83%	7.63%
Time of Day Primary – TODP	5.89%	7.58%
Retail Transmission Service - RTS	6.06%	7.82%
Fluctuating Load Service - FLS	-1.59%	6.13%
Lighting	7.13%	8.05%
Total System	6.02%	7.59%

Determination of the actual adjusted and proposed rates of return are detailed in Conroy Exhibit C4, pages 29-30 and pages 33-34, respectively.

IV. RATE DESIGN AND ALLOCATION OF INCREASE

A. ALLOCATION OF ELECTRIC REVENUE INCREASE

Q. What is the basic objective of the rate design being proposed?

A. It is the Companies' intent to continue the principles followed in the previous two rate cases of gradually eliminating cross-subsidization and bringing both the structure and the charges of the rate design in line with the results of the cost of service study. My testimony will address the charges supported by the cost of service studies.

Q. What changes does KU propose to its rate structures?

A. Though KU proposes to change most charges, it proposes no structural changes to its existing rate schedules, and a re-evaluation of the lighting rates. I will address only those rates the Company proposes to change structurally or with significant text changes.

Q. What efforts have LG&E and KU made towards harmonizing the service schedules offered by each company?

A. The Companies continue to take strides towards harmonizing the rate schedules where possible and have consolidated schedules, renamed schedules, added schedules, and revised language to be as consistent as possible between the two Companies. The table below summarizes the current and proposed KU rate schedule designations.

Current Rate Schedule	Proposed Rate Schedule	Availability kW or KVA
RS	RS	All
GS	GS	0 - 50
AES - Restricted	AES – Restricted	All
PS Secondary	PS (Secondary)	50 - 250
PS Primary	PS (Primary)	0 - 250
TOD Secondary	TODS (Secondary)	250 - 5,000
TOD Primary	TODP (Primary)	250 - 75,000 kVA
RTS	RTS	0 - 75,000 kVA
FLS	FLS	20,000 - 200,000 kVA

Through the changes made in the previous rate cases and those proposed for LG&E in its current proceeding, the Companies are close to completely harmonizing the rate schedules between LG&E and KU. Conroy Exhibit R1 shows a visual comparison between the LG&E and KU rate schedules for most of the service offerings.

Q. Please summarize how KU proposes to allocate the electric revenue increase to the classes of service.

A. KU relied on the results of the cost of service study to determine the methodology used to allocate the revenues to the classes of service, although consistent with gradualism, KU is not proposing rate adjustments that will move all classes of service to the overall rate of return. Instead, KU took a multi-step approach at allocating the revenue increase. First, KU allocated the increase across all rate schedules in an equal percentage. Second, in recognition of the fact that class subsidization exists, KU adjusted the revenue allocation to eliminate 15% of the subsidy received/(provided) between rate classes. Finally, given that the Rate PS Secondary class had a significantly higher rate of return than the other classes, KU made a further adjustment to lower the allocation to this class of customers. The Company is proposing a total revenue increase from sales to ultimate consumers of 6.49%. In recognition of differences in class rates of return, larger percentage increases are proposed for those classes with a rate of return from the cost of service study below the overall pro forma rate of return; conversely, smaller percentage increases are proposed for classes with rates of return that are higher than the overall.

The following table shows the pro forma class rates of return alongside the proposed percentage increase for each rate class:

TABLE 2
Class Rates of Return and
Proposed Percentage Increases

Customer Class	**Actual Adjusted Rate of Return**	**Proposed Increase**
Residential - RS	3.97%	8.03%
General Service - GS	8.72%	4.97%
All Electric Schools - AES	7.25%	5.81%
Power Service – Rate PS		
- Secondary	10.51%	1.96%
- Primary	8.52%	5.23%
Time of Day Secondary – TODS	5.83%	6.59%
Time of Day Primary – TODP	5.89%	6.62%
Retail Transmission Service - RTS	6.06%	6.50%
Fluctuating Load Service - FLS	-1.59%	6.25%
Lighting	7.13%	5.40%
Total System	6.02%	6.49%

B. RESIDENTIAL ELECTRIC RATE DESIGN & INCREASE

Q. Does KU propose to change its Residential Service, Rate RS, rate structure?

A. No. The rate structure will remain the same and consist of a Basic Service Charge and a flat energy charge.

Q. Is KU proposing to bring the rate components in residential electric rates more in line with the unit costs shown in the cost of service study?

A. Yes. KU is proposing to increase the monthly residential basic service charge from \$8.50 to \$13.00 to bring it more in line with the customer-related costs identified in the cost of service study. Even considering this increase, the basic service charge will be less than the cost of service. The cost of service study indicates that the customer-related cost for the residential class is \$18.82 per customer per month, so KU is proposing to increase the basic service charge in a direction that will more accurately reflect the actual cost of providing service. This cost is derived in Conroy Exhibit R2.

Q. Does the current monthly basic service charge of \$8.50 adequately recover customer-related costs from residential customers?

A. No. The current basic service charge of \$8.50 per customer per month does not even recover all of the customer-related operating expenses, let alone any of the margins (return) that would normally be assigned as customer-related cost. Based on calculations from the cost of service study, customer-related costs are \$18.82 per customer per month; therefore, there is an under-recovery of \$10.32 per customer per month through the basic service charge. When this under-recovery of \$10.32 per customer per month is multiplied by the 5,044,174 customer months for the residential rate class during the test year, the result is \$52,055,876 in customer related fixed operating expenses and margins that are not being recovered through the basic service charge. When this amount is recovered through the energy charge instead, the result is about 0.876 cents per kWh of customer fixed operating expenses and margins collected through the energy charge (calculated as $52,055,876 / 5,944,171,807 kWh = $0.00876 per kWh). Thus, the basic service charge is $10.32 per customer per month too low and the energy charge is 0.876 cents per kWh too high. This recovery of fixed operating expenses and margins through the energy charge results in intra-class subsidies. The proposed basic service charge of $13.00 partially mitigates this intra-class subsidy by removing a portion of fixed cost recovery from the energy component of residential rates. Consistent with the Commission's long-standing acceptance of gradualism, KU is not proposing the basic service charge that is supported by the cost of service study.

Q. What are intra-class subsidies and how can intra-class subsidies be avoided?

A. When one rate class subsidizes another rate class it is referred to as "inter-class subsidies," but when customers within a particular rate class subsidize other customers served under the same rate schedule it is referred to as "intra-class subsidies." The rate-making principle that should be followed to avoid intra-class subsidies is that, as much as possible, fixed costs should be recovered through fixed charges (such as the basic service charge and demand charge) and variable costs should be recovered through variable charges (such as the energy charge). If fixed costs are recovered through variable charges, each kWh contains a component of fixed costs and customers using more energy than the average customer in the class are paying more than their fair share of fixed costs and margins, while customers using less energy than the average customer in the class are paying less than their fair share of fixed costs and margins. These fixed costs and margins should be collected through the billing units associated with the appropriate cost driver, and energy usage clearly is *not* the correct cost driver for fixed costs. The collection of fixed costs through the energy charge typically results in customers with above-average usage subsidizing customers with below-average usage. The collection of variable costs through fixed charges also results in an intra-class subsidy, with customers with below-average usage subsidizing customers with above-average usage. To eliminate this source of intra-class subsidies, KU wants to pursue a rate design that moves more in the direction of recovering fixed costs through fixed charges and variable costs through variable charges.

Q. What impact would recovering more of the increase through the basic service charge than the energy charge have on the average customer?

A. Given a specified increase for the class, the average residential customer would see the same increase whether more is recovered through the basic service charge or the energy charge. Ultimately, the proposed rate for any given class of customers is based on averages and any rate design that is revenue neutral (i.e., generates the same amount of revenue) will have no impact whatsoever on a customer with a usage equal to the class average. Even average customers would see greater seasonal fluctuation as the impact on customer energy bills would be greatest at the extremes of very low energy usage and very high energy usage. The change would result in higher energy bills for low-usage customers, as the subsidy that they had been receiving was removed, and lower energy bills for high-usage customers as the subsidies that they had been paying were eliminated. Both would see smaller seasonal fluctuations.

Q. Typically, who are the low-usage customers who would be paying higher energy bills once the subsidies were removed?

A. For utilities such as KU, operating in a mixed service territory consisting of both urban and suburban customers, their low-usage customers tend to be loads like garages, workshops, outbuildings, vacation homes, hunting camps, and fishing camps, and for utilities such as LG&E, operating in an urban service territory, low usage customers tend to be loads like garages, workshops, outbuildings, and unusual service connections. All of these loads typically consume very few kilowatt hours during the course of a year and the usage is sporadic. However, the utility still incurs fixed costs in installing the minimum system requirements necessary to serve these loads. A rate design with a low basic service charge and with a significant portion of fixed operating expenses and margins recovered through the energy charge would result in the intra-class subsidies discussed above. It sends a signal that it is relatively inexpensive to provide the physical equipment necessary to provide service to customers, and this is definitely not the case.

Q. Would recovering more of the increase through the basic service charge rather than through the energy charge send the wrong signals for energy conservation?

A. No. The problem with recovering fixed costs through the energy charge is that whenever customers take measures to conserve energy they reduce the amount of fixed costs recovered by the utility. In this situation, even though its revenues have been reduced by the efforts of its customers to conserve energy, none of the utility's fixed costs have been avoided. What happens in this situation is that the utility's earnings are reduced as a result of customers using less energy. As customers have installed more efficient appliances, customer usage has gone down resulting in a corresponding reduction in revenues. The utility's fixed costs, however, have remained the same or may have even gone up causing its earnings to go down.

Q. Would recovering more of the cost through the basic service charge rather than through the energy charge have the effect of stabilizing customers' monthly bills?

A. Yes. Increasing the basic service charge will reduce the spikes that customers see in their bills during high usage months and cause customer bills to be somewhat more level throughout the course of a year.

C. LARGE CUSTOMER TIME OF DAY RATES

Q. Is KU proposing to modify the rate structure of its Time of Day rate schedules?

A. No. KU proposes to retain the same rate structure with the demand rates billed on a kW basis for Time of Day Secondary Rate TODS, and on a kVA basis for Time of Day Primary Rate TODP, Retail Transmission Service Rate RTS, and Fluctuating Load Service Rate FLS. The proposed Basic Service Charge, flat Energy Charge, and Peak, Intermediate, and Basic Demand charges for the time of day rate schedules are detailed on pages 6-9 of Conroy Exhibit R5.

D. OTHER STANDARD RATE SCHEDULES

Q. What changes does KU propose to make to its lighting rates?

A. Furthering the harmonization process, KU is aligning its lighting rate format with that of LG&E. Rather than have a separate rate sheet for public authorities and one for private customers both with fixtures and services at essentially the same rates and both rate sheets with restricted lighting styles, types, and sizes, KU proposed a simplified lighting offering. Similar to the LG&E rate schedules, lighting styles no longer offered will be listed on a Restricted Lighting Service ("Rate RLS") rate sheet. At the customer's option, these units will continue in service as long as KU can get replacement parts for maintenance. Both public authorities and private citizens will have an array of lighting options to choose from on a Lighting Service ("Rate LS") rate similar to the structure of LG&E. In addition, the lighting fixtures contained in Rate DSK are being incorporated in the Rate LS rate schedule. Throughout both Rate LS and Rate RLS, KU has consolidated various lights with the same or similar rates and has eliminated other lights which are not in service to simplify the number of lighting offerings. The lighting rates as a group, inclusive of Rates LS, RLS, LE and TE, are being increased by an average of approximately 5.4%.

Q. Does KU propose to change its All Electric School, Rate AES, rate structure?

A. No, and this rate will remain frozen to new customers. In accordance with Section 5.24 of the Settlement Agreement in Case No. 2009-00548, KU opened the Rate AES up to additional all electric schools. After identification by the Kentucky School Board Association ("KSBA") and assessment by KU of KSBA member schools located in KU's service territory of their eligibility to be on Rate AES, KU allowed a limited number of schools (up to an annual savings of $500,000) to migrate to the then-frozen rate schedule. KU allowed such migration to occur prior to July 1, 2011, as specified in Section 5.24 of the Settlement Agreement; however, the $500,000 threshold was not exceeded. Therefore, there are no additional KSBA member schools to be considered for service under Rate AES.

The rate structure will remain the same but the charges will increase to a proposed Basic Service Charge of $20.00 for single-phase service and $35.00 for three-phase service with a flat Energy Charge of $0.07060 per kWh. Although the rate structure is not appropriate for such an atypical customer grouping and the charges are less than what could be supported by the cost of service study, KU does not propose a redesign of the rate schedule to minimize individual impacts. Additionally, the Availability parameters have been rewritten for clarity. There has been no change in the meaning or application.

Q. Is KU proposing to modify the Fluctuating Load Service, Rate FLS?

A. Yes. The rate itself will retain the same structure but the minimum application will be restored to agree with the minimum structure in both Companies' Rate RTS, Rate TODP, Rate TODS, and even the minimum structure of LG&E's identical Rate FLS rate schedule. The separate minimum applicable only to a transmission customer has been removed and replaced by the same percentages of 50% for the Peak and Intermediate ratchet and 75% for the Base ratchet applied as they are for all other customers. This continues the harmonization process between Companies and the application of this revision to the minimum calculation for the test year has no impact on the customer served under Rate FLS. For transmission service, the charges themselves are proposed to increase to a Basic Service Charge of $750.00 per month, a flat Energy Charge of $0.03092 per kWh, and a time differentiated Demand Charges of $2.40 per kVA for the Peak Period, $1.44 per kVA for the Intermediate Period, and $1.00 per kVA for the Base Period. For primary service, the charges are proposed to be a Basic Service Charge of $750.00 per month, a flat Energy Charge of

$0.03419 per kWh, and a time differentiated Demand Charges of $2.40 per kVA for the Peak Period, $1.44 per kVA for the Intermediate Period, and $1.75 per kVA for the Base Period.

Q. Other than the changes mentioned previously, is the Company proposing any other significant structural changes to its rates?

A. No. However, in general, the Company is proposing to modify individual rate components to more accurately reflect the results of the cost of service study. The details of the proposed rates for each rate schedule are shown in Conroy Exhibit R5.

E. SUMMARY OF ELECTRIC RATE INCREASES

Q. Have you prepared exhibits reconstructing KU's test-year billing determinants for the electric business and showing the impact of applying the new rates to test-year billing determinants?

A. Yes. The reconstruction of KU's electric billing determinants is shown on Conroy Exhibit R3. The revenue increase by rate class is summarized on Conroy Exhibit R4. Conroy Exhibit R5 shows the impact of applying the current and proposed rates to test-year billing units. Conroy Exhibit R6 shows the impact of the proposed changes to the Company's miscellaneous charges. Specifically, the increase in other revenues is included in the Company’s proposed revenue increase on Conroy Exhibit R4. Consequently, these increased miscellaneous charges reduce the amount of the increase that would otherwise be recovered through the Company’s base rates. Changes to the miscellaneous charges are discussed below.

Q. What revenue increase is KU proposing?

A. KU is proposing an increase in test-year revenues of $82,432,892, which is calculated by applying the proposed rates to test-year billing determinants and including the proposed increases in miscellaneous charges discussed below. This increase is slightly different from the revenue requirement increase of $82,448,833 shown in Blake Exhibit 8 because the number of decimal places in the proposed charges cannot be carried out far enough to yield the exact amount shown in Mr. Blake's exhibit.

V. RIDERS, PILOT PROGRAMS, AND ADJUSTMENT CLAUSES

A. RIDERS

Q. Is KU proposing to change its Curtailable Service Rider (CSR 10 and CSR 30)?

A. Yes. The discussion of the changes is contained in the testimony of Lonnie E. Bellar.

Q. What changes does KU propose to make to its Load Reduction Incentive Rider, Rider LRI?

A. The Company proposes to eliminate Rider LRI. Rider LRI was initially implemented in 2000 as a three-year pilot program. It was extended for an additional three year period and subsequently made a permanent rate schedule in 2006. However, since it was made a permanent rate schedule, there have been no customers requesting to participate in Rider LRI. Since there are other options (through Rider CSR, Rider SQF or LQF, or Net Metering Service) for customers to utilize the output of their own generation, KU is proposing to remove this rider.

Q. What changes does KU propose to make to its Excess Facilities Rider, Rider EF?

A. The language was revised generally to provide greater clarity without changing the intent or application of the rate. In addition, a change to prevent an increase in the monthly charge during the initial 5-year term of contract was made in response to customer concerns over a possible failure in facilities requiring a replacement of equipment that would increase the installed cost.

Q. Is KU proposing any changes to the calculation of the Excess Facilities Rider, Rider EF charges?

A. No. The calculation of the two charges is consistent with the methodology used in prior rate proceedings. The Excess Facilities Rider applies to customer requests for service arrangements requiring equipment and facilities in excess of those the Company would normally install. Examples of excess facilities would include requests for non-standard facilities such as emergency backup feeds, automatic transfer switches, redundant transformer capacity, and duplicate or check meters. As shown in the Rider EF rate schedule, the customer has the option of either (a) requesting that KU incur the full cost of the equipment (including up-front equipment cost), in which event the monthly excess facilities charge (percentage with no Contribution-in-Aid of Construction) would cover the expected carrying charges on the equipment, the estimated maintenance cost on the equipment, and the estimated cost of replacing the equipment if it fails prior to the service life of the facilities, or (b) making an up-front payment to cover the cost of the facilities, in which event the monthly excess facilities charge (percentage with Contribution-in-Aid of Construction) would only cover the Company's estimated maintenance cost on the equipment and the estimated cost of replacing the facilities if they fail prior to the expected service life of the equipment. Because estimated failure costs would be included in the charge for either scenario, KU would replace the equipment if it fails prior to the end of the specified service life under either option.

Q. What are the proposed excess facilities charges?

A. Under the first option (a) discussed above, in which the Company makes the up-front investment the monthly charge would be 1.28% of the original cost of the facilities. Under the second option (b) discussed above, in which the customer makes the initial up-front investment the monthly charge would be 0.49% of the original cost of the facilities. Cost support for the proposed excess facilities charges is included in Conroy Exhibit M1.

Q. What changes does KU propose to make to its Redundant Capacity Rider, Rider RC?

A. The rider as originally provided considered a load being served on one delivery feed where an alternate feed allowed the transfer of that load to a second feed. There have been requests for a configuration allowing the load to be served on a split bus so that, in effect, half the load is served on each of two feeds and each of the half-loads can be switched to put the total load on either circuit. The Rider RC language is being changed to ensure these configurations will have the proper metering.

Q. What are the proposed Redundant Capacity charges?

A. The proposed demand charge for primary voltage customers is $0.99 per kW or kVA per month of billing demand and the proposed demand charge for secondary voltage customers is $1.55 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 standard demand/energy rates (Rates PS, TODS, and TODP) and dividing this amount by the billing demands for these classes of customers. There are different demand charges for customers served at primary and secondary voltages. The cost support for the proposed demand charges is included in Conroy Exhibit M2.

Q. What changes does KU propose to make to its Supplemental/Stand-by Rider, Rider SS?

A. Historically, KU's services have been provided under firm service rates. With the advent of customer-owned generation, this situation is gradually changing. The statement being added to Rider SS simply clarifies that KU is obligated only to provide firm service and is not required to provide supplemental or standby service unless that service is contracted for under Rider SS. This provision is supported by "EXCLUSIVE SERVICE ON INSTALLATION CONNECTED" on Rate Sheet No. 97.2. This provision does not in any way restrict or impinge upon a customer's right to receive firm service under the applicable rate schedule while also taking service under the Company's Net Metering Service rider, Rider NMS.

Q. What are the proposed Supplemental/Standby Service charges?

A. The proposed demand charge per contract demand (kW or kVA) for secondary customers is $12.91 per kW per month, for primary customers is $12.35 per kW or kVA per month, and for transmission customers is $11.17 per kVA per month.

Q. How were the demand charges for the Supplemental/Standby Service charges determined?

A. The proposed rates for Supplemental/Standby Service were determined by calculating unit charges for production, transmission and distribution services based on information contained in the cost-of-service study. For customers served at transmission voltage, the Supplemental/Standby Service demand charge includes fixed production and transmission costs. For customers served at primary voltages, the Supplemental/Standby Service demand charge includes fixed production, transmission, and primary distribution costs. For customers served at secondary voltages, the Supplemental/Standby Service demand charge includes fixed production, transmission, primary, and secondary distribution costs. The fixed costs are calculated based on cost information from the cost of service study for the following cost categories: (i) Production and Transmission, (ii) Primary Distribution, and (iii) Secondary Distribution. The additive nature of the Supplemental/Standby Service demand charges is illustrated in the table below:

Fixed Cost Category	**Transmission Voltage Service**	**Primary Voltage Service**	**Secondary Voltage Service**
Production and Transmission Costs	$11.17/kVA	$11.17/kW/kVA	$11.17/kW
Primary Distribution Costs	-	$1.18/kW/kVA	$1.18/kW
Secondary Distribution Costs	-	-	$0.56/kW
Total	**$11.17/kVA**	**$12.35/kW/kVA**	**$12.91/kW**

Production and Transmission Costs represent annual fixed cost revenue requirements. The unit charge is calculated by multiplying the KU jurisdictional coincident peak demand by twelve months and dividing this product into the production and transmission fixed cost determined based on the rate of return in this proceeding. Because customers on KU's system are served at different voltages, distribution fixed costs must be based on a fixed charge calculation for customers served exclusively under a primary-voltage rate or a secondary-voltage rate. Primary Distribution Costs were determined based on the fixed cost revenue requirements for the Power Service - Primary and Time of Day Primary customer classes on a combined basis, and Secondary Distribution Costs were determined based on the fixed cost revenue requirements for the Power Service - Secondary and Time of Day Secondary customer classes on a combined basis. The cost support for the proposed demand charges is included in Conroy Exhibit M3.

Q. What changes does KU propose to make to its Temporary Service Rider, Rider TS?

A. KU is clarifying the availability of service under Rider TS. The intent of Rider TS is for temporary service of short term duration where the Company is not required to permanently install facilities to serve the customer’s load requirements. Additionally, a correction is being made to state that the Excess Facilities percentage will be applied to salvageable materials.

B. PILOT PROGRAMS

Q. What changes does KU propose to make to its pilot program Real Time Pricing, RTP?

A. On December 21, 2006, the Commission issued an order in Administrative Case No. 2006-00045.[7] Among other things, the order required KU and LG&E to "develop voluntary pilot real-time pricing programs for their commercial and industrial customers."[8] The Commission further ordered the Companies to "submit the proposed real-time pricing tariffs for their large commercial and industrial customers for Commission consideration within 120 days of the date of this Order."[9]

In compliance with the Commission's order, the Companies applied and received Commission approval for the Real Time Pricing Program in Case No. 2007-00161.[10] As approved by the Commission, the pilot was to run for a term of three years, which began on December 1, 2008, though the tariff continues to be in effect until the Commission approves termination of the program. Because the pilot was intended to have only a three-year term, the Availability of Service section of Rider RTP states that no customers may begin to participate in the program after the end of the program's second year.

KU respectfully proposes to terminate the RTP program and eliminate Rider RTP. None of KU's customers has ever participated in the program, and none has expressed any interest in doing so. Moreover, because the pilot's second year ended

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[7] *In the Matter of: Consideration of the Requirements of the Federal Energy Policy Act of 2005 Regarding Time-Based Metering, Demand Response, and Interconnection Service*, Admin. Case No. 2006-00045, Order (December 21, 2006).
[8] *Id.* at 13.
[9] *Id.* at 18.
[10] *In the Matter of: Joint Application of Louisville Gas and Electric Company and Kentucky Utilities Company for an Order Approving a Large Commercial and Industrial Real-Time Pricing Pilot Program*, Case No. 2007-00161, Order (Feb. 1, 2008).

on November 31, 2010, Rider RTP currently does not permit customers to begin to participate in the pilot, rendering it moot. Therefore, it is now appropriate to eliminate Rider RTP and terminate the pilot program.

Q. What changes does KU propose to make to its pilot program Low Emissions Vehicle, Rate LEV?

A. The language is being modified to recognize that there may be Rate RS customers with detached garages on Rate GS that are precluded from taking advantage of Rate LEV because the current language is restricted to Rate RS customers only. With this change Rate LEV will be available to them.

C. ADJUSTMENT CLAUSES

Q. What changes does KU propose to make to its adjustment clause rate schedule ECR?

A. KU proposes to make conforming language changes to the ECR schedule that are necessary due to the proposed names for the rate schedules and the elimination of the 2005 and 2006 ECR Plans.

VI. MISCELLANEOUS SERVICE CHARGES AND CUSTOMER DEPOSITS

A. CABLE TV ATTACHMENT CHARGES

Q. Is the Company proposing to adjust the Cable TV Attachment charges?

A. Yes. The charges were last updated in Case No. 2009-00548 through a unanimous settlement agreement. KU's proposed Cable TV attachment charge is $10.01 per attachment per year.

Q. How were the proposed charges for Cable Television Attachment Charges developed?

A. The proposed charges were calculated in the same manner as KU utilized in Case No. 2009-00548. In its Order in Administrative Case No. 251, the Commission prescribed a methodology for determining the attachment charges. The calculations proposed in this filing, shown in Conroy Exhibit M4, follow the guidelines established in Administrative Case No. 251 and also follow the methodology that was approved by the Commission in LG&E's Case No. 90-158.

B. METER TEST CHARGE

Q. Is the Company proposing any changes to the meter test charge set forth in the electric tariff?

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 $60.00 to $75.00 to collect the reasonable costs of this service. The cost support for the proposed charge is included in Conroy Exhibit M5.

C. DISCONNECT / RECONNECT SERVICE CHARGE

Q. Is KU proposing any changes to its Disconnect/Reconnect Service Charge?

A. Yes. 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 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.

While KU could support a charge of $29.37, the Company proposes to increase its Charge for Disconnecting and Reconnecting Service from $25.00 to $28.00, which is applied only when a customer's service is reconnected. To harmonize the application of this charge across both LG&E and KU to allow for easier communication with customers, KU and LG&E are proposing the same charge. The cost support for the proposed charge is included in Conroy Exhibit M6.

D. METER PULSE CHARGE

Q. Is the Company proposing any changes to the meter pulse charge set forth in the electric tariff?

A. Yes. KU currently under-recovers its costs for providing data meter pulses. The meter pulse relay service is a special service provided strictly at the option of the customer whereby the Company installs special equipment on industrial and commercial demand meters to provide customers a demand pulse so that they can better manage their demands. The charge was filed for the first time in Case No. 2008-00251 and was not revised in Case No. 2009-00548. The charge is somewhat understated because the costs as originally set were simply amortized over 5 years without any consideration for carrying costs and replacement. The proper calculation of a charge that includes carrying costs is included in Conroy Exhibit M7. The carrying charge methodology is consistent with the methodology shown in the Excess Facilities Rider, except the life of electronic metering equipment is much shorter than the type of long-lived utility property contemplated under the Excess Facilities Rider. This calculation would support a charge of $24.97. However, due to the magnitude of the increase required to provide full recovery, to minimize the impact on customers recently signing up for this services, and because the charge was introduced only recently, the Company is only proposing a modest increase from $9.00 to $15.00 per month per installed set of pulse-generating equipment.

E. CUSTOMER DEPOSITS

Q. Is KU proposing any changes to its customer deposit requirements?

A. No. The current deposit requirements are $135.00 for residential customers and $220.00 for general service customers. The Commission's regulations 807 KAR 5:005, Section 7(b) state that, "The utility may establish an equal amount for each class based on the average bill of customers in that class. Deposit amounts shall not exceed two-twelfths (2/12) of the average bill of customers in the class where bills are rendered monthly…." Consistent with these regulations, KU could have supported higher customer deposit requirements for residential and general service customers. To minimize the impact on affected customers and to harmonize the deposit requirements with those proposed for LG&E, KU is proposing no change to the current deposit requirements of $135.00 for residential customers and $220.00 for general service customers. The determination of the customer deposits that could be supported are shown in Conroy Exhibit M8.

F. OTHER SPECIAL CHARGES

Q. Is KU proposing changes to any other Special Charges?

A. No. KU is not proposing to change the Returned Payment Charge or the Meter Data Processing Charge. The cost of service for these charges does not support a change to the charges at this time.

VII. TARIFF CHANGES

Q. What changes does KU propose to make to its Terms and Conditions tariff which sets the parameters for Customer Responsibilities and the Company Responsibilities?

A. Similar to the change discussed above for Rider SS regarding the obligation of the customer to receive firm service when the customers provides some or all of their own load through a customer owned generator, KU is proposing to add the same statement to the Customer Responsibility section. Likewise, the obligation of the Company to provide firm service under such a situation is being included in the Company Responsibilities section.

Q. What changes does KU propose to make to its Terms and Conditions tariff which sets the parameters for Billing?

A. The Company is adding a section on Customer Rate Migration which defines the circumstances for customer migration from one rate to another. When such change in rate schedule occurs, the language added is in recognition of the need to allow time for metering, meter programming, and meter reading changes to occur prior to the new rate schedule being effective for the customer.

Q. Please describe the Customer Rate Assignment provision KU proposes to add to its Terms and Conditions.

A. The Company is adding a Customer Rate Assignment provision to clarify the procedure the Company will use to determine whether a customer taking service under a rate schedule with a demand component continues to be eligible to take service under that rate schedule or should be moved to another rate schedule. The provision states that the Company will at least annually evaluate such a customer's demand and usage for the prior 12 months to determine if the customer should change rate schedules base on the eligibility requirements set out in the rate schedules that contain demand-based billing components. The Company will also conduct such a review at the customer's request. Any change will be made only after consulting with the affected customer to determine if changing rates is appropriate in view of the customer's anticipated demand.

Once the Company has made a rate determination, the proposed provision states that the Company will neither be liable for a refund nor be able to back-bill a customer for the period following the determination until the next review and determination because the rate determination will be deemed to be conclusively correct for all purposes. This provision does not apply to misread or defective meters or other errors or events not related to rate assignment that could result in inaccurate bills, and it does not apply if the Company's rate determination is erroneous at the time it is made. Rather, the purpose of the provision is to clarify how the Company will make rate determinations and to ensure that such determinations, once made, are dispositive and protect customers and the Company.

Q. What changes does KU propose to make to its Terms and Conditions tariff which sets the parameters for Deposits?

A. KU proposes to change the requirement for the collection of deposits from a residential customer served under Rate RS who also has a service under Rate GS through a second meter for service to a detached building with minor electric use. The Company is proposing to collect only one deposit from the customer under such circumstances when the customer's energy usage for the detached building is less than 300 kWh per month.

Q. Has KU proposed 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 are proposed to simplify or clarify the language in the tariff. Each of the changes can be seen in the side-by-side comparison of the present and proposed tariff provided in response to filing requirement 807 KAR 5:001 Section 10(1)(a)8.

Q. Does this conclude your testimony?

A. Yes, it does.

VERIFICATION

COMMONWEALTH OF KENTUCKY)
) SS:
COUNTY OF JEFFERSON)

The undersigned, **Robert M. Conroy**, being duly sworn, deposes and says that he is Director - Rates for LG&E and KU Services Company, and that he has personal knowledge of the matters set forth in the foregoing testimony, and that the answers contained therein are true and correct to the best of his information, knowledge and belief.

Robert M. Conroy
Robert M. Conroy

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 20th day of June 2012.

Joan R. Henry (SEAL)
Notary Public

My Commission Expires:

July 21, 2015

APPENDIX A

Robert M. Conroy
Director, Rates
LG&E and KU Energy LLC
220 West Main Street
Louisville, Kentucky 40202
Telephone: (502) 627-3324

Education

Masters of Business Administration
Indiana University (Southeast campus), December 1998. GPA: 3.9

Bachelor of Science in Electrical Engineering
Rose Hulman Institute of Technology, May 1987. GPA: 3.3

Essentials of Leadership, London Business School, 2004

Center for Creative Leadership, Foundations in Leadership program, 1998

Registered Professional Engineer in Kentucky, 1995

Previous Positions

Manager, Rates	April 2004 – Feb 2008
Manager, Generation Systems Planning	Feb. 2001 – April 2004
Group Leader, Generation Systems Planning	Feb. 2000 – Feb. 2001
Lead Planning Engineer	Oct. 1999 – Feb. 2000
Consulting System Planning Analyst	April 1996 – Oct. 1999
System Planning Analyst III & IV	Oct. 1992 - April 1996
System Planning Analyst II	Jan. 1991 - Oct. 1992
Electrical Engineer II	Jun. 1990 - Jan. 1991
Electrical Engineer I	Jun. 1987 - Jun. 1990

Professional/Trade Memberships

Registered Professional Engineer in Kentucky, 1995

Conroy Exhibit P1

Effect on Electric Base Rate Revenues of Rate Changes for Full Year

KENTUCKY UTILITIES COMPANY
Summary of Effect of Rate Changes for the Test Period
Twelve Months Ended March 31, 2012

		As Billed Base Rates Revenues	FAC Rollin Rates For a Full Year		ECR Rollin Rates For a Full Year	
			Calculated Base Rates Revenue	Increased Revenue	Calculated Base Rates Revenue	Increased Revenue
Residential Service						
Residential Rate RS	RS	$ 444,430,028	$ 443,324,770	$ (1,105,258)	$ 457,936,279	$ 14,611,509
Voluneer Fire Department Rate VFD	RS-VFD	$ 67,118	$ 66,947	$ (171)	$ 69,186	$ 2,239
Residential Rate RS	RS	$ -	$ -	$ -	$ -	$ -
		$ 444,497,146	$ 443,391,717	$ (1,105,429)	$ 458,005,465	$ 14,613,748
General Service Rate GS	GS	$ 77,739,936	$ 77,574,628	$ (165,308)	$ 82,297,414	$ 4,722,786
	GS 3 Phase	$ 93,664,731	$ 93,436,750	$ (227,981)	$ 99,861,044	$ 6,424,294
		$ 171,404,667	$ 171,011,378	$ (393,289)	$ 182,158,458	$ 11,147,080
All Electric School Service Rate - AES	AES	$ 751,527	$ 747,802	$ (3,725)	$ 752,602	$ 4,800
	AES 3-Phase	$ 9,880,009	$ 9,849,066	$ (30,943)	$ 9,915,664	$ 66,598
		$ 10,631,536	$ 10,596,868	$ (34,668)	$ 10,668,266	$ 71,398
Power Service						
Power Service Rate PSS - Secondary	PSS	$ 212,854,315	$ 212,206,416	$ (647,899)	$ 221,396,753	$ 9,190,337
Power Service Rate PSP - Primary	PSP	$ 49,420,027	$ 49,227,341	$ (192,686)	$ 51,224,549	$ 1,997,208
		$ 262,274,342	$ 261,433,757	$ (840,585)	$ 272,621,302	$ 11,187,545
Time of Day Service						
Time-of-Day Service - TODS Secondary	TODS	$ 24,101,382	$ 24,017,054	$ (84,328)	$ 22,889,891	$ (1,127,163)
Time-of-Day Service - TODP Primary	TODP	$ 194,137,903	$ 193,459,114	$ (678,789)	$ 184,047,357	$ (9,411,757)
		$ 218,239,285	$ 217,476,168	$ (763,117)	$ 206,937,248	$ (10,538,920)
Retail Transmission Service -- RTS	RTS	$ 82,177,985	$ 81,836,969	$ (341,016)	$ 79,886,044	$ (1,950,925)
Fluctuating Load Service -- FLS	FLS	$ 25,193,075	$ 25,080,876	$ (112,199)	$ 24,102,240	$ (978,636)
Outdoor Lighting Service -- LE	LE	$ 2,165	$ 2,157	$ (8)	$ 2,255	$ 98
Traffic Lighting Energy -- TE	TE	$ 103,028	$ 102,832	$ (196)	$ 105,565	$ 2,733
Street Lighting	SL	$ 9,810,056	$ 9,800,571	$ (9,485)	$ 10,106,521	$ 305,950
Private Outdoor Lighting	POL	$ 12,581,696	$ 12,565,463	$ (16,233)	$ 12,980,727	$ 415,264
Dark Sky Lighting	DSK	$ 84	$ 84	$ -	$ 85	$ 1
		$ 22,497,029	$ 22,471,107	$ (25,922)	$ 23,195,153	$ 724,046
TOTAL		$ 1,236,915,065	$ 1,233,298,840	$ (3,616,225)	$ 1,257,574,176	$ 24,275,336

Kentucky Utilities Company
Effect of Rate Changes for the Test Period
Twelve Months Ended March 31, 2012

Based on Sales for the 12 months ended March 31, 2012
Including the rate change due to FAC roll-in effective on July 01, 2011
Including the rate change due to ECR roll-in effective on March 01, 2012

	Customers 12mos Mar 2012	Basic Demand	Peak Demand	kWh's	"As Billed Rates" During 12 Month Period Unit Charges	"As Billed Rates" During 12 Month Period Calculated Revenue	FAC Rollin for Full Year Unit Charges	FAC Rollin for Full Year Calculated Revenue	ECR Rollin for Full Year Unit Charges	ECR Rollin for Full Year Calculated Revenue
RESIDENTIAL RATE RS										
Residential Service										
Customers Apr11-Jun11	1,263,709				$ 8.50	$ 10,741,527	$ 8.50	$ 10,741,527	$ 8.50	$ 10,741,527
Customers Jul11-Feb12	3,359,976				$ 8.50	$ 28,559,796	$ 8.50	$ 28,559,796	$ 8.50	$ 28,559,796
Customers Mar12	419,856				$ 8.50	$ 3,568,775	$ 8.50	$ 3,568,775	$ 8.50	$ 3,568,775
Partial month, prorated and corrected billings						(217,347)		(217,347)		(217,347)
kWh billed Apr11-Jun11				1,285,182,976	$ 0.06805	$ 87,456,702	$ 0.06719	$ 86,351,444	$ 0.06987	$ 89,795,735
kWh billed Jul11-Feb12				4,166,872,468	$ 0.06719	$ 279,972,161	$ 0.06719	$ 279,972,161	$ 0.06987	$ 291,139,379
kWh billed Mar12				491,647,240	$ 0.06987	$ 34,351,393	$ 0.06987	$ 34,351,393	$ 0.06987	$ 34,351,393
Minimum and Partial Month Billings						(2,979)		(2,979)		(2,979)
TOTAL	5,043,541			5,943,702,684		$ 444,430,028		$ 443,324,770		$ 457,936,279
Residential Service Volunteer Fire Departments										
Customers Apr11-Jun11	135				$ 8.50	$ 1,148	$ 8.50	$ 1,148	$ 8.50	$ 1,148
Customers Jul11-Feb12	367				$ 8.50	$ 3,120	$ 8.50	$ 3,120	$ 8.50	$ 3,120
Customers Mar12	46				$ 8.50	$ 391	$ 8.50	$ 391	$ 8.50	$ 391
Partial month, prorated and corrected billings						-		-		-
kWh billed Apr11-Jun11				199,756	$ 0.06805	$ 13,593	$ 0.06719	$ 13,422	$ 0.06987	$ 13,957
kWh billed Jul11-Feb12				635,503	$ 0.06719	$ 42,699	$ 0.06719	$ 42,699	$ 0.06987	$ 44,403
kWh billed Mar12				88,302	$ 0.06987	$ 6,170	$ 0.06987	$ 6,170	$ 0.06987	$ 6,170
Minimum and Partial Month Billings						(3)		(3)		(3)
TOTAL	548			923,561		$ 67,118		$ 66,947		$ 69,186

Kentucky Utilities Company
Effect of Rate Changes for the Test Period
Twelve Months Ended March 31, 2012

Based on Sales for the 12 months ended March 31, 2012
Including the rate change due to FAC roll-in effective on July 01, 2011
Including the rate change due to ECR roll-in effective on March 01, 2012

					"As Billed Rates" During 12 Month Period		FAC Rollin for Full Year		ECR Rollin for Full Year	
	Customers 12mos Mar 2012	Basic Demand	Peak Demand	kWh's	Unit Charges	Calculated Revenue	Unit Charges	Calculated Revenue	Unit Charges	Calculated Revenue
Residential Service Low Emission Vehicle Service										
Customers Apr11-Jun11	-				$ 8.50	$ -	$ 8.50	$ -	$ 8.50	$ -
Customers Jul11-Feb12	-				$ 8.50	$ -	$ 8.50	$ -	$ 8.50	$ -
Customers Mar12	-				$ 8.50	$ -	$ 8.50	$ -	$ 8.50	$ -
						$ -				
kWh billed Apr11-Jun11 Period 1				-	$ 0.04722	$ -	$ 0.04636	$ -	$ 0.04904	$ -
kWh billed Jul11-Feb12 Period 1				-	$ 0.04636	$ -	$ 0.04636	$ -	$ 0.04904	$ -
kWh billed Mar12 Period 1				-	$ 0.04904	$ -	$ 0.04904	$ -	$ 0.04904	$ -
kWh billed Apr11-Jun11 Period 2				-	$ 0.06823	$ -	$ 0.06737	$ -	$ 0.07005	$ -
kWh billed Jul11-Feb12 Period 2				-	$ 0.06737	$ -	$ 0.06737	$ -	$ 0.07005	$ -
kWh billed Mar12 Period 2				-	$ 0.07005	$ -	$ 0.07005	$ -	$ 0.07005	$ -
kWh billed Apr11-Jun11 Period 3				-	$ 0.13133	$ -	$ 0.13047	$ -	$ 0.13315	$ -
kWh billed Jul11-Feb12 Period 3				-	$ 0.13047	$ -	$ 0.13047	$ -	$ 0.13315	$ -
kWh billed Mar12 Period 3				-	$ 0.13315	$ -	$ 0.13315	$ -	$ 0.13315	$ -
Minimum and Partial Month Billings						-		-		-
TOTAL	-			-		$ -		$ -		$ -
TOTAL RESIDENTIAL	5,044,089			5,944,626,245		$ 444,497,146		$ 443,391,717		$ 458,005,465
					Correction Factor -	1.000000000		1.000000000		1.000000000
TOTAL AFTER APPLICATION OF CORRECTION FACTOR						$ 444,497,146		$ 443,391,717		$ 458,005,465
RESIDENTIAL INCREASE IN BASE RATES REVENUE								$ (1,105,429)		$ 14,613,748
PRO FORMA REVENUE ADJUSTMENTS:										
Fuel Adjustment Clause Billings										$ 2,593,257
Demand Side Management Billings										$ 11,425,450
Environmental Cost Recovery Surcharge Billings										$ 14,370,108
Total Pro Forma Revenue Adjustments										$ 28,388,814
Total Test Year Adjusted Revenues										**$ 486,394,279**

Kentucky Utilities Company
Effect of Rate Changes for the Test Period
Twelve Months Ended March 31, 2012

Based on Sales for the 12 months ended March 31, 2012
Including the rate change due to FAC roll-in effective on July 01, 2011
Including the rate change due to ECR roll-in effective on March 01, 2012

	Customers 12mos Mar 2012	Basic Demand	Peak Demand	kWh's	"As Billed Rates" During 12 Month Period Unit Charges	"As Billed Rates" During 12 Month Period Calculated Revenue	FAC Rollin for Full Year Unit Charges	FAC Rollin for Full Year Calculated Revenue	ECR Rollin for Full Year Unit Charges	ECR Rollin for Full Year Calculated Revenue
GENERAL SERVICE RATE GS										
General Service Single Phase										
Customers Apr11-Jun11	195,084				$ 17.50	$ 3,413,970	$ 17.50	$ 3,413,970	$ 17.50	$ 3,413,970
Customers Jul11-Feb12	519,513				$ 17.50	$ 9,091,478	$ 17.50	$ 9,091,478	$ 17.50	$ 9,091,478
Customers Mar12	64,944				$ 17.50	$ 1,136,520	$ 17.50	$ 1,136,520	$ 17.50	$ 1,136,520
Partial month, prorated and corrected billings						583		583		583
kWh billed Apr11-Jun11				192,219,154	$ 0.07796	$ 14,985,405	$ 0.07710	$ 14,820,097	$ 0.08332	$ 16,015,700
kWh billed Jul11-Feb12				567,071,188	$ 0.07710	$ 43,721,189	$ 0.07710	$ 43,721,189	$ 0.08332	$ 47,248,371
kWh billed Mar12				64,868,584	$ 0.08332	$ 5,404,850	$ 0.08332	$ 5,404,850	$ 0.08332	$ 5,404,850
Minimum and Partial Month Billings						(14,059)		(14,059)		(14,059)
TOTAL	779,541			824,158,926		$ 77,739,936		$ 77,574,628		$ 82,297,414
General Service Three Phase										
Customers Apr11-Jun11	50,891				$ 32.50	$ 1,653,957	$ 32.50	$ 1,653,957	$ 32.50	$ 1,653,957
Customers Jul11-Feb12	136,436				$ 32.50	$ 4,434,170	$ 32.50	$ 4,434,170	$ 32.50	$ 4,434,170
Customers Mar12	17,125				$ 32.50	$ 556,563	$ 32.50	$ 556,563	$ 32.50	$ 556,563
Partial month, prorated and corrected billings						2,729		2,729		2,729
kWh billed Apr11-Jun11				265,094,391	$ 0.07796	$ 20,666,759	$ 0.07710	$ 20,438,778	$ 0.08332	$ 22,087,665
kWh billed Jul11-Feb12				767,750,289	$ 0.07710	$ 59,193,547	$ 0.07710	$ 59,193,547	$ 0.08332	$ 63,968,954
kWh billed Mar12				86,092,852	$ 0.08332	$ 7,173,256	$ 0.08332	$ 7,173,256	$ 0.08332	$ 7,173,256
Minimum and Partial Month Billings						(16,250)		(16,250)		(16,250)
TOTAL	204,452			1,118,937,532		$ 93,664,731		$ 93,436,750		$ 99,861,044
TOTAL GENERAL SERVICE	983,993			1,943,096,458		$ 171,404,667		$ 171,011,378		$ 182,158,458
					Correction Factor -	1.000000000		1.000000000		1.000000000
TOTAL AFTER APPLICATION OF CORRECTION FACTOR						$ 171,404,667		$ 171,011,378		$ 182,158,458
GENERAL SERVICE INCREASE IN BASE RATES REVENUE								$ (393,289)		$ 11,147,080
PRO FORMA REVENUE ADJUSTMENTS:										
Fuel Adjustment Clause Billings										$ 1,033,757
Demand Side Management Billings										$ 3,105,552
Environmental Cost Recovery Surcharge Billings										$ 5,441,411
Merger Surcredit Billings										$ (4)
Total Pro Forma Revenue Adjustments										$ 9,580,716
Total Test Year Adjusted Revenues										**$ 191,739,174**

Kentucky Utilities Company
Effect of Rate Changes for the Test Period
Twelve Months Ended March 31, 2012

Based on Sales for the 12 months ended March 31, 2012
Including the rate change due to FAC roll-in effective on July 01, 2011
Including the rate change due to ECR roll-in effective on March 01, 2012

	Customers 12mos Mar 2012	Basic Demand	Peak Demand	kWh's	"As Billed Rates" During 12 Month Period Unit Charges	"As Billed Rates" During 12 Month Period Calculated Revenue	FAC Rollin for Full Year Unit Charges	FAC Rollin for Full Year Calculated Revenue	ECR Rollin for Full Year Unit Charges	ECR Rollin for Full Year Calculated Revenue
ALL ELECTRIC SCHOOL RATE AES										
All Electric School Single Phase										
Customers Apr11-Jun11	1,160				$ 17.50	$ 20,300	$ 17.50	$ 20,300	$ 17.50	$ 20,300
Customers Jul11-Feb12	3,030				$ 17.50	$ 53,025	$ 17.50	$ 53,025	$ 17.50	$ 53,025
Customers Mar12	374				$ 17.50	$ 6,545	$ 17.50	$ 6,545	$ 17.50	$ 6,545
Partial month, prorated and corrected billings						$ 88		$ 88		$ 88
kWh billed Apr11-Jun11				4,330,344	$ 0.06706	$ 290,393	$ 0.06620	$ 286,669	$ 0.06670	$ 288,834
kWh billed Jul11-Feb12				5,268,905	$ 0.06620	$ 348,802	$ 0.06620	$ 348,802	$ 0.06670	$ 351,436
kWh billed Mar12				807,734	$ 0.06670	$ 53,876	$ 0.06670	$ 53,876	$ 0.06670	$ 53,876
Minimum and Partial Month Billings						$ (21,502)		$ (21,502)		$ (21,502)
TOTAL	4,564			10,406,983		$ 751,527		$ 747,802		$ 752,602
All Electric School Three Phase										
Customers Apr11-Jun11	781				$ 32.50	$ 25,383	$ 32.50	$ 25,383	$ 32.50	$ 25,383
Customers Jul11-Feb12	2,081				$ 32.50	$ 67,633	$ 32.50	$ 67,633	$ 32.50	$ 67,633
Customers Mar12	269				$ 32.50	$ 8,743	$ 32.50	$ 8,743	$ 32.50	$ 8,743
Partial month, prorated and corrected billings						$ 304		$ 304		$ 304
kWh billed Apr11-Jun11				35,981,233	$ 0.06706	$ 2,412,901	$ 0.06620	$ 2,381,958	$ 0.06670	$ 2,399,949
kWh billed Jul11-Feb12				97,213,753	$ 0.06620	$ 6,435,550	$ 0.06620	$ 6,435,550	$ 0.06670	$ 6,484,157
kWh billed Mar12				13,935,414	$ 0.06670	$ 929,492	$ 0.06670	$ 929,492	$ 0.06670	$ 929,492
Minimum and Partial Month Billings						$ 3		$ 3		$ 3
TOTAL	3,131			147,130,400		$ 9,880,009		$ 9,849,066		$ 9,915,664
TOTAL ALL ELECTRIC SCHOOL SERVICE	7,695			157,537,383		$ 10,631,536		$ 10,596,868		$ 10,668,266
					Correction Factor -	1.000000000		1.000000000		1.000000000
TOTAL AFTER APPLICATION OF CORRECTION FACTOR						$ 10,631,536		$ 10,596,868		$ 10,668,266
ALL ELECTRIC SCHOOL INCREASE IN BASE RATES REVENUE								$ (34,668)		$ 71,398
PRO FORMA REVENUE ADJUSTMENTS:										
Fuel Adjustment Clause Billings										$ 76,171
Demand Side Management Billings										$ 38,693
Environmental Cost Recovery Surcharge Billings										$ 334,865
Merger Surcredit Revenues										$ 22
Total Pro Forma Revenue Adjustments										$ 449,751
Total Test Year Adjusted Revenues										**$ 11,118,017**

Kentucky Utilities Company
Effect of Rate Changes for the Test Period
Twelve Months Ended March 31, 2012

Based on Sales for the 12 months ended March 31, 2012
Including the rate change due to FAC roll-in effective on July 01, 2011
Including the rate change due to ECR roll-in effective on March 01, 2012

	Customers 12mos Mar 2012	Basic Demand	Peak Demand	kWh's	"As Billed Rates" During 12 Month Period Unit Charges	"As Billed Rates" During 12 Month Period Calculated Revenue	FAC Rollin for Full Year Unit Charges	FAC Rollin for Full Year Calculated Revenue	ECR Rollin for Full Year Unit Charges	ECR Rollin for Full Year Calculated Revenue
POWER SERVICE RATE PS -- SECONDARY DELIVERY										
Customers Apr11-Jun11	17,716				$ 90.00	$ 1,594,440	$ 90.00	$ 1,594,440	$ 90.00	$ 1,594,440
Customers Jul11-Feb12	45,742				$ 90.00	$ 4,116,780	$ 90.00	$ 4,116,780	$ 90.00	$ 4,116,780
Customers Mar12	5,627				$ 90.00	$ 506,430	$ 90.00	$ 506,430	$ 90.00	$ 506,430
Partial month, prorated and corrected billings						$ 1,642		$ 1,642		$ 1,642
kWh billed Apr11-Jun11				753,370,726	$ 0.03386	$ 25,509,133	$ 0.03300	$ 24,861,234	$ 0.03300	$ 24,861,234
kWh billed Jul11-Feb12				2,081,412,725	$ 0.03300	$ 68,686,620	$ 0.03300	$ 68,686,620	$ 0.03300	$ 68,686,620
kWh billed Mar12				234,994,734	$ 0.03300	$ 7,754,826	$ 0.03300	$ 7,754,826	$ 0.03300	$ 7,754,826
Minimum and Partial Month Billings						14,678		14,678		14,678
kW billed at Summer rates Apr11-Jun11		1,370,096			$ 12.78	$ 17,509,823	$ 12.78	$ 17,509,823	$ 13.90	$ 19,044,330
kW billed at Summer rates Jul11-Feb12		2,127,365			$ 12.78	$ 27,187,721	$ 12.78	$ 27,187,721	$ 13.90	$ 29,570,369
kW billed at Summer rates Mar12		-			$ 13.90	$ -	$ 13.90	$ -	$ 13.90	$ -
Minimum Summer Demands		377,364								
kW billed at Winter rates Apr11-Jun11		646,938			$ 10.53	$ 6,812,262	$ 10.53	$ 6,812,262	$ 11.65	$ 7,536,833
kW billed at Winter rates Jul11-Feb12		3,184,760			$ 10.53	$ 33,535,524	$ 10.53	$ 33,535,524	$ 11.65	$ 37,102,456
kW billed at Winter rates Mar12		628,155			$ 11.65	$ 7,318,009	$ 11.65	$ 7,318,009	$ 11.65	$ 7,318,009
Minimum Winter Demands		580,802								
Minimum Demand billings						$ 11,030,024		$ 11,030,024		$ 12,011,703
Partial Month and Prorated Billings						$ (218,647)		$ (218,647)		$ (218,647)
Power Factor Revenue Adjustment						$ 1,493,329		$ 1,493,329		$ 1,493,329
Redundant Capacity Rider		2,025			$ 0.85	$ 1,721	$0.85	$ 1,721	$0.85	$ 1,721
TOTAL	69,085	8,915,480		3,069,778,185		$ 212,854,315		$ 212,206,416		$ 221,396,753
					Correction Factor -	1.000000000		1.000000000		1.000000000
TOTAL AFTER APPLICATION OF CORRECTION FACTOR						$ 212,854,315		$ 212,206,416		$ 221,396,753
POWER SERVICE SECONDARY INCREASE IN BASE RATES REVENUE								$ (647,899)		$ 9,190,337
PRO FORMA REVENUE ADJUSTMENTS:										
Fuel Adjustment Clause Billings										$ 1,728,895
Demand Side Management Billings										$ 527,094
Environmental Cost Recovery Surcharge Billings										$ 6,481,232
Total Pro Forma Revenue Adjustments										$ 8,737,221
Total Test Year Adjusted Revenues										**$ 230,133,974**

Kentucky Utilities Company
Effect of Rate Changes for the Test Period
Twelve Months Ended March 31, 2012

Based on Sales for the 12 months ended March 31, 2012
Including the rate change due to FAC roll-in effective on July 01, 2011
Including the rate change due to ECR roll-in effective on March 01, 2012

	Customers 12mos Mar 2012	Basic Demand	Peak Demand	kWh's	"As Billed Rates" During 12 Month Period Unit Charges	"As Billed Rates" During 12 Month Period Calculated Revenue	FAC Rollin for Full Year Unit Charges	FAC Rollin for Full Year Calculated Revenue	ECR Rollin for Full Year Unit Charges	ECR Rollin for Full Year Calculated Revenue
POWER SERVICE RATE PS -- PRIMARY DELIVERY										
Customers Apr11-Jun11	982				$ 90.00	$ 88,380	$ 90.00	$ 88,380	$ 90.00	$ 88,380
Customers Jul11-Feb12	2,462				$ 90.00	$ 221,580	$ 90.00	$ 221,580	$ 90.00	$ 221,580
Customers Mar12	299				$ 90.00	$ 26,910	$ 90.00	$ 26,910	$ 90.00	$ 26,910
Partial month, prorated and corrected billings						(1,126)		(1,126)		(1,126)
kWh billed Apr11-Jun11				224,053,935	$ 0.03386	$ 7,586,466	$ 0.03300	$ 7,393,780	$ 0.03300	$ 7,393,780
kWh billed Jul11-Feb12				522,599,107	$ 0.03300	$ 17,245,771	$ 0.03300	$ 17,245,771	$ 0.03300	$ 17,245,771
kWh billed Mar12				55,776,011	$ 0.03300	$ 1,840,608	$ 0.03300	$ 1,840,608	$ 0.03300	$ 1,840,608
Minimum and Partial Month Billings						5,659		5,659		5,659
kW billed at Summer rates Apr11-Jun11		338,101			$ 12.60	$ 4,260,067	$ 12.60	$ 4,260,067	$ 13.72	$ 4,638,740
kW billed at Summer rates Jul11-Feb12		507,707			$ 12.60	$ 6,397,104	$ 12.60	$ 6,397,104	$ 13.72	$ 6,965,736
kW billed at Summer rates Mar12		-			$ 13.72	$ -	$ 13.72	$ -	$ 13.72	$ -
kW billed at Winter rates Apr11-Jun11		169,482			$ 10.33	$ 1,750,745	$ 10.33	$ 1,750,745	$ 11.45	$ 1,940,565
kW billed at Winter rates Jul11-Feb12		685,095			$ 10.33	$ 7,077,034	$ 10.33	$ 7,077,034	$ 11.45	$ 7,844,340
kW billed at Winter rates Mar12		130,537			$ 11.45	$ 1,494,646	$ 11.45	$ 1,494,646	$ 11.45	$ 1,494,646
Minimum Demand and Billings		35,640				$ 1,011,513		$ 1,011,513		$ 1,104,290
Partial Month and Prorated Billings						$ (49,401)		$ (49,401)		$ (49,401)
Power Factor Revenue Adjustment						$ 429,197		$ 429,197		$ 429,197
Redundant Capacity Rider		51,285			$ 0.68	$ 34,874	$0.68	$ 34,874	$0.68	$ 34,874
TOTAL	3,743	1,866,561		802,429,053		$ 49,420,027		$ 49,227,341		$ 51,224,549
					Correction Factor -	1.000000000		1.000000000		1.000000000
TOTAL AFTER APPLICATION OF CORRECTION FACTOR						$ 49,420,027		$ 49,227,341		$ 51,224,549
POWER SERVICE PRIMARY INCREASE IN BASE RATES REVENUE								$ (192,686)		$ 1,997,208
PRO FORMA REVENUE ADJUSTMENTS:										
Fuel Adjustment Clause Billings										$ 438,178
Demand Side Management Billings										$ 97,296
Environmental Cost Recovery Surcharge Billings										$ 1,489,519
Total Pro Forma Revenue Adjustments										$ 2,024,993
Total Test Year Adjusted Revenues										**$ 53,249,542**

Kentucky Utilities Company
Effect of Rate Changes for the Test Period
Twelve Months Ended March 31, 2012

Based on Sales for the 12 months ended March 31, 2012
Including the rate change due to FAC roll-in effective on July 01, 2011
Including the rate change due to ECR roll-in effective on March 01, 2012

	Customers 12mos Mar 2012	Basic Demand	Peak Demand	kWh's	"As Billed Rates" During 12 Month Period Unit Charges	"As Billed Rates" During 12 Month Period Calculated Revenue	FAC Rollin for Full Year Unit Charges	FAC Rollin for Full Year Calculated Revenue	ECR Rollin for Full Year Unit Charges	ECR Rollin for Full Year Calculated Revenue
TIME OF DAY SECONDARY SERVICE										
Customers Apr11-Jun11	318				$ 200.00	$ 63,600	$ 200.00	$ 63,600	$ 200.00	$ 63,600
Customers Jul11-Feb12	974				$ 200.00	$ 194,800	$ 200.00	$ 194,800	$ 200.00	$ 194,800
Customers Mar12	137				$ 200.00	$ 27,400	$ 200.00	$ 27,400	$ 200.00	$ 27,400
Partial month, prorated and corrected billings						(1,311)		(1,311)		(1,311)
kWh billed Apr11-Jun11				98,056,750	$ 0.03576	$ 3,506,509	$ 0.03490	$ 3,422,181	$ 0.03490	$ 3,422,181
kWh billed Jul11-Feb12				280,709,906	$ 0.03490	$ 9,796,776	$ 0.03490	$ 9,796,776	$ 0.03490	$ 9,796,776
kWh billed Mar12				34,356,480	$ 0.03490	$ 1,199,041	$ 0.03490	$ 1,199,041	$ 0.03490	$ 1,199,041
Minimum and Partial Month Billings						508		508		508
Demand Billings										
Base Demand Period										
kW billed Apr11-Jun11		199,429			$ 3.53	$ 703,984	$ 3.53	$ 703,984	$ 3.05	$ 608,258
kW billed Jul11-Feb12		559,646			$ 3.53	$ 1,975,549	$ 3.53	$ 1,975,549	$ 3.05	$ 1,706,919
kW billed Mar12		72,356			$ 3.05	$ 220,686	$ 3.05	$ 220,686	$ 3.05	$ 220,686
Base Minimum Demands		88,313								
Intermediate Demand Period										
kW billed Apr11-Jun11		197,548			$ 2.91	$ 574,863	$ 2.91	$ 574,863	$ 2.43	$ 480,040
kW billed Jul11-Feb12		562,110			$ 2.91	$ 1,635,739	$ 2.91	$ 1,635,739	$ 2.43	$ 1,365,926
kW billed Mar12		71,986			$ 2.43	$ 174,926	$ 2.43	$ 174,926	$ 2.43	$ 174,926
Intermediate Minimum Demands		4,385								
Peak Demand Period										
kW billed Apr11-Jun11		193,347			$ 4.37	$ 844,925	$ 4.37	$ 844,925	$ 3.89	$ 752,118
kW billed Jul11-Feb12		552,091			$ 4.37	$ 2,412,638	$ 4.37	$ 2,412,638	$ 3.89	$ 2,147,635
kW billed Mar12		69,742			$ 3.89	$ 271,297	$ 3.89	$ 271,297	$ 3.89	$ 271,297
Minimum Peak Demands, Total Minimum Demand Billings		4,566				338,131		338,131		297,770
Power Factor Demand Revenue						121,926		121,926		121,926
Partial Month and Prorated Billings						8,259		8,259		8,259
Redundant Capacity Rider		36,631			$ 0.85	31,136	$ 0.85	31,136	$ 0.85	31,136
TOTAL	1,429	2,575,517		413,123,136		$ 24,101,382		$ 24,017,054		$ 22,889,891
					Correction Factor -	1.000000000		1.000000000		1.000000000
TOTAL AFTER APPLICATION OF CORRECTION FACTOR						$ 24,101,382		$ 24,017,054		$ 22,889,891
TIME OF DAY SECONDARY SERVICE INCREASE IN BASE RATES REVENUE								$ (84,328)		$ (1,127,163)
PRO FORMA REVENUE ADJUSTMENTS:										
Fuel Adjustment Clause Billings										$ 221,536
Demand Side Management Billings										$ 70,049
Environmental Cost Recovery Surcharge Billings										$ 739,189
Total Pro Forma Revenue Adjustments										$ 1,030,774
Total Test Year Adjusted Revenues										**$ 23,920,665**

Kentucky Utilities Company
Effect of Rate Changes for the Test Period
Twelve Months Ended March 31, 2012

Based on Sales for the 12 months ended March 31, 2012
Including the rate change due to FAC roll-in effective on July 01, 2011
Including the rate change due to ECR roll-in effective on March 01, 2012

	Customers 12mos Mar 2012	Basic Demand	Peak Demand	kWh's	"As Billed Rates" During 12 Month Period: Unit Charges	"As Billed Rates" During 12 Month Period: Calculated Revenue	FAC Rollin for Full Year: Unit Charges	FAC Rollin for Full Year: Calculated Revenue	ECR Rollin for Full Year: Unit Charges	ECR Rollin for Full Year: Calculated Revenue
TIME OF DAY PRIMARY SERVICE										
Customers Apr11-Jun11	405				$ 300.00	$ 121,500	$ 300.00	$ 121,500	$ 300.00	$ 121,500
Customers Jul11-Feb12	1,259				$ 300.00	$ 377,700	$ 300.00	$ 377,700	$ 300.00	$ 377,700
Customers Mar12	167				$ 300.00	$ 50,100	$ 300.00	$ 50,100	$ 300.00	$ 50,100
Partial month, prorated and corrected billings						$ (1,200)		$ (1,200)		$ (1,200)
kWh billed Apr11-Jun11				789,289,724	$ 0.03608	$ 28,477,573	$ 0.03522	$ 27,798,784	$ 0.03522	$ 27,798,784
kWh billed Jul11-Feb12				2,466,564,341	$ 0.03522	$ 86,872,396	$ 0.03522	$ 86,872,396	$ 0.03522	$ 86,872,396
kWh billed Mar12				296,451,448	$ 0.03522	$ 10,441,020	$ 0.03522	$ 10,441,020	$ 0.03522	$ 10,441,020
Minimum and Partial Month Billings						$ 41,617		$ 41,617		$ 41,617
Demand Billings										
Base Demand Period										
kVA billed Apr11-Jun11		1,790,520			$ 1.70	$ 3,043,884	$ 1.70	$ 3,043,884	$ 1.28	$ 2,291,866
kVA billed Jul11-Feb12		5,650,894			$ 1.70	$ 9,606,520	$ 1.70	$ 9,606,520	$ 1.28	$ 7,233,145
kVA billed Mar12		668,925			$ 1.28	$ 856,224	$ 1.28	$ 856,224	$ 1.28	$ 856,224
Minimum Demand		259,295								
Intermediate Demand Period										
kVA billed Apr11-Jun11		1,821,509			$ 2.73	$ 4,972,720	$ 2.73	$ 4,972,720	$ 2.31	$ 4,207,686
kVA billed Jul11-Feb12		5,565,818			$ 2.73	$ 15,194,684	$ 2.73	$ 15,194,684	$ 2.31	$ 12,857,040
kVA billed Mar12		662,636			$ 2.31	$ 1,530,690	$ 2.31	$ 1,530,690	$ 2.31	$ 1,530,690
Minimum Demand		49,393								
Peak Demand Period										
kVA billed Apr11-Jun11		1,795,721			$ 4.09	$ 7,344,499	$ 4.09	$ 7,344,499	$ 3.67	$ 6,590,296
kVA billed Jul11-Feb12		5,476,542			$ 4.09	$ 22,399,058	$ 4.09	$ 22,399,058	$ 3.67	$ 20,098,911
kVA billed Mar12		651,086			$ 3.67	$ 2,389,486	$ 3.67	$ 2,389,486	$ 3.67	$ 2,389,486
Minimum Demand and Billings		49,057				$ 755,370		$ 755,370		$ 626,034
Partial Month and Prorated Billings						$ (364,548)		$ (364,548)		$ (364,548)
Redundant Capacity Rider		42,074			$ 0.68	$ 28,610	$ 0.68	$ 28,610	$ 0.68	$ 28,610
TOTAL	1,831	24,441,397		3,552,305,513		$ 194,137,903		$ 193,459,114		$ 184,047,357
					Correction Factor -	1.000000000		1.000000000		1.000000000
TOTAL AFTER APPLICATION OF CORRECTION FACTOR						$ 194,137,903		$ 193,459,114		$ 184,047,357
TIME OF DAY PRIMARY SERVICE INCREASE IN BASE RATES REVENUE								$ (678,789)		$ (9,411,757)
PRO FORMA REVENUE ADJUSTMENTS:										
Fuel Adjustment Clause Billings										$ 2,013,521
Demand Side Management Billings										$ 137,309
Environmental Cost Recovery Surcharge Billings										$ 5,888,222
Total Pro Forma Revenue Adjustments										$ 8,039,052
Total Test Year Adjusted Revenues										**$ 192,086,409**

Kentucky Utilities Company
Effect of Rate Changes for the Test Period
Twelve Months Ended March 31, 2012

Based on Sales for the 12 months ended March 31, 2012
Including the rate change due to FAC roll-in effective on July 01, 2011
Including the rate change due to ECR roll-in effective on March 01, 2012

	Customers 12mos Mar 2012	Basic Demand	Peak Demand	kWh's	"As Billed Rates" During 12 Month Period Unit Charges	Calculated Revenue	FAC Rollin for Full Year Unit Charges	Calculated Revenue	ECR Rollin for Full Year Unit Charges	Calculated Revenue
RETAIL TRANSMISSION SERVICE										
Customers Apr11-Jun11	107				$ 500.00	$ 53,500	$ 500.00	$ 53,500	$ 500.00	$ 53,500
Customers Jul11-Feb12	290				$ 500.00	$ 145,000	$ 500.00	$ 145,000	$ 500.00	$ 145,000
Customers Mar12	35				$ 500.00	$ 17,500	$ 500.00	$ 17,500	$ 500.00	$ 17,500
Partial month, prorated and corrected billings						(3,167)		(3,167)		(3,167)
kWh billed Apr11-Jun11				396,529,561	$ 0.03500	$ 13,878,535	$ 0.03414	$ 13,537,519	$ 0.03414	$ 13,537,519
kWh billed Jul11-Feb12				1,075,754,904	$ 0.03414	$ 36,726,272	$ 0.03414	$ 36,726,272	$ 0.03414	$ 36,726,272
kWh billed Mar12				136,025,647	$ 0.03414	$ 4,643,916	$ 0.03414	$ 4,643,916	$ 0.03414	$ 4,643,916
Minimum and Partial Month Billings						-		-		-
Demand Billings										
Base Demand Period										
kVA billed Apr11-Jun11		913,673			$ 1.04	$ 950,220	$ 1.04	$ 950,220	$ 0.85	$ 776,622
kVA billed Jul11-Feb12		2,523,886			$ 1.04	$ 2,624,841	$ 1.04	$ 2,624,841	$ 0.85	$ 2,145,303
kVA billed Mar12		305,007			$ 0.85	$ 259,256	$ 0.85	$ 259,256	$ 0.85	$ 259,256
Minimum Base Period Demand		96,043								
Intermediate Demand Period										
kVA billed Apr11-Jun11		906,264			$ 2.49	$ 2,256,597	$ 2.49	$ 2,256,597.11	$ 2.30	$ 2,084,407
kVA billed Jul11-Feb12		2,477,235			$ 2.49	$ 6,168,315	$ 2.49	$ 6,168,315.40	$ 2.30	$ 5,697,641
kVA billed Mar12		306,307			$ 2.30	$ 704,506	$ 2.30	$ 704,506	$ 2.30	$ 704,506
Minimum Intermediate Period Demand		8,942								
Peak Demand Period										
kVA billed Apr11-Jun11		900,601			$ 3.73	$ 3,359,242	$ 3.73	$ 3,359,242	$ 3.54	$ 3,188,128
kVA billed Jul11-Feb12		2,445,857			$ 3.73	$ 9,123,048	$ 3.73	$ 9,123,048	$ 3.54	$ 8,658,335
kVA billed Mar12		300,747			$ 3.54	$ 1,064,643	$ 3.54	$ 1,064,643	$ 3.54	$ 1,064,643
Minimum Peak Period Demand		8,989								
Total Minimum Demand Billings						153,120		153,120		134,022
Partial Month and Prorated Billings						52,641		52,641		52,641
TOTAL	432	11,193,550		1,608,310,112		$ 82,177,985		$ 81,836,969		$ 79,886,044
					Correction Factor -	1.000000000		1.000000000		1.000000000
TOTAL AFTER APPLICATION OF CORRECTION FACTOR						$ 82,177,985		$ 81,836,969		$ 79,886,044
RETAIL TRANSMISSION SERVICE INCREASE IN BASE RATES REVENUE								$ (341,016)		$ (1,950,925)
PRO FORMA REVENUE ADJUSTMENTS:										
Fuel Adjustment Clause Billings										$ 847,670
Demand Side Management Billings										$ -
Environmental Cost Recovery Surcharge Billings										$ 2,464,908
Total Pro Forma Revenue Adjustments										$ 3,312,578
Total Test Year Adjusted Revenues										**$ 83,198,622**

Kentucky Utilities Company
Effect of Rate Changes for the Test Period
Twelve Months Ended March 31, 2012

Based on Sales for the 12 months ended March 31, 2012
Including the rate change due to FAC roll-in effective on July 01, 2011
Including the rate change due to ECR roll-in effective on March 01, 2012

	Customers 12mos Mar 2012	Basic Demand	Peak Demand	kWh's	"As Billed Rates" During 12 Month Period Unit Charges	"As Billed Rates" During 12 Month Period Calculated Revenue	FAC Rollin for Full Year Unit Charges	FAC Rollin for Full Year Calculated Revenue	ECR Rollin for Full Year Unit Charges	ECR Rollin for Full Year Calculated Revenue
FLUCTUATING LOAD SERVICE -- PRIMARY DELIVERY										
Customers Apr11-Jun11	-				$ 500.00	$ -	$ 500.00	$ -	$ 500.00	$ -
Customers Jul11-Feb12	-				$ 500.00	$ -	$ 500.00	$ -	$ 500.00	$ -
Customers Mar12	-				$ 500.00	$ -	$ 500.00	$ -	$ 500.00	$ -
Partial month, prorated and corrected billings						-		-		-
kWh billed Apr11-Jun11				-	$ 0.03505	$ -	$ 0.03419	$ -	$ 0.03419	$ -
kWh billed Jul11-Feb12				-	$ 0.03419	$ -	$ 0.03419	$ -	$ 0.03419	$ -
kWh billed Mar12				-	$ 0.03419	$ -	$ 0.03419	$ -	$ 0.03419	$ -
Minimum and Partial Month Billings						-		-		-
Demand Billings										
Base Demand Period										
kVA billed Apr11-Jun11		-			$ 1.75	$ -	$ 1.75	$ -	$ 1.57	$ -
kVA billed Jul11-Feb12		-			$ 1.75	$ -	$ 1.75	$ -	$ 1.57	$ -
kVA billed Mar12		-			$ 1.57	$ -	$ 1.57	$ -	$ 1.57	$ -
Intermediate Demand Period										
kVA billed Apr11-Jun11		-			$ 1.59	$ -	$ 1.59	$ -	$ 1.41	$ -
kVA billed Jul11-Feb12		-			$ 1.59	$ -	$ 1.59	$ -	$ 1.41	$ -
kVA billed Mar12		-			$ 1.41	$ -	$ 1.41	$ -	$ 1.41	$ -
Peak Demand Period										
kVA billed Apr11-Jun11		-			$ 2.48	$ -	$ 2.48	$ -	$ 2.30	$ -
kVA billed Jul11-Feb12		-			$ 2.48	$ -	$ 2.48	$ -	$ 2.30	$ -
kVA billed Mar12		-			$ 2.30	$ -	$ 2.30	$ -	$ 2.30	$ -
Minimum Demand and Billings		-				-		-		-
Partial Month and Prorated Billings						-		-		-
TOTAL	-	-		-		$ -		$ -		$ -
					Correction Factor -	1.000000000		1.000000000		1.000000000
TOTAL AFTER APPLICATION OF CORRECTION FACTOR						$ -		$ -		$ -
						25,193,075				
FLUCTUATING LOAD SERVICE INCREASE IN BASE RATES REVENUE								$ -		$ -
PRO FORMA REVENUE ADJUSTMENTS:										
Fuel Adjustment Clause Billings										$ -
Demand Side Management Billings										$ -
Environmental Cost Recovery Surcharge Billings										$ -
Total Pro Forma Revenue Adjustments										$ -
Total Test Year Adjusted Revenues										$ -

Kentucky Utilities Company
Effect of Rate Changes for the Test Period
Twelve Months Ended March 31, 2012

Based on Sales for the 12 months ended March 31, 2012
Including the rate change due to FAC roll-in effective on July 01, 2011
Including the rate change due to ECR roll-in effective on March 01, 2012

	Customers 12mos Mar 2012	Basic Demand	Peak Demand	kWh's	"As Billed Rates" During 12 Month Period Unit Charges	Calculated Revenue	FAC Rollin for Full Year Unit Charges	Calculated Revenue	ECR Rollin for Full Year Unit Charges	Calculated Revenue
FLUCTUATING LOAD SERVICE -- TRANSMISSION DELIVERY										
Customers Apr11-Jun11	3				$ 500.00	$ 1,500	$ 500.00	$ 1,500	$ 500.00	$ 1,500
Customers Jul11-Feb12	8				$ 500.00	$ 4,000	$ 500.00	$ 4,000	$ 500.00	$ 4,000
Customers Mar12	1				$ 500.00	$ 500	$ 500.00	$ 500	$ 500.00	$ 500
Partial month, prorated and corrected billings						500		500		500
kWh billed Apr11-Jun11				130,464,000	$ 0.03033	$ 3,956,973	$ 0.02947	$ 3,844,774	$ 0.02947	$ 3,844,774
kWh billed Jul11-Feb12				370,247,246	$ 0.02947	$ 10,911,186	$ 0.02947	$ 10,911,186	$ 0.02947	$ 10,911,186
kWh billed Mar12				45,576,000	$ 0.02947	$ 1,343,125	$ 0.02947	$ 1,343,125	$ 0.02947	$ 1,343,125
Minimum and Partial Month Billings						-		-		-
Demand Billings										
Base Demand Period										
kVA billed Apr11-Jun11		534,597			$ 1.00	$ 534,597	$ 1.00	$ 534,597	$ 0.82	$ 438,369
kVA billed Jul11-Feb12		1,630,197			$ 1.00	$ 1,630,197	$ 1.00	$ 1,630,197	$ 0.82	$ 1,336,762
kVA billed Mar12		182,441			$ 0.82	$ 149,601	$ 0.82	$ 149,601	$ 0.82	$ 149,601
Intermediate Demand Period										
kVA billed Apr11-Jun11		534,597			$ 1.59	$ 850,008	$ 1.59	$ 850,008.44	$ 1.41	$ 753,781
kVA billed Jul11-Feb12		1,587,068			$ 1.59	$ 2,523,438	$ 1.59	$ 2,523,437.80	$ 1.41	$ 2,237,766
kVA billed Mar12		182,441			$ 1.41	$ 257,241	$ 1.41	$ 257,241	$ 1.41	$ 257,241
Peak Demand Period										
kVA billed Apr11-Jun11		366,289			$ 2.48	$ 908,398	$ 2.48	$ 908,397.46	$ 2.30	$ 842,465
kVA billed Jul11-Feb12		784,119			$ 2.48	$ 1,944,614	$ 2.48	$ 1,944,614.38	$ 2.30	$ 1,803,473
kVA billed Mar12		77,042			$ 2.30	$ 177,197	$ 2.30	$ 177,197	$ 2.30	$ 177,197
Minimum Demand and Billings		-				-		-		-
Partial Month and Prorated Billings						-		-		-
TOTAL	12	5,878,789		546,287,246		$ 25,193,075		$ 25,080,876		$ 24,102,240
					Correction Factor -	1.000000000		1.000000000		1.000000000
TOTAL AFTER APPLICATION OF CORRECTION FACTOR						$ 25,193,075		$ 25,080,876		$ 24,102,240
FLUCTUATING LOAD SERVICE INCREASE IN BASE RATES REVENUE								$ (112,199)		$ (978,636)
PRO FORMA REVENUE ADJUSTMENTS:										
Fuel Adjustment Clause Billings										$ 296,727
Demand Side Management Billings										$ -
Environmental Cost Recovery Surcharge Billings										$ 745,290
Total Pro Forma Revenue Adjustments										$ 1,042,017
Total Test Year Adjusted Revenues										**$ 25,144,257**

Kentucky Utilities Company
Effect of Rate Changes for the Test Period
Twelve Months Ended March 31, 2012

Based on Sales for the 12 months ended March 31, 2012
Including the rate change due to FAC roll-in effective on July 01, 2011
Including the rate change due to ECR roll-in effective on March 01, 2012

	Customers 12mos Mar 2012	Basic Demand	Peak Demand	kWh's	"As Billed Rates" During 12 Month Period Unit Charges	"As Billed Rates" During 12 Month Period Calculated Revenue	FAC Rollin for Full Year Unit Charges	FAC Rollin for Full Year Calculated Revenue	ECR Rollin for Full Year Unit Charges	ECR Rollin for Full Year Calculated Revenue
LIGHTING ENERGY RATE LE										
Customers Apr11-Jun11	2				$ -	$ -	$ -	$ -	$ -	$ -
Customers Jul11-Feb12	8				$ -	$ -	$ -	$ -	$ -	$ -
Customers Mar12	1				$ -	$ -	$ -	$ -	$ -	$ -
Partial month, prorated and corrected billings						-		-		-
kWh billed Apr11-Jun11				9,586	$ 0.05465	$ 524	$ 0.05379	$ 516	$ 0.05647	$ 541
kWh billed Jul11-Feb12				26,872	$ 0.05379	$ 1,445	$ 0.05379	$ 1,445	$ 0.05647	$ 1,517
kWh billed Mar12				3,592	$ 0.05647	$ 203	$ 0.05647	$ 203	$ 0.05647	$ 203
Minimum and Partial Month Billings						(7)		(7)		(7)
TOTAL	11			40,050		$ 2,165		$ 2,157		$ 2,255
					Correction Factor -	1.000000000		1.000000000		1.000000000
TOTAL AFTER APPLICATION OF CORRECTION FACTOR						$ 2,165		$ 2,157		$ 2,255
LIGHTING ENERGY SERVICE INCREASE IN BASE RATES REVENUE								$ (8)		$ 98
PRO FORMA REVENUE ADJUSTMENTS:										
Fuel Adjustment Clause Billings										$ 17
Demand Side Management Billings										$ -
Environmental Cost Recovery Surcharge Billings										$ 63
Total Pro Forma Revenue Adjustments										$ 81
Total Test Year Adjusted Revenues										**$ 2,335**

	Customers 12mos Mar 2012	Basic Demand	Peak Demand	kWh's	"As Billed Rates" During 12 Month Period Unit Charges	"As Billed Rates" During 12 Month Period Calculated Revenue	FAC Rollin for Full Year Unit Charges	FAC Rollin for Full Year Calculated Revenue	ECR Rollin for Full Year Unit Charges	ECR Rollin for Full Year Calculated Revenue
TRAFFIC LIGHTING SERVICE RATE TE										
Customers Apr11-Jun11	1,340				$ 3.14	$ 4,208	$ 3.14	$ 4,208	$ 3.14	$ 4,208
Customers Jul11-Feb12	6,026				$ 3.14	$ 18,922	$ 3.14	$ 18,922	$ 3.14	$ 18,922
Customers Mar12	720				$ 3.14	$ 2,261	$ 3.14	$ 2,261	$ 3.14	$ 2,261
Partial month, prorated and corrected billings						(65)		(65)		(65)
kWh billed Apr11-Jun11				229,173	$ 0.07000	$ 16,042	$ 0.06914	$ 15,845	$ 0.07182	$ 16,459
kWh billed Jul11-Feb12				790,895	$ 0.06914	$ 54,682	$ 0.06914	$ 54,682	$ 0.07182	$ 56,802
kWh billed Mar12				98,599	$ 0.07182	$ 7,081	$ 0.07182	$ 7,081	$ 0.07182	$ 7,081
Minimum and Partial Month Billings						(103)		(103)		(103)
TOTAL	8,086			1,118,667		$ 103,028		$ 102,832		$ 105,565
					Correction Factor -	1.000000000		1.000000000		1.000000000
TOTAL AFTER APPLICATION OF CORRECTION FACTOR						$ 103,028		$ 102,832		$ 105,565
TRAFFICE LIGHTING SERVICE INCREASE IN BASE RATES REVENUE								$ (196)		$ 2,733
PRO FORMA REVENUE ADJUSTMENTS:										
Fuel Adjustment Clause Billings										$ 565
Demand Side Management Billings										$ -
Environmental Cost Recovery Surcharge Billings										$ 3,101
Total Pro Forma Revenue Adjustments										$ 3,666
Total Test Year Adjusted Revenues										**$ 109,231**

Kentucky Utilities Company
Effect of Rate Changes for the Test Period
Twelve Months Ended March 31, 2012

Based on Sales for the 12 months ended March 31, 2012
Including the rate change due to FAC roll-in effective on July 01, 2011
Including the rate change due to ECR roll-in effective on February 27, 2012

		Lights at Apr11-Jun11 Rates	Lights at Jul11-Feb12 Rates	Lights at Mar12 Rates	Apr11-Jun11 Rates	Jul11-Feb12 Rates	Mar12 Rates	Revenue for 12 Months Ended March 31, 2012	Revenue Reflecting FAC Rollin	Revenue Reflecting ECR Rollin
STREET LIGHTING SERVICE										
Overhead Service										
High Pressure Sodium										
4,000 Lumen Standard	KUUM_461	20,907	55,711	6,953	$ 6.67	$ 6.65	$ 6.93	$ 558,112	$ 557,694	$ 579,147
4,000 Lumen Ornamental	KUUM_471	11,461	30,356	3,783	$ 9.50	$ 9.48	$ 9.76	$ 433,576	$ 433,347	$ 445,056
5,800 Lumen Standard	KUUM_462	26,313	70,158	8,789	$ 7.54	$ 7.52	$ 7.90	$ 795,421	$ 794,895	$ 831,554
5,800 Lumen Ornamental	KUUM_472	25,680	68,772	8,604	$ 10.37	$ 10.35	$ 10.73	$ 1,070,413	$ 1,069,899	$ 1,105,791
9,500 Lumen Standard	KUUM_463	60,688	161,570	20,280	$ 8.15	$ 8.12	$ 8.41	$ 1,977,110	$ 1,975,287	$ 2,039,746
9,500 Lumen Ornamental	KUUM_473	9,437	25,499	3,218	$ 11.19	$ 11.16	$ 11.45	$ 427,015	$ 426,732	$ 436,863
22,000 Lumen Standard	KUUM_464	17,524	46,823	5,918	$ 12.58	$ 12.51	$ 13.04	$ 883,378	$ 882,152	$ 916,256
22,000 Lumen Ornamental	KUUM_474	14,833	39,729	5,045	$ 15.62	$ 15.55	$ 16.08	$ 930,601	$ 929,563	$ 958,481
50,000 Lumen Standard	KUUM_465	2,647	7,029	875	$ 20.50	$ 20.36	$ 20.95	$ 215,705	$ 215,335	$ 221,043
50,000 Lumen Ornamental	KUUM_475	1,412	3,797	483	$ 22.06	$ 21.92	$ 22.51	$ 125,251	$ 125,054	$ 128,127
Mercury Vapor										
7,000 Lumen Standard	KUUM_446	3,464	9,138	1,135	$ 8.55	$ 8.49	$ 8.72	$ 117,096	$ 116,888	$ 119,787
7,000 Lumen Ornamental	KUUM_456	426	1,124	142	$ 10.77	$ 10.71	$ 10.94	$ 18,180	$ 18,154	$ 18,510
10,000 Lumen Standard	KUUM_447	2,500	6,480	801	$ 10.09	$ 10.01	$ 10.29	$ 98,332	$ 98,132	$ 100,646
10,000 Lumen Ornamental	KUUM_457	1,534	4,012	497	$ 12.06	$ 11.98	$ 12.26	$ 72,657	$ 72,534	$ 74,087
20,000 Lumen Standard	KUUM_448	4,368	11,249	1,398	$ 12.35	$ 12.22	$ 12.57	$ 208,980	$ 208,413	$ 213,879
20,000 Lumen Ornamental	KUUM_458	3,925	10,322	1,277	$ 13.92	$ 13.79	$ 14.14	$ 215,033	$ 214,523	$ 219,509
Incandescent										
1,000 Lumen Standard	KUUM_421	48	128	16	$ 3.04	$ 3.01	$ 3.08	$ 580	$ 579	$ 591
1,000 Lumen Ornamental	KUUM_431	-	-	-	$ 3.69	$ 3.66	$ 3.73	$ -	$ -	$ -
2,500 Lumen Standard	KUUM_422	2,707	6,646	832	$ 4.05	$ 3.99	$ 4.09	$ 40,884	$ 40,721	$ 41,657
2,500 Lumen Ornamental	KUUM_432	-	-	-	$ 4.84	$ 4.78	$ 4.88	$ -	$ -	$ -
4,000 Lumen Standard	KUUM_424	824	1,958	244	$ 6.15	$ 6.06	$ 6.08	$ 18,417	$ 18,342	$ 18,398
4,000 Lumen Ornamental	KUUM_434	107	252	31	$ 7.07	$ 6.98	$ 7.00	$ 2,732	$ 2,723	$ 2,730
6,000 Lumen Standard	KUUM_425	9	24	(19)	$ 8.06	$ 7.93	$ 8.11	$ 109	$ 108	$ 114
6,000 Lumen Ornamental	KUUM_435	-	-	-	$ 8.06	$ 8.95	$ 9.13	$ -	$ -	$ -
Underground Service										
High Pressure Sodium										
4,000 Lumen Acorn (Decorative Pole)	KUUM_400	-	-	-	$ 12.51	$ 12.49	$ 12.77	$ -	$ -	$ -
4,000 Lumen Acorn (Historic Pole)	KUUM_410	459	1,257	164	$ 18.90	$ 18.88	$ 19.16	$ 35,550	$ 35,540	$ 36,021
5,800 Lumen Acorn (Decorative Pole)	KUUM_401	105	280	35	$ 13.50	$ 13.48	$ 13.86	$ 5,677	$ 5,675	$ 5,821
5,800 Lumen Acorn (Historic Pole)	KUUM_411	216	576	72	$ 19.78	$ 19.76	$ 20.14	$ 17,104	$ 17,100	$ 17,401
9,500 Lumen Acorn (Decorative Pole)	KUUM_420	574	1,495	206	$ 14.13	$ 14.10	$ 14.39	$ 32,154	$ 32,137	$ 32,737
9,500 Lumen Acorn (Historic Pole)	KUUM_430	1,357	3,494	441	$ 20.52	$ 20.49	$ 20.78	$ 108,602	$ 108,561	$ 109,968
4,000 Lumen Colonial	KUUM_466	2,232	5,952	744	$ 8.67	$ 8.65	$ 8.93	$ 77,480	$ 77,436	$ 79,727
5,800 Lumen Colonial	KUUM_467	3,345	9,025	1,138	$ 9.57	$ 9.55	$ 9.93	$ 129,501	$ 129,434	$ 134,134
9,500 Lumen Colonial	KUUM_468	5,778	15,645	1,972	$ 10.09	$ 10.06	$ 10.35	$ 236,099	$ 235,926	$ 242,138
5,800 Lumen Coach	KUUM_413	335	802	97	$ 29.39	$ 29.36	$ 29.65	$ 36,268	$ 36,258	$ 36,588
9,500 Lumen Coach	KUUM_415	30	80	10	$ 29.39	$ 29.36	$ 29.65	$ 3,527	$ 3,526	$ 3,558
5,800 Lumen Contemporary	KUUM_483	132	356	44	$ 21.45	$ 21.43	$ 21.81	$ 11,420	$ 11,417	$ 11,603
9,500 Lumen Contemporary	KUUM_484	1,302	3,455	433	$ 21.59	$ 21.56	$ 21.85	$ 112,061	$ 112,022	$ 113,402
22,000 Lumen Contemporary	KUUM_485	2,175	5,847	755	$ 27.38	$ 27.31	$ 27.84	$ 240,252	$ 240,100	$ 244,352
50,000 Lumen Contemporary	KUUM_486	2,547	6,701	864	$ 30.67	$ 30.53	$ 31.12	$ 309,586	$ 309,229	$ 314,685

Kentucky Utilities Company
Effect of Rate Changes for the Test Period
Twelve Months Ended March 31, 2012

Based on Sales for the 12 months ended March 31, 2012
Including the rate change due to FAC roll-in effective on July 01, 2011
Including the rate change due to ECR roll-in effective on February 27, 2012

		Lights at Apr11-Jun11 Rates	Lights at Jul11-Feb12 Rates	Lights at Mar12 Rates	Apr11-Jun11 Rates	Jul11-Feb12 Rates	Mar12 Rates	Revenue for 12 Months Ended March 31, 2012	Revenue Reflecting FAC Rollin	Revenue Reflecting ECR Rollin
Granville Lights										
Pole and Fixture	0	1,166	3,091	387	$ 49.34	$ 49.29	$ 51.00	$ 229,623	$ 229,565	$ 236,844
Granville Accessories										
Single Crossarm Bracket	1	-	-	-	$ 17.78	$ 17.78	$ 17.78	$ -	$ -	$ -
Twin Crossarm Bracket (includes 1 fixture)	2	91	248	31	$ 19.79	$ 19.79	$ 19.79	$ 7,322	$ 7,322	$ 7,322
24 Inch Banner Arm	3	72	192	24	$ 3.09	$ 3.09	$ 3.09	$ 890	$ 890	$ 890
24 Inch Clamp Banner Arm	4	306	816	102	$ 4.26	$ 4.26	$ 4.26	$ 5,214	$ 5,214	$ 5,214
18 Inch Banner Arm	5	312	832	104	$ 2.84	$ 2.84	$ 2.84	$ 3,544	$ 3,544	$ 3,544
18 Inch Clamp On Banner Arm	7	-	-	-	$ 3.52	$ 3.52	$ 3.52	$ -	$ -	$ -
Flagpole Holder	6	108	288	36	$ 1.31	$ 1.31	$ 1.31	$ 566	$ 566	$ 566
Post-Mounted Receptacle	8	171	456	57	$ 18.46	$ 18.46	$ 18.46	$ 12,627	$ 12,627	$ 12,627
Base-Mounted Receptacle	9	-	-	-	$ 17.81	$ 17.81	$ 17.81	$ -	$ -	$ -
Additional Receptacles	10	-	-	-	$ 2.52	$ 2.52	$ 2.52	$ -	$ -	$ -
Planter	11	162	432	54	$ 4.28	$ 4.28	$ 4.28	$ 2,773	$ 2,773	$ 2,773
Clamp On Planter	12	-	-	-	$ 4.75	$ 4.75	$ 4.75	$ -	$ -	$ -
Prorated and corrected billings								$ (17,366)	$ (17,366)	$ (17,366)
Total Street Lighting		233,789	622,097	78,072				$ 9,810,056	$ 9,800,571	$ 10,106,521
						Correction Factor -		1.000000000	1.000000000	1.000000000
TOTAL AFTER APPLICATION OF CORRECTION FACTOR								$ 9,810,056	$ 9,800,571	$ 10,106,521
OUTDOOR LIGHTING INCREASE IN BASE RATES REVENUE									$ (9,485)	$ 305,950
PRO FORMA REVENUE ADJUSTMENTS:										
Fuel Adjustment Clause Billings										$ 18,993
Demand Side Management Billings										$ -
Environmental Cost Recovery Surcharge Billings										$ 291,075
Total Pro Forma Revenue Adjustments										$ 310,068
Total Test Year Adjusted Revenues										**$ 10,416,589**

Kentucky Utilities Company
Effect of Rate Changes for the Test Period
Twelve Months Ended March 31, 2012

Based on Sales for the 12 months ended March 31, 2012
Including the rate change due to FAC roll-in effective on July 01, 2011
Including the rate change due to ECR roll-in effective on February 27, 2012

		Lights at Apr11-Jun11 Rates	Lights at Jul11-Feb12 Rates	Lights at Mar12 Rates	Apr11-Jun11 Rates	Jul11-Feb12 Rates	Mar12 Rates	Revenue for 12 Months Ended March 31, 2012	Revenue Reflecting FAC Rollin	Revenue Reflecting ECR Rollin
PRIVATE OUTDOOR LIGHTING										
Overhead Service (Fixture Only)										
High Pressure Sodium										
22,000 Lumen Cobra Head	KUUM_429	4,617	12,515	1,560	$ 12.58	$ 12.51	$ 13.04	$ 234,987	$ 234,664	$ 243,744
50,000 Lumen Cobra Head	KUUM_407	6,086	16,254	2,036	$ 20.50	$ 20.36	$ 20.95	$ 498,349	$ 497,497	$ 510,677
9,500 Lumen Directional	KUUM_487	32,263	86,340	10,767	$ 8.01	$ 7.98	$ 8.27	$ 1,036,463	$ 1,035,495	$ 1,069,890
22,000 Lumen Directional	KUUM_488	19,167	51,756	6,581	$ 11.99	$ 11.92	$ 12.45	$ 928,677	$ 927,336	$ 964,925
50,000 Lumen Directional	KUUM_489	23,658	63,643	8,060	$ 17.25	$ 17.11	$ 17.70	$ 1,639,694	$ 1,636,382	$ 1,687,890
5,800 Lumen Open Bottom	KUUM_426	634	1,665	182	$ 6.36	$ 6.34	$ 6.72	$ 15,811	$ 15,799	$ 16,672
9,500 Lumen Open Bottom	KUUM_428	106,067	285,567	35,988	$ 6.90	$ 6.87	$ 7.16	$ 2,951,382	$ 2,948,200	$ 3,061,773
Mercury Vapor										
20,000 Lumen Cobra Head	KUUM_405	1,364	3,624	401	$ 12.35	$ 12.22	$ 12.57	$ 66,171	$ 65,994	$ 67,740
7,000 Lumen Open Bottom	KUUM_404	25,703	66,645	8,094	$ 9.52	$ 9.46	$ 9.69	$ 953,585	$ 952,043	$ 973,283
7,000 Lumen Open Bottom	KUUM_406	-	-	-	$ -	$ 9.82	$ 10.05	$ -	$ -	$ -
Restricted Special Lighting										
20,000 Lumen Cobra Head (Mercury Vapor)	KUUM_408	1,189	3,106	375	$ 7.63	$ 7.50	$ 7.85	$ 35,311	$ 35,156	$ 36,660
50,000 Lumen Cobra Head (High Pressure Sodium)	KUUM_409	483	1,272	167	$ 9.80	$ 9.66	$ 10.25	$ 18,733	$ 18,665	$ 19,701
Underground Service										
High Pressure Sodium										
4,000 Lumen Acorn (Decorative Pole)	KUUM_440	6	16	2	$ 12.51	$ 12.49	$ 12.77	$ 300	$ 300	$ 306
4,000 Lumen Acorn (Historic Pole)	KUUM_444	186	496	62	$ 18.90	$ 18.88	$ 19.16	$ 14,068	$ 14,064	$ 14,255
5,800 Lumen Acorn (Decorative Pole)	KUUM_441	51	136	17	$ 13.50	$ 13.48	$ 13.86	$ 2,757	$ 2,756	$ 2,827
5,800 Lumen Acorn (Historic Pole)	KUUM_445	222	592	74	$ 19.78	$ 19.76	$ 20.14	$ 17,579	$ 17,575	$ 17,884
9,500 Lumen Acorn (Decorative Pole)	KUUM_442	678	1,805	235	$ 14.13	$ 14.10	$ 14.39	$ 38,412	$ 38,392	$ 39,112
9,500 Lumen Acorn (Historic Pole)	KUUM_449	1,941	5,049	650	$ 20.52	$ 20.49	$ 20.78	$ 156,790	$ 156,732	$ 158,759
4,000 Lumen Colonial	KUUM_480	249	666	84	$ 8.67	$ 8.65	$ 8.93	$ 8,670	$ 8,665	$ 8,921
5,800 Lumen Colonial	KUUM_481	520	1,248	178	$ 9.57	$ 9.55	$ 9.93	$ 18,662	$ 18,652	$ 19,324
9,500 Lumen Colonial	KUUM_482	5,132	13,917	1,781	$ 10.09	$ 10.06	$ 10.35	$ 210,220	$ 210,066	$ 215,591
5,800 Lumen Coach	KUUM_412	84	224	28	$ 28.88	$ 28.86	$ 29.24	$ 9,709	$ 9,708	$ 9,825
9,500 Lumen Coach	KUUM_414	63	168	21	$ 28.88	$ 28.86	$ 29.24	$ 7,282	$ 7,281	$ 7,368
5,800 Lumen Contemporary	KUUM_476	13,514	36,075	4,510	$ 15.30	$ 15.28	$ 15.66	$ 828,617	$ 828,347	$ 847,190
Additional Fixture	KUUM_492	-	4	2	$ -	$ 13.97	$ 14.35	$ 85	$ 85	$ 86
9,500 Lumen Contemporary	KUUM_477	1,666	4,464	558	$ 17.93	$ 17.90	$ 18.19	$ 119,927	$ 119,877	$ 121,655
Additional Fixture	KUUM_497	-	-	-	$ -	$ -	$ 14.38	$ -	$ -	$ -
22,000 Lumen Contemporary	KUUM_478	1,696	5,296	674	$ 21.65	$ 21.58	$ 22.11	$ 165,908	$ 165,790	$ 169,495
Additional Fixture	KUUM_498	18	48	12	$ 15.91	$ 15.84	$ 16.37	$ 1,243	$ 1,242	$ 1,277
50,000 Lumen Contemporary	KUUM_479	239	686	87	$ 27.68	$ 27.54	$ 28.13	$ 27,955	$ 27,922	$ 28,468
Additional Fixture	KUUM_499	-	18	3	$ 19.22	$ 19.06	$ 19.65	$ 402	$ 402	$ 413

Kentucky Utilities Company
Effect of Rate Changes for the Test Period
Twelve Months Ended March 31, 2012

Based on Sales for the 12 months ended March 31, 2012
Including the rate change due to FAC roll-in effective on July 01, 2011
Including the rate change due to ECR roll-in effective on February 27, 2012

		Lights at Apr11-Jun11 Rates	Lights at Jul11-Feb12 Rates	Lights at Mar12 Rates	Apr11-Jun11 Rates	Jul11-Feb12 Rates	Mar12 Rates	Revenue for 12 Months Ended March 31, 2012	Revenue Reflecting FAC Rollin	Revenue Reflecting ECR Rollin
Metal Halide										
12,000 Lumen Directional Fixture Only	KUUM_450	1,770	4,855	604	$ 12.38	$ 12.34	$ 13.04	$ 89,699	$ 89,629	$ 94,266
12,000 Lumen Directional Fixture with Wood Pole	KUUM_454	440	1,193	154	$ 16.61	$ 16.57	$ 17.27	$ 29,736	$ 29,718	$ 30,861
12,000 Lumen Directional Fixture with Metal Pole	KUUM_460	75	200	25	$ 24.79	$ 24.75	$ 25.45	$ 7,446	$ 7,443	$ 7,635
32,000 Lumen Directional Fixture Only	KUUM_451	13,728	37,109	4,573	$ 17.75	$ 17.65	$ 18.45	$ 983,018	$ 981,645	$ 1,022,315
32,000 Lumen Directional Fixture with Wood Pole	KUUM_455	3,005	8,247	1,031	$ 21.98	$ 21.88	$ 22.68	$ 269,877	$ 269,577	$ 278,578
32,000 Lumen Directional Fixture with Metal Pole	KUUM_469	801	2,142	277	$ 30.16	$ 30.06	$ 30.86	$ 97,095	$ 97,015	$ 99,369
107,800 Lumen Directional Fixture Only	KUUM_452	3,036	8,327	1,084	$ 37.26	$ 36.95	$ 38.48	$ 462,516	$ 461,575	$ 478,961
107,800 Lumen Directional Fixture with Wood Pole	KUUM_459	745	2,099	260	$ 41.49	$ 41.18	$ 42.71	$ 128,451	$ 128,221	$ 132,572
107,800 Lumen Directional Fixture with Metal Pole	KUUM_470	222	602	75	$ 49.67	$ 49.36	$ 50.89	$ 44,558	$ 44,489	$ 45,750
12,000 Lumen Contemporary Fixture Only	KUUM_490	174	464	58	$ 13.55	$ 13.51	$ 14.21	$ 9,451	$ 9,444	$ 9,890
12,000 Lumen Contemporary Fixture With Direct B	KUUM_494	663	1,706	204	$ 25.96	$ 25.92	$ 26.62	$ 66,861	$ 66,835	$ 68,493
32,000 Lumen Contemporary Fixture Only	KUUM_491	882	2,370	300	$ 19.42	$ 19.32	$ 20.12	$ 68,953	$ 68,865	$ 71,466
32,000 Lumen Contemporary Fixture With Metal Pc	KUUM_495	1,784	4,750	597	$ 31.83	$ 31.73	$ 32.53	$ 226,923	$ 226,744	$ 231,971
107,800 Lumen Contemporary Fixture Only	KUUM_493	147	392	49	$ 40.48	$ 40.17	$ 41.70	$ 23,741	$ 23,695	$ 24,520
107,800 Lumen Contemporary Fixture With Metal F	KUUM_496	447	1,346	176	$ 52.89	$ 52.58	$ 54.11	$ 103,938	$ 103,799	$ 106,543
Granville Lights										
Pole and Fixture	20	27	57	4	$ 49.34	$ 49.29	$ 51.00	$ 4,346	$ 4,344	$ 4,488
Granville Accessories										
Single Crossarm Bracket	21	-	-	-	$ -	$ -	$ -	$ -	$ -	$ -
Twin Crossarm Bracket (includes 1 fixture)	22	-	-	-	$ -	$ -	$ -	$ -	$ -	$ -
24 Inch Banner Arm	23	-	-	-	$ -	$ -	$ -	$ -	$ -	$ -
24 Inch Clamp Banner Arm	24	-	-	-	$ -	$ -	$ -	$ -	$ -	$ -
18 Inch Banner Arm	25	-	-	-	$ -	$ -	$ -	$ -	$ -	$ -
18 Inch Clamp On Banner Arm	27	-	-	-	$ -	$ -	$ -	$ -	$ -	$ -
Flagpole Holder	26	-	-	-	$ -	$ -	$ -	$ -	$ -	$ -
Post-Mounted Receptacle	28	-	-	-	$ -	$ -	$ -	$ -	$ -	$ -
Base-Mounted Receptacle	29	-	-	-	$ -	$ -	$ -	$ -	$ -	$ -
Additional Receptacles	30	-	-	-	$ -	$ -	$ -	$ -	$ -	$ -
Planter	31	-	-	-	$ -	$ -	$ -	$ -	$ -	$ -
Prorated and corrected billings								$ (42,662)	$ (42,662)	$ (42,662)
Total Private Outdoor Lighting		275,415	739,097	92,656				$ 12,581,696	$ 12,565,463	$ 12,980,727
						Correction Factor -		1.000000000	1.000000000	1.000000000
TOTAL AFTER APPLICATION OF CORRECTION FACTOR								$ 12,581,696	$ 12,565,463	$ 12,980,727
OUTDOOR LIGHTING INCREASE IN BASE RATES REVENUE									$ (16,233)	$ 415,264
PRO FORMA REVENUE ADJUSTMENTS:										
Fuel Adjustment Clause Billings										$ 31,413
Demand Side Management Billings										$ -
Environmental Cost Recovery Surcharge Billings										$ 381,708
Total Pro Forma Revenue Adjustments										$ 413,120
Total Test Year Adjusted Revenues										**$ 13,393,847**

Kentucky Utilities Company
Effect of Rate Changes for the Test Period
Twelve Months Ended March 31, 2012

Based on Sales for the 12 months ended March 31, 2012
Including the rate change due to FAC roll-in effective on July 01, 2011
Including the rate change due to ECR roll-in effective on February 27, 2012

		Lights at Apr11-Jun11 Rates	Lights at Jul11-Feb12 Rates	Lights at Mar12 Rates	Apr11-Jun11 Rates	Jul11-Feb12 Rates	Mar12 Rates	Revenue for 12 Months Ended March 31, 2012	Revenue Reflecting FAC Rollin	Revenue Reflecting ECR Rollin
DARK SKY FRIENDLY LIGHTING SERVICE										
Overhead Service										
High Pressure Sodium										
4,000 Lumen DSK Lantern	KUUM_300	-	4	-	$ 21.04	$ 21.03	$ 21.31	$ 84	$ 84	$ 85
9,500 Lumen DSK Lantern	KUUM_301	-	-	-	$ 21.96	$ 21.93	$ 22.22	$ -	$ -	$ -
Total Dark Sky Friendly Lighting		-	4	-				$ 84	$ 84	$ 85
						Correction Factor -		1.000000000	1.000000000	1.000000000
TOTAL AFTER APPLICATION OF CORRECTION FACTOR								$ 84	$ 84	$ 85
OUTDOOR LIGHTING INCREASE IN BASE RATES REVENUE									$ -	$ 1
PRO FORMA REVENUE ADJUSTMENTS:										
Fuel Adjustment Clause Billings										$ (0)
Demand Side Management Billings										$ -
Environmental Cost Recovery Surcharge Billings										$ 3
Total Pro Forma Revenue Adjustments										$ 3
Total Test Year Adjusted Revenues										**$ 88**

Conroy Exhibit P2

Impact on FAC Billings
Reflecting New Base Fuel Cost
for Full Year

KENTUCKY UTILITIES COMPANY
Adjustment to Reflect FAC Billings for a Full Year of the Roll-in
Twelve Months Ended March 31, 2012

	January-12	February-12	March-12	April-11	May-11	June-11	July-11	August-11	September-11	October-11	November-11	December-11	TOTAL 12 Mos. Ended
BASE RATE ACTUAL FUEL ADJUSTMENT CLAUSE BILLINGS													
FAC RATE CHARGED:	*(0.00056)*	*(0.00035)*	*(0.00010)*	*(0.00017)*	*(0.00059)*	*0.00029*	*0.00138*	*0.00108*	*0.00312*	*0.00236*	*0.00163*	*(0.00210)*	
Residential Rate													
Residential Rate RS	$ (375,054)	$ (207,522)	$ (49,165)	$ (74,503)	$ (212,910)	$ 140,959	$ 744,532	$ 682,274	$ 1,595,162	$ 816,495	$ 599,332	$ (1,066,861)	$ 2,592,739
Volunteer Fire Department Rate VFD	$ (59)	$ (34)	$ (9)	$ (11)	$ (35)	$ 22	$ 112	$ 100	$ 225	$ 131	$ 87	$ (166)	$ 363
Low Emission Vehicle Rate LEV	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	$ (375,113)	$ (207,556)	$ (49,174)	$ (74,514)	$ (212,945)	$ 140,981	$ 744,644	$ 682,374	$ 1,595,387	$ 816,626	$ 599,419	$ (1,067,027)	$ 2,593,102
General Service													
General Service Secondary	$ (44,449)	$ (25,459)	$ (6,487)	$ (10,724)	$ (34,449)	$ 20,516	$ 103,565	$ 91,906	$ 233,508	$ 139,830	$ 89,166	$ (138,633)	$ 418,290
General Service Three Phase	$ (55,339)	$ (31,934)	$ (8,609)	$ (14,104)	$ (48,125)	$ 29,163	$ 142,651	$ 123,755	$ 333,541	$ 207,957	$ 125,687	$ (183,966)	$ 620,677
	$ (99,788)	$ (57,393)	$ (15,096)	$ (24,828)	$ (82,574)	$ 49,679	$ 246,216	$ 215,661	$ 567,049	$ 347,787	$ 214,853	$ (322,599)	$ 1,038,967
All Electric School													
AES	$ (528)	$ (338)	$ (81)	$ (123)	$ (530)	$ 786	$ 642	$ 631	$ 1,803	$ 1,232	$ 853	$ (1,441)	$ 2,906
AES Three Phase	$ (7,767)	$ (4,967)	$ (1,394)	$ (2,043)	$ (6,800)	$ 3,608	$ 13,393	$ 12,942	$ 39,319	$ 31,325	$ 17,303	$ (23,043)	$ 71,876
AES Time of Day	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	$ (8,295)	$ (5,305)	$ (1,475)	$ (2,166)	$ (7,330)	$ 4,394	$ 14,035	$ 13,573	$ 41,122	$ 32,557	$ 18,156	$ (24,484)	$ 74,782
Power Service Rate													
Power Service Rate PS - Secondary	$ (142,184)	$ (83,965)	$ (23,499)	$ (40,166)	$ (144,000)	$ 79,180	$ 384,345	$ 329,991	$ 911,921	$ 605,295	$ 358,847	$ (492,744)	$ 1,743,021
Power Service Rate PS - Primary	$ (34,988)	$ (19,583)	$ (5,578)	$ (13,066)	$ (43,406)	$ 21,351	$ 102,231	$ 82,304	$ 232,743	$ 150,792	$ 90,599	$ (125,595)	$ 437,804
	$ (177,172)	$ (103,548)	$ (29,077)	$ (53,232)	$ (187,406)	$ 100,531	$ 486,576	$ 412,295	$ 1,144,664	$ 756,087	$ 449,446	$ (618,339)	$ 2,180,825
Time of Day Power Rate													
Time-of-Day Service - TODS Secondary	$ (164,466)	$ (105,206)	$ (29,645)	$ (44,882)	$ (138,629)	$ 84,192	$ 455,099	$ 350,473	$ 1,035,695	$ 793,445	$ 411,325	$ (624,724)	$ 2,022,677
Time-of-Day Service - TODP Primary	$ (18,856)	$ (12,308)	$ (3,436)	$ (5,158)	$ (18,968)	$ 10,315	$ 49,914	$ 44,531	$ 117,766	$ 77,690	$ 49,343	$ (70,423)	$ 220,410
	$ (183,322)	$ (117,514)	$ (33,081)	$ (50,040)	$ (157,597)	$ 94,507	$ 505,013	$ 395,004	$ 1,153,461	$ 871,135	$ 460,668	$ (695,147)	$ 2,243,087
Retail Transmission Service Rate RTS	$ (51,918)	$ (66,943)	$ (13,603)	$ (20,718)	$ (84,127)	$ 38,300	$ 154,708	$ 135,382	$ 390,009	$ 412,304	$ 216,847	$ (255,302)	$ 854,939
Fluctuating Load Service Rate FLS	$ -	$ (33,793)	$ (4,558)	$ (7,381)	$ (27,400)	$ 11,776	$ 44,811	$ 35,360	$ 128,993	$ 183,405	$ 71,472	$ (95,710)	$ 306,975
Lighting Rates													
Lighting Energy Service -- LE	$ (2)	$ (2)	$ -	$ -	$ (4)	$ 1	$ 4	$ 3	$ 9	$ 8	$ 5	$ (7)	$ 15
Traffic Energy Service -- TE	$ (59)	$ (38)	$ (10)	$ (13)	$ (46)	$ 21	$ 140	$ 97	$ 278	$ 256	$ 150	$ (201)	$ 575
Dark Sky Lighting -- DSK	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Street Lighting - St. Lt.	$ (2,708)	$ (1,607)	$ (398)	$ (638)	$ (2,049)	$ 941	$ 4,179	$ 3,297	$ 11,030	$ 8,947	$ 6,457	$ (9,139)	$ 18,312
Private Outdoor Lighting - P. O. Lt.	$ (4,789)	$ (2,577)	$ (668)	$ (1,064)	$ (3,364)	$ 1,561	$ 6,955	$ 5,837	$ 19,173	$ 15,683	$ 10,981	$ (16,316)	$ 31,412
	$ (7,558)	$ (4,224)	$ (1,076)	$ (1,715)	$ (5,463)	$ 2,524	$ 11,278	$ 9,234	$ 30,490	$ 24,894	$ 17,593	$ (25,663)	$ 50,314
Total	$ (903,166)	$ (596,276)	$ (147,140)	$ (234,594)	$ (764,842)	$ 442,692	$ 2,207,281	$ 1,898,883	$ 5,051,175	$ 3,444,795	$ 2,048,454	$ (3,104,271)	$ 9,342,991

KENTUCKY UTILITIES COMPANY
Adjustment to Reflect FAC Billings for a Full Year of the Roll-in
Twelve Months Ended March 31, 2012

	January-12	February-12	March-12	April-11	May-11	June-11	July-11	August-11	September-11	October-11	November-11	December-11	TOTAL 12 Mos. Ended
FUEL ADJUSTMENT CLAUSE BILLINGS REFLECTING BASE RATE ROLL-IN FOR A FULL YEAR													
FAC RATE CHARGED:	*(0.00056)*	*(0.00035)*	*(0.00010)*	*(0.00017)*	*(0.00059)*	*0.00029*	*0.00138*	*0.00108*	*0.00312*	*0.00236*	*0.00163*	*(0.00210)*	
FAC Rate Rolled in:	-	-	*0.00000*	*0.00086*	*0.00086*	*0.00086*	*0.00086*	*0.00086*	-	-	-	-	
FAC Rate After Roll-in:	*(0.00056)*	*(0.00035)*	*(0.00010)*	*0.00069*	*0.00027*	*0.00115*	*0.00224*	*0.00194*	*0.00312*	*0.00236*	*0.00163*	*(0.00210)*	
Residential Rate													
Residential Rate RS	$ (375,054)	$ (207,522)	$ (49,165)	$ 302,395	$ 97,433	$ 558,974	$ 1,208,516	$ 1,225,567	$ 1,595,162	$ 816,495	$ 599,332	$ (1,066,861)	$ 4,705,272
Volunteer Fire Department Rate VFD	$ (59)	$ (34)	$ (9)	$ 44	$ 16	$ 87	$ 181	$ 179	$ 225	$ 131	$ 87	$ (166)	$ 682
Low Emission Vehicle Rate LEV	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	$ (375,113)	$ (207,556)	$ (49,174)	$ 302,439	$ 97,449	$ 559,061	$ 1,208,697	$ 1,225,746	$ 1,595,387	$ 816,626	$ 599,419	$ (1,067,027)	$ 4,705,954
General Service													
General Service Secondary	$ (44,449)	$ (25,459)	$ (6,487)	$ 43,529	$ 15,765	$ 81,358	$ 168,106	$ 165,091	$ 233,508	$ 139,830	$ 89,166	$ (138,633)	$ 721,325
General Service Three Phase	$ (55,339)	$ (31,934)	$ (8,609)	$ 57,245	$ 22,023	$ 115,646	$ 231,549	$ 222,300	$ 333,541	$ 207,957	$ 125,687	$ (183,966)	$ 1,036,100
	$ (99,788)	$ (57,393)	$ (15,096)	$ 100,774	$ 37,788	$ 197,004	$ 399,655	$ 387,391	$ 567,049	$ 347,787	$ 214,853	$ (322,599)	$ 1,757,425
All Electric School													
AES	$ (528)	$ (338)	$ (81)	$ 498	$ 243	$ 3,116	$ 1,042	$ 1,134	$ 1,803	$ 1,232	$ 853	$ (1,441)	$ 7,533
AES Three Phase	$ (7,767)	$ (4,967)	$ (1,394)	$ 8,291	$ 3,112	$ 14,306	$ 21,739	$ 23,248	$ 39,319	$ 31,325	$ 17,303	$ (23,043)	$ 121,472
AES Time of Day	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	$ (8,295)	$ (5,305)	$ (1,475)	$ 8,789	$ 3,355	$ 17,422	$ 22,781	$ 24,382	$ 41,122	$ 32,557	$ 18,156	$ (24,484)	$ 129,005
Power Service Rate													
Power Service Rate PS - Secondary	$ (142,184)	$ (83,965)	$ (23,499)	$ 163,025	$ 65,898	$ 313,991	$ 623,865	$ 592,762	$ 911,921	$ 605,295	$ 358,847	$ (492,744)	$ 2,893,212
Power Service Rate PS - Primary	$ (34,988)	$ (19,583)	$ (5,578)	$ 53,034	$ 19,864	$ 84,668	$ 165,940	$ 147,843	$ 232,743	$ 150,792	$ 90,599	$ (125,595)	$ 759,739
	$ (177,172)	$ (103,548)	$ (29,077)	$ 216,059	$ 85,762	$ 398,659	$ 789,805	$ 740,605	$ 1,144,664	$ 756,087	$ 449,446	$ (618,339)	$ 3,652,951
Time of Day Power Rate													
Time-of-Day Service - TODS Secondary	$ (164,466)	$ (105,206)	$ (29,645)	$ 182,166	$ 63,440	$ 333,864	$ 738,711	$ 629,554	$ 1,035,695	$ 793,445	$ 411,325	$ (624,724)	$ 3,264,159
Time-of-Day Service - TODP Primary	$ (18,856)	$ (12,308)	$ (3,436)	$ 20,934	$ 8,680	$ 40,904	$ 81,020	$ 79,990	$ 117,766	$ 77,690	$ 49,343	$ (70,423)	$ 371,304
	$ (183,322)	$ (117,514)	$ (33,081)	$ 203,100	$ 72,120	$ 374,768	$ 819,731	$ 709,544	$ 1,153,461	$ 871,135	$ 460,668	$ (695,147)	$ 3,635,463
Retail Transmission Service Rate RTS	$ (51,918)	$ (66,943)	$ (13,603)	$ 84,091	$ 38,499	$ 151,881	$ 251,121	$ 243,187	$ 390,009	$ 412,304	$ 216,847	$ (255,302)	$ 1,400,173
Fluctuating Load Service Rate FLS	$ -	$ (33,793)	$ (4,558)	$ 29,957	$ 12,539	$ 46,699	$ 72,737	$ 63,518	$ 128,993	$ 183,405	$ 71,472	$ (95,710)	$ 475,259
Lighting Rates													
Lighting Energy Service -- LE	$ (2)	$ (2)	$ -	$ -	$ 2	$ 3	$ 6	$ 5	$ 9	$ 8	$ 5	$ (7)	$ 27
Traffic Energy Service -- TE	$ (59)	$ (38)	$ (10)	$ 53	$ 21	$ 85	$ 228	$ 175	$ 278	$ 256	$ 150	$ (201)	$ 938
Dark Sky Lighting -- DSK	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Street Lighting - St. Lt.	$ (2,708)	$ (1,607)	$ (398)	$ 2,589	$ 938	$ 3,732	$ 6,783	$ 5,922	$ 11,030	$ 8,947	$ 6,457	$ (9,139)	$ 32,546
Private Outdoor Lighting - P. O. Lt.	$ (4,789)	$ (2,577)	$ (668)	$ 4,321	$ 1,539	$ 6,191	$ 11,290	$ 10,486	$ 19,173	$ 15,683	$ 10,981	$ (16,316)	$ 55,314
	$ (7,558)	$ (4,224)	$ (1,076)	$ 6,963	$ 2,500	$ 10,011	$ 18,307	$ 16,588	$ 30,490	$ 24,894	$ 17,593	$ (25,663)	$ 88,825
Total	$ (903,166)	$ (596,276)	$ (147,140)	$ 952,172	$ 350,012	$ 1,755,505	$ 3,582,834	$ 3,410,961	$ 5,051,175	$ 3,444,795	$ 2,048,454	$ (3,104,271)	$ 15,845,055

KENTUCKY UTILITIES COMPANY
Adjustment to Reflect FAC Billings for a Full Year of the Roll-in
Twelve Months Ended March 31, 2012

	January-12	February-12	March-12	April-11	May-11	June-11	July-11	August-11	September-11	October-11	November-11	December-11	TOTAL 12 Mos. Ended
REDUCED FUEL ADJUSTMENT CLAUSE BILLINGS REFLECTING BASE RATE ROLL-IN FOR A FULL YEAR													
Residential Rate													
Residential Rate RS	$ -	$ -	$ -	$ 376,898	$ 310,343	$ 418,015	$ 463,984	$ 543,293	$ -	$ -	$ -	$ -	$ 2,112,533
Volunteer Fire Department Rate VFD	$ -	$ -	$ -	$ 55	$ 51	$ 65	$ 69	$ 79	$ -	$ -	$ -	$ -	$ 319
Low Emission Vehicle Rate LEV	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	$ -	$ -	$ -	$ 376,953	$ 310,394	$ 418,080	$ 464,053	$ 543,372	$ -	$ -	$ -	$ -	$ 2,112,852
General Service													
General Service Secondary	$ -	$ -	$ -	$ 54,253	$ 50,214	$ 60,842	$ 64,541	$ 73,185	$ -	$ -	$ -	$ -	$ 303,035
General Service Three Phase	$ -	$ -	$ -	$ 71,349	$ 70,148	$ 86,483	$ 88,898	$ 98,545	$ -	$ -	$ -	$ -	$ 415,423
	$ -	$ -	$ -	$ 125,602	$ 120,362	$ 147,325	$ 153,439	$ 171,730	$ -	$ -	$ -	$ -	$ 718,458
All Electric School													
AES	$ -	$ -	$ -	$ 621	$ 773	$ 2,330	$ 400	$ 503	$ -	$ -	$ -	$ -	$ 4,627
AES Three Phase	$ -	$ -	$ -	$ 10,334	$ 9,912	$ 10,698	$ 8,346	$ 10,306	$ -	$ -	$ -	$ -	$ 49,596
AES Time of Day	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	$ -	$ -	$ -	$ 10,955	$ 10,685	$ 13,028	$ 8,746	$ 10,809	$ -	$ -	$ -	$ -	$ 54,223
Power Service Rate													
Power Service Rate PS - Secondary	$ -	$ -	$ -	$ 203,191	$ 209,898	$ 234,811	$ 239,520	$ 262,771	$ -	$ -	$ -	$ -	$ 1,150,191
Power Service Rate PS - Primary	$ -	$ -	$ -	$ 66,100	$ 63,270	$ 63,317	$ 63,709	$ 65,539	$ -	$ -	$ -	$ -	$ 321,935
	$ -	$ -	$ -	$ 269,291	$ 273,168	$ 298,128	$ 303,229	$ 328,310	$ -	$ -	$ -	$ -	$ 1,472,126
Time of Day Power Rate													
Time-of-Day Service - TODS Secondary	$ -	$ -	$ -	$ 227,048	$ 202,069	$ 249,672	$ 283,612	$ 279,081	$ -	$ -	$ -	$ -	$ 1,241,482
Time-of-Day Service - TODP Primary	$ -	$ -	$ -	$ 26,092	$ 27,648	$ 30,589	$ 31,106	$ 35,459	$ -	$ -	$ -	$ -	$ 150,894
	$ -	$ -	$ -	$ 253,140	$ 229,717	$ 280,261	$ 314,718	$ 314,540	$ -	$ -	$ -	$ -	$ 1,392,376
Retail Transmission Service Rate RTS	$ -	$ -	$ -	$ 104,809	$ 122,626	$ 113,581	$ 96,413	$ 107,805	$ -	$ -	$ -	$ -	$ 545,234
Fluctuating Load Service Rate FLS	$ -	$ -	$ -	$ 37,338	$ 39,939	$ 34,923	$ 27,926	$ 28,158	$ -	$ -	$ -	$ -	$ 168,284
Lighting Rates													
Lighting Energy Service -- LE	$ -	$ -	$ -	$ -	$ 6	$ 2	$ 2	$ 2	$ -	$ -	$ -	$ -	$ 12
Traffic Energy Service -- TE	$ -	$ -	$ -	$ 66	$ 67	$ 64	$ 88	$ 78	$ -	$ -	$ -	$ -	$ 363
Dark Sky Lighting -- DSK	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Street Lighting - St. Lt.	$ -	$ -	$ -	$ 3,227	$ 2,987	$ 2,791	$ 2,604	$ 2,625	$ -	$ -	$ -	$ -	$ 14,234
Private Outdoor Lighting - P. O. Lt.	$ -	$ -	$ -	$ 5,385	$ 4,903	$ 4,630	$ 4,335	$ 4,649	$ -	$ -	$ -	$ -	$ 23,902
	$ -	$ -	$ -	$ 8,678	$ 7,963	$ 7,487	$ 7,029	$ 7,354	$ -	$ -	$ -	$ -	$ 38,511
Total	$ -	$ -	$ -	$ 1,186,766	$ 1,114,854	$ 1,312,813	$ 1,375,553	$ 1,512,078	$ -	$ -	$ -	$ -	$ 6,502,064

Conroy Exhibit P3

Adjustment to FAC Mechanism for Use of Total System Losses

Kentucky Utilities Company
Modification to Fuel Adjustment Clause to Include Total System Losses
Twelve Months Ended March 31, 2012

Expense Month	Proposed Modification Revenue Form A Page 5 of 6 Line 3 (Conroy Exhibit P3, Page 2)	As Filed Revenue Form A Page 5 of 6 Line 3** (Conroy Exhibit P3, Page 3)	Change Revenue Form A Page 5 of 6 Line 3 (Proposed less As Filed)	Proposed Modification Expense Form A* Page 5 of 6 Line 8 (Conroy Exhibit P3, Page 2)	As Filed Expense Form A* Page 5 of 6 Line 8** (Conroy Exhibit P3, Page 3)	Change Expense Form A Page 5 of 6 Line 8 (Proposed less As Filed)
Apr-11	(413,989)	(413,989)	-	713,650	373,214	340,436
May-11	(764,843)	(764,843)	-	2,225,189	1,868,842	356,347
Jun-11	854,359	442,436	411,923	1,917,915	1,659,021	258,894
Jul-11	2,651,046	2,203,882	447,164	5,716,338	5,453,175	263,163
Aug-11	2,213,662	1,897,425	316,237	4,325,174	4,052,858	272,316
Sep-11	5,340,026	5,048,751	291,275	2,448,083	2,211,016	237,067
Oct-11	3,707,536	3,444,797	262,739	(2,649,993)	(2,873,345)	223,352
Nov-11	2,287,232	2,048,455	238,777	(600,413)	(786,511)	186,098
Dec-11	(2,882,538)	(3,104,271)	221,733	(425,373)	(553,491)	128,118
Jan-12	(693,503)	(903,167)	209,664	(51,282)	(171,525)	120,243
Feb-12	(459,985)	(596,277)	136,292	938,903	834,055	104,848
Mar-12	(44,141)	(147,138)	102,997	841,654	717,840	123,815
Total	$ 11,794,862	$ 9,156,061	$ 2,638,801	$ 15,399,845	$ 12,785,149	$ 2,614,696
Adjustment	$ (11,794,862)	$ (9,156,061)	$ (2,638,801)	$ (15,399,845)	$ (12,785,149)	$ (2,614,696)

* NOTE : Expenses are recovered in the second succeeding month. For example,
January 2012 would be reflected in March 2012.

** See Blake Exhibit 1, Reference Schedule 1.01, To Adjust Mismatch in Fuel Cost Recovery

Kentucky Utilities Company
Modification to the Fuel Adjustment Clause to Include Total System Losses
Twelve Months Ended March 31, 2012

		Apr-11	May-11	Jun-11	Jul-11	Aug-11	Sep-11	Oct-11	Nov-11	Dec-11	Jan-12	Feb-12	Mar-12
Page 1:													
F(m)	Page 2	$ 41,524,559	$ 45,542,996	$ 50,838,238	$ 60,281,345	$ 57,546,107	$ 44,360,925	$ 38,898,173	$ 42,556,430	$ 48,445,120	$ 53,067,702	$ 48,807,853	$ 44,213,592
S(m)	Page 3	1,477,781,808	1,559,756,683	1,765,193,074	2,010,781,895	1,969,433,550	1,556,578,005	1,572,629,075	1,621,439,620	1,834,212,933	1,991,504,469	1,788,356,290	1,620,768,969
		$ 0.02810	$ 0.02920	$ 0.02880	$ 0.02998	$ 0.02922	$ 0.02850	$ 0.02473	$ 0.02625	$ 0.02641	$ 0.02665	$ 0.02729	$ 0.02728
Base Factor		$ 0.02754	$ 0.02754	$ 0.02754	$ 0.02668	$ 0.02668	$ 0.02668	$ 0.02668	$ 0.02668	$ 0.02668	$ 0.02668	$ 0.02668	$ 0.02668
FAC Factor		$ 0.00056	$ 0.00166	$ 0.00126	$ 0.00330	$ 0.00254	$ 0.00182	$ (0.00195)	$ (0.00043)	$ (0.00027)	$ (0.00003)	$ 0.00061	$ 0.00060
Page 2:													
Company Generation													
	Coal Burned	28,250,751	38,317,949	46,044,320	50,370,042	47,183,859	33,361,757	34,500,884	35,798,119	39,652,132	43,306,850	40,149,822	33,752,502
	Oil Burned	349,994	1,110,930	470,216	483,845	666,487	907,441	423,687	1,036,708	570,984	632,447	418,780	528,094
	Gas Burned	2,920,783	3,021,112	4,009,164	6,544,355	4,840,688	2,367,224	822,535	1,444,103	859,400	1,483,807	1,372,797	2,008,793
	Assigned Fuel	519,851	1,682,233	670,349	932,682	1,997,774	933,198	3,500,261	1,181,520	185,719	1,243,427	423,959	2,217,827
	Substitute Fuel	368,867	1,620,023	556,017	648,159	2,157,168	797,234	2,520,520	723,967	127,403	1,496,970	410,960	2,021,134
	Subtotal Fuel	31,672,512	42,512,201	50,638,032	57,682,765	52,531,640	36,636,422	35,747,106	38,278,930	41,082,516	45,169,561	41,941,399	36,289,389
Purchases													
	Economy	2,822,352	1,690,050	1,337,603	2,444,033	2,016,587	1,344,989	638,195	628,174	743,539	622,061	772,641	1,061,781
	Substitute Purchases	196,422	448,257	352,704	471,521	74,581	6,304	4,729	35,547	1,910	2,714	445	85,929
	Non-Economic	-	-	-	13,399	2,039	12	-	-	-	-	-	-
	Internal Economy	8,118,393	4,953,044	3,009,742	4,056,643	5,039,518	8,278,923	6,625,524	5,409,753	9,545,513	9,670,814	6,444,957	7,405,050
	Internal Purchases	41	27,814	45,630	33,493	7,255	-	769	-	-	-	-	-
	Subtotal	10,744,364	6,222,651	4,040,271	6,049,248	6,986,740	9,623,900	7,264,488	6,037,927	10,289,052	10,290,161	7,217,598	8,466,831
Intersystem Sales													
	Off-system sales	525	426,533	790,251	441,991	164,279	11,432	801,531	82,555	17,849	7,525	2,826	3,768
	Internal Economy	324	230,565	850,816	326,077	166,228	-	55,056	-	-	1,278	1,559	9,084
	Internal Replacement	910,535	2,448,554	2,027,919	2,183,842	1,298,071	2,323,327	3,963,563	1,863,831	3,179,160	2,491,594	386,945	521,486
	Cost of OSS losses	5	4,265	7,903	4,420	1,643	114	8,015	826	178	75	28	38
	Subtotal	911,389	3,109,917	3,676,889	2,956,329	1,630,221	2,334,874	4,828,165	1,947,212	3,197,187	2,500,472	391,359	534,377
Over/(Under) Recovery - Pg 5		$ (19,072)	$ 81,938	$ 163,176	$ 494,339	$ 342,052	$ (435,476)	$ (714,744)	$ (186,785)	$ (270,739)	$ (108,452)	$ (40,215)	$ 8,251
Fuel Cost Adjustment													
	Total Fuel Cost	$ 41,524,559	$ 45,542,996	$ 50,838,238	$ 60,281,345	$ 57,546,107	$ 44,360,925	$ 38,898,173	$ 42,556,430	$ 48,445,120	$ 53,067,702	$ 48,807,853	$ 44,213,592
Page 3:													
	Net Generation	1,145,800,000	1,502,522,000	1,819,593,000	2,000,480,000	1,842,203,000	1,316,353,000	1,482,794,000	1,460,319,000	1,552,744,000	1,683,046,000	1,530,817,000	1,320,335,000
	Purchases+Interchange	93,222,451	54,861,924	53,248,800	71,334,212	70,304,313	45,527,812	59,582,000	62,801,000	64,205,000	60,641,000	63,911,374	77,798,000
	Internal Economy	367,550,000	211,197,000	128,241,000	165,231,000	214,643,000	367,228,000	298,394,000	240,256,000	425,541,000	436,448,000	290,185,000	317,379,000
	Internal Replacement	1,000	882,000	1,000,000	714,000	177,000	-	34,000	-	-	-	-	-
	Subtotal	1,606,573,451	1,769,462,924	2,002,082,800	2,237,759,212	2,127,327,313	1,729,108,812	1,840,804,000	1,763,376,000	2,042,490,000	2,180,135,000	1,884,913,374	1,715,512,000
	Intersystem Sales	14,000	13,001,000	23,568,000	12,175,000	4,828,000	384,000	29,307,000	2,890,000	542,000	265,000	84,000	109,000
	Internal Economy	8,000	8,230,000	21,663,000	8,108,000	3,723,000	-	2,102,000	-	-	44,000	56,000	267,000
	Internal Replacement	32,734,000	86,379,000	75,035,000	76,982,000	43,067,000	90,092,000	158,275,000	71,349,000	120,983,000	93,872,000	13,054,000	17,109,000
	System Losses (pg 4)	96,035,643	102,096,241	116,623,726	129,712,317	106,275,763	82,054,807	78,490,925	67,697,380	86,752,067	94,449,531	83,363,084	77,258,031
	Subtotal	128,791,643	209,706,241	236,889,726	226,977,317	157,893,763	172,530,807	268,174,925	141,936,380	208,277,067	188,630,531	96,557,084	94,743,031
	Total Sales	1,477,781,808	1,559,756,683	1,765,193,074	2,010,781,895	1,969,433,550	1,556,578,005	1,572,629,075	1,621,439,620	1,834,212,933	1,991,504,469	1,788,356,290	1,620,768,969
Page 4													
	12 Month Sources	23,675,027,033	23,640,633,957	23,625,327,757	23,729,886,969	23,548,179,282	23,424,340,094	23,646,057,094	23,700,249,094	23,397,548,844	23,179,699,779	23,093,492,172	22,899,544,886
	12 Month Losses	1,415,214,727	1,364,041,006	1,376,203,788	1,375,509,379	1,176,406,120	1,111,601,347	1,008,255,561	909,871,015	993,779,892	1,004,209,225	1,021,343,849	1,031,280,322
	CM Sources	1,606,573,451	1,769,462,924	2,002,082,800	2,237,759,212	2,127,327,313	1,729,108,812	1,840,804,000	1,763,376,000	2,042,490,000	2,180,135,000	1,884,913,374	1,715,512,000
	Average Loss Factor	5.977669%	5.769900%	5.825120%	5.796527%	4.995741%	4.745497%	4.263948%	3.839078%	4.247368%	4.332279%	4.422648%	4.503497%
	CM Losses	96,035,643	102,096,241	116,623,726	129,712,317	106,275,763	82,054,807	78,490,925	67,697,380	86,752,067	94,449,531	83,363,084	77,258,031
Page 5:													
	Last FAC Rate Billed	$ (0.00030)	$ (0.00059)	$ 0.00056	$ 0.00166	$ 0.00126	$ 0.00330	$ 0.00254	$ 0.00182	$ (0.00195)	$ (0.00043)	$ (0.00027)	$ (0.00003)
	KWH Billed	1,379,963,352	1,296,344,179	1,525,640,447	1,597,015,695	1,756,874,684	1,618,189,554	1,459,659,884	1,256,720,738	1,478,224,470	1,612,798,139	1,703,648,389	1,471,376,467
L. 3	FAC Revenue (Refund)	$ (413,989)	$ (764,843)	$ 854,359	$ 2,651,046	$ 2,213,662	$ 5,340,026	$ 3,707,536	$ 2,287,232	$ (2,882,538)	$ (693,503)	$ (459,985)	$ (44,141)
	S(m), last FAC Rate	1,573,817,451	1,661,852,924	1,477,781,808	1,559,756,683	1,765,193,074	2,010,781,895	1,969,433,550	1,556,578,005	1,572,629,075	1,621,439,620	1,834,212,933	1,991,504,469
	Non-juris. Included	248,678,057	246,153,843	203,406,862	219,281,338	243,038,425	278,558,144	266,609,165	211,477,643	213,658,418	225,131,058	258,756,068	282,098,142
	Kentucky Jurisdiction	1,325,139,394	1,415,699,081	1,274,374,946	1,340,475,345	1,522,154,649	1,732,223,751	1,702,824,385	1,345,100,362	1,358,970,657	1,396,308,562	1,575,456,865	1,709,406,327
	Revised FAC Factor	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
L. 8	Recoverable FAC cost	$ (397,542)	$ (835,262)	$ 713,650	$ 2,225,189	$ 1,917,915	$ 5,716,338	$ 4,325,174	$ 2,448,083	$ (2,649,993)	$ (600,413)	$ (425,373)	$ (51,282)
	O/U -- retail	$ (16,447)	$ 70,419	$ 140,709	$ 425,857	$ 295,747	$ (376,312)	$ (617,638)	$ (160,851)	$ (232,545)	$ (93,090)	$ (34,612)	$ 7,141
	S(m), current month	1,477,781,808	1,559,756,683	1,765,193,074	2,010,781,895	1,969,433,550	1,556,578,005	1,572,629,075	1,621,439,620	1,834,212,933	1,991,504,469	1,788,356,290	1,620,768,969
	Kentucky Jurisdiction	1,274,374,946	1,340,475,345	1,522,154,649	1,732,223,751	1,702,824,385	1,345,100,362	1,358,970,657	1,396,308,562	1,575,456,865	1,709,406,327	1,539,185,173	1,402,757,286
	Gross-up Factor	1.15961304	1.16358476	1.15966737	1.16080956	1.1565688	1.15722072	1.15722077	1.16123303	1.16424192	1.16502697	1.16188508	1.15541654
	O/U, total company	$ (19,072)	$ 81,938	$ 163,176	$ 494,339	$ 342,052	$ (435,476)	$ (714,744)	$ (186,785)	$ (270,739)	$ (108,452)	$ (40,215)	$ 8,251

Kentucky Utilities Company
Modification to Fuel Adjustment Clause to Include Total System Losses
Twelve Months Ended March 31, 2012

Calculation of the Fuel Clause As Originally Filed

		Apr-11	May-11	Jun-11	Jul-11	Aug-11	Sep-11	Oct-11	Nov-11	Dec-11	Jan-12	Feb-12	Mar-12
Page 1:													
F(m)	Page 2	$ 41,469,088	$ 45,512,019	$ 50,921,240	$ 60,387,247	$ 57,612,743	$ 44,392,925	$ 38,886,441	$ 42,558,264	$ 48,443,092	$ 53,095,092	$ 48,817,326	$ 44,193,679
S(m)	Page 3	1,490,352,072	1,573,514,629	1,779,169,014	2,026,370,618	1,983,922,032	1,567,929,086	1,581,918,011	1,629,615,195	1,840,157,989	1,997,349,084	1,793,717,493	1,625,540,682
		$ 0.02783	$ 0.02892	$ 0.02862	$ 0.02980	$ 0.02904	$ 0.02831	$ 0.02458	$ 0.02612	$ 0.02633	$ 0.02658	$ 0.02722	$ 0.02719
Base Factor		$ 0.02754	$ 0.02754	$ 0.02754	$ 0.02668	$ 0.02668	$ 0.02668	$ 0.02668	$ 0.02668	$ 0.02668	$ 0.02668	$ 0.02668	$ 0.02668
FAC Factor		$ 0.00029	$ 0.00138	$ 0.00108	$ 0.00312	$ 0.00236	$ 0.00163	$ (0.00210)	$ (0.00056)	$ (0.00035)	$ (0.00010)	$ 0.00054	$ 0.00051
Page 2:													
Company Generation													
	Coal Burned	28,250,751	38,317,949	46,044,320	50,370,042	47,183,859	33,361,757	34,500,884	35,798,119	39,652,132	43,306,850	40,149,822	33,752,502
	Oil Burned	349,994	1,110,930	470,216	483,845	666,487	907,441	423,687	1,036,708	570,984	632,447	418,780	528,094
	Gas Burned	2,920,783	3,021,112	4,009,164	6,544,355	4,840,688	2,367,224	822,535	1,444,103	859,400	1,483,807	1,372,797	2,008,793
	Assigned Fuel	519,851	1,682,233	670,349	932,682	1,997,774	933,198	3,500,261	1,181,520	185,719	1,243,427	423,959	2,217,827
	Substitute Fuel	368,867	1,620,023	556,017	648,159	2,157,168	797,234	2,520,520	723,967	127,403	1,496,970	410,960	2,021,134
	Subtotal Fuel	31,672,512	42,512,201	50,638,032	57,682,765	52,531,640	36,636,422	35,747,106	38,278,930	41,082,516	45,169,561	41,941,399	36,289,389
Purchases													
	Economy	2,822,352	1,690,050	1,337,603	2,444,033	2,016,587	1,344,989	638,195	628,174	743,539	622,061	772,641	1,061,781
	Substitute Purchases	196,422	448,257	352,704	471,521	74,581	6,304	4,729	35,547	1,910	2,714	445	85,929
	Non-Economic	-	-	-	13,399	2,039	12	-	-	-	-	-	-
	Internal Economy	8,118,393	4,953,044	3,009,742	4,056,643	5,039,518	8,278,923	6,625,524	5,409,753	9,545,513	9,670,814	6,444,957	7,405,050
	Internal Purchases	41	27,814	45,630	33,493	7,255	-	769	-	-	-	-	-
	Subtotal	10,744,364	6,222,651	4,040,271	6,049,248	6,986,740	9,623,900	7,264,488	6,037,927	10,289,052	10,290,161	7,217,598	8,466,831
Intersystem Sales													
	Off-system sales	525	426,533	790,251	441,991	164,279	11,432	801,531	82,555	17,849	7,525	2,826	3,768
	Internal Economy	324	230,565	850,816	326,077	166,228	-	55,056	-	-	1,278	1,559	9,084
	Internal Replacement	910,535	2,448,554	2,027,919	2,183,842	1,298,071	2,323,327	3,963,563	1,863,831	3,179,160	2,491,594	386,945	521,486
	Cost of OSS losses	5	4,265	7,903	4,420	1,643	114	8,015	826	178	75	28	38
	Subtotal	911,389	3,109,917	3,676,889	2,956,329	1,630,221	2,334,874	4,828,165	1,947,212	3,197,187	2,500,472	391,359	534,377
Over/(Under) Recovery - Pg 5		$ 36,399	$ 112,915	$ 80,174	$ 388,437	$ 275,416	$ (467,476)	$ (703,012)	$ (188,619)	$ (268,711)	$ (135,842)	$ (49,688)	$ 28,164
Fuel Cost Adjustment													
	Total Fuel Cost	$ 41,469,088	$ 45,512,019	$ 50,921,240	$ 60,387,247	$ 57,612,743	$ 44,392,925	$ 38,886,441	$ 42,558,264	$ 48,443,092	$ 53,095,092	$ 48,817,326	$ 44,193,679
Page 3:													
	Net Generation	1,145,800,000	1,502,522,000	1,819,593,000	2,000,480,000	1,842,203,000	1,316,353,000	1,482,794,000	1,460,319,000	1,552,744,000	1,683,046,000	1,530,817,000	1,320,335,000
	Purchases+Interchange	93,222,451	54,861,924	53,248,800	71,334,212	70,304,313	45,527,812	59,582,000	62,801,000	64,205,000	60,641,000	63,911,374	77,798,000
	Internal Economy	367,550,000	211,197,000	128,241,000	165,231,000	214,643,000	367,228,000	298,394,000	240,256,000	425,541,000	436,448,000	290,185,000	317,379,000
	Internal Replacement	1,000	882,000	1,000,000	714,000	177,000	-	34,000	-	-	-	-	-
	Subtotal	1,606,573,451	1,769,462,924	2,002,082,800	2,237,759,212	2,127,327,313	1,729,108,812	1,840,804,000	1,763,376,000	2,042,490,000	2,180,135,000	1,884,913,374	1,715,512,000
	Intersystem Sales	14,000	13,001,000	23,568,000	12,175,000	4,828,000	384,000	29,307,000	2,890,000	542,000	265,000	84,000	109,000
	Internal Economy	8,000	8,230,000	21,663,000	8,108,000	3,723,000	-	2,102,000	-	-	44,000	56,000	267,000
	Internal Replacement	32,734,000	86,379,000	75,035,000	76,982,000	43,067,000	90,092,000	158,275,000	71,349,000	120,983,000	93,872,000	13,054,000	17,109,000
	System Losses (pg 4)	83,465,379	88,338,295	102,647,786	114,123,594	91,787,281	70,703,726	69,201,989	59,521,805	80,807,011	88,604,916	78,001,881	72,486,318
	Subtotal	116,221,379	195,948,295	222,913,786	211,388,594	143,405,281	161,179,726	258,885,989	133,760,805	202,332,011	182,785,916	91,195,881	89,971,318
	Total Sales	1,490,352,072	1,573,514,629	1,779,169,014	2,026,370,618	1,983,922,032	1,567,929,086	1,581,918,011	1,629,615,195	1,840,157,989	1,997,349,084	1,793,717,493	1,625,540,682
Page 4													
	12 Month Sources	23,675,027,033	23,640,633,957	23,625,327,757	23,729,886,969	23,548,179,282	23,424,340,094	23,646,057,094	23,700,249,094	23,397,548,844	23,179,699,779	23,093,492,172	22,899,544,886
	12 Month Losses	1,229,975,029	1,180,230,082	1,211,282,345	1,210,201,637	1,016,027,714	957,827,701	888,934,419	799,989,203	925,676,935	942,068,025	955,659,770	967,585,024
	CM Sources	1,606,573,451	1,769,462,924	2,002,082,800	2,237,759,212	2,127,327,313	1,729,108,812	1,840,804,000	1,763,376,000	2,042,490,000	2,180,135,000	1,884,913,374	1,715,512,000
	Average Loss Factor	5.195242%	4.992379%	5.127050%	5.099905%	4.314676%	4.089027%	3.759335%	3.375446%	3.956299%	4.064194%	4.138221%	4.225346%
	CM Losses	83,465,379	88,338,295	102,647,786	114,123,594	91,787,281	70,703,726	69,201,989	59,521,805	80,807,011	88,604,916	78,001,881	72,486,318
Page 5:													
	Last FAC Rate Billed	$ (0.00030)	$ (0.00059)	$ 0.00029	$ 0.00138	$ 0.00108	$ 0.00312	$ 0.00236	$ 0.00163	$ (0.00210)	$ (0.00056)	$ (0.00035)	$ (0.00010)
	KWH Billed	1,379,963,352	1,296,344,179	1,525,640,447	1,597,015,695	1,756,874,684	1,618,189,554	1,459,659,884	1,256,720,738	1,478,224,470	1,612,798,139	1,703,648,389	1,471,376,467
L. 3	FAC Revenue (Refund)	$ (413,989)	$ (764,843)	$ 442,436	$ 2,203,882	$ 1,897,425	$ 5,048,751	$ 3,444,797	$ 2,048,455	$ (3,104,271)	$ (903,167)	$ (596,277)	$ (147,138)
	S(m), last FAC Rate	1,733,410,436	1,707,207,991	1,490,352,072	1,573,514,629	1,779,169,014	2,026,370,618	1,983,922,032	1,567,929,086	1,581,918,011	1,629,615,195	1,840,157,989	1,997,349,084
	Non-juris. Included	248,678,057	246,153,843	203,406,862	219,281,338	243,038,425	278,558,144	266,609,165	211,477,643	213,658,418	225,131,058	258,756,068	282,098,142
	Kentucky Jurisdiction	1,484,732,379	1,461,054,148	1,286,945,210	1,354,233,291	1,536,130,589	1,747,812,474	1,717,312,867	1,356,451,443	1,368,259,593	1,404,484,137	1,581,401,921	1,715,250,942
	Revised FAC Factor	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
L. 8	Recoverable FAC cost	$ (445,420)	$ (862,022)	$ 373,214	$ 1,868,842	$ 1,659,021	$ 5,453,175	$ 4,052,858	$ 2,211,016	$ (2,873,345)	$ (786,511)	$ (553,491)	$ (171,525)
	O/U -- retail	$ 31,431	$ 97,179	$ 69,222	$ 335,040	$ 238,404	$ (404,424)	$ (608,061)	$ (162,561)	$ (230,926)	$ (116,656)	$ (42,786)	$ 24,387
	S(m), current month	1,490,352,072	1,573,514,629	1,779,169,014	2,026,370,618	1,983,922,032	1,567,929,086	1,581,918,011	1,629,615,195	1,840,157,989	1,997,349,084	1,793,717,493	1,625,540,682
	Kentucky Jurisdiction	1,286,945,210	1,354,233,291	1,536,130,589	1,747,812,474	1,717,312,867	1,356,451,443	1,368,259,593	1,404,484,137	1,581,401,921	1,715,250,942	1,544,546,376	1,407,528,999
	Gross-up Factor	1.15805402	1.16192287	1.15821469	1.1593753	1.15524787	1.15590506	1.15615342	1.16029448	1.16362448	1.16446465	1.16132317	1.15488966
	O/U, total company	$ 36,399	$ 112,915	$ 80,174	$ 388,437	$ 275,416	$ (467,476)	$ (703,012)	$ (188,619)	$ (268,711)	$ (135,842)	$ (49,688)	$ 28,164

Form A As Filed

Conroy Exhibit P4

Calculation ECR Revenue Requirement by Plan as of March 31, 2012

Kentucky Utilities Company

Calculation of ECR Plan Elimination as of March 31, 2012

Calculation of Revenue Requirement	TOTAL: Pre-2011 Environmental Compliance Plans at March 31, 2012	TOTAL: Jurisdictional Basis	TOTAL: 2011 Environmental Compliance Plan at March 31, 2012	TOTAL: Jurisdictional Basis	Eliminated Plans (2005 & 2006): Pre-2011 Environmental Compliance Plans at March 31, 2012	Eliminated Plans (2005 & 2006): Jurisdictional Basis	Post Rate Case ECR Plan (2009): Pre-2011 Environmental Compliance Plans at March 31, 2012	Post Rate Case ECR Plan (2009): Jurisdictional Basis	Post Rate Case ECR Plan (2011): 2011 Environmental Compliance Plan at March 31, 2012	Post Rate Case ECR Plan (2011): Jurisdictional Basis
Environmental Compliance Rate Base										
Pollution Control Plant in Service	1,313,355,220	1,129,307,985	-	-	1,304,252,751	1,121,481,092	9,102,469	7,826,893	-	-
Pollution Control CWIP Excluding AFUDC	180,494,800	155,201,134	22,514,782	19,359,670	1,370,221	1,178,205	179,124,579	154,022,929	22,514,782	19,359,670
Subtotal	1,493,850,020	1,284,509,119	22,514,782	19,359,670	1,305,622,972	1,122,659,297	188,227,048	161,849,822	22,514,782	19,359,670
Additions:										
Limestone, net of amount in base rates	956,459	822,425	-	-	956,459	822,425	-	-	-	-
Emission Allowances, net of amount in base rates	345,842	297,377	-	-	(69,415)	(59,688)	415,257	357,065	-	-
Cash Working Capital Allowance	1,562,579	1,343,607	1,290,572	1,109,717	1,561,888	1,343,013	691	594	1,290,572	1,109,717
Subtotal	2,864,880	2,463,409	1,290,572	1,109,717	2,448,932	2,105,751	415,948	357,659	1,290,572	1,109,717
Deductions:										
Accumulated Depreciation on Pollution Control Plant	120,858,671	103,922,123	-	-	120,790,724	103,863,697	67,947	58,425	-	-
Pollution Control Deferred Income Taxes	101,950,287	87,663,468	-	-	101,780,033	87,517,072	170,254	146,395	-	-
Pollution Control Deferred Investment Tax Credit	26,410,795	22,709,714	-	-	26,410,795	22,709,714	-	-	-	-
Subtotal	249,219,753	214,295,305	-	-	248,981,552	214,090,484	238,201	204,821	-	-
Environmental Compliance Rate Base	$ 1,247,495,147	$ 1,072,677,224	$ 23,805,354	$ 20,469,387	$ 1,059,090,352	$ 910,674,563	$ 188,404,795	$ 162,002,660	$ 23,805,354	$ 20,469,387
Rate of Return -- Environmental Compliance Rate Base	10.56%	10.56%	10.13%	10.13%	10.56%	10.56%	10.56%	10.56%	10.13%	10.13%
Return on Environmental Compliance Rate Base	$ 131,735,488	$ 113,274,715	$ 2,411,482	$ 2,073,549	$ 111,839,941	$ 96,167,234	$ 19,895,546	$ 17,107,481	$ 2,411,482	$ 2,073,549
Pollution Control Operating Expenses										
12 Month Depreciation and Amortization Expense	47,677,192	40,995,941	-	-	47,609,246	40,937,517	67,946	58,424	-	-
12 Month Taxes Other than Income Taxes	1,969,753	1,693,721	7,221	6,209	1,859,356	1,598,795	110,397	94,926	7,221	6,209
12 Month Operating and Maintenance Expense	12,495,101	10,744,098	10,324,590	8,877,752	12,495,101	10,744,098	-	-	10,324,590	8,877,752
12 Month Emission Allowance Expense, net of amounts in base rates	65,607	56,413	-	-	(58,344)	(50,168)	123,951	106,581	-	-
12 Month Beneficial Reuse Expense, net of amounts in base rates	5,524	4,750	-	-	-	-	5,524	4,750	-	-
12 Month KPSC Consultant Expense	-	-	104,548	89,897	-	-	-	-	104,548	89,897
Total Pollution Control Operating Expenses	$ 62,213,177	$ 53,494,924	$ 10,436,359	$ 8,973,858	$ 61,905,359	$ 53,230,242	$ 307,818	$ 264,682	$ 10,436,359	$ 8,973,858
Gross Proceeds from By-Product Sales and Allowance Sales-Base Rate amount only	(280,396)	(241,103)	-	-	(280,396)	(241,103)	-	-	-	-
Gross Proceeds from Allowance Sales (less Base Rate amount)	1,751	1,506			-	-	1,751	1,506	-	-
Total Company Environmental Surcharge Gross Revenue Requirement										
Return on Environmental Compliance Rate Base	131,735,488	113,274,715	2,411,482	2,073,549	111,839,941	96,167,234	19,895,546	17,107,481	2,411,482	2,073,549
Pollution Control Operating Expenses	62,213,177	53,494,924	10,436,359	8,973,858	61,905,359	53,230,242	307,818	264,682	10,436,359	8,973,858
Less Gross Proceeds from By-Product & Allowance Sales	278,645	239,597	-	-	280,396	241,103	(1,751)	(1,506)	-	-
Total Company Environmental Surcharge Gross Revenue Requirement	$ 194,227,310	$ 167,009,236	$ 12,847,841	$ 11,047,407	$ 174,025,696	$ 149,638,579	$ 20,201,614	$ 17,370,657	$ 12,847,841	$ 11,047,407
Jurisdictional Allocation Ratio	85.9865%		85.9865%		85.9865%		85.9865%		85.9865%	
Jurisdictional Revenues for 12 Months	$ 1,261,744,424		$ 1,261,744,424		$ 1,261,744,424		$ 1,261,744,424		$ 1,261,744,424	
Total Company Environmental Surcharge Gross Revenue Requirement	$ 194,227,310		$ 12,847,841		$ 174,025,696		$ 20,201,614		$ 12,847,841	
Jurisdictional Allocation Ratio	85.9865%		85.9865%		85.9865%		85.9865%		85.9865%	
Jurisdictional Environmental Surcharge Gross Revenue Requirement	$ 167,009,236		$ 11,047,407		$ 149,638,579		$ 17,370,657		$ 11,047,407	

Kentucky Utilities Company
Calculation of 2005 & 2006 Plans Monthly Jurisdictional Revenue Requirements

Line		Note	Apr-11	May-11	Jun-11	Jul-11	Aug-11	Sep-11
(1)	Eligible Pollution Control Plant	(a)	$ 1,252,797,141	$ 1,252,797,141	$ 1,264,238,872	$ 1,264,238,872	$ 1,264,238,872	$ 1,264,238,872
(2)	Eligible Pollution CWIP Excluding AFUDC	(a)	75,471,929	77,489,960	62,633,726	63,086,716	63,198,553	63,182,601
(3)	Subtotal		$ 1,328,269,070	$ 1,330,287,101	$ 1,326,872,598	$ 1,327,325,588	$ 1,327,437,425	$ 1,327,421,473
(4)	Additions:							
(5)	Inventory - Limestone	(b)	$ 781,592	$ 689,930	$ 619,310	$ 563,097	$ 614,230	$ 612,729
(6)	Less: Limestone Inventory in base rates	(b)	76,473	76,473	76,473	76,473	76,473	76,473
(7)	Less: Allowance Inventory Baseline	(c)	69,415	69,415	69,415	69,415	69,415	69,415
(8)	Cash Working Capital Allowance	(d)	2,067,240	2,126,610	2,178,430	2,250,134	2,337,037	2,407,496
(9)	Subtotal		$ 2,702,944	$ 2,670,652	$ 2,651,852	$ 2,667,343	$ 2,805,379	$ 2,874,337
(10)	Deductions:							
(11)	Accum Depreciation on Eligible Pollution Control Plant	(a)	$ 86,868,281	$ 90,780,094	$ 94,683,811	$ 98,633,052	$ 102,582,293	$ 106,531,533
(12)	Pollution Control Deferred Income Taxes	(a)	65,694,618	69,036,294	72,367,195	75,718,218	79,069,241	82,419,799
(13)	Pollution Control Deferred Investment Tax Credit	(a)	27,341,841	27,341,841	27,217,701	27,217,701	27,217,701	27,217,701
(14)	Subtotal		$ 179,904,740	$ 187,158,229	$ 194,268,707	$ 201,568,971	$ 208,869,235	$ 216,169,033
(15)	Environmental Compliance Rate Base [Lines (3)+(9)-(14)]		$ 1,151,067,274	$ 1,145,799,524	$ 1,135,255,743	$ 1,128,423,960	$ 1,121,373,569	$ 1,114,126,777
(16)	Monthly Environmental Compliance Rate Base [Line (15)/12]		$ 95,922,273	$ 95,483,294	$ 94,604,645	$ 94,035,330	$ 93,447,797	$ 92,843,898
(17)	Rate of Return on Environmental Compliance Rate Base	(e)	11.04%	11.04%	11.04%	11.04%	11.04%	11.04%
(18)	Pollution Control Operating Expenses	(f)	4,992,022	5,063,154	5,018,201	5,007,773	5,509,301	4,954,400
(19)	Total Proceeds from By-Product Sales and Allowance Sales (base rate amount only)	(g)	37,954	(8,495)	(9,720)	(1,066)	(12,812)	(11,158)
(20)	Total Revenue Requirement [Lines (16)x(17)+(18)-(19)]		$ 15,543,887	$ 15,613,005	$ 15,472,274	$ 15,390,339	$ 15,838,750	$ 15,215,524
(21)	Jurisdictional Allocation Ratio for Expense Month	(h)	87.31%	84.19%	84.42%	85.70%	87.18%	87.51%
(22)	2005-2006 Plans Jurisdictional Revenue Requirement		$ 13,571,366	$ 13,144,590	$ 13,061,693	$ 13,189,522	$ 13,808,222	$ 13,315,107
(23)	2005-2006 Plans Expenses [Lines (18) - (19)]		$ 4,954,068	$ 5,071,649	$ 5,027,921	$ 5,008,839	$ 5,522,113	$ 4,965,558

Line		Note	Oct-11	Nov-11	Dec-11	Jan-12	Feb-12	Mar-12
(1)	Eligible Pollution Control Plant	(a)	$ 1,264,238,872	$ 1,264,238,872	$ 1,307,347,784	$ 1,307,347,784	$ 1,307,347,784	$ 1,304,252,751
(2)	Eligible Pollution CWIP Excluding AFUDC	(a)	64,205,774	65,171,209	11,209,428	11,670,079	11,787,432	1,370,221
(3)	Subtotal		$ 1,328,444,646	$ 1,329,410,081	$ 1,318,557,212	$ 1,319,017,863	$ 1,319,135,216	$ 1,305,622,972
(4)	Additions:							
(5)	Inventory - Limestone	(b)	$ 589,086	$ 661,141	$ 708,595	$ 814,016	$ 923,835	$ 1,032,932
(6)	Less: Limestone Inventory in base rates	(b)	76,473	76,473	76,473	76,473	76,473	76,473
(7)	Less: Allowance Inventory Baseline	(c)	69,415	69,415	69,415	69,415	69,415	69,415
(8)	Cash Working Capital Allowance	(d)	2,507,856	2,617,461	2,649,591	2,580,444	2,486,996	2,445,362
(9)	Subtotal		$ 2,951,054	$ 3,132,714	$ 3,212,298	$ 3,248,572	$ 3,264,943	$ 3,332,406
(10)	Deductions:							
(11)	Accum Depreciation on Eligible Pollution Control Plant	(a)	$ 110,480,774	$ 114,430,015	$ 118,448,111	$ 122,535,064	$ 126,622,017	$ 120,790,724
(12)	Pollution Control Deferred Income Taxes	(a)	85,770,356	89,120,914	92,831,013	96,303,074	100,225,457	101,780,033
(13)	Pollution Control Deferred Investment Tax Credit	(a)	27,217,701	27,155,631	27,155,631	27,031,491	26,721,142	26,410,795
(14)	Subtotal		$ 223,468,831	$ 230,706,560	$ 238,434,755	$ 245,869,629	$ 253,568,616	$ 248,981,552
(15)	Environmental Compliance Rate Base [Lines (3)+(9)-(14)]		$ 1,107,926,869	$ 1,101,836,235	$ 1,083,334,755	$ 1,076,396,806	$ 1,068,831,543	$ 1,059,973,826
(16)	Monthly Environmental Compliance Rate Base [Line (15)/12]		$ 92,327,239	$ 91,819,686	$ 90,277,896	$ 89,699,734	$ 89,069,295	$ 88,331,152
(17)	Rate of Return on Environmental Compliance Rate Base	(e)	11.04%	11.04%	11.04%	10.56%	10.56%	10.56%
(18)	Pollution Control Operating Expenses	(f)	4,866,211	5,194,379	5,223,317	5,296,208	5,313,661	5,466,732
(19)	Total Proceeds from By-Product Sales and Allowance Sales (base rate amount only)	(g)	(9,565)	(4,271)	2,416	(2,152)	11,946	(273,473)
(20)	Total Revenue Requirement [Lines (16)x(17)+(18)-(19)]		$ 15,068,703	$ 15,335,543	$ 15,187,581	$ 14,770,652	$ 14,707,433	$ 15,067,975
(21)	Jurisdictional Allocation Ratio for Expense Month	(h)	85.36%	86.51%	83.93%	84.75%	87.48%	87.24%
(22)	Jurisdictional Revenue Requirement		$ 12,862,646	$ 13,266,778	$ 12,746,938	$ 12,518,128	$ 12,866,061	$ 13,145,301
(23)	2005-2006 Plans Expenses [Lines (18) - (19)]		$ 4,875,776	$ 5,198,650	$ 5,220,901	$ 5,298,360	$ 5,301,715	$ 5,740,205

(a) ES Form 2.10 - Net Total 2005 & 2006 Plans
(b) ES Form 2.01 - Limestone Inventory
(c) ES Form 2.00 - Allowance Inventory Baseline
(d) ES Form 2.40 - Recalculation based on 2005 & 2006 Plans only
(e) ES Form 1.10, line 3
(f) ES Form 2.50 - Total 2005 & 2006 Plan O&M Expenses
(g) ES Form 2.00 - Proceeds from By-Product and Allowance Sales
(h) ES Form 1.10, line 8 for Apr-Nov, line 9 for Dec-Mar expense months

Kentucky Utilities Company
Balances for Selected Operating Expense Accounts for 12-months ended March 31, 2012

All Plans	Depreciation & Amortization Steam Plant	Taxes Other than Income Taxes	Operating and Maintenance Expense FERC 502	FERC 506	FERC 512	Emission Allowance Expense (Base Rate Amount) FERC 509	Emission Allowance Expense (net of Base Rate Amount) FERC 509	Beneficial Reuse Expense FERC 501	KPSC Consultant	Total
Apr-11	3,901,713	162,365	259,568	658,367	674,899	(4,862)	9,235	-	-	5,661,285
May-11	3,901,949	162,365	457,237	992,127	341,017	(4,862)	7,409	-	-	5,857,242
Jun-11	3,920,254	162,352	527,831	1,110,985	366,370	(4,862)	11,026	-	-	6,093,956
Jul-11	3,939,299	162,352	486,595	1,084,647	294,314	(4,862)	11,050	-	-	5,973,395
Aug-11	3,939,299	162,352	423,142	1,597,469	415,341	(4,862)	11,046	-	-	6,543,787
Sep-11	3,939,299	162,352	381,719	1,081,037	326,113	(4,862)	7,836	-	16,425	5,909,919
Oct-11	3,939,299	162,352	371,339	1,043,368	174,737	(4,862)	10,133	-	61,393	5,757,759
Nov-11	3,939,299	162,352	434,478	1,230,671	304,968	(4,862)	10,743	-	8,480	6,086,129
Dec-11	4,017,862	162,352	507,453	1,194,980	281,507	(4,862)	10,502	-	16,258	6,186,052
Jan-12	4,096,424	172,102	445,573	1,165,355	360,180	(4,862)	12,532	-	1,993	6,249,297
Feb-12	4,096,424	172,102	391,236	903,219	425,718	(4,862)	11,870	-	-	5,995,707
Mar-12	4,046,071	171,576	304,335	1,033,322	768,473	(4,862)	10,569	5,524	-	6,335,008
Totals	47,677,192	1,976,974	4,990,506	13,095,548	4,733,637	(58,344)	123,951	5,524	104,548	72,649,536

Balances for Allowance Sales and By-Product Sales for 12-months ended March 31, 2012

	Proceeds from Allowance Sales Net of Base Rate Amount ES Form 2.00	Proceeds from By-Product Sales & Base Rate Amount of Allowance Sales ES Form 2.00	Total All Sale Proceeds
Apr-11	-	37,954	37,954
May-11	-	(8,495)	(8,495)
Jun-11	-	(9,720)	(9,720)
Jul-11	-	(1,066)	(1,066)
Aug-11	-	(12,812)	(12,812)
Sep-11	864	(11,158)	(10,294)
Oct-11	-	(9,565)	(9,565)
Nov-11	-	(4,271)	(4,271)
Dec-11	-	2,416	2,416
Jan-12	-	(2,152)	(2,152)
Feb-12	-	11,946	11,946
Mar-12	887	(273,473)	(272,586)
Totals	1,751	(280,396)	(278,645)

Determination of Cash Working Capital Allowance - by Plan

	2005 Plan	**2006 Plan**	**2009 Plan**	**2011 Plan**	**Total**
12 Months O&M	8,260,111	4,234,990	5,524	10,324,590	22,825,215
(1/8) of 12 mo O&M Expenses	1/8	1/8	1/8	1/8	1/8
Cash Working Capital Allowance	1,032,514	529,374	691	1,290,572	2,853,151

12 Month Balances for Jurisdictional Revenues and Allocation Ratio

	KY Retail Revenues, Excl. Envir. Surch. Revenues ES Form 3.10	Total Company Revenues, Excluding Envir. Surch. Revenues ES Form 3.10	KY Retail Allocation Ratio KY Retail/ Total Company
Apr-11	$ 95,882,475	$ 109,820,943	87.3080%
May-11	91,980,703	109,257,901	84.1868%
Jun-11	107,968,505	127,892,282	84.4214%
Jul-11	113,758,668	132,738,782	85.7012%
Aug-11	123,043,042	141,140,253	87.1779%
Sep-11	115,894,324	132,428,088	87.5149%
Oct-11	100,772,017	118,057,368	85.3585%
Nov-11	89,304,719	103,229,231	86.5111%
Dec-11	97,878,004	116,619,190	83.9296%
Jan-12	110,285,253	130,130,828	84.7495%
Feb-12	112,626,035	128,746,223	87.4791%
Mar-12	102,350,679	117,314,195	87.2449%
Totals	$ 1,261,744,424	$ 1,467,375,284	85.9865%

Kentucky Utilities Company
Balances for Selected Operating Expense Accounts for 12-months ended March 31, 2012
Eliminated Plans (2005 & 2006)

2005 Plan	Depreciation & Amortization	Taxes Other than Income Taxes	Operating and Maintenance Expense			Emission Allowance Expense (Base Rate Amount)	Emission Allowance Expense (net of Base Rate Amount)	Beneficial Reuse Expense	KPSC Consultant	Total
	Steam Plant		FERC 502	FERC 506	FERC 512		FERC 509	FERC 501		
Apr-11	3,221,657	131,769	259,568	-	635,436	(4,862)	-	-	-	4,243,568
May-11	3,221,657	131,769	369,409	-	298,698	(4,862)	-	-	-	4,016,671
Jun-11	3,237,152	131,756	444,332	-	324,141	(4,862)	-	-	-	4,132,519
Jul-11	3,253,387	131,756	406,121	-	234,475	(4,862)	-	-	-	4,020,877
Aug-11	3,253,387	131,756	365,175	-	356,449	(4,862)	-	-	-	4,101,905
Sep-11	3,253,387	131,756	350,379	-	260,958	(4,862)	-	-	-	3,991,618
Oct-11	3,253,387	131,756	276,828	-	131,563	(4,862)	-	-	-	3,788,672
Nov-11	3,253,387	131,756	351,749	-	232,669	(4,862)	-	-	-	3,964,699
Dec-11	3,322,243	131,756	429,112	-	224,384	(4,862)	-	-	-	4,102,633
Jan-12	3,391,099	125,652	375,058	-	316,480	(4,862)	-	-	-	4,203,427
Feb-12	3,391,099	125,652	294,777	-	328,851	(4,862)	-	-	-	4,135,517
Mar-12	3,335,341	125,126	260,168	-	733,331	(4,862)	-	-	-	4,449,104
Jan-00										
Totals	39,387,183	1,562,260	4,182,676	-	4,077,435	(58,344)	-	-	-	49,151,210

2006 Plan	Depreciation & Amortization	Taxes Other than Income Taxes	Operating and Maintenance Expense			Emission Allowance Expense (Base Rate Amount)	Emission Allowance Expense (net of Base Rate Amount)	Beneficial Reuse Expense	KPSC Consultant	Total
	Steam Plant		FERC 502	FERC 506	FERC 512		FERC 509	FERC 501		
Apr-11	680,056	24,913	-	8,575	34,910	-	-	-	-	748,454
May-11	680,292	24,913	87,828	220,476	32,974	-	-	-	-	1,046,483
Jun-11	683,102	24,913	83,499	56,711	37,457	-	-	-	-	885,682
Jul-11	685,912	24,913	80,474	163,202	32,395	-	-	-	-	986,896
Aug-11	685,912	24,913	57,967	588,868	49,736	-	-	-	-	1,407,396
Sep-11	685,912	24,913	31,340	159,822	60,795	-	-	-	-	962,782
Oct-11	685,912	24,913	94,511	229,320	42,883	-	-	-	-	1,077,539
Nov-11	685,912	24,913	82,729	364,361	71,765	-	-	-	-	1,229,680
Dec-11	685,912	24,913	78,341	279,437	52,081	-	-	-	-	1,120,684
Jan-12	685,912	24,293	70,515	271,401	40,660	-	-	-	-	1,092,781
Feb-12	685,912	24,293	96,459	293,611	77,869	-	-	-	-	1,178,144
Mar-12	691,317	24,293	44,167	229,139	28,712	-	-	-	-	1,017,628
Jan-00										
Totals	8,222,063	297,096	807,830	2,864,923	562,237	-	-	-	-	12,754,149

2005 & 2006 Plans	Depreciation & Amortization	Taxes Other than Income Taxes	Operating and Maintenance Expense			Emission Allowance Expense (Base Rate Amount)	Emission Allowance Expense (net of Base Rate Amount)	Beneficial Reuse Expense	KPSC Consultant	Total
	Steam Plant		FERC 502	FERC 506	FERC 512		FERC 509	FERC 501		
Apr-11	3,901,713	156,682	259,568	8,575	670,346	(4,862)	-	-	-	4,992,022
May-11	3,901,949	156,682	457,237	220,476	331,672	(4,862)	-	-	-	5,063,154
Jun-11	3,920,254	156,669	527,831	56,711	361,598	(4,862)	-	-	-	5,018,201
Jul-11	3,939,299	156,669	486,595	163,202	266,870	(4,862)	-	-	-	5,007,773
Aug-11	3,939,299	156,669	423,142	588,868	406,185	(4,862)	-	-	-	5,509,301
Sep-11	3,939,299	156,669	381,719	159,822	321,753	(4,862)	-	-	-	4,954,400
Oct-11	3,939,299	156,669	371,339	229,320	174,446	(4,862)	-	-	-	4,866,211
Nov-11	3,939,299	156,669	434,478	364,361	304,434	(4,862)	-	-	-	5,194,379
Dec-11	4,008,155	156,669	507,453	279,437	276,465	(4,862)	-	-	-	5,223,317
Jan-12	4,077,011	149,945	445,573	271,401	357,140	(4,862)	-	-	-	5,296,208
Feb-12	4,077,011	149,945	391,236	293,611	406,720	(4,862)	-	-	-	5,313,661
Mar-12	4,026,658	149,419	304,335	229,139	762,043	(4,862)	-	-	-	5,466,732
Jan-00										
Totals	47,609,246	1,859,356	4,990,506	2,864,923	4,639,672	(58,344)	-	-	-	61,905,359

Kentucky Utilities Company
Balances for Selected Operating Expense Accounts for 12-months ended March 31, 2012
Post Rate Case ECR Plans (2009 & 2011)

2009 Plan	Depreciation & Amortization	Taxes Other than Income Taxes	Operating and Maintenance Expense			Emission Allowance Expense (Base Rate Amount)	Emission Allowance Expense (net of Base Rate Amount)	Beneficial Reuse Expense	KPSC Consultant	Total
	Steam Plant		FERC 502	FERC 506	FERC 512		FERC 509	FERC 501		
Apr-11	-	5,683	-	-	-	-	9,235	-	-	14,918
May-11	-	5,683	-	-	-	-	7,409	-	-	13,092
Jun-11	-	5,683	-	-	-	-	11,026	-	-	16,709
Jul-11	-	5,683	-	-	-	-	11,050	-	-	16,733
Aug-11	-	5,683	-	-	-	-	11,046	-	-	16,729
Sep-11	-	5,683	-	-	-	-	7,836	-	-	13,519
Oct-11	-	5,683	-	-	-	-	10,133	-	-	15,816
Nov-11	-	5,683	-	-	-	-	10,743	-	-	16,426
Dec-11	9,707	5,683	-	-	-	-	10,502	-	-	25,892
Jan-12	19,413	19,750	-	-	-	-	12,532	-	-	51,695
Feb-12	19,413	19,750	-	-	-	-	11,870	-	-	51,033
Mar-12	19,413	19,750	-	-	-	-	10,569	5,524	-	55,256
Jan-00										
Totals	67,946	110,397	-	-	-	-	123,951	5,524	-	307,818

2011 Plan	Depreciation & Amortization	Taxes Other than Income Taxes	Operating and Maintenance Expense			Emission Allowance Expense (Base Rate Amount)	Emission Allowance Expense (net of Base Rate Amount)	Beneficial Reuse Expense	KPSC Consultant	Total
	Steam Plant		FERC 502	FERC 506	FERC 512		FERC 509	FERC 501		
Apr-11	-	-	-	649,792	4,553	-	-	-	-	654,345
May-11	-	-	-	771,651	9,345	-	-	-	-	780,996
Jun-11	-	-	-	1,054,274	4,772	-	-	-	-	1,059,046
Jul-11	-	-	-	921,445	27,444	-	-	-	-	948,889
Aug-11	-	-	-	1,008,601	9,156	-	-	-	-	1,017,757
Sep-11	-	-	-	921,215	4,360	-	-	-	16,425	942,000
Oct-11	-	-	-	814,048	291	-	-	-	61,393	875,732
Nov-11	-	-	-	866,310	534	-	-	-	8,480	875,324
Dec-11	-	-	-	915,543	5,042	-	-	-	16,258	936,843
Jan-12	-	2,407	-	893,954	3,040	-	-	-	1,993	901,394
Feb-12	-	2,407	-	609,608	18,998	-	-	-	-	631,013
Mar-12	-	2,407	-	804,183	6,430	-	-	-	-	813,020
Jan-00										
Totals	-	7,221	-	10,230,625	93,965	-	-	-	104,548	10,436,359

2009 & 2011 Plans	Depreciation & Amortization	Taxes Other than Income Taxes	Operating and Maintenance Expense			Emission Allowance Expense (Base Rate Amount)	Emission Allowance Expense (net of Base Rate Amount)	Beneficial Reuse Expense	KPSC Consultant	Total
	Steam Plant		FERC 502	FERC 506	FERC 512		FERC 509	FERC 501		
Apr-11	-	5,683	-	649,792	4,553	-	9,235	-	-	669,263
May-11	-	5,683	-	771,651	9,345	-	7,409	-	-	794,088
Jun-11	-	5,683	-	1,054,274	4,772	-	11,026	-	-	1,075,755
Jul-11	-	5,683	-	921,445	27,444	-	11,050	-	-	965,622
Aug-11	-	5,683	-	1,008,601	9,156	-	11,046	-	-	1,034,486
Sep-11	-	5,683	-	921,215	4,360	-	7,836	-	16,425	955,519
Oct-11	-	5,683	-	814,048	291	-	10,133	-	61,393	891,548
Nov-11	-	5,683	-	866,310	534	-	10,743	-	8,480	891,750
Dec-11	9,707	5,683	-	915,543	5,042	-	10,502	-	16,258	962,735
Jan-12	19,413	22,157	-	893,954	3,040	-	12,532	-	1,993	953,089
Feb-12	19,413	22,157	-	609,608	18,998	-	11,870	-	-	682,046
Mar-12	19,413	22,157	-	804,183	6,430	-	10,569	5,524	-	868,276
Jan-00										
Totals	67,946	117,618	-	10,230,625	93,965	-	123,951	5,524	104,548	10,744,177

Conroy Exhibit P5

Adjustment for Electric
Year-End Number of Customers

Kentucky Utilities Company
Adjustment to Reflect Year End Number of Customers
Twelve Months Ended March 31, 2012

	(1) Average Number of Customers, 13 Months Ended March 31, 2012	(2) Number of Customers Served at March 31, 2012	(3) Year-End Over / (Under) 13-Month Average (2) - (1)	(4) Actual kWh Adjusted for Rate Switching See Col(8), pg 6 of 7	(5) Average kWh per Customer per Year (4) / (1)	(6) Year-End kWh Adjustment (3) * (5)	(7) Current Rates Net Revenue (Base Rates + FAC - Base ECR) See Col (9), pg 7 of 7	(8) Average Revenue per kWh (7) / (4)	(9) Revenue Adjustment (6) * (8)
Residential Service including VFD	420,497	419,902	(595)	6,476,721,487	15,402	(9,164,190)	$ 501,964,179	$ 0.07750	$ (710,225)
Residential Service -- Electric Vehicle Only	-	-	-	-	-	-	$ -	$ -	$ -
General Service	82,051	82,069	18	2,062,711,973	25,139	452,502	$ 194,742,616	$ 0.09441	$ 42,721
Rate AES	639	643	4	172,056,010	269,258	1,077,032	$ 11,745,983	$ 0.06827	$ 73,529
Power Service									
Primary	298	299	1	802,391,464	2,692,588	2,692,588	$ 51,195,941	$ 0.06380	$ 171,787
Secondary	5,664	5,627	(37)	3,304,297,758	583,385	(21,585,245)	$ 239,206,230	$ 0.07239	$ (1,562,556)
Industrial Time of Day									
Primary (a)		167		3,919,386,372			$ 206,128,280		$ (1,816,142)
Secondary (b)		137		483,570,548			$ 27,444,267		$ 116,378
Retail Transmisison Service (c)		35		1,735,742,252			$ 87,459,641		$ 166,983
Fluctuating Load Service	1	1	-	591,215,246	591,215,246	-	$ 26,478,266	$ 0.04479	$ -
Lighting Energy	1	1	-	40,050	40,050	-	$ 2,270	$ 0.05668	$ -
Traffic Energy	656	720	64	1,200,051	1,829	117,056	$ 113,471	$ 0.09455	$ 11,068
	Number of Lights								
POL								per Light per Year	
Dark Sky Friendly, DSK	-	1		77			$ 85		
Street Lighting, St.Lt.	77,387	77,663	276	49,621,139			$ 10,941,443		
Private Outdoor Lighting, P.O.Lt.	92,266	92,660	394	84,627,546			$ 14,067,679		
	169,653	170,324	671	134,248,762	791	530,761	25,009,206	$ 147.41	98,915
Totals	679,460	679,925		19,683,581,973			$ 1,371,490,351		$ (3,407,542)
Expenses at an Operating Ratio of	0.560237503	(see page 2)							(1,909,033)
					Adjustment to Net Operating Income Before Taxes				$ (1,498,509)

(a) See page 3 of 7 for supporting calculations
(b) See page 4 of 7 for supporting calculations
(c) See page 5 of 7 for supporting calculations

Kentucky Utilities Company
Adjustment to Reflect Year End Number of Customers
Twelve Months Ended March 31, 2012

CALCULATION OF ELECTRIC OPERATING RATIO

Total Electric Operating Expenses	$	858,787,983
Less Wages and Salaries	$	99,645,519
Less Pensions and Benefits	$	35,853,084
Less Regulatory Commission Expense	$	1,496,158
Net Expenses	$	721,793,222
Total Electric Operating Revenues (As Billed)	$	1,288,370,053
Operating Ratio		0.560237503

Kentucky Utilities Company
Adjustment to Reflect Year End Number of Customers
Twelve Months Ended March 31, 2012

Calculation of Year End Adjustment for Time of Day Primary Rate

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
				Test Year Billing Data			Test Year Billing Data at Current Rates	Revenue Adjustment
		Customer-Months	kWh	kW or kVa-Base	kw or kVa-Intermediate	kW or kVa-Peak		
Customer #1	Left the System	6.0	153,031,200.0	301,267.2	298,202.4	295,429.0	$ 7,836,560	$ (7,836,560)
Customer #2	Left the System	5.0	7,243,200.0	13,824.9	13,696.1	13,590.7	$ 376,936	$ (376,936)
Customer #3	Left the System	1.0	-	2,278.0	1,518.6	1,518.6	$ 8,898	$ (8,898)
Customer #4	Left the System	9.0	12,310,832.0	60,746.8	60,746.8	56,992.0	$ 907,837	$ (907,837)
Customer #5	Left the System	1.0	475,200.0	5,322.3	5,322.3	5,156.4	$ 45,361	$ (45,361)
Customer #6	Left the System	10.0	2,217,600.0	13,751.4	11,739.4	10,821.8	$ 181,036	$ (181,036)
Customer #7	Left the System	4.0	1,784,700.0	5,375.8	5,375.8	5,258.0	$ 99,417	$ (99,417)
Customer #8	Left the System	12.0	928,200.0	3,319.0	2,462.3	2,444.2	$ 58,916	$ (58,916)
Customer #9	Left the System	11.0	6,559,200.0	14,341.7	14,015.3	13,943.8	$ 355,827	$ (355,827)
Customer #10	Left the System	7.0	9,456,000.0	21,844.7	20,214.5	19,733.1	$ 508,170	$ (508,170)
Customer #11	New in June 2011	9.0	5,539,500.0	12,025.6	12,025.6	11,636.9	$ 297,614	
	Test Year Billing Data Annualized for 12 months	12.0	7,386,000.0	16,034.1	16,034.1	15,515.9	$ 378,241	$ 80,627
Customer #12	New in June 2011	7.0	8,802,000.0	17,362.2	17,296.9	17,296.9	$ 457,687	
	Test Year Billing Data Annualized for 12 months	12.0	15,089,143.0	29,763.8	29,651.8	29,651.8	$ 750,455	$ 292,768
Customer #13								
	New in June 2011	3.0	835,200.0	4,786.7	4,632.2	4,256.1	$ 67,067	
	Test Year Billing Data Annualized for 12 months	12.0	3,340,800.0	19,146.8	18,528.8	17,024.4	$ 251,052	$ 183,985
Customer #14								
	New in June 2011	3.0	3,667,971.0	19,189.5	18,931.4	18,093.9	$ 283,269	
	Test Year Billing Data Annualized for 12 months	12.0	14,671,884.0	76,758.0	75,725.6	72,375.6	$ 1,059,139	$ 775,870
Customer #15	New in July 2011	2.0	1,754,400.0	-	-	-	$ 97,405	
	Test Year Billing Data Annualized for 12 months	12.0	10,526,400.0	-	-	-	$ 374,340	$ 276,935
Customer #16	New in June 2011	3.0	124,800.0	1,010.9	1,003.9	1,002.2	$ 12,344	
	Test Year Billing Data Annualized for 12 months	12.0	499,200.0	4,043.6	4,015.6	4,008.8	$ 50,346	$ 38,002
Customer #17	New in June 2011	7.0	204,355,200.0	375,237.3	374,600.9	371,041.1	$ 10,101,314	
	Test Year Billing Data Annualized for 12 months	12.0	350,323,200.0	643,263.9	642,173.0	636,070.5	$ 16,983,159	$ 6,881,845
Customer #18	New in November 201	5.0	194,400.0	3,993.1	1,842.1	1,842.1	$ 25,954	
	Test Year Billing Data Annualized for 12 months	12.0	466,560.0	9,583.4	4,421.0	4,421.0	$ 58,737	$ 32,783

Customers leaving the system:	(10)
Customers joinging the system:	8
Net change in time of day primary customers:	(2)

Net primary time of day revenue adjustment for change in customers: $ (1,816,142)

Kentucky Utilities Company
Adjustment to Reflect Year End Number of Customers
Twelve Months Ended March 31, 2012

Calculation of Year End Adjustment for Time of Day Secondary Rate

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
				Test Year Billing Data			Test Year Billing Data at Current Rates	Revenue Adjustment
		Customer-Months	kWh	kW or kVa-Base	kw or kVa-Intermediate	kW or kVa-Peak		
Customer #1	Left the System	1.0	120,300.0	900.0	629.9	624.0	$ 10,507	$ (10,507)
Customer #2	New in June 2011	10.0	837,900.0	5,534.0	2,035.0	1,936.3	$ 64,618	
	Test Year Billing Data Annualized for 12 months	12.0	1,005,480.0	6,640.8	2,442.0	2,323.6	$ 73,040	$ 8,423
Customer #3	New in June 2011	10.0	1,084,500.0	7,968.4	2,611.7	2,534.6	$ 85,948	
	Test Year Billing Data Annualized for 12 months	12.0	1,301,400.0	9,562.0	3,134.0	3,041.5	$ 96,846	$ 10,898
Customer #4	New in June 2011	10.0	687,600.0	1,558.1	1,558.1	1,558.1	$ 53,516	
	Test Year Billing Data Annualized for 12 months	12.0	825,120.0	1,869.7	1,869.7	1,869.7	$ 48,980	$ (4,536)
Customer #5	New in June 2011	10.0	401,120.0	3,112.5	977.1	936.2	$ 33,703	
	Test Year Billing Data Annualized for 12 months	12.0	481,344.0	3,735.0	1,172.5	1,123.4	$ 37,964	$ 4,261
Customer #6	New in July 2011	9.0	1,184,000.0	7,647.4	3,526.3	3,521.1	$ 94,763	
	Test Year Billing Data Annualized for 12 months	12.0	1,578,667.0	10,196.5	4,701.7	4,694.8	$ 118,788	$ 24,025
Customer #7	New in June 2011	10.0	588,720.0	2,175.8	1,345.8	1,324.2	$ 39,464	
	Test Year Billing Data Annualized for 12 months	12.0	706,464.0	2,611.0	1,615.0	1,589.0	$ 45,351	$ 5,887
Customer #8	New in June 2011	10.0	3,853,600.0	7,872.1	7,539.2	7,316.6	$ 217,478	
	Test Year Billing Data Annualized for 12 months	12.0	4,624,320.0	9,446.5	9,047.0	8,779.9	$ 250,218	$ 32,740
Customer #9	New in November 201	5.0	154,000.0	1,950.9	1,646.6	1,542.1	$ 23,967	
	Test Year Billing Data Annualized for 12 months	12.0	369,600.0	4,682.2	3,951.8	3,701.0	$ 53,698	$ 29,731
Customer #10	New in November 201	5.0	111,600.0	1,234.4	469.4	431.3	$ 12,177	
	Test Year Billing Data Annualized for 12 months	12.0	267,840.0	2,962.6	1,126.6	1,035.1	$ 27,633	$ 15,456

Customers leaving the system:	(1)
Customers joinging the system:	9
Net change in time of day secondary customers:	8

Net secondary time of day revenue adjustment for change in customers: $ 116,378

Kentucky Utilities Company
Adjustment to Reflect Year End Number of Customers
Twelve Months Ended March 31, 2012

Calculation of Year End Adjustment for Retail Transmission Service Rate

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
			Test Year Billing Data				Test Year Billing Data at Current Rates	Revenue Adjustment
		Customer-Months	kWh	kW or kVa-Base	kw or kVa-Intermediate	kW or kVa-Peak		
Customer #1	Left the System	5.0	4,638,000.0	20,075.8	19,414.3	18,861.4	$ 289,328	$ (289,328)
Customer #2	Left the System	8.0	90,000.0	2,636.8	1,757.6	1,757.6	$ 19,578	$ (19,578)
Customer #3	Left the System	8.0	6,000.0	2,625.0	103.6	103.6	$ 6,541	$ (6,541)
Customer #4	Left the System	2.0	18,000.0	500.0	136.6	123.0	$ 2,506	$ (2,506)
Customer #5	New in May 2011	11.0	180,000.0	2,750.0	485.2	479.8	$ 16,614	
	Test Year Billing Data Annualized for 12 months	12.0	196,363.6	3,000.0	529.3	523.4	$ 18,324	$ 1,710
Customer #6	New in August 2011	8.0	6,600,000.0	28,350.1	27,145.8	26,662.9	$ 409,977	
	Test Year Billing Data Annualized for 12 months	12.0	9,900,000.0	42,525.2	40,718.7	39,994.4	$ 615,365	$ 205,388
Customer #7	New in October 2011	7.0	198,000.0	6,300.0	1,637.3	1,549.4	$ 24,415	
	Test Year Billing Data Annualized for 12 months	12.0	339,428.6	10,800.0	2,806.8	2,656.1	$ 42,626	$ 18,211
Customer #8	New in August 2011	8.0	6,582,000.0	32,400.0	21,934.1	21,320.8	$ 382,357	
	Test Year Billing Data Annualized for 12 months	12.0	9,873,000.0	48,600.0	32,901.2	31,981.2	$ 573,260	$ 190,903
Customer #9	New in October 2011	6.0	912,000.0	5,982.0	5,351.4	5,319.1	$ 71,992	
	Test Year Billing Data Annualized for 12 months	12.0	1,824,000.0	11,964.0	10,702.8	10,638.2	$ 140,716	$ 68,724

Customers leaving the system:	(4)
Customers joinging the system:	5
Net change in retail transmission customers:	1

Retail transmission service revenue adjustment for change in customers: $ 166,983

Kentucky Utilities Company
Adjustment to Reflect Year End Number of Customers
Twelve Months Ended March 31, 2012

Impact of Customers Switching Rates on the Calculation of the Year End Customer Revenue Adjustment

	(1)	(2)	(3)	(4)	(5)	(6)		(7)	(8)
	Actual Number of Customers for the 13-Month Period	Customers Switching TO the Rate	Customers Switching FROM the Rate	Adjusted 13-Month Customer Count to Reflect Rate Switching		Actual Energy Delivered for the 13-month period	Energy Used by Customers Switching TO the Rate Before the Rate Switch	Energy Used by Customers Switching FROM the Rate Before the Rate Switch	Adjusted Energy Usage to Reflect Rate Switching
Residential Service including VFD	5,466,549	618	(533)	5,466,464		6,476,267,049	273,592	(728,030)	6,476,721,487
Residential Service -- Electric Vehicle Only	-	-	-	-		-	-	-	-
General Service	1,067,880	3,678	(2,451)	1,066,653		2,022,284,233	27,411,715	(67,839,455)	2,062,711,973
Rate AES	8,294	5	(26)	8,315		171,754,793	82,214	(383,431)	172,056,010
Power Service									
Primary	3,677	11	(210)	3,876		723,132,177	5,497,600	(84,756,887)	802,391,464
Secondary	72,141	1,722	(3,211)	73,630		3,297,329,011	50,973,404	(57,942,151)	3,304,297,758
Industrial Time of Day									
Primary (a)	2,324	181	-	2,143		4,008,491,302	89,104,930	-	3,919,386,372
Secondary (b)	1,962	214	-	1,748		523,850,024	40,279,476	-	483,570,548
Retail Transmisison Service (c)	464	-	(1)	465		1,733,768,422	-	(1,973,830)	1,735,742,252
Fluctuating Load Service	13	-	-	13		591,215,246	-	-	591,215,246
Lighting Energy	11	-	-	11		40,050	-	-	40,050
Traffic Energy	8,531	3	-	8,528		1,200,904	853	-	1,200,051
Lighting Service						134,248,762	-	-	134,248,762
Totals	6,631,846	6,432	(6,432)	6,631,846		19,683,581,973	213,623,784	(213,623,784)	19,683,581,973

Kentucky Utilities Company
Adjustment to Reflect Year End Number of Customers
Twelve Months Ended March 31, 2012

Impact of the ECR Elimination and Customer Rate Switching on Test Year Revenues Used in the Year End Customer Adjustment

	(1) Test Year Base Revenues At Current Rates	(2) Test Year FAC Revenues At Current Rates	(3) Test Year ECR Base Revenues Reflecting Plan Elimination	(4) March 2011 Revenues at Current Rates	(5) March 2011 Actual FAC Revenues	(6) March 2011 Base ECR Revenue Reflecting Plan Elimination	(7) Base + FAC Revenues From Customers Switching TO the Rate Before the Rate Switch (Current Rates, Reflecting ECR Plan Elimination)	(8) Energy Used by Customers Switching FROM the Rate Before the Rate Switch	(9) Adjusted Revenue Totals Used to Calculate Average Cost per kWh
Residential Service including VFD	$ 458,005,465	$ 4,705,957	$ (1,783,388)	$ 40,779,950	$ 447,342	$ (159,765)	$ 24,500	$ (55,882)	$ 501,964,179
Residential Service -- Electric Vehicle Only	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
General Service	$ 182,158,458	$ 1,757,424	$ (874,393)	$ 15,035,693	$ 134,436	$ (72,019)	$ 2,373,260	$ (5,770,242)	$ 194,742,616
Rate AES	$ 10,668,265	$ 129,003	$ (42,535)	$ 1,003,658	$ 12,449	$ (4,001)	$ 5,617	$ (26,472)	$ 11,745,983
Power Service									
Primary	$ 51,224,549	$ 759,739	$ (211,233)	$ 4,848,972	$ 66,546	$ (20,687)	$ 343,281	$ (5,815,225)	$ 51,195,941
Secondary	$ 221,396,753	$ 2,893,211	$ (980,703)	$ 17,136,435	$ 202,850	$ (70,254)	$ 4,055,510	$ (5,427,572)	$ 239,206,230
Industrial Time of Day									
Primary	$ 184,047,357	$ 3,264,160	$ (733,242)	$ 14,317,966	$ 233,500	$ (55,080)	$ 5,053,619	$ -	$ 206,128,280
Secondary	$ 22,889,891	$ 371,306	$ (77,266)	$ 1,664,275	$ 25,341	$ (5,139)	$ 2,575,858	$ -	$ 27,444,267
Retail Transmisison Service	$ 79,886,044	$ 1,400,173	$ (223,871)	$ 6,424,257	$ 108,701	$ (17,863)	$ -	$ (117,800)	$ 87,459,641
Fluctuating Load Service	$ 24,102,240	$ 475,261	$ (58,788)	$ 1,926,237	$ 37,740	$ (4,424)	$ -	$ -	$ 26,478,266
Lighting Energy	$ 2,255	$ 27	$ (12)	$ -	$ -	$ -	$ -	$ -	$ 2,270
Traffic Energy	$ 105,565	$ 937	$ (336)	$ 7,193	$ 68	$ (24)	$ 68	$ -	$ 113,471
Street and Private Outdoor Lighting Service, Including Dark Sky	$ 23,087,330	$ 87,859	$ (88,627)	$ 1,920,798	$ 9,217	$ (7,372)	$ -	$ -	$ 25,009,206
Totals	$ 1,257,574,172	$ 15,845,056	$ (5,074,393)	$ 105,065,434	$ 1,278,190	$ (416,628)	$ 14,431,713	$ (17,213,193)	$ 1,371,490,351

Conroy Exhibit P6

Adjustment for Rate Switching During Test Year

Kentucky Utilities Company

Adjustment to Reflect Rate Switching During the Twelve Months Ended March 31, 2012

		Test Year Billing Determinants at Original Rates					Revenue Increase to Report for Current Tariff Due to Additonal Customers From Rate Switching						
Rate Switch To:	From Rate Category:	Customer-Months on the Old Rate	Energy -- kWh on Old Rate	Summer or Peak Demand, kW or kVa on Old Rate	Winter or Intermediate Demand, kW or kVa on Old Rate	Basic Demand, kW or kVa on Old Rate	Basic Service Charge Revenues	Energy Revenues	Demand Revenues	Base Rate Component of ECR	Total Base Revenues Net of ECR	FAC Revenues	Total Base Revenues Net of ECR Including FAC
Rate RS	GS	583	198,087	-	-	-	$ 4,955.50	$ 13,840.50	$ -	$ 59.00	$ 18,737.00	$ 205.00	$ 18,942.00
	GS 3 phase	1	407	-	-	-	$ 8.50	$ 28.50	$ -	$ -	$ 37.00	$ -	$ 37.00
	VFD	34	75,098	-	-	-	$ 289.00	$ 5,247.00	$ -	$ 23.00	$ 5,513.00	$ 8.00	$ 5,521.00
		618	273,592	-	-	-	$ 5,253.00	$ 19,116.00	$ -	$ 82.00	$ 24,287.00	$ 213.00	$ 24,500.00
Rate GS	RS	471	468,872	-	-	-	$ 8,243.00	$ 39,066.00	$ -	$ 210.00	$ 47,099.00	$ 451.00	$ 47,550.00
	VFD	10	33,577	-	-	-	$ 175.00	$ 2,798.00	$ -	$ 15.00	$ 2,958.00	$ 45.00	$ 3,003.00
	GS 3 phase	53	113,237	-	-	-	$ 927.00	$ 9,435.00	$ -	$ 51.00	$ 10,311.00	$ 33.00	$ 10,344.00
	AES	15	53,213	-	-	-	$ 263.00	$ 4,434.00	$ -	$ 24.00	$ 4,673.00	$ 87.00	$ 4,760.00
	PS Secondary	1,021	6,873,463	30,663	20,449	-	$ 17,867.00	$ 572,697.00	$ -	$ 3,093.00	$ 587,471.00	$ 9,174.00	$ 596,645.00
		1,570	7,542,362	30,663	20,449	-	$ 27,475.00	$ 628,430.00	$ -	$ 3,393.00	$ 652,512.00	$ 9,790.00	$ 662,302.00
Rate GS 3 Phase	RS	18	150,483	-	-	-	$ 315.00	$ 12,538.00	$ -	$ 68.00	$ 12,785.00	$ 200.00	$ 12,985.00
	AES	5	12,658	-	-	-	$ 87.00	$ 1,055.00	$ -	$ 6.00	$ 1,136.00	$ 17.00	$ 1,153.00
	PS Secondary	2,072	19,563,972	164,231	45,467	-	$ 36,260.00	$ 1,630,070.00	$ -	$ 8,804.00	$ 1,657,526.00	$ 27,118.00	$ 1,684,644.00
	PS Primary	13	142,240	255	150	-	$ 228.00	$ 11,851.00	$ -	$ 64.00	$ 12,015.00	$ 161.00	$ 12,176.00
		2,108	19,869,353	164,486	45,617	-	$ 36,890.00	$ 1,655,514.00	$ -	$ 8,942.00	$ 1,683,462.00	$ 27,496.00	$ 1,710,958.00
Rate AES	GS	3	5,414	-	-	-	$ 52.50	$ 361.00	$ -	$ 1.50	$ 412.00	$ 3.00	$ 415.00
Rate AES 3 Phase	PS Secondary	2	76,800	131	180	-	$ 65.00	$ 5,123.00	$ -	$ 21.00	$ 5,167.00	$ 35.00	$ 5,202.00
PS Secondary	GS (a)	603	17,508,813	33,564	24,666	-	$ 54,270.00	$ 577,791.00	$ 753,904.00	$ 6,405.00	$ 1,379,560.00	$ 22,888.00	$ 1,402,448.00
	GS 3 Phase (a)	1,089	32,379,484	58,842	47,434	-	$ 98,010.00	$ 1,068,523.00	$ 1,370,523.00	$ 11,690.00	$ 2,525,366.00	$ 40,371.00	$ 2,565,737.00
	AES 3 Phase	6	317,560	728	728	-	$ 540.00	$ 10,479.00	$ 15,746.00	$ 160.00	$ 26,605.00	$ 351.00	$ 26,956.00
	PS Primary	24	767,547	1,961	419	-	$ 2,160.00	$ 25,329.00	$ 32,139.00	$ 262.00	$ 59,366.00	$ 1,003.00	$ 60,369.00
		1,722	50,973,404	95,095	73,247	-	$ 154,980.00	$ 1,682,122.00	$ 2,172,312.00	$ 18,517.00	$ 3,990,897.00	$ 64,613.00	$ 4,055,510.00
PS Primary	GS 3 Phase (a)	9	5,071,800	5,639	4,568	-	$ 810.00	$ 167,369.00	$ 129,671.00	$ 1,123.00	$ 296,727.00	$ 6,744.00	$ 303,471.00
		2	425,800	1,051	884	-	$ 720.00	$ 14,051.00	$ 24,542.00	$ 213.00	$ 39,100.00	$ 710.00	$ 39,810.00
		11	5,497,600	6,690	5,452	-	$ 1,530.00	$ 181,420.00	$ 154,213.00	$ 1,336.00	$ 335,827.00	$ 7,454.00	$ 343,281.00
TOD Secondary	GS (a)	48	5,342,200	16,938	8,067	-	$ 9,600.00	$ 186,443.00	$ 234,297.00	$ 2,250.00	$ 428,090.00	$ 7,995.00	$ 436,085.00
	GS 3 Phase (a)	51	6,893,560	9,955	15,232	-	$ 10,200.00	$ 240,585.00	$ 236,002.00	$ 2,267.00	$ 484,520.00	$ 6,904.00	$ 491,424.00
	PS Secondary	107	26,356,116	37,442	24,296	-	$ 21,400.00	$ 919,828.00	$ 578,485.00	$ 5,556.00	$ 1,514,157.00	$ 39,941.00	$ 1,554,098.00
	PS Primary	8	1,687,600	2,133	1,182	-	$ 1,600.00	$ 58,897.00	$ 31,062.00	$ 298.00	$ 91,261.00	$ 2,990.00	$ 94,251.00
		214	40,279,476	66,468	48,777	-	$ 42,800.00	$ 1,405,753.00	$ 1,079,846.00	$ 10,371.00	$ 2,518,028.00	$ 57,830.00	$ 2,575,858.00
TOD Primary	GS (a)	12	4,433,400	10,501	5,691	-	$ 3,600.00	$ 156,144.00	$ 117,554.00	$ 1,457.00	$ 275,841.00	$ 6,909.00	$ 282,750.00
	GS 3 Phase (a)	3	538,200	881	1,543	-	$ 900.00	$ 18,955.00	$ 17,598.00	$ 218.00	$ 37,235.00	$ 1,298.00	$ 38,533.00
	PS Secondary	-	-	-	-	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	PS Primary	165	82,159,500	131,890	91,003	-	$ 49,500.00	$ 2,893,657.00	$ 1,618,203.00	$ 20,061.00	$ 4,541,299.00	$ 89,035.00	$ 4,630,334.00
	RTS	1	1,973,830	4,335	4,335	4,335	$ 300.00	$ 69,518.00	$ 31,469.00	$ 390.00	$ 100,897.00	$ 1,105.00	$ 102,002.00
		181	89,104,930	147,607	102,572	4,335	$ 54,300.00	$ 3,138,274.00	$ 1,784,824.00	$ 22,126.00	$ 4,955,272.00	$ 98,347.00	$ 5,053,619.00
TE	GS	3	853	-	-	-	$ 9.00	$ 61.00	$ -	$ -	$ 70.00	$ (2.00)	$ 68.00
Total Moving to New Rates		6,432	213,623,784	511,140	296,294	4,335	$ 323,354.50	$ 8,716,174.00	$ 5,191,195.00	$ 64,789.50	$ 14,165,934.00	$ 265,779.00	$ 14,431,713.00

Kentucky Utilities Company

Adjustment to Reflect Rate Switching During the Twelve Months Ended March 31, 2012

		Test Year Billing Determinants at Original Rates					Revenue Decrease to Report for Previous Tariff Due to Additonal Customers From Rate Switching						
Rate Switch From	To Rate Category:	Customer-Months on the Old Rate	Energy -- kWh on Old Rate	Summer or Peak Demand, kW or kVa on Old Rate	Winter or Intermediate Demand, kW or kVa on Old Rate	Basic Demand, kW or kVa on Old Rate	Basic Service Charge Revenues	Energy Revenues	Demand Revenues	Base Rate Component of ECR	Total Base Revenues Net of ECR	FAC Revenues	Total Base Revenues Net of ECR Including FAC
Rate RS	GS	471	468,872	-	-	-	$ 4,003.00	$ 32,760.00	$ -	$ 141.00	$ 36,622.00	$ 451.00	$ 37,073.00
	GS 3 phase	18	150,483	-	-	-	$ 153.00	$ 10,514.00	$ -	$ 45.00	$ 10,622.00	$ 200.00	$ 10,822.00
		489	619,355	-	-	-	$ 4,156.00	$ 43,274.00	$ -	$ 186.00	$ 47,244.00	$ 651.00	$ 47,895.00
Rate VFD	RS	34	75,098	-	-	-	$ 289.00	$ 5,247.00	$ -	$ 23.00	$ 5,513.00	$ 8.00	$ 5,521.00
	GS	10	33,577	-	-	-	$ 85.00	$ 2,346.00	$ -	$ 10.00	$ 2,421.00	$ 45.00	$ 2,466.00
		44	108,675	-	-	-	$ 374.00	$ 7,593.00	$ -	$ 33.00	$ 7,934.00	$ 53.00	$ 7,987.00
Rate GS	RS	583	198,087	-	-	-	$ 10,203.00	$ 16,504.00	$ -	$ 89.00	$ 26,618.00	$ 205.00	$ 26,823.00
	AES	3	5,414	-	-	-	$ 52.50	$ 451.00	$ -	$ 2.50	$ 501.00	$ 3.00	$ 504.00
	PS Secondary	603	17,508,813	33,564	24,666	-	$ 10,553.00	$ 1,458,834.00	$ -	$ 7,879.00	$ 1,461,508.00	$ 22,888.00	$ 1,484,396.00
	TOD Secondary	48	5,342,200	16,938	8,067	-	$ 840.00	$ 445,112.00	$ -	$ 2,404.00	$ 443,548.00	$ 7,995.00	$ 451,543.00
	TOD Primary	12	4,433,400	10,501	5,691	-	$ 210.00	$ 369,391.00	$ -	$ 1,995.00	$ 367,606.00	$ 6,909.00	$ 374,515.00
	TE	3	853	-	-	-	$ 52.50	$ 71.00	$ -	$ 0.50	$ 123.00	$ (2.00)	$ 121.00
		1,252	27,488,767	61,003	38,424	-	$ 21,911.00	$ 2,290,363.00	$ -	$ 12,370.00	$ 2,299,904.00	$ 37,998.00	$ 2,337,902.00
Rate GS 3 Phase	RS	1	407	-	-	-	$ 32.50	$ 33.50	$ -	$ -	$ 66.00	$ -	$ 66.00
	GS	53	113,237	-	-	-	$ 1,723.00	$ 9,435.00	$ -	$ 51.00	$ 11,107.00	$ 33.00	$ 11,140.00
	PS Secondary	1,089	32,379,484	58,842	47,434	-	$ 35,392.50	$ 2,697,858.50	$ -	$ 14,571.00	$ 2,718,680.00	$ 40,371.00	$ 2,759,051.00
	PS Primary	2	425,800	1,051	884	-	$ 260.00	$ 35,478.00	$ -	$ 192.00	$ 35,546.00	$ 710.00	$ 36,256.00
	TOD Secondary	51	6,893,560	9,955	15,232	-	$ 1,658.00	$ 574,371.00	$ -	$ 3,102.00	$ 572,927.00	$ 6,904.00	$ 579,831.00
	TOD Primary	3	538,200	881	1,543	-	$ 97.50	$ 44,843.00	$ -	$ 242.50	$ 44,698.00	$ 1,298.00	$ 45,996.00
		1,199	40,350,688	70,729	65,093	-	$ 39,163.50	$ 3,362,019.00	$ -	$ 18,158.50	$ 3,383,024.00	$ 49,316.00	$ 3,432,340.00
Rate AES	GS	15	53,213	-	-	-	$ 262.50	$ 3,549.50	$ -	$ 14.00	$ 3,798.00	$ 87.00	$ 3,885.00
	GS 3 Phase	5	12,658	-	-	-	$ 87.50	$ 844.50	$ -	$ 3.00	$ 929.00	$ 17.00	$ 946.00
		20	65,871	-	-	-	$ 350.00	$ 4,394.00	$ -	$ 17.00	$ 4,727.00	$ 104.00	$ 4,831.00
Rate AES 3 Phase	PS Secondary	6	317,560	728	728	-	$ 195.00	$ 21,181.00	$ -	$ 86.00	$ 21,290.00	$ 351.00	$ 21,641.00
PS Secondary	GS	1,021	6,873,463	30,663	20,449	-	$ 91,890.00	$ 226,825.00	$ 664,447.00	$ 5,622.00	$ 977,540.00	$ 9,174.00	$ 986,714.00
	GS 3 Phase	2,072	19,563,972	164,231	45,467	-	$ 186,480.00	$ 645,612.00	$ 1,576,659.00	$ 23,067.00	$ 2,385,684.00	$ 27,118.00	$ 2,412,802.00
	AES 3 Phase	2	76,800	131	180	-	$ 180.00	$ 2,534.00	$ 3,918.00	$ 34.00	$ 6,598.00	$ 35.00	$ 6,633.00
	PS Primary	9	5,071,800	5,639	4,568	-	$ 810.00	$ 167,369.00	$ 131,599.00	$ 1,123.00	$ 298,655.00	$ 6,744.00	$ 305,399.00
	TOD Secondary	107	26,356,116	37,442	24,296	-	$ 9,630.00	$ 869,752.00	$ 803,492.00	$ 6,791.00	$ 1,676,083.00	$ 39,941.00	$ 1,716,024.00
	TOD Primary	-	-	-	-	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -
		3,211	57,942,151	238,106	94,960	-	$ 288,990.00	$ 1,912,092.00	$ 3,180,115.00	$ 36,637.00	$ 5,344,560.00	$ 83,012.00	$ 5,427,572.00
PS Primary	GS 3 Phase	13	142,240	255	150	-	$ 1,170.00	$ 4,694.00	$ 5,333.00	$ 45.00	$ 11,152.00	$ 161.00	$ 11,313.00
	PS Secondary	24	767,547	1,961	419	-	$ 2,160.00	$ 25,329.00	$ 31,702.00	$ 262.00	$ 58,929.00	$ 1,003.00	$ 59,932.00
	TOD Secondary	8	1,687,600	2,133	1,182	-	$ 720.00	$ 55,691.00	$ 42,799.00	$ 365.00	$ 98,845.00	$ 2,990.00	$ 101,835.00
	TOD Primary	165	82,159,500	131,890	91,003	-	$ 14,850.00	$ 2,711,263.00	$ 2,851,515.00	$ 24,518.00	$ 5,553,110.00	$ 89,035.00	$ 5,642,145.00
		210	84,756,887	136,239	92,754	-	$ 18,900.00	$ 2,796,977.00	$ 2,931,349.00	$ 25,190.00	$ 5,722,036.00	$ 93,189.00	$ 5,815,225.00
RTS	TOD Primary	1	1,973,830	4,335	4,335	4,335	$ 500.00	$ 67,387.00	$ 48,938.00	$ 130.00	$ 116,695.00	$ 1,105.00	$ 117,800.00
Total Moving From Previous Rates		6,432	213,623,784	511,140	296,294	4,335	$ 374,539.50	$ 10,505,280.00	$ 6,160,402.00	$ 92,807.50	$ 16,947,414.00	$ 265,779.00	$ 17,213,193.00
Net Change From Previous Rate to Current Rate							$ (51,185.00)	$ (1,789,106.00)	$ (969,207.00)	$ (28,018.00)	$ (2,781,480.00)	$ -	$ (2,781,480.00)

Conroy Exhibit P7

Adjustment for Customers Moving to Cycle 20 Billing

Kentucky Utilities Company
Effect of Change in Billing Cycles on Large Customers

		Test Year Billing Determinants					Test Year Revenues			
				Demands, kVa						
	Rate	Customer-Months	Energy, kWh	Base	Intermediate	Peak	Basic Service Charge	Energy	Demand	Total
Customer 1	CSR	13	-	-	-	-	$ -	$ -	$ (11,801,238)	$ (11,801,238)
Customer 2	FLS	13	546,287,246	2,347,234	2,304,105	1,227,450	$ 6,500	$ 16,211,284	$ 8,975,291	$ 25,193,075
Customer 3	RTS	13	85,578,000	155,616	153,392	152,361	$ 6,500	$ 3,041,463	$ 1,106,673	$ 4,154,636
Customer 4	RTS	13	197,120,000	377,841	373,472	371,817	$ 6,500	$ 6,769,505	$ 2,689,526	$ 9,465,531
Customer 5	RTS	13	457,072,000	887,685	843,890	866,053	$ 6,500	$ 15,696,713	$ 6,290,277	$ 21,993,490
Customer 6	TOD-P	13	241,279,680	582,278	575,215	568,065	$ 3,900	$ 8,538,081	$ 4,828,867	$ 13,370,848
Customer 7	TOD-P	13	162,504,120	390,415	377,590	365,873	$ 3,900	$ 5,750,879	$ 3,154,854	$ 8,909,634

		Billing Determinants Base on Cycle 20 for the Test Year					Test Year Revenues Based on Cycle 20 for the Test Year			
				Demands, kVa						
	Rate	Customer-Months	Energy, kWh	Base	Intermediate	Peak	Basic Service Charge	Energy	Demand	Total
Customer 1	CSR	12	-	-	-	-	$ -	$ -	$ (10,887,152)	$ (10,887,152)
Customer 2	FLS	12	502,871,246	2,169,914	2,126,785	1,133,869	$ 6,000	$ 14,894,477	$ 8,283,951	$ 23,184,427
Customer 3	RTS	12	79,236,000	143,913	141,772	140,846	$ 6,000	$ 2,819,493	$ 1,022,615	$ 3,848,108
Customer 4	RTS	12	181,328,000	348,440	344,071	342,415	$ 6,000	$ 6,216,785	$ 2,476,073	$ 8,698,858
Customer 5	RTS	12	421,176,000	818,282	774,708	796,872	$ 6,000	$ 14,440,353	$ 5,787,788	$ 20,234,141
Customer 6	TOD-P	12	223,509,840	541,648	536,098	528,947	$ 3,600	$ 7,896,945	$ 4,493,015	$ 12,393,560
Customer 7	TOD-P	12	150,235,920	363,352	352,082	340,365	$ 3,600	$ 5,308,243	$ 2,934,883	$ 8,246,726

		Billing Determinants to Remove from Test Year Results					Revenue to Remove from Test Year Results			
				Demands, kVa						
	Rate	Customer-Months	Energy, kWh	Base	Intermediate	Peak	Basic Service Charge	Energy	Demand	Total
Customer 1	CSR	1	-	-	-	-	$ -	$ -	$ (914,086)	$ (914,086)
Customer 2	FLS	1	43,416,000	177,320	177,320	93,581	500	1,316,807	691,341	2,008,648
Customer 3	RTS	1	6,342,000	11,703	11,620	11,516	500	221,970	84,058	306,528
Customer 4	RTS	1	15,792,000	29,401	29,401	29,401	500	552,720	213,453	766,673
Customer 5	RTS	1	35,896,000	69,403	69,182	69,182	500	1,256,360	502,489	1,759,349
Customer 6	TOD-P	1	17,769,840	40,630	39,117	39,117	300	641,136	335,852	977,288
Customer 7	TOD-P	1	12,268,200	27,063	25,508	25,508	300	442,637	219,971	662,908

Total Adjustment

CSR	1	-	-	-	-	$ -	$ -	$ (914,086)	$ (914,086)
FLS	1	43,416,000	177,320	177,320	93,581	$ 500	$ 1,316,807	$ 691,341	$ 2,008,648
RTS	3	58,030,000	110,508	110,203	110,099	$ 1,500	$ 2,031,050	$ 800,000	$ 2,832,550
TOD-P	2	30,038,040	67,693	64,625	64,625	$ 600	$ 1,083,772	$ 555,823	$ 1,640,196
Total	7	131,484,040	355,521	352,148	268,305	$ 2,600	$ 4,431,630	$ 1,133,078	$ 5,567,308

Conroy Exhibit C1

Base-Intermediate-Peak (BIP) Differentiation

Louisville Gas and Electric Company and Kentucky Utilities Company
Assignment of Production and Transmission Demand-Related Costs
Twelve Months Ended March 31, 2012

Minimum System Demand	2,321
Winter System Peak Demand	5,704
Summer System Peak Demand	6,756

Assignment of Production and Transmission
Demand-Related Costs to the Costing Periods

Non-Time-Differentiated Capacity Costs

1. Minimum System Demand	2,321		
2. Maximum System Demand	6,756		
3. Non-Time-Differentiated Capacity Factor (Line 1/Line 2)	0.3435		
4. Non-Time-Differentiated Cost (Line 3)		34.35%	

Winter Peak Period Costs

5. Maximum Winter System Demand	5,704		
6. Intermediate Peak Period Capacity Factor (Line 5/Line2 - Line 3)	0.5008		
7. Winter Peak Period Hours	2,416		
8. Summer Peak Period Hours	1,320		
9. Total Summer and Winter Peak Period Hours (Line 7 + Line 8)	3,736		
10. Winter Peak Period Costs (Line 7/Line 9 x Line 6)		32.39%	

Summer Peak Period Costs

11. Peak Capacity Factor (1.0000 - Line 3 - Line 6)	0.1557		
12. Summer Peak Period Costs (Line 11 + Line 8/Line 9 x Line 6)		33.26%	100.00%

Conroy Exhibit C2

Kentucky Jurisdictional Separation Study

KENTUCKY UTILITIES COMPANY
ELECTRIC COST OF SERVICE STUDY
JURISDICTIONAL SEPARATION

RATE BASE: END OF YEAR
ALLOCATION METHOD: AVG 12 CP (COMBINED CO SYS)

12 MONTHS ENDING MARCH 31, 2012

	ALLOC	TOTAL KENTUCKY UTILITIES (1)	KENTUCKY STATE JURISDICTION (2)	VIRGINIA STATE JURISDICTION (3)	FERC & TENNESSEE JURISDICTION (4)	TENNESSEE STATE JURISDICTION (5)	FERC JURISDICTION (6)	PRIMARY (7)	TRANSMISSION (8)
SUMMARY OF RESULTS AS ALLOCATED									
ELEMENTS OF RATE BASE									
1 PLANT IN SERVICE		6,492,570,023	5,653,048,566	385,619,848	453,901,608	204,724	453,696,884	144,053,837	309,643,047
2 LESS RESERVE FOR DEPRECIATION		2,419,286,203	2,091,528,460	159,664,578	168,093,165	156,838	167,936,327	53,369,105	114,567,222
3 NET PLANT IN SERVICE		4,073,283,819	3,561,520,106	225,955,270	285,808,443	47,886	285,760,557	90,684,732	195,075,824
4 CONST WORK IN PROGRESS		345,238,438	299,563,000	18,539,714	27,135,725	2,779	27,132,946	8,513,304	18,619,642
5 NET PLANT		4,418,522,258	3,861,083,106	244,494,984	312,944,168	50,665	312,893,502	99,198,036	213,695,466
ADD:									
6 MATERIALS & SUPPLIES		43,434,959	37,642,731	2,561,510	3,230,718	1,157	3,229,562	1,020,690	2,208,871
7 FUEL INVENTORY		89,278,978	77,455,484	4,095,411	7,728,083	426	7,727,657	2,522,667	5,204,990
8 PREPAYMENTS		7,326,676	6,567,467	360,097	399,113	196	398,917	127,832	271,085
9 WORKING CASH		104,067,439	96,090,910	-	7,976,529	1,716	7,974,813	2,592,828	5,381,985
10 EMISSION ALLOWANCES		480,272	415,671	24,411	40,190	4	40,187	12,539	27,647
11 TOTAL ADDITIONS		244,588,324	218,172,263	7,041,428	19,374,633	3,498	19,371,135	6,276,556	13,094,579
DEDUCT:									
12 RESERVE FOR DEF TAXES		502,196,487	439,643,557	28,594,743	33,958,187	15,555	33,942,632	10,778,578	23,164,054
13 RESERVE FOR ITC		100,707,740	86,299,724	5,223,560	9,184,455	763	9,183,692	2,865,545	6,318,147
14 CUSTOMER ADVANCES		3,147,887	2,936,189	211,698	-	-	-	-	-
15 CUSTOMER DEPOSITS-VIRGINIA		23,057,678	-	525,361	-	-	-	-	-
16 DEFERRED FUEL-VIRGINIA		(2,824,747)	-	(2,824,747)	-	-	-	-	-
17 OPEB UNFUNDED-VIRGINIA		59,597,738	-	3,265,538	-	-	-	-	-
18 TOTAL DEDUCTIONS		685,882,783	528,879,470	34,996,154	43,142,642	16,318	43,126,324	13,644,123	29,482,201
19 NET ORIGINAL COST RATE BASE		3,977,227,799	3,550,375,899	216,540,258	289,176,158	37,845	289,138,313	91,830,469	197,307,844
DEVELOPMENT OF RETURN									
20 OPERATING REVENUES		1,522,035,957	1,342,076,920	75,816,559	104,142,478	6,663	104,135,815	33,654,442	70,481,373
OPERATING EXPENSES									
21 OPERATION & MAINT EXPENSE		980,861,389	858,787,983	49,298,744	72,774,663	14,250	72,760,413	23,657,671	49,102,742
22 DEPRECIATION & AMORT EXP		192,192,743	167,700,749	10,428,736	14,063,259	3,777	14,059,482	4,451,801	9,607,681
23 REGULATORY CREDITS		(6,011,854)	(5,207,773)	(303,782)	(500,299)	(46)	(500,253)	(156,154)	(344,099)
24 TAXES OTHER THAN INC TAX		29,144,074	25,846,050	1,501,721	1,796,303	465	1,795,837	573,098	1,222,740
25 INCOME TAXES		98,561,045	89,659,334	4,324,429	4,532,758	(4,836)	4,537,594	1,455,234	3,082,360
26 (GAIN) / LOSS DISPOSITION ALLOWANCES		(887)	(767)	(45)	(74)	(0)	(74)	(23)	(51)
27 (GAIN) / LOSS DISPOSITION PROPERTY-VA		(44,239)	-	(2,628)	-	-	-	-	-
28 CHARITABLE CONTRIBUTIONS-VA		734,837	-	20,132	-	-	-	-	-
29 INTEREST ON CUSTOMER DEPOSITS-VA		1,373,106	-	1,719	-	-	-	-	-
30 ACCRETION EXPENSE		2,934,109	2,542,421	147,970	243,717	22	243,695	76,080	167,615
31 TOTAL OPERATING EXPENSES		1,299,744,322	1,139,327,996	65,416,997	92,910,327	13,632	92,896,694	30,057,707	62,838,988
32 RETURN		222,291,634	202,748,924	10,399,563	11,232,151	(6,969)	11,239,121	3,596,735	7,642,385
33 RATE OF RETURN		5.59%	5.71%	4.80%	3.88%	-18.42%	3.89%	3.92%	3.87%

KENTUCKY UTILITIES COMPANY
ELECTRIC COST OF SERVICE STUDY
JURISDICTIONAL SEPARATION

RATE BASE: END OF YEAR
ALLOCATION METHOD: AVG 12 CP (COMBINED CO SYS)

12 MONTHS ENDING MARCH 31, 2012

	ALLOC	TOTAL KENTUCKY UTILITIES (1)	KENTUCKY STATE JURISDICTION (2)	VIRGINIA STATE JURISDICTION (3)	FERC & TENNESSEE JURISDICTION (4)	TENNESSEE STATE JURISDICTION (5)	FERC JURISDICTION (6)	PRIMARY (7)	TRANSMISSION (8)
ELECTRIC PLANT IN SERVICE									
INTANGIBLE PLANT									
1 301-ORGANIZATION	PTDGPLT	44,456	38,707	2,640	3,108	1	3,107	986	2,120
2 302-FRANCHISE	KURETPLT	55,919	55,919	-	-	-	-	-	-
3 303-SOFTWARE	PTDGPLT	60,103,759	52,331,978	3,569,835	4,201,946	1,895	4,200,051	1,333,563	2,866,488
4 TOTAL INTANGIBLE PLANT		60,204,133	52,426,604	3,572,475	4,205,054	1,897	4,203,157	1,334,549	2,868,608
PRODUCTION PLANT									
STEAM PRODUCTION PLANT									
5 310-LAND	DEMPROD	10,881,104	9,417,488	553,061	910,554	83	910,471	284,090	626,381
6 311-STRUCTURES AND IMPROVEMENTS	DEMPROD	331,497,470	286,907,803	16,849,244	27,740,424	2,537	27,737,887	8,654,925	19,082,962
7 312-BOILER PLANT EQUIPMENT	DEMPROD	2,633,157,905	2,278,972,291	133,837,278	220,348,336	20,150	220,328,186	68,747,984	151,580,202
8 314-TURBOGENERATOR UNITS	DEMPROD	316,044,025	273,532,998	16,063,781	26,447,246	2,419	26,444,828	8,251,457	18,193,370
9 315-ACCESSORY ELECTRIC EQUIP	DEMPROD	209,742,019	181,529,656	10,660,698	17,551,665	1,605	17,550,060	5,476,064	12,073,996
10 316-MISC POWER PLANT EQUIP	DEMPROD	30,545,308	26,436,664	1,552,547	2,556,097	234	2,555,864	797,494	1,758,369
11 317-ARO COST STEAM EQUIP	DEMPROD	56,489,771	48,891,342	2,871,243	4,727,186	432	4,726,754	1,474,867	3,251,887
12 FERC-AFUDC PRE	DEMFERC	17,109,216	-	6,465,483	10,643,733	-	10,643,733	3,321,115	7,322,618
13 FERC-AFUDC POST	DEMFERCP	22,166,665	-	-	22,166,665	-	22,166,665	6,916,562	15,250,103
14 TOTAL STEAM PROD PLANT		3,627,633,483	3,105,688,242	188,853,335	333,091,906	27,460	333,064,446	103,924,558	229,139,889
HYDRAULIC PRODUCTION PLANT									
15 330-LAND RIGHTS	DEMPROD	879,311	761,035	44,693	73,583	7	73,576	22,958	50,618
16 331-STRUCTURES AND IMPROVEMENTS	DEMPROD	616,527	533,598	31,337	51,592	5	51,588	16,097	35,491
17 332-RESERVOIRS, DAMS, AND WATER	DEMPROD	21,558,918	18,659,031	1,095,790	1,804,097	165	1,803,932	562,872	1,241,059
18 333-WATER WHEEL, TURBINES, GEN	DEMPROD	4,533,222	3,923,459	230,413	379,350	35	379,315	118,356	260,959
19 334-ACCESSORY ELECTRIC EQUIP	DEMPROD	578,333	500,542	29,395	48,396	4	48,392	15,099	33,292
20 335-MISC POWER PLANT EQUIP	DEMPROD	296,204	256,362	15,055	24,787	2	24,785	7,733	17,051
21 336-ROADS, RAILROADS, AND BRIDGES	DEMPROD	176,360	152,637	8,964	14,758	1	14,757	4,604	10,152
22 337-ARO COST HYDRO PROD EQUIP	DEMPROD	57,609	49,860	2,928	4,821	0	4,820	1,504	3,316
23 FERC-AFUDC PRE	DEMFERC	820	-	310	510	-	510	159	351
24 FERC-AFUDC POST	DEMFERCP	59,167	-	-	59,167	-	59,167	18,461	40,705
25 TOTAL HYDRAULIC PROD PLANT		28,756,470	24,836,524	1,458,885	2,461,060	220	2,460,841	767,845	1,692,996
OTHER PRODUCTION PLANT									
26 340-LAND & LAND RIGHTS	DEMPROD	294,924	255,254	14,990	24,680	2	24,678	7,700	16,978
27 341-STRUCTURES AND IMPROVEMENTS	DEMPROD	35,819,882	31,001,756	1,820,641	2,997,485	274	2,997,211	935,206	2,062,005
28 342-FUEL HOLDERS, PRODUCERS, ACC	DEMPROD	22,685,928	19,634,447	1,153,073	1,898,407	174	1,898,234	592,297	1,305,937
29 343-PRIME MOVERS	DEMPROD	363,401,098	314,520,079	18,470,831	30,410,188	2,781	30,407,407	9,487,883	20,919,525
30 344-GENERATORS	DEMPROD	59,091,569	51,143,172	3,003,487	4,944,910	452	4,944,458	1,542,796	3,401,662
31 345-ACCESSORY ELECTRIC EQUIP	DEMPROD	44,623,313	38,621,039	2,268,099	3,734,175	341	3,733,834	1,165,051	2,568,783
32 346-MISC POWER PLANT EQUIP	DEMPROD	5,356,925	4,636,366	272,280	448,279	41	448,238	139,862	308,376
33 347-ARO COST OTHER PROD EQUIP	DEMPROD	17,791	15,398	904	1,489	0	1,489	464	1,024
34 FERC-AFUDC PRE	DEMFERC	2,005	-	758	1,247	-	1,247	389	858
35 FERC-AFUDC POST	DEMFERCP	2,089,710	-	-	2,089,710	-	2,089,710	652,043	1,437,668
36 TOTAL OTHER PROD PLANT		533,383,145	459,827,511	27,005,062	46,550,571	4,066	46,546,505	14,523,691	32,022,815
37 TOTAL PRODUCTION PLANT		4,189,773,098	3,590,352,278	217,317,282	382,103,538	31,745	382,071,793	119,216,093	262,855,699

KENTUCKY UTILITIES COMPANY
ELECTRIC COST OF SERVICE STUDY
JURISDICTIONAL SEPARATION

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12 MONTHS ENDING MARCH 31, 2012

	ALLOC	TOTAL KENTUCKY UTILITIES (1)	KENTUCKY STATE JURISDICTION (2)	VIRGINIA STATE JURISDICTION (3)	FERC & TENNESSEE JURISDICTION (4)	TENNESSEE STATE JURISDICTION (5)	FERC JURISDICTION (6)	PRIMARY (7)	TRANSMISSION (8)
ELECTRIC PLANT IN SERVICE CON'T									
TRANSMISSION PLANT									
KENTUCKY SYSTEM PROPERTY									
1 350-LAND & LAND RIGHTS	DEMTRAN	23,367,025	20,223,931	1,187,691	1,955,403	179	1,955,224	610,080	1,345,145
2 352-STRUCTURES AND IMPROVEMENTS	DEMTRAN	16,662,948	14,421,618	846,939	1,394,391	128	1,394,264	435,046	959,218
3 353-STATION EQUIPMENT	DEMTRAN	189,274,083	163,814,859	9,620,360	15,838,864	1,448	15,837,415	4,941,675	10,895,740
4 354-TOWERS AND FIXTURES	DEMTRAN	86,348,155	74,733,479	4,388,875	7,225,800	661	7,225,139	2,254,427	4,970,712
5 355-POLES AND FIXTURES	DEMTRAN	142,592,932	123,412,781	7,247,666	11,932,484	1,091	11,931,393	3,722,897	8,208,496
6 356-OH CONDUCTORS AND DEVICES	DEMTRAN	150,242,447	130,033,361	7,636,473	12,572,612	1,150	12,571,462	3,922,615	8,648,847
7 357-UNDERGROUND CONDUIT	DEMTRAN	447,363	387,189	22,738	37,436	3	37,433	11,680	25,753
8 358-UG CONDUCTORS AND DEVICES	DEMTRAN	1,158,210	1,002,420	58,869	96,922	9	96,913	30,239	66,673
9 359-ARO COST KY TRANS	DEMTRAN	539,999	467,364	27,447	45,188	4	45,184	14,099	31,086
10 FERC-AFUDC PRE	DEMFERCT	3,160,680	-	1,194,404	1,966,275	-	1,966,275	613,528	1,352,748
11 FERC-AFUDC POST	DFERCTP	1,422,356	-	-	1,422,356	-	1,422,356	443,811	978,545
12 TOTAL KENTUCKY SYSTEM PROPERTY		615,216,199	528,497,002	32,231,464	54,487,733	4,673	54,483,060	17,000,097	37,482,963
VIRGINIA PROPERTY									
13 350-LAND & LAND RIGHTS	DEMVA	1,883,961	-	1,883,961	-	-	-	-	-
14 352-STRUCTURES AND IMPROVEMENTS	DEMVA	1,447,987	-	1,447,987	-	-	-	-	-
15 353-STATION EQUIPMENT	DEMVA	17,612,494	-	17,612,494	-	-	-	-	-
16 354-TOWERS AND FIXTURES	DEMVA	2,421,964	-	2,421,964	-	-	-	-	-
17 355-POLES AND FIXTURES	DEMVA	8,035,933	-	8,035,933	-	-	-	-	-
18 356-OH CONDUCTORS AND DEVICES	DEMVA	13,092,361	-	13,092,361	-	-	-	-	-
19 FERC-AFUDC PRE	DEMFERCT	324	-	122	202	-	202	63	139
20 FERC-AFUDC POST	DFERCTP	4,332	-	-	4,332	-	4,332	1,352	2,980
21 TOTAL VIRGINIA PROPERTY		44,499,356	-	44,494,822	4,533	-	4,533	1,415	3,119
VIRGINIA PROPERTY-500 KV LINE									
22 350-LAND & LAND RIGHTS	DEMPRODNV	280,371	255,652	-	24,718	2	24,716	7,712	17,004
23 354-TOWERS AND FIXTURES	DEMPRODNV	4,769,323	4,348,844	-	420,479	38	420,441	131,188	289,253
24 355-POLES AND FIXTURES	DEMPRODNV	51,358	46,830	-	4,528	0	4,527	1,413	3,115
25 356-OH CONDUCTORS AND DEVICES	DEMPRODNV	3,129,378	2,853,482	-	275,896	25	275,871	86,079	189,792
26 FERC-AFUDC PRE	DEMFERCT	-	-	-	-	-	-	-	-
27 FERC-AFUDC POST	DFERCTP	-	-	-	-	-	-	-	-
28 TOTAL VIRGINIA PROPERTY-500 KV LINE		8,230,429	7,504,808	-	725,622	66	725,555	226,392	499,164
29 TOTAL TRANSMISSION PLANT		667,945,984	536,001,810	76,726,287	55,217,888	4,739	55,213,149	17,227,903	37,985,245

KENTUCKY UTILITIES COMPANY
ELECTRIC COST OF SERVICE STUDY
JURISDICTIONAL SEPARATION

RATE BASE: END OF YEAR
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12 MONTHS ENDING MARCH 31, 2012

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	ELECTRIC PLANT IN SERVICE CON'T									
	DISTRIBUTION PLANT									
	KENTUCKY DISTRIBUTION PLANT									
1	360-LAND & LAND RIGHTS	DEM360K	5,112,550	5,103,392	-	9,158	-	9,158	9,158	-
2	361-STRUCTURES AND IMPROVEMENTS	DEM361K	7,214,275	6,940,989	-	273,286	-	273,286	273,286	-
3	362-STATION EQUIPMENT	DEM362K	137,609,926	134,408,400	-	3,201,526	-	3,201,526	3,201,526	-
4	364-POLES, TOWERS, AND FIXTURES	DEM364K	273,798,351	273,798,351	-	-	-	-	-	-
5	365-OH CONDUCTORS AND DEVICES	DEM365K	263,336,954	263,336,954	-	-	-	-	-	-
6	366-UNDERGROUND CONDUIT	DEM366K	1,831,865	1,831,865	-	-	-	-	-	-
7	367-UG CONDUCTORS AND DEVICES	DEM367K	139,509,219	139,509,219	-	-	-	-	-	-
	368-LINE TRANSFORMERS									
8	POWER POOL	DPRODKY	5,932,406	5,409,429	-	522,977	-	522,977	163,182	359,795
9	ALL OTHER	DEM368K	267,984,931	267,984,931	-	-	-	-	-	-
10	TOTAL 368-LINE TRANSFORMERS		273,917,337	273,394,360	-	522,977	-	522,977	163,182	359,795
11	369-SERVICES	CUST369K	84,507,618	84,507,618	-	-	-	-	-	-
12	370-METERS	CUST370K	67,284,795	66,969,753	-	315,042	-	315,042	66,911	248,131
13	371-INSTALL ON CUSTOMER PREMISES	CUST371K	17,384,575	17,384,575	-	-	-	-	-	-
14	373-STREET LIGHTING	CUST373K	80,975,590	80,975,590	-	-	-	-	-	-
15	374-ARO COST KY ELEC DISTRIB	DEM374K	786,955	786,955	-	-	-	-	-	-
16	TOTAL KENTUCKY DISTRIB PLANT		1,353,270,008	1,348,948,020	-	4,321,989	-	4,321,989	3,714,063	607,926
	VIRGINIA DISTRIBUTION PLANT									
17	360-LAND & LAND RIGHTS	DEM360V	193,250	-	193,250	-	-	-	-	-
18	361-STRUCTURES AND IMPROVEMENTS	DEM361V	448,174	-	448,174	-	-	-	-	-
19	362-STATION EQUIPMENT	DEM362V	7,696,928	-	7,696,928	-	-	-	-	-
20	364-POLES, TOWERS, AND FIXTURES	DEM364V	23,371,899	-	23,371,899	-	-	-	-	-
21	365-OH CONDUCTORS AND DEVICES	DEM365V	20,121,983	-	20,121,983	-	-	-	-	-
22	367-UG CONDUCTORS AND DEVICES	DEM367V	2,763,964	-	2,763,964	-	-	-	-	-
	368-LINE TRANSFORMERS									
23	POWER POOL	DPRODVA	128,028	-	128,028	-	-	-	-	-
24	ALL OTHER	DEM368V	13,895,429	-	13,895,429	-	-	-	-	-
25	TOTAL 368-LINE TRANSFORMERS		14,023,456	-	14,023,456	-	-	-	-	-
26	369-SERVICES	CUST369V	5,175,446	-	5,175,446	-	-	-	-	-
27	370-METERS	CUST370V	3,637,512	-	3,637,512	-	-	-	-	-
28	371-INSTALL ON CUSTOMER PREMISES	CUST371V	856,341	-	856,341	-	-	-	-	-
29	373-STREET LIGHTING	CUST373V	2,038,654	-	2,038,654	-	-	-	-	-
30	TOTAL VIRGINIA DISTRIB PLANT		80,327,606	-	80,327,606	-	-	-	-	-
	TENNESSEE DISTRIBUTION PLANT									
31	360-LAND & LAND RIGHTS	DEM360T	5,040	-	-	5,040	5,040	-	-	-
32	361-STRUCTURES AND IMPROVEMENTS	DEM361T	2,621	-	-	2,621	2,621	-	-	-
33	362-STATION EQUIPMENT	DEM362T	56,020	-	-	56,020	56,020	-	-	-
34	364-POLES, TOWERS, AND FIXTURES	DEM364T	48,114	-	-	48,114	48,114	-	-	-
35	365-OH CONDUCTORS AND DEVICES	DEM365T	46,763	-	-	46,763	46,763	-	-	-
36	368-LINE TRANSFORMERS	DEM368T	3,118	-	-	3,118	3,118	-	-	-
37	369-SERVICES	CUST369T	255	-	-	255	255	-	-	-
38	370-METERS	CUST370T	111	-	-	111	111	-	-	-
39	371-INSTALL ON CUSTOMER PREMISES	CUST371T	-	-	-	-	-	-	-	-
40	TOTAL TENNESSEE DISTRIB PLANT		162,043	-	-	162,043	162,043	-	-	-
41	TOTAL DISTRIBUTION PLANT		1,433,759,657	1,348,948,020	80,327,606	4,484,032	162,043	4,321,989	3,714,063	607,926

RATE BASE: END OF YEAR
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		ALLOC	TOTAL KENTUCKY UTILITIES (1)	KENTUCKY STATE JURISDICTION (2)	VIRGINIA STATE JURISDICTION (3)	FERC & TENNESSEE JURISDICTION (4)	TENNESSEE STATE JURISDICTION (5)	FERC JURISDICTION (6)	PRIMARY (7)	TRANSMISSION (8)
	ELECTRIC PLANT IN SERVICE CON'T									
	GENERAL PLANT									
1	389-LAND & LAND RIGHTS	LABOR	2,629,528	2,338,646	144,080	146,802	81	146,721	47,664	99,057
2	390-STRUCTURES AND IMPROVEMENTS	LABOR	46,799,330	41,622,333	2,564,275	2,612,722	1,437	2,611,285	848,309	1,762,976
3	391-OFFICE EQUIPMENT	LABOR	32,854,981	29,220,524	1,800,223	1,834,234	1,009	1,833,225	595,546	1,237,679
4	392-TRANSPORTATION EQUIPMENT	LABOR	15,969,955	14,203,340	875,042	891,574	490	891,083	289,480	601,604
5	393-STORES EQUIPMENT	LABOR	551,794	490,754	30,234	30,806	17	30,789	10,002	20,787
6	394-TOOLS, SHOP, AND GARAGE EQUIP	LABOR	8,221,697	7,312,203	450,491	459,002	252	458,750	149,031	309,719
7	395-LABORATORY EQUIPMENT	LABOR	-	-	-	-	-	-	-	-
8	396-POWER OPERATED EQUIPMENT	LABOR	1,188,993	1,057,465	65,148	66,379	37	66,343	21,552	44,791
9	397-COMMUNICATION EQUIPMENT	LABOR	31,878,275	28,351,863	1,746,706	1,779,706	979	1,778,728	577,842	1,200,886
10	398-MISC EQUIPMENT	LABOR	-	-	-	-	-	-	-	-
11	TOTAL GENERAL PLANT		140,094,552	124,597,128	7,676,199	7,821,225	4,301	7,816,924	2,539,426	5,277,498
	PLANT HELD FOR FUTURE USE									
12	PRODUCTION	DEMPROD	-	-	-	-	-	-	-	-
13	TRANSMISSION	DEMTRAN	-	-	-	-	-	-	-	-
14	DISTRIBUTION	DPRODKY	792,599	722,727	-	69,872	-	69,872	21,802	48,070
15	GENERAL	LABOR	-	-	-	-	-	-	-	-
16	TOTAL PLANT HELD FOR FUTURE USE		792,599	722,727	-	69,872	-	69,872	21,802	48,070
17	TOTAL ELECTRIC PLANT		6,492,570,023	5,653,048,566	385,619,848	453,901,608	204,724	453,696,884	144,053,837	309,643,047

KENTUCKY UTILITIES COMPANY
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12 MONTHS ENDING MARCH 31, 2012

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	ELECTRIC PLANT IN SERVICE CON'T									
	ACCUMULATED PROVISION FOR DEP									
	PRODUCTION PLANT									
	STEAM PRODUCTION PLANT									
1	SYSTEM	STMSYS	1,247,297,917	1,079,524,091	63,397,245	104,376,582	9,545	104,367,037	32,565,163	71,801,873
2	FERC-AFUDC PRE	DEMFERC	15,482,538	-	5,850,770	9,631,768	-	9,631,768	3,005,356	6,626,412
3	FERC-AFUDC POST	DEMFERCP	2,872,593	-	-	2,872,593	-	2,872,593	896,322	1,976,271
4	TOTAL STEAM PROD PLT		1,265,653,049	1,079,524,091	69,248,016	116,880,943	9,545	116,871,398	36,466,841	80,404,556
	HYDRAULIC PRODUCTION PLANT									
5	SYSTEM	HYDSYS	7,807,864	6,757,630	396,856	653,379	60	653,319	203,852	449,467
6	FERC-AFUDC PRE	DEMFERC	3,253	-	1,229	2,023	-	2,023	631	1,392
7	FERC-AFUDC POST	DEMFERCP	948	-	-	948	-	948	296	652
8	TOTAL HYDRO PROD PLT		7,812,064	6,757,630	398,085	656,350	60	656,290	204,779	451,511
	OTHER PRODUCTION PLANT									
9	SYSTEM	OTHSYS	178,845,192	154,788,757	9,090,284	14,966,152	1,369	14,964,783	4,669,392	10,295,391
10	FERC-AFUDC PRE	DEMFERC	1,237	-	467	769	-	769	240	529
11	FERC-AFUDC POST	DEMFERCP	889,036	-	-	889,036	-	889,036	277,402	611,634
12	TOTAL OTHER PROD PLT		179,735,465	154,788,757	9,090,752	15,855,957	1,369	15,854,588	4,947,034	10,907,554
13	TOTAL PRODUCTION PLANT		1,453,200,578	1,241,070,477	78,736,852	133,393,249	10,973	133,382,276	41,618,654	91,763,622
	TRANSMISSION PLANT									
14	KENTUCKY SYSTEM PROPERTY	KYTRPLT	296,820,640	254,981,613	15,550,572	26,288,455	2,254	26,286,201	8,201,962	18,084,239
15	VIRGINIA PROPERTY	TRPLTVA	27,212,125	3,872,987	22,962,329	376,809	34	376,775	117,563	259,212
16	FERC-AFUDC PRE	DEMFERCT	2,585,484	-	977,041	1,608,443	-	1,608,443	501,875	1,106,568
17	FERC-AFUDC POST	DFERCTP	166,227	-	-	166,227	-	166,227	51,867	114,360
18	TOTAL TRANSMISSION PLANT		326,784,475	258,854,599	39,489,942	28,439,934	2,289	28,437,645	8,873,267	19,564,378
19	DISTRIBUTION PLANT-VA & TN	DIRACDEP	37,401,886	-	37,260,617	141,269	141,269	-	-	-
20	DISTRIBUTION PLANT-KY & FERC	DISTPLTKF	527,227,587	525,543,760	-	1,683,826	-	1,683,826	1,446,981	236,845
21	TOTAL DISTRIBUTION PLANT		564,629,473	525,543,760	37,260,617	1,825,095	141,269	1,683,826	1,446,981	236,845
22	GENERAL PLANT	GENPLT	55,605,423	49,454,286	3,046,787	3,104,350	1,707	3,102,643	1,007,933	2,094,710
23	INTANGIBLE PLANT-FRANCHISES	PLT302TOT	34,535	34,535	-	-	-	-	-	-
24	INTANGIBLE PLANT-SOFTWARE	PLT303TOT	19,031,720	16,570,803	1,130,380	1,330,537	600	1,329,937	422,270	907,667
25	TOTAL DEPRECIATION RESERVE		2,419,286,203	2,091,528,460	159,664,578	168,093,165	156,838	167,936,327	53,369,105	114,567,222
26	NET ELECTRIC PLANT IN SERVICE		4,073,283,819	3,561,520,106	225,955,270	285,808,443	47,886	285,760,557	90,684,732	195,075,824

KENTUCKY UTILITIES COMPANY
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12 MONTHS ENDING MARCH 31, 2012

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ADDITIONS TO NET PLANT									
CONSTRUCTION WORK IN PROGRESS									
PRODUCTION PLANT									
1 SYSTEM	PRODSYS	265,520,100	229,805,038	13,495,768	22,219,295	2,032	22,217,263	6,932,350	15,284,913
2 FERC-AFUDC PRE	DEMFERC	-	-	-	-	-	-	-	-
3 FERC-AFUDC POST	DEMFERCP	332,113	-	-	332,113	-	332,113	103,628	228,486
4 TOTAL PRODUCTION PLANT		265,852,214	229,805,038	13,495,768	22,551,408	2,032	22,549,377	7,035,978	15,513,399
TRANSMISSION PLANT									
5 SYSTEM	KYTRPLT	42,124,236	36,186,518	2,206,908	3,730,809	320	3,730,489	1,164,007	2,566,482
6 TRANS VIRGINIA-KY SYSTEM	KYTRPLT	-	-	-	-	-	-	-	-
7 TRANS VIRGINIA	VATRPLT	908,363	-	908,270	93	-	93	29	64
8 FERC-AFUDC PRE	DEMFERCT	-	-	-	-	-	-	-	-
9 FERC-AFUDC POST	DFERCTP	8,716	-	-	8,716	-	8,716	2,720	5,997
10 TOTAL TRANSMISSION PLT		43,041,315	36,186,518	3,115,178	3,739,618	320	3,739,298	1,166,756	2,572,542
11 DISTRIBUTION - VA & TN	DIRCWIP	1,166,386	-	1,166,386	-	-	-	-	-
12 DISTRIBUTION - KY & FERC	DISTPLTKF	21,264,678	21,196,765	-	67,914	-	67,914	58,361	9,553
13 TOTAL DISTRIBUTION PLT		22,431,065	21,196,765	1,166,386	67,914	-	67,914	58,361	9,553
14 GENERAL	GENPLT	13,913,845	12,374,679	762,381	776,785	427	776,358	252,210	524,148
15 TOTAL CWIP		345,238,438	299,563,000	18,539,714	27,135,725	2,779	27,132,946	8,513,304	18,619,642
WORKING CAPITAL									
MATERIALS & SUPPLIES									
16 FUEL STOCK	ENERGY	89,278,978	77,455,484	4,095,411	7,728,083	426	7,727,657	2,522,667	5,204,990
PLANT MATERIAL & SUPPLIES									
17 PRODUCTION	PRODPLT	24,117,434	20,667,011	1,250,935	2,199,488	183	2,199,306	686,239	1,513,066
18 TRANSMISSION	TRANPLT	3,386,565	2,717,592	389,011	279,961	24	279,937	87,348	192,590
19 DISTRIBUTION	DISTPLT	6,086,546	5,726,507	341,004	19,035	688	18,348	15,767	2,581
20 GENERAL	GENPLT	-	-	-	-	-	-	-	-
21 STORES UNDISTRIBUTED	M_S	9,844,414	8,531,621	580,559	732,233	262	731,971	231,337	500,635
22 TOTAL PLT MAT & SUPPLIES		43,434,959	37,642,731	2,561,510	3,230,718	1,157	3,229,562	1,020,690	2,208,871
23 TOTAL MATERIALS & SUPPLIES		132,713,937	115,098,215	6,656,920	10,958,801	1,583	10,957,219	3,543,357	7,413,862
PREPAYMENTS									
24 PREPAYMENTS OTHER THAN TAXES	EXP9245TOT	6,284,028	5,524,819	360,097	399,113	196	398,917	127,832	271,085
25 PUBLIC SERVICE COMM TAX	REVKY	1,042,648	1,042,648	-	-	-	-	-	-
26 TOTAL PREPAYMENTS		7,326,676	6,567,467	360,097	399,113	196	398,917	127,832	271,085
27 WORKING CASH - CALC BY JURIS		104,067,439	96,090,910	-	7,976,529	1,716	7,974,813	2,592,828	5,381,985
28 TOTAL WORKING CAPITAL		244,108,052	217,756,592	7,017,017	19,334,443	3,495	19,330,948	6,264,017	13,066,931
29 EMISSION ALLOWANCES	DEMPROD	480,272	415,671	24,411	40,190	4	40,187	12,539	27,647
30 TOTAL ADDITIONS TO NET PLANT		589,826,762	517,735,263	25,581,142	46,510,358	6,277	46,504,081	14,789,860	31,714,220

KENTUCKY UTILITIES COMPANY
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DEDUCTIONS FROM NET PLANT									
ACCUMULATED DEFERRED INC TAX									
PRODUCTION PLANT									
1 SYSTEM	PRODSYS	339,799,367	294,093,013	17,271,210	28,435,144	2,600	28,432,544	8,871,675	19,560,869
2 FERC-AFUDC PRE	DEMFERC	1,401,506	-	529,622	871,884	-	871,884	272,050	599,834
3 FERC-AFUDC POST	DEMFERCP	99,540	-	-	99,540	-	99,540	31,059	68,481
4 TOTAL PRODUCTION PLANT		341,300,413	294,093,013	17,800,831	29,406,569	2,600	29,403,968	9,174,784	20,229,184
TRANSMISSION PLANT									
5 KENTUCKY SYSTEM PROPERTY	KYTRPLT	38,541,449	33,108,751	2,019,205	3,413,493	293	3,413,200	1,065,005	2,348,195
6 VIRGINIA PROPERTY-500 KV LINE	DEMPRODNV	425,142	387,660	-	37,482	3	37,478	11,694	25,784
7 VIRGINIA PROPERTY-OTHER	VATRPLT	2,733,631	-	2,733,353	278	-	278	87	192
8 FERC-AFUDC PRE	DEMFERCT	262,968	-	99,374	163,594	-	163,594	51,045	112,548
9 FERC-AFUDC POST	DFERCTP	7,528	-	-	7,528	-	7,528	2,349	5,179
10 TOTAL TRANSMISSION PLANT		41,970,718	33,496,412	4,851,931	3,622,375	296	3,622,079	1,130,181	2,491,898
11 DISTRIBUTION - VA	DIRACDFTX	5,364,985	-	5,364,985	-	-	-	-	-
12 DISTRIBUTION PLT KY,FERC & TN	DPLTXVA	103,029,906	102,688,559	-	341,347	12,335	329,011	282,733	46,278
13 TOTAL DISTRIBUTION PLANT		108,394,891	102,688,559	5,364,985	341,347	12,335	329,011	282,733	46,278
14 GENERAL	GENPLT	10,530,465	9,365,573	576,996	587,897	323	587,574	190,881	396,693
15 TOTAL DEFERRED INCOME TAX		502,196,487	439,643,557	28,594,743	33,958,187	15,555	33,942,632	10,778,578	23,164,054
ACCUM DEFER INVEST TAX CREDITS									
16 PRODUCTION	PRODPLT	100,707,740	86,299,724	5,223,560	9,184,455	763	9,183,692	2,865,545	6,318,147
17 TRANSMISSION	TRANPLTX	-	-	-	-	-	-	-	-
18 TRANSMISSION - VA	TRPLTVA	-	-	-	-	-	-	-	-
18 DISTRIBUTION - VA	DIRACITC	-	-	-	-	-	-	-	-
20 DISTRIBUTION PLT KY,FERC & TN	DPLTXVA	-	-	-	-	-	-	-	-
21 GENERAL	GENPLT	-	-	-	-	-	-	-	-
22 TOTAL DEFERRED INVEST CREDIT		100,707,740	86,299,724	5,223,560	9,184,455	763	9,183,692	2,865,545	6,318,147
23 CUSTOMER ADVANCES	CUSTADV	3,147,887	2,936,189	211,698	-	-	-	-	-
24 CUSTOMER DEPOSITS-VIRGINIA	CUSTDEP	23,057,678	-	525,361	-	-	-	-	-
25 DEFERRED FUEL-VIRGINIA	DFUELVA	(2,824,747)	-	(2,824,747)	-	-	-	-	-
26 OPEB UNFUNDED-VIRGINIA	LABOR	59,597,738	-	3,265,538	-	-	-	-	-
27 TOTAL DEDUCTIONS FROM NET PLT		685,882,783	528,879,470	34,996,154	43,142,642	16,318	43,126,324	13,644,123	29,482,201
28 RATE BASE		3,977,227,799	3,550,375,899	216,540,258	289,176,158	37,845	289,138,313	91,830,469	197,307,844

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	OPERATING REVENUES									
	SALES OF ELECTRICITY									
1	440-RESIDENTIAL		509,303,763	476,589,863	32,707,845	6,055	6,055	-	-	-
2	442-SMALL COMMERCIAL		181,449,246	175,113,848	6,335,398	-	-	-	-	-
3	442-LARGE COMMERCIAL		159,939,302	149,946,899	9,992,403	-	-	-	-	-
4	442-INDUSTRIAL		342,664,409	339,425,792	3,238,617	-	-	-	-	-
5	442-MINE POWER		43,926,569	29,838,196	14,088,373	-	-	-	-	-
6	444-PUBLIC ST & HWY LIGHTING		10,746,105	10,423,250	322,855	-	-	-	-	-
7	445-OTHER PUBLIC AUTHORITIES		111,947,307	105,659,337	6,287,971	-	-	-	-	-
8	445-MUNICIPAL PUMPING		4,874,901	4,703,887	171,014	-	-	-	-	-
9	447-SALES FOR RESALE-MUNICIPALS		98,298,885	-	-	98,298,885	-	98,298,885	31,838,591	66,460,294
10	447-SALES FOR RESALE-CITY OF PARIS	ENERGY	2,912,962	2,527,190	133,624	252,149	14	252,135	82,309	169,827
11	447-SALES FOR RESALE-OFF SYSTEM:									
12	DEMAND	DEMPROD	-	-	-	-	-	-	-	-
13	ENERGY	ENERGY	29,862,147	25,907,410	1,369,838	2,584,899	142	2,584,757	843,785	1,740,972
14	TOTAL 447-OFF SYSTEM		29,862,147	25,907,410	1,369,838	2,584,899	142	2,584,757	843,785	1,740,972
15	449-PROVISION FOR RATE REFUND		-	-	-	-	-	-	-	-
16	TOTAL ELECTRIC SALES REVENUES		1,495,925,596	1,320,135,670	74,647,937	101,141,988	6,211	101,135,777	32,764,685	68,371,092
	OTHER OPERATING REVENUES									
17	450-LATE PAYMENT CHARGES	DIR450REV	7,125,786	6,910,624	213,937	1,225	-	1,225	1,199	27
18	451-RECONNECT CHARGES	DIR451REC	1,791,597	1,659,612	131,985	-	-	-	-	-
19	451-OTHER SERVICE CHARGES	DIR451OTH	559,380	547,025	12,355	-	-	-	-	-
20	454-RENT FROM ELEC PROPERTY	DIR454REV	2,338,708	2,153,990	184,359	359	359	-	-	-
21	456-TRANSMISSION SERVICE	DEMTRANNF	14,103,930	10,488,823	616,201	2,998,905	93	2,998,812	888,558	2,110,254
22	456-TAX REMITTANCE COMPENSATION	REVKY	17,113	17,113	-	-	-	-	-	-
23	456-RETURN CHECK CHARGES	DIR456CHK	139,732	130,862	8,870	-	-	-	-	-
24	456-OTHER MISC REVENUES	DIR456OTH	22,525	22,525	-	-	-	-	-	-
25	456-EXCESS FACILITIES CHARGES	DIR456FAC	15,192	14,277	915	-	-	-	-	-
26	456-FORFEITED REFUNDABLE ADVANCES	REVKY	(3,602)	(3,602)	-	-	-	-	-	-
27	TOTAL OTHER REVENUES		26,110,361	21,941,249	1,168,622	3,000,490	452	3,000,038	889,757	2,110,281
28	TOTAL OPERATING REVENUES		1,522,035,957	1,342,076,920	75,816,559	104,142,478	6,663	104,135,815	33,654,442	70,481,373

KENTUCKY UTILITIES COMPANY
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		ALLOC	TOTAL KENTUCKY UTILITIES (1)	KENTUCKY STATE JURISDICTION (2)	VIRGINIA STATE JURISDICTION (3)	FERC & TENNESSEE JURISDICTION (4)	TENNESSEE STATE JURISDICTION (5)	FERC JURISDICTION (6)	PRIMARY (7)	TRANSMISSION (8)
	OPERATION & MAINTENANCE EXP									
	PRODUCTION EXPENSE-STEAM									
1	500-SUPERV & ENGINEERING	STMPLT	5,863,735	5,020,059	305,264	538,412	44	538,368	167,984	370,383
2	501-FUEL	ENERGY	485,118,157	420,872,445	22,253,369	41,992,343	2,314	41,990,029	13,707,501	28,282,528
3	501-I/S SALES & PARIS VAR EXP.	REVFERC	-	-	-	-	-	-	-	-
4	502 & 504-STEAM EXPENSES	STMPLT	17,641,803	15,103,336	918,417	1,620,050	134	1,619,917	505,455	1,114,462
5	505-ELECTRIC EXPENSES	STMPLT	7,242,233	6,200,218	377,028	664,987	55	664,932	207,476	457,457
6	506-MISC STEAM POWER EXP	STMPLT	24,650,925	21,102,860	1,283,241	2,264,825	187	2,264,638	706,625	1,558,014
7	507 & 509 - RENTS & ALLOWANCE	STMPLT	138,987	118,990	7,236	12,762	1	12,761	3,982	8,779
8	TOTAL STEAM OPERATIONS		540,655,841	468,417,908	25,144,554	47,093,379	2,734	47,090,645	15,299,022	31,791,623
9	510-SUPERV & ENGINEERING	STMPLT	7,698,349	6,590,708	400,773	706,868	58	706,810	220,543	486,267
10	511-STRUCTURES	STMPLT	5,922,843	5,063,205	307,888	551,750	45	551,705	172,146	379,559
11	512-BOILER PLANT	ENERGY	40,474,320	34,867,058	1,843,574	3,763,688	192	3,763,496	1,228,580	2,534,916
12	513-ELECTRIC PLANT	ENERGY	12,821,462	11,091,401	586,451	1,143,610	61	1,143,549	373,308	770,242
13	514-MISC STEAM PLANT	STMPLT	2,252,600	1,928,065	117,243	207,292	17	207,275	64,675	142,600
14	TOTAL STEAM MAINTENANCE		69,169,574	59,540,437	3,255,929	6,373,208	373	6,372,835	2,059,252	4,313,583
15	TOTAL STEAM GENERATION		609,825,415	527,958,344	28,400,484	53,466,587	3,107	53,463,480	17,358,274	36,105,206
	PRODUCTION EXPENSE-HYDRO									
16	535-SUPERV & ENGINEERING	HYDPLT	7,944	6,861	403	680	0	680	212	468
17	536-WATER FOR POWER	HYDPLT	-	-	-	-	-	-	-	-
18	537-HYDRAULIC EXPENSES	HYDPLT	-	-	-	-	-	-	-	-
19	538-ELECTRIC EXPENSES	HYDPLT	-	-	-	-	-	-	-	-
20	539-MISC HYDR POWER GENER	HYDPLT	44,637	38,553	2,265	3,820	0	3,820	1,192	2,628
21	540-RENTS	HYDPLT	-	-	-	-	-	-	-	-
22	TOTAL HYDRO OPERATIONS		52,581	45,414	2,668	4,500	0	4,500	1,404	3,096
23	541-SUPERV & ENGINEERING	HYDPLT	118,804	102,609	6,027	10,168	1	10,167	3,172	6,994
23	542-STRUCTURES	HYDPLT	169,133	146,078	8,581	14,475	1	14,474	4,516	9,957
25	543-RESERV, DAMS & WATERWAY	HYDPLT	42,400	36,620	2,151	3,629	0	3,628	1,132	2,496
26	544-ELECTRIC PLANT	ENERGY	92,183	79,975	4,229	7,979	0	7,979	2,605	5,374
27	545-MISC HYDRAULIC PLANT	HYDPLT	7,916	6,837	402	677	0	677	211	466
28	TOTAL HYDRO MAINTENANCE		430,436	372,119	21,389	36,928	3	36,925	11,637	25,288
29	TOTAL HYDRO GENERATION		483,017	417,533	24,057	41,428	3	41,425	13,041	28,384
	PRODUCTION EXPENSE-OTHER									
30	546-SUPERV & ENGINEERING	OTHPLT	211,588	182,409	10,713	18,466	2	18,465	5,761	12,703
31	547-FUEL	ENERGY	31,699,199	27,501,175	1,454,108	2,743,916	151	2,743,765	895,693	1,848,072
32	548-GENERATION EXPENSES	OTHPLT	309,790	267,069	15,685	27,037	2	27,034	8,435	18,599
33	549-550 MISC & RENTS	OTHPLT	162,568	140,149	8,231	14,188	1	14,187	4,427	9,760
34	TOTAL OTHER OPERATIONS		32,383,145	28,090,802	1,488,736	2,803,607	156	2,803,451	914,316	1,889,135
35	551-SUPERV & ENGINEERING	OTHPLT	49,628	42,784	2,513	4,331	0	4,331	1,351	2,980
36	552-STRUCTURES	OTHPLT	265,097	228,539	13,422	23,136	2	23,134	7,218	15,916
37	553-GENERATING & ELECT PLT	OTHPLT	1,581,845	1,363,702	80,088	138,054	12	138,042	43,073	94,969
38	554-MISC OTH POWER GEN PLT	OTHPLT	228,247	196,771	11,556	19,920	2	19,918	6,215	13,703
39	TOTAL OTHER MAINTENANCE		2,124,817	1,831,796	107,579	185,442	16	185,425	57,857	127,568
40	TOTAL OTHER GENERATION		34,507,962	29,922,598	1,596,315	2,989,049	173	2,988,876	972,174	2,016,703
	555-PURCHASED POWER									
41	CAPACITY COMPONENT	DEMPROD	8,732,448	7,557,848	443,850	730,750	67	730,683	227,992	502,692
42	ENERGY COMPONENT	ENERGY	95,096,822	82,502,853	4,362,287	8,231,682	454	8,231,228	2,687,056	5,544,172
43	TOTAL ACCT 555		103,829,270	90,060,701	4,806,137	8,962,432	520	8,961,912	2,915,048	6,046,864
44	556-SYSTEM CONTROL & DISP	DEMPROD	1,841,937	1,594,179	93,621	154,137	14	154,123	48,090	106,033
45	557-OTHER EXPENSES	PRODPLT	403,738	345,976	20,941	36,821	3	36,817	11,488	25,329
46	TOTAL PRODUCTION EXPENSES		750,891,339	650,299,331	34,941,555	65,650,454	3,820	65,646,633	21,318,114	44,328,519

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	OPERATION & MAINT EXP CON'T									
	TRANSMISSION EXPENSES									
1	560-SUPERV & ENGINEERING	LABTROP	1,499,599	1,203,373	172,257	123,969	11	123,959	38,678	85,280
2	561-LOAD DISPATCHING	TRANPLT	2,847,534	2,285,040	327,093	235,400	20	235,380	73,445	161,936
3	562-STATION EXPENSES	TRANPLT	771,551	619,141	88,627	63,783	5	63,777	19,900	43,877
4	563-OVERHEAD LINE EXPENSES	TRANPLT	487,466	391,173	55,995	40,298	3	40,294	12,573	27,722
5	564-UNDERGROUND LINE EXP	TRANPLT	-	-	-	-	-	-	-	-
6	565-TRANSM OF ELECT BY OTH	TRANPLT	2,390,404	1,918,210	274,583	197,610	17	197,593	61,654	135,939
7	566-MISC TRANSMISSION EXP	TRANPLT	12,105,330	9,779,438	1,352,519	973,372	84	973,289	303,691	669,598
8	567-RENTS	TRANPLT	142,847	114,629	16,409	11,809	1	11,808	3,684	8,124
9	575-MISO DAY 1 &2 EXP	TRANPLT	1,397,356	1,224,445	172,877	33	(4)	38	12	26
10	TOTAL TRANSM OPERATIONS		21,642,085	17,535,449	2,460,361	1,646,275	137	1,646,138	513,637	1,132,501
11	568-SUPERV & ENGINEERING	TRANPLT	-	-	-	-	-	-	-	-
12	569-MAINT OF STRUCTURES	TRANPLT	-	-	-	-	-	-	-	-
13	570-MAINT OF STATION EQUIP	TRANPLT	1,954,951	1,568,775	224,563	161,612	14	161,598	50,423	111,176
14	571-MAINT OF OH LINES	TRANPLT	4,660,622	3,755,066	526,586	378,970	33	378,938	118,238	260,699
15	572-MAINT OF UG LINES	TRANPLT	-	-	-	-	-	-	-	-
16	573-MAINT OF MISC TRAN PLT	TRANPLT	680,913	546,407	78,216	56,290	5	56,285	17,562	38,723
17	TOTAL TRANSM MAINTENANCE		7,296,486	5,870,249	829,365	596,872	51	596,821	186,223	410,598
18	TOTAL TRANSMISSION EXPENSES		28,938,571	23,405,698	3,289,726	2,243,147	188	2,242,959	699,860	1,543,099
	DISTRIBUTION EXPENSES									
19	580-SUPERV & ENGINEERING	DISTPLT	2,005,458	1,886,829	112,358	6,272	227	6,045	5,195	850
20	581-DIST SYSTEM CONTROL	PLT3602TOT	762,447	705,213	40,152	17,083	307	16,776	16,776	-
21	582-STATION EXPENSES	PLT3602TOT	1,518,314	1,404,339	79,957	34,019	611	33,408	33,408	-
22	583-OVERHEAD LINES	PLT3645TOT	3,566,081	3,298,413	267,085	583	583	-	-	-
23	584-UNDERGROUND LINES	PLT3667TOT	260,295	255,302	4,993	-	-	-	-	-
24	585-STREET LIGHTING	PLT373TOT	22,470	21,918	552	-	-	-	-	-
25	586-METERS	PLT370TOT	7,762,013	7,329,419	398,103	34,492	12	34,479	7,323	27,156
26	587-CUSTOMER INSTALLATIONS	PLT371TOT	(74,303)	(70,814)	(3,488)	-	-	-	-	-
27	588-MISCELLANEOUS EXP	DISTPLT	5,002,069	4,706,180	280,245	15,644	565	15,078	12,958	2,121
28	589-RENTS	DISTPLT	11,380	10,707	638	36	1	34	29	5
29	TOTAL DISTR OPERATIONS		20,836,225	19,547,506	1,180,592	108,127	2,305	105,822	75,689	30,132
30	590-SUPERV & ENGINEERING	DISTPLT	141,390	133,026	7,921	442	16	426	366	60
31	591-MAINT OF STRUCTURES	PLT3602TOT	-	-	-	-	-	-	-	-
32	592-MAINT OF STATION EQUIP	PLT3602TOT	702,683	649,934	37,004	15,744	283	15,461	15,461	-
33	593-MAINT OF OH LINES	PLT3645TOT	32,306,694	29,856,454	2,446,003	4,237	4,237	-	-	-
34	594-MAINT OF UG LINES	PLT3667TOT	485,649	476,335	9,315	-	-	-	-	-
35	595-MAINT OF LINE TRANSF	PLT368TOT	196,998	187,044	9,594	360	2	358	112	246
36	596-MAINT OF ST LIGHTING	PLT373TOT	-	-	-	-	-	-	-	-
37	597-MAINT OF METERS	PLT370TOT	-	-	-	-	-	-	-	-
38	598-MISCELLANEOUS	DISTPLT	135,084	127,093	7,568	422	15	407	350	57
39	TOTAL DISTR MAINTENANCE		33,968,498	31,429,886	2,517,406	21,206	4,553	16,653	16,289	363
40	TOTAL DISTRIBUTION EXPENSES		54,804,723	50,977,392	3,697,998	129,333	6,859	122,474	91,978	30,496

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	OPERATION & MAINT EXP CON'T									
	CUSTOMER ACCOUNTING EXPENSES									
1	901-SUPERVISION	LABCA	2,728,449	2,581,408	143,646	3,395	26	3,369	1,803	1,566
2	902-METER READING	CUST902	4,920,048	4,654,897	259,029	6,122	46	6,076	3,252	2,824
3	903-CUSTOMER RECORDS	CUST903	14,319,515	13,547,808	753,889	17,818	134	17,684	9,465	8,219
4	904-UNCOLLECTIBLE ACCOUNTS	CUST904	5,413,178	5,121,451	284,991	6,736	51	6,685	3,578	3,107
5	905-MISCELLANEOUS	EXP9024CA	750,345	709,907	39,504	934	7	927	496	431
6	TOTAL CUSTOMER ACCOUNTS		28,131,535	26,615,472	1,481,059	35,004	263	34,741	18,594	16,147
	CUSTOMER SERVICES									
7	907-SUPERVISION	LABSA	205,691	205,546	145	0	0	-	-	-
8	908-CUSTOMER ASSISTANCE	CUST908	13,664,342	13,664,342	-	-	-	-	-	-
9	909-INFORMATION & INSTRUCT	CUST909	157,093	148,605	8,487	1	1	-	-	-
10	910-MISCELLANEOUS	EXP9089CS	417,606	417,350	256	0	0	-	-	-
11	TOTAL CUSTOMER SERVICE		14,444,733	14,435,844	8,888	1	1	-	-	-
	SALES EXPENSE									
12	911-SUPERVISION	LABSA	-	-	-	-	-	-	-	-
13	912-DEMONSTRATING & SELLING	CUST912	-	-	-	-	-	-	-	-
14	913-ADVERTISING	CUST913	23,966	22,672	1,295	0	0	-	-	-
15	916-MISCELLANEOUS	EXP9123SA	-	-	-	-	-	-	-	-
16	TOTAL SALES EXPENSE		23,966	22,672	1,295	0	0	-	-	-
	ADMINISTRATIVE & GENERAL									
	PLANT COMPONENT									
17	924-PROPERTY INSURANCE	PLANT	4,275,705	3,722,836	253,951	298,919	135	298,784	94,867	203,917
18	TOTAL NET PLT COMPONENT		4,275,705	3,722,836	253,951	298,919	135	298,784	94,867	203,917
	LABOR COMPONENT									
19	920-ADMIN & GENERAL EXP	LABOR	21,838,736	19,422,909	1,196,610	1,219,217	670	1,218,547	395,860	822,686
20	921-OFFICE SUPPLIES & EXP	LABOR	7,450,944	6,626,712	408,259	415,973	229	415,744	135,060	280,684
21	922-ADMIN EXP TRANSF-CRED	LABOR	(2,900,745)	(2,579,862)	(158,941)	(161,943)	(89)	(161,854)	(52,580)	(109,274)
22	923-OUTSIDE SERVICES	LABOR	8,857,900	7,878,029	485,351	494,521	272	494,249	160,563	333,686
23	925-INJURIES & DAMAGES	LABOR	3,560,504	3,166,637	195,091	198,776	109	198,667	64,540	134,128
24	926-PENSIONS & BENEFITS	LABOR	39,264,089	35,853,084	2,208,842	1,202,163	1,238	1,200,925	390,136	810,790
25	929-DUPLICATE CHARGES-CR	REVNJVA	(3,752)	-	(3,752)	-	-	-	-	-
26	930-MISC GENERAL EXPENSE	LABOR	2,489,747	2,251,157	118,178	120,411	66	120,345	39,096	81,249
27	931-RENTS	LABOR	2,376,358	2,113,482	130,208	132,668	73	132,595	43,075	89,520
28	935-MAINTENANCE	LABOR	13,215,869	11,753,914	724,137	737,818	406	737,412	239,558	497,855
29	TOTAL LABOR COMPONENT		96,149,650	86,486,064	5,303,983	4,359,603	2,974	4,356,629	1,415,306	2,941,324
	928-REGULATORY COMMISSION									
30	STATE JURISDICTION	DIRECT	1,093,702	1,093,702	-	-	-	-	-	-
31	FEDERAL JURISDICTION	REVFERC	18,040	-	-	18,040	-	18,040	5,844	12,195
32	VIRGINIA JURISDICTION	REVVA	225,118	-	225,118	-	-	-	-	-
33	928 ALLOCATED	ENERGY	463,891	402,456	21,280	40,155	2	40,153	13,108	27,045
34	TOTAL ACCOUNT 928		1,800,751	1,496,158	246,398	58,194	2	58,192	18,952	39,240
35	927-FRANCHISE NJ VA	REVNJVA	3,752	-	3,752	-	-	-	-	-
36	930-ASSOC DUES & ADVERTISING	ENERGY1	1,396,664	1,326,518	70,139	7	7	-	-	-
37	TOTAL ADMINISTRATIVE & GEN		103,626,523	93,031,576	5,878,223	4,716,724	3,118	4,713,605	1,529,125	3,184,481
38	TOTAL OPERATION & MAINTENANCE		980,861,389	858,787,983	49,298,744	72,774,663	14,250	72,760,413	23,657,671	49,102,742

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	DEPRECIATION & AMORT EXPENSE									
	DEPRECIATION EXPENSE									
	PRODUCTION PLANT									
	STEAM PRODUCTION PLANT									
1	SYSTEM	STMSYS	113,654,364	98,366,735	5,776,786	9,510,842	870	9,509,973	2,967,353	6,542,620
2	FERC-AFUDC PRE	DEMFERC	422,038	-	159,486	262,552	-	262,552	81,923	180,629
3	FERC-AFUDC POST	DEMFERCP	755,124	-	-	755,124	-	755,124	235,618	519,506
4	TOTAL STEAM PROD PLT		114,831,526	98,366,735	5,936,272	10,528,518	870	10,527,648	3,284,893	7,242,755
	HYDRAULIC PRODUCTION PLANT									
5	SYSTEM	HYDSYS	150,128	129,934	7,631	12,563	1	12,562	3,920	8,642
6	FERC-AFUDC PRE	DEMFERC	6	-	2	4	-	4	1	3
7	FERC-AFUDC POST	DEMFERCP	414	-	-	414	-	414	129	285
8	TOTAL HYDRO PROD PLT		150,548	129,934	7,633	12,981	1	12,980	4,050	8,930
	OTHER PRODUCTION PLANT									
9	SYSTEM	OTHSYS	17,257,381	14,936,094	877,152	1,444,135	132	1,444,003	450,566	993,437
10	FERC-AFUDC PRE	DEMFERC	59	-	22	37	-	37	11	25
11	FERC-AFUDC POST	DEMFERCP	69,979	-	-	69,979	-	69,979	21,835	48,144
12	TOTAL OTHER PROD PLT		17,327,419	14,936,094	877,175	1,514,151	132	1,514,019	472,412	1,041,606
13	TOTAL PRODUCTION PLANT		132,309,492	113,432,763	6,821,080	12,055,650	1,003	12,054,647	3,761,356	8,293,291
	TRANSMISSION PLANT									
14	KENTUCKY SYSTEM PROPERTY	KYTRPLT	10,659,468	9,156,938	558,454	944,075	81	943,994	294,550	649,444
15	VIRGINIA PROPERTY	TRPLTVA	937,293	133,401	790,913	12,979	1	12,978	4,049	8,928
17	FERC-AFUDC PRE	DEMFERCT	56,873	-	21,492	35,381	-	35,381	11,040	24,341
18	FERC-AFUDC POST	DFERCTP	25,528	-	-	25,528	-	25,528	7,965	17,562
19	TOTAL TRANSMISSION PLANT		11,679,161	9,290,339	1,370,859	1,017,962	82	1,017,880	317,604	700,276
	DISTRIBUTION PLANT									
20	DISTRIBUTION-KENTUCKY	KYDIST	32,848,142	32,743,234	-	104,908	-	104,908	90,152	14,756
21	DISTRIBUTION-VIRGINIA	VADIST	1,439,882	-	1,439,882	-	-	-	-	-
22	DISTRIBUTION-TENNESSEE	TNDIST	2,258	-	-	2,258	2,258	-	-	-
23	TOTAL DISTRIBUTION PLANT		34,290,283	32,743,234	1,439,882	107,167	2,258	104,908	90,152	14,756
24	GENERAL PLANT	GENPLT	6,408,658	5,699,724	351,149	357,784	197	357,587	116,167	241,420
25	INTANGIBLE PLANT-SOFTWARE	PLT303TOT	7,505,149	6,534,688	445,765	524,696	237	524,460	166,522	357,938
26	INTANGIBLE PLANT-FRANCHISES	PLT302TOT	-	-	-	-	-	-	-	-
27	TOTAL DEPREC & AMORT EXP		192,192,743	167,700,749	10,428,736	14,063,259	3,777	14,059,482	4,451,801	9,607,681

KENTUCKY UTILITIES COMPANY
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		ALLOC	TOTAL KENTUCKY UTILITIES (1)	KENTUCKY STATE JURISDICTION (2)	VIRGINIA STATE JURISDICTION (3)	FERC & TENNESSEE JURISDICTION (4)	TENNESSEE STATE JURISDICTION (5)	FERC JURISDICTION (6)	PRIMARY (7)	TRANSMISSION (8)
	REGULATORY CREDITS AND ACCRETION									
	REGULATORY CREDITS									
	PRODUCTION PLANT									
1	STEAM PRODUCTION PLANT	STMSYS	(5,958,724)	(5,157,217)	(302,868)	(498,639)	(46)	(498,593)	(155,574)	(343,020)
2	HYDRAULIC PRODUCTION PLANT	HYDSYS	-	-	-	-	-	-	-	-
3	OTHER PRODUCTION PLANT	OTHSYS	-	-	-	-	-	-	-	-
4	TOTAL PRODUCTION PLANT		(5,958,724)	(5,157,217)	(302,868)	(498,639)	(46)	(498,593)	(155,574)	(343,020)
	TRANSMISSION PLANT									
5	KENTUCKY SYSTEM PROPERTY	KYTRPLT	(17,452)	(14,992)	(914)	(1,546)	(0)	(1,546)	(482)	(1,063)
6	VIRGINIA PROPERTY	TRPLTVA	-	-	-	-	-	-	-	-
7	TOTAL TRANSMISSION PLANT		(17,452)	(14,992)	(914)	(1,546)	(0)	(1,546)	(482)	(1,063)
	DISTRIBUTION PLANT									
8	KENTUCKY DISTRIBUTION PROPERTY	KYDIST	(35,678)	(35,564)	-	(114)	-	(114)	(98)	(16)
9	VIRGINIA DISTRIBUTION PROPERTY	VADIST	-	-	-	-	-	-	-	-
10	TOTAL DISTRIBUTION PLANT		(35,678)	(35,564)	-	(114)	-	(114)	(98)	(16)
11	TOTAL REGULATORY CREDITS		(6,011,854)	(5,207,773)	(303,782)	(500,299)	(46)	(500,253)	(156,154)	(344,099)
	ACCRETION									
	PRODUCTION PLANT									
12	STEAM PRODUCTION PLANT	STMSYS	2,899,713	2,509,673	147,386	242,654	22	242,632	75,707	166,925
13	HYDRAULIC PRODUCTION PLANT	HYDSYS	-	-	-	-	-	-	-	-
14	OTHER PRODUCTION PLANT	OTHSYS	-	-	-	-	-	-	-	-
15	TOTAL PRODUCTION PLANT		2,899,713	2,509,673	147,386	242,654	22	242,632	75,707	166,925
	TRANSMISSION PLANT									
16	KENTUCKY SYSTEM PROPERTY	KYTRPLT	11,162	9,589	585	989	0	988	308	680
17	VIRGINIA PROPERTY	TRPLTVA	-	-	-	-	-	-	-	-
18	TOTAL TRANSMISSION PLANT		11,162	9,589	585	989	0	988	308	680
	DISTRIBUTION PLANT									
19	KENTUCKY SYSTEM PROPERTY	KYDIST	23,234	23,160	-	74	-	74	64	10
20	VIRGINIA PROPERTY	DPLTXVA	-	-	-	-	-	-	-	-
21	TOTAL DISTRIBUTION PLANT		23,234	23,160	-	74	-	74	64	10
22	TOTAL ACCRETION EXPENSE		2,934,109	2,542,421	147,970	243,717	22	243,695	76,080	167,615

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OTHER TAXES & OTHER EXPENSES									
TAXES OTHER THAN INCOME TAX									
1 PROPERTY TAXES	NETPLANT	19,442,861	17,000,077	1,078,544	1,364,239	229	1,364,011	432,862	931,149
2 PSC ASSESSMENT-KY REVENUE	REVKY	1,985,994	1,985,994	-	-	-	-	-	-
3 VA GROSS RECEIPTS TAX	REVVA	-	-	-	-	-	-	-	-
4 UNEMPLOYMENT	LABOR	247,951	220,522	13,586	13,843	8	13,835	4,494	9,341
5 FICA	LABOR	7,372,339	6,556,802	403,952	411,584	226	411,358	133,635	277,723
6 MISCELLANEOUS	PLANT	94,929	82,654	5,638	6,637	3	6,634	2,106	4,527
7 TOTAL OTHER TAXES		29,144,074	25,846,050	1,501,721	1,796,303	465	1,795,837	573,098	1,222,740
8 GAIN DISPOSITION OF ALLOWANCES	DEMPROD	(887)	(767)	(45)	(74)	(0)	(74)	(23)	(51)
9 GAIN/LOSS PROP DISPOSITION (NET)	PLANT	(44,239)	-	(2,628)	-	-	-	-	-
10 CHARITABLE CONTRIBUTIONS-VA ONLY	LABOR	734,837	-	20,132	-	-	-	-	-
203(E) EXCESS									
11 PRODUCTION PLANT	PRODSYS	(853,975)	(739,107)	(43,406)	(71,462)	(7)	(71,456)	(22,296)	(49,160)
TRANSMISSION PLANT									
12 KENTUCKY SYSTEM PROPERTY	KYTRPLT	(97,112)	(83,423)	(5,088)	(8,601)	(1)	(8,600)	(2,683)	(5,917)
13 VIRGINIA PROPERTY	TRPLTVA	(7,904)	(1,125)	(6,670)	(109)	(0)	(109)	(34)	(75)
14 TOTAL TRANSMISSION PLANT		(105,016)	(84,548)	(11,757)	(8,710)	(1)	(8,710)	(2,718)	(5,992)
15 DISTRIBUTION - VA	DIR203E	(13,424)	-	(13,424)	-	-	-	-	-
16 DISTRIBUTION PLT KY,FERC & TN	DPLTXVA	(257,793)	(256,939)	-	(854)	(31)	(823)	(707)	(116)
17 GENERAL	GENPLT	(26,349)	(23,434)	(1,444)	(1,471)	(1)	(1,470)	(478)	(993)
18 TOTAL 203(E) EXCESS		(1,256,557)	(1,104,028)	(70,031)	(82,498)	(39)	(82,459)	(26,199)	(56,260)
INVESTMENT TAX CREDIT ADJ									
19 PRODUCTION	PRODPLT	-	-	-	-	-	-	-	-
20 TRANSMISSION	TRANPLTX	-	-	-	-	-	-	-	-
21 TRANSMISSION VA	TRPLTVA	-	-	-	-	-	-	-	-
22 DISTRIBUTION - DIRECT	DIRITCADJ	-	-	-	-	-	-	-	-
23 DISTRIBUTION PLT KY,FERC & TN	DPLTXVA	-	-	-	-	-	-	-	-
24 GENERAL	GENPLT	-	-	-	-	-	-	-	-
25 TOTAL INVEST TAX CREDIT ADJ		-	-	-	-	-	-	-	-
26 TOTAL EXP OTHER THAN INC TAX		1,199,119,574	1,049,668,662	61,073,343	88,377,569	18,469	88,359,100	28,602,472	59,756,628

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INCOME TAXES									
1 OPERATING INC BEFORE INC TAXES		322,916,383	292,408,257	14,743,216	15,764,909	(11,806)	15,776,715	5,051,970	10,724,745
DEVELOPMENT OF FED INC TAX									
ADDITIONS TO INCOME									
2									
3									
4 TOTAL ADDITIONS		-	-	-	-	-	-	-	-
DEDUCTIONS FROM INCOME									
INTEREST EXPENSE									
5 LONG TERM DEBT OTHER	RATEBASE	68,412,281	59,882,590	3,652,287	4,877,404	638	4,876,766	1,548,863	3,327,902
6 INT ON CUSTOMER DEPOSITS	CUSTDEPI	-	-	1,719	-	-	-	-	-
7 AFUDC-INTEREST POST FERC	AFUDC	(13,892)	-	-	(13,892)	-	(13,892)	(4,335)	(9,557)
8 TOTAL DEDUCTIONS		68,398,389	59,882,590	3,654,006	4,863,512	638	4,862,874	1,544,528	3,318,345
PLUS: ABOVE THE LINE DIFF:									
9 SEC. 199 DEDUCTION-STATE	STMSYS	(3,773,628)	(3,266,038)	(191,805)	(315,785)	(29)	(315,756)	(98,524)	(217,232)
10 DEPREC-EQUITY AFUDC PRE	DEMFERC	219,243	-	82,851	136,392	-	136,392	42,558	93,834
11 DEPREC-EQUITY AFUDC POST	DEMFERCP	785,220	-	-	785,220	-	785,220	245,009	540,211
12 OTHER	RATEBASE	137,097	120,004	7,319	9,774	1	9,773	3,104	6,669
13 TOTAL PERMANENT DIFFERENCES		(2,632,068)	(3,146,034)	(101,635)	615,601	(28)	615,629	192,146	423,482
14 STATE TAXABLE INCOME		251,885,926	229,379,633	10,987,575	11,516,998	(12,472)	11,529,470	3,699,588	7,829,882
15 APPORTIONED STATE TAXABLE INCOME		251,885,926	229,379,633	9,863,125	11,516,998	(12,472)	11,529,470	3,699,588	7,829,882
16 STATE TAX		15,113,156	13,762,778	591,787	691,020	(748)	691,768	221,975	469,793
17 STATE TAX TRUE-UP AND ADJ	RATEBASE	(194,310)	(170,083)	(10,374)	(13,853)	(2)	(13,851)	(4,399)	(9,452)
18 203(E) EXCESS-STATE	KYRATEBASE	(148,917)	(137,702)	-	(11,215)	-	(11,215)	(3,562)	(7,653)
19 KY COAL TAX CREDIT	KYRATEBASE	(1,773,106)	(1,639,580)	-	(133,526)	-	(133,526)	(42,408)	(91,118)
20 STATE TAX TOTAL		12,996,823	11,815,413	581,413	532,426	(750)	533,176	171,606	361,570
21 SEC. 199 DEDUCTION-FEDERAL INCREMENT	STMSYS	3,803,487	3,291,881	193,322	318,284	29	318,255	99,304	218,951
22 STATE TAX ADJUSTS FOR FEDERAL	RATEBASE	-	-	-	-	-	-	-	-
23 FEDERAL TAXABLE INCOME (LINE 14-20-21)		242,692,590	220,856,101	10,599,484	11,302,856	(11,693)	11,314,549	3,627,286	7,687,263
24 FEDERAL TAXES @ 35%		84,942,407	77,299,635	3,709,819	3,956,000	(4,092)	3,960,092	1,269,550	2,690,542
25 EXCESS DEFERRED TAXES	RATEBASE	-	-	-	-	-	-	-	-
26 203(E) EXCESS-FEDERAL	RATEBASE	(515,496)	(451,224)	(27,520)	(36,752)	(5)	(36,747)	(11,671)	(25,076)
27 INVESTMENT TAX CREDIT ADJ		-	-	-	-	-	-	-	-
28 FEDERAL TAX TRUE-UP AND ADJ	RATEBASE	1,137,311	995,510	60,717	81,084	11	81,073	25,749	55,324
29 FEDERAL TAX TOTAL		85,564,222	77,843,921	3,743,016	4,000,332	(4,086)	4,004,418	1,283,628	2,720,790
30 RETURN		224,355,338	202,748,924	10,418,786	11,232,151	(6,969)	11,239,121	3,596,735	7,642,385
31 RATE OF RETURN		5.6410%	5.7106%	4.8115%	3.8842%	-18.4152%	3.8871%	3.9167%	3.8733%
STATE TAX RATE		0.06000	0.06000	0.06000	0.06000	0.06000	0.06000	0.06000	0.06000
FEDERAL TAX RATE - CURRENT		0.35000	0.35000	0.35000	0.35000	0.35000	0.35000	0.35000	0.35000
1 - EFFECTIVE TAX RATE		0.61100	0.61100	0.61100	0.61100	0.61100	0.61100	0.61100	0.61100
EFFECTIVE TAX RATE		0.38900	0.38900	0.38900	0.38900	0.38900	0.38900	0.38900	0.38900
FACTOR FOR TAXABLE BASIS		1.63666	1.63666	1.63666	1.63666	1.63666	1.63666	1.63666	1.63666

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	LABOR ALLOCATOR									
	LABOR EXPENSE									
	PRODUCTION LABOR									
	ENERGY RELATED									
1	FERC 501	ENERGY	3,499,087	3,035,692	160,510	302,885	17	302,868	98,870	203,998
2	FERC 510	ENERGY	6,556,679	5,688,357	300,768	567,553	31	567,522	185,266	382,256
3	FERC 512	ENERGY	9,034,370	7,837,920	414,425	782,025	43	781,982	255,275	526,706
4	FERC 513	ENERGY	2,257,568	1,958,591	103,559	195,417	11	195,407	63,790	131,617
5	FERC 547	ENERGY	-	-	-	-	-	-	-	-
6	TOTAL ENERGY LABOR		21,347,704	18,520,561	979,263	1,847,880	102	1,847,778	603,201	1,244,577
	DEMAND RELATED									
7	FERC 500	PRODPLT	4,888,804	4,189,374	253,575	445,854	37	445,817	139,106	306,711
8	FERC 502	PRODPLT	9,216,023	7,897,509	478,021	840,493	70	840,423	262,233	578,190
9	FERC 505	PRODPLT	6,422,403	5,503,565	333,120	585,717	49	585,669	182,743	402,925
10	FERC 506	PRODPLT	1,529,894	1,311,016	79,353	139,525	12	139,513	43,532	95,982
11	FERC 509	PRODPLT	-	-	-	-	-	-	-	-
12	FERC 511	PRODPLT	1,154,804	989,589	59,898	105,317	9	105,308	32,859	72,449
13	FERC 514	PRODPLT	224,144	192,076	11,626	20,442	2	20,440	6,378	14,062
14	FERC 535	PRODPLT	7,944	6,807	412	724	0	724	226	498
15	FERC 538	PRODPLT	-	-	-	-	-	-	-	-
16	FERC 539	PRODPLT	5,362	4,595	278	489	0	489	153	336
17	FERC 541	PRODPLT	108,732	93,176	5,640	9,916	1	9,915	3,094	6,822
18	FERC 542	PRODPLT	22,546	19,320	1,169	2,056	0	2,056	642	1,414
19	FERC 544	PRODPLT	53,550	45,888	2,778	4,884	0	4,883	1,524	3,360
20	FERC 545	PRODPLT	3,544	3,037	184	323	0	323	101	222
21	FERC 546	PRODPLT	202,549	173,570	10,506	18,472	2	18,471	5,763	12,707
22	FERC 548	PRODPLT	241,293	206,772	12,516	22,006	2	22,004	6,866	15,138
23	FERC 549	PRODPLT	21,446	18,378	1,112	1,956	0	1,956	610	1,345
24	FERC 550	PRODPLT	-	-	-	-	-	-	-	-
25	FERC 551	PRODPLT	41,773	35,796	2,167	3,810	0	3,809	1,189	2,621
26	FERC 552	PRODPLT	130,669	111,975	6,778	11,917	1	11,916	3,718	8,198
27	FERC 553	PRODPLT	637,281	546,106	33,055	58,119	5	58,115	18,133	39,981
28	FERC 554	PRODPLT	87,476	74,961	4,537	7,978	1	7,977	2,489	5,488
29	FERC 555	PRODPLT	-	-	-	-	-	-	-	-
30	FERC 556	PRODPLT	1,721,353	1,475,083	89,284	156,986	13	156,973	48,979	107,993
31	FERC 557	PRODPLT	0	0	0	0	0	0	0	0
32	TOTAL DEMAND		26,721,588	22,898,595	1,386,009	2,436,985	202	2,436,782	760,338	1,676,444
33	TOTAL PRODUCTION		48,069,292	41,419,155	2,365,272	4,284,865	304	4,284,560	1,363,539	2,921,022

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	TRANSMISSION LABOR									
1	FERC 560	TRANPLT	1,303,428	1,045,952	149,723	107,752	9	107,743	33,618	74,124
2	FERC 561	TRANPLT	2,653,387	2,129,244	304,792	219,351	19	219,332	68,437	150,895
3	FERC 562	TRANPLT	334,610	268,512	38,436	27,662	2	27,659	8,630	19,029
4	FERC 563	TRANPLT	69,428	55,713	7,975	5,739	0	5,739	1,791	3,948
5	FERC 565	TRANPLT	-	-	-	-	-	-	-	-
6	FERC 566	TRANPLT	417,945	335,386	48,009	34,551	3	34,548	10,780	23,768
7	FERC 567	TRANPLT	-	-	-	-	-	-	-	-
8	FERC 569	TRANPLT	-	-	-	-	-	-	-	-
9	FERC 570	TRANPLT	696,734	559,103	80,033	57,598	5	57,593	17,970	39,622
10	FERC 571	TRANPLT	220,635	177,051	25,344	18,239	2	18,238	5,691	12,547
11	FERC 572	TRANPLT	-	-	-	-	-	-	-	-
12	FERC 573	TRANPLT	109,871	88,167	12,621	9,083	1	9,082	2,834	6,248
13	TOTAL TRANSMISSION LABOR	TRANPLT	5,806,037	4,659,129	666,934	479,975	41	479,933	149,751	330,182
	DISTRIBUTION LABOR									
1	FERC 580	DISTPLT	1,376,759	1,295,320	77,134	4,306	156	4,150	3,566	584
2	FERC 581	DISTPLT	762,447	717,346	42,717	2,385	86	2,298	1,975	323
3	FERC 582	DISTPLT	803,769	756,223	45,032	2,514	91	2,423	2,082	341
4	FERC 583	DISTPLT	1,689,770	1,589,814	94,671	5,285	191	5,094	4,377	716
5	FERC 584	DISTPLT	101,764	95,744	5,701	318	12	307	264	43
6	FERC 585	DISTPLT	2,664	2,507	149	8	0	8	7	1
7	FERC 586	DISTPLT	4,583,824	4,312,676	256,813	14,336	518	13,818	11,874	1,944
8	FERC 587	DISTPLT	1,733	1,631	97	5	0	5	4	1
9	FERC 588	DISTPLT	2,781,962	2,617,399	155,862	8,700	314	8,386	7,206	1,180
10	FERC 589	DISTPLT	-	-	-	-	-	-	-	-
11	FERC 590	DISTPLT	89,122	83,850	4,993	279	10	269	231	38
13	FERC 592	DISTPLT	350,791	330,041	19,653	1,097	40	1,057	909	149
14	FERC 593	DISTPLT	6,644,012	6,250,997	372,236	20,779	751	20,028	17,211	2,817
15	FERC 594	DISTPLT	178,370	167,819	9,993	558	20	538	462	76
16	FERC 595	DISTPLT	72,638	68,342	4,070	227	8	219	188	31
17	FERC 596	DISTPLT	-	-	-	-	-	-	-	-
18	FERC 597	DISTPLT	-	-	-	-	-	-	-	-
19	FERC 598	DISTPLT	70,556	66,382	3,953	221	8	213	183	30
20	TOTAL DISTRIBUTION LABOR	DISTPLT	19,510,181	18,356,090	1,093,075	61,017	2,205	58,812	50,540	8,272
21	TOT PROD, TRNS & DISTR LABOR		73,385,511	64,434,374	4,125,280	4,825,857	2,550	4,823,306	1,563,830	3,259,476

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ALLOCATION METHOD: AVG 12 CP (COMBINED CO SYS)

12 MONTHS ENDING MARCH 31, 2012

		ALLOC	TOTAL KENTUCKY UTILITIES (1)	KENTUCKY STATE JURISDICTION (2)	VIRGINIA STATE JURISDICTION (3)	FERC & TENNESSEE JURISDICTION (4)	TENNESSEE STATE JURISDICTION (5)	FERC JURISDICTION (6)	PRIMARY (7)	TRANSMISSION (8)
	CUSTOMER ACCOUNTING									
1	FERC 901	EXP9025CA	2,455,747	2,323,402	129,289	3,056	23	3,033	1,623	1,410
2	FERC 902	EXP9025CA	285,949	270,538	15,055	356	3	353	189	164
3	FERC 903	EXP9025CA	8,670,690	8,203,410	456,491	10,789	81	10,708	5,731	4,977
4	FERC 904	EXP9025CA	-	-	-	-	-	-	-	-
5	FERC 905	EXP9025CA	450,527	426,247	23,719	561	4	556	298	259
6	TOTAL CUSTOMER ACCOUNTING LABOR		11,862,913	11,223,597	624,554	14,761	111	14,650	7,841	6,809
	CUSTOMER SERVICE & SALES EXP									
7	FERC 907	EXP9080CS	180,508	180,381	127	0	0	-	-	-
8	FERC 908	EXP9080CS	1,276,694	1,275,796	898	0	0	-	-	-
9	FERC 909	EXP9080CS	-	-	-	-	-	-	-	-
10	FERC 910	EXP9080CS	-	-	-	-	-	-	-	-
11	FERC 912	EXP9080CS	-	-	-	-	-	-	-	-
12	FERC 913	EXP9080CS	-	-	-	-	-	-	-	-
13	FERC 916	EXP9080CS	-	-	-	-	-	-	-	-
14	TOTAL CUSTOMER SERVICE AND SALES LABOR		1,457,202	1,456,176	1,026	0	0	-	-	-
15	TOTAL PROD, TRAN, DIST, CUSTOMER LABOR		86,705,626	77,114,148	4,750,860	4,840,618	2,662	4,837,956	1,571,671	3,266,285
	ADMIN & GENERAL LABOR									
16	FERC 920	PTDCUSTLABOR	21,837,389	19,421,711	1,196,536	1,219,142	670	1,218,471	395,836	822,636
17	FERC 921	PTDCUSTLABOR	38,925	34,619	2,133	2,173	1	2,172	706	1,466
18	FERC 922	PTDCUSTLABOR	(2,118,579)	(1,884,219)	(116,083)	(118,276)	(65)	(118,211)	(38,402)	(79,809)
19	FERC 923	PTDCUSTLABOR	-	-	-	-	-	-	-	-
20	FERC 924	PTDCUSTLABOR	-	-	-	-	-	-	-	-
21	FERC 925	PTDCUSTLABOR	894,372	795,436	49,005	49,931	27	49,904	16,212	33,692
22	FERC 926	PTDCUSTLABOR	39,264,089	34,920,650	2,151,397	2,192,043	1,205	2,190,838	711,721	1,479,116
23	FERC 927	PTDCUSTLABOR	-	-	-	-	-	-	-	-
24	FERC 929	PTDCUSTLABOR	-	-	-	-	-	-	-	-
25	FERC 930	PTDCUSTLABOR	34,853	30,997	1,910	1,946	1	1,945	632	1,313
26	FERC 931	PTDCUSTLABOR	-	-	-	-	-	-	-	-
27	FERC 935	PTDCUSTLABOR	5,695,280	5,065,262	312,061	317,957	175	317,782	103,236	214,547
28	TOTAL ADMIN & GENERAL LABOR		65,646,330	58,384,456	3,596,958	3,664,916	2,015	3,662,900	1,189,939	2,472,961
29	TOTAL LABOR EXPENSES		152,351,955	135,498,603	8,347,819	8,505,534	4,677	8,500,857	2,761,610	5,739,247

KENTUCKY UTILITIES COMPANY
ELECTRIC COST OF SERVICE STUDY
JURISDICTIONAL SEPARATION

RATE BASE: END OF YEAR
ALLOCATION METHOD: AVG 12 CP (COMBINED CO SYS)

12 MONTHS ENDING MARCH 31, 2012

	ALLOC	TOTAL KENTUCKY UTILITIES (1)	KENTUCKY STATE JURISDICTION (2)	VIRGINIA STATE JURISDICTION (3)	FERC & TENNESSEE JURISDICTION (4)	TENNESSEE STATE JURISDICTION (5)	FERC JURISDICTION (6)	PRIMARY (7)	TRANSMISSION (8)
ALLOCATION FACTOR TABLE									
DEMAND RELATED									
-									
PRODUCTION ALLOCATORS							0-Jan-00		
1 DEMAND (12 CP GEN LEV)-PROD	DEMPROD	3,658,952	3,166,787	185,976	306,189	28	306,161	95,530	210,631
2 DEMAND (12 CP GEN LEV)-FERC	DEMFERC	492,137	-	185,976	306,161	-	306,161	95,530	210,631
3 DEMAND (12 CP GEN)-PROD VA	DPRODVA	185,976	-	185,976	-	-	-	-	-
4 DEMAND (12 CP GEN)-PROD KY	DPRODKY	3,472,948	3,166,787	-	306,161	-	306,161	95,530	210,631
5 DEM (12 CP GEN LV)-FERC POST	DEMFERCP	306,161	-	-	306,161	-	306,161	95,530	210,631
6 DEM (12 CP GEN LV)-NON VA	DEMPRODNV	3,472,976	3,166,787	-	306,189	28	306,161	95,530	210,631
TRANSMISSION ALLOCATORS									
7 DEMAND (12 CP GEN LEV)-TRAN	DEMTRAN	3,658,952	3,166,787	185,976	306,189	28	306,161	95,530	210,631
8 DEMAND (12 CP GEN LEV)-VA	DEMVA	185,976	-	185,976	-	-	-	-	-
9 DEM (12 CP GEN LEV)-NON FERC	DEMTRANNF	3,352,791	3,166,787	185,976	28	28	-	-	-
10 DEM (12 CP GN LEV)-TRAN FERC	DEMFERCT	492,137	-	185,976	306,161	-	306,161	95,530	210,631
11 DEM (12 CP GN)-TR FERC POST	DFERCTP	306,161	-	-	306,161	-	306,161	95,530	210,631
DISTRIBUTION ALLOCATORS									
12 DIRECT ASSIGN 360 KY	DEM360K	5,112,550	5,103,392	-	9,158	-	9,158	9,158	-
13 DIRECT ASSIGN 361 KY	DEM361K	7,214,275	6,940,989	-	273,286	-	273,286	273,286	-
14 DIRECT ASSIGN 362 KY	DEM362K	137,609,926	134,408,400	-	3,201,526	-	3,201,526	3,201,526	-
15 DIRECT ASSIGN 364 KY	DEM364K	273,798,351	273,798,351	-	-	-	-	-	-
16 DIRECT ASSIGN 365 KY	DEM365K	263,336,954	263,336,954	-	-	-	-	-	-
17 DIRECT ASSIGN 366 KY	DEM366K	1,831,865	1,831,865	-	-	-	-	-	-
18 DIRECT ASSIGN 367 KY	DEM367K	139,509,219	139,509,219	-	-	-	-	-	-
19 DIRECT ASSIGN 368 KY	DEM368K	273,917,337	273,917,337	-	-	-	-	-	-
20 DIRECT ASSIGN 374 KY	DEM374K	287,376	287,376	-	-	-	-	-	-
21 DIRECT ASSIGN 360-VA	DEM360V	193,250	-	193,250	-	-	-	-	-
22 DIRECT ASSIGN 361-VA	DEM361V	448,174	-	448,174	-	-	-	-	-
23 DIRECT ASSIGN 362-VA	DEM362V	7,696,928	-	7,696,928	-	-	-	-	-
24 DIRECT ASSIGN 360-362-FERC VA	DIR3602V	-	-	-	-	-	-	-	-
25 DIRECT ASSIGN 364-VA	DEM364V	23,371,899	-	23,371,899	-	-	-	-	-
26 DIRECT ASSIGN 365-VA	DEM365V	20,121,983	-	20,121,983	-	-	-	-	-
27 DIRECT ASSIGN 367-VA	DEM367V	2,763,964	-	2,763,964	-	-	-	-	-
28 DIRECT ASSIGN 368-VA	DEM368V	14,023,456	-	14,023,456	-	-	-	-	-
29 DIRECT ASSIGN 360-TN	DEM360T	5,040	-	-	5,040	5,040	-	-	-
30 DIRECT ASSIGN 361-TN	DEM361T	2,621	-	-	2,621	2,621	-	-	-
31 DIRECT ASSIGN 362-TN	DEM362T	56,020	-	-	56,020	56,020	-	-	-
32 DIRECT ASSIGN 364-TN	DEM364T	48,114	-	-	48,114	48,114	-	-	-
33 DIRECT ASSIGN 365-TN	DEM365T	46,763	-	-	46,763	46,763	-	-	-
34 DIRECT ASSIGN 368-TN	DEM368T	3,118	-	-	3,118	3,118	-	-	-
35 DIRECT ASSIGN 369-TN	CUST369T	255	-	-	255	255	-	-	-
36 DIRECT ASSIGN 370-TN	CUST370T	111	-	-	111	111	-	-	-
37 DIRECT ASSIGN 371-TN	CUST371T	-	-	-	-	-	-	-	-
38 DIR ASSIGN ACC.DEPRC.DIST.VA&TN	DIRACDEP	37,401,886	-	37,260,617	141,269	141,269	-	-	-
39 DIR ASSIGN CWIP DIST VA & TN	DIRCWIP	1,166,386	-	1,166,386	-	-	-	-	-
40 DIR ASSIGN ACC.DFDTX.DIST.VA&TN	DIRACDFTX	5,364,985	-	5,364,985	-	-	-	-	-
41 DIR ASSIGN ACC.ITC.DIST.VA & TN	DIRACITC	-	-	-	-	-	-	-	-
42 DIR ASSIGN RENT REVENUE	DIR454REV	2,338,708	2,153,990	184,359	359	359	-	-	-
43 DIR ASSIGN EXCESS FACILITIES REV.	DIR456FAC	15,192	14,277	916	-	-	-	-	-
44 DIR ASSIGN OTHER MISC REV.	DIR456OTH	22,525	22,525	-	-	-	-	-	-
45 DIR ASSIGN RECONNECT REV	DIR451REC	1,791,597	1,659,613	131,985	-	-	-	-	-
46 DIR ASSIGN OTHER SERVICE REV	DIR451OTH	559,380	547,024	12,355	-	-	-	-	-
47 DIR ASSIGN RETURN CHECK REV	DIR456CHK	139,732	130,862	8,870	-	-	-	-	-
48 DIR ASSIGN 203(E) EXCESS	DIR203E	21,847	-	21,847	-	-	-	-	-
49 DIR ASSIGN ITC ADJ	DIRITCADJ	-	-	-	-	-	-	-	-
50 DIR ASSIGN DEFERRED FUEL-VIRGINIA	DFUELVA	(2,824,747)	-	(2,824,747)	-	-	-	-	-

KENTUCKY UTILITIES COMPANY
ELECTRIC COST OF SERVICE STUDY
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12 MONTHS ENDING MARCH 31, 2012

	ALLOC	TOTAL KENTUCKY UTILITIES (1)	KENTUCKY STATE JURISDICTION (2)	VIRGINIA STATE JURISDICTION (3)	FERC & TENNESSEE JURISDICTION (4)	TENNESSEE STATE JURISDICTION (5)	FERC JURISDICTION (6)	PRIMARY (7)	TRANSMISSION (8)
ENERGY									
-									
1 ENERGY (MWH AT GEN LEVEL)	ENERGY	21,597,286	18,737,090	990,712	1,869,484	103	1,869,381	610,253	1,259,128
2 ENERGY (MWH RETAIL @ GEN LEVEL)	ENERGY1	19,727,905	18,737,090	990,712	103	103	-	-	-
3									
4									
CUSTOMER									
-									
1 DIRECT ASSIGN 369-SERV KY	CUST369K	84,507,618	84,507,618	-	-	-	-	-	-
2 DIRECT ASSIGN 370 METERS KY	CUST370K	67,284,795	66,969,753	-	315,042	-	315,042	66,911	248,131
3 DIRECT ASSIGN 371 CUST INST KY	CUST371K	17,384,575	17,384,575	-	-	-	-	-	-
4 DIRECT ASSIGN 373 ST LIGHT KY	CUST373K	80,975,590	80,975,590	-	-	-	-	-	-
5 CUSTOMER ADVANCES	CUSTADV	3,147,887	2,936,189	211,698	-	-	-	-	-
6 CUSTOMER DEPOSITS	CUSTDEP	23,057,678	22,532,317	525,361	-	-	-	-	-
7 DIR ASSIGN 902-METER READING	CUST902	747,403	707,124	39,349	930	7	923	494	429
8 DIR ASSIGN 903-CUSTOMER REC	CUST903	747,403	707,124	39,349	930	7	923	494	429
9 DIR ASSIGN 904-UNCOLL ACCTS	CUST904	747,403	707,124	39,349	930	7	923	494	429
10 DIR ASSIGN ACCT 369-SERV VA	CUST369V	5,175,446	-	5,175,446	-	-	-	-	-
11 DIR ASSIGN ACCT 370 METERS VA	CUST370V	3,637,512	-	3,637,512	-	-	-	-	-
12 DIR ASSIGN ACCT 371 CUST INST VA	CUST371V	856,341	-	856,341	-	-	-	-	-
13 DIR ASGN ACCT 373 ST LIGHT VA	CUST373V	2,038,654	-	2,038,654	-	-	-	-	-
14 DIR ASSIGN 908-CUST ASSIST	CUST908	510,585	510,585	-	-	-	-	-	-
15 DIR ASSIGN 909-INFO & INSTRCT	CUST909	539,748	510,585	29,159	4	4	-	-	-
16 DIR ASSIGN 912-DEM & SELLING	CUST912	539,748	510,585	29,159	4	4	-	-	-
17 DIR ASSIGN 913-ADVERTISING	CUST913	539,748	510,585	29,159	4	4	-	-	-
18 CUSTOMER ANNUALIZATION	CUSTANN	-	-	-	-	-	-	-	-
19 CUSTOMER DEPOSITS INTEREST	CUSTDEPI	1,373,106	1,371,386	1,719	-	-	-	-	-
20 DIR ASSIGN LATE PAYMENT REVENUE	DIR450REV	7,125,786	6,910,624	213,937	1,225	-	1,225	1,199	27
21									
22									
23									
24									
25									

KENTUCKY UTILITIES COMPANY
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INTERNALLY DEVELOPED									
-									
1 PROD-TRANSM-DISTR-GENL PLT	PTDGPLT	6,432,365,889	5,600,621,962	382,047,373	449,696,554	202,828	449,493,727	142,719,288	306,774,439
2 PROD-TRANSM-DISTR-GENL PLT KY	KURETPLT	5,600,621,962	5,600,621,962	-	-	-	-	-	-
3 ALLOCATED O&M LABOR EXPENSE	LABOR	152,351,955	135,498,603	8,347,819	8,505,534	4,677	8,500,857	2,761,610	5,739,247
4 TOTAL STEAM PROD PLANT-SYSTEM	STMSYS	3,588,357,602	3,105,688,242	182,387,851	300,281,508	27,460	300,254,049	93,686,881	206,567,167
5 ALLOCATED NON A&G LABOR EXPENSE	PTDCUSTLABOR	86,705,626	77,114,148	4,750,860	4,840,618	2,662	4,837,956	1,571,671	3,266,285
6 TOT HYDRAULIC PROD PLANT-SYS	HYDSYS	28,696,483	24,836,524	1,458,575	2,401,384	220	2,401,164	749,224	1,651,940
7 TOTAL OTHER PROD PLANT-SYS	OTHSYS	531,291,430	459,827,511	27,004,305	44,459,613	4,066	44,455,548	13,871,259	30,584,289
8 TRANSM KENTUCKY SYSTEM PROP	KYTRPLT	615,216,199	528,497,002	32,231,464	54,487,733	4,673	54,483,060	17,000,097	37,482,963
9 TRANSM VIRGINIA PROPERTY	VATRPLT	44,499,356	-	44,494,822	4,533	-	4,533	1,415	3,119
10 TRANSM VIRGINIA PROP TOTAL	VATRPLTT	52,729,785	7,504,808	44,494,822	730,155	66	730,089	227,806	502,283
11 TOTAL DISTRIBUTION PLANT	DISTPLT	1,433,759,657	1,348,948,020	80,327,606	4,484,032	162,043	4,321,989	3,714,063	607,926
12 TOTAL DIST PLANT KY & FERC	DISTPLTKF	1,353,270,008	1,348,948,020	-	4,321,989	-	4,321,989	3,714,063	607,926
13 TOTAL GENERAL PLANT	GENPLT	140,094,552	124,597,128	7,676,199	7,821,225	4,301	7,816,924	2,539,426	5,277,498
14 ACCT 302-FRANCHISE	PLT302TOT	55,919	55,919	-	-	-	-	-	-
15 ACCT 303-SOFTWARE	PLT303TOT	60,103,759	52,331,978	3,569,835	4,201,946	1,895	4,200,051	1,333,563	2,866,488
16 TOTAL PRODUCTION PLANT SYSTEM	PRODSYS	4,148,345,515	3,590,352,278	210,850,731	347,142,506	31,745	347,110,760	108,307,364	238,803,396
17 TOTAL PRODUCTION PLANT	PRODPLT	4,189,773,098	3,590,352,278	217,317,282	382,103,538	31,745	382,071,793	119,216,093	262,855,699
18 TOTAL TRANSMISSION PLANT	TRANPLT	667,945,984	536,001,810	76,726,287	55,217,888	4,739	55,213,149	17,227,903	37,985,245
19 MAT & SUPPLIES DISTRIBUTED	M_S	33,590,545	29,111,109	1,980,951	2,498,485	895	2,497,590	789,353	1,708,237
20 ACCT 924 & 925 INSURANCE	EXP9245TOT	7,836,210	6,889,473	449,042	497,695	244	497,451	159,407	338,044
21 REVENUE SALE OF ELECT-KY	REVKY	1,320,135,670	1,320,135,670	-	-	-	-	-	-
22 CWIP PROD FERC-POST ALLOC	CWIPPP	22,217,263	-	-	22,217,263	-	22,217,263	6,932,350	15,284,913
23 CWIP TRAN FERC-POST ALLOC	CWIPTP	3,730,582	-	-	3,730,582	-	3,730,582	1,164,036	2,566,545
24 ACC DEF INC TX PROD FERC-POST	ADITPP	971,424	-	-	971,424	-	971,424	303,109	668,315
25 ACC DEF INC TX TRAN FERC-POST	ADITTP	3,614,551	-	-	3,614,551	-	3,614,551	1,127,832	2,486,719
26 TRANSMISSION PLANT EXCL VA	TRANPLTX	615,216,199	528,497,002	32,231,464	54,487,733	4,673	54,483,060	17,000,097	37,482,963
27 TRANSM PLANT VA	TRPLTVA	52,729,785	7,504,808	44,494,822	730,155	66	730,089	227,806	502,283
28 TOT ACCT 364 & 365-OVHD LINE	PLT3645TOT	580,724,064	537,135,305	43,493,882	94,877	94,877	-	-	-
29 TOTAL ELECTRIC PLANT	PLANT	6,492,570,023	5,653,048,566	385,619,848	453,901,608	204,724	453,696,884	144,053,837	309,643,047
30 TOTAL ELECTRIC PLANT KY	PLANTKY	5,653,048,566	5,653,048,566	-	-	-	-	-	-
31 TOTAL ELECTRIC PLANT KY & FERC	PLANTKF	6,106,745,450	5,653,048,566	-	453,696,884	-	453,696,884	144,053,837	309,643,047
32 TOTAL ELECTRIC PLANT VA	PLANTVA	385,619,848	-	385,619,848	-	-	-	-	-
33 TOTAL STEAM PROD PLANT	STMPLT	3,627,633,483	3,105,688,242	188,853,335	333,091,906	27,460	333,064,446	103,924,558	229,139,889
34 TOTAL HYDRAULIC PROD PLANT	HYDPLT	28,756,470	24,836,524	1,458,885	2,461,060	220	2,460,841	767,845	1,692,996
35 TOTAL OTHER PROD PLANT	OTHPLT	533,383,145	459,827,511	27,005,062	46,550,571	4,066	46,546,505	14,523,691	32,022,815
36 TOT ACCT 360-362 SUBSTATIONS	PLT3602TOT	158,338,784	146,452,780	8,338,352	3,547,651	63,681	3,483,970	3,483,970	-
37 TOT ACCT 366 & 367-UG LINES	PLT3667TOT	144,105,048	141,341,084	2,763,964	-	-	-	-	-
38 TOT ACCT 373-STREET LIGHTING	PLT373TOT	83,014,243	80,975,590	2,038,654	-	-	-	-	-
39 TOTAL ACCT 370-METERS	PLT370TOT	70,922,417	66,969,753	3,637,512	315,153	111	315,042	66,911	248,131
40 TOT ACCT 371-CUSTOMER INSTALL	PLT371TOT	18,240,916	17,384,575	856,341	-	-	-	-	-
41 TOT ACCT 368-LINE TRANSFORMER	PLT368TOT	287,943,911	273,394,360	14,023,456	526,095	3,118	522,977	163,182	359,795
42 TOT ACCT 902-904 CUST ACCTS	EXP9024CA	24,652,741	23,324,157	1,297,909	30,676	231	30,445	16,294	14,150
43 TOT ACCT 908-909 CUST SERV	EXP9089CS	13,821,436	13,812,948	8,487	1	1	-	-	-
44 TOTAL TRANS & DISTRIB PLANT	TRDSPLT	2,101,705,641	1,884,949,829	157,053,892	59,701,919	166,782	59,535,137	20,941,966	38,593,171

KENTUCKY UTILITIES COMPANY
ELECTRIC COST OF SERVICE STUDY
JURISDICTIONAL SEPARATION

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12 MONTHS ENDING MARCH 31, 2012

	ALLOC	TOTAL KENTUCKY UTILITIES (1)	KENTUCKY STATE JURISDICTION (2)	VIRGINIA STATE JURISDICTION (3)	FERC & TENNESSEE JURISDICTION (4)	TENNESSEE STATE JURISDICTION (5)	FERC JURISDICTION (6)	PRIMARY (7)	TRANSMISSION (8)
INTERNALLY DEVELOPED-CON'T									
-									
1 TOT ACCT 912-913 SALES EXP	EXP9123SA	23,966	22,672	1,295	0	0	-	-	-
2 REVENUE SALE OF ELECT-FERC	REVFERC	101,135,777	-	-	101,135,777	-	101,135,777	32,764,685	68,371,092
3 REVENUE SALE OF ELECT-VA	REVVA	74,647,937	-	74,647,937	-	-	-	-	-
4 REVENUE SALE OF ELECT	REVENUE	1,495,925,596	1,320,135,670	74,647,937	101,141,988	6,211	101,135,777	32,764,685	68,371,092
5 REV SALE OF ELECT-VA NON JUR	REVNJVA	1	-	1	-	-	-	-	-
6 REV SALE OF ELECT-EXCL FERC	REVENUEX	1,394,789,819	1,320,135,670	74,647,937	6,211	6,211	-	-	-
7 KENTUCKY DISTRIBUTION PLANT	KYDIST	1,353,270,008	1,348,948,020	-	4,321,989	-	4,321,989	3,714,063	607,926
8 VIRGINIA DISTRIBUTION PLANT	VADIST	80,327,606	-	80,327,606	-	-	-	-	-
9 TENNESSEE DISTRIBUTION PLT	TNDIST	162,043	-	-	162,043	162,043	-	-	-
10 NET ELECTRIC PLANT IN SERVICE	NETPLANT	4,073,283,819	3,561,520,106	225,955,270	285,808,443	47,886	285,760,557	90,684,732	195,075,824
11 RATE BASE	RATEBASE	4,056,092,315	3,550,375,899	216,540,258	289,176,158	37,845	289,138,313	91,830,469	197,307,844
12 TOTAL CWIP FERC-AFUDC POST	AFUDC	340,830	-	-	340,830	-	340,830	106,348	234,482
13 TOTAL 203(E) EXCESS	DEFTAX	(1,256,557)	(1,104,028)	(70,031)	(82,498)	(39)	(82,459)	(26,199)	(56,260)
14 STEAM OPERATING EXP 501-507	EXP5017STM	534,792,106	463,397,849	24,839,290	46,554,967	2,690	46,552,277	15,131,038	31,421,239
15 STEAM MAINTENANCE EXP 511-514	EXP5114STM	61,471,225	52,949,729	2,855,156	5,666,340	314	5,666,025	1,838,709	3,827,316
16 HYDRO OPERATING EXP 536-540	EXP5360HYD	44,637	38,553	2,265	3,820	0	3,820	1,192	2,628
17 HYDRO MAINTENANCE EXP 542-545	EXP5425HYD	311,632	269,510	15,362	26,761	2	26,758	8,464	18,294
18 OTHER PROD OPER EXP 547-549	EXP5479OTH	32,008,989	27,768,244	1,469,792	2,770,953	154	2,770,799	904,128	1,866,671
19 OTHER PROD MAINT EXP 552-554	EXP5524OTH	2,075,188	1,789,012	105,066	181,110	16	181,095	56,506	124,588
20 TOT STEAM OPERATIONS LABOR	LABSTMOP	-	-	-	-	-	-	-	-
21 TOT STEAM MAINTENANCE LABOR	LABSTMMN	-	-	-	-	-	-	-	-
22 TOT HYDRO OPERATIONS LABOR	LABHYDOP	-	-	-	-	-	-	-	-
23 TOT HYDRO MAINTENANCE LABOR	LABHYDMN	-	-	-	-	-	-	-	-
24 TOT OTHER OPERATIONS LABOR	LABOTHOP	-	-	-	-	-	-	-	-
25 TOT OTHER MAINTENANCE LABOR	LABOTHMN	-	-	-	-	-	-	-	-
26 TRANSM OPER EXP 562-567	EXP5627TX	15,897,597	12,822,592	1,788,133	1,286,872	110	1,286,762	401,502	885,259
27 TRANSM MAINT EXP 569-573	EXP5693TX	7,296,486	5,870,249	829,365	596,872	51	596,821	186,223	410,598
28 TOT TRANSM OPERATIONS LABOR	LABTROP	5,806,037	4,659,129	666,934	479,975	41	479,933	149,751	330,182
29 TOT TRANSM MAINTENANCE LABOR	LABTRMN	-	-	-	-	-	-	-	-
30 DISTR OPER EXP 582-589	EXP5829DIS	18,068,320	16,955,464	1,028,083	84,772	1,772	83,000	53,718	29,282
31 DISTR MAINT EXP 591-598	EXP5918DIS	33,827,108	31,296,860	2,509,484	20,764	4,537	16,226	15,923	303
32 TOT DISTR OPERATIONS LABOR	LABDISOP	19,510,181	18,356,090	1,093,075	61,017	2,205	58,812	50,540	8,272
33 TOT DISTR MAINTENANCE LABOR	LABDISMN	-	-	-	-	-	-	-	-
34 CUST ACCT EXP 902, 903 & 905	EXP9025CA	19,989,908	18,912,613	1,052,421	24,874	187	24,686	13,212	11,474
35 TOTAL CUST ACCOUNTS LABOR	LABCA	2,455,747	2,323,402	129,289	3,056	23	3,033	1,623	1,410
36 CUST SERVICES & SALES EXP	EXP9080CS	14,263,008	14,252,969	10,038	1	1	-	-	-
37 TOTAL CUST SERVICES LABOR	LABCS	2,455,747	2,323,402	129,289	3,056	23	3,033	1,623	1,410
38 SALES EXPENSE 912-916	EXP9126SA	23,966	22,672	1,295	0	0	-	-	-
39 TOTAL SALES EXP LABOR	LABSA	1,457,202	1,456,176	1,026	0	0	-	-	-
40 TOT ADMINISTRATIVE & GEN EXP	A_GEXP	103,626,523	93,031,576	5,878,223	4,716,724	3,118	4,713,605	1,529,125	3,184,481

KENTUCKY UTILITIES COMPANY
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12 MONTHS ENDING MARCH 31, 2012

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INTERNALLY DEVELOPED-CON'T									
-									
1 ACCT 930-EPRI & ADVERTISING	EXP930A	1,396,664	1,326,518	70,139	7	7	-	-	-
2 TOTAL CUSTOMER SERVICES EXP	CUSTSER	14,444,733	14,435,844	8,888	1	1	-	-	-
3 DISTRIBUTION PLANT EXCL VA	DPLTXVA	1,353,432,051	1,348,948,020	-	4,484,032	162,043	4,321,989	3,714,063	607,926
4 ACCT 926 DIR ASSIGN COMP.KY RET	LABPTDKY	64,434,374	64,434,374	-	-	-	-	-	-
5 ACCT 926 DIR ASSIGN COMP.VAJ	LABPTDVAJ	4,125,280	-	4,125,280	-	-	-	-	-
6 ACCT 926 DIR ASSIGN COMP.VANJ	LABPTDVNJ	-	-	-	-	-	-	-	-
7 ACCT 926 DIR ASSIGN COMP.FERC	LABPTDFER	4,823,306	-	-	4,823,306	-	4,823,306	1,563,830	3,259,476
8 203(E) EXCESS DEFERRED TAXES	TOT203E	(1,256,557)	(1,104,028)	(70,031)	(82,498)	(39)	(82,459)	(26,199)	(56,260)
9 RATE BASE-KY	KYRATEBASE	3,839,514,212	3,550,375,899	-	289,138,313	-	289,138,313	91,830,469	197,307,844
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REVENUES FROM ELECTRIC SALES									
-									
1 440-RESIDENTIAL		509,303,763	476,589,863	32,707,845	6,055	6,055	-	-	-
2 442-SMALL COMMERCIAL		181,449,246	175,113,848	6,335,398	-	-	-	-	-
3 442-LARGE COMMERCIAL		159,939,302	149,946,899	9,992,403	-	-	-	-	-
4 442-INDUSTRIAL		342,664,409	339,425,792	3,238,617	-	-	-	-	-
5 442-MINE POWER		43,926,569	29,838,196	14,088,373	-	-	-	-	-
6 444-PUBLIC ST & HWY LIGHTING		10,746,105	10,423,250	322,855	-	-	-	-	-
7 445-OTHER PUBLIC AUTHORITIES		111,947,307	105,659,337	6,287,971	-	-	-	-	-
8 445-MUNICIPAL PUMPING		4,874,901	4,703,887	171,014	-	-	-	-	-
9 447-SALES FOR RESALE-MUNICIPAL WHOLESALE		98,298,885	-	-	98,298,885	-	98,298,885	31,838,591	66,460,294
10 ANNUALIZATION		-	-	-	-	-	-	-	-
11 449-PROVISION FOR RATE REFUND		-	-	-	-	-	-	-	-
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KENTUCKY UTILITIES COMPANY
ELECTRIC COST OF SERVICE STUDY
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	RATIO TABLE									
	CAPACITY RELATED									
	-									
	PRODUCTION ALLOCATORS									
1	DEMAND (12 CP GEN LEV)-PROD	DEMPROD	1.00000	0.86549	0.05083	0.08368	0.00001	0.08367	0.02611	0.05757
2	DEMAND (12 CP GEN LEV)-FERC	DEMFERC	1.00000	-	0.37789	0.62211	-	0.62211	0.19411	0.42799
3	DEMAND (12 CP GEN)-PROD VA	DPRODVA	1.00000	-	1.00000	-	-	-	-	-
4	DEMAND (12 CP GEN)-PROD KY	DPRODKY	1.00000	0.91184	-	0.08816	-	0.08816	0.02751	0.06065
5	DEM (12 CP GEN LV)-FERC POST	DEMFERCP	1.00000	-	-	1.00000	-	1.00000	0.31203	0.68797
6	DEM (12 CP GEN LV)-NON VA	DEMPRODNV	1.00000	0.91184	-	0.08816	0.00001	0.08816	0.02751	0.06065
	TRANSMISSION ALLOCATORS									
7	DEMAND (12 CP GEN LEV)-TRAN	DEMTRAN	1.00000	0.86549	0.05083	0.08368	0.00001	0.08367	0.02611	0.05757
8	DEMAND (12 CP GEN LEV)-VA	DEMVA	1.00000	-	1.00000	-	-	-	-	-
9	DEM (12 CP GEN LEV)-NON FERC	DEMTRANNF	1.00000	0.94452	0.05547	0.00001	0.00001	-	-	-
10	DEM (12 CP GN LEV)-TRAN FERC	DEMFERCT	1.00000	-	0.37789	0.62211	-	0.62211	0.19411	0.42799
11	DEM (12 CP GN)-TR FERC POST	DFERCTP	1.00000	-	-	1.00000	-	1.00000	0.31203	0.68797
	DISTRIBUTION ALLOCATORS									
12	DIRECT ASSIGN 360 KY	DEM360K	1.00000	0.99821	-	0.00179	-	0.00179	0.00179	-
13	DIRECT ASSIGN 361 KY	DEM361K	1.00000	0.96212	-	0.03788	-	0.03788	0.03788	-
14	DIRECT ASSIGN 362 KY	DEM362K	1.00000	0.97673	-	0.02327	-	0.02327	0.02327	-
15	DIRECT ASSIGN 364 KY	DEM364K	1.00000	1.00000	-	-	-	-	-	-
16	DIRECT ASSIGN 365 KY	DEM365K	1.00000	1.00000	-	-	-	-	-	-
17	DIRECT ASSIGN 366 KY	DEM366K	1.00000	1.00000	-	-	-	-	-	-
18	DIRECT ASSIGN 367 KY	DEM367K	1.00000	1.00000	-	-	-	-	-	-
19	DIRECT ASSIGN 368 KY	DEM368K	1.00000	1.00000	-	-	-	-	-	-
20	DIRECT ASSIGN 374 KY	DEM374K	1.00000	1.00000	-	-	-	-	-	-
21	DIRECT ASSIGN 360-VA	DEM360V	1.00000	-	1.00000	-	-	-	-	-
22	DIRECT ASSIGN 361-VA	DEM361V	1.00000	-	1.00000	-	-	-	-	-
23	DIRECT ASSIGN 362-VA	DEM362V	1.00000	-	1.00000	-	-	-	-	-
24	DIRECT ASSIGN 360-362-FERC VA	DIR3602V	-	-	-	-	-	-	-	-
25	DIRECT ASSIGN 364-VA	DEM364V	1.00000	-	1.00000	-	-	-	-	-
26	DIRECT ASSIGN 365-VA	DEM365V	1.00000	-	1.00000	-	-	-	-	-
27	DIRECT ASSIGN 367-VA	DEM367V	1.00000	-	1.00000	-	-	-	-	-
28	DIRECT ASSIGN 368-VA	DEM368V	1.00000	-	1.00000	-	-	-	-	-
29	DIRECT ASSIGN 360-TN	DEM360T	1.00000	-	-	1.00000	1.00000	-	-	-
30	DIRECT ASSIGN 361-TN	DEM361T	1.00000	-	-	1.00000	1.00000	-	-	-
31	DIRECT ASSIGN 362-TN	DEM362T	1.00000	-	-	1.00000	1.00000	-	-	-
32	DIRECT ASSIGN 364-TN	DEM364T	1.00000	-	-	1.00000	1.00000	-	-	-
33	DIRECT ASSIGN 365-TN	DEM365T	1.00000	-	-	1.00000	1.00000	-	-	-
34	DIRECT ASSIGN 368-TN	DEM368T	1.00000	-	-	1.00000	1.00000	-	-	-
35	DIRECT ASSIGN 369-TN	CUST369T	1.00000	-	-	1.00000	1.00000	-	-	-
36	DIRECT ASSIGN 370-TN	CUST370T	1.00000	-	-	1.00000	1.00000	-	-	-
37	DIRECT ASSIGN 371-TN	CUST371T	-	-	-	-	-	-	-	-
38	DIR ASSIGN ACCUM DEPREC.VA & TN	DIRACDEP	1.00000	-	0.99622	0.00378	0.00378	-	-	-
39	DIR ASSIGN CWIP VA & TN	DIRCWIP	1.00000	-	1.00000	-	-	-	-	-
40	DIR ASSIGN ACC DFD TAX VA	DIRACDFTX	1.00000	-	1.00000	-	-	-	-	-
41	DIR ASSIGN ACC ITC VA	DIRACITC	-	-	-	-	-	-	-	-
42	DIR ASSIGN RENT REVENUE	DIR454REV	1.00000	0.92102	0.07883	0.00015	0.00015	-	-	-
43	DIR ASSIGN EXCESS FACILITIES REV.	DIR456FAC	1.00000	0.93974	0.06026	-	-	-	-	-
44	DIR ASSIGN OTHER MISC REV.	DIR456OTH	1.00000	1.00000	-	-	-	-	-	-
45	DIR ASSIGN RECONNECT REV.	DIR451REC	1.00000	0.92633	0.07367	-	-	-	-	-
46	DIR ASSIGN OTHER SERVICE REV.	DIR451OTH	1.00000	0.97791	0.02209	-	-	-	-	-
47	DIR ASSIGN RETURN CHECK REV.	DIR456CHK	1.00000	0.93652	0.06348	-	-	-	-	-
48	DIR ASSIGN 203(E) EXCESS	DIR203E	1.00000	-	1.00000	-	-	-	-	-
49	DIR ASSIGN ITC ADJ	DIRITCADJ	-	-	-	-	-	-	-	-
50	DIR ASSIGN DEFERRED FUEL-VIRGINIA	DFUELVA	1.00000	-	1.00000	-	-	-	-	-

KENTUCKY UTILITIES COMPANY
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ENERGY									
-									
1 ENERGY (MWH AT GEN LEVEL)	ENERGY	1.00000	0.86757	0.04587	0.08656	0.00000	0.08656	0.02826	0.05830
2 ENERGY (MWH RETAIL @ GEN LEVEL)	ENERGY1	1.00000	0.94978	0.05022	0.00001	0.00001	-	-	-
3									
4									
CUSTOMER									
-									
1 DIR ASSIGN ACCT 369-SERV KY	CUST369K	1.00000	1.00000	-	-	-	-	-	-
2 DIR ASSIGN ACCT 370 METERS KY	CUST370K	1.00000	0.99532	-	0.00468	-	0.00468	0.00099	0.00369
3 DIR ASN ACCT 371 CUST INST KY	CUST371K	1.00000	1.00000	-	-	-	-	-	-
4 DIR ASGN ACCT 373 ST LIGHT KY	CUST373K	1.00000	1.00000	-	-	-	-	-	-
5 CUSTOMER ADVANCES	CUSTADV	1.00000	0.93275	0.06725	-	-	-	-	-
6 CUSTOMER DEPOSITS	CUSTDEP	1.00000	0.97722	0.02278	-	-	-	-	-
7 DIR ASSIGN 902-METER READING	CUST902	1.00000	0.94611	0.05265	0.00124	0.00001	0.00123	0.00066	0.00057
8 DIR ASSIGN 903-CUSTOMER REC	CUST903	1.00000	0.94611	0.05265	0.00124	0.00001	0.00123	0.00066	0.00057
9 DIR ASSIGN 904-UNCOLL ACCTS	CUST904	1.00000	0.94611	0.05265	0.00124	0.00001	0.00123	0.00066	0.00057
10 DIR ASSIGN ACCT 369-SERV VA	CUST369V	1.00000	-	1.00000	-	-	-	-	-
11 DIR ASSIGN ACCT 370 METERS VA	CUST370V	1.00000	-	1.00000	-	-	-	-	-
12 DIR ASN ACCT 371 CUST INST VA	CUST371V	1.00000	-	1.00000	-	-	-	-	-
13 DIR ASGN ACCT 373 ST LIGHT VA	CUST373V	1.00000	-	1.00000	-	-	-	-	-
14 DIR ASSIGN 908-CUST ASSIST	CUST908	1.00000	1.00000	-	-	-	-	-	-
15 DIR ASSIGN 909-INFO & INSTRCT	CUST909	1.00000	0.94597	0.05402	0.00001	0.00001	-	-	-
16 DIR ASSIGN 912-DEM & SELLING	CUST912	1.00000	0.94597	0.05402	0.00001	0.00001	-	-	-
17 DIR ASSIGN 913-ADVERTISING	CUST913	1.00000	0.94597	0.05402	0.00001	0.00001	-	-	-
18 CUSTOMER ANNUALIZATION	CUSTANN	-	-	-	-	-	-	-	-
19 CUSTOMER DEPOSITS INTEREST	CUSTDEPI	1.00000	0.99875	0.00125	-	-	-	-	-
20 LATE PAYMENT REVENUES	DIR450REV	1.00000	0.96981	0.03002	0.00017	-	0.00017	0.00017	0.00000
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INTERNALLY DEVELOPED									
-									
1 PROD-TRANSM-DISTR-GENL PLT	PTDGPLT	1.00000	0.87069	0.05939	0.06991	0.00003	0.06988	0.02219	0.04769
2 PROD-TRANSM-DISTR-GENL PLT KY	KURETPLT	1.00000	1.00000	-	-	-	-	-	-
3 ALLOCATED O&M LABOR EXPENSE	LABOR	1.00000	0.88938	0.05479	0.05583	0.00003	0.05580	0.01813	0.03767
4 ALLOCATED O&M LABOR EXPENSE	PTDCUSTLABOR	1.00000	0.88938	0.05479	0.05583	0.00003	0.05580	0.01813	0.03767
5 TOTAL STEAM PROD PLANT-SYSTEM	STMSYS	1.00000	0.86549	0.05083	0.08368	0.00001	0.08367	0.02611	0.05757
6 TOT HYDRAULIC PROD PLANT-SYS	HYDSYS	1.00000	0.86549	0.05083	0.08368	0.00001	0.08367	0.02611	0.05757
7 TOTAL OTHER PROD PLANT-SYS	OTHSYS	1.00000	0.86549	0.05083	0.08368	0.00001	0.08367	0.02611	0.05757
8 TRANSM KENTUCKY SYSTEM PROP	KYTRPLT	1.00000	0.85904	0.05239	0.08857	0.00001	0.08856	0.02763	0.06093
9 TRANSM VIRGINIA PROPERTY	VATRPLT	1.00000	-	0.99990	0.00010	-	0.00010	0.00003	0.00007
10 TRANSM VIRGINIA PROP TOTAL	VATRPLTT	1.00000	0.14233	0.84383	0.01385	0.00000	0.01385	0.00432	0.00953
11 TOTAL DISTRIBUTION PLANT	DISTPLT	1.00000	0.94085	0.05603	0.00313	0.00011	0.00301	0.00259	0.00042
12 TOTAL DIST PLANT KY & FERC	DISTPLTKF	1.00000	0.99681	-	0.00319	-	0.00319	0.00274	0.00045
13 TOTAL GENERAL PLANT	GENPLT	1.00000	0.88938	0.05479	0.05583	0.00003	0.05580	0.01813	0.03767
14 ACCT 302-FRANCHISE	PLT302TOT	1.00000	1.00000	-	-	-	-	-	-
15 ACCT 303-SOFTWARE	PLT303TOT	1.00000	0.87069	0.05939	0.06991	0.00003	0.06988	0.02219	0.04769
16 TOTAL PRODUCTION PLANT SYSTEM	PRODSYS	1.00000	0.86549	0.05083	0.08368	0.00001	0.08367	0.02611	0.05757
17 TOTAL PRODUCTION PLANT	PRODPLT	1.00000	0.85693	0.05187	0.09120	0.00001	0.09119	0.02845	0.06274
18 TOTAL TRANSMISSION PLANT	TRANPLT	1.00000	0.80246	0.11487	0.08267	0.00001	0.08266	0.02579	0.05687
19 MAT & SUPPLIES DISTRIBUTED	M_S	1.00000	0.86665	0.05897	0.07438	0.00003	0.07435	0.02350	0.05085
20 ACCT 924 & 925 INSURANCE	EXP9245TOT	1.00000	0.87918	0.05730	0.06351	0.00003	0.06348	0.02034	0.04314
21 REVENUE SALE OF ELECT-KY	REVKY	1.00000	1.00000	-	-	-	-	-	-
22 CWIP PROD FERC-POST ALLOC	CWIPPP	1.00000	-	-	1.00000	-	1.00000	0.31203	0.68797
23 CWIP TRAN FERC-POST ALLOC	CWIPTP	1.00000	-	-	1.00000	-	1.00000	0.31203	0.68797
24 ACC DEF INC TX PROD FERC-POST	ADITPP	1.00000	-	-	1.00000	-	1.00000	0.31203	0.68797
25 ACC DEF INC TX TRAN FERC-POST	ADITTP	1.00000	-	-	1.00000	-	1.00000	0.31203	0.68797
26 TRANSMISSION PLANT EXCL VA	TRANPLTX	1.00000	0.85904	0.05239	0.08857	0.00001	0.08856	0.02763	0.06093
27 TRANSM PLANT VA & 500 KV	TRPLTVA	1.00000	0.14233	0.84383	0.01385	0.00000	0.01385	0.00432	0.00953
28 TOT ACCT 364 & 365-OVHD LINE	PLT3645TOT	1.00000	0.92494	0.07490	0.00016	0.00016	-	-	-
29 TOTAL ELECTRIC PLANT	PLANT	1.00000	0.87070	0.05939	0.06991	0.00003	0.06988	0.02219	0.04769
30 TOTAL ELECTRIC PLANT KY	PLANTKY	1.00000	1.00000	-	-	-	-	-	-
31 TOTAL ELECTRIC PLANT KY & FERC	PLANTKF	1.00000	0.92571	-	0.07429	-	0.07429	0.02359	0.05071
32 TOTAL ELECTRIC PLANT VA	PLANTVA	1.00000	-	1.00000	-	-	-	-	-
33 TOTAL STEAM PROD PLANT	STMPLT	1.00000	0.85612	0.05206	0.09182	0.00001	0.09181	0.02865	0.06317
34 TOTAL HYDRAULIC PROD PLANT	HYDPLT	1.00000	0.86368	0.05073	0.08558	0.00001	0.08558	0.02670	0.05887
35 TOTAL OTHER PROD PLANT	OTHPLT	1.00000	0.86210	0.05063	0.08727	0.00001	0.08727	0.02723	0.06004
36 TOT ACCT 360-362 SUBSTATIONS	PLT3602TOT	1.00000	0.92493	0.05266	0.02241	0.00040	0.02200	0.02200	-
37 TOT ACCT 366 & 367-UG LINES	PLT3667TOT	1.00000	0.98082	0.01918	-	-	-	-	-
38 TOT ACCT 373-STREET LIGHTING	PLT373TOT	1.00000	0.97544	0.02456	-	-	-	-	-
39 TOTAL ACCT 370-METERS	PLT370TOT	1.00000	0.94427	0.05129	0.00444	0.00000	0.00444	0.00094	0.00350
40 TOT ACCT 371-CUSTOMER INSTALL	PLT371TOT	1.00000	0.95305	0.04695	-	-	-	-	-
41 TOT ACCT 368-LINE TRANSFORMER	PLT368TOT	1.00000	0.94947	0.04870	0.00183	0.00001	0.00182	0.00057	0.00125
42 TOT ACCT 902-904 CUST ACCTS	EXP9024CA	1.00000	0.94611	0.05265	0.00124	0.00001	0.00123	0.00066	0.00057
43 TOT ACCT 908-909 CUST SERV	EXP9089CS	1.00000	0.99939	0.00061	0.00000	0.00000	-	-	-
44 TOTAL TRANS & DISTRIB PLANT	TRDSPLT	1.00000	0.89687	0.07473	0.02841	0.00008	0.02833	0.00996	0.01836

KENTUCKY UTILITIES COMPANY
ELECTRIC COST OF SERVICE STUDY
JURISDICTIONAL SEPARATION

RATE BASE: END OF YEAR
ALLOCATION METHOD: AVG 12 CP (COMBINED CO SYS)

12 MONTHS ENDING MARCH 31, 2012

	ALLOC	TOTAL KENTUCKY UTILITIES (1)	KENTUCKY STATE JURISDICTION (2)	VIRGINIA STATE JURISDICTION (3)	FERC & TENNESSEE JURISDICTION (4)	TENNESSEE STATE JURISDICTION (5)	FERC JURISDICTION (6)	PRIMARY (7)	TRANSMISSION (8)
INTERNALLY DEVELOPED-CON'T									
-									
1 TOT ACCT 912-913 SALES EXP	EXP9123SA	1.00000	0.94597	0.05402	0.00001	0.00001	-	-	-
2 REVENUE SALE OF ELECT-FERC	REVFERC	1.00000	-	-	1.00000	-	1.00000	0.32397	0.67603
3 REVENUE SALE OF ELECT-VA	REVVA	1.00000	-	1.00000	-	-	-	-	-
4 REVENUE SALE OF ELECT	REVENUE	1.00000	0.88249	0.04990	0.06761	0.00000	0.06761	0.02190	0.04570
5 REV SALE OF ELECT-VA NON JUR	REVNJVA	1.00000	-	1.00000	-	-	-	-	-
6 REV SALE OF ELECT-EXCL FERC	REVENUEX	1.00000	0.94648	0.05352	0.00000	0.00000	-	-	-
7 KENTUCKY DISTRIBUTION PLANT	KYDIST	1.00000	0.99681	-	0.00319	-	0.00319	0.00274	0.00045
8 VIRGINIA DISTRIBUTION PLANT	VADIST	1.00000	-	1.00000	-	-	-	-	-
9 TENNESSEE DISTRIBUTION PLT	TNDIST	1.00000	-	-	1.00000	1.00000	-	-	-
10 NET ELECTRIC PLANT IN SERVICE	NETPLANT	1.00000	0.87436	0.05547	0.07017	0.00001	0.07015	0.02226	0.04789
11 RATE BASE	RATEBASE	1.00000	0.87532	0.05339	0.07129	0.00001	0.07128	0.02264	0.04864
12 TOTAL CWIP FERC-AFUDC POST	AFUDC	1.00000	-	-	1.00000	-	1.00000	0.31203	0.68797
13 TOTAL 201(E) EXCESS	DEFTAX	1.00000	0.87861	0.05573	0.06565	0.00003	0.06562	0.02085	0.04477
14 STEAM OPERATING EXP 501-507	EXP5017STM	1.00000	0.86650	0.04645	0.08705	0.00001	0.08705	0.02829	0.05875
15 STEAM MAINTENANCE EXP 511-514	EXP5114STM	1.00000	0.86137	0.04645	0.09218	0.00001	0.09217	0.02991	0.06226
16 HYDRO OPERATING EXP 536-540	EXP5360HYD	1.00000	0.86368	0.05073	0.08558	0.00001	0.08558	0.02670	0.05887
17 HYDRO MAINTENANCE EXP 542-545	EXP5425HYD	1.00000	0.86483	0.04929	0.08587	0.00001	0.08587	0.02716	0.05870
18 OTHER PROD OPER EXP 547-549	EXP5479OTH	1.00000	0.86751	0.04592	0.08657	0.00000	0.08656	0.02825	0.05832
19 OTHER PROD MAINT EXP 552-554	EXP5524OTH	1.00000	0.86210	0.05063	0.08727	0.00001	0.08727	0.02723	0.06004
20 TOTAL STEAM OPERATIONS LABOR	LABSTMOP	-	-	-	-	-	-	-	-
21 TOTAL STEAM MAINTENANCE LABOR	LABSTMMN	-	-	-	-	-	-	-	-
22 TOTAL HYDRO OPERATIONS LABOR	LABHYDOP	-	-	-	-	-	-	-	-
23 TOTAL HYDRO MAINTENANCE LABOR	LABHYDMN	-	-	-	-	-	-	-	-
24 TOTAL OTHER OPERATIONS LABOR	LABOTHOP	-	-	-	-	-	-	-	-
25 TOTAL OTHER MAINTENANCE LABOR	LABOTHMN	-	-	-	-	-	-	-	-
26 TRANSM OPER EXP 562-567	EXP5627TX	1.00000	0.80657	0.11248	0.08095	0.00001	0.08094	0.02526	0.05569
27 TRANSM MAINT EXP 569-573	EXP5693TX	1.00000	0.80453	0.11367	0.08180	0.00001	0.08180	0.02552	0.05627
28 TOT TRANSM OPERATIONS LABOR	LABTROP	1.00000	0.80246	0.11487	0.08267	0.00001	0.08266	0.02579	0.05687
29 TOT TRANSM MAINTENANCE LABOR	LABTRMN	-	-	-	-	-	-	-	-
30 DISTR OPER EXP 582-589	EXP5829DIS	1.00000	0.93841	0.05690	0.00469	0.00010	0.00459	0.00297	0.00162
31 DISTR MAINT EXP 591-598	EXP5918DIS	1.00000	0.92520	0.07419	0.00061	0.00013	0.00048	0.00047	0.00001
32 TOT DISTR OPERATIONS LABOR	LABDISOP	1.00000	0.94085	0.05603	0.00313	0.00011	0.00301	0.00259	0.00042
33 TOT DISTR MAINTENANCE LABOR	LABDISMN	-	-	-	-	-	-	-	-
34 CUST ACCT EXP 902, 903 & 905	EXP9025CA	1.00000	0.94611	0.05265	0.00124	0.00001	0.00123	0.00066	0.00057
35 TOTAL CUST ACCOUNTS LABOR	LABCA	1.00000	0.94611	0.05265	0.00124	0.00001	0.00123	0.00066	0.00057
36 CUST SERVICES EXP 908-910	EXP9080CS	1.00000	0.99930	0.00070	0.00000	0.00000	-	-	-
37 TOTAL CUST SERVICES LABOR	LABCS	1.00000	0.94611	0.05265	0.00124	0.00001	0.00123	0.00066	0.00057
38 SALES EXPENSE 912-916	EXP9126SA	1.00000	0.94597	0.05402	0.00001	0.00001	-	-	-
39 TOTAL SALES EXP LABOR	LABSA	1.00000	0.99930	0.00070	0.00000	0.00000	-	-	-
40 TOT ADMINISTRATIVE & GEN EXP	A_GEXP	1.00000	0.89776	0.05673	0.04552	0.00003	0.04549	0.01476	0.03073

KENTUCKY UTILITIES COMPANY
ELECTRIC COST OF SERVICE STUDY
JURISDICTIONAL SEPARATION

RATE BASE: END OF YEAR
ALLOCATION METHOD: AVG 12 CP (COMBINED CO SYS)

12 MONTHS ENDING MARCH 31, 2012

		ALLOC	TOTAL KENTUCKY UTILITIES (1)	KENTUCKY STATE JURISDICTION (2)	VIRGINIA STATE JURISDICTION (3)	FERC & TENNESSEE JURISDICTION (4)	TENNESSEE STATE JURISDICTION (5)	FERC JURISDICTION (6)	PRIMARY (7)	TRANSMISSION (8)
	INTERNALLY DEVELOPED-CON'T									
	-									
1	ACCT 930-EPRI & ADVERTISING	EXP930A	1.00000	0.94978	0.05022	0.00001	0.00001	-	-	-
2	TOTAL CUSTOMER SERVICES EXP	CUSTSER	1.00000	0.99938	0.00062	0.00000	0.00000	-	-	-
3	DISTRIBUTION PLANT EXCL VA	DPLTXVA	1.00000	0.99669	-	0.00331	0.00012	0.00319	0.00274	0.00045
4	ACCT 926 DIR ASSIGN COMP.KY RET	LABPTDKY	1.00000	1.00000	-	-	-	-	-	-
5	ACCT 926 DIR ASSIGN COMP.VAJ	LABPTDVAJ	1.00000	-	1.00000	-	-	-	-	-
6	ACCT 926 DIR ASSIGN COMP.VANJ	LABPTDVNJ	-	-	-	-	-	-	-	-
7	ACCT 926 DIR ASSIGN COMP.FERC	LABPTDFER	1.00000	-	-	1.00000	-	1.00000	0.32422	0.67578
8	203(E) EXCESS DEFERRED TAXES	TOT203E	1.00000	0.87861	0.05573	0.06565	0.00003	0.06562	0.02085	0.04477
9	RATE BASE-KY	KYRATEBASE	1.00000	0.92469	-	0.07531	-	0.07531	0.02392	0.05139
10										
11										
12										
13										

Conroy Exhibit C3

Electric Cost of Service Study – Functional Assignment

KENTUCKY UTILITIES COMPANY
Cost of Service Study
Functional Assignment and Classification
12 Months Ended March 31, 2012

Description	Name	Functional Vector	Total System	Production Demand Base	Production Demand Inter.	Production Demand Peak	Production Energy Base	Production Energy Inter.	Production Energy Peak
Plant in Service									
Intangible Plant									
301.00 ORGANIZATION	P301	PT&D	$ 38,707	8,721	8,221	8,443	-	-	-
302.00 FRANCHISE AND CONSENTS	P301	PT&D	55,919	12,599	11,877	12,198	-	-	-
303.00 SOFTWARE	P302	PT&D	52,331,978	11,790,821	11,114,945	11,415,125	-	-	-
Total Intangible Plant	PINT		$ 52,426,604	$ 11,812,141	$ 11,135,043	$ 11,435,766	$ -	$ -	$ -
Steam Production Plant									
Total Steam Production Plant	PSTPR	F017	$ 3,105,688,242	1,066,948,255	1,005,788,379	1,032,951,608	-	-	-
Hydraulic Production Plant									
Total Hydraulic Production Plant	PHDPR	F017	$ 24,836,524	8,532,500	8,043,398	8,260,626	-	-	-
Other Production Plant									
Total Other Production Plant	POTPR	F017	$ 459,827,511	157,972,122	148,916,804	152,938,586	-	-	-
Total Production Plant	PPRTL		$ 3,590,352,278	$ 1,233,452,877	$ 1,162,748,581	$ 1,194,150,820	$ -	$ -	$ -
Transmission									
KENTUCKY SYSTEM PROPERTY	P350	F011	$ 528,497,002	-	-	-	-	-	-
VIRGINIA PROPERTY - 500 KV LINE	P352	F011	7,504,808	-	-	-	-	-	-
Total Transmission Plant	PTRAN		$ 536,001,810	$ -	$ -	$ -	$ -	$ -	$ -
Distribution									
TOTAL ACCTS 360-362	P362	F001	$ 146,452,780	-	-	-	-	-	-
364 & 365-OVERHEAD LINES	P365	F003	537,135,305	-	-	-	-	-	-
366 & 367-UNDERGROUND LINES	P367	F004	141,341,084	-	-	-	-	-	-
368-TRANSFORMERS - POWER POOL	P368	F005	5,409,429	-	-	-	-	-	-
368-TRANSFORMERS - ALL OTHER	P368a	F005	267,984,931	-	-	-	-	-	-
369-SERVICES	P369	F006	84,507,618	-	-	-	-	-	-
370-METERS	P370	F007	66,969,753	-	-	-	-	-	-
371-CUSTOMER INSTALLATION	P371	F008	17,384,575	-	-	-	-	-	-
373-STREET LIGHTING	P373	F008	80,975,590	-	-	-	-	-	-
Total Distribution Plant	PDIST		$ 1,348,161,065	$ -	$ -	$ -	$ -	$ -	$ -
Total Prod, Trans, and Dist Plant	PT&D		$ 5,474,515,153	$ 1,233,452,877	$ 1,162,748,581	$ 1,194,150,820	$ -	$ -	$ -

KENTUCKY UTILITIES COMPANY
Cost of Service Study
Functional Assignment and Classification
12 Months Ended March 31, 2012

Description	Name	Functional Vector	Transmission Demand Base	Transmission Demand Winter	Transmission Demand Summer	Distribution Poles Specific	Distribution Substation General	Distribution Primary Lines Specific	Distribution Primary Lines Demand	Distribution Primary Lines Customer
Plant in Service										
Intangible Plant										
301.00 ORGANIZATION	P301	PT&D	1,302	1,227	1,260	-	1,035	-	1,677	2,400
302.00 FRANCHISE AND CONSENTS	P301	PT&D	1,881	1,773	1,821	-	1,496	-	2,423	3,468
303.00 SOFTWARE	P302	PT&D	1,760,246	1,659,344	1,704,158	-	1,399,971	-	2,267,444	3,245,393
Total Intangible Plant	PINT		$ 1,763,428	$ 1,662,345	$ 1,707,239	$ -	$ 1,402,503	$ -	$ 2,271,544	$ 3,251,262
Steam Production Plant										
Total Steam Production Plant	PSTPR	F017	-	-	-	-	-	-	-	-
Hydraulic Production Plant										
Total Hydraulic Production Plant	PHDPR	F017	-	-	-	-	-	-	-	-
Other Production Plant										
Total Other Production Plant	POTPR	F017	-	-	-	-	-	-	-	-
Total Production Plant	PPRTL		$ -	$ -	$ -	$ -		$ -	$ -	
Transmission										
KENTUCKY SYSTEM PROPERTY	P350	F011	181,563,283	171,155,667	175,778,052	-	-	-	-	-
VIRGINIA PROPERTY - 500 KV LINE	P352	F011	2,578,250	2,430,459	2,496,098	-	-	-	-	-
Total Transmission Plant	PTRAN		$ 184,141,534	$ 173,586,126	$ 178,274,150	$ -	$ -	$ -	$ -	$ -
Distribution										
TOTAL ACCTS 360-362	P362	F001	-	-	-	-	146,452,780	-	-	-
364 & 365-OVERHEAD LINES	P365	F003	-	-	-	-	-	-	207,417,484	249,147,525
366 & 367-UNDERGROUND LINES	P367	F004	-	-	-	-	-	-	29,782,687	90,357,235
368-TRANSFORMERS - POWER POOL	P368	F005	-	-	-	-	-	-	-	-
368-TRANSFORMERS - ALL OTHER	P368a	F005	-	-	-	-	-	-	-	-
369-SERVICES	P369	F006	-	-	-	-	-	-	-	-
370-METERS	P370	F007	-	-	-	-	-	-	-	-
371-CUSTOMER INSTALLATION	P371	F008	-	-	-	-	-	-	-	-
373-STREET LIGHTING	P373	F008	-	-	-	-	-	-	-	-
Total Distribution Plant	PDIST		$ -	$ -	$ -	$ -	$ 146,452,780	$ -	$ 237,200,170	$ 339,504,761
Total Prod, Trans, and Dist Plant	PT&D		$ 184,141,534	$ 173,586,126	$ 178,274,150	$ -	$ 146,452,780	$ -	$ 237,200,170	$ 339,504,761

KENTUCKY UTILITIES COMPANY
Cost of Service Study
Functional Assignment and Classification
12 Months Ended March 31, 2012

Description	Name	Functional Vector	Distribution Sec. Lines Demand	Distribution Sec. Lines Customer	Distribution Line Trans. Demand	Distribution Line Trans. Customer	Distribution Services Customer	Distribution Meters	Distribution St. & Cust. Lighting
Plant in Service									
Intangible Plant									
301.00 ORGANIZATION	P301	PT&D	296	424	1,042	891	598	474	695
302.00 FRANCHISE AND CONSENTS	P301	PT&D	428	612	1,505	1,288	863	684	1,005
303.00 SOFTWARE	P302	PT&D	400,137	572,716	1,408,378	1,205,053	807,825	640,177	940,244
Total Intangible Plant	PINT		$ 400,861	$ 573,752	$ 1,410,925	$ 1,207,232	$ 809,286	$ 641,335	$ 941,944
Steam Production Plant									
Total Steam Production Plant	PSTPR	F017	-	-	-	-	-	-	-
Hydraulic Production Plant									
Total Hydraulic Production Plant	PHDPR	F017	-	-	-	-	-	-	-
Other Production Plant									
Total Other Production Plant	POTPR	F017	-	-	-	-	-	-	-
Total Production Plant	PPRTL				$ -	$ -			$ -
Transmission									
KENTUCKY SYSTEM PROPERTY	P350	F011	-	-	-	-	-	-	-
VIRGINIA PROPERTY - 500 KV LINE	P352	F011	-	-	-	-	-	-	-
Total Transmission Plant	PTRAN		$ -	$ -	$ -	$ -	$ -	$ -	$ -
Distribution									
TOTAL ACCTS 360-362	P362	F001	-	-	-	-	-	-	-
364 & 365-OVERHEAD LINES	P365	F003	36,603,085	43,967,210	-	-	-	-	-
366 & 367-UNDERGROUND LINES	P367	F004	5,255,768	15,945,394	-	-	-	-	-
368-TRANSFORMERS - POWER POOL	P368	F005	-	-	2,915,141	2,494,288	-	-	-
368-TRANSFORMERS - ALL OTHER	P368a	F005	-	-	144,417,079	123,567,852	-	-	-
369-SERVICES	P369	F006	-	-	-	-	84,507,618	-	-
370-METERS	P370	F007	-	-	-	-	-	66,969,753	-
371-CUSTOMER INSTALLATION	P371	F008	-	-	-	-	-	-	17,384,575
373-STREET LIGHTING	P373	F008	-	-	-	-	-	-	80,975,590
Total Distribution Plant	PDIST		$ 41,858,854	$ 59,912,605	$ 147,332,221	$ 126,062,140	$ 84,507,618	$ 66,969,753	$ 98,360,165
Total Prod, Trans, and Dist Plant	PT&D		$ 41,858,854	$ 59,912,605	$ 147,332,221	$ 126,062,140	$ 84,507,618	$ 66,969,753	$ 98,360,165

KENTUCKY UTILITIES COMPANY
Cost of Service Study
Functional Assignment and Classification
12 Months Ended March 31, 2012

Description	Name	Functional Vector	Customer Accounts Expense	Customer Service & Info.	Sales Expense
Plant in Service					
Intangible Plant					
301.00 ORGANIZATION	P301	PT&D	-	-	-
302.00 FRANCHISE AND CONSENTS	P301	PT&D	-	-	-
303.00 SOFTWARE	P302	PT&D	-	-	-
Total Intangible Plant	PINT		$ -	$ -	$ -
Steam Production Plant					
Total Steam Production Plant	PSTPR	F017	-	-	-
Hydraulic Production Plant					
Total Hydraulic Production Plant	PHDPR	F017	-	-	-
Other Production Plant					
Total Other Production Plant	POTPR	F017	-	-	-
Total Production Plant	PPRTL		$ -	$ -	$ -
Transmission					
KENTUCKY SYSTEM PROPERTY	P350	F011	-	-	-
VIRGINIA PROPERTY - 500 KV LINE	P352	F011	-	-	-
Total Transmission Plant	PTRAN		$ -	$ -	$ -
Distribution					
TOTAL ACCTS 360-362	P362	F001	-	-	-
364 & 365-OVERHEAD LINES	P365	F003	-	-	-
366 & 367-UNDERGROUND LINES	P367	F004	-	-	-
368-TRANSFORMERS - POWER POOL	P368	F005	-	-	-
368-TRANSFORMERS - ALL OTHER	P368a	F005	-	-	-
369-SERVICES	P369	F006	-	-	-
370-METERS	P370	F007	-	-	-
371-CUSTOMER INSTALLATION	P371	F008	-	-	-
373-STREET LIGHTING	P373	F008	-	-	-
Total Distribution Plant	PDIST		$ -	$ -	$ -
Total Prod, Trans, and Dist Plant	PT&D		$ -	$ -	$ -

KENTUCKY UTILITIES COMPANY
Cost of Service Study
Functional Assignment and Classification
12 Months Ended March 31, 2012

Description	Name	Functional Vector	Total System	Production Demand Base	Production Demand Inter.	Production Demand Peak	Production Energy Base	Production Energy Inter.	Production Energy Peak
Plant in Service (Continued)									
General Plant									
Total General Plant	PGP	PT&D	$ 124,597,128	28,072,748	26,463,555	27,178,254	-	-	-
TOTAL COMMON PLANT	PCOM	PT&D	$ -	-	-	-	-	-	-
106.00 COMPLETED CONSTR NOT CLASSIFIED	P106	PT&D	$ -	-	-	-	-	-	-
105.00 PLANT HELD FOR FUTURE USE	P105	PDIST	$ 722,727	-	-	-	-	-	-
OTHER		PDIST	786,955	-	-	-	-	-	-
Total Plant in Service	TPIS		$ 5,653,048,566	$ 1,273,337,766	$ 1,200,347,179	$ 1,232,764,839	$ -	$ -	$ -
Construction Work in Progress (CWIP)									
CWIP Production	CWIP1	F017	$ 229,805,038	78,948,711	74,423,193	76,433,133	-	-	-
CWIP Transmission	CWIP2	F011	36,186,518	-	-	-	-	-	-
CWIP Distribution Plant	CWIP3	PDIST	21,196,765	-	-	-	-	-	-
CWIP General Plant	CWIP4	PT&D	12,374,679	2,788,116	2,628,295	2,699,277	-	-	-
RWIP	CWIP5	F004	-	-	-	-	-	-	-
Total Construction Work in Progress	TCWIP		$ 299,563,000	$ 81,736,827	$ 77,051,488	$ 79,132,410	$ -	$ -	$ -
Total Utility Plant			$ 5,952,611,566	$ 1,355,074,594	$ 1,277,398,667	$ 1,311,897,250	$ -	$ -	$ -

KENTUCKY UTILITIES COMPANY
Cost of Service Study
Functional Assignment and Classification
12 Months Ended March 31, 2012

			Transmission Demand			Distribution Poles	Distribution Substation	Distribution Primary Lines		
Description	**Name**	**Functional Vector**	**Base**	**Winter**	**Summer**	**Specific**	**General**	**Specific**	**Demand**	**Customer**
Plant in Service (Continued)										
General Plant										
Total General Plant	PGP	PT&D	4,190,966	3,950,730	4,057,427	-	3,333,189	-	5,398,553	7,726,952
TOTAL COMMON PLANT	PCOM	PT&D	-	-	-	-	-	-	-	-
106.00 COMPLETED CONSTR NOT CLASSIFIED	P106	PT&D	-	-	-	-	-	-	-	-
105.00 PLANT HELD FOR FUTURE USE	P105	PDIST	-	-	-	-	78,511	-	127,159	182,003
OTHER		PDIST	-	-	-	-	85,488	-	138,460	198,177
Total Plant in Service	TPIS		$ 190,095,928	$ 179,199,201	$ 184,038,817	$ -	$ 151,352,471	$ -	$ 245,135,885	$ 350,863,155
Construction Work in Progress (CWIP)										
CWIP Production	CWIP1	F017	-	-	-	-	-	-	-	-
CWIP Transmission	CWIP2	F011	12,431,751	11,719,135	12,035,633	-	-	-	-	-
CWIP Distribution Plant	CWIP3	PDIST	-	-	-	-	2,302,637	-	3,729,433	5,337,940
CWIP General Plant	CWIP4	PT&D	416,236	392,377	402,974	-	331,044	-	536,171	767,422
RWIP	CWIP5	F004	-	-	-	-	-	-	-	-
Total Construction Work in Progress	TCWIP		$ 12,847,987	$ 12,111,512	$ 12,438,606	$ -	$ 2,633,681	$ -	$ 4,265,604	$ 6,105,362
Total Utility Plant			$ 202,943,915	$ 191,310,713	$ 196,477,423	$ -	$ 153,986,152	$ -	$ 249,401,489	$ 356,968,516

KENTUCKY UTILITIES COMPANY
Cost of Service Study
Functional Assignment and Classification
12 Months Ended March 31, 2012

Description	Name	Functional Vector	Distribution Sec. Lines Demand	Distribution Sec. Lines Customer	Distribution Line Trans. Demand	Distribution Line Trans. Customer	Distribution Services Customer	Distribution Meters	Distribution St. & Cust. Lighting
Plant in Service (Continued)									
General Plant									
Total General Plant	PGP	PT&D	952,686	1,363,580	3,353,205	2,869,109	1,923,350	1,524,197	2,238,626
TOTAL COMMON PLANT	PCOM	PT&D	-	-	-	-	-	-	-
106.00 COMPLETED CONSTR NOT CLASSIFIED	P106	PT&D	-	-	-	-	-	-	-
105.00 PLANT HELD FOR FUTURE USE	P105	PDIST	22,440	32,118	78,982	67,580	45,303	35,901	52,729
OTHER		PDIST	24,434	34,972	86,001	73,586	49,329	39,092	57,415
Total Plant in Service	TPIS		$ 43,259,274	$ 61,917,027	$ 152,261,334	$ 130,279,646	$ 87,334,885	$ 69,210,278	$ 101,650,880
Construction Work in Progress (CWIP)									
CWIP Production	CWIP1	F017	-	-	-	-	-	-	-
CWIP Transmission	CWIP2	F011	-	-	-	-	-	-	-
CWIP Distribution Plant	CWIP3	PDIST	658,135	941,989	2,316,464	1,982,040	1,328,690	1,052,947	1,546,490
CWIP General Plant	CWIP4	PT&D	94,618	135,427	333,032	284,953	191,022	151,379	222,335
RWIP	CWIP5	F004	-	-	-	-	-	-	-
Total Construction Work in Progress	TCWIP		$ 752,754	$ 1,077,417	$ 2,649,496	$ 2,266,993	$ 1,519,712	$ 1,204,326	$ 1,768,825
Total Utility Plant			$ 44,012,027	$ 62,994,444	$ 154,910,830	$ 132,546,639	$ 88,854,598	$ 70,414,604	$ 103,419,705

Description	Name	Functional Vector	Customer Accounts Expense	Customer Service & Info.	Sales Expense
Plant in Service (Continued)					
General Plant					
Total General Plant	PGP	PT&D	-	-	-
TOTAL COMMON PLANT	PCOM	PT&D	-	-	-
106.00 COMPLETED CONSTR NOT CLASSIFIED	P106	PT&D	-	-	-
105.00 PLANT HELD FOR FUTURE USE	P105	PDIST	-	-	-
OTHER		PDIST	-	-	-
Total Plant in Service	TPIS		$ -	$ -	$ -
Construction Work in Progress (CWIP)					
CWIP Production	CWIP1	F017	-	-	-
CWIP Transmission	CWIP2	F011	-	-	-
CWIP Distribution Plant	CWIP3	PDIST	-	-	-
CWIP General Plant	CWIP4	PT&D	-	-	-
RWIP	CWIP5	F004	-	-	-
Total Construction Work in Progress	TCWIP		$ -	$ -	$ -
Total Utility Plant			$ -	$ -	$ -

KENTUCKY UTILITIES COMPANY
Cost of Service Study
Functional Assignment and Classification
12 Months Ended March 31, 2012

Description	Name	Functional Vector	Total System	Production Demand Base	Production Demand Inter.	Production Demand Peak	Production Energy Base	Production Energy Inter.	Production Energy Peak
Rate Base									
Utility Plant									
Plant in Service			$ 5,653,048,566	$ 1,273,337,766	$ 1,200,347,179	$ 1,232,764,839	$ -	$ -	$ -
Construction Work in Progress (CWIP)			299,563,000	81,736,827.23	77,051,488.28	79,132,410.38	-	-	-
Total Utility Plant	TUP		$ 5,952,611,566	$ 1,355,074,594	$ 1,277,398,667	$ 1,311,897,250	$ -	$ -	$ -
Less: Acummulated Provision for Depreciation									
Steam Production	ADEPREPA	F017	$ 1,079,524,091	370,866,698	349,607,784	359,049,608	-	-	-
Hydraulic Production	RWIP	F017	6,757,630	2,321,560	2,188,483	2,247,587	-	-	-
Other Production		F017	154,788,757	53,177,132	50,128,899	51,482,725	-	-	-
Transmission - Kentucky System Property	ADEPRTP	PTRAN	254,981,613	-	-	-	-	-	-
Transmission - Virginia Property	ADEPRD1	PTRAN	3,872,987	-	-	-	-	-	-
Distribution	ADEPRD11	PDIST	525,543,760	-	-	-	-	-	-
General Plant	ADEPRD12	PT&D	49,454,286	11,142,454	10,503,743	10,787,417	-	-	-
Intangible Plant	ADEPRGP	PT&D	16,605,338	3,741,318	3,526,857	3,622,107	-	-	-
Total Accumulated Depreciation	TADEPR		$ 2,091,528,460	$ 441,249,162	$ 415,955,766	$ 427,189,444	$ -	$ -	$ -
Net Utility Plant	NTPLANT		$ 3,861,083,106	$ 913,825,432	$ 861,442,901	$ 884,707,806	$ -	$ -	$ -
Working Capital									
Cash Working Capital - Operation and Maintenance Expenses	CWC	OMLPP	$ 96,090,910	3,567,742	3,363,231	3,454,061	66,178,542	-	-
Materials and Supplies	M&S	TPIS	115,098,215	25,925,640	24,439,524	25,099,560	-	-	-
Prepayments	PREPAY	TPIS	6,567,467	1,479,309	1,394,511	1,432,173	-	-	-
Total Working Capital	TWC		$ 217,756,592	$ 30,972,691	$ 29,197,266	$ 29,985,794	$ 66,178,542	$ -	$ -
Emission Allowance	EMALL	PROFIX	415,671	142,802	134,616	138,252	-	-	-
Deferred Debits									
Service Pension Cost	PENSCOST	TLB	$ -	-	-	-	-	-	-
Accumulated Deferred Income Tax									
Total Production Plant	ADITPP	F017	294,093,013	101,034,619	95,243,087	97,815,308	-	-	-
Total Transmission Plant	ADITTP	F011	33,496,412	-	-	-	-	-	-
Total Distribution Plant	ADITDP	PDIST	102,688,559	-	-	-	-	-	-
Total General Plant	ADITGP	PT&D	9,365,573	2,110,140	1,989,182	2,042,904	-	-	-
Total Accumulated Deferred Income Tax	ADITT		439,643,557	103,144,758	97,232,269	99,858,211	-	-	-
Accumulated Deferred Investment Tax Credits									
Production	ADITCP	F017	$ 86,299,724	29,647,966	27,948,478	28,703,280	-	-	-
Transmission	ADITCT	F011	-	-	-	-	-	-	-
Transmission VA	ADITCTVA	F011	-	-	-	-	-	-	-
Distribution VA	ADITCDVA	PDIST	-	-	-	-	-	-	-
Distribution Plant KY,FERC & TN	ADITCDKY	PDIST	-	-	-	-	-	-	-
General	ADITCG	PT&D	-	-	-	-	-	-	-
Total Accum. Deferred Investment Tax Credits	ADITCTL		86,299,724	29,647,966	27,948,478	28,703,280	-	-	-
Total Deferred Debits			$ 525,943,281	$ 132,792,725	$ 125,180,747	$ 128,561,491	$ -	$ -	$ -
Less: Customer Advances	CSTDEP	F027	$ 2,936,189	-	-	-	-	-	-
Less: Asset Retirement Obligations		F017	$ 49,440,753	16,985,197	16,011,567	16,443,990	-	-	-
Net Rate Base	RB		$ 3,500,935,146	$ 795,163,003	$ 749,582,470	$ 769,826,371	$ 66,178,542	$ -	$ -

KENTUCKY UTILITIES COMPANY
Cost of Service Study
Functional Assignment and Classification
12 Months Ended March 31, 2012

Description	Name	Functional Vector	Transmission Demand Base	Transmission Demand Winter	Transmission Demand Summer	Distribution Poles Specific	Distribution Substation General	Distribution Primary Lines Specific	Distribution Primary Lines Demand	Distribution Primary Lines Customer
Rate Base										
Utility Plant										
Plant in Service			$ 190,095,928	$ 179,199,201	$ 184,038,817	$ -	$ 151,352,471	$ -	$ 245,135,885	$ 350,863,155
Construction Work in Progress (CWIP)			12,847,987.31	12,111,511.75	12,438,606.18	-	2,633,680.82	-	4,265,603.81	6,105,361.55
Total Utility Plant	TUP		$ 202,943,915	$ 191,310,713	$ 196,477,423	$ -	$ 153,986,152	$ -	$ 249,401,489	$ 356,968,516
Less: Acummulated Provision for Depreciation										
Steam Production	ADEPREPA	F017	-	-	-	-	-	-	-	-
Hydraulic Production	RWIP	F017	-	-	-	-	-	-	-	-
Other Production		F017	-	-	-	-	-	-	-	-
Transmission - Kentucky System Property	ADEPRTP	PTRAN	87,598,035	82,576,718	84,806,860	-	-	-	-	-
Transmission - Virginia Property	ADEPRD1	PTRAN	1,330,551	1,254,281	1,288,155	-	-	-	-	-
Distribution	ADEPRD11	PDIST	-	-	-	-	57,090,615	-	92,466,006	132,346,656
General Plant	ADEPRD12	PT&D	1,663,451	1,568,098	1,610,448	-	1,322,988	-	2,142,759	3,066,932
Intangible Plant	ADEPRGP	PT&D	558,539	526,523	540,742	-	444,222	-	719,477	1,029,788
Total Accumulated Depreciation	TADEPR		$ 91,150,576	$ 85,925,620	$ 88,246,205	$ -	$ 58,857,825	$ -	$ 95,328,242	$ 136,443,376
Net Utility Plant	NTPLANT		$ 111,793,339	$ 105,385,093	$ 108,231,218	$ -	$ 95,128,327	$ -	$ 154,073,247	$ 220,525,140
Working Capital										
Cash Working Capital - Operation and Maintenance Expenses	CWC	OMLPP	1,277,522	1,204,291	1,236,815	-	754,865	-	2,247,245	2,875,352
Materials and Supplies	M&S	TPIS	3,870,425	3,648,564	3,747,100	-	3,081,594	-	4,991,060	7,143,707
Prepayments	PREPAY	TPIS	220,845	208,186	213,808	-	175,835	-	284,788	407,618
Total Working Capital	TWC		$ 5,368,792	$ 5,061,041	$ 5,197,724	$ -	$ 4,012,294	$ -	$ 7,523,093	$ 10,426,677
Emission Allowance	EMALL	PROFIX	-	-	-	-	-	-	-	-
Deferred Debits										
Service Pension Cost	PENSCOST	TLB	-	-	-	-	-	-	-	-
Accumulated Deferred Income Tax										
Total Production Plant	ADITPP	F017	-	-	-	-	-	-	-	-
Total Transmission Plant	ADITTP	F011	11,507,574	10,847,934	11,140,903	-	-	-	-	-
Total Distribution Plant	ADITDP	PDIST	-	-	-	-	11,155,214	-	18,067,384	25,859,859
Total General Plant	ADITGP	PT&D	315,022	296,964	304,984	-	250,545	-	405,792	580,811
Total Accumulated Deferred Income Tax	ADITT		11,822,596	11,144,898	11,445,887	-	11,405,759	-	18,473,176	26,440,669
Accumulated Deferred Investment Tax Credits										
Production	ADITCP	F017	-	-	-	-	-	-	-	-
Transmission	ADITCT	F011	-	-	-	-	-	-	-	-
Transmission VA	ADITCTVA	F011	-	-	-	-	-	-	-	-
Distribution VA	ADITCDVA	PDIST	-	-	-	-	-	-	-	-
Distribution Plant KY,FERC & TN	ADITCDKY	PDIST	-	-	-	-	-	-	-	-
General	ADITCG	PT&D	-	-	-	-	-	-	-	-
Total Accum. Deferred Investment Tax Credits	ADITCTL		-	-	-	-	-	-	-	-
Total Deferred Debits			$ 11,822,596	$ 11,144,898	$ 11,445,887	$ -	$ 11,405,759	$ -	$ 18,473,176	$ 26,440,669
Less: Customer Advances	CSTDEP	F027	-	-	-	-	-	-	1,026,512	1,469,248
Less: Asset Retirement Obligations		F017	-	-	-	-	-	-	-	-
Net Rate Base	RB		$ 105,339,535	$ 99,301,236	$ 101,983,055	$ -	$ 87,734,862	$ -	$ 142,096,651	$ 203,041,900

KENTUCKY UTILITIES COMPANY
Cost of Service Study
Functional Assignment and Classification
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Description	Name	Functional Vector	Distribution Sec. Lines Demand	Distribution Sec. Lines Customer	Distribution Line Trans. Demand	Distribution Line Trans. Customer	Distribution Services Customer	Distribution Meters	Distribution St. & Cust. Lighting
Rate Base									
Utility Plant									
Plant in Service			$ 43,259,274	$ 61,917,027	$ 152,261,334	$ 130,279,646	$ 87,334,885	$ 69,210,278	$ 101,650,880
Construction Work in Progress (CWIP)			752,753.61	1,077,416.74	2,649,495.92	2,266,993.07	1,519,712.30	1,204,326.42	1,768,824.59
Total Utility Plant	TUP		$ 44,012,027	$ 62,994,444	$ 154,910,830	$ 132,546,639	$ 88,854,598	$ 70,414,604	$ 103,419,705
Less: Acummulated Provision for Depreciation									
Steam Production	ADEPREPA	F017	-	-	-	-	-	-	-
Hydraulic Production	RWIP	F017	-	-	-	-	-	-	-
Other Production		F017	-	-	-	-	-	-	-
Transmission - Kentucky System Property	ADEPRTP	PTRAN	-	-	-	-	-	-	-
Transmission - Virginia Property	ADEPRD1	PTRAN	-	-	-	-	-	-	-
Distribution	ADEPRD11	PDIST	16,317,531	23,355,292	57,433,441	49,141,881	32,942,986	26,106,329	38,343,023
General Plant	ADEPRD12	PT&D	378,134	541,223	1,330,932	1,138,788	763,403	604,974	888,541
Intangible Plant	ADEPRGP	PT&D	126,967	181,727	446,889	382,373	256,329	203,133	298,347
Total Accumulated Depreciation	TADEPR		$ 16,822,631	$ 24,078,243	$ 59,211,263	$ 50,663,042	$ 33,962,719	$ 26,914,436	$ 39,529,911
Net Utility Plant	NTPLANT		$ 27,189,397	$ 38,916,201	$ 95,699,567	$ 81,883,597	$ 54,891,879	$ 43,500,168	$ 63,889,794
Working Capital									
Cash Working Capital - Operation and Maintenance Expenses	CWC	OMLPP	396,573	507,415	389,638	333,386	216,212	1,188,295	245,639
Materials and Supplies	M&S	TPIS	880,775	1,260,654	3,100,099	2,652,543	1,778,171	1,409,148	2,069,651
Prepayments	PREPAY	TPIS	50,257	71,933	176,891	151,353	101,462	80,406	118,094
Total Working Capital	TWC		$ 1,327,605	$ 1,840,002	$ 3,666,627	$ 3,137,283	$ 2,095,846	$ 2,677,848	$ 2,433,383
Emission Allowance	EMALL	PROFIX	-	-	-	-	-	-	-
Deferred Debits									
Service Pension Cost	PENSCOST	TLB	-	-	-	-	-	-	-
Accumulated Deferred Income Tax									
Total Production Plant	ADITPP	F017	-	-	-	-	-	-	-
Total Transmission Plant	ADITTP	F011	-	-	-	-	-	-	-
Total Distribution Plant	ADITDP	PDIST	3,188,362	4,563,504	11,222,200	9,602,072	6,436,891	5,101,043	7,492,030
Total General Plant	ADITGP	PT&D	71,610	102,496	252,050	215,662	144,572	114,569	168,270
Total Accumulated Deferred Income Tax	ADITT		3,259,972	4,666,000	11,474,250	9,817,734	6,581,463	5,215,612	7,660,301
Accumulated Deferred Investment Tax Credits									
Production	ADITCP	F017	-	-	-	-	-	-	-
Transmission	ADITCT	F011	-	-	-	-	-	-	-
Transmission VA	ADITCTVA	F011	-	-	-	-	-	-	-
Distribution VA	ADITCDVA	PDIST	-	-	-	-	-	-	-
Distribution Plant KY,FERC & TN	ADITCDKY	PDIST	-	-	-	-	-	-	-
General	ADITCG	PT&D	-	-	-	-	-	-	-
Total Accum. Deferred Investment Tax Credits	ADITCTL		-	-	-	-	-	-	-
Total Deferred Debits			$ 3,259,972	$ 4,666,000	$ 11,474,250	$ 9,817,734	$ 6,581,463	$ 5,215,612	$ 7,660,301
Less: Customer Advances	CSTDEP	F027	181,149	259,279	-	-	-	-	-
Less: Asset Retirement Obligations		F017	-	-	-	-	-	-	-
Net Rate Base	RB		$ 25,075,880	$ 35,830,924	$ 87,891,944	$ 75,203,146	$ 50,406,262	$ 40,962,404	$ 58,662,876

KENTUCKY UTILITIES COMPANY
Cost of Service Study
Functional Assignment and Classification
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Description	Name	Functional Vector	Customer Accounts Expense	Customer Service & Info.	Sales Expense
Rate Base					
Utility Plant					
Plant in Service			$ -	$ -	$ -
Construction Work in Progress (CWIP)			-	-	-
Total Utility Plant	TUP		$ -	$ -	$ -
Less: Acummulated Provision for Depreciation					
Steam Production	ADEPREPA	F017	-	-	-
Hydraulic Production	RWIP	F017	-	-	-
Other Production		F017	-	-	-
Transmission - Kentucky System Property	ADEPRTP	PTRAN	-	-	-
Transmission - Virginia Property	ADEPRD1	PTRAN	-	-	-
Distribution	ADEPRD11	PDIST	-	-	-
General Plant	ADEPRD12	PT&D	-	-	-
Intangible Plant	ADEPRGP	PT&D	-	-	-
Total Accumulated Depreciation	TADEPR		$ -	$ -	$ -
Net Utility Plant	NTPLANT		$ -	$ -	$ -
Working Capital					
Cash Working Capital - Operation and Maintenance Expenses	CWC	OMLPP	4,672,230	1,981,856	-
Materials and Supplies	M&S	TPIS	-	-	-
Prepayments	PREPAY	TPIS	-	-	-
Total Working Capital	TWC		$ 4,672,230	$ 1,981,856	$ -
Emission Allowance	EMALL	PROFIX	-	-	-
Deferred Debits					
Service Pension Cost	PENSCOST	TLB	-	-	-
Accumulated Deferred Income Tax					
Total Production Plant	ADITPP	F017	-	-	-
Total Transmission Plant	ADITTP	F011	-	-	-
Total Distribution Plant	ADITDP	PDIST	-	-	-
Total General Plant	ADITGP	PT&D	-	-	-
Total Accumulated Deferred Income Tax	ADITT		-	-	-
Accumulated Deferred Investment Tax Credits					
Production	ADITCP	F017	-	-	-
Transmission	ADITCT	F011	-	-	-
Transmission VA	ADITCTVA	F011	-	-	-
Distribution VA	ADITCDVA	PDIST	-	-	-
Distribution Plant KY,FERC & TN	ADITCDKY	PDIST	-	-	-
General	ADITCG	PT&D	-	-	-
Total Accum. Deferred Investment Tax Credits	ADITCTL		-	-	-
Total Deferred Debits			$ -	$ -	$ -
Less: Customer Advances	CSTDEP	F027	-	-	-
Less: Asset Retirement Obligations		F017	-	-	-
Net Rate Base	RB		$ 4,672,230	$ 1,981,856	$ -

KENTUCKY UTILITIES COMPANY
Cost of Service Study
Functional Assignment and Classification
12 Months Ended March 31, 2012

Description	Name	Functional Vector	Total System	Production Demand Base	Production Demand Inter.	Production Demand Peak	Production Energy Base	Production Energy Inter.	Production Energy Peak
Operation and Maintenance Expenses									
Steam Power Generation Operation Expenses									
500 OPERATION SUPERVISION & ENGINEERING	OM500	LBSUB1	$ 5,020,059	1,429,633	1,347,683	1,384,080	858,662	-	-
501 FUEL	OM501	Energy	420,872,445	-	-	-	420,872,445	-	-
502 STEAM EXPENSES	OM502		15,103,336	2,713,161	2,557,637	2,626,711	7,205,828	-	-
505 ELECTRIC EXPENSES	OM505		6,200,218	1,890,730	1,782,349	1,830,485	696,653	-	-
506 MISC. STEAM POWER EXPENSES	OM506	PROFIX	21,102,860	7,249,813	6,834,238	7,018,809	-	-	-
507 RENTS	OM507	PROFIX	118,990	40,879	38,535	39,576	-	-	-
Total Steam Power Operation Expenses			$ 468,417,908	$ 13,324,216	$ 12,560,442	$ 12,899,661	$ 429,633,588	$ -	$ -
Steam Power Generation Maintenance Expenses									
510 MAINTENANCE SUPERVISION & ENGINEERING	OM510	LBSUB2	$ 6,590,708	204,100	192,400	197,596	5,996,611	-	-
511 MAINTENANCE OF STRUCTURES	OM511	PROFIX	5,063,205	1,739,446	1,639,737	1,684,021	-	-	-
512 MAINTENANCE OF BOILER PLANT	OM512	Energy	34,867,058	-	-	-	34,867,058	-	-
513 MAINTENANCE OF ELECTRIC PLANT	OM513	Energy	11,091,401	-	-	-	11,091,401	-	-
514 MAINTENANCE OF MISC STEAM PLANT	OM514	Energy	1,928,065	-	-	-	1,928,065	-	-
Total Steam Power Generation Maintenance Expense			$ 59,540,437	$ 1,943,546	$ 1,832,137	$ 1,881,618	$ 53,883,136	$ -	$ -
Total Steam Power Generation Expense			$ 527,958,344	$ 15,267,762	$ 14,392,580	$ 14,781,279	$ 483,516,724	$ -	$ -
Hydraulic Power Generation Operation Expenses									
535 OPERATION SUPERVISION & ENGINEERING	OM535	LBSUB3	$ 6,861	2,357	2,222	2,282	-	-	-
536 WATER FOR POWER	OM536	PROFIX	-	-	-	-	-	-	-
537 HYDRAULIC EXPENSES	OM537	PROFIX	-	-	-	-	-	-	-
538 ELECTRIC EXPENSES	OM538		-	-	-	-	-	-	-
539 MISC. HYDRAULIC POWER EXPENSES	OM539	PROFIX	38,553	13,245	12,485	12,823	-	-	-
540 RENTS		PROFIX	-	-	-	-	-	-	-
Total Hydraulic Power Operation Expenses			$ 45,414	$ 15,602	$ 14,707	$ 15,105	$ -	$ -	$ -
Hydraulic Power Generation Maintenance Expenses									
541 MAINTENANCE SUPERVISION & ENGINEERING	OM541	LBSUB4	$ 102,609	9,979	9,407	9,661	73,561	-	-
542 MAINTENANCE OF STRUCTURES	OM542	PROFIX	146,078	50,184	47,308	48,585	-	-	-
543 MAINT. OF RESERVES, DAMS, AND WATERWAYS	OM543	PROFIX	36,620	12,581	11,860	12,180	-	-	-
544 MAINTENANCE OF ELECTRIC PLANT	OM544	Energy	79,975	-	-	-	79,975	-	-
545 MAINTENANCE OF MISC HYDRAULIC PLANT	OM545	Energy	6,837	-	-	-	6,837	-	-
Total Hydraulic Power Generation Maint. Expense			$ 372,119	$ 72,745	$ 68,575	$ 70,427	$ 160,373	$ -	$ -
Total Hydraulic Power Generation Expense			$ 417,533	$ 88,346	$ 83,282	$ 85,531	$ 160,373	$ -	$ -
Other Power Generation Operation Expense									
546 OPERATION SUPERVISION & ENGINEERING	OM546	LBSUB5	$ 182,409	62,666	59,074	60,669	-	-	-
547 FUEL	OM547	Energy	27,501,175	-	-	-	27,501,175	-	-
548 GENERATION EXPENSE	OM548	PROFIX	267,069	91,750	86,491	88,827	-	-	-
549 MISC OTHER POWER GENERATION	OM549	PROFIX	140,149	48,148	45,388	46,614	-	-	-
550 RENTS	OM550	PROFIX	-	-	-	-	-	-	-
Total Other Power Generation Expenses			$ 28,090,802	$ 202,564	$ 190,953	$ 196,110	$ 27,501,175	$ -	$ -

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		Functional	Transmission Demand			Distribution Poles	Distribution Substation	Distribution Primary Lines		
Description	**Name**	**Vector**	**Base**	**Winter**	**Summer**	**Specific**	**General**	**Specific**	**Demand**	**Customer**
Operation and Maintenance Expenses										
Steam Power Generation Operation Expenses										
500 OPERATION SUPERVISION & ENGINEERING	OM500	LBSUB1	-	-	-	-	-	-	-	-
501 FUEL	OM501	Energy	-	-	-	-	-	-	-	-
502 STEAM EXPENSES	OM502		-	-	-	-	-	-	-	-
505 ELECTRIC EXPENSES	OM505		-	-	-	-	-	-	-	-
506 MISC. STEAM POWER EXPENSES	OM506	PROFIX	-	-	-	-	-	-	-	-
507 RENTS	OM507	PROFIX	-	-	-	-	-	-	-	-
Total Steam Power Operation Expenses			$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Steam Power Generation Maintenance Expenses										
510 MAINTENANCE SUPERVISION & ENGINEERING	OM510	LBSUB2	-	-	-	-	-	-	-	-
511 MAINTENANCE OF STRUCTURES	OM511	PROFIX	-	-	-	-	-	-	-	-
512 MAINTENANCE OF BOILER PLANT	OM512	Energy	-	-	-	-	-	-	-	-
513 MAINTENANCE OF ELECTRIC PLANT	OM513	Energy	-	-	-	-	-	-	-	-
514 MAINTENANCE OF MISC STEAM PLANT	OM514	Energy	-	-	-	-	-	-	-	-
Total Steam Power Generation Maintenance Expense			$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Steam Power Generation Expense			$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Hydraulic Power Generation Operation Expenses										
535 OPERATION SUPERVISION & ENGINEERING	OM535	LBSUB3	-	-	-	-	-	-	-	-
536 WATER FOR POWER	OM536	PROFIX	-	-	-	-	-	-	-	-
537 HYDRAULIC EXPENSES	OM537	PROFIX	-	-	-	-	-	-	-	-
538 ELECTRIC EXPENSES	OM538		-	-	-	-	-	-	-	-
539 MISC. HYDRAULIC POWER EXPENSES	OM539	PROFIX	-	-	-	-	-	-	-	-
540 RENTS		PROFIX	-	-	-	-	-	-	-	-
Total Hydraulic Power Operation Expenses			$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Hydraulic Power Generation Maintenance Expenses										
541 MAINTENANCE SUPERVISION & ENGINEERING	OM541	LBSUB4	-	-	-	-	-	-	-	-
542 MAINTENANCE OF STRUCTURES	OM542	PROFIX	-	-	-	-	-	-	-	-
543 MAINT. OF RESERVES, DAMS, AND WATERWAYS	OM543	PROFIX	-	-	-	-	-	-	-	-
544 MAINTENANCE OF ELECTRIC PLANT	OM544	Energy	-	-	-	-	-	-	-	-
545 MAINTENANCE OF MISC HYDRAULIC PLANT	OM545	Energy	-	-	-	-	-	-	-	-
Total Hydraulic Power Generation Maint. Expense			$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Hydraulic Power Generation Expense			$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Other Power Generation Operation Expense										
546 OPERATION SUPERVISION & ENGINEERING	OM546	LBSUB5	-	-	-	-	-	-	-	-
547 FUEL	OM547	Energy	-	-	-	-	-	-	-	-
548 GENERATION EXPENSE	OM548	PROFIX	-	-	-	-	-	-	-	-
549 MISC OTHER POWER GENERATION	OM549	PROFIX	-	-	-	-	-	-	-	-
550 RENTS	OM550	PROFIX	-	-	-	-	-	-	-	-
Total Other Power Generation Expenses			$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

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Description	Name	Functional Vector	Distribution Sec. Lines Demand	Distribution Sec. Lines Customer	Distribution Line Trans. Demand	Distribution Line Trans. Customer	Distribution Services Customer	Distribution Meters	Distribution St. & Cust. Lighting
Operation and Maintenance Expenses									
Steam Power Generation Operation Expenses									
500 OPERATION SUPERVISION & ENGINEERING	OM500	LBSUB1	-	-	-	-	-	-	-
501 FUEL	OM501	Energy	-	-	-	-	-	-	-
502 STEAM EXPENSES	OM502		-	-	-	-	-	-	-
505 ELECTRIC EXPENSES	OM505		-	-	-	-	-	-	-
506 MISC. STEAM POWER EXPENSES	OM506	PROFIX	-	-	-	-	-	-	-
507 RENTS	OM507	PROFIX	-	-	-	-	-	-	-
Total Steam Power Operation Expenses			$ -	$ -	$ -	$ -	$ -	$ -	$ -
Steam Power Generation Maintenance Expenses									
510 MAINTENANCE SUPERVISION & ENGINEERING	OM510	LBSUB2	-	-	-	-	-	-	-
511 MAINTENANCE OF STRUCTURES	OM511	PROFIX	-	-	-	-	-	-	-
512 MAINTENANCE OF BOILER PLANT	OM512	Energy	-	-	-	-	-	-	-
513 MAINTENANCE OF ELECTRIC PLANT	OM513	Energy	-	-	-	-	-	-	-
514 MAINTENANCE OF MISC STEAM PLANT	OM514	Energy	-	-	-	-	-	-	-
Total Steam Power Generation Maintenance Expense			$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Steam Power Generation Expense			$ -	$ -	$ -	$ -	$ -	$ -	$ -
Hydraulic Power Generation Operation Expenses									
535 OPERATION SUPERVISION & ENGINEERING	OM535	LBSUB3	-	-	-	-	-	-	-
536 WATER FOR POWER	OM536	PROFIX	-	-	-	-	-	-	-
537 HYDRAULIC EXPENSES	OM537	PROFIX	-	-	-	-	-	-	-
538 ELECTRIC EXPENSES	OM538		-	-	-	-	-	-	-
539 MISC. HYDRAULIC POWER EXPENSES	OM539	PROFIX	-	-	-	-	-	-	-
540 RENTS		PROFIX	-	-	-	-	-	-	-
Total Hydraulic Power Operation Expenses			$ -	$ -	$ -	$ -	$ -	$ -	$ -
Hydraulic Power Generation Maintenance Expenses									
541 MAINTENANCE SUPERVISION & ENGINEERING	OM541	LBSUB4	-	-	-	-	-	-	-
542 MAINTENANCE OF STRUCTURES	OM542	PROFIX	-	-	-	-	-	-	-
543 MAINT. OF RESERVES, DAMS, AND WATERWAYS	OM543	PROFIX	-	-	-	-	-	-	-
544 MAINTENANCE OF ELECTRIC PLANT	OM544	Energy	-	-	-	-	-	-	-
545 MAINTENANCE OF MISC HYDRAULIC PLANT	OM545	Energy	-	-	-	-	-	-	-
Total Hydraulic Power Generation Maint. Expense			$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Hydraulic Power Generation Expense			$ -	$ -	$ -	$ -	$ -	$ -	$ -
Other Power Generation Operation Expense									
546 OPERATION SUPERVISION & ENGINEERING	OM546	LBSUB5	-	-	-	-	-	-	-
547 FUEL	OM547	Energy	-	-	-	-	-	-	-
548 GENERATION EXPENSE	OM548	PROFIX	-	-	-	-	-	-	-
549 MISC OTHER POWER GENERATION	OM549	PROFIX	-	-	-	-	-	-	-
550 RENTS	OM550	PROFIX	-	-	-	-	-	-	-
Total Other Power Generation Expenses			$ -	$ -	$ -	$ -	$ -	$ -	$ -

Description	Name	Functional Vector	Customer Accounts Expense	Customer Service & Info.	Sales Expense
Operation and Maintenance Expenses					
Steam Power Generation Operation Expenses					
500 OPERATION SUPERVISION & ENGINEERING	OM500	LBSUB1	-	-	-
501 FUEL	OM501	Energy	-	-	-
502 STEAM EXPENSES	OM502		-	-	-
505 ELECTRIC EXPENSES	OM505		-	-	-
506 MISC. STEAM POWER EXPENSES	OM506	PROFIX	-	-	-
507 RENTS	OM507	PROFIX	-	-	-
Total Steam Power Operation Expenses			$ -	$ -	$ -
Steam Power Generation Maintenance Expenses					
510 MAINTENANCE SUPERVISION & ENGINEERING	OM510	LBSUB2	-	-	-
511 MAINTENANCE OF STRUCTURES	OM511	PROFIX	-	-	-
512 MAINTENANCE OF BOILER PLANT	OM512	Energy	-	-	-
513 MAINTENANCE OF ELECTRIC PLANT	OM513	Energy	-	-	-
514 MAINTENANCE OF MISC STEAM PLANT	OM514	Energy	-	-	-
Total Steam Power Generation Maintenance Expense			$ -	$ -	$ -
Total Steam Power Generation Expense			$ -	$ -	$ -
Hydraulic Power Generation Operation Expenses					
535 OPERATION SUPERVISION & ENGINEERING	OM535	LBSUB3	-	-	-
536 WATER FOR POWER	OM536	PROFIX	-	-	-
537 HYDRAULIC EXPENSES	OM537	PROFIX	-	-	-
538 ELECTRIC EXPENSES	OM538		-	-	-
539 MISC. HYDRAULIC POWER EXPENSES	OM539	PROFIX	-	-	-
540 RENTS		PROFIX	-	-	-
Total Hydraulic Power Operation Expenses			$ -	$ -	$ -
Hydraulic Power Generation Maintenance Expenses					
541 MAINTENANCE SUPERVISION & ENGINEERING	OM541	LBSUB4	-	-	-
542 MAINTENANCE OF STRUCTURES	OM542	PROFIX	-	-	-
543 MAINT. OF RESERVES, DAMS, AND WATERWAYS	OM543	PROFIX	-	-	-
544 MAINTENANCE OF ELECTRIC PLANT	OM544	Energy	-	-	-
545 MAINTENANCE OF MISC HYDRAULIC PLANT	OM545	Energy	-	-	-
Total Hydraulic Power Generation Maint. Expense			$ -	$ -	$ -
Total Hydraulic Power Generation Expense			$ -	$ -	$ -
Other Power Generation Operation Expense					
546 OPERATION SUPERVISION & ENGINEERING	OM546	LBSUB5	-	-	-
547 FUEL	OM547	Energy	-	-	-
548 GENERATION EXPENSE	OM548	PROFIX	-	-	-
549 MISC OTHER POWER GENERATION	OM549	PROFIX	-	-	-
550 RENTS	OM550	PROFIX	-	-	-
Total Other Power Generation Expenses			$ -	$ -	$ -

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Description	Name	Functional Vector		Total System	Production Demand Base		Production Demand Inter.		Production Demand Peak		Production Energy Base		Production Energy Inter.		Production Energy Peak
Operation and Maintenance Expenses (Continued)															
Other Power Generation Maintenance Expense															
551 MAINTENANCE SUPERVISION & ENGINEERING	OM551	PROFIX	$	42,784	14,698		13,856		14,230		-		-		-
552 MAINTENANCE OF STRUCTURES	OM552	PROFIX		228,539	78,514		74,013		76,012		-		-		-
553 MAINTENANCE OF GENERATING & ELEC PLANT	OM553	PROFIX		1,363,702	468,495		441,640		453,567		-		-		-
554 MAINTENANCE OF MISC OTHER POWER GEN PLT	OM554	PROFIX		196,771	67,600		63,725		65,446		-		-		-
Total Other Power Generation Maintenance Expense			$	1,831,796	$ 629,307	$	593,234	$	609,255	$	-	$	-	$	-
Total Other Power Generation Expense			$	29,922,598	$ 831,871	$	784,187	$	805,365	$	27,501,175	$	-	$	-
Total Station Expense			$	558,298,475	$ 16,187,980	$	15,260,048	$	15,672,175	$	511,178,272	$	-	$	-
Other Power Supply Expenses															
555 PURCHASED POWER	OM555	OMPP	$	90,060,701	2,596,472		2,447,636		2,513,740		82,502,853		-		-
555 PURCHASED POWER OPTIONS	OMO555	OMPP		-	-		-		-		-		-		-
555 BROKERAGE FEES	OMB555	OMPP		-	-		-		-		-		-		-
555 MISO TRANSMISSION EXPENSES	OMM555	OMPP		-	-		-		-		-		-		-
556 SYSTEM CONTROL AND LOAD DISPATCH	OM556	PROFIX		1,594,179	547,674		516,281		530,224		-		-		-
557 OTHER EXPENSES	OM557	PROFIX		345,976	118,859		112,046		115,072		-		-		-
Total Other Power Supply Expenses	TPP		$	92,000,855	$ 3,263,005	$	3,075,963	$	3,159,035	$	82,502,853	$	-	$	-
Total Electric Power Generation Expenses			$	650,299,331	$ 19,450,985	$	18,336,011	$	18,831,210	$	593,681,125	$	-	$	-
Transmission Expenses															
560 OPERATION SUPERVISION AND ENG	OM560	LBTRAN	$	1,203,373	-		-		-		-		-		-
561 LOAD DISPATCHING	OM561	LBTRAN		2,285,040	-		-		-		-		-		-
562 STATION EXPENSES	OM562	LBTRAN		619,141	-		-		-		-		-		-
563 OVERHEAD LINE EXPENSES	OM563	LBTRAN		391,173	-		-		-		-		-		-
565 TRANSMISSION OF ELECTRICITY BY OTHERS	OM565	LBTRAN		1,918,210	-		-		-		-		-		-
566 MISC. TRANSMISSION EXPENSES	OM566	PTRAN		9,779,438	-		-		-		-		-		-
567 RENTS	OM567	PTRAN		114,629	-		-		-		-		-		-
568 MAINTENACE SUPERVISION AND ENG	OM568	LBTRAN		-	-		-		-		-		-		-
569 STRUCTURES	OM569	LBTRAN		-	-		-		-		-		-		-
570 MAINT OF STATION EQUIPMENT	OM570	LBTRAN		1,568,775	-		-		-		-		-		-
571 MAINT OF OVERHEAD LINES	OM571	LBTRAN		3,755,066	-		-		-		-		-		-
572 UNDERGROUND LINES	OM572	LBTRAN		-	-		-		-		-		-		-
573 MISC PLANT	OM573	PTRAN		546,407	-		-		-		-		-		-
575 MISO DAY 1&2 EXPENSE	OM575	PTRAN		1,224,445	-		-		-		-		-		-
Total Transmission Expenses			$	23,405,698	$ -	$	-	$	-	$	-	$	-	$	-
Distribution Operation Expense															
580 OPERATION SUPERVISION AND ENGI	OM580	LBDO	$	1,886,829	-		-		-		-		-		-
581 LOAD DISPATCHING	OM581	P362		705,213	-		-		-		-		-		-
582 STATION EXPENSES	OM582	P362		1,404,339	-		-		-		-		-		-
583 OVERHEAD LINE EXPENSES	OM583	P365		3,298,413	-		-		-		-		-		-
584 UNDERGROUND LINE EXPENSES	OM584	P367		255,302	-		-		-		-		-		-
585 STREET LIGHTING EXPENSE	OM585	P373		21,918	-		-		-		-		-		-
586 METER EXPENSES	OM586	P370		7,329,419	-		-		-		-		-		-
586 METER EXPENSES - LOAD MANAGEMENT	OM586x	F012		-	-		-		-		-		-		-
587 CUSTOMER INSTALLATIONS EXPENSE	OM587	P371		(70,814)	-		-		-		-		-		-
588 MISCELLANEOUS DISTRIBUTION EXP	OM588	PDIST		4,706,180	-		-		-		-		-		-
588 MISC DISTR EXP -- MAPPIN	OM588x	PDIST		-	-		-		-		-		-		-
589 RENTS	OM589	PDIST		10,707	-		-		-		-		-		-
Total Distribution Operation Expense	OMDO		$	19,547,506	$ -	$	-	$	-	$	-	$	-	$	-

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Description	Name	Functional Vector	Transmission Demand Base	Transmission Demand Winter	Transmission Demand Summer	Distribution Poles Specific	Distribution Substation General	Distribution Primary Lines Specific	Distribution Primary Lines Demand	Distribution Primary Lines Customer
Operation and Maintenance Expenses (Continued)										
Other Power Generation Maintenance Expense										
551 MAINTENANCE SUPERVISION & ENGINEERING	OM551	PROFIX	-	-	-	-	-	-	-	-
552 MAINTENANCE OF STRUCTURES	OM552	PROFIX	-	-	-	-	-	-	-	-
553 MAINTENANCE OF GENERATING & ELEC PLANT	OM553	PROFIX	-	-	-	-	-	-	-	-
554 MAINTENANCE OF MISC OTHER POWER GEN PLT	OM554	PROFIX	-	-	-	-	-	-	-	-
Total Other Power Generation Maintenance Expense			$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Other Power Generation Expense			$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Station Expense			$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Other Power Supply Expenses										
555 PURCHASED POWER	OM555	OMPP	-	-	-	-	-	-	-	-
555 PURCHASED POWER OPTIONS	OMO555	OMPP	-	-	-	-	-	-	-	-
555 BROKERAGE FEES	OMB555	OMPP	-	-	-	-	-	-	-	-
555 MISO TRANSMISSION EXPENSES	OMM555	OMPP	-	-	-	-	-	-	-	-
556 SYSTEM CONTROL AND LOAD DISPATCH	OM556	PROFIX	-	-	-	-	-	-	-	-
557 OTHER EXPENSES	OM557	PROFIX	-	-	-	-	-	-	-	-
Total Other Power Supply Expenses	TPP		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Electric Power Generation Expenses			$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Transmission Expenses										
560 OPERATION SUPERVISION AND ENG	OM560	LBTRAN	413,414	389,717	400,242	-	-	-	-	-
561 LOAD DISPATCHING	OM561	LBTRAN	785,017	740,018	760,004	-	-	-	-	-
562 STATION EXPENSES	OM562	LBTRAN	212,704	200,511	205,926	-	-	-	-	-
563 OVERHEAD LINE EXPENSES	OM563	LBTRAN	134,386	126,683	130,104	-	-	-	-	-
565 TRANSMISSION OF ELECTRICITY BY OTHERS	OM565	LBTRAN	658,994	621,219	637,997	-	-	-	-	-
566 MISC. TRANSMISSION EXPENSES	OM566	PTRAN	3,359,692	3,167,107	3,252,640	-	-	-	-	-
567 RENTS	OM567	PTRAN	39,380	37,123	38,126	-	-	-	-	-
568 MAINTENACE SUPERVISION AND ENG	OM568	LBTRAN	-	-	-	-	-	-	-	-
569 STRUCTURES	OM569	LBTRAN	-	-	-	-	-	-	-	-
570 MAINT OF STATION EQUIPMENT	OM570	LBTRAN	538,947	508,054	521,775	-	-	-	-	-
571 MAINT OF OVERHEAD LINES	OM571	LBTRAN	1,290,040	1,216,092	1,248,935	-	-	-	-	-
572 UNDERGROUND LINES	OM572	LBTRAN	-	-	-	-	-	-	-	-
573 MISC PLANT	OM573	PTRAN	187,716	176,956	181,735	-	-	-	-	-
575 MISO DAY 1&2 EXPENSE	OM575	PTRAN	420,654	396,541	407,250	-	-	-	-	-
Total Transmission Expenses			$ 8,040,945	$ 7,580,020	$ 7,784,733	$ -	$ -	$ -	$ -	$ -
Distribution Operation Expense										
580 OPERATION SUPERVISION AND ENGI	OM580	LBDO	-	-	-	-	328,619	-	204,623	272,513
581 LOAD DISPATCHING	OM581	P362	-	-	-	-	705,213	-	-	-
582 STATION EXPENSES	OM582	P362	-	-	-	-	1,404,339	-	-	-
583 OVERHEAD LINE EXPENSES	OM583	P365	-	-	-	-	-	-	1,273,699	1,529,953
584 UNDERGROUND LINE EXPENSES	OM584	P367	-	-	-	-	-	-	53,796	163,211
585 STREET LIGHTING EXPENSE	OM585	P373	-	-	-	-	-	-	-	-
586 METER EXPENSES	OM586	P370	-	-	-	-	-	-	-	-
586 METER EXPENSES - LOAD MANAGEMENT	OM586x	F012	-	-	-	-	-	-	-	-
587 CUSTOMER INSTALLATIONS EXPENSE	OM587	P371	-	-	-	-	-	-	-	-
588 MISCELLANEOUS DISTRIBUTION EXP	OM588	PDIST	-	-	-	-	511,240	-	828,022	1,185,148
588 MISC DISTR EXP -- MAPPIN	OM588x	PDIST	-	-	-	-	-	-	-	-
589 RENTS	OM589	PDIST	-	-	-	-	1,163	-	1,884	2,696
Total Distribution Operation Expense	OMDO		$ -	$ -	$ -	$ -	$ 2,950,573	$ -	$ 2,362,023	$ 3,153,520

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Description	Name	Functional Vector	Distribution Sec. Lines Demand	Distribution Sec. Lines Customer	Distribution Line Trans. Demand	Distribution Line Trans. Customer	Distribution Services Customer	Distribution Meters	Distribution St. & Cust. Lighting
Operation and Maintenance Expenses (Continued)									
Other Power Generation Maintenance Expense									
551 MAINTENANCE SUPERVISION & ENGINEERING	OM551	PROFIX	-	-	-	-	-	-	-
552 MAINTENANCE OF STRUCTURES	OM552	PROFIX	-	-	-	-	-	-	-
553 MAINTENANCE OF GENERATING & ELEC PLANT	OM553	PROFIX	-	-	-	-	-	-	-
554 MAINTENANCE OF MISC OTHER POWER GEN PLT	OM554	PROFIX	-	-	-	-	-	-	-
Total Other Power Generation Maintenance Expense			$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Other Power Generation Expense			$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Station Expense			$ -	$ -	$ -	$ -	$ -	$ -	$ -
Other Power Supply Expenses									
555 PURCHASED POWER	OM555	OMPP	-	-	-	-	-	-	-
555 PURCHASED POWER OPTIONS	OMO555	OMPP	-	-	-	-	-	-	-
555 BROKERAGE FEES	OMB555	OMPP	-	-	-	-	-	-	-
555 MISO TRANSMISSION EXPENSES	OMM555	OMPP	-	-	-	-	-	-	-
556 SYSTEM CONTROL AND LOAD DISPATCH	OM556	PROFIX	-	-	-	-	-	-	-
557 OTHER EXPENSES	OM557	PROFIX	-	-	-	-	-	-	-
Total Other Power Supply Expenses	TPP		$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Electric Power Generation Expenses			$ -	$ -	$ -	$ -	$ -	$ -	$ -
Transmission Expenses									
560 OPERATION SUPERVISION AND ENG	OM560	LBTRAN	-	-	-	-	-	-	-
561 LOAD DISPATCHING	OM561	LBTRAN	-	-	-	-	-	-	-
562 STATION EXPENSES	OM562	LBTRAN	-	-	-	-	-	-	-
563 OVERHEAD LINE EXPENSES	OM563	LBTRAN	-	-	-	-	-	-	-
565 TRANSMISSION OF ELECTRICITY BY OTHERS	OM565	LBTRAN	-	-	-	-	-	-	-
566 MISC. TRANSMISSION EXPENSES	OM566	PTRAN	-	-	-	-	-	-	-
567 RENTS	OM567	PTRAN	-	-	-	-	-	-	-
568 MAINTENACE SUPERVISION AND ENG	OM568	LBTRAN	-	-	-	-	-	-	-
569 STRUCTURES	OM569	LBTRAN	-	-	-	-	-	-	-
570 MAINT OF STATION EQUIPMENT	OM570	LBTRAN	-	-	-	-	-	-	-
571 MAINT OF OVERHEAD LINES	OM571	LBTRAN	-	-	-	-	-	-	-
572 UNDERGROUND LINES	OM572	LBTRAN	-	-	-	-	-	-	-
573 MISC PLANT	OM573	PTRAN	-	-	-	-	-	-	-
575 MISO DAY 1&2 EXPENSE	OM575	PTRAN	-	-	-	-	-	-	-
Total Transmission Expenses			$ -	$ -	$ -	$ -	$ -	$ -	$ -
Distribution Operation Expense									
580 OPERATION SUPERVISION AND ENGI	OM580	LBDO	36,110	48,090	53,472	45,752	30,671	830,508	36,472
581 LOAD DISPATCHING	OM581	P362	-	-	-	-	-	-	-
582 STATION EXPENSES	OM582	P362	-	-	-	-	-	-	-
583 OVERHEAD LINE EXPENSES	OM583	P365	224,770	269,992	-	-	-	-	-
584 UNDERGROUND LINE EXPENSES	OM584	P367	9,493	28,802	-	-	-	-	-
585 STREET LIGHTING EXPENSE	OM585	P373	-	-	-	-	-	-	21,918
586 METER EXPENSES	OM586	P370	-	-	-	-	-	7,329,419	-
586 METER EXPENSES - LOAD MANAGEMENT	OM586x	F012	-	-	-	-	-	-	-
587 CUSTOMER INSTALLATIONS EXPENSE	OM587	P371	-	-	-	-	-	-	(70,814)
588 MISCELLANEOUS DISTRIBUTION EXP	OM588	PDIST	146,122	209,144	514,309	440,060	295,000	233,779	343,357
588 MISC DISTR EXP -- MAPPIN	OM588x	PDIST	-	-	-	-	-	-	-
589 RENTS	OM589	PDIST	332	476	1,170	1,001	671	532	781
Total Distribution Operation Expense	OMDO		$ 416,828	$ 556,504	$ 568,951	$ 486,813	$ 326,342	$ 8,394,238	$ 331,713

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Description	Name	Functional Vector	Customer Accounts Expense	Customer Service & Info.	Sales Expense
Operation and Maintenance Expenses (Continued)					
Other Power Generation Maintenance Expense					
551 MAINTENANCE SUPERVISION & ENGINEERING	OM551	PROFIX	-	-	-
552 MAINTENANCE OF STRUCTURES	OM552	PROFIX	-	-	-
553 MAINTENANCE OF GENERATING & ELEC PLANT	OM553	PROFIX	-	-	-
554 MAINTENANCE OF MISC OTHER POWER GEN PLT	OM554	PROFIX	-	-	-
Total Other Power Generation Maintenance Expense			$ -	$ -	$ -
Total Other Power Generation Expense			$ -	$ -	$ -
Total Station Expense			$ -	$ -	$ -
Other Power Supply Expenses					
555 PURCHASED POWER	OM555	OMPP	-	-	-
555 PURCHASED POWER OPTIONS	OMO555	OMPP	-	-	-
555 BROKERAGE FEES	OMB555	OMPP	-	-	-
555 MISO TRANSMISSION EXPENSES	OMM555	OMPP	-	-	-
556 SYSTEM CONTROL AND LOAD DISPATCH	OM556	PROFIX	-	-	-
557 OTHER EXPENSES	OM557	PROFIX	-	-	-
Total Other Power Supply Expenses	TPP		$ -	$ -	$ -
Total Electric Power Generation Expenses			$ -	$ -	$ -
Transmission Expenses					
560 OPERATION SUPERVISION AND ENG	OM560	LBTRAN	-	-	-
561 LOAD DISPATCHING	OM561	LBTRAN	-	-	-
562 STATION EXPENSES	OM562	LBTRAN	-	-	-
563 OVERHEAD LINE EXPENSES	OM563	LBTRAN	-	-	-
565 TRANSMISSION OF ELECTRICITY BY OTHERS	OM565	LBTRAN	-	-	-
566 MISC. TRANSMISSION EXPENSES	OM566	PTRAN	-	-	-
567 RENTS	OM567	PTRAN	-	-	-
568 MAINTENACE SUPERVISION AND ENG	OM568	LBTRAN	-	-	-
569 STRUCTURES	OM569	LBTRAN	-	-	-
570 MAINT OF STATION EQUIPMENT	OM570	LBTRAN	-	-	-
571 MAINT OF OVERHEAD LINES	OM571	LBTRAN	-	-	-
572 UNDERGROUND LINES	OM572	LBTRAN	-	-	-
573 MISC PLANT	OM573	PTRAN	-	-	-
575 MISO DAY 1&2 EXPENSE	OM575	PTRAN	-	-	-
Total Transmission Expenses			$ -	$ -	$ -
Distribution Operation Expense					
580 OPERATION SUPERVISION AND ENGI	OM580	LBDO	-	-	-
581 LOAD DISPATCHING	OM581	P362	-	-	-
582 STATION EXPENSES	OM582	P362	-	-	-
583 OVERHEAD LINE EXPENSES	OM583	P365	-	-	-
584 UNDERGROUND LINE EXPENSES	OM584	P367	-	-	-
585 STREET LIGHTING EXPENSE	OM585	P373	-	-	-
586 METER EXPENSES	OM586	P370	-	-	-
586 METER EXPENSES - LOAD MANAGEMENT	OM586x	F012	-	-	-
587 CUSTOMER INSTALLATIONS EXPENSE	OM587	P371	-	-	-
588 MISCELLANEOUS DISTRIBUTION EXP	OM588	PDIST	-	-	-
588 MISC DISTR EXP -- MAPPIN	OM588x	PDIST	-	-	-
589 RENTS	OM589	PDIST	-	-	-
Total Distribution Operation Expense	OMDO		$ -	$ -	$ -

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Description	Name	Functional Vector	Total System	Production Demand Base	Production Demand Inter.	Production Demand Peak	Production Energy Base	Production Energy Inter.	Production Energy Peak
Operation and Maintenance Expenses (Continued)									
Distribution Maintenance Expense									
590 MAINTENANCE SUPERVISION AND EN	OM590	LBDM	$ 133,026	-	-	-	-	-	-
591 STRUCTURES	OM591	P362	-	-	-	-	-	-	-
592 MAINTENANCE OF STATION EQUIPME	OM592	P362	649,934.3	-	-	-	-	-	-
593 MAINTENANCE OF OVERHEAD LINES	OM593	P365	29,856,454.0	-	-	-	-	-	-
594 MAINTENANCE OF UNDERGROUND LIN	OM594	P367	476,334.5	-	-	-	-	-	-
595 MAINTENANCE OF LINE TRANSFORME	OM595	P368	187,043.7	-	-	-	-	-	-
596 MAINTENANCE OF ST LIGHTS & SIG SYSTEMS	OM596	P373	-	-	-	-	-	-	-
597 MAINTENANCE OF METERS	OM597	P370	-	-	-	-	-	-	-
598 MISCELLANEOUS DISTRIBUTION EXPENSES	OM598	PDIST	127,093.2	-	-	-	-	-	-
Total Distribution Maintenance Expense	OMDM		$ 31,429,886	$ -	$ -	$ -	$ -	$ -	$ -
Total Distribution Operation and Maintenance Expenses			50,977,392	-	-	-	-	-	-
Transmission and Distribution Expenses			74,383,089	-	-	-	-	-	-
Production, Transmission and Distribution Expenses	OMSUB		$ 724,682,420	$ 19,450,985	$ 18,336,011	$ 18,831,210	$ 593,681,125	$ -	$ -
Customer Accounts Expense									
901 SUPERVISION/CUSTOMER ACCTS	OM901	F025	$ 2,581,408	-	-	-	-	-	-
902 METER READING EXPENSES	OM902	F025	4,654,897	-	-	-	-	-	-
903 RECORDS AND COLLECTION	OM903	F025	13,547,808	-	-	-	-	-	-
904 UNCOLLECTIBLE ACCOUNTS	OM904	F025	5,121,451	-	-	-	-	-	-
905 MISC CUST ACCOUNTS	OM903	F025	709,907	-	-	-	-	-	-
Total Customer Accounts Expense	OMCA		$ 26,615,472	$ -	$ -	$ -	$ -	$ -	$ -
Customer Service Expense									
907 SUPERVISION	OM907	F026	$ 205,546	-	-	-	-	-	-
908 CUSTOMER ASSISTANCE EXPENSES	OM908	F026	13,664,342	-	-	-	-	-	-
908 CUSTOMER ASSISTANCE EXP-INCENTIVES	OM908x	F026	-	-	-	-	-	-	-
909 INFORMATIONAL AND INSTRUCTIONA	OM909	F026	148,605	-	-	-	-	-	-
909 INFORM AND INSTRUC -LOAD MGMT	OM909x	F026	-	-	-	-	-	-	-
910 MISCELLANEOUS CUSTOMER SERVICE	OM910	F026	417,350	-	-	-	-	-	-
911 DEMONSTRATION AND SELLING EXP	OM911	F026	-	-	-	-	-	-	-
912 DEMONSTRATION AND SELLING EXP	OM912	F026	-	-	-	-	-	-	-
913 ADVERTISING EXPENSES	OM913	F026	22,672	-	-	-	-	-	-
915 MDSE-JOBBING-CONTRACT	OM915	F026	-	-	-	-	-	-	-
916 MISC SALES EXPENSE	OM916	F026	-	-	-	-	-	-	-
Total Customer Service Expense	OMCS		$ 14,458,515	$ -	$ -	$ -	$ -	$ -	$ -
Sub-Total Prod, Trans, Dist, Cust Acct and Cust Service	OMSUB2		765,756,407	19,450,985	18,336,011	18,831,210	593,681,125	-	-

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		Functional	Transmission Demand			Distribution Poles	Distribution Substation	Distribution Primary Lines		
Description	**Name**	**Vector**	**Base**	**Winter**	**Summer**	**Specific**	**General**	**Specific**	**Demand**	**Customer**
Operation and Maintenance Expenses (Continued)										
Distribution Maintenance Expense										
590 MAINTENANCE SUPERVISION AND EN	OM590	LBDM	-	-	-	-	6,517	-	47,557	58,430
591 STRUCTURES	OM591	P362	-	-	-	-	-	-	-	-
592 MAINTENANCE OF STATION EQUIPME	OM592	P362	-	-	-	-	649,934	-	-	-
593 MAINTENANCE OF OVERHEAD LINES	OM593	P365	-	-	-	-	-	-	11,529,219	13,848,767
594 MAINTENANCE OF UNDERGROUND LIN	OM594	P367	-	-	-	-	-	-	100,371	304,514
595 MAINTENANCE OF LINE TRANSFORME	OM595	P368	-	-	-	-	-	-	-	-
596 MAINTENANCE OF ST LIGHTS & SIG SYSTEMS	OM596	P373	-	-	-	-	-	-	-	-
597 MAINTENANCE OF METERS	OM597	P370	-	-	-	-	-	-	-	-
598 MISCELLANEOUS DISTRIBUTION EXPENSES	OM598	PDIST	-	-	-	-	13,806	-	22,361	32,006
Total Distribution Maintenance Expense	OMDM		$ -	$ -	$ -	$ -	$ 670,258	$ -	$ 11,699,508	$ 14,243,716
Total Distribution Operation and Maintenance Expenses			-	-	-	-	3,620,831	-	14,061,532	17,397,236
Transmission and Distribution Expenses			8,040,945	7,580,020	7,784,733	-	3,620,831	-	14,061,532	17,397,236
Production, Transmission and Distribution Expenses	OMSUB		$ 8,040,945	$ 7,580,020	$ 7,784,733	$ -	$ 3,620,831	$ -	$ 14,061,532	$ 17,397,236
Customer Accounts Expense										
901 SUPERVISION/CUSTOMER ACCTS	OM901	F025	-	-	-	-	-	-	-	-
902 METER READING EXPENSES	OM902	F025	-	-	-	-	-	-	-	-
903 RECORDS AND COLLECTION	OM903	F025	-	-	-	-	-	-	-	-
904 UNCOLLECTIBLE ACCOUNTS	OM904	F025	-	-	-	-	-	-	-	-
905 MISC CUST ACCOUNTS	OM903	F025	-	-	-	-	-	-	-	-
Total Customer Accounts Expense	OMCA		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Customer Service Expense										
907 SUPERVISION	OM907	F026	-	-	-	-	-	-	-	-
908 CUSTOMER ASSISTANCE EXPENSES	OM908	F026	-	-	-	-	-	-	-	-
908 CUSTOMER ASSISTANCE EXP-INCENTIVES	OM908x	F026	-	-	-	-	-	-	-	-
909 INFORMATIONAL AND INSTRUCTIONA	OM909	F026	-	-	-	-	-	-	-	-
909 INFORM AND INSTRUC -LOAD MGMT	OM909x	F026	-	-	-	-	-	-	-	-
910 MISCELLANEOUS CUSTOMER SERVICE	OM910	F026	-	-	-	-	-	-	-	-
911 DEMONSTRATION AND SELLING EXP	OM911	F026	-	-	-	-	-	-	-	-
912 DEMONSTRATION AND SELLING EXP	OM912	F026	-	-	-	-	-	-	-	-
913 ADVERTISING EXPENSES	OM913	F026	-	-	-	-	-	-	-	-
915 MDSE-JOBBING-CONTRACT	OM915	F026	-	-	-	-	-	-	-	-
916 MISC SALES EXPENSE	OM916	F026	-	-	-	-	-	-	-	-
Total Customer Service Expense	OMCS		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Sub-Total Prod, Trans, Dist, Cust Acct and Cust Service	OMSUB2		8,040,945	7,580,020	7,784,733	-	3,620,831	-	14,061,532	17,397,236

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Description	Name	Functional Vector	Distribution Sec. Lines Demand	Distribution Sec. Lines Customer	Distribution Line Trans. Demand	Distribution Line Trans. Customer	Distribution Services Customer	Distribution Meters	Distribution St. & Cust. Lighting
Operation and Maintenance Expenses (Continued)									
Distribution Maintenance Expense									
590 MAINTENANCE SUPERVISION AND EN	OM590	LBDM	8,392	10,311	852	729	80	64	94
591 STRUCTURES	OM591	P362	-	-	-	-	-	-	-
592 MAINTENANCE OF STATION EQUIPME	OM592	P362	-	-	-	-	-	-	-
593 MAINTENANCE OF OVERHEAD LINES	OM593	P365	2,034,568	2,443,900	-	-	-	-	-
594 MAINTENANCE OF UNDERGROUND LIN	OM594	P367	17,712	53,738	-	-	-	-	-
595 MAINTENANCE OF LINE TRANSFORME	OM595	P368	-	-	100,798	86,246	-	-	-
596 MAINTENANCE OF ST LIGHTS & SIG SYSTEMS	OM596	P373	-	-	-	-	-	-	-
597 MAINTENANCE OF METERS	OM597	P370	-	-	-	-	-	-	-
598 MISCELLANEOUS DISTRIBUTION EXPENSES	OM598	PDIST	3,946	5,648	13,889	11,884	7,967	6,313	9,273
Total Distribution Maintenance Expense	OMDM		$ 2,064,619	$ 2,513,597	$ 115,539	$ 98,859	$ 8,047	$ 6,377	$ 9,366
Total Distribution Operation and Maintenance Expenses			2,481,447	3,070,100	684,490	585,672	334,389	8,400,615	341,079
Transmission and Distribution Expenses			2,481,447	3,070,100	684,490	585,672	334,389	8,400,615	341,079
Production, Transmission and Distribution Expenses	OMSUB		$ 2,481,447	$ 3,070,100	$ 684,490	$ 585,672	$ 334,389	$ 8,400,615	$ 341,079
Customer Accounts Expense									
901 SUPERVISION/CUSTOMER ACCTS	OM901	F025	-	-	-	-	-	-	-
902 METER READING EXPENSES	OM902	F025	-	-	-	-	-	-	-
903 RECORDS AND COLLECTION	OM903	F025	-	-	-	-	-	-	-
904 UNCOLLECTIBLE ACCOUNTS	OM904	F025	-	-	-	-	-	-	-
905 MISC CUST ACCOUNTS	OM903	F025	-	-	-	-	-	-	-
Total Customer Accounts Expense	OMCA		$ -	$ -	$ -	$ -	$ -	$ -	$ -
Customer Service Expense									
907 SUPERVISION	OM907	F026	-	-	-	-	-	-	-
908 CUSTOMER ASSISTANCE EXPENSES	OM908	F026	-	-	-	-	-	-	-
908 CUSTOMER ASSISTANCE EXP-INCENTIVES	OM908x	F026	-	-	-	-	-	-	-
909 INFORMATIONAL AND INSTRUCTIONA	OM909	F026	-	-	-	-	-	-	-
909 INFORM AND INSTRUC -LOAD MGMT	OM909x	F026	-	-	-	-	-	-	-
910 MISCELLANEOUS CUSTOMER SERVICE	OM910	F026	-	-	-	-	-	-	-
911 DEMONSTRATION AND SELLING EXP	OM911	F026	-	-	-	-	-	-	-
912 DEMONSTRATION AND SELLING EXP	OM912	F026	-	-	-	-	-	-	-
913 ADVERTISING EXPENSES	OM913	F026	-	-	-	-	-	-	-
915 MDSE-JOBBING-CONTRACT	OM915	F026	-	-	-	-	-	-	-
916 MISC SALES EXPENSE	OM916	F026	-	-	-	-	-	-	-
Total Customer Service Expense	OMCS		$ -	$ -	$ -	$ -	$ -	$ -	$ -
Sub-Total Prod, Trans, Dist, Cust Acct and Cust Service	OMSUB2		2,481,447	3,070,100	684,490	585,672	334,389	8,400,615	341,079

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Description	Name	Functional Vector	Customer Accounts Expense	Customer Service & Info.	Sales Expense
Operation and Maintenance Expenses (Continued)					
Distribution Maintenance Expense					
590 MAINTENANCE SUPERVISION AND EN	OM590	LBDM	-	-	-
591 STRUCTURES	OM591	P362	-	-	-
592 MAINTENANCE OF STATION EQUIPME	OM592	P362	-	-	-
593 MAINTENANCE OF OVERHEAD LINES	OM593	P365	-	-	-
594 MAINTENANCE OF UNDERGROUND LIN	OM594	P367	-	-	-
595 MAINTENANCE OF LINE TRANSFORME	OM595	P368	-	-	-
596 MAINTENANCE OF ST LIGHTS & SIG SYSTEMS	OM596	P373	-	-	-
597 MAINTENANCE OF METERS	OM597	P370	-	-	-
598 MISCELLANEOUS DISTRIBUTION EXPENSES	OM598	PDIST	-	-	-
Total Distribution Maintenance Expense	OMDM		$ -	$ -	$ -
Total Distribution Operation and Maintenance Expenses			-	-	-
Transmission and Distribution Expenses			-	-	-
Production, Transmission and Distribution Expenses	OMSUB		$ -	$ -	$ -
Customer Accounts Expense					
901 SUPERVISION/CUSTOMER ACCTS	OM901	F025	2,581,408	-	-
902 METER READING EXPENSES	OM902	F025	4,654,897	-	-
903 RECORDS AND COLLECTION	OM903	F025	13,547,808	-	-
904 UNCOLLECTIBLE ACCOUNTS	OM904	F025	5,121,451	-	-
905 MISC CUST ACCOUNTS	OM903	F025	709,907	-	-
Total Customer Accounts Expense	OMCA		$ 26,615,472	$ -	$ -
Customer Service Expense					
907 SUPERVISION	OM907	F026	-	205,546	-
908 CUSTOMER ASSISTANCE EXPENSES	OM908	F026	-	13,664,342	-
908 CUSTOMER ASSISTANCE EXP-INCENTIVES	OM908x	F026	-	-	-
909 INFORMATIONAL AND INSTRUCTIONA	OM909	F026	-	148,605	-
909 INFORM AND INSTRUC -LOAD MGMT	OM909x	F026	-	-	-
910 MISCELLANEOUS CUSTOMER SERVICE	OM910	F026	-	417,350	-
911 DEMONSTRATION AND SELLING EXP	OM911	F026	-	-	-
912 DEMONSTRATION AND SELLING EXP	OM912	F026	-	-	-
913 ADVERTISING EXPENSES	OM913	F026	-	22,672	-
915 MDSE-JOBBING-CONTRACT	OM915	F026	-	-	-
916 MISC SALES EXPENSE	OM916	F026	-	-	-
Total Customer Service Expense	OMCS		$ -	$ 14,458,515	$ -
Sub-Total Prod, Trans, Dist, Cust Acct and Cust Service	OMSUB2		26,615,472	14,458,515	-

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Description	Name	Functional Vector	Total System	Production Demand Base	Production Demand Inter.	Production Demand Peak	Production Energy Base	Production Energy Inter.	Production Energy Peak
Operation and Maintenance Expenses (Continued)									
Administrative and General Expense									
920 ADMIN. & GEN. SALARIES-	OM920	LBSUB7	$ 19,422,909	1,937,141	1,826,099	1,875,417	4,793,677	-	-
921 OFFICE SUPPLIES AND EXPENSES	OM921	LBSUB7	6,626,712	660,914	623,029	639,855	1,635,508	-	-
922 ADMINISTRATIVE EXPENSES TRANSFERRED	OM922	LBSUB7	(2,579,862)	(257,302)	(242,553)	(249,104)	(636,724)	-	-
923 OUTSIDE SERVICES EMPLOYED	OM923	LBSUB7	7,878,029	785,714	740,675	760,678	1,944,339	-	-
924 PROPERTY INSURANCE	OM924	TUP	3,722,836	847,480	798,901	820,476	-	-	-
925 INJURIES AND DAMAGES - INSURAN	OM925	LBSUB7	3,166,637	315,824	297,720	305,761	781,543	-	-
926 EMPLOYEE BENEFITS	OM926	LBSUB7	35,853,084	3,575,801	3,370,828	3,461,864	8,848,731	-	-
928 REGULATORY COMMISSION FEES	OM928	TUP	1,496,158	340,591	321,068	329,739	-	-	-
929 DUPLICATE CHARGES	OM929	LBSUB7	-	-	-	-	-	-	-
930 MISCELLANEOUS GENERAL EXPENSES	OM930	LBSUB7	3,577,675	356,819	336,365	345,449	882,989	-	-
931 RENTS AND LEASES	OM931	PGP	2,113,482	476,185	448,889	461,012	-	-	-
932 MAINTENANCE OF GENERAL PLANT	OM932	PGP	-	-	-	-	-	-	-
935 MAINTENANCE OF GENERAL PLANT	OM935	PGP	11,753,914	2,648,253	2,496,449	2,563,870	-	-	-
Total Administrative and General Expense	OMAG		$ 93,031,576	$ 11,687,419	$ 11,017,470	$ 11,315,017	$ 18,250,064	$ -	$ -
Total Operation and Maintenance Expenses	TOM		$ 858,787,983	$ 31,138,404	$ 29,353,481	$ 30,146,227	$ 611,931,189	$ -	$ -
Operation and Maintenance Expenses Less Purchase Power	OMLPP		$ 768,727,282	$ 28,541,932	$ 26,905,844	$ 27,632,488	$ 529,428,336	$ -	$ -

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Description	Name	Functional Vector	Transmission Demand Base	Transmission Demand Winter	Transmission Demand Summer	Distribution Poles Specific	Distribution Substation General	Distribution Primary Lines Specific	Distribution Primary Lines Demand	Distribution Primary Lines Customer
Operation and Maintenance Expenses (Continued)										
Administrative and General Expense										
920 ADMIN. & GEN. SALARIES-	OM920	LBSUB7	403,154	380,044	390,308	-	502,246	-	813,455	1,164,299
921 OFFICE SUPPLIES AND EXPENSES	OM921	LBSUB7	137,548	129,663	133,165	-	171,356	-	277,535	397,236
922 ADMINISTRATIVE EXPENSES TRANSFERRED	OM922	LBSUB7	(53,549)	(50,480)	(51,843)	-	(66,711)	-	(108,048)	(154,649)
923 OUTSIDE SERVICES EMPLOYED	OM923	LBSUB7	163,521	154,148	158,311	-	203,713	-	329,941	472,245
924 PROPERTY INSURANCE	OM924	TUP	126,924	119,648	122,879	-	96,305	-	155,979	223,252
925 INJURIES AND DAMAGES - INSURAN	OM925	LBSUB7	65,729	61,961	63,634	-	81,884	-	132,623	189,823
926 EMPLOYEE BENEFITS	OM926	LBSUB7	744,188	701,530	720,476	-	927,104	-	1,501,571	2,149,199
928 REGULATORY COMMISSION FEES	OM928	TUP	51,009	48,085	49,384	-	38,704	-	62,686	89,722
929 DUPLICATE CHARGES	OM929	LBSUB7	-	-	-	-	-	-	-	-
930 MISCELLANEOUS GENERAL EXPENSES	OM930	LBSUB7	74,260	70,004	71,894	-	92,513	-	149,837	214,462
931 RENTS AND LEASES	OM931	PGP	71,089	67,014	68,824	-	56,539	-	91,573	131,069
932 MAINTENANCE OF GENERAL PLANT	OM932	PGP	-	-	-	-	-	-	-	-
935 MAINTENANCE OF GENERAL PLANT	OM935	PGP	395,356	372,694	382,759	-	314,438	-	509,274	728,925
Total Administrative and General Expense	OMAG		$ 2,179,229	$ 2,054,310	$ 2,109,791	$ -	$ 2,418,091	$ -	$ 3,916,427	$ 5,605,584
Total Operation and Maintenance Expenses	TOM		$ 10,220,174	$ 9,634,330	$ 9,894,524	$ -	$ 6,038,922	$ -	$ 17,977,958	$ 23,002,820
Operation and Maintenance Expenses Less Purchase Power	OMLPP		$ 10,220,174	$ 9,634,330	$ 9,894,524	$ -	$ 6,038,922	$ -	$ 17,977,958	$ 23,002,820

KENTUCKY UTILITIES COMPANY
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Functional Assignment and Classification
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Description	Name	Functional Vector	Distribution Sec. Lines Demand	Distribution Sec. Lines Customer	Distribution Line Trans. Demand	Distribution Line Trans. Customer	Distribution Services Customer	Distribution Meters	Distribution St. & Cust. Lighting
Operation and Maintenance Expenses (Continued)									
Administrative and General Expense									
920 ADMIN. & GEN. SALARIES-	OM920	LBSUB7	143,551	205,465	505,262	432,318	289,811	229,666	337,317
921 OFFICE SUPPLIES AND EXPENSES	OM921	LBSUB7	48,977	70,100	172,385	147,498	98,878	78,358	115,086
922 ADMINISTRATIVE EXPENSES TRANSFERRED	OM922	LBSUB7	(19,067)	(27,291)	(67,112)	(57,423)	(38,494)	(30,506)	(44,804)
923 OUTSIDE SERVICES EMPLOYED	OM923	LBSUB7	58,225	83,337	204,937	175,350	117,549	93,154	136,817
924 PROPERTY INSURANCE	OM924	TUP	27,526	39,397	96,883	82,896	55,571	44,038	64,680
925 INJURIES AND DAMAGES - INSURAN	OM925	LBSUB7	23,404	33,498	82,376	70,483	47,250	37,444	54,995
926 EMPLOYEE BENEFITS	OM926	LBSUB7	264,983	379,270	932,671	798,023	534,967	423,945	622,659
928 REGULATORY COMMISSION FEES	OM928	TUP	11,062	15,833	38,936	33,315	22,333	17,698	25,994
929 DUPLICATE CHARGES	OM929	LBSUB7	-	-	-	-	-	-	-
930 MISCELLANEOUS GENERAL EXPENSES	OM930	LBSUB7	26,442	37,846	93,069	79,632	53,383	42,304	62,133
931 RENTS AND LEASES	OM931	PGP	16,160	23,130	56,879	48,667	32,625	25,854	37,973
932 MAINTENANCE OF GENERAL PLANT	OM932	PGP	-	-	-	-	-	-	-
935 MAINTENANCE OF GENERAL PLANT	OM935	PGP	89,872	128,634	316,326	270,658	181,440	143,786	211,182
Total Administrative and General Expense	OMAG		$ 691,134	$ 989,221	$ 2,432,611	$ 2,081,420	$ 1,395,310	$ 1,105,742	$ 1,624,031
Total Operation and Maintenance Expenses	TOM		$ 3,172,581	$ 4,059,321	$ 3,117,102	$ 2,667,091	$ 1,729,700	$ 9,506,357	$ 1,965,110
Operation and Maintenance Expenses Less Purchase Power	OMLPP		$ 3,172,581	$ 4,059,321	$ 3,117,102	$ 2,667,091	$ 1,729,700	$ 9,506,357	$ 1,965,110

KENTUCKY UTILITIES COMPANY
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Description	Name	Functional Vector	Customer Accounts Expense	Customer Service & Info.	Sales Expense
Operation and Maintenance Expenses (Continued)					
Administrative and General Expense					
920 ADMIN. & GEN. SALARIES-	OM920	LBSUB7	2,826,912	366,770	-
921 OFFICE SUPPLIES AND EXPENSES	OM921	LBSUB7	964,486	125,135	-
922 ADMINISTRATIVE EXPENSES TRANSFERRED	OM922	LBSUB7	(375,487)	(48,717)	-
923 OUTSIDE SERVICES EMPLOYED	OM923	LBSUB7	1,146,610	148,764	-
924 PROPERTY INSURANCE	OM924	TUP	-	-	-
925 INJURIES AND DAMAGES - INSURAN	OM925	LBSUB7	460,889	59,797	-
926 EMPLOYEE BENEFITS	OM926	LBSUB7	5,218,246	677,028	-
928 REGULATORY COMMISSION FEES	OM928	TUP	-	-	-
929 DUPLICATE CHARGES	OM929	LBSUB7	-	-	-
930 MISCELLANEOUS GENERAL EXPENSES	OM930	LBSUB7	520,714	67,559	-
931 RENTS AND LEASES	OM931	PGP	-	-	-
932 MAINTENANCE OF GENERAL PLANT	OM932	PGP	-	-	-
935 MAINTENANCE OF GENERAL PLANT	OM935	PGP	-	-	-
Total Administrative and General Expense	OMAG		$ 10,762,370	$ 1,396,336	$ -
Total Operation and Maintenance Expenses	TOM		$ 37,377,842	$ 15,854,851	$ -
Operation and Maintenance Expenses Less Purchase Power	OMLPP		$ 37,377,842	$ 15,854,851	$ -

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Description	Name	Functional Vector	Total System	Production Demand Base	Production Demand Inter.	Production Demand Peak	Production Energy Base	Production Energy Inter.	Production Energy Peak
Labor Expenses									
Steam Power Generation Operation Expenses									
500 OPERATION SUPERVISION & ENGINEERING	LB500	F019	$ 4,189,374	1,193,067	1,124,678	1,155,052	716,577	-	-
501 FUEL	LB501	Energy	3,035,692	-	-	-	3,035,692	-	-
502 STEAM EXPENSES	LB502	PROFIX	7,897,509	2,713,161	2,557,637	2,626,711	-	-	-
505 ELECTRIC EXPENSES	LB505	PROFIX	5,503,565	1,890,730	1,782,349	1,830,485	-	-	-
506 MISC. STEAM POWER EXPENSES	LB506	PROFIX	1,311,016	450,395	424,577	436,044	-	-	-
507 RENTS	LB507	PROFIX	-	-	-	-	-	-	-
Total Steam Power Operation Expenses	LBSUB1		$ 21,937,156	$ 6,247,354	$ 5,889,241	$ 6,048,292	$ 3,752,269	$ -	$ -
Steam Power Generation Maintenance Expenses									
510 MAINTENANCE SUPERVISION & ENGINEERING	LB510	F020	$ 5,688,357	176,156	166,058	170,543	5,175,600	-	-
511 MAINTENANCE OF STRUCTURES	LB511	PROFIX	989,589	339,970	320,482	329,137	-	-	-
512 MAINTENANCE OF BOILER PLANT	LB512	Energy	7,837,920	-	-	-	7,837,920	-	-
513 MAINTENANCE OF ELECTRIC PLANT	LB513	Energy	1,958,591	-	-	-	1,958,591	-	-
514 MAINTENANCE OF MISC STEAM PLANT	LB514	Energy	192,076	-	-	-	192,076	-	-
Total Steam Power Generation Maintenance Expense	LBSUB2		$ 16,666,534	$ 516,126	$ 486,540	$ 499,680	$ 15,164,188	$ -	$ -
Total Steam Power Generation Expense			$ 38,603,689	$ 6,763,479	$ 6,375,781	$ 6,547,972	$ 18,916,457	$ -	$ -
Hydraulic Power Generation Operation Expenses									
535 OPERATION SUPERVISION & ENGINEERING	LB535	F021	$ 6,807	2,339	2,205	2,264	-	-	-
536 WATER FOR POWER	LB536	PROFIX	-	-	-	-	-	-	-
537 HYDRAULIC EXPENSES	LB537	PROFIX	-	-	-	-	-	-	-
538 ELECTRIC EXPENSES	LB538	PROFIX	-	-	-	-	-	-	-
539 MISC. HYDRAULIC POWER EXPENSES	LB539	PROFIX	4,595	1,578	1,488	1,528	-	-	-
540 RENTS	LB540	PROFIX	-	-	-	-	-	-	-
Total Hydraulic Power Operation Expenses	LBSUB3		$ 11,402	$ 3,917	$ 3,693	$ 3,792	$ -	$ -	$ -
Hydraulic Power Generation Maintenance Expenses									
541 MAINTENANCE SUPERVISION & ENGINEERING	LB541	F022	$ 93,176	9,062	8,543	8,773	66,798	-	-
542 MAINTENANCE OF STRUCTURES	LB542	PROFIX	19,320	6,637	6,257	6,426	-	-	-
543 MAINT. OF RESERVES, DAMS, AND WATERWAYS	LB543	PROFIX	-	-	-	-	-	-	-
544 MAINTENANCE OF ELECTRIC PLANT	LB544	Energy	45,888	-	-	-	45,888	-	-
545 MAINTENANCE OF MISC HYDRAULIC PLANT	LB545	Energy	3,037	-	-	-	3,037	-	-
Total Hydraulic Power Generation Maint. Expense	LBSUB4		$ 161,422	$ 15,699	$ 14,799	$ 15,199	$ 115,724	$ -	$ -
Total Hydraulic Power Generation Expense			$ 172,824	$ 19,617	$ 18,492	$ 18,991	$ 115,724	$ -	$ -
Other Power Generation Operation Expense									
546 OPERATION SUPERVISION & ENGINEERING	LB546	PROFIX	$ 173,570	59,630	56,211	57,730	-	-	-
547 FUEL	LB547	Energy	-	-	-	-	-	-	-
548 GENERATION EXPENSE	LB548	PROFIX	206,772	71,036	66,964	68,772	-	-	-
549 MISC OTHER POWER GENERATION	LB549	PROFIX	18,378	6,314	5,952	6,112	-	-	-
550 RENTS	LB550	PROFIX	-	-	-	-	-	-	-
Total Other Power Generation Expenses	LBSUB5		$ 398,720	$ 136,979	$ 129,127	$ 132,614	$ -	$ -	$ -

			Transmission Demand			Distribution Poles	Distribution Substation	Distribution Primary Lines		
Description	**Name**	**Functional Vector**	**Base**	**Winter**	**Summer**	**Specific**	**General**	**Specific**	**Demand**	**Customer**
Labor Expenses										
Steam Power Generation Operation Expenses										
500 OPERATION SUPERVISION & ENGINEERING	LB500	F019	-	-	-	-	-	-	-	-
501 FUEL	LB501	Energy	-	-	-	-	-	-	-	-
502 STEAM EXPENSES	LB502	PROFIX	-	-	-	-	-	-	-	-
505 ELECTRIC EXPENSES	LB505	PROFIX	-	-	-	-	-	-	-	-
506 MISC. STEAM POWER EXPENSES	LB506	PROFIX	-	-	-	-	-	-	-	-
507 RENTS	LB507	PROFIX	-	-	-	-	-	-	-	-
Total Steam Power Operation Expenses	LBSUB1		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Steam Power Generation Maintenance Expenses										
510 MAINTENANCE SUPERVISION & ENGINEERING	LB510	F020	-	-	-	-	-	-	-	-
511 MAINTENANCE OF STRUCTURES	LB511	PROFIX	-	-	-	-	-	-	-	-
512 MAINTENANCE OF BOILER PLANT	LB512	Energy	-	-	-	-	-	-	-	-
513 MAINTENANCE OF ELECTRIC PLANT	LB513	Energy	-	-	-	-	-	-	-	-
514 MAINTENANCE OF MISC STEAM PLANT	LB514	Energy	-	-	-	-	-	-	-	-
Total Steam Power Generation Maintenance Expense	LBSUB2		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Steam Power Generation Expense			$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Hydraulic Power Generation Operation Expenses										
535 OPERATION SUPERVISION & ENGINEERING	LB535	F021	-	-	-	-	-	-	-	-
536 WATER FOR POWER	LB536	PROFIX	-	-	-	-	-	-	-	-
537 HYDRAULIC EXPENSES	LB537	PROFIX	-	-	-	-	-	-	-	-
538 ELECTRIC EXPENSES	LB538	PROFIX	-	-	-	-	-	-	-	-
539 MISC. HYDRAULIC POWER EXPENSES	LB539	PROFIX	-	-	-	-	-	-	-	-
540 RENTS	LB540	PROFIX	-	-	-	-	-	-	-	-
Total Hydraulic Power Operation Expenses	LBSUB3		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Hydraulic Power Generation Maintenance Expenses										
541 MAINTENANCE SUPERVISION & ENGINEERING	LB541	F022	-	-	-	-	-	-	-	-
542 MAINTENANCE OF STRUCTURES	LB542	PROFIX	-	-	-	-	-	-	-	-
543 MAINT. OF RESERVES, DAMS, AND WATERWAYS	LB543	PROFIX	-	-	-	-	-	-	-	-
544 MAINTENANCE OF ELECTRIC PLANT	LB544	Energy	-	-	-	-	-	-	-	-
545 MAINTENANCE OF MISC HYDRAULIC PLANT	LB545	Energy	-	-	-	-	-	-	-	-
Total Hydraulic Power Generation Maint. Expense	LBSUB4		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Hydraulic Power Generation Expense			$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Other Power Generation Operation Expense										
546 OPERATION SUPERVISION & ENGINEERING	LB546	PROFIX	-	-	-	-	-	-	-	-
547 FUEL	LB547	Energy	-	-	-	-	-	-	-	-
548 GENERATION EXPENSE	LB548	PROFIX	-	-	-	-	-	-	-	-
549 MISC OTHER POWER GENERATION	LB549	PROFIX	-	-	-	-	-	-	-	-
550 RENTS	LB550	PROFIX	-	-	-	-	-	-	-	-
Total Other Power Generation Expenses	LBSUB5		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

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Description	Name	Functional Vector	Distribution Sec. Lines Demand	Distribution Sec. Lines Customer	Distribution Line Trans. Demand	Distribution Line Trans. Customer	Distribution Services Customer	Distribution Meters	Distribution St. & Cust. Lighting
Labor Expenses									
Steam Power Generation Operation Expenses									
500 OPERATION SUPERVISION & ENGINEERING	LB500	F019	-	-	-	-	-	-	-
501 FUEL	LB501	Energy	-	-	-	-	-	-	-
502 STEAM EXPENSES	LB502	PROFIX	-	-	-	-	-	-	-
505 ELECTRIC EXPENSES	LB505	PROFIX	-	-	-	-	-	-	-
506 MISC. STEAM POWER EXPENSES	LB506	PROFIX	-	-	-	-	-	-	-
507 RENTS	LB507	PROFIX	-	-	-	-	-	-	-
Total Steam Power Operation Expenses	LBSUB1		$ -	$ -	$ -	$ -	$ -	$ -	$ -
Steam Power Generation Maintenance Expenses									
510 MAINTENANCE SUPERVISION & ENGINEERING	LB510	F020	-	-	-	-	-	-	-
511 MAINTENANCE OF STRUCTURES	LB511	PROFIX	-	-	-	-	-	-	-
512 MAINTENANCE OF BOILER PLANT	LB512	Energy	-	-	-	-	-	-	-
513 MAINTENANCE OF ELECTRIC PLANT	LB513	Energy	-	-	-	-	-	-	-
514 MAINTENANCE OF MISC STEAM PLANT	LB514	Energy	-	-	-	-	-	-	-
Total Steam Power Generation Maintenance Expense	LBSUB2		$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Steam Power Generation Expense			$ -	$ -	$ -	$ -	$ -	$ -	$ -
Hydraulic Power Generation Operation Expenses									
535 OPERATION SUPERVISION & ENGINEERING	LB535	F021	-	-	-	-	-	-	-
536 WATER FOR POWER	LB536	PROFIX	-	-	-	-	-	-	-
537 HYDRAULIC EXPENSES	LB537	PROFIX	-	-	-	-	-	-	-
538 ELECTRIC EXPENSES	LB538	PROFIX	-	-	-	-	-	-	-
539 MISC. HYDRAULIC POWER EXPENSES	LB539	PROFIX	-	-	-	-	-	-	-
540 RENTS	LB540	PROFIX	-	-	-	-	-	-	-
Total Hydraulic Power Operation Expenses	LBSUB3		$ -	$ -	$ -	$ -	$ -	$ -	$ -
Hydraulic Power Generation Maintenance Expenses									
541 MAINTENANCE SUPERVISION & ENGINEERING	LB541	F022	-	-	-	-	-	-	-
542 MAINTENANCE OF STRUCTURES	LB542	PROFIX	-	-	-	-	-	-	-
543 MAINT. OF RESERVES, DAMS, AND WATERWAYS	LB543	PROFIX	-	-	-	-	-	-	-
544 MAINTENANCE OF ELECTRIC PLANT	LB544	Energy	-	-	-	-	-	-	-
545 MAINTENANCE OF MISC HYDRAULIC PLANT	LB545	Energy	-	-	-	-	-	-	-
Total Hydraulic Power Generation Maint. Expense	LBSUB4		$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Hydraulic Power Generation Expense			$ -	$ -	$ -	$ -	$ -	$ -	$ -
Other Power Generation Operation Expense									
546 OPERATION SUPERVISION & ENGINEERING	LB546	PROFIX	-	-	-	-	-	-	-
547 FUEL	LB547	Energy	-	-	-	-	-	-	-
548 GENERATION EXPENSE	LB548	PROFIX	-	-	-	-	-	-	-
549 MISC OTHER POWER GENERATION	LB549	PROFIX	-	-	-	-	-	-	-
550 RENTS	LB550	PROFIX	-	-	-	-	-	-	-
Total Other Power Generation Expenses	LBSUB5		$ -	$ -	$ -	$ -	$ -	$ -	$ -

Description	Name	Functional Vector	Customer Accounts Expense	Customer Service & Info.	Sales Expense
Labor Expenses					
Steam Power Generation Operation Expenses					
500 OPERATION SUPERVISION & ENGINEERING	LB500	F019	-	-	-
501 FUEL	LB501	Energy	-	-	-
502 STEAM EXPENSES	LB502	PROFIX	-	-	-
505 ELECTRIC EXPENSES	LB505	PROFIX	-	-	-
506 MISC. STEAM POWER EXPENSES	LB506	PROFIX	-	-	-
507 RENTS	LB507	PROFIX	-	-	-
Total Steam Power Operation Expenses	LBSUB1		$ -	$ -	$ -
Steam Power Generation Maintenance Expenses					
510 MAINTENANCE SUPERVISION & ENGINEERING	LB510	F020	-	-	-
511 MAINTENANCE OF STRUCTURES	LB511	PROFIX	-	-	-
512 MAINTENANCE OF BOILER PLANT	LB512	Energy	-	-	-
513 MAINTENANCE OF ELECTRIC PLANT	LB513	Energy	-	-	-
514 MAINTENANCE OF MISC STEAM PLANT	LB514	Energy	-	-	-
Total Steam Power Generation Maintenance Expense	LBSUB2		$ -	$ -	$ -
Total Steam Power Generation Expense			$ -	$ -	$ -
Hydraulic Power Generation Operation Expenses					
535 OPERATION SUPERVISION & ENGINEERING	LB535	F021	-	-	-
536 WATER FOR POWER	LB536	PROFIX	-	-	-
537 HYDRAULIC EXPENSES	LB537	PROFIX	-	-	-
538 ELECTRIC EXPENSES	LB538	PROFIX	-	-	-
539 MISC. HYDRAULIC POWER EXPENSES	LB539	PROFIX	-	-	-
540 RENTS	LB540	PROFIX	-	-	-
Total Hydraulic Power Operation Expenses	LBSUB3		$ -	$ -	$ -
Hydraulic Power Generation Maintenance Expenses					
541 MAINTENANCE SUPERVISION & ENGINEERING	LB541	F022	-	-	-
542 MAINTENANCE OF STRUCTURES	LB542	PROFIX	-	-	-
543 MAINT. OF RESERVES, DAMS, AND WATERWAYS	LB543	PROFIX	-	-	-
544 MAINTENANCE OF ELECTRIC PLANT	LB544	Energy	-	-	-
545 MAINTENANCE OF MISC HYDRAULIC PLANT	LB545	Energy	-	-	-
Total Hydraulic Power Generation Maint. Expense	LBSUB4		$ -	$ -	$ -
Total Hydraulic Power Generation Expense			$ -	$ -	$ -
Other Power Generation Operation Expense					
546 OPERATION SUPERVISION & ENGINEERING	LB546	PROFIX	-	-	-
547 FUEL	LB547	Energy	-	-	-
548 GENERATION EXPENSE	LB548	PROFIX	-	-	-
549 MISC OTHER POWER GENERATION	LB549	PROFIX	-	-	-
550 RENTS	LB550	PROFIX	-	-	-
Total Other Power Generation Expenses	LBSUB5		$ -	$ -	$ -

Description	Name	Functional Vector	Total System	Production Demand Base	Production Demand Inter.	Production Demand Peak	Production Energy Base	Production Energy Inter.	Production Energy Peak
Labor Expenses (Continued)									
Other Power Generation Maintenance Expense									
551 MAINTENANCE SUPERVISION & ENGINEERING	LB551	PROFIX	$ 35,796	12,298	11,593	11,906	-	-	-
552 MAINTENANCE OF STRUCTURES	LB552	PROFIX	111,975	38,469	36,263	37,243	-	-	-
553 MAINTENANCE OF GENERATING & ELEC PLANT	LB553	PROFIX	546,106	187,613	176,859	181,635	-	-	-
554 MAINTENANCE OF MISC OTHER POWER GEN PLT	LB554	PROFIX	74,961	25,753	24,276	24,932	-	-	-
Total Other Power Generation Maintenance Expense	LBSUB6		$ 768,839	$ 264,132	$ 248,991	$ 255,716	$ -	$ -	$ -
Total Other Power Generation Expense			$ 1,167,559	$ 401,111	$ 378,118	$ 388,330	$ -	$ -	$ -
Total Production Expense	LPREX		$ 39,944,072	$ 7,184,207	$ 6,772,392	$ 6,955,293	$ 19,032,181	$ -	$ -
Purchased Power									
555 PURCHASED POWER	LB555	OMPP	$ -	-	-	-	-	-	-
556 SYSTEM CONTROL AND LOAD DISPATCH	LB556	PROFIX	$ 1,475,083	506,760	477,711	490,612	-	-	-
557 OTHER EXPENSES	LB557	PROFIX	$ 0	0	0	0	-	-	-
Total Purchased Power Labor	LBPP		$ 1,475,083	$ 506,760	$ 477,711	$ 490,612	$ -	$ -	$ -
Transmission Labor Expenses									
560 OPERATION SUPERVISION AND ENG	LB560	PTRAN	$ 1,045,952	-	-	-	-	-	-
561 LOAD DISPATCHING	LB561	PTRAN	2,129,244	-	-	-	-	-	-
562 STATION EXPENSES	LB562	PTRAN	268,512	-	-	-	-	-	-
563 OVERHEAD LINE EXPENSES	LB563	PTRAN	55,713	-	-	-	-	-	-
566 MISC. TRANSMISSION EXPENSES	LB566	PTRAN	335,386	-	-	-	-	-	-
568 MAINTENACE SUPERVISION AND ENG	LB568	PTRAN	-	-	-	-	-	-	-
570 MAINT OF STATION EQUIPMENT	LB570	PTRAN	559,103	-	-	-	-	-	-
571 MAINT OF OVERHEAD LINES	LB571	PTRAN	177,051	-	-	-	-	-	-
572 UNDERGROUND LINES	LB572	PTRAN	-	-	-	-	-	-	-
573 MISC PLANT	LB573	PTRAN	88,167	-	-	-	-	-	-
Total Transmission Labor Expenses	LBTRAN		$ 4,659,129	$ -	$ -	$ -	$ -	$ -	$ -
Distribution Operation Labor Expense									
580 OPERATION SUPERVISION AND ENGI	LB580	F023	$ 1,295,320	-	-	-	-	-	-
581 LOAD DISPATCHING	LB581	P362	717,346	-	-	-	-	-	-
582 STATION EXPENSES	LB582	P362	756,223	-	-	-	-	-	-
583 OVERHEAD LINE EXPENSES	LB583	P365	1,589,814	-	-	-	-	-	-
584 UNDERGROUND LINE EXPENSES	LB584	P367	95,744	-	-	-	-	-	-
585 STREET LIGHTING EXPENSE	LB585	P371	2,507	-	-	-	-	-	-
586 METER EXPENSES	LB586	P370	4,312,676	-	-	-	-	-	-
586 METER EXPENSES - LOAD MANAGEMENT	LB586x	F012	-	-	-	-	-	-	-
587 CUSTOMER INSTALLATIONS EXPENSE	LB587	P371	1,631	-	-	-	-	-	-
588 MISCELLANEOUS DISTRIBUTION EXP	LB588	PDIST	2,617,399	-	-	-	-	-	-
589 RENTS	LB589	PDIST	-	-	-	-	-	-	-
Total Distribution Operation Labor Expense	LBDO		$ 11,388,660	$ -	$ -	$ -	$ -	$ -	$ -

Description	Name	Functional Vector	Transmission Demand Base	Transmission Demand Winter	Transmission Demand Summer	Distribution Poles Specific	Distribution Substation General	Distribution Primary Lines Specific	Distribution Primary Lines Demand	Distribution Primary Lines Customer
Labor Expenses (Continued)										
Other Power Generation Maintenance Expense										
551 MAINTENANCE SUPERVISION & ENGINEERING	LB551	PROFIX	-	-	-	-	-	-	-	-
552 MAINTENANCE OF STRUCTURES	LB552	PROFIX	-	-	-	-	-	-	-	-
553 MAINTENANCE OF GENERATING & ELEC PLANT	LB553	PROFIX	-	-	-	-	-	-	-	-
554 MAINTENANCE OF MISC OTHER POWER GEN PLT	LB554	PROFIX	-	-	-	-	-	-	-	-
Total Other Power Generation Maintenance Expense	LBSUB6		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Other Power Generation Expense			$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Production Expense	LPREX		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Purchased Power										
555 PURCHASED POWER	LB555	OMPP	-	-	-	-	-	-	-	-
556 SYSTEM CONTROL AND LOAD DISPATCH	LB556	PROFIX	-	-	-	-	-	-	-	-
557 OTHER EXPENSES	LB557	PROFIX	-	-	-	-	-	-	-	-
Total Purchased Power Labor	LBPP		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Transmission Labor Expenses										
560 OPERATION SUPERVISION AND ENG	LB560	PTRAN	359,333	338,735	347,884	-	-	-	-	-
561 LOAD DISPATCHING	LB561	PTRAN	731,494	689,563	708,186	-	-	-	-	-
562 STATION EXPENSES	LB562	PTRAN	92,246	86,959	89,307	-	-	-	-	-
563 OVERHEAD LINE EXPENSES	LB563	PTRAN	19,140	18,043	18,530	-	-	-	-	-
566 MISC. TRANSMISSION EXPENSES	LB566	PTRAN	115,221	108,616	111,549	-	-	-	-	-
568 MAINTENACE SUPERVISION AND ENG	LB568	PTRAN	-	-	-	-	-	-	-	-
570 MAINT OF STATION EQUIPMENT	LB570	PTRAN	192,078	181,068	185,958	-	-	-	-	-
571 MAINT OF OVERHEAD LINES	LB571	PTRAN	60,825	57,339	58,887	-	-	-	-	-
572 UNDERGROUND LINES	LB572	PTRAN	-	-	-	-	-	-	-	-
573 MISC PLANT	LB573	PTRAN	30,289	28,553	29,324	-	-	-	-	-
Total Transmission Labor Expenses	LBTRAN		$ 1,600,627	$ 1,508,876	$ 1,549,626	$ -	$ -	$ -	$ -	$ -
Distribution Operation Labor Expense										
580 OPERATION SUPERVISION AND ENGI	LB580	F023	-	-	-	-	225,599	-	140,475	187,082
581 LOAD DISPATCHING	LB581	P362	-	-	-	-	717,346	-	-	-
582 STATION EXPENSES	LB582	P362	-	-	-	-	756,223	-	-	-
583 OVERHEAD LINE EXPENSES	LB583	P365	-	-	-	-	-	-	613,915	737,427
584 UNDERGROUND LINE EXPENSES	LB584	P367	-	-	-	-	-	-	20,175	61,208
585 STREET LIGHTING EXPENSE	LB585	P371	-	-	-	-	-	-	-	-
586 METER EXPENSES	LB586	P370	-	-	-	-	-	-	-	-
586 METER EXPENSES - LOAD MANAGEMENT	LB586x	F012	-	-	-	-	-	-	-	-
587 CUSTOMER INSTALLATIONS EXPENSE	LB587	P371	-	-	-	-	-	-	-	-
588 MISCELLANEOUS DISTRIBUTION EXP	LB588	PDIST	-	-	-	-	284,332	-	460,514	659,135
589 RENTS	LB589	PDIST	-	-	-	-	-	-	-	-
Total Distribution Operation Labor Expense	LBDO		$ -	$ -	$ -	$ -	$ 1,983,500	$ -	$ 1,235,079	$ 1,644,851

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Description	Name	Functional Vector	Distribution Sec. Lines Demand	Distribution Sec. Lines Customer	Distribution Line Trans. Demand	Distribution Line Trans. Customer	Distribution Services Customer	Distribution Meters	Distribution St. & Cust. Lighting
Labor Expenses (Continued)									
Other Power Generation Maintenance Expense									
551 MAINTENANCE SUPERVISION & ENGINEERING	LB551	PROFIX	-	-	-	-	-	-	-
552 MAINTENANCE OF STRUCTURES	LB552	PROFIX	-	-	-	-	-	-	-
553 MAINTENANCE OF GENERATING & ELEC PLANT	LB553	PROFIX	-	-	-	-	-	-	-
554 MAINTENANCE OF MISC OTHER POWER GEN PLT	LB554	PROFIX	-	-	-	-	-	-	-
Total Other Power Generation Maintenance Expense	LBSUB6		$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Other Power Generation Expense			$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Production Expense	LPREX		$ -	$ -	$ -	$ -	$ -	$ -	$ -
Purchased Power									
555 PURCHASED POWER	LB555	OMPP	-	-	-	-	-	-	-
556 SYSTEM CONTROL AND LOAD DISPATCH	LB556	PROFIX	-	-	-	-	-	-	-
557 OTHER EXPENSES	LB557	PROFIX	-	-	-	-	-	-	-
Total Purchased Power Labor	LBPP		$ -	$ -	$ -	$ -	$ -	$ -	$ -
Transmission Labor Expenses									
560 OPERATION SUPERVISION AND ENG	LB560	PTRAN	-	-	-	-	-	-	-
561 LOAD DISPATCHING	LB561	PTRAN	-	-	-	-	-	-	-
562 STATION EXPENSES	LB562	PTRAN	-	-	-	-	-	-	-
563 OVERHEAD LINE EXPENSES	LB563	PTRAN	-	-	-	-	-	-	-
566 MISC. TRANSMISSION EXPENSES	LB566	PTRAN	-	-	-	-	-	-	-
568 MAINTENACE SUPERVISION AND ENG	LB568	PTRAN	-	-	-	-	-	-	-
570 MAINT OF STATION EQUIPMENT	LB570	PTRAN	-	-	-	-	-	-	-
571 MAINT OF OVERHEAD LINES	LB571	PTRAN	-	-	-	-	-	-	-
572 UNDERGROUND LINES	LB572	PTRAN	-	-	-	-	-	-	-
573 MISC PLANT	LB573	PTRAN	-	-	-	-	-	-	-
Total Transmission Labor Expenses	LBTRAN		$ -	$ -	$ -	$ -	$ -	$ -	$ -
Distribution Operation Labor Expense									
580 OPERATION SUPERVISION AND ENGI	LB580	F023	24,790	33,014	36,709	31,409	21,056	570,149	25,038
581 LOAD DISPATCHING	LB581	P362	-	-	-	-	-	-	-
582 STATION EXPENSES	LB582	P362	-	-	-	-	-	-	-
583 OVERHEAD LINE EXPENSES	LB583	P365	108,338	130,134	-	-	-	-	-
584 UNDERGROUND LINE EXPENSES	LB584	P367	3,560	10,801	-	-	-	-	-
585 STREET LIGHTING EXPENSE	LB585	P371	-	-	-	-	-	-	2,507
586 METER EXPENSES	LB586	P370	-	-	-	-	-	4,312,676	-
586 METER EXPENSES - LOAD MANAGEMENT	LB586x	F012	-	-	-	-	-	-	-
587 CUSTOMER INSTALLATIONS EXPENSE	LB587	P371	-	-	-	-	-	-	1,631
588 MISCELLANEOUS DISTRIBUTION EXP	LB588	PDIST	81,267	116,318	286,039	244,744	164,068	130,019	190,962
589 RENTS	LB589	PDIST	-	-	-	-	-	-	-
Total Distribution Operation Labor Expense	LBDO		$ 217,955	$ 290,268	$ 322,748	$ 276,154	$ 185,124	$ 5,012,844	$ 220,138

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Description	Name	Functional Vector	Customer Accounts Expense	Customer Service & Info.	Sales Expense
Labor Expenses (Continued)					
Other Power Generation Maintenance Expense					
551 MAINTENANCE SUPERVISION & ENGINEERING	LB551	PROFIX	-	-	-
552 MAINTENANCE OF STRUCTURES	LB552	PROFIX	-	-	-
553 MAINTENANCE OF GENERATING & ELEC PLANT	LB553	PROFIX	-	-	-
554 MAINTENANCE OF MISC OTHER POWER GEN PLT	LB554	PROFIX	-	-	-
Total Other Power Generation Maintenance Expense	LBSUB6		$ -	$ -	$ -
Total Other Power Generation Expense			$ -	$ -	$ -
Total Production Expense	LPREX		$ -	$ -	$ -
Purchased Power					
555 PURCHASED POWER	LB555	OMPP	-	-	-
556 SYSTEM CONTROL AND LOAD DISPATCH	LB556	PROFIX	-	-	-
557 OTHER EXPENSES	LB557	PROFIX	-	-	-
Total Purchased Power Labor	LBPP		$ -	$ -	$ -
Transmission Labor Expenses					
560 OPERATION SUPERVISION AND ENG	LB560	PTRAN	-	-	-
561 LOAD DISPATCHING	LB561	PTRAN	-	-	-
562 STATION EXPENSES	LB562	PTRAN	-	-	-
563 OVERHEAD LINE EXPENSES	LB563	PTRAN	-	-	-
566 MISC. TRANSMISSION EXPENSES	LB566	PTRAN	-	-	-
568 MAINTENACE SUPERVISION AND ENG	LB568	PTRAN	-	-	-
570 MAINT OF STATION EQUIPMENT	LB570	PTRAN	-	-	-
571 MAINT OF OVERHEAD LINES	LB571	PTRAN	-	-	-
572 UNDERGROUND LINES	LB572	PTRAN	-	-	-
573 MISC PLANT	LB573	PTRAN	-	-	-
Total Transmission Labor Expenses	LBTRAN		$ -	$ -	$ -
Distribution Operation Labor Expense					
580 OPERATION SUPERVISION AND ENGI	LB580	F023	-	-	-
581 LOAD DISPATCHING	LB581	P362	-	-	-
582 STATION EXPENSES	LB582	P362	-	-	-
583 OVERHEAD LINE EXPENSES	LB583	P365	-	-	-
584 UNDERGROUND LINE EXPENSES	LB584	P367	-	-	-
585 STREET LIGHTING EXPENSE	LB585	P371	-	-	-
586 METER EXPENSES	LB586	P370	-	-	-
586 METER EXPENSES - LOAD MANAGEMENT	LB586x	F012	-	-	-
587 CUSTOMER INSTALLATIONS EXPENSE	LB587	P371	-	-	-
588 MISCELLANEOUS DISTRIBUTION EXP	LB588	PDIST	-	-	-
589 RENTS	LB589	PDIST	-	-	-
Total Distribution Operation Labor Expense	LBDO		$ -	$ -	$ -

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Description	Name	Functional Vector		Total System	Production Demand Base	Production Demand Inter.	Production Demand Peak	Production Energy Base	Production Energy Inter.	Production Energy Peak
Labor Expenses (Continued)										
Distribution Maintenance Labor Expense										
590 MAINTENANCE SUPERVISION AND EN	LB590	F024	$	83,850	-	-	-	-	-	-
591 MAINTENANCE OF STRUCTURES	LB591	P362		-	-	-	-	-	-	-
592 MAINTENANCE OF STATION EQUIPME	LB592	P362		330,041	-	-	-	-	-	-
593 MAINTENANCE OF OVERHEAD LINES	LB593	P365		6,250,997	-	-	-	-	-	-
594 MAINTENANCE OF UNDERGROUND LIN	LB594	P367		167,819	-	-	-	-	-	-
595 MAINTENANCE OF LINE TRANSFORME	LB595	P368		68,342	-	-	-	-	-	-
596 MAINTENANCE OF ST LIGHTS & SIG SYSTEMS	LB596	P373		-	-	-	-	-	-	-
597 MAINTENANCE OF METERS	LB597	P370		-	-	-	-	-	-	-
598 MAINTENANCE OF MISC DISTR PLANT	LB598	PDIST		66,382	-	-	-	-	-	-
Total Distribution Maintenance Labor Expense	LBDM		$	6,967,429	$ -	$ -	$ -	$ -	$ -	$ -
Total Distribution Operation and Maintenance Labor Expenses		PDIST		18,356,090	-	-	-	-	-	-
Transmission and Distribution Labor Expenses				23,015,218	-	-	-	-	-	-
Production, Transmission and Distribution Labor Expenses	LBSUB		$	64,434,374	$ 7,690,966	$ 7,250,103	$ 7,445,906	$ 19,032,181	$ -	$ -
Customer Accounts Expense										
901 SUPERVISION/CUSTOMER ACCTS	LB901	F025	$	2,323,402	-	-	-	-	-	-
902 METER READING EXPENSES	LB902	F025		270,538	-	-	-	-	-	-
903 RECORDS AND COLLECTION	LB903	F025		8,203,410	-	-	-	-	-	-
904 UNCOLLECTIBLE ACCOUNTS	LB904	F025		-	-	-	-	-	-	-
905 MISC CUST ACCOUNTS	LB903	F025		426,247	-	-	-	-	-	-
Total Customer Accounts Labor Expense	LBCA		$	11,223,597	$ -	$ -	$ -	$ -	$ -	$ -
Customer Service Expense										
907 SUPERVISION	LB907	F026	$	180,381	-	-	-	-	-	-
908 CUSTOMER ASSISTANCE EXPENSES	LB908	F026		1,275,796	-	-	-	-	-	-
908 CUSTOMER ASSISTANCE EXP-LOAD MGMT	LB908x	F026		-	-	-	-	-	-	-
909 INFORMATIONAL AND INSTRUCTIONA	LB909	F026		-	-	-	-	-	-	-
909 INFORM AND INSTRUC -LOAD MGMT	LB909x	F026		-	-	-	-	-	-	-
910 MISCELLANEOUS CUSTOMER SERVICE	LB910	F026		-	-	-	-	-	-	-
911 DEMONSTRATION AND SELLING EXP	LB911	F026		-	-	-	-	-	-	-
912 DEMONSTRATION AND SELLING EXP	LB912	F026		-	-	-	-	-	-	-
913 WATER HEATER - HEAT PUMP PROGRAM	LB913	F026		-	-	-	-	-	-	-
915 MDSE-JOBBING-CONTRACT	LB915	F026		-	-	-	-	-	-	-
916 MISC SALES EXPENSE	LB916	F026		-	-	-	-	-	-	-
Total Customer Service Labor Expense	LBCS		$	1,456,176	$ -	$ -	$ -	$ -	$ -	$ -
Sub-Total Labor Exp	LBSUB7			77,114,148	7,690,966	7,250,103	7,445,906	19,032,181	-	-

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			Transmission Demand			Distribution Poles	Distribution Substation	Distribution Primary Lines		
Description	**Name**	**Functional Vector**	**Base**	**Winter**	**Summer**	**Specific**	**General**	**Specific**	**Demand**	**Customer**
Labor Expenses (Continued)										
Distribution Maintenance Labor Expense										
590 MAINTENANCE SUPERVISION AND EN	LB590	F024	-	-	-	-	4,108	-	29,977	36,830
591 MAINTENANCE OF STRUCTURES	LB591	P362	-	-	-	-	-	-	-	-
592 MAINTENANCE OF STATION EQUIPME	LB592	P362	-	-	-	-	330,041	-	-	-
593 MAINTENANCE OF OVERHEAD LINES	LB593	P365	-	-	-	-	-	-	2,413,854	2,899,493
594 MAINTENANCE OF UNDERGROUND LIN	LB594	P367	-	-	-	-	-	-	35,362	107,284
595 MAINTENANCE OF LINE TRANSFORME	LB595	P368	-	-	-	-	-	-	-	-
596 MAINTENANCE OF ST LIGHTS & SIG SYSTEMS	LB596	P373	-	-	-	-	-	-	-	-
597 MAINTENANCE OF METERS	LB597	P370	-	-	-	-	-	-	-	-
598 MAINTENANCE OF MISC DISTR PLANT	LB598	PDIST	-	-	-	-	7,211	-	11,679	16,717
Total Distribution Maintenance Labor Expense	LBDM		$ -	$ -	$ -	$ -	$ 341,360	$ -	$ 2,490,872	$ 3,060,324
Total Distribution Operation and Maintenance Labor Expenses		PDIST	-	-	-	-	1,994,050	-	3,229,635	4,622,578
Transmission and Distribution Labor Expenses			1,600,627	1,508,876	1,549,626	-	1,994,050	-	3,229,635	4,622,578
Production, Transmission and Distribution Labor Expenses	LBSUB		$ 1,600,627	$ 1,508,876	$ 1,549,626	$ -	$ 1,994,050	$ -	$ 3,229,635	$ 4,622,578
Customer Accounts Expense										
901 SUPERVISION/CUSTOMER ACCTS	LB901	F025	-	-	-	-	-	-	-	-
902 METER READING EXPENSES	LB902	F025	-	-	-	-	-	-	-	-
903 RECORDS AND COLLECTION	LB903	F025	-	-	-	-	-	-	-	-
904 UNCOLLECTIBLE ACCOUNTS	LB904	F025	-	-	-	-	-	-	-	-
905 MISC CUST ACCOUNTS	LB903	F025	-	-	-	-	-	-	-	-
Total Customer Accounts Labor Expense	LBCA		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Customer Service Expense										
907 SUPERVISION	LB907	F026	-	-	-	-	-	-	-	-
908 CUSTOMER ASSISTANCE EXPENSES	LB908	F026	-	-	-	-	-	-	-	-
908 CUSTOMER ASSISTANCE EXP-LOAD MGMT	LB908x	F026	-	-	-	-	-	-	-	-
909 INFORMATIONAL AND INSTRUCTIONA	LB909	F026	-	-	-	-	-	-	-	-
909 INFORM AND INSTRUC -LOAD MGMT	LB909x	F026	-	-	-	-	-	-	-	-
910 MISCELLANEOUS CUSTOMER SERVICE	LB910	F026	-	-	-	-	-	-	-	-
911 DEMONSTRATION AND SELLING EXP	LB911	F026	-	-	-	-	-	-	-	-
912 DEMONSTRATION AND SELLING EXP	LB912	F026	-	-	-	-	-	-	-	-
913 WATER HEATER - HEAT PUMP PROGRAM	LB913	F026	-	-	-	-	-	-	-	-
915 MDSE-JOBBING-CONTRACT	LB915	F026	-	-	-	-	-	-	-	-
916 MISC SALES EXPENSE	LB916	F026	-	-	-	-	-	-	-	-
Total Customer Service Labor Expense	LBCS		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Sub-Total Labor Exp	LBSUB7		1,600,627	1,508,876	1,549,626	-	1,994,050	-	3,229,635	4,622,578

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Description	Name	Functional Vector		Distribution Sec. Lines Demand		Distribution Sec. Lines Customer		Distribution Line Trans. Demand		Distribution Line Trans. Customer		Distribution Services Customer		Distribution Meters		Distribution St. & Cust. Lighting
Labor Expenses (Continued)																
Distribution Maintenance Labor Expense																
590 MAINTENANCE SUPERVISION AND EN	LB590	F024		5,290		6,499		537		459		51		40		59
591 MAINTENANCE OF STRUCTURES	LB591	P362		-		-		-		-		-		-		-
592 MAINTENANCE OF STATION EQUIPME	LB592	P362		-		-		-		-		-		-		-
593 MAINTENANCE OF OVERHEAD LINES	LB593	P365		425,974		511,675		-		-		-		-		-
594 MAINTENANCE OF UNDERGROUND LIN	LB594	P367		6,240		18,932		-		-		-		-		-
595 MAINTENANCE OF LINE TRANSFORME	LB595	P368		-		-		36,829		31,512		-		-		-
596 MAINTENANCE OF ST LIGHTS & SIG SYSTEMS	LB596	P373		-		-		-		-		-		-		-
597 MAINTENANCE OF METERS	LB597	P370		-		-		-		-		-		-		-
598 MAINTENANCE OF MISC DISTR PLANT	LB598	PDIST		2,061		2,950		7,254		6,207		4,161		3,298		4,843
Total Distribution Maintenance Labor Expense	LBDM		$	439,566	$	540,057	$	44,621	$	38,179	$	4,212	$	3,338	$	4,902
Total Distribution Operation and Maintenance Labor Expenses		PDIST		569,936		815,749		2,006,024		1,716,418		1,150,626		911,837		1,339,238
Transmission and Distribution Labor Expenses				569,936		815,749		2,006,024		1,716,418		1,150,626		911,837		1,339,238
Production, Transmission and Distribution Labor Expenses	LBSUB		$	569,936	$	815,749	$	2,006,024	$	1,716,418	$	1,150,626	$	911,837	$	1,339,238
Customer Accounts Expense																
901 SUPERVISION/CUSTOMER ACCTS	LB901	F025		-		-		-		-		-		-		-
902 METER READING EXPENSES	LB902	F025		-		-		-		-		-		-		-
903 RECORDS AND COLLECTION	LB903	F025		-		-		-		-		-		-		-
904 UNCOLLECTIBLE ACCOUNTS	LB904	F025		-		-		-		-		-		-		-
905 MISC CUST ACCOUNTS	LB903	F025		-		-		-		-		-		-		-
Total Customer Accounts Labor Expense	LBCA		$	-	$	-	$	-	$	-	$	-	$	-	$	-
Customer Service Expense																
907 SUPERVISION	LB907	F026		-		-		-		-		-		-		-
908 CUSTOMER ASSISTANCE EXPENSES	LB908	F026		-		-		-		-		-		-		-
908 CUSTOMER ASSISTANCE EXP-LOAD MGMT	LB908x	F026		-		-		-		-		-		-		-
909 INFORMATIONAL AND INSTRUCTIONA	LB909	F026		-		-		-		-		-		-		-
909 INFORM AND INSTRUC -LOAD MGMT	LB909x	F026		-		-		-		-		-		-		-
910 MISCELLANEOUS CUSTOMER SERVICE	LB910	F026		-		-		-		-		-		-		-
911 DEMONSTRATION AND SELLING EXP	LB911	F026		-		-		-		-		-		-		-
912 DEMONSTRATION AND SELLING EXP	LB912	F026		-		-		-		-		-		-		-
913 WATER HEATER - HEAT PUMP PROGRAM	LB913	F026		-		-		-		-		-		-		-
915 MDSE-JOBBING-CONTRACT	LB915	F026		-		-		-		-		-		-		-
916 MISC SALES EXPENSE	LB916	F026		-		-		-		-		-		-		-
Total Customer Service Labor Expense	LBCS		$	-	$	-	$	-	$	-	$	-	$	-	$	-
Sub-Total Labor Exp	LBSUB7			569,936		815,749		2,006,024		1,716,418		1,150,626		911,837		1,339,238

Description	Name	Functional Vector		Customer Accounts Expense		Customer Service & Info.		Sales Expense
Labor Expenses (Continued)								
Distribution Maintenance Labor Expense								
590 MAINTENANCE SUPERVISION AND EN	LB590	F024		-		-		-
591 MAINTENANCE OF STRUCTURES	LB591	P362		-		-		-
592 MAINTENANCE OF STATION EQUIPME	LB592	P362		-		-		-
593 MAINTENANCE OF OVERHEAD LINES	LB593	P365		-		-		-
594 MAINTENANCE OF UNDERGROUND LIN	LB594	P367		-		-		-
595 MAINTENANCE OF LINE TRANSFORME	LB595	P368		-		-		-
596 MAINTENANCE OF ST LIGHTS & SIG SYSTEMS	LB596	P373		-		-		-
597 MAINTENANCE OF METERS	LB597	P370		-		-		-
598 MAINTENANCE OF MISC DISTR PLANT	LB598	PDIST		-		-		-
Total Distribution Maintenance Labor Expense	LBDM		$	-	$	-	$	-
Total Distribution Operation and Maintenance Labor Expenses		PDIST		-		-		-
Transmission and Distribution Labor Expenses				-		-		-
Production, Transmission and Distribution Labor Expenses	LBSUB		$	-	$	-	$	-
Customer Accounts Expense								
901 SUPERVISION/CUSTOMER ACCTS	LB901	F025		2,323,402		-		-
902 METER READING EXPENSES	LB902	F025		270,538		-		-
903 RECORDS AND COLLECTION	LB903	F025		8,203,410		-		-
904 UNCOLLECTIBLE ACCOUNTS	LB904	F025		-		-		-
905 MISC CUST ACCOUNTS	LB903	F025		426,247		-		-
Total Customer Accounts Labor Expense	LBCA		$	11,223,597	$	-	$	-
Customer Service Expense								
907 SUPERVISION	LB907	F026		-		180,381		-
908 CUSTOMER ASSISTANCE EXPENSES	LB908	F026		-		1,275,796		-
908 CUSTOMER ASSISTANCE EXP-LOAD MGMT	LB908x	F026		-		-		-
909 INFORMATIONAL AND INSTRUCTIONA	LB909	F026		-		-		-
909 INFORM AND INSTRUC -LOAD MGMT	LB909x	F026		-		-		-
910 MISCELLANEOUS CUSTOMER SERVICE	LB910	F026		-		-		-
911 DEMONSTRATION AND SELLING EXP	LB911	F026		-		-		-
912 DEMONSTRATION AND SELLING EXP	LB912	F026		-		-		-
913 WATER HEATER - HEAT PUMP PROGRAM	LB913	F026		-		-		-
915 MDSE-JOBBING-CONTRACT	LB915	F026		-		-		-
916 MISC SALES EXPENSE	LB916	F026		-		-		-
Total Customer Service Labor Expense	LBCS		$	-	$	1,456,176	$	-
Sub-Total Labor Exp	LBSUB7			11,223,597		1,456,176		-

KENTUCKY UTILITIES COMPANY
Cost of Service Study
Functional Assignment and Classification
12 Months Ended March 31, 2012

Description	Name	Functional Vector	Total System	Production Demand Base	Production Demand Inter.	Production Demand Peak	Production Energy Base	Production Energy Inter.	Production Energy Peak
Labor Expenses (Continued)									
Administrative and General Expense									
920 ADMIN. & GEN. SALARIES-	LB920	LBSUB7	$ 19,421,711	1,937,021	1,825,987	1,875,301	4,793,381	-	-
921 OFFICE SUPPLIES AND EXPENSES	LB921	LBSUB7	34,619	3,453	3,255	3,343	8,544	-	-
922 ADMIN. EXPENSES TRANSFERRED - CREDIT	LB922	LBSUB7	(1,884,219)	(187,922)	(177,150)	(181,934)	(465,035)	-	-
923 OUTSIDE SERVICES EMPLOYED	LB923	LBSUB7	-	-	-	-	-	-	-
924 PROPERTY INSURANCE	LB924	TUP	-	-	-	-	-	-	-
925 INJURIES AND DAMAGES - INSURAN	LB925	LBSUB7	795,436	79,333	74,785	76,805	196,318	-	-
926 EMPLOYEE BENEFITS	LB926	LBSUB7	34,920,650	3,482,805	3,283,163	3,371,831	8,618,602	-	-
928 REGULATORY COMMISSION FEES	LB928	TUP	-	-	-	-	-	-	-
929 DUPLICATE CHARGES-CR	LB929	LBSUB7	-	-	-	-	-	-	-
930 MISCELLANEOUS GENERAL EXPENSES	LB930	LBSUB7	30,997	3,091	2,914	2,993	7,650	-	-
931 RENTS AND LEASES	LB931	PGP	-	-	-	-	-	-	-
932 MAINTENANCE OF GENERAL PLANT	LB932	PGP	-	-	-	-	-	-	-
935 MAINTENANCE OF GENERAL PLANT	LB935	PGP	5,065,262	1,141,245	1,075,826	1,104,881	-	-	-
Total Administrative and General Expense	LBAG		$ 58,384,456	$ 6,459,025	$ 6,088,779	$ 6,253,219	$ 13,159,460	$ -	$ -
Total Operation and Maintenance Expenses	TLB		$ 135,498,603	$ 14,149,992	$ 13,338,882	$ 13,699,124	$ 32,191,641	$ -	$ -
Operation and Maintenance Expenses Less Purchase Power	LBLPP		$ 135,498,603	$ 14,149,992	$ 13,338,882	$ 13,699,124	$ 32,191,641	$ -	$ -

KENTUCKY UTILITIES COMPANY
Cost of Service Study
Functional Assignment and Classification
12 Months Ended March 31, 2012

Description	Name	Functional Vector	Transmission Demand Base	Transmission Demand Winter	Transmission Demand Summer	Distribution Poles Specific	Distribution Substation General	Distribution Primary Lines Specific	Distribution Primary Lines Demand	Distribution Primary Lines Customer
Labor Expenses (Continued)										
Administrative and General Expense										
920 ADMIN. & GEN. SALARIES-	LB920	LBSUB7	403,129	380,020	390,284	-	502,215	-	813,405	1,164,227
921 OFFICE SUPPLIES AND EXPENSES	LB921	LBSUB7	719	677	696	-	895	-	1,450	2,075
922 ADMIN. EXPENSES TRANSFERRED - CREDIT	LB922	LBSUB7	(39,110)	(36,868)	(37,864)	-	(48,723)	-	(78,913)	(112,949)
923 OUTSIDE SERVICES EMPLOYED	LB923	LBSUB7	-	-	-	-	-	-	-	-
924 PROPERTY INSURANCE	LB924	TUP	-	-	-	-	-	-	-	-
925 INJURIES AND DAMAGES - INSURAN	LB925	LBSUB7	16,511	15,564	15,984	-	20,569	-	33,314	47,682
926 EMPLOYEE BENEFITS	LB926	LBSUB7	724,834	683,285	701,738	-	902,993	-	1,462,519	2,093,305
928 REGULATORY COMMISSION FEES	LB928	TUP	-	-	-	-	-	-	-	-
929 DUPLICATE CHARGES-CR	LB929	LBSUB7	-	-	-	-	-	-	-	-
930 MISCELLANEOUS GENERAL EXPENSES	LB930	LBSUB7	643	607	623	-	802	-	1,298	1,858
931 RENTS AND LEASES	LB931	PGP	-	-	-	-	-	-	-	-
932 MAINTENANCE OF GENERAL PLANT	LB932	PGP	-	-	-	-	-	-	-	-
935 MAINTENANCE OF GENERAL PLANT	LB935	PGP	170,376	160,609	164,947	-	135,505	-	219,468	314,125
Total Administrative and General Expense	LBAG		$ 1,277,101	$ 1,203,895	$ 1,236,408	$ -	$ 1,514,255	$ -	$ 2,452,541	$ 3,510,323
Total Operation and Maintenance Expenses	TLB		$ 2,877,728	$ 2,712,770	$ 2,786,034	$ -	$ 3,508,304	$ -	$ 5,682,175	$ 8,132,901
Operation and Maintenance Expenses Less Purchase Power	LBLPP		$ 2,877,728	$ 2,712,770	$ 2,786,034	$ -	$ 3,508,304	$ -	$ 5,682,175	$ 8,132,901

KENTUCKY UTILITIES COMPANY
Cost of Service Study
Functional Assignment and Classification
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Description	Name	Functional Vector	Distribution Sec. Lines Demand	Distribution Sec. Lines Customer	Distribution Line Trans. Demand	Distribution Line Trans. Customer	Distribution Services Customer	Distribution Meters	Distribution St. & Cust. Lighting
Labor Expenses (Continued)									
Administrative and General Expense									
920 ADMIN. & GEN. SALARIES-	LB920	LBSUB7	143,542	205,452	505,230	432,291	289,793	229,652	337,296
921 OFFICE SUPPLIES AND EXPENSES	LB921	LBSUB7	256	366	901	771	517	409	601
922 ADMIN. EXPENSES TRANSFERRED - CREDIT	LB922	LBSUB7	(13,926)	(19,932)	(49,016)	(41,939)	(28,115)	(22,280)	(32,723)
923 OUTSIDE SERVICES EMPLOYED	LB923	LBSUB7	-	-	-	-	-	-	-
924 PROPERTY INSURANCE	LB924	TUP	-	-	-	-	-	-	-
925 INJURIES AND DAMAGES - INSURAN	LB925	LBSUB7	5,879	8,414	20,692	17,705	11,869	9,406	13,814
926 EMPLOYEE BENEFITS	LB926	LBSUB7	258,092	369,407	908,415	777,269	521,054	412,919	606,465
928 REGULATORY COMMISSION FEES	LB928	TUP	-	-	-	-	-	-	-
929 DUPLICATE CHARGES-CR	LB929	LBSUB7	-	-	-	-	-	-	-
930 MISCELLANEOUS GENERAL EXPENSES	LB930	LBSUB7	229	328	806	690	463	367	538
931 RENTS AND LEASES	LB931	PGP	-	-	-	-	-	-	-
932 MAINTENANCE OF GENERAL PLANT	LB932	PGP	-	-	-	-	-	-	-
935 MAINTENANCE OF GENERAL PLANT	LB935	PGP	38,730	55,434	136,318	116,638	78,190	61,963	91,007
Total Administrative and General Expense	LBAG		$ 432,801	$ 619,469	$ 1,523,348	$ 1,303,425	$ 873,770	$ 692,437	$ 1,016,999
Total Operation and Maintenance Expenses	TLB		$ 1,002,737	$ 1,435,218	$ 3,529,372	$ 3,019,843	$ 2,024,396	$ 1,604,273	$ 2,356,237
Operation and Maintenance Expenses Less Purchase Power	LBLPP		$ 1,002,737	$ 1,435,218	$ 3,529,372	$ 3,019,843	$ 2,024,396	$ 1,604,273	$ 2,356,237

KENTUCKY UTILITIES COMPANY
Cost of Service Study
Functional Assignment and Classification
12 Months Ended March 31, 2012

Description	Name	Functional Vector	Customer Accounts Expense	Customer Service & Info.	Sales Expense
Labor Expenses (Continued)					
Administrative and General Expense					
920 ADMIN. & GEN. SALARIES-	LB920	LBSUB7	2,826,738	366,748	-
921 OFFICE SUPPLIES AND EXPENSES	LB921	LBSUB7	5,039	654	-
922 ADMIN. EXPENSES TRANSFERRED - CREDIT	LB922	LBSUB7	(274,239)	(35,580)	-
923 OUTSIDE SERVICES EMPLOYED	LB923	LBSUB7	-	-	-
924 PROPERTY INSURANCE	LB924	TUP	-	-	-
925 INJURIES AND DAMAGES - INSURAN	LB925	LBSUB7	115,772	15,021	-
926 EMPLOYEE BENEFITS	LB926	LBSUB7	5,082,534	659,420	-
928 REGULATORY COMMISSION FEES	LB928	TUP	-	-	-
929 DUPLICATE CHARGES-CR	LB929	LBSUB7	-	-	-
930 MISCELLANEOUS GENERAL EXPENSES	LB930	LBSUB7	4,511	585	-
931 RENTS AND LEASES	LB931	PGP	-	-	-
932 MAINTENANCE OF GENERAL PLANT	LB932	PGP	-	-	-
935 MAINTENANCE OF GENERAL PLANT	LB935	PGP	-	-	-
Total Administrative and General Expense	LBAG		$ 7,760,355	$ 1,006,847	$ -
Total Operation and Maintenance Expenses	TLB		$ 18,983,953	$ 2,463,024	$ -
Operation and Maintenance Expenses Less Purchase Power	LBLPP		$ 18,983,953	$ 2,463,024	$ -

KENTUCKY UTILITIES COMPANY
Cost of Service Study
Functional Assignment and Classification
12 Months Ended March 31, 2012

Description	Name	Functional Vector	Total System	Production Demand Base	Production Demand Inter.	Production Demand Peak	Production Energy Base	Production Energy Inter.	Production Energy Peak
Other Expenses									
Depreciation Expenses									
Steam Production	DEPRTP	PPRTL	$ 98,366,735	33,793,545	31,856,423	32,716,767	-	-	-
Hydraulic Production	DEPRDP1	PPRTL	129,934	44,638	42,080	43,216	-	-	-
Other Production	DEPRDP2	PPRTL	14,936,094	5,131,242	4,837,108	4,967,743	-	-	-
Transmission - Kentucky System Property	DEPRDP3	PTRAN	9,156,938	-	-	-	-	-	-
Transmission - Virginia Property	DEPRDP4	PTRAN	133,401	-	-	-	-	-	-
Distribution	DEPRDP5	PDIST	32,743,234	-	-	-	-	-	-
General Plant	DEPRDP6	PGP	5,699,724	1,284,194	1,210,581	1,243,276	-	-	-
Intangible Plant	DEPRAADJ	PINT	6,534,688	1,472,318	1,387,922	1,425,405	-	-	-
Total Depreciation Expense	TDEPR		$ 167,700,749	41,725,939	39,334,114	40,396,407	-	-	-
Regulatory Credits and Accretion Expenses									
Production Plant	ACRTPP	PPRTL	$ (2,647,544)	(909,555)	(857,417)	(880,573)	-	-	-
Transmission Plant	ACRTTP	PTRAN	(5,404)	-	-	-	-	-	-
Distribution Plant		PDIST	(12,404)	-	-	-	-	-	-
Total Regulatory Credits and Accretion Expenses	TACRT		$ (2,665,352)	$ (909,555)	$ (857,417)	$ (880,573)	$ -	$ -	$ -
Property Taxes	PTAX	TUP	$ 17,000,077	3,869,961	3,648,126	3,746,650	-	-	-
Other Taxes	OTAX	TUP	$ 8,845,973	2,013,730	1,898,299	1,949,566	-	-	-
Gain Disposition of Allowances	GAIN	F013	$ (767)	-	-	-	(767)	-	-
Interest	INTLTD	TUP	$ 59,882,590	13,631,895	12,850,484	13,197,536	-	-	-
Other Expenses	OT	TUP	$ -	-	-	-	-	-	-
Total Other Expenses	TOE		$ 250,763,269	$ 60,331,970	$ 56,873,606	$ 58,409,586	$ (767)	$ -	$ -
Total Cost of Service (O&M + Other Expenses)			$ 1,109,551,252	$ 91,470,374	$ 86,227,087	$ 88,555,813	$ 611,930,422	$ -	$ -
Non-Operating Items									
Non-Operating Margins - Interest			-						
AFUDC			-						
Income (Loss) from Equity Investments			-						
Non-Operating Margins - Other			-						
Generation and Transmission Capital Credits			-						
Other Capital Credits and Patronage Dividends			-						
Extraordinary Items			-						
Long Term Debt Service Requirements			-						

KENTUCKY UTILITIES COMPANY
Cost of Service Study
Functional Assignment and Classification
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			Transmission Demand			Distribution Poles	Distribution Substation	Distribution Primary Lines		
Description	**Name**	**Functional Vector**	**Base**	**Winter**	**Summer**	**Specific**	**General**	**Specific**	**Demand**	**Customer**
Other Expenses										
Depreciation Expenses										
Steam Production	DEPRTP	PPRTL	-	-	-	-	-	-	-	-
Hydraulic Production	DEPRDP1	PPRTL	-	-	-	-	-	-	-	-
Other Production	DEPRDP2	PPRTL	-	-	-	-	-	-	-	-
Transmission - Kentucky System Property	DEPRDP3	PTRAN	3,145,834	2,965,508	3,045,597	-	-	-	-	-
Transmission - Virginia Property	DEPRDP4	PTRAN	45,829	43,202	44,369	-	-	-	-	-
Distribution	DEPRDP5	PDIST	-	-	-	-	3,556,947	-	5,760,959	8,245,664
General Plant	DEPRDP6	PGP	191,717	180,727	185,608	-	152,478	-	246,958	353,471
Intangible Plant	DEPRAADJ	PINT	219,802	207,202	212,798	-	174,814	-	283,135	405,252
Total Depreciation Expense	TDEPR		3,603,182	3,396,639	3,488,372	-	3,884,239	-	6,291,053	9,004,388
Regulatory Credits and Accretion Expenses										
Production Plant	ACRTPP	PPRTL	-	-	-	-	-	-	-	-
Transmission Plant	ACRTTP	PTRAN	(1,856)	(1,750)	(1,797)	-	-	-	-	-
Distribution Plant		PDIST	-	-	-	-	(1,347)	-	(2,182)	(3,124)
Total Regulatory Credits and Accretion Expenses	TACRT		$ (1,856)	$ (1,750)	$ (1,797)	$ -	$ (1,347)	$ -	$ (2,182)	$ (3,124)
Property Taxes	PTAX	TUP	579,588	546,365	561,120	-	439,769	-	712,266	1,019,467
Other Taxes	OTAX	TUP	301,588	284,300	291,978	-	228,834	-	370,627	530,479
Gain Disposition of Allowances	GAIN	F013	-	-	-	-	-	-	-	-
Interest	INTLTD	TUP	2,041,593	1,924,564	1,976,540	-	1,549,083	-	2,508,950	3,591,062
Other Expenses	OT	TUP	-	-	-	-	-	-	-	-
Total Other Expenses	TOE		$ 6,524,094	$ 6,150,118	$ 6,316,214	$ -	$ 6,100,577	$ -	$ 9,880,714	$ 14,142,272
Total Cost of Service (O&M + Other Expenses)			$ 16,744,267	$ 15,784,448	$ 16,210,737	$ -	$ 12,139,499	$ -	$ 27,858,672	$ 37,145,092

Non-Operating Items
Non-Operating Margins - Interest
AFUDC
Income (Loss) from Equity Investments
Non-Operating Margins - Other
Generation and Transmission Capital Credits
Other Capital Credits and Patronage Dividends
Extraordinary Items

Long Term Debt Service Requirements

KENTUCKY UTILITIES COMPANY
Cost of Service Study
Functional Assignment and Classification
12 Months Ended March 31, 2012

Description	Name	Functional Vector		Distribution Sec. Lines Demand	Distribution Sec. Lines Customer	Distribution Line Trans. Demand	Distribution Line Trans. Customer	Distribution Services Customer	Distribution Meters	Distribution St. & Cust. Lighting
Other Expenses										
Depreciation Expenses										
Steam Production	DEPRTP	PPRTL		-	-	-	-	-	-	-
Hydraulic Production	DEPRDP1	PPRTL		-	-	-	-	-	-	-
Other Production	DEPRDP2	PPRTL		-	-	-	-	-	-	-
Transmission - Kentucky System Property	DEPRDP3	PTRAN		-	-	-	-	-	-	-
Transmission - Virginia Property	DEPRDP4	PTRAN		-	-	-	-	-	-	-
Distribution	DEPRDP5	PDIST		1,016,640	1,455,117	3,578,306	3,061,713	2,052,464	1,626,517	2,388,906
General Plant	DEPRDP6	PGP		43,581	62,377	153,393	131,248	87,984	69,725	102,406
Intangible Plant	DEPRAADJ	PINT		49,965	71,515	175,864	150,475	100,873	79,939	117,408
Total Depreciation Expense	TDEPR			1,110,186	1,589,010	3,907,564	3,343,436	2,241,322	1,776,180	2,608,721
Regulatory Credits and Accretion Expenses										
Production Plant	ACRTPP	PPRTL		-	-	-	-	-	-	-
Transmission Plant	ACRTTP	PTRAN		-	-	-	-	-	-	-
Distribution Plant		PDIST		(385)	(551)	(1,356)	(1,160)	(778)	(616)	(905)
Total Regulatory Credits and Accretion Expenses	TACRT		$	(385) $	(551) $	(1,356) $	(1,160) $	(778) $	(616) $	(905)
Property Taxes	PTAX	TUP		125,694	179,906	442,410	378,540	253,760	201,097	295,357
Other Taxes	OTAX	TUP		65,405	93,614	230,208	196,973	132,044	104,641	153,688
Gain Disposition of Allowances	GAIN	F013		-	-	-	-	-	-	-
Interest	INTLTD	TUP		442,756	633,717	1,558,385	1,333,404	893,867	708,363	1,040,390
Other Expenses	OT	TUP		-	-	-	-	-	-	-
Total Other Expenses	TOE		$	1,743,655 $	2,495,695 $	6,137,211 $	5,251,193 $	3,520,215 $	2,789,665 $	4,097,251
Total Cost of Service (O&M + Other Expenses)			$	4,916,236 $	6,555,016 $	9,254,313 $	7,918,285 $	5,249,915 $	12,296,022 $	6,062,361

Non-Operating Items
Non-Operating Margins - Interest
AFUDC
Income (Loss) from Equity Investments
Non-Operating Margins - Other
Generation and Transmission Capital Credits
Other Capital Credits and Patronage Dividends
Extraordinary Items

Long Term Debt Service Requirements

KENTUCKY UTILITIES COMPANY
Cost of Service Study
Functional Assignment and Classification
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Description	Name	Functional Vector	Customer Accounts Expense	Customer Service & Info.	Sales Expense
Other Expenses					
Depreciation Expenses					
Steam Production	DEPRTP	PPRTL	-	-	-
Hydraulic Production	DEPRDP1	PPRTL	-	-	-
Other Production	DEPRDP2	PPRTL	-	-	-
Transmission - Kentucky System Property	DEPRDP3	PTRAN	-	-	-
Transmission - Virginia Property	DEPRDP4	PTRAN	-	-	-
Distribution	DEPRDP5	PDIST	-	-	-
General Plant	DEPRDP6	PGP	-	-	-
Intangible Plant	DEPRAADJ	PINT	-	-	-
Total Depreciation Expense	TDEPR		-	-	-
Regulatory Credits and Accretion Expenses					
Production Plant	ACRTPP	PPRTL	-	-	-
Transmission Plant	ACRTTP	PTRAN	-	-	-
Distribution Plant		PDIST	-	-	-
Total Regulatory Credits and Accretion Expenses	TACRT		$ -	$ -	$ -
Property Taxes	PTAX	TUP	-	-	-
Other Taxes	OTAX	TUP	-	-	-
Gain Disposition of Allowances	GAIN	F013	-	-	-
Interest	INTLTD	TUP	-	-	-
Other Expenses	OT	TUP	-	-	-
Total Other Expenses	TOE		$ -	$ -	$ -
Total Cost of Service (O&M + Other Expenses)			$ 37,377,842	$ 15,854,851	$ -
Non-Operating Items					
Non-Operating Margins - Interest					
AFUDC					
Income (Loss) from Equity Investments					
Non-Operating Margins - Other					
Generation and Transmission Capital Credits					
Other Capital Credits and Patronage Dividends					
Extraordinary Items					
Long Term Debt Service Requirements					

KENTUCKY UTILITIES COMPANY
Cost of Service Study
Functional Assignment and Classification
12 Months Ended March 31, 2012

Description	Name	Functional Vector	Total System	Production Demand Base	Production Demand Inter.	Production Demand Peak	Production Energy Base	Production Energy Inter.	Production Energy Peak
Functional Vectors									
Station Equipment	F001		1.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
Poles, Towers and Fixtures	F002		1.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
Overhead Conductors and Devices	F003		1.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
Underground Conductors and Devices	F004		1.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
Line Transformers	F005		1.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
Services	F006		1.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
Meters	F007		1.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
Street Lighting	F008		1.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
Meter Reading	F009		1.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
Billing	F010		1.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
Transmission	F011		1.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
Load Management	F012		1.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
Production Plant	F017		1.000000	0.343546	0.323854	0.332600	0.000000	0.000000	0.000000
Provar	PROVAR		1.000000	0.000000	0.000000	0.000000	1.000000	0.000000	0.000000
Fuel	F018		1.000000	0.000000	0.000000	0.000000	1.000000	0.000000	0.000000
Steam Generation Operation Labor	F019		17,747,781	5,054,286.44	4,764,563	4,893,239	3,035,692	-	-
PROFIX	PROFIX		1.000000	0.343546	0.323854	0.332600	0.000000	0.000000	0.000000
Steam Generation Maintenance Labor	F020		10,978,176	339,970	320,482	329,137	9,988,588	-	-
Hydraulic Generation Operation Labor	F021		4,595	1,578	1,488	1,528	-	-	-
Hydraulic Generation Maintenance Labor	F022		68,246	6,637	6,257	6,426	48,926	-	-
Distribution Operation Labor	F023		10,093,340	-	-	-	-	-	-
Distribution Maintenance Labor	F024		6,883,579	-	-	-	-	-	-
Customer Accounts Expense	F025		1.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
Customer Service Expense	F026		1.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
Customer Advances	F027		678,476,389	-	-	-	-	-	-
Purchase Power Demand		F017	7,557,848	2,596,472	2,447,636	2,513,740	-	-	-
Purchase Power Energy		F018	82,502,853	-	-	-	82,502,853	-	-
Purchased Power Expenses	OMPP	F017	90,060,701	2,596,472	2,447,636	2,513,740	82,502,853	-	-
Gain Disposition of Allowances	F013		1.00000	-	-	-	1.000000	-	-
Intallations on Customer Premises - Accum Depr	F014		1.00000	-	-	-	-	-	-
Generators -Energy	F015		1.000000	0.000000	0.000000	0.000000	0.000000	0.000000	1.000000
	Energy		1.000000	0.000000	0.000000	0.000000	1.000000	0.000000	0.000000
Internally Generated Functional Vectors									
Total Prod, Trans, and Dist Plant		PT&D	1.000000	0.225308	0.212393	0.218129	-	-	-
Total Distribution Plant		PDIST	1.000000	-	-	-	-	-	-
Total Transmission Plant		PTRAN	1.000000	-	-	-	-	-	-
Operation and Maintenance Expenses Less Purchase Power		OMLPP	1.000000	0.037129	0.035001	0.035946	0.688708	-	-
Total Plant in Service		TPIS	1.000000	0.225248	0.212336	0.218071	-	-	-
Total Operation and Maintenance Expenses (Labor)		TLB	1.000000	0.104429	0.098443	0.101102	0.237579	-	-
Sub-Total Prod, Trans, Dist, Cust Acct and Cust Service		OMSUB2	1.000000	0.025401	0.023945	0.024592	0.775287	-	-
Total Steam Power Operation Expenses (Labor)		LBSUB1	1.000000	0.284784	0.268460	0.275710	0.171046	-	-
Total Steam Power Generation Maintenance Expense (Labor)		LBSUB2	1.000000	0.030968	0.029193	0.029981	0.909859	-	-
Total Hydraulic Power Operation Expenses (Labor)		LBSUB3	1.000000	0.343546	0.323854	0.332600	-	-	-
Total Hydraulic Power Generation Maint. Expense (Labor)		LBSUB4	1.000000	0.097257	0.091682	0.094158	0.716904	-	-
Total Other Power Generation Expenses (Labor)		LBSUB5	1.000000	0.343546	0.323854	0.332600	-	-	-
Total Transmission Labor Expenses		LBTRAN	1.000000	-	-	-	-	-	-
Total Distribution Operation Labor Expense		LBDO	1.000000	-	-	-	-	-	-
Total Distribution Maintenance Labor Expense		LBDM	1.000000	-	-	-	-	-	-
Sub-Total Labor Exp		LBSUB7	1.000000	0.099735	0.094018	0.096557	0.246805	-	-
Total General Plant		PGP	1.000000	0.225308	0.212393	0.218129	-	-	-
Total Production Plant		PPRTL	1.000000	0.343546	0.323854	0.332600	-	-	-
Total Intangible Plant		PINT	1.000000	0.225308	0.212393	0.218129	-	-	-

KENTUCKY UTILITIES COMPANY
Cost of Service Study
Functional Assignment and Classification
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			Transmission Demand			Distribution Poles	Distribution Substation	Distribution Primary Lines		
Description	Name	Functional Vector	Base	Winter	Summer	Specific	General	Specific	Demand	Customer
Functional Vectors										
Station Equipment	F001		0.000000	0.000000	0.000000	0.000000	1.000000	0.000000	0.000000	0.000000
Poles, Towers and Fixtures	F002		0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.386155	0.463845
Overhead Conductors and Devices	F003		0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.386155	0.463845
Underground Conductors and Devices	F004		0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.210715	0.639285
Line Transformers	F005		0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
Services	F006		0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
Meters	F007		0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
Street Lighting	F008		0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
Meter Reading	F009		0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
Billing	F010		0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
Transmission	F011		0.343546	0.323854	0.332600	0.000000	0.000000	0.000000	0.000000	0.000000
Load Management	F012		0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
Production Plant	F017		0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
Provar	PROVAR		0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
Fuel	F018		0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
Steam Generation Operation Labor	F019		-	-	-	-	-	-	-	-
PROFIX	PROFIX		0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
Steam Generation Maintenance Labor	F020		-	-	-	-	-	-	-	-
Hydraulic Generation Operation Labor	F021		-	-	-	-	-	-	-	-
Hydraulic Generation Maintenance Labor	F022		-	-	-	-	-	-	-	-
Distribution Operation Labor	F023		-	-	-	-	1,757,901	-	1,094,604	1,457,770
Distribution Maintenance Labor	F024		-	-	-	-	337,252	-	2,460,895	3,023,494
Customer Accounts Expense	F025		0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
Customer Service Expense	F026		0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
Customer Advances	F027		-	-	-	-	-	-	237,200,170	339,504,761
Purchase Power Demand		F017	-	-	-	-	-	-	-	-
Purchase Power Energy		F018	-	-	-	-	-	-	-	-
Purchased Power Expenses	OMPP	F017	-	-	-	-	-	-	-	-
Gain Disposition of Allowances	F013		-	-	-	-	-	-	-	-
Intallations on Customer Premises - Accum Depr	F014		-	-	-	-	-	-	-	-
Generators -Energy	F015		0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
	Energy		0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
Internally Generated Functional Vectors										
Total Prod, Trans, and Dist Plant		PT&D	0.033636	0.031708	0.032564	-	0.026752	-	0.043328	0.062015
Total Distribution Plant		PDIST	-	-	-	-	0.108632	-	0.175943	0.251828
Total Transmission Plant		PTRAN	0.343546	0.323854	0.332600	-	-	-	-	-
Operation and Maintenance Expenses Less Purchase Power		OMLPP	0.013295	0.012533	0.012871	-	0.007856	-	0.023387	0.029923
Total Plant in Service		TPIS	0.033627	0.031700	0.032556	-	0.026774	-	0.043363	0.062066
Total Operation and Maintenance Expenses (Labor)		TLB	0.021238	0.020021	0.020561	-	0.025892	-	0.041935	0.060022
Sub-Total Prod, Trans, Dist, Cust Acct and Cust Service		OMSUB2	0.010501	0.009899	0.010166	-	0.004728	-	0.018363	0.022719
Total Steam Power Operation Expenses (Labor)		LBSUB1	-	-	-	-	-	-	-	-
Total Steam Power Generation Maintenance Expense (Labor)		LBSUB2	-	-	-	-	-	-	-	-
Total Hydraulic Power Operation Expenses (Labor)		LBSUB3	-	-	-	-	-	-	-	-
Total Hydraulic Power Generation Maint. Expense (Labor)		LBSUB4	-	-	-	-	-	-	-	-
Total Other Power Generation Expenses (Labor)		LBSUB5	-	-	-	-	-	-	-	-
Total Transmission Labor Expenses		LBTRAN	0.3435465	0.3238536	0.3325999	-	-	-	-	-
Total Distribution Operation Labor Expense		LBDO	-	-	-	-	0.174164	-	0.108448	0.144429
Total Distribution Maintenance Labor Expense		LBDM	-	-	-	-	0.048994	-	0.357502	0.439233
Sub-Total Labor Exp		LBSUB7	0.020757	0.019567	0.020095	-	0.025858	-	0.041881	0.059945
Total General Plant		PGP	0.033636	0.031708	0.032564	-	0.026752	-	0.043328	0.062015
Total Production Plant		PPRTL	-	-	-	-	-	-	-	-
Total Intangible Plant		PINT	0.033636	0.031708	0.032564	-	0.026752	-	0.043328	0.062015

KENTUCKY UTILITIES COMPANY
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Description	Name	Functional Vector	Distribution Sec. Lines Demand	Distribution Sec. Lines Customer	Distribution Line Trans. Demand	Distribution Line Trans. Customer	Distribution Services Customer	Distribution Meters	Distribution St. & Cust. Lighting
Functional Vectors									
Station Equipment	F001		0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
Poles, Towers and Fixtures	F002		0.068145	0.081855	0.000000	0.000000	0.000000	0.000000	0.000000
Overhead Conductors and Devices	F003		0.068145	0.081855	0.000000	0.000000	0.000000	0.000000	0.000000
Underground Conductors and Devices	F004		0.037185	0.112815	0.000000	0.000000	0.000000	0.000000	0.000000
Line Transformers	F005		0.000000	0.000000	0.538900	0.461100	0.000000	0.000000	0.000000
Services	F006		0.000000	0.000000	0.000000	0.000000	1.000000	0.000000	0.000000
Meters	F007		0.000000	0.000000	0.000000	0.000000	0.000000	1.000000	0.000000
Street Lighting	F008		0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	1.000000
Meter Reading	F009		0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
Billing	F010		0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
Transmission	F011		0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
Load Management	F012		0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
Production Plant	F017		0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
Provar	PROVAR		0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
Fuel	F018		0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
Steam Generation Operation Labor	F019		-	-	-	-	-	-	-
PROFIX	PROFIX		0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
Steam Generation Maintenance Labor	F020		-	-	-	-	-	-	-
Hydraulic Generation Operation Labor	F021		-	-	-	-	-	-	-
Hydraulic Generation Maintenance Labor	F022		-	-	-	-	-	-	-
Distribution Operation Labor	F023		193,165	257,253	286,039	244,744	164,068	4,442,695	195,100
Distribution Maintenance Labor	F024		434,276	533,558	44,084	37,719	4,161	3,298	4,843
Customer Accounts Expense	F025		0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
Customer Service Expense	F026		0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
Customer Advances	F027		41,858,854	59,912,605	-	-	-	-	-
Purchase Power Demand		F017	-	-	-	-	-	-	-
Purchase Power Energy		F018	-	-	-	-	-	-	-
Purchased Power Expenses	OMPP	F017	-	-	-	-	-	-	-
Gain Disposition of Allowances	F013		-	-	-	-	-	-	-
Intallations on Customer Premises - Accum Depr	F014		-	-	-	-	-	-	-
Generators -Energy	F015		0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
	Energy		0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
Internally Generated Functional Vectors									
Total Prod, Trans, and Dist Plant		PT&D	0.007646	0.010944	0.026912	0.023027	0.015437	0.012233	0.017967
Total Distribution Plant		PDIST	0.031049	0.044440	0.109284	0.093507	0.062684	0.049675	0.072959
Total Transmission Plant		PTRAN	-	-	-	-	-	-	-
Operation and Maintenance Expenses Less Purchase Power		OMLPP	0.004127	0.005281	0.004055	0.003469	0.002250	0.012366	0.002556
Total Plant in Service		TPIS	0.007652	0.010953	0.026934	0.023046	0.015449	0.012243	0.017982
Total Operation and Maintenance Expenses (Labor)		TLB	0.007400	0.010592	0.026047	0.022287	0.014940	0.011840	0.017389
Sub-Total Prod, Trans, Dist, Cust Acct and Cust Service		OMSUB2	0.003241	0.004009	0.000894	0.000765	0.000437	0.010970	0.000445
Total Steam Power Operation Expenses (Labor)		LBSUB1	-	-	-	-	-	-	-
Total Steam Power Generation Maintenance Expense (Labor)		LBSUB2	-	-	-	-	-	-	-
Total Hydraulic Power Operation Expenses (Labor)		LBSUB3	-	-	-	-	-	-	-
Total Hydraulic Power Generation Maint. Expense (Labor)		LBSUB4	-	-	-	-	-	-	-
Total Other Power Generation Expenses (Labor)		LBSUB5	-	-	-	-	-	-	-
Total Transmission Labor Expenses		LBTRAN	-	-	-	-	-	-	-
Total Distribution Operation Labor Expense		LBDO	0.019138	0.025487	0.028339	0.024248	0.016255	0.440161	0.019330
Total Distribution Maintenance Labor Expense		LBDM	0.063089	0.077512	0.006404	0.005480	0.000604	0.000479	0.000704
Sub-Total Labor Exp		LBSUB7	0.007391	0.010578	0.026014	0.022258	0.014921	0.011825	0.017367
Total General Plant		PGP	0.007646	0.010944	0.026912	0.023027	0.015437	0.012233	0.017967
Total Production Plant		PPRTL	-	-	-	-	-	-	-
Total Intangible Plant		PINT	0.007646	0.010944	0.026912	0.023027	0.015437	0.012233	0.017967

KENTUCKY UTILITIES COMPANY
Cost of Service Study
Functional Assignment and Classification
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Description	Name	Functional Vector	Customer Accounts Expense	Customer Service & Info.	Sales Expense
Functional Vectors					
Station Equipment	F001		0.000000	0.000000	0.000000
Poles, Towers and Fixtures	F002		0.000000	0.000000	0.000000
Overhead Conductors and Devices	F003		0.000000	0.000000	0.000000
Underground Conductors and Devices	F004		0.000000	0.000000	0.000000
Line Transformers	F005		0.000000	0.000000	0.000000
Services	F006		0.000000	0.000000	0.000000
Meters	F007		0.000000	0.000000	0.000000
Street Lighting	F008		0.000000	0.000000	0.000000
Meter Reading	F009		0.000000	1.000000	0.000000
Billing	F010		0.000000	1.000000	0.000000
Transmission	F011		0.000000	0.000000	0.000000
Load Management	F012		0.000000	0.000000	1.000000
Production Plant	F017		0.000000	0.000000	0.000000
Provar	PROVAR		0.000000	0.000000	0.000000
Fuel	F018		0.000000	0.000000	0.000000
Steam Generation Operation Labor	F019		-	-	-
PROFIX	PROFIX		0.000000	0.000000	0.000000
Steam Generation Maintenance Labor	F020		-	-	-
Hydraulic Generation Operation Labor	F021		-	-	-
Hydraulic Generation Maintenance Labor	F022		-	-	-
Distribution Operation Labor	F023		-	-	-
Distribution Maintenance Labor	F024		-	-	-
Customer Accounts Expense	F025		1.000000	0.000000	0.000000
Customer Service Expense	F026		0.000000	1.000000	0.000000
Customer Advances	F027		-	-	-
Purchase Power Demand		F017	-	-	-
Purchase Power Energy		F018	-	-	-
Purchased Power Expenses	OMPP	F017	-	-	-
Gain Disposition of Allowances	F013		-	-	-
Intallations on Customer Premises - Accum Depr	F014		1.00000	-	-
Generators -Energy	F015		0.000000	0.000000	0.000000
	Energy		0.000000	0.000000	0.000000
Internally Generated Functional Vectors					
Total Prod, Trans, and Dist Plant		PT&D	-	-	-
Total Distribution Plant		PDIST	-	-	-
Total Transmission Plant		PTRAN	-	-	-
Operation and Maintenance Expenses Less Purchase Power		OMLPP	0.048623	0.020625	-
Total Plant in Service		TPIS	-	-	-
Total Operation and Maintenance Expenses (Labor)		TLB	0.140104	0.018177	-
Sub-Total Prod, Trans, Dist, Cust Acct and Cust Service		OMSUB2	0.034757	0.018881	-
Total Steam Power Operation Expenses (Labor)		LBSUB1	-	-	-
Total Steam Power Generation Maintenance Expense (Labor)		LBSUB2	-	-	-
Total Hydraulic Power Operation Expenses (Labor)		LBSUB3	-	-	-
Total Hydraulic Power Generation Maint. Expense (Labor)		LBSUB4	-	-	-
Total Other Power Generation Expenses (Labor)		LBSUB5	-	-	-
Total Transmission Labor Expenses		LBTRAN	-	-	-
Total Distribution Operation Labor Expense		LBDO	-	-	-
Total Distribution Maintenance Labor Expense		LBDM	-	-	-
Sub-Total Labor Exp		LBSUB7	0.145545	0.018883	-
Total General Plant		PGP	-	-	-
Total Production Plant		PPRTL	-	-	-
Total Intangible Plant		PINT	-	-	-

Conroy Exhibit C4

Electric Cost of Service Study – Class Allocation

KENTUCKY UTILITIES COMPANY
Cost of Service Study
Class Allocation
12 Months Ended March 31, 2012

Description	Ref	Name	Allocation Vector	Total System	Residential Rate RS	General Service GSS	All Electric School AES	Power Service PS-Secondary	Power Service PS-Primary
Plant in Service									
Power Production Plant									
Production Demand - Base	TPIS	PLPPDB	PPBDA	$ 1,273,337,766	$ 425,444,050	$ 134,265,577	$ 11,181,798	$ 218,564,167	$ 46,610,017
Production Demand - Inter.	TPIS	PLPPDI	PPWDA	1,200,347,179	548,195,325	151,392,458	10,206,645	152,114,466	33,777,770
Production Demand - Peak	TPIS	PLPPDP	PPSDA	1,232,764,839	490,783,247	148,960,213	8,506,454	193,222,049	48,924,108
Production Energy - Base	TPIS	PLPPEB	E01	-	-	-	-	-	-
Production Energy - Inter.	TPIS	PLPPEI	E01	-	-	-	-	-	-
Production Energy - Peak	TPIS	PLPPEP	E01	-	-	-	-	-	-
Total Power Production Plant		PLPPT		$ 3,706,449,784	$ 1,464,422,623	$ 434,618,248	$ 29,894,897	$ 563,900,682	$ 129,311,896
					39.5%	11.7%	0.8%	15.2%	3.5%
Transmission Plant									
Transmission Demand - Base	TPIS	PLTRB	PPBDA	$ 190,095,928	$ 63,514,319	$ 20,044,438	$ 1,669,325	$ 32,629,330	$ 6,958,385
Transmission Demand - Inter.	TPIS	PLTRI	PPWDA	179,199,201	81,839,793	22,601,301	1,523,745	22,709,089	5,042,666
Transmission Demand - Peak	TPIS	PLTRP	PPSDA	184,038,817	73,268,774	22,238,192	1,269,924	28,846,018	7,303,854
Total Transmission Plant		PLTRT		$ 553,333,946	$ 218,622,886	$ 64,883,931	$ 4,462,993	$ 84,184,437	$ 19,304,905
Distribution Poles									
Specific	TPIS	PLDPS	NCPL	$ -	$ -	$ -	$ -	$ -	$ -
Distribution Substation									
General	TPIS	PLDSG	NCPS	$ 151,352,471	$ 68,463,183	$ 20,989,527	$ 1,976,633	$ 23,177,701	$ 5,780,228
Distribution Primary & Secondary Lines									
Primary Specific	TPIS	PLDPLS	NCPL	$ -	$ -	$ -	$ -	$ -	$ -
Primary Demand	TPIS	PLDPLD	NCPL	245,135,885	110,885,424	33,995,390	3,201,425	37,539,435	9,361,865
Primary Customer	TPIS	PLDPLC	YECust08	350,863,155	279,111,448	54,551,770	427,406	3,740,302	198,082
Secondary Demand	TPIS	PLDSLD	SICD	43,259,274	29,629,670	6,885,290	404,270	5,316,036	-
Secondary Customer	TPIS	PLDSLC	YECust07	61,917,027	49,298,390	9,635,271	75,491	660,635	-
Total Distribution Primary & Secondary Lines		PLDLT		$ 701,175,341	$ 468,924,932	$ 105,067,720	$ 4,108,592	$ 47,256,409	$ 9,559,947
Distribution Line Transformers									
Demand	TPIS	PLDLTD	SICD	$ 152,261,334	$ 104,288,691	$ 24,234,419	$ 1,422,926	$ 18,711,058	$ -
Customer	TPIS	PLDLTC	YECust07	130,279,646	103,728,766	20,273,578	158,841	1,390,043	-
Total Line Transformers		PLDLTT		$ 282,540,980	$ 208,017,456	$ 44,507,997	$ 1,581,766	$ 20,101,101	$ -
Distribution Services									
Customer	TPIS	PLDSC	C02	$ 87,334,885	$ 41,520,074	$ 27,249,219	$ 130,064	$ 1,495,512	$ -
Distribution Meters									
Customer	TPIS	PLDMC	C03	$ 69,210,278	$ 43,430,580	$ 15,833,937	$ 370,036	$ 4,646,207	$ 1,705,268
Distribution Street & Customer Lighting									
Customer	TPIS	PLDSCL	YECust04	$ 101,650,880	$ -	$ -	$ -	$ -	$ -
Customer Accounts Expense									
Customer	TPIS	PLCAE	YECust05	$ -	$ -	$ -	$ -	$ -	$ -
Customer Service & Info.									
Customer	TPIS	PLCSI	YECust05	$ -	$ -	$ -	$ -	$ -	$ -
Sales Expense									
Customer	TPIS	PLSEC	YECust06	$ -	$ -	$ -	$ -	$ -	$ -
Total		PLT		$ 5,653,048,566	$ 2,513,401,732	$ 713,150,579	$ 42,524,982	$ 744,762,048	$ 165,662,244

KENTUCKY UTILITIES COMPANY
Cost of Service Study
Class Allocation
12 Months Ended March 31, 2012

Description	Ref	Name	Allocation Vector	Time of Day TOD-Secondary	Time of Day TOD-Primary	Retail Transmission RTS	Fluctuating Load FLS - Transmission	Outdoor Lighting ST & POL	Lighting Energy LE	Traffic Energy TE
<u>Plant in Service</u>										
Power Production Plant										
Production Demand - Base	TPIS	PLPPDB	PPBDA	$ 35,327,849	$ 254,609,515	$ 104,464,508	$ 33,952,207	$ 8,830,718	$ 2,872	$ 84,490
Production Demand - Inter.	TPIS	PLPPDI	PPWDA	22,623,056	181,393,263	80,817,606	19,780,058	-	-	46,531
Production Demand - Peak	TPIS	PLPPDP	PPSDA	30,233,956	201,125,552	84,713,160	26,249,361	-	-	46,739
Production Energy - Base	TPIS	PLPPEB	E01	-	-	-	-	-	-	-
Production Energy - Inter.	TPIS	PLPPEI	E01	-	-	-	-	-	-	-
Production Energy - Peak	TPIS	PLPPEP	E01	-	-	-	-	-	-	-
Total Power Production Plant		PLPPT		$ 88,184,861	$ 637,128,330	$ 269,995,274	$ 79,981,626	$ 8,830,718	$ 2,872	$ 177,760
				2.4%						
Transmission Plant										
Transmission Demand - Base	TPIS	PLTRB	PPBDA	$ 5,274,076	$ 38,010,521	$ 15,595,452	$ 5,068,707	$ 1,318,333	$ 429	$ 12,613
Transmission Demand - Inter.	TPIS	PLTRI	PPWDA	3,377,384	27,080,105	12,065,218	2,952,955	-	-	6,947
Transmission Demand - Peak	TPIS	PLTRP	PPSDA	4,513,611	30,025,928	12,646,783	3,918,753	-	-	6,978
Total Transmission Plant		PLTRT		$ 13,165,072	$ 95,116,554	$ 40,307,453	$ 11,940,415	$ 1,318,333	$ 429	$ 26,538
Distribution Poles										
Specific	TPIS	PLDPS	NCPL	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Distribution Substation										
General	TPIS	PLDSG	NCPS	$ 3,428,302	$ 26,364,477	$ -	$ -	$ 1,166,261	$ 379	$ 5,781
Distribution Primary & Secondary Lines										
Primary Specific	TPIS	PLDPLS	NCPL	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Primary Demand	TPIS	PLDPLD	NCPL	5,552,600	42,700,851	-	-	1,888,918	614	9,363
Primary Customer	TPIS	PLDPLC	YECust08	91,065	111,006	-	-	12,578,235	665	53,176
Secondary Demand	TPIS	PLDSLD	SICD	803,610	-	-	-	219,134	71	1,193
Secondary Customer	TPIS	PLDSLC	YECust07	16,084	-	-	-	2,221,646	117	9,392
Total Distribution Primary & Secondary Lines		PLDLT		$ 6,463,359	$ 42,811,857	$ -	$ -	$ 16,907,933	$ 1,468	$ 73,125
Distribution Line Transformers										
Demand	TPIS	PLDLTD	SICD	$ 2,828,496	$ -	$ -	$ -	$ 771,296	$ 251	$ 4,198
Customer	TPIS	PLDLTC	YECust07	33,843	-	-	-	4,674,566	247	19,762
Total Line Transformers		PLDLTT		$ 2,862,340	$ -	$ -	$ -	$ 5,445,861	$ 498	$ 23,961
Distribution Services										
Customer	TPIS	PLDSC	C02	$ 27,712	$ -	$ -	$ -	$ 16,840,023	$ 1,088	$ 71,194
Distribution Meters										
Customer	TPIS	PLDMC	C03	$ 174,701	$ 1,233,917	$ 1,678,362	$ 61,662	$ -	$ 1,138	$ 74,470
Distribution Street & Customer Lighting										
Customer	TPIS	PLDSCL	YECust04	$ -	$ -	$ -	$ -	$ 101,650,880	$ -	$ -
Customer Accounts Expense										
Customer	TPIS	PLCAE	YECust05	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Customer Service & Info.										
Customer	TPIS	PLCSI	YECust05	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Sales Expense										
Customer	TPIS	PLSEC	YECust06	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total		PLT		$ 114,306,345	$ 802,655,135	$ 311,981,090	$ 91,983,704	$ 152,160,008	$ 7,871	$ 452,828

KENTUCKY UTILITIES COMPANY
Cost of Service Study
Class Allocation
12 Months Ended March 31, 2012

Description	Ref	Name	Allocation Vector	Total System	Residential Rate RS	General Service GSS	All Electric School AES	Power Service PS-Secondary	Power Service PS-Primary
Net Utility Plant									
Power Production Plant									
Production Demand - Base	NTPLANT	UPPPDB	PPBDA	$ 913,825,432	$ 305,324,796	$ 96,357,229	$ 8,024,745	$ 156,855,077	$ 33,450,213
Production Demand - Inter.	NTPLANT	UPPPDI	PPWDA	861,442,901	393,418,654	108,648,532	7,324,916	109,166,689	24,241,004
Production Demand - Peak	NTPLANT	UPPPDP	PPSDA	884,707,806	352,216,218	106,903,003	6,104,754	138,668,016	35,110,947
Production Energy - Base	NTPLANT	UPPPEB	E01	-	-	-	-	-	-
Production Energy - Inter.	NTPLANT	UPPPEI	E01	-	-	-	-	-	-
Production Energy - Peak	NTPLANT	UPPPEP	E01	-	-	-	-	-	-
Total Power Production Plant		UPPPT		$ 2,659,976,138	$ 1,050,959,668	$ 311,908,764	$ 21,454,415	$ 404,689,783	$ 92,802,163
Transmission Plant									
Transmission Demand - Base	NTPLANT	UPTRB	PPBDA	$ 111,793,339	$ 37,352,077	$ 11,787,915	$ 981,712	$ 19,188,953	$ 4,092,150
Transmission Demand - Inter.	NTPLANT	UPTRI	PPWDA	105,385,093	48,129,088	13,291,578	896,098	13,354,967	2,965,537
Transmission Demand - Peak	NTPLANT	UPTRP	PPSDA	108,231,218	43,088,566	13,078,038	746,828	16,964,028	4,295,317
Total Transmission Plant		UPTRT		$ 325,409,650	$ 128,569,731	$ 38,157,531	$ 2,624,638	$ 49,507,948	$ 11,353,004
Distribution Poles									
Specific	NTPLANT	UPDPS	NCPL	$ -	$ -	$ -	$ -	$ -	$ -
Distribution Substation									
General	NTPLANT	UPDSG	NCPS	$ 95,128,327	$ 43,030,603	$ 13,192,375	$ 1,242,357	$ 14,567,690	$ 3,632,999
Distribution Primary & Secondary Lines									
Primary Specific	NTPLANT	UPDPLS	NCPL	$ -	$ -	$ -	$ -	$ -	$ -
Primary Demand	NTPLANT	UPDPLD	NCPL	154,073,247	69,693,906	21,366,843	2,012,165	23,594,353	5,884,136
Primary Customer	NTPLANT	UPDPLC	YECust08	220,525,140	175,427,629	34,286,977	268,634	2,350,861	124,499
Secondary Demand	NTPLANT	UPDSLD	SICD	27,189,397	18,622,893	4,327,555	254,093	3,341,245	-
Secondary Customer	NTPLANT	UPDSLC	YECust07	38,916,201	30,985,113	6,055,978	47,448	415,224	-
Total Distribution Primary & Secondary Lines		UPDLT		$ 440,703,985	$ 294,729,540	$ 66,037,352	$ 2,582,340	$ 29,701,683	$ 6,008,635
Distribution Line Transformers									
Demand	NTPLANT	UPDLTD	SICD	$ 95,699,567	$ 65,547,715	$ 15,231,861	$ 894,340	$ 11,760,308	$ -
Customer	NTPLANT	UPDLTC	YECust07	81,883,597	65,195,790	12,742,386	99,835	873,672	-
Total Line Transformers		UPDLTT		$ 177,583,164	$ 130,743,505	$ 27,974,246	$ 994,175	$ 12,633,980	$ -
Distribution Services									
Customer	NTPLANT	UPDSC	C02	$ 54,891,879	$ 26,096,271	$ 17,126,728	$ 81,748	$ 939,962	$ -
Distribution Meters									
Customer	NTPLANT	UPDMC	C03	$ 43,500,168	$ 27,297,066	$ 9,951,974	$ 232,576	$ 2,920,242	$ 1,071,798
Distribution Street & Customer Lighting									
Customer	NTPLANT	UPDSCL	YECust04	$ 63,889,794	$ -	$ -	$ -	$ -	$ -
Customer Accounts Expense									
Customer	NTPLANT	UPCAE	YECust05	$ -	$ -	$ -	$ -	$ -	$ -
Customer Service & Info.									
Customer	NTPLANT	UPCSI	YECust05	$ -	$ -	$ -	$ -	$ -	$ -
Sales Expense									
Customer	NTPLANT	UPSEC	YECust06	$ -	$ -	$ -	$ -	$ -	$ -
Total		UPT		$ 3,861,083,106	$ 1,701,426,384	$ 484,348,971	$ 29,212,248	$ 514,961,288	$ 114,868,600

KENTUCKY UTILITIES COMPANY
Cost of Service Study
Class Allocation
12 Months Ended March 31, 2012

Description	Ref	Name	Allocation Vector	Time of Day TOD-Secondary	Time of Day TOD-Primary	Retail Transmission RTS	Fluctuating Load FLS - Transmission	Outdoor Lighting ST & POL	Lighting Energy LE	Traffic Energy TE
Net Utility Plant										
Power Production Plant										
Production Demand - Base	NTPLANT	UPPPDB	PPBDA	$ 25,353,435	$ 182,723,434	$ 74,970,151	$ 24,366,190	$ 6,337,466	$ 2,061	$ 60,635
Production Demand - Inter.	NTPLANT	UPPPDI	PPWDA	16,235,695	130,178,952	57,999,681	14,195,385	-	-	33,393
Production Demand - Peak	NTPLANT	UPPPDP	PPSDA	21,697,745	144,340,056	60,795,369	18,838,155	-	-	33,543
Production Energy - Base	NTPLANT	UPPPEB	E01	-	-	-	-	-	-	-
Production Energy - Inter.	NTPLANT	UPPPEI	E01	-	-	-	-	-	-	-
Production Energy - Peak	NTPLANT	UPPPEP	E01	-	-	-	-	-	-	-
Total Power Production Plant		UPPPT		$ 63,286,875	$ 457,242,443	$ 193,765,201	$ 57,399,730	$ 6,337,466	$ 2,061	$ 127,571
Transmission Plant										
Transmission Demand - Base	NTPLANT	UPTRB	PPBDA	$ 3,101,627	$ 22,353,572	$ 9,171,515	$ 2,980,851	$ 775,297	$ 252	$ 7,418
Transmission Demand - Inter.	NTPLANT	UPTRI	PPWDA	1,986,203	15,925,514	7,095,423	1,736,600	-	-	4,085
Transmission Demand - Peak	NTPLANT	UPTRP	PPSDA	2,654,406	17,657,920	7,437,435	2,304,576	-	-	4,103
Total Transmission Plant		UPTRT		$ 7,742,235	$ 55,937,007	$ 23,704,373	$ 7,022,028	$ 775,297	$ 252	$ 15,606
Distribution Poles										
Specific	NTPLANT	UPDPS	NCPL	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Distribution Substation										
General	NTPLANT	UPDSG	NCPS	$ 2,154,762	$ 16,570,648	$ -	$ -	$ 733,020	$ 238	$ 3,634
Distribution Primary & Secondary Lines										
Primary Specific	NTPLANT	UPDPLS	NCPL	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Primary Demand	NTPLANT	UPDPLD	NCPL	3,489,930	26,838,416	-	-	1,187,226	386	5,885
Primary Customer	NTPLANT	UPDPLC	YECust08	57,236	69,770	-	-	7,905,695	418	33,423
Secondary Demand	NTPLANT	UPDSLD	SICD	505,086	-	-	-	137,731	45	750
Secondary Customer	NTPLANT	UPDSLC	YECust07	10,109	-	-	-	1,396,353	74	5,903
Total Distribution Primary & Secondary Lines		UPDLT		$ 4,062,362	$ 26,908,185	$ -	$ -	$ 10,627,004	$ 922	$ 45,961
Distribution Line Transformers										
Demand	NTPLANT	UPDLTD	SICD	$ 1,777,772	$ -	$ -	$ -	$ 484,776	$ 158	$ 2,639
Customer	NTPLANT	UPDLTC	YECust07	21,271	-	-	-	2,938,066	155	12,421
Total Line Transformers		UPDLTT		$ 1,799,043	$ -	$ -	$ -	$ 3,422,842	$ 313	$ 15,060
Distribution Services										
Customer	NTPLANT	UPDSC	C02	$ 17,418	$ -	$ -	$ -	$ 10,584,321	$ 684	$ 44,747
Distribution Meters										
Customer	NTPLANT	UPDMC	C03	$ 109,803	$ 775,544	$ 1,054,887	$ 38,756	$ -	$ 715	$ 46,806
Distribution Street & Customer Lighting										
Customer	NTPLANT	UPDSCL	YECust04	$ -	$ -	$ -	$ -	$ 63,889,794	$ -	$ -
Customer Accounts Expense										
Customer	NTPLANT	UPCAE	YECust05	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Customer Service & Info.										
Customer	NTPLANT	UPCSI	YECust05	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Sales Expense										
Customer	NTPLANT	UPSEC	YECust06	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total		UPT		$ 79,172,498	$ 557,433,827	$ 218,524,461	$ 64,460,514	$ 96,369,745	$ 5,185	$ 299,385

KENTUCKY UTILITIES COMPANY
Cost of Service Study
Class Allocation
12 Months Ended March 31, 2012

Description	Ref	Name	Allocation Vector		Total System		Residential Rate RS		General Service GSS		All Electric School AES		Power Service PS-Secondary		Power Service PS-Primary
Net Cost Rate Base															
Power Production Plant															
Production Demand - Base	RB	RBPPDB	PPBDA	$	795,163,003	$	265,677,637	$	83,845,011	$	6,982,713	$	136,487,069	$	29,106,622
Production Demand - Inter.	RB	RBPPDI	PPWDA		749,582,470		342,332,296		94,540,259		6,373,758		94,991,132		21,093,251
Production Demand - Peak	RB	RBPPDP	PPSDA		769,826,371		306,480,096		93,021,391		5,312,037		120,661,641		30,551,706
Production Energy - Base	RB	RBPPEB	E01		66,178,542		22,130,120		7,083,626		585,389		11,402,823		2,607,305
Production Energy - Inter.	RB	RBPPEI	E01		-		-		-		-		-		-
Production Energy - Peak	RB	RBPPEP	E01		-		-		-		-		-		-
Total Power Production Plant		RBPPT		$	2,380,750,386	$	936,620,149	$	278,490,287	$	19,253,897	$	363,542,665	$	83,358,884
Transmission Plant															
Transmission Demand - Base	RB	RBTRB	PPBDA	$	105,339,535	$	35,195,751	$	11,107,401	$	925,038	$	18,081,179	$	3,855,911
Transmission Demand - Inter.	RB	RBTRI	PPWDA		99,301,236		45,350,607		12,524,258		844,366		12,583,988		2,794,337
Transmission Demand - Peak	RB	RBTRP	PPSDA		101,983,055		40,601,073		12,323,046		703,714		15,984,699		4,047,349
Total Transmission Plant		RBTRT		$	306,623,826	$	121,147,430	$	35,954,705	$	2,473,118	$	46,649,866	$	10,697,598
Distribution Poles															
Specific	RB	RBDPS	NCPL	$	-	$	-	$	-	$	-	$	-	$	-
Distribution Substation															
General	RB	RBDSG	NCPS	$	87,734,862	$	39,686,223	$	12,167,051	$	1,145,799	$	13,435,476	$	3,350,639
Distribution Primary & Secondary Lines															
Primary Specific	RB	RBDPLS	NCPL	$	-	$	-	$	-	$	-	$	-	$	-
Primary Demand	RB	RBDPLD	NCPL		142,096,651		64,276,380		19,705,932		1,855,753		21,760,290		5,426,744
Primary Customer	RB	RBDPLC	YECust08		203,041,900		161,519,721		31,568,704		247,337		2,164,485		114,629
Secondary Demand	RB	RBDSLD	SICD		25,075,880		17,175,277		3,991,160		234,341		3,081,519		-
Secondary Customer	RB	RBDSLC	YECust07		35,830,924		28,528,612		5,575,860		43,686		382,305		-
Total Distribution Primary & Secondary Lines		RBDLT		$	406,045,354	$	271,499,990	$	60,841,656	$	2,381,117	$	27,388,599	$	5,541,373
Distribution Line Transformers															
Demand	RB	RBDLTD	SICD	$	87,891,944	$	60,200,023	$	13,989,173	$	821,375	$	10,800,846	$	-
Customer	RB	RBDLTC	YECust07		75,203,146		59,876,809		11,702,802		91,690		802,394		-
Total Line Transformers		RBDLTT		$	163,095,090	$	120,076,832	$	25,691,975	$	913,065	$	11,603,240	$	-
Distribution Services															
Customer	RB	RBDSC	C02	$	50,406,262	$	23,963,754	$	15,727,178	$	75,068	$	863,151	$	-
Distribution Meters															
Customer	RB	RBDMC	C03	$	40,962,404	$	25,704,577	$	9,371,384	$	219,008	$	2,749,878	$	1,009,270
Distribution Street & Customer Lighting															
Customer	RB	RBDSCL	YECust04	$	58,662,876	$	-	$	-	$	-	$	-	$	-
Customer Accounts Expense															
Customer	RB	RBCAE	YECust05	$	4,672,230	$	3,030,167	$	1,184,480	$	46,401	$	203,033	$	10,752
Customer Service & Info.															
Customer	RB	RBCSI	YECust05	$	1,981,856	$	1,285,330	$	502,430	$	19,682	$	86,122	$	4,561
Sales Expense															
Customer	RB	RBSEC	YECust06	$	-	$	-	$	-	$	-	$	-	$	-
Total		RBT		$	3,500,935,146	$	1,543,014,453	$	439,931,146	$	26,527,156	$	466,522,028	$	103,973,077

KENTUCKY UTILITIES COMPANY
Cost of Service Study
Class Allocation
12 Months Ended March 31, 2012

Description	Ref	Name	Allocation Vector	Time of Day TOD-Secondary	Time of Day TOD-Primary	Retail Transmission RTS	Fluctuating Load FLS - Transmission	Outdoor Lighting ST & POL	Lighting Energy LE	Traffic Energy TE
Net Cost Rate Base										
Power Production Plant										
Production Demand - Base	RB	RBPPDB	PPBDA	$ 22,061,231	$ 158,996,357	$ 65,235,097	$ 21,202,182	$ 5,514,531	$ 1,793	$ 52,762
Production Demand - Inter.	RB	RBPPDI	PPWDA	14,127,451	113,274,903	50,468,283	12,352,080	-	-	29,057
Production Demand - Peak	RB	RBPPDP	PPSDA	18,880,240	125,597,153	52,900,945	16,391,975	-	-	29,187
Production Energy - Base	RB	RBPPEB	E01	1,688,016	13,020,386	5,433,025	1,764,581	458,954	149	4,168
Production Energy - Inter.	RB	RBPPEI	E01	-	-	-	-	-	-	-
Production Energy - Peak	RB	RBPPEP	E01	-	-	-	-	-	-	-
Total Power Production Plant		RBPPT		$ 56,756,938	$ 410,888,798	$ 174,037,349	$ 51,710,818	$ 5,973,485	$ 1,942	$ 115,174
Transmission Plant										
Transmission Demand - Base	RB	RBTRB	PPBDA	$ 2,922,570	$ 21,063,106	$ 8,642,045	$ 2,808,767	$ 730,540	$ 238	$ 6,990
Transmission Demand - Inter.	RB	RBTRI	PPWDA	1,871,540	15,006,138	6,685,806	1,636,347	-	-	3,849
Transmission Demand - Peak	RB	RBTRP	PPSDA	2,501,167	16,638,533	7,008,074	2,171,533	-	-	3,867
Total Transmission Plant		RBTRT		$ 7,295,277	$ 52,707,776	$ 22,335,925	$ 6,616,648	$ 730,540	$ 238	$ 14,706
Distribution Poles										
Specific	RB	RBDPS	NCPL	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Distribution Substation										
General	RB	RBDSG	NCPS	$ 1,987,292	$ 15,282,762	$ -	$ -	$ 676,049	$ 220	$ 3,351
Distribution Primary & Secondary Lines										
Primary Specific	RB	RBDPLS	NCPL	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Primary Demand	RB	RBDPLD	NCPL	3,218,647	24,752,182	-	-	1,094,939	356	5,428
Primary Customer	RB	RBDPLC	YECust08	52,698	64,238	-	-	7,278,931	385	30,773
Secondary Demand	RB	RBDSLD	SICD	465,824	-	-	-	127,024	41	691
Secondary Customer	RB	RBDSLC	YECust07	9,308	-	-	-	1,285,650	68	5,435
Total Distribution Primary & Secondary Lines		RBDLT		$ 3,746,478	$ 24,816,420	$ -	$ -	$ 9,786,544	$ 850	$ 42,327
Distribution Line Transformers										
Demand	RB	RBDLTD	SICD	$ 1,632,733	$ -	$ -	$ -	$ 445,226	$ 145	$ 2,423
Customer	RB	RBDLTC	YECust07	19,536	-	-	-	2,698,365	143	11,408
Total Line Transformers		RBDLTT		$ 1,652,268	$ -	$ -	$ -	$ 3,143,591	$ 287	$ 13,831
Distribution Services										
Customer	RB	RBDSC	C02	$ 15,994	$ -	$ -	$ -	$ 9,719,399	$ 628	$ 41,090
Distribution Meters										
Customer	RB	RBDMC	C03	$ 103,398	$ 730,299	$ 993,346	$ 36,495	$ -	$ 673	$ 44,075
Distribution Street & Customer Lighting										
Customer	RB	RBDSCL	YECust04	$ -	$ -	$ -	$ -	$ 58,662,876	$ -	$ -
Customer Accounts Expense										
Customer	RB	RBCAE	YECust05	$ 24,716	$ 30,128	$ 5,051	$ 361	$ 136,555	$ 7	$ 577
Customer Service & Info.										
Customer	RB	RBCSI	YECust05	$ 10,484	$ 12,780	$ 2,143	$ 153	$ 57,924	$ 3	$ 245
Sales Expense										
Customer	RB	RBSEC	YECust06	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total		RBT		$ 71,592,845	$ 504,468,963	$ 197,373,814	$ 58,364,475	$ 88,886,963	$ 4,849	$ 275,377

KENTUCKY UTILITIES COMPANY
Cost of Service Study
Class Allocation
12 Months Ended March 31, 2012

Description	Ref	Name	Allocation Vector	Total System	Residential Rate RS	General Service GSS	All Electric School AES	Power Service PS-Secondary	Power Service PS-Primary
Operation and Maintenance Expenses									
Power Production Plant									
Production Demand - Base	TOM	OMPPDB	PPBDA	$ 31,138,404	$ 10,403,876	$ 3,283,352	$ 273,441	$ 5,344,803	$ 1,139,809
Production Demand - Inter.	TOM	OMPPDI	PPWDA	29,353,481	13,405,656	3,702,175	249,595	3,719,831	826,007
Production Demand - Peak	TOM	OMPPDP	PPSDA	30,146,227	12,001,691	3,642,697	208,018	4,725,083	1,196,398
Production Energy - Base	TOM	OMPPEB	E01	611,931,189	204,629,937	65,499,954	5,412,903	105,438,154	24,108,891
Production Energy - Inter.	TOM	OMPPEI	E01	-	-	-	-	-	-
Production Energy - Peak	TOM	OMPPEP	E01	-	-	-	-	-	-
Total Power Production Plant		OMPPT		$ 702,569,301	$ 240,441,160	$ 76,128,178	$ 6,143,958	$ 119,227,871	$ 27,271,104
					34.2%	10.8%	0.9%	17.0%	3.9%
Transmission Plant									
Transmission Demand - Base	TOM	OMTRB	PPBDA	$ 10,220,174	$ 3,414,736	$ 1,077,654	$ 89,748	$ 1,754,259	$ 374,105
Transmission Demand - Inter.	TOM	OMTRI	PPWDA	9,634,330	4,399,973	1,215,119	81,921	1,220,914	271,110
Transmission Demand - Peak	TOM	OMTRP	PPSDA	9,894,524	3,939,167	1,195,597	68,275	1,550,855	392,679
Total Transmission Plant		OMTRT		$ 29,749,027	$ 11,753,875	$ 3,488,371	$ 239,945	$ 4,526,028	$ 1,037,894
Distribution Poles									
Specific	TOM	OMDPS	NCPL	$ -	$ -	$ -	$ -	$ -	$ -
Distribution Substation									
General	TOM	OMDSG	NCPS	$ 6,038,922	$ 2,731,662	$ 837,476	$ 78,867	$ 924,784	$ 230,630
Distribution Primary & Secondary Lines									
Primary Specific	TOM	OMDPLS	NCPL	$ -	$ -	$ -	$ -	$ -	$ -
Primary Demand	TOM	OMDPLD	NCPL	17,977,958	8,132,198	2,493,179	234,788	2,753,095	686,587
Primary Customer	TOM	OMDPLC	Cust08	23,002,820	18,304,242	3,575,168	27,869	245,292	12,933
Secondary Demand	TOM	OMDSLD	SICD	3,172,581	2,173,003	504,958	29,649	389,871	-
Secondary Customer	TOM	OMDSLC	Cust07	4,059,321	3,232,994	631,466	4,922	43,325	-
Total Distribution Primary & Secondary Lines		OMDLT		$ 48,212,680	$ 31,842,437	$ 7,204,772	$ 297,229	$ 3,431,583	$ 699,520
Distribution Line Transformers									
Demand	TOM	OMDLTD	SICD	$ 3,117,102	$ 2,135,003	$ 496,128	$ 29,130	$ 383,054	$ -
Customer	TOM	OMDLTC	Cust07	2,667,091	2,124,171	414,891	3,234	28,466	-
Total Line Transformers		OMDLTT		$ 5,784,193	$ 4,259,174	$ 911,019	$ 32,364	$ 411,519	$ -
Distribution Services									
Customer	TOM	OMDSC	C02	$ 1,729,700	$ 822,320	$ 539,681	$ 2,576	$ 29,619	$ -
Distribution Meters									
Customer	TOM	OMDMC	C03	$ 9,506,357	$ 5,965,394	$ 2,174,866	$ 50,826	$ 638,178	$ 234,227
Distribution Street & Customer Lighting									
Customer	TOM	OMDSCL	C04	$ 1,965,110	$ -	$ -	$ -	$ -	$ -
Customer Accounts Expense									
Customer	TOM	OMCAE	C05	$ 37,377,842	$ 24,251,243	$ 9,473,463	$ 369,237	$ 1,624,930	$ 85,674
Customer Service & Info.									
Customer	TOM	OMCSI	C05	$ 15,854,851	$ 10,286,839	$ 4,018,433	$ 156,622	$ 689,259	$ 36,341
Sales Expense									
Customer	TOM	OMSEC	C06	$ -	$ -	$ -	$ -	$ -	$ -
Total		OMT		$ 858,787,983	$ 332,354,104	$ 104,776,257	$ 7,371,624	$ 131,503,772	$ 29,595,391

KENTUCKY UTILITIES COMPANY
Cost of Service Study
Class Allocation
12 Months Ended March 31, 2012

Description	Ref	Name	Allocation Vector	Time of Day TOD-Secondary	Time of Day TOD-Primary	Retail Transmission RTS	Fluctuating Load FLS - Transmission	Outdoor Lighting ST & POL	Lighting Energy LE	Traffic Energy TE
Operation and Maintenance Expenses										
Power Production Plant										
Production Demand - Base	TOM	OMPPDB	PPBDA	$ 863,913	$ 6,226,262	$ 2,554,592	$ 830,273	$ 215,948	$ 70	$ 2,066
Production Demand - Inter.	TOM	OMPPDI	PPWDA	553,228	4,435,820	1,976,327	483,705	-	-	1,138
Production Demand - Peak	TOM	OMPPDP	PPSDA	739,346	4,918,356	2,071,589	641,906	-	-	1,143
Production Energy - Base	TOM	OMPPEB	E01	15,608,524	120,395,219	50,237,389	16,316,499	4,243,801	1,379	38,540
Production Energy - Inter.	TOM	OMPPEI	E01	-	-	-	-	-	-	-
Production Energy - Peak	TOM	OMPPEP	E01	-	-	-	-	-	-	-
Total Power Production Plant		OMPPT		$ 17,765,011	$ 135,975,656	$ 56,839,897	$ 18,272,383	$ 4,459,748	$ 1,449	$ 42,887
				2.5%	19.4%	8.1%	2.6%			
Transmission Plant										
Transmission Demand - Base	TOM	OMTRB	PPBDA	$ 283,551	$ 2,043,569	$ 838,462	$ 272,510	$ 70,878	$ 23	$ 678
Transmission Demand - Inter.	TOM	OMTRI	PPWDA	181,579	1,455,914	648,665	158,760	-	-	373
Transmission Demand - Peak	TOM	OMTRP	PPSDA	242,666	1,614,291	679,932	210,685	-	-	375
Total Transmission Plant		OMTRT		$ 707,797	$ 5,113,774	$ 2,167,059	$ 641,955	$ 70,878	$ 23	$ 1,427
Distribution Poles										
Specific	TOM	OMDPS	NCPL	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Distribution Substation										
General	TOM	OMDSG	NCPS	$ 136,788	$ 1,051,935	$ -	$ -	$ 46,533	$ 15	$ 231
Distribution Primary & Secondary Lines										
Primary Specific	TOM	OMDPLS	NCPL	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Primary Demand	TOM	OMDPLD	NCPL	407,221	3,131,627	-	-	138,531	45	687
Primary Customer	TOM	OMDPLC	Cust08	5,966	7,229	-	-	820,808	53	3,261
Secondary Demand	TOM	OMDSLD	SICD	58,936	-	-	-	16,071	5	87
Secondary Customer	TOM	OMDSLC	Cust07	1,054	-	-	-	144,975	9	576
Total Distribution Primary & Secondary Lines		OMDLT		$ 473,176	$ 3,138,855	$ -	$ -	$ 1,120,385	$ 113	$ 4,611
Distribution Line Transformers										
Demand	TOM	OMDLTD	SICD	$ 57,905	$ -	$ -	$ -	$ 15,790	$ 5	$ 86
Customer	TOM	OMDLTC	Cust07	692	-	-	-	95,253	6	378
Total Line Transformers		OMDLTT		$ 58,597	$ -	$ -	$ -	$ 111,043	$ 11	$ 464
Distribution Services										
Customer	TOM	OMDSC	C02	$ 549	$ -	$ -	$ -	$ 333,523	$ 22	$ 1,410
Distribution Meters										
Customer	TOM	OMDMC	C03	$ 23,996	$ 169,484	$ 230,531	$ 8,470	$ -	$ 156	$ 10,229
Distribution Street & Customer Lighting										
Customer	TOM	OMDSCL	C04	$ -	$ -	$ -	$ -	$ 1,965,110	$ -	$ -
Customer Accounts Expense										
Customer	TOM	OMCAE	C05	$ 197,599	$ 239,427	$ 41,539	$ 2,885	$ 1,087,460	$ 58	$ 4,327
Customer Service & Info.										
Customer	TOM	OMCSI	C05	$ 83,817	$ 101,560	$ 17,620	$ 1,224	$ 461,276	$ 24	$ 1,835
Sales Expense										
Customer	TOM	OMSEC	C06	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total		OMT		$ 19,447,331	$ 145,790,692	$ 59,296,646	$ 18,926,916	$ 9,655,957	$ 1,871	$ 67,421

KENTUCKY UTILITIES COMPANY
Cost of Service Study
Class Allocation
12 Months Ended March 31, 2012

Description	Ref	Name	Allocation Vector	Total System	Residential Rate RS	General Service GSS	All Electric School AES	Power Service PS-Secondary	Power Service PS-Primary
Labor Expenses									
Power Production Plant									
Production Demand - Base	TLB	LBPPDB	PPBDA	$ 14,149,992	$ 4,727,756	$ 1,492,029	$ 124,258	$ 2,428,799	$ 517,955
Production Demand - Inter.	TLB	LBPPDI	PPWDA	13,338,882	6,091,832	1,682,352	113,422	1,690,375	375,356
Production Demand - Peak	TLB	LBPPDP	PPSDA	13,699,124	5,453,839	1,655,323	94,528	2,147,184	543,670
Production Energy - Base	TLB	LBPPEB	E01	32,191,641	10,764,892	3,445,732	284,755	5,546,746	1,268,288
Production Energy - Inter.	TLB	LBPPEI	E01	-	-	-	-	-	-
Production Energy - Peak	TLB	LBPPEP	E01	-	-	-	-	-	-
Total Power Production Plant		LBPPT		$ 73,379,639	$ 27,038,318	$ 8,275,436	$ 616,962	$ 11,813,104	$ 2,705,269
Transmission Plant									
Transmission Demand - Base	TLB	LBTRB	PPBDA	$ 2,877,728	$ 961,498	$ 303,439	$ 25,271	$ 493,952	$ 105,338
Transmission Demand - Inter.	TLB	LBTRI	PPWDA	2,712,770	1,238,915	342,145	23,067	343,777	76,337
Transmission Demand - Peak	TLB	LBTRP	PPSDA	2,786,034	1,109,164	336,648	19,224	436,680	110,568
Total Transmission Plant		LBTRT		$ 8,376,532	$ 3,309,578	$ 982,232	$ 67,562	$ 1,274,409	$ 292,243
Distribution Poles									
Specific	TLB	LBDPS	NCPL	$ -	$ -	$ -	$ -	$ -	$ -
Distribution Substation									
General	TLB	LBDSG	NCPS	$ 3,508,304	$ 1,586,956	$ 486,531	$ 45,818	$ 537,252	$ 133,984
Distribution Primary & Secondary Lines									
Primary Specific	TLB	LBDPLS	NCPL	$ -	$ -	$ -	$ -	$ -	$ -
Primary Demand	TLB	LBDPLD	NCPL	5,682,175	2,570,290	788,003	74,208	870,153	217,005
Primary Customer	TLB	LBDPLC	Cust08	8,132,901	6,471,667	1,264,040	9,853	86,726	4,573
Secondary Demand	TLB	LBDSLD	SICD	1,002,737	686,807	159,599	9,371	123,224	-
Secondary Customer	TLB	LBDSLC	Cust07	1,435,218	1,143,061	223,262	1,740	15,318	-
Total Distribution Primary & Secondary Lines		LBDLT		$ 16,253,032	$ 10,871,825	$ 2,434,904	$ 95,173	$ 1,095,420	$ 221,578
Distribution Line Transformers									
Demand	TLB	LBDLTD	SICD	$ 3,529,372	$ 2,417,380	$ 561,746	$ 32,983	$ 433,717	$ -
Customer	TLB	LBDLTC	Cust07	3,019,843	2,405,115	469,765	3,662	32,230	-
Total Line Transformers		LBDLTT		$ 6,549,214	$ 4,822,495	$ 1,031,511	$ 36,645	$ 465,947	$ -
Distribution Services									
Customer	TLB	LBDSC	C02	$ 2,024,396	$ 962,423	$ 631,629	$ 3,015	$ 34,666	$ -
Distribution Meters									
Customer	TLB	LBDMC	C03	$ 1,604,273	$ 1,006,708	$ 367,026	$ 8,577	$ 107,698	$ 39,528
Distribution Street & Customer Lighting									
Customer	TLB	LBDSCL	C04	$ 2,356,237	$ -	$ -	$ -	$ -	$ -
Customer Accounts Expense									
Customer	TLB	LBCAE	C05	$ 18,983,953	$ 12,317,042	$ 4,811,507	$ 187,533	$ 825,291	$ 43,513
Customer Service & Info.									
Customer	TLB	LBCSI	C05	$ 2,463,024	$ 1,598,043	$ 624,257	$ 24,331	$ 107,075	$ 5,646
Sales Expense									
Customer	TLB	LBSEC	C06	$ -	$ -	$ -	$ -	$ -	$ -
Total		LBT		$ 135,498,603	$ 63,513,387	$ 19,645,033	$ 1,085,616	$ 16,260,862	$ 3,441,760

KENTUCKY UTILITIES COMPANY
Cost of Service Study
Class Allocation
12 Months Ended March 31, 2012

Description	Ref	Name	Allocation Vector	Time of Day TOD-Secondary	Time of Day TOD-Primary	Retail Transmission RTS	Fluctuating Load FLS - Transmission	Outdoor Lighting ST & POL	Lighting Energy LE	Traffic Energy TE
Labor Expenses										
Power Production Plant										
Production Demand - Base	TLB	LBPPDB	PPBDA	$ 392,581	$ 2,829,353	$ 1,160,864	$ 377,295	$ 98,132	$ 32	$ 939
Production Demand - Inter.	TLB	LBPPDI	PPWDA	251,399	2,015,736	898,087	219,806	-	-	517
Production Demand - Peak	TLB	LBPPDP	PPSDA	335,975	2,235,012	941,377	291,697	-	-	519
Production Energy - Base	TLB	LBPPEB	E01	821,112	6,333,587	2,642,820	858,356	223,252	73	2,027
Production Energy - Inter.	TLB	LBPPEI	E01	-	-	-	-	-	-	-
Production Energy - Peak	TLB	LBPPEP	E01	-	-	-	-	-	-	-
Total Power Production Plant		LBPPT		$ 1,801,068	$ 13,413,689	$ 5,643,148	$ 1,747,154	$ 321,384	$ 104	$ 4,003
Transmission Plant										
Transmission Demand - Base	TLB	LBTRB	PPBDA	$ 79,841	$ 575,414	$ 236,089	$ 76,732	$ 19,957	$ 6	$ 191
Transmission Demand - Inter.	TLB	LBTRI	PPWDA	51,128	409,947	182,647	44,703	-	-	105
Transmission Demand - Peak	TLB	LBTRP	PPSDA	68,328	454,541	191,451	59,323	-	-	106
Total Transmission Plant		LBTRT		$ 199,297	$ 1,439,902	$ 610,186	$ 180,758	$ 19,957	$ 6	$ 402
Distribution Poles										
Specific	TLB	LBDPS	NCPL	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Distribution Substation										
General	TLB	LBDSG	NCPS	$ 79,467	$ 611,121	$ -	$ -	$ 27,034	$ 9	$ 134
Distribution Primary & Secondary Lines										
Primary Specific	TLB	LBDPLS	NCPL	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Primary Demand	TLB	LBDPLD	NCPL	128,708	989,793	-	-	43,785	14	217
Primary Customer	TLB	LBDPLC	Cust08	2,109	2,556	-	-	290,206	19	1,153
Secondary Demand	TLB	LBDSLD	SICD	18,627	-	-	-	5,079	2	28
Secondary Customer	TLB	LBDSLC	Cust07	373	-	-	-	51,258	3	204
Total Distribution Primary & Secondary Lines		LBDLT		$ 149,817	$ 992,349	$ -	$ -	$ 390,327	$ 38	$ 1,601
Distribution Line Transformers										
Demand	TLB	LBDLTD	SICD	$ 65,564	$ -	$ -	$ -	$ 17,878	$ 6	$ 97
Customer	TLB	LBDLTC	Cust07	784	-	-	-	107,851	7	428
Total Line Transformers		LBDLTT		$ 66,348	$ -	$ -	$ -	$ 125,730	$ 13	$ 526
Distribution Services										
Customer	TLB	LBDSC	C02	$ 642	$ -	$ -	$ -	$ 390,347	$ 25	$ 1,650
Distribution Meters										
Customer	TLB	LBDMC	C03	$ 4,050	$ 28,602	$ 38,904	$ 1,429	$ -	$ 26	$ 1,726
Distribution Street & Customer Lighting										
Customer	TLB	LBDSCL	C04	$ -	$ -	$ -	$ -	$ 2,356,237	$ -	$ -
Customer Accounts Expense										
Customer	TLB	LBCAE	C05	$ 100,359	$ 121,603	$ 21,097	$ 1,465	$ 552,314	$ 29	$ 2,198
Customer Service & Info.										
Customer	TLB	LBCSI	C05	$ 13,021	$ 15,777	$ 2,737	$ 190	$ 71,658	$ 4	$ 285
Sales Expense										
Customer	TLB	LBSEC	C06	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total		LBT		$ 2,414,068	$ 16,623,043	$ 6,316,073	$ 1,930,996	$ 4,254,987	$ 255	$ 12,525

KENTUCKY UTILITIES COMPANY
Cost of Service Study
Class Allocation
12 Months Ended March 31, 2012

Description	Ref	Name	Allocation Vector		Total System		Residential Rate RS		General Service GSS		All Electric School AES		Power Service PS-Secondary		Power Service PS-Primary
<u>Depreciation Expenses</u>															
Power Production Plant															
Production Demand - Base	TDEPR	DEPPDB	PPBDA	$	41,725,939	$	13,941,354	$	4,399,742	$	366,416	$	7,162,118	$	1,527,361
Production Demand - Inter.	TDEPR	DEPPDI	PPWDA		39,334,114		17,963,784		4,960,972		334,461		4,984,631		1,106,862
Production Demand - Peak	TDEPR	DEPPDP	PPSDA		40,396,407		16,082,451		4,881,269		278,748		6,331,683		1,603,192
Production Energy - Base	TDEPR	DEPPEB	E01		-		-		-		-		-		-
Production Energy - Inter.	TDEPR	DEPPEI	E01		-		-		-		-		-		-
Production Energy - Peak	TDEPR	DEPPEP	E01		-		-		-		-		-		-
Total Power Production Plant		DEPPT		$	121,456,460	$	47,987,589	$	14,241,983	$	979,624	$	18,478,432	$	4,237,415
Transmission Plant															
Transmission Demand - Base	TDEPR	DETRB	PPBDA	$	3,603,182	$	1,203,885	$	379,933	$	31,641	$	618,474	$	131,893
Transmission Demand - Inter.	TDEPR	DETRI	PPWDA		3,396,639		1,551,236		428,397		28,882		430,440		95,581
Transmission Demand - Peak	TDEPR	DETRP	PPSDA		3,488,372		1,388,776		421,515		24,071		546,763		138,441
Total Transmission Plant		DETRT		$	10,488,193	$	4,143,897	$	1,229,845	$	84,594	$	1,595,678	$	365,916
Distribution Poles															
Specific	TDEPR	DEDPS	NCPL	$	-	$	-	$	-	$	-	$	-	$	-
Distribution Substation															
General	TDEPR	DEDSG	NCPS	$	3,884,239	$	1,757,007	$	538,665	$	50,727	$	594,822	$	148,341
Distribution Primary & Secondary Lines															
Primary Specific	TDEPR	DEDPLS	NCPL	$	-	$	-	$	-	$	-	$	-	$	-
Primary Demand	TDEPR	DEDPLD	NCPL		6,291,053		2,845,712		872,442		82,160		963,394		240,259
Primary Customer	TDEPR	DEDPLC	Cust08		9,004,388		7,165,143		1,399,489		10,909		96,019		5,063
Secondary Demand	TDEPR	DEDSLD	SICD		1,110,186		760,402		176,701		10,375		136,428		-
Secondary Customer	TDEPR	DEDSLC	Cust07		1,589,010		1,265,546		247,185		1,927		16,959		-
Total Distribution Primary & Secondary Lines		DEDLT		$	17,994,635	$	12,036,803	$	2,695,817	$	105,371	$	1,212,801	$	245,321
Distribution Line Transformers															
Demand	TDEPR	DEDLTD	SICD	$	3,907,564	$	2,676,416	$	621,941	$	36,517	$	480,192	$	-
Customer	TDEPR	DEDLTC	Cust07		3,343,436		2,662,836		520,103		4,054		35,684		-
Total Line Transformers		DEDLTT		$	7,250,999	$	5,339,252	$	1,142,044	$	40,572	$	515,876	$	-
Distribution Services															
Customer	TDEPR	DEDSC	C02	$	2,241,322	$	1,065,552	$	699,311	$	3,338	$	38,380	$	-
Distribution Meters															
Customer	TDEPR	DEDMC	C03	$	1,776,180	$	1,114,582	$	406,355	$	9,496	$	119,238	$	43,763
Distribution Street & Customer Lighting															
Customer	TDEPR	DEDSCL	C04	$	2,608,721	$	-	$	-	$	-	$	-	$	-
Customer Accounts Expense															
Customer	TDEPR	DECAE	C05	$	-	$	-	$	-	$	-	$	-	$	-
Customer Service & Info.															
Customer	TDEPR	DECSI	C05	$	-	$	-	$	-	$	-	$	-	$	-
Sales Expense															
Customer	TDEPR	DESEC	C06	$	-	$	-	$	-	$	-	$	-	$	-
Total		DET		$	167,700,749	$	73,444,682	$	20,954,020	$	1,273,723	$	22,555,226	$	5,040,756

KENTUCKY UTILITIES COMPANY
Cost of Service Study
Class Allocation
12 Months Ended March 31, 2012

Description	Ref	Name	Allocation Vector	Time of Day TOD-Secondary	Time of Day TOD-Primary	Retail Transmission RTS	Fluctuating Load FLS - Transmission	Outdoor Lighting ST & POL	Lighting Energy LE	Traffic Energy TE
Depreciation Expenses										
Power Production Plant										
Production Demand - Base	TDEPR	DEPPDB	PPBDA	$ 1,157,656	$ 8,343,286	$ 3,423,192	$ 1,112,578	$ 289,373	$ 94	$ 2,769
Production Demand - Inter.	TDEPR	DEPPDI	PPWDA	741,334	5,944,066	2,648,308	648,172	-	-	1,525
Production Demand - Peak	TDEPR	DEPPDP	PPSDA	990,735	6,590,673	2,775,961	860,164	-	-	1,532
Production Energy - Base	TDEPR	DEPPEB	E01	-	-	-	-	-	-	-
Production Energy - Inter.	TDEPR	DEPPEI	E01	-	-	-	-	-	-	-
Production Energy - Peak	TDEPR	DEPPEP	E01	-	-	-	-	-	-	-
Total Power Production Plant		DEPPT		$ 2,889,725	$ 20,878,025	$ 8,847,461	$ 2,620,914	$ 289,373	$ 94	$ 5,825
Transmission Plant										
Transmission Demand - Base	TDEPR	DETRB	PPBDA	$ 99,968	$ 720,472	$ 295,605	$ 96,075	$ 24,988	$ 8	$ 239
Transmission Demand - Inter.	TDEPR	DETRI	PPWDA	64,017	513,291	228,691	55,972	-	-	132
Transmission Demand - Peak	TDEPR	DETRP	PPSDA	85,553	569,128	239,714	74,278	-	-	132
Total Transmission Plant		DETRT		$ 249,538	$ 1,802,891	$ 764,009	$ 226,325	$ 24,988	$ 8	$ 503
Distribution Poles										
Specific	TDEPR	DEDPS	NCPL	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Distribution Substation										
General	TDEPR	DEDSG	NCPS	$ 87,982	$ 676,606	$ -	$ -	$ 29,930	$ 10	$ 148
Distribution Primary & Secondary Lines										
Primary Specific	TDEPR	DEDPLS	NCPL	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Primary Demand	TDEPR	DEDPLD	NCPL	142,499	1,095,855	-	-	48,476	16	240
Primary Customer	TDEPR	DEDPLC	Cust08	2,335	2,830	-	-	321,303	21	1,277
Secondary Demand	TDEPR	DEDSLD	SICD	20,623	-	-	-	5,624	2	31
Secondary Customer	TDEPR	DEDSLC	Cust07	412	-	-	-	56,750	4	225
Total Distribution Primary & Secondary Lines		DEDLT		$ 165,871	$ 1,098,684	$ -	$ -	$ 432,153	$ 42	$ 1,773
Distribution Line Transformers										
Demand	TDEPR	DEDLTD	SICD	$ 72,589	$ -	$ -	$ -	$ 19,794	$ 6	$ 108
Customer	TDEPR	DEDLTC	Cust07	868	-	-	-	119,408	8	474
Total Line Transformers		DEDLTT		$ 73,457	$ -	$ -	$ -	$ 139,202	$ 14	$ 582
Distribution Services										
Customer	TDEPR	DEDSC	C02	$ 711	$ -	$ -	$ -	$ 432,174	$ 28	$ 1,827
Distribution Meters										
Customer	TDEPR	DEDMC	C03	$ 4,483	$ 31,667	$ 43,073	$ 1,582	$ -	$ 29	$ 1,911
Distribution Street & Customer Lighting										
Customer	TDEPR	DEDSCL	C04	$ -	$ -	$ -	$ -	$ 2,608,721	$ -	$ -
Customer Accounts Expense										
Customer	TDEPR	DECAE	C05	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Customer Service & Info.										
Customer	TDEPR	DECSI	C05	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Sales Expense										
Customer	TDEPR	DESEC	C06	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total		DET		$ 3,471,768	$ 24,487,872	$ 9,654,543	$ 2,848,821	$ 3,956,542	$ 225	$ 12,570

KENTUCKY UTILITIES COMPANY
Cost of Service Study
Class Allocation
12 Months Ended March 31, 2012

Description	Ref	Name	Allocation Vector	Total System	Residential Rate RS	General Service GSS	All Electric School AES	Power Service PS-Secondary	Power Service PS-Primary
Accretion Expenses									
Power Production Plant									
Production Demand - Base	TACRT	ACPPDB	PPBDA	$ (909,555)	$ (303,898)	$ (95,907)	$ (7,987)	$ (156,122)	$ (33,294)
Production Demand - Inter.	TACRT	ACPPDI	PPWDA	(857,417)	(391,580)	(108,141)	(7,291)	(108,656)	(24,128)
Production Demand - Peak	TACRT	ACPPDP	PPSDA	(880,573)	(350,570)	(106,403)	(6,076)	(138,020)	(34,947)
Production Energy - Base	TACRT	ACPPEB	E01	-	-	-	-	-	-
Production Energy - Inter.	TACRT	ACPPEI	E01	-	-	-	-	-	-
Production Energy - Peak	TACRT	ACPPEP	E01	-	-	-	-	-	-
Total Power Production Plant		ACPPT		$ (2,647,544)	$ (1,046,048)	$ (310,451)	$ (21,354)	$ (402,798)	$ (92,368)
Transmission Plant									
Transmission Demand - Base	TACRT	ACTRB	PPBDA	$ (1,856)	$ (620)	$ (196)	$ (16)	$ (319)	$ (68)
Transmission Demand - Inter.	TACRT	ACTRI	PPWDA	(1,750)	(799)	(221)	(15)	(222)	(49)
Transmission Demand - Peak	TACRT	ACTRP	PPSDA	(1,797)	(716)	(217)	(12)	(282)	(71)
Total Transmission Plant		ACTRT		$ (5,404)	$ (2,135)	$ (634)	$ (44)	$ (822)	$ (189)
Distribution Poles									
Specific	TACRT	ACDPS	NCPL	$ -	$ -	$ -	$ -	$ -	$ -
Distribution Substation									
General	TACRT	ACDSG	NCPS	$ (1,347)	$ (610)	$ (187)	$ (18)	$ (206)	$ (51)
Distribution Primary & Secondary Lines									
Primary Specific	TACRT	ACDPLS	NCPL	$ -	$ -	$ -	$ -	$ -	$ -
Primary Demand	TACRT	ACDPLD	NCPL	(2,182)	(987)	(303)	(29)	(334)	(83)
Primary Customer	TACRT	ACDPLC	Cust08	(3,124)	(2,486)	(485)	(4)	(33)	(2)
Secondary Demand	TACRT	ACDSLD	SICD	(385)	(264)	(61)	(4)	(47)	-
Secondary Customer	TACRT	ACDSLC	Cust07	(551)	(439)	(86)	(1)	(6)	-
Total Distribution Primary & Secondary Lines		ACDLT		$ (6,243)	$ (4,176)	$ (935)	$ (37)	$ (421)	$ (85)
Distribution Line Transformers									
Demand	TACRT	ACDLTD	SICD	$ (1,356)	$ (928)	$ (216)	$ (13)	$ (167)	$ -
Customer	TACRT	ACDLTC	Cust07	(1,160)	(924)	(180)	(1)	(12)	-
Total Line Transformers		ACDLTT		$ (2,515)	$ (1,852)	$ (396)	$ (14)	$ (179)	$ -
Distribution Services									
Customer	TACRT	ACDSC	C02	$ (778)	$ (370)	$ (243)	$ (1)	$ (13)	$ -
Distribution Meters									
Customer	TACRT	ACDMC	C03	$ (616)	$ (387)	$ (141)	$ (3)	$ (41)	$ (15)
Distribution Street & Customer Lighting									
Customer	TACRT	ACDSCL	C04	$ (905)	$ -	$ -	$ -	$ -	$ -
Customer Accounts Expense									
Customer	TACRT	ACCAE	C05	$ -	$ -	$ -	$ -	$ -	$ -
Customer Service & Info.									
Customer	TACRT	ACCSI	C05	$ -	$ -	$ -	$ -	$ -	$ -
Sales Expense									
Customer	TACRT	DESEC	C06	$ -	$ -	$ -	$ -	$ -	$ -
Total		ACT		$ (2,665,352)	$ (1,055,577)	$ (312,986)	$ (21,470)	$ (404,481)	$ (92,709)

KENTUCKY UTILITIES COMPANY
Cost of Service Study
Class Allocation
12 Months Ended March 31, 2012

Description	Ref	Name	Allocation Vector	Time of Day TOD-Secondary	Time of Day TOD-Primary	Retail Transmission RTS	Fluctuating Load FLS - Transmission	Outdoor Lighting ST & POL	Lighting Energy LE	Traffic Energy TE
Accretion Expenses										
Power Production Plant										
Production Demand - Base	TACRT	ACPPDB	PPBDA	$ (25,235)	$ (181,869)	$ (74,620)	$ (24,252)	$ (6,308)	$ (2)	$ (60)
Production Demand - Inter.	TACRT	ACPPDI	PPWDA	(16,160)	(129,571)	(57,729)	(14,129)	-	-	(33)
Production Demand - Peak	TACRT	ACPPDP	PPSDA	(21,596)	(143,665)	(60,511)	(18,750)	-	-	(33)
Production Energy - Base	TACRT	ACPPEB	E01	-	-	-	-	-	-	-
Production Energy - Inter.	TACRT	ACPPEI	E01	-	-	-	-	-	-	-
Production Energy - Peak	TACRT	ACPPEP	E01	-	-	-	-	-	-	-
Total Power Production Plant		ACPPT		$ (62,991)	$ (455,105)	$ (192,860)	$ (57,131)	$ (6,308)	$ (2)	$ (127)
Transmission Plant										
Transmission Demand - Base	TACRT	ACTRB	PPBDA	$ (52)	$ (371)	$ (152)	$ (49)	$ (13)	$ (0)	$ (0)
Transmission Demand - Inter.	TACRT	ACTRI	PPWDA	(33)	(264)	(118)	(29)	-	-	(0)
Transmission Demand - Peak	TACRT	ACTRP	PPSDA	(44)	(293)	(124)	(38)	-	-	(0)
Total Transmission Plant		ACTRT		$ (129)	$ (929)	$ (394)	$ (117)	$ (13)	$ (0)	$ (0)
Distribution Poles										
Specific	TACRT	ACDPS	NCPL	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Distribution Substation										
General	TACRT	ACDSG	NCPS	$ (31)	$ (235)	$ -	$ -	$ (10)	$ (0)	$ (0)
Distribution Primary & Secondary Lines										
Primary Specific	TACRT	ACDPLS	NCPL	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Primary Demand	TACRT	ACDPLD	NCPL	(49)	(380)	-	-	(17)	(0)	(0)
Primary Customer	TACRT	ACDPLC	Cust08	(1)	(1)	-	-	(111)	(0)	(0)
Secondary Demand	TACRT	ACDSLD	SICD	(7)	-	-	-	(2)	(0)	(0)
Secondary Customer	TACRT	ACDSLC	Cust07	(0)	-	-	-	(20)	(0)	(0)
Total Distribution Primary & Secondary Lines		ACDLT		$ (58)	$ (381)	$ -	$ -	$ (150)	$ (0)	$ (1)
Distribution Line Transformers										
Demand	TACRT	ACDLTD	SICD	$ (25)	$ -	$ -	$ -	$ (7)	$ (0)	$ (0)
Customer	TACRT	ACDLTC	Cust07	(0)	-	-	-	(41)	(0)	(0)
Total Line Transformers		ACDLTT		$ (25)	$ -	$ -	$ -	$ (48)	$ (0)	$ (0)
Distribution Services										
Customer	TACRT	ACDSC	C02	$ (0)	$ -	$ -	$ -	$ (150)	$ (0)	$ (1)
Distribution Meters										
Customer	TACRT	ACDMC	C03	$ (2)	$ (11)	$ (15)	$ (1)	$ -	$ (0)	$ (1)
Distribution Street & Customer Lighting										
Customer	TACRT	ACDSCL	C04	$ -	$ -	$ -	$ -	$ (905)	$ -	$ -
Customer Accounts Expense										
Customer	TACRT	ACCAE	C05	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Customer Service & Info.										
Customer	TACRT	ACCSI	C05	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Sales Expense										
Customer	TACRT	DESEC	C06	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total		ACT		$ (63,235)	$ (456,661)	$ (193,268)	$ (57,249)	$ (7,584)	$ (2)	$ (129)

KENTUCKY UTILITIES COMPANY
Cost of Service Study
Class Allocation
12 Months Ended March 31, 2012

Description	Ref	Name	Allocation Vector	Total System	Residential Rate RS	General Service GSS	All Electric School AES	Power Service PS-Secondary	Power Service PS-Primary
Property Taxes									
Power Production Plant									
Production Demand - Base	PTAX	PTPPDB	PPBDA	$ 3,869,961	$ 1,293,020	$ 408,063	$ 33,984	$ 664,266	$ 141,658
Production Demand - Inter.	PTAX	PTPPDI	PPWDA	3,648,126	1,666,089	460,116	31,020	462,310	102,658
Production Demand - Peak	PTAX	PTPPDP	PPSDA	3,746,650	1,491,601	452,724	25,853	587,245	148,691
Production Energy - Base	PTAX	PTPPEB	E01	-	-	-	-	-	-
Production Energy - Inter.	PTAX	PTPPEI	E01	-	-	-	-	-	-
Production Energy - Peak	PTAX	PTPPEP	E01	-	-	-	-	-	-
Total Power Production Plant		PTPPT		$ 11,264,737	$ 4,450,711	$ 1,320,903	$ 90,857	$ 1,713,821	$ 393,008
Transmission Plant									
Transmission Demand - Base	PTAX	PTTRB	PPBDA	$ 579,588	$ 193,650	$ 61,114	$ 5,090	$ 99,484	$ 21,216
Transmission Demand - Inter.	PTAX	PTTRI	PPWDA	546,365	249,523	68,910	4,646	69,238	15,375
Transmission Demand - Peak	PTAX	PTTRP	PPSDA	561,120	223,391	67,803	3,872	87,949	22,269
Total Transmission Plant		PTTRT		$ 1,687,073	$ 666,565	$ 197,826	$ 13,607	$ 256,672	$ 58,859
Distribution Poles									
Specific	PTAX	PTDPS	NCPL	$ -	$ -	$ -	$ -	$ -	$ -
Distribution Substation									
General	PTAX	PTDSG	NCPS	$ 439,769	$ 198,926	$ 60,987	$ 5,743	$ 67,345	$ 16,795
Distribution Primary & Secondary Lines									
Primary Specific	PTAX	PTDPLS	NCPL	$ -	$ -	$ -	$ -	$ -	$ -
Primary Demand	PTAX	PTDPLD	NCPL	712,266	322,188	98,777	9,302	109,075	27,202
Primary Customer	PTAX	PTDPLC	Cust08	1,019,467	811,230	158,449	1,235	10,871	573
Secondary Demand	PTAX	PTDSLD	SICD	125,694	86,092	20,006	1,175	15,446	-
Secondary Customer	PTAX	PTDSLC	Cust07	179,906	143,284	27,986	218	1,920	-
Total Distribution Primary & Secondary Lines		PTDLT		$ 2,037,334	$ 1,362,794	$ 305,218	$ 11,930	$ 137,312	$ 27,775
Distribution Line Transformers									
Demand	PTAX	PTDLTD	SICD	$ 442,410	$ 303,021	$ 70,415	$ 4,134	$ 54,367	$ -
Customer	PTAX	PTDLTC	Cust07	378,540	301,484	58,885	459	4,040	-
Total Line Transformers		PTDLTT		$ 820,950	$ 604,505	$ 129,301	$ 4,593	$ 58,407	$ -
Distribution Services									
Customer	PTAX	PTDSC	C02	$ 253,760	$ 120,641	$ 79,175	$ 378	$ 4,345	$ -
Distribution Meters									
Customer	PTAX	PTDMC	C03	$ 201,097	$ 126,192	$ 46,007	$ 1,075	$ 13,500	$ 4,955
Distribution Street & Customer Lighting									
Customer	PTAX	PTDSCL	C04	$ 295,357	$ -	$ -	$ -	$ -	$ -
Customer Accounts Expense									
Customer	PTAX	PTCAE	C05	$ -	$ -	$ -	$ -	$ -	$ -
Customer Service & Info.									
Customer	PTAX	PTCSI	C05	$ -	$ -	$ -	$ -	$ -	$ -
Sales Expense									
Customer	PTAX	PTSEC	C06	$ -	$ -	$ -	$ -	$ -	$ -
Total		PTT		$ 17,000,077	$ 7,530,333	$ 2,139,417	$ 128,185	$ 2,251,403	$ 501,392

KENTUCKY UTILITIES COMPANY
Cost of Service Study
Class Allocation
12 Months Ended March 31, 2012

Description	Ref	Name	Allocation Vector	Time of Day TOD-Secondary	Time of Day TOD-Primary	Retail Transmission RTS	Fluctuating Load FLS - Transmission	Outdoor Lighting ST & POL	Lighting Energy LE	Traffic Energy TE
Property Taxes										
Power Production Plant										
Production Demand - Base	PTAX	PTPPDB	PPBDA	$ 107,369	$ 773,816	$ 317,491	$ 103,188	$ 26,839	$ 9	$ 257
Production Demand - Inter.	PTAX	PTPPDI	PPWDA	68,757	551,295	245,623	60,116	-	-	141
Production Demand - Peak	PTAX	PTPPDP	PPSDA	91,888	611,266	257,462	79,778	-	-	142
Production Energy - Base	PTAX	PTPPEB	E01	-	-	-	-	-	-	-
Production Energy - Inter.	PTAX	PTPPEI	E01	-	-	-	-	-	-	-
Production Energy - Peak	PTAX	PTPPEP	E01	-	-	-	-	-	-	-
Total Power Production Plant		PTPPT		$ 268,014	$ 1,936,377	$ 820,577	$ 243,082	$ 26,839	$ 9	$ 540
Transmission Plant										
Transmission Demand - Base	PTAX	PTTRB	PPBDA	$ 16,080	$ 115,891	$ 47,549	$ 15,454	$ 4,019	$ 1	$ 38
Transmission Demand - Inter.	PTAX	PTTRI	PPWDA	10,297	82,565	36,786	9,003	-	-	21
Transmission Demand - Peak	PTAX	PTTRP	PPSDA	13,762	91,547	38,559	11,948	-	-	21
Total Transmission Plant		PTTRT		$ 40,139	$ 290,003	$ 122,894	$ 36,405	$ 4,019	$ 1	$ 81
Distribution Poles										
Specific	PTAX	PTDPS	NCPL	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Distribution Substation										
General	PTAX	PTDSG	NCPS	$ 9,961	$ 76,605	$ -	$ -	$ 3,389	$ 1	$ 17
Distribution Primary & Secondary Lines										
Primary Specific	PTAX	PTDPLS	NCPL	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Primary Demand	PTAX	PTDPLD	NCPL	16,134	124,072	-	-	5,488	2	27
Primary Customer	PTAX	PTDPLC	Cust08	264	320	-	-	36,378	2	145
Secondary Demand	PTAX	PTDSLD	SICD	2,335	-	-	-	637	0	3
Secondary Customer	PTAX	PTDSLC	Cust07	47	-	-	-	6,425	0	26
Total Distribution Primary & Secondary Lines		PTDLT		$ 18,780	$ 124,392	$ -	$ -	$ 48,928	$ 5	$ 201
Distribution Line Transformers										
Demand	PTAX	PTDLTD	SICD	$ 8,218	$ -	$ -	$ -	$ 2,241	$ 1	$ 12
Customer	PTAX	PTDLTC	Cust07	98	-	-	-	13,519	1	54
Total Line Transformers		PTDLTT		$ 8,317	$ -	$ -	$ -	$ 15,760	$ 2	$ 66
Distribution Services										
Customer	PTAX	PTDSC	C02	$ 81	$ -	$ -	$ -	$ 48,930	$ 3	$ 207
Distribution Meters										
Customer	PTAX	PTDMC	C03	$ 508	$ 3,585	$ 4,877	$ 179	$ -	$ 3	$ 216
Distribution Street & Customer Lighting										
Customer	PTAX	PTDSCL	C04	$ -	$ -	$ -	$ -	$ 295,357	$ -	$ -
Customer Accounts Expense										
Customer	PTAX	PTCAE	C05	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Customer Service & Info.										
Customer	PTAX	PTCSI	C05	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Sales Expense										
Customer	PTAX	PTSEC	C06	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total		PTT		$ 345,799	$ 2,430,962	$ 948,348	$ 279,667	$ 443,222	$ 24	$ 1,328

KENTUCKY UTILITIES COMPANY
Cost of Service Study
Class Allocation
12 Months Ended March 31, 2012

Description	Ref	Name	Allocation Vector		Total System		Residential Rate RS		General Service GSS		All Electric School AES		Power Service PS-Secondary		Power Service PS-Primary
Other Taxes															
Power Production Plant															
Production Demand - Base	OTAX	OTPPDB	PPBDA	$	2,013,730	$	672,822	$	212,335	$	17,684	$	345,650	$	73,712
Production Demand - Inter.	OTAX	OTPPDI	PPWDA		1,898,299		866,948		239,421		16,141		240,563		53,418
Production Demand - Peak	OTAX	OTPPDP	PPSDA		1,949,566		776,153		235,574		13,453		305,573		77,371
Production Energy - Base	OTAX	OTPPEB	E01		-		-		-		-		-		-
Production Energy - Inter.	OTAX	OTPPEI	E01		-		-		-		-		-		-
Production Energy - Peak	OTAX	OTPPEP	E01		-		-		-		-		-		-
Total Power Production Plant		OTPPT		$	5,861,594	$	2,315,923	$	687,330	$	47,278	$	891,785	$	204,501
Transmission Plant															
Transmission Demand - Base	OTAX	OTTRB	PPBDA	$	301,588	$	100,766	$	31,801	$	2,648	$	51,767	$	11,040
Transmission Demand - Inter.	OTAX	OTTRI	PPWDA		284,300		129,839		35,857		2,417		36,028		8,000
Transmission Demand - Peak	OTAX	OTTRP	PPSDA		291,978		116,241		35,281		2,015		45,764		11,588
Total Transmission Plant		OTTRT		$	877,867	$	346,846	$	102,939	$	7,081	$	133,559	$	30,627
Distribution Poles															
Specific	OTAX	OTDPS	NCPL	$	-	$	-	$	-	$	-	$	-	$	-
Distribution Substation															
General	OTAX	OTDSG	NCPS	$	228,834	$	103,511	$	31,735	$	2,989	$	35,043	$	8,739
Distribution Primary & Secondary Lines															
Primary Specific	OTAX	OTDPLS	NCPL	$	-	$	-	$	-	$	-	$	-	$	-
Primary Demand	OTAX	OTDPLD	NCPL		370,627		167,650		51,398		4,840		56,757		14,154
Primary Customer	OTAX	OTDPLC	Cust08		530,479		422,123		82,449		643		5,657		298
Secondary Demand	OTAX	OTDSLD	SICD		65,405		44,798		10,410		611		8,037		-
Secondary Customer	OTAX	OTDSLC	Cust07		93,614		74,558		14,563		114		999		-
Total Distribution Primary & Secondary Lines		OTDLT		$	1,060,124	$	709,128	$	158,820	$	6,208	$	71,450	$	14,453
Distribution Line Transformers															
Demand	OTAX	OTDLTD	SICD	$	230,208	$	157,677	$	36,641	$	2,151	$	28,290	$	-
Customer	OTAX	OTDLTC	Cust07		196,973		156,877		30,641		239		2,102		-
Total Line Transformers		OTDLTT		$	427,181	$	314,553	$	67,282	$	2,390	$	30,392	$	-
Distribution Services															
Customer	OTAX	OTDSC	C02	$	132,044	$	62,775	$	41,199	$	197	$	2,261	$	-
Distribution Meters															
Customer	OTAX	OTDMC	C03	$	104,641	$	65,664	$	23,940	$	559	$	7,025	$	2,578
Distribution Street & Customer Lighting															
Customer	OTAX	OTDSCL	C04	$	153,688	$	-	$	-	$	-	$	-	$	-
Customer Accounts Expense															
Customer	OTAX	OTCAE	C05	$	-	$	-	$	-	$	-	$	-	$	-
Customer Service & Info.															
Customer	OTAX	OTCSI	C05	$	-	$	-	$	-	$	-	$	-	$	-
Sales Expense															
Customer	OTAX	OTSEC	C06	$	-	$	-	$	-	$	-	$	-	$	-
Total		OTT		$	8,845,973	$	3,918,401	$	1,113,243	$	66,701	$	1,171,515	$	260,899

KENTUCKY UTILITIES COMPANY
Cost of Service Study
Class Allocation
12 Months Ended March 31, 2012

Description	Ref	Name	Allocation Vector	Time of Day TOD-Secondary	Time of Day TOD-Primary	Retail Transmission RTS	Fluctuating Load FLS - Transmission	Outdoor Lighting ST & POL	Lighting Energy LE	Traffic Energy TE
Other Taxes										
Power Production Plant										
Production Demand - Base	OTAX	OTPPDB	PPBDA	$ 55,870	$ 402,654	$ 165,206	$ 53,694	$ 13,965	$ 5	$ 134
Production Demand - Inter.	OTAX	OTPPDI	PPWDA	35,777	286,866	127,810	31,281	-	-	74
Production Demand - Peak	OTAX	OTPPDP	PPSDA	47,814	318,072	133,970	41,512	-	-	74
Production Energy - Base	OTAX	OTPPEB	E01	-	-	-	-	-	-	-
Production Energy - Inter.	OTAX	OTPPEI	E01	-	-	-	-	-	-	-
Production Energy - Peak	OTAX	OTPPEP	E01	-	-	-	-	-	-	-
Total Power Production Plant		OTPPT		$ 139,461	$ 1,007,592	$ 426,986	$ 126,488	$ 13,965	$ 5	$ 281
Transmission Plant										
Transmission Demand - Base	OTAX	OTTRB	PPBDA	$ 8,367	$ 60,304	$ 24,742	$ 8,042	$ 2,092	$ 1	$ 20
Transmission Demand - Inter.	OTAX	OTTRI	PPWDA	5,358	42,963	19,142	4,685	-	-	11
Transmission Demand - Peak	OTAX	OTTRP	PPSDA	7,161	47,636	20,064	6,217	-	-	11
Total Transmission Plant		OTTRT		$ 20,886	$ 150,903	$ 63,948	$ 18,944	$ 2,092	$ 1	$ 42
Distribution Poles										
Specific	OTAX	OTDPS	NCPL	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Distribution Substation										
General	OTAX	OTDSG	NCPS	$ 5,183	$ 39,861	$ -	$ -	$ 1,763	$ 1	$ 9
Distribution Primary & Secondary Lines										
Primary Specific	OTAX	OTDPLS	NCPL	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Primary Demand	OTAX	OTDPLD	NCPL	8,395	64,560	-	-	2,856	1	14
Primary Customer	OTAX	OTDPLC	Cust08	138	167	-	-	18,929	1	75
Secondary Demand	OTAX	OTDSLD	SICD	1,215	-	-	-	331	0	2
Secondary Customer	OTAX	OTDSLC	Cust07	24	-	-	-	3,343	0	13
Total Distribution Primary & Secondary Lines		OTDLT		$ 9,772	$ 64,727	$ -	$ -	$ 25,460	$ 2	$ 104
Distribution Line Transformers										
Demand	OTAX	OTDLTD	SICD	$ 4,276	$ -	$ -	$ -	$ 1,166	$ 0	$ 6
Customer	OTAX	OTDLTC	Cust07	51	-	-	-	7,035	0	28
Total Line Transformers		OTDLTT		$ 4,328	$ -	$ -	$ -	$ 8,201	$ 1	$ 34
Distribution Services										
Customer	OTAX	OTDSC	C02	$ 42	$ -	$ -	$ -	$ 25,461	$ 2	$ 108
Distribution Meters										
Customer	OTAX	OTDMC	C03	$ 264	$ 1,866	$ 2,538	$ 93	$ -	$ 2	$ 113
Distribution Street & Customer Lighting										
Customer	OTAX	OTDSCL	C04	$ -	$ -	$ -	$ -	$ 153,688	$ -	$ -
Customer Accounts Expense										
Customer	OTAX	OTCAE	C05	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Customer Service & Info.										
Customer	OTAX	OTCSI	C05	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Sales Expense										
Customer	OTAX	OTSEC	C06	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total		OTT		$ 179,936	$ 1,264,948	$ 493,472	$ 145,524	$ 230,630	$ 12	$ 691

KENTUCKY UTILITIES COMPANY
Cost of Service Study
Class Allocation
12 Months Ended March 31, 2012

Description	Ref	Name	Allocation Vector	Total System	Residential Rate RS	General Service GSS	All Electric School AES	Power Service PS-Secondary	Power Service PS-Primary
Gain Disposition of Allowances									
Power Production Plant									
Production Demand - Base	GAIN	OTPPDB	PPBDA	$ -	$ -	$ -	$ -	$ -	$ -
Production Demand - Inter.	GAIN	OTPPDI	PPWDA	-	-	-	-	-	-
Production Demand - Peak	GAIN	OTPPDP	PPSDA	-	-	-	-	-	-
Production Energy - Base	GAIN	OTPPEB	E01	(767)	(257)	(82)	(7)	(132)	(30)
Production Energy - Inter.	GAIN	OTPPEI	E01	-	-	-	-	-	-
Production Energy - Peak	GAIN	OTPPEP	E01	-	-	-	-	-	-
Total Power Production Plant		OTPPT		$ (767)	$ (257)	$ (82)	$ (7)	$ (132)	$ (30)
Transmission Plant									
Transmission Demand - Base	GAIN	OTTRB	PPBDA	$ -	$ -	$ -	$ -	$ -	$ -
Transmission Demand - Inter.	GAIN	OTTRI	PPWDA	-	-	-	-	-	-
Transmission Demand - Peak	GAIN	OTTRP	PPSDA	-	-	-	-	-	-
Total Transmission Plant		OTTRT		$ -	$ -	$ -	$ -	$ -	$ -
Distribution Poles									
Specific	GAIN	OTDPS	NCPL	$ -	$ -	$ -	$ -	$ -	$ -
Distribution Substation									
General	GAIN	OTDSG	NCPS	$ -	$ -	$ -	$ -	$ -	$ -
Distribution Primary & Secondary Lines									
Primary Specific	GAIN	OTDPLS	NCPL	$ -	$ -	$ -	$ -	$ -	$ -
Primary Demand	GAIN	OTDPLD	NCPL	-	-	-	-	-	-
Primary Customer	GAIN	OTDPLC	Cust08	-	-	-	-	-	-
Secondary Demand	GAIN	OTDSLD	SICD	-	-	-	-	-	-
Secondary Customer	GAIN	OTDSLC	Cust07	-	-	-	-	-	-
Total Distribution Primary & Secondary Lines		OTDLT		$ -	$ -	$ -	$ -	$ -	$ -
Distribution Line Transformers									
Demand	GAIN	OTDLTD	SICD	$ -	$ -	$ -	$ -	$ -	$ -
Customer	GAIN	OTDLTC	Cust07	-	-	-	-	-	-
Total Line Transformers		OTDLTT		$ -	$ -	$ -	$ -	$ -	$ -
Distribution Services									
Customer	GAIN	OTDSC	C02	$ -	$ -	$ -	$ -	$ -	$ -
Distribution Meters									
Customer	GAIN	OTDMC	C03	$ -	$ -	$ -	$ -	$ -	$ -
Distribution Street & Customer Lighting									
Customer	GAIN	OTDSCL	C04	$ -	$ -	$ -	$ -	$ -	$ -
Customer Accounts Expense									
Customer	GAIN	OTCAE	C05	$ -	$ -	$ -	$ -	$ -	$ -
Customer Service & Info.									
Customer	GAIN	OTCSI	C05	$ -	$ -	$ -	$ -	$ -	$ -
Sales Expense									
Customer	GAIN	OTSEC	C06	$ -	$ -	$ -	$ -	$ -	$ -
Total		OTT		$ (767)	$ (257)	$ (82)	$ (7)	$ (132)	$ (30)

KENTUCKY UTILITIES COMPANY
Cost of Service Study
Class Allocation
12 Months Ended March 31, 2012

Description	Ref	Name	Allocation Vector	Time of Day TOD-Secondary	Time of Day TOD-Primary	Retail Transmission RTS	Fluctuating Load FLS - Transmission	Outdoor Lighting ST & POL	Lighting Energy LE	Traffic Energy TE
Gain Disposition of Allowances										
Power Production Plant										
Production Demand - Base	GAIN	OTPPDB	PPBDA	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Production Demand - Inter.	GAIN	OTPPDI	PPWDA	-	-	-	-	-	-	-
Production Demand - Peak	GAIN	OTPPDP	PPSDA	-	-	-	-	-	-	-
Production Energy - Base	GAIN	OTPPEB	E01	(20)	(151)	(63)	(20)	(5)	(0)	(0)
Production Energy - Inter.	GAIN	OTPPEI	E01	-	-	-	-	-	-	-
Production Energy - Peak	GAIN	OTPPEP	E01	-	-	-	-	-	-	-
Total Power Production Plant		OTPPT		$ (20)	$ (151)	$ (63)	$ (20)	$ (5)	$ (0)	$ (0)
Transmission Plant										
Transmission Demand - Base	GAIN	OTTRB	PPBDA	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Transmission Demand - Inter.	GAIN	OTTRI	PPWDA	-	-	-	-	-	-	-
Transmission Demand - Peak	GAIN	OTTRP	PPSDA	-	-	-	-	-	-	-
Total Transmission Plant		OTTRT		$ -	$ -	$ -	$ -	$ -	$ -	$ -
Distribution Poles										
Specific	GAIN	OTDPS	NCPL	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Distribution Substation										
General	GAIN	OTDSG	NCPS	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Distribution Primary & Secondary Lines										
Primary Specific	GAIN	OTDPLS	NCPL	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Primary Demand	GAIN	OTDPLD	NCPL	-	-	-	-	-	-	-
Primary Customer	GAIN	OTDPLC	Cust08	-	-	-	-	-	-	-
Secondary Demand	GAIN	OTDSLD	SICD	-	-	-	-	-	-	-
Secondary Customer	GAIN	OTDSLC	Cust07	-	-	-	-	-	-	-
Total Distribution Primary & Secondary Lines		OTDLT		$ -	$ -	$ -	$ -	$ -	$ -	$ -
Distribution Line Transformers										
Demand	GAIN	OTDLTD	SICD	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Customer	GAIN	OTDLTC	Cust07	-	-	-	-	-	-	-
Total Line Transformers		OTDLTT		$ -	$ -	$ -	$ -	$ -	$ -	$ -
Distribution Services										
Customer	GAIN	OTDSC	C02	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Distribution Meters										
Customer	GAIN	OTDMC	C03	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Distribution Street & Customer Lighting										
Customer	GAIN	OTDSCL	C04	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Customer Accounts Expense										
Customer	GAIN	OTCAE	C05	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Customer Service & Info.										
Customer	GAIN	OTCSI	C05	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Sales Expense										
Customer	GAIN	OTSEC	C06	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total		OTT		$ (20)	$ (151)	$ (63)	$ (20)	$ (5)	$ (0)	$ (0)

KENTUCKY UTILITIES COMPANY
Cost of Service Study
Class Allocation
12 Months Ended March 31, 2012

Description	Ref	Name	Allocation Vector	Total System	Residential Rate RS	General Service GSS	All Electric School AES	Power Service PS-Secondary	Power Service PS-Primary
Interest									
Power Production Plant									
Production Demand - Base	INTLTD	INTPPDB	PPBDA	$ 13,631,895	$ 4,554,651	$ 1,437,399	$ 119,708	$ 2,339,869	$ 498,990
Production Demand - Inter.	INTLTD	INTPPDI	PPWDA	12,850,484	5,868,782	1,620,753	109,269	1,628,483	361,613
Production Demand - Peak	INTLTD	INTPPDP	PPSDA	13,197,536	5,254,149	1,594,714	91,067	2,068,566	523,764
Production Energy - Base	INTLTD	INTPPEB	E01	-	-	-	-	-	-
Production Energy - Inter.	INTLTD	INTPPEI	E01	-	-	-	-	-	-
Production Energy - Peak	INTLTD	INTPPEP	E01	-	-	-	-	-	-
Total Power Production Plant		INTPPT		$ 39,679,915	$ 15,677,581	$ 4,652,866	$ 320,044	$ 6,036,917	$ 1,384,367
Transmission Plant									
Transmission Demand - Base	INTLTD	INTTRB	PPBDA	$ 2,041,593	$ 682,131	$ 215,273	$ 17,928	$ 350,433	$ 74,732
Transmission Demand - Inter.	INTLTD	INTTRI	PPWDA	1,924,564	878,943	242,733	16,365	243,891	54,157
Transmission Demand - Peak	INTLTD	INTTRP	PPSDA	1,976,540	786,892	238,834	13,639	309,801	78,442
Total Transmission Plant		INTTRT		$ 5,942,697	$ 2,347,966	$ 696,841	$ 47,932	$ 904,124	$ 207,331
Distribution Poles									
Specific	INTLTD	INTDPS	NCPL	$ -	$ -	$ -	$ -	$ -	$ -
Distribution Substation									
General	INTLTD	INTDSG	NCPS	$ 1,549,083	$ 700,716	$ 214,826	$ 20,231	$ 237,222	$ 59,160
Distribution Primary & Secondary Lines									
Primary Specific	INTLTD	INTDPLS	NCPL	$ -	$ -	$ -	$ -	$ -	$ -
Primary Demand	INTLTD	INTDPLD	NCPL	2,508,950	1,134,905	347,941	32,766	384,214	95,818
Primary Customer	INTLTD	INTDPLC	Cust08	3,591,062	2,857,549	558,134	4,351	38,293	2,019
Secondary Demand	INTLTD	INTDSLD	SICD	442,756	303,258	70,471	4,138	54,409	-
Secondary Customer	INTLTD	INTDSLC	Cust07	633,717	504,716	98,581	768	6,764	-
Total Distribution Primary & Secondary Lines		INTDLT		$ 7,176,486	$ 4,800,427	$ 1,075,126	$ 42,023	$ 483,680	$ 97,837
Distribution Line Transformers									
Demand	INTLTD	INTDLTD	SICD	$ 1,558,385	$ 1,067,388	$ 248,038	$ 14,564	$ 191,507	$ -
Customer	INTLTD	INTDLTC	Cust07	1,333,404	1,061,972	207,424	1,617	14,231	-
Total Line Transformers		INTDLTT		$ 2,891,789	$ 2,129,361	$ 455,461	$ 16,180	$ 205,738	$ -
Distribution Services									
Customer	INTLTD	INTDSC	C02	$ 893,867	$ 424,955	$ 278,894	$ 1,331	$ 15,306	$ -
Distribution Meters									
Customer	INTLTD	INTDMC	C03	$ 708,363	$ 444,509	$ 162,059	$ 3,787	$ 47,554	$ 17,453
Distribution Street & Customer Lighting									
Customer	INTLTD	INTDSCL	C04	$ 1,040,390	$ -	$ -	$ -	$ -	$ -
Customer Accounts Expense									
Customer	INTLTD	INTCAE	C05	$ -	$ -	$ -	$ -	$ -	$ -
Customer Service & Info.									
Customer	INTLTD	INTCSI	C05	$ -	$ -	$ -	$ -	$ -	$ -
Sales Expense									
Customer	INTLTD	INTSEC	C06	$ -	$ -	$ -	$ -	$ -	$ -
Total		INTT		$ 59,882,590	$ 26,525,516	$ 7,536,074	$ 451,529	$ 7,930,542	$ 1,766,148

KENTUCKY UTILITIES COMPANY
Cost of Service Study
Class Allocation
12 Months Ended March 31, 2012

Description	Ref	Name	Allocation Vector	Time of Day TOD-Secondary	Time of Day TOD-Primary	Retail Transmission RTS	Fluctuating Load FLS - Transmission	Outdoor Lighting ST & POL	Lighting Energy LE	Traffic Energy TE
<u>Interest</u>										
Power Production Plant										
Production Demand - Base	INTLTD	INTPPDB	PPBDA	$ 378,207	$ 2,725,758	$ 1,118,359	$ 363,480	$ 94,538	$ 31	$ 905
Production Demand - Inter.	INTLTD	INTPPDI	PPWDA	242,194	1,941,931	865,204	211,758	-	-	498
Production Demand - Peak	INTLTD	INTPPDP	PPSDA	323,674	2,153,178	906,909	281,016	-	-	500
Production Energy - Base	INTLTD	INTPPEB	E01	-	-	-	-	-	-	-
Production Energy - Inter.	INTLTD	INTPPEI	E01	-	-	-	-	-	-	-
Production Energy - Peak	INTLTD	INTPPEP	E01	-	-	-	-	-	-	-
Total Power Production Plant		INTPPT		$ 944,075	$ 6,820,866	$ 2,890,472	$ 856,254	$ 94,538	$ 31	$ 1,903
Transmission Plant										
Transmission Demand - Base	INTLTD	INTTRB	PPBDA	$ 56,643	$ 408,225	$ 167,492	$ 54,437	$ 14,159	$ 5	$ 135
Transmission Demand - Inter.	INTLTD	INTTRI	PPWDA	36,272	290,835	129,578	31,714	-	-	75
Transmission Demand - Peak	INTLTD	INTTRP	PPSDA	48,475	322,473	135,824	42,087	-	-	75
Total Transmission Plant		INTTRT		$ 141,390	$ 1,021,533	$ 432,894	$ 128,238	$ 14,159	$ 5	$ 285
Distribution Poles										
Specific	INTLTD	INTDPS	NCPL	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Distribution Substation										
General	INTLTD	INTDSG	NCPS	$ 35,088	$ 269,839	$ -	$ -	$ 11,937	$ 4	$ 59
Distribution Primary & Secondary Lines										
Primary Specific	INTLTD	INTDPLS	NCPL	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Primary Demand	INTLTD	INTDPLD	NCPL	56,831	437,041	-	-	19,333	6	96
Primary Customer	INTLTD	INTDPLC	Cust08	931	1,128	-	-	128,140	8	509
Secondary Demand	INTLTD	INTDSLD	SICD	8,225	-	-	-	2,243	1	12
Secondary Customer	INTLTD	INTDSLC	Cust07	164	-	-	-	22,633	1	90
Total Distribution Primary & Secondary Lines		INTDLT		$ 66,151	$ 438,169	$ -	$ -	$ 172,348	$ 17	$ 707
Distribution Line Transformers										
Demand	INTLTD	INTDLTD	SICD	$ 28,949	$ -	$ -	$ -	$ 7,894	$ 3	$ 43
Customer	INTLTD	INTDLTC	Cust07	346	-	-	-	47,621	3	189
Total Line Transformers		INTDLTT		$ 29,296	$ -	$ -	$ -	$ 55,516	$ 6	$ 232
Distribution Services										
Customer	INTLTD	INTDSC	C02	$ 284	$ -	$ -	$ -	$ 172,357	$ 11	$ 729
Distribution Meters										
Customer	INTLTD	INTDMC	C03	$ 1,788	$ 12,629	$ 17,178	$ 631	$ -	$ 12	$ 762
Distribution Street & Customer Lighting										
Customer	INTLTD	INTDSCL	C04	$ -	$ -	$ -	$ -	$ 1,040,390	$ -	$ -
Customer Accounts Expense										
Customer	INTLTD	INTCAE	C05	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Customer Service & Info.										
Customer	INTLTD	INTCSI	C05	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Sales Expense										
Customer	INTLTD	INTSEC	C06	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total		INTT		$ 1,218,073	$ 8,563,036	$ 3,340,544	$ 985,123	$ 1,561,244	$ 84	$ 4,677

KENTUCKY UTILITIES COMPANY
Cost of Service Study
Class Allocation
12 Months Ended March 31, 2012

Description	Ref	Name	Allocation Vector		Total System		Residential Rate RS		General Service GSS		All Electric School AES		Power Service PS-Secondary		Power Service PS-Primary
Cost of Service Summary -- Unadjusted															
Operating Revenues															
Sales		REVUC	R01	$	1,291,701,071	$	474,158,148	$	181,472,282	$	11,111,098	$	222,187,654	$	51,446,772
Franchise Fees and HEA			FFHEA	$	-		-		-		-		-		-
Other Accrued Revenue			R01		-	$	-	$	-	$	-	$	-	$	-
Intercompany Sales		SFRS	E01		22,834,450		7,635,846		2,444,156		201,985		3,934,466		899,633
Off-System Sales			OSSALL		5,895,029		2,160,092		662,785		49,719		953,024		218,226
Brokered Sales			Energy		(294,880)		(98,608)		(31,563)		(2,608)		(50,809)		(11,618)
LATE PAYMENT CHARGES			LPAY		6,910,624		5,226,739		1,128,697		5,854		225,327		29,221
RECONNECT CHARGES			MISCSERV		1,659,612		1,505,487		53,535		662		3,314		63,194
OTHER SERVICE CHARGES			MISCSERV		547,025		496,224		17,646		218		1,092		20,830
RENT FROM ELEC PROPERTY			UPT		2,153,991		949,179		270,205		16,297		287,283		64,082
TRANSMISSION SERVICE			PLTRT		10,488,823		4,144,146		1,229,919		84,599		1,595,774		365,938
TAX REMITTANCE COMPENSATION			R01		17,113		6,282		2,404		147		2,944		682
RETURN CHECK CHARGES			MISCSERV		130,862		118,709		4,221		52		261		4,983
OTHER MISC REVENUES			MISCSERV		22,525		20,433		727		9		45		858
EXCESS FACILITIES CHARGES			MISCSERV		14,277		12,951		461		6		29		544
FORFEITED REFUNDABLE ADVANCES			R01		(3,602)		(1,322)		(506)		(31)		(620)		(143)
Unbilled Revenue		UNBREV	R01		-		-		-		-		-		-
Total Operating Revenues		TOR		$	1,342,076,920	$	496,334,305	$	187,254,967	$	11,468,006	$	229,139,783	$	53,103,200
Operating Expenses															
Operation and Maintenance Expenses				$	858,787,983	$	332,354,104	$	104,776,257	$	7,371,624	$	131,503,772	$	29,595,391
Depreciation and Amortization Expenses					167,700,749		73,444,682		20,954,020		1,273,723		22,555,226		5,040,756
Regulatory Credits and Accretion Expenses					(2,665,352)		(1,055,577)		(312,986)		(21,470)		(404,481)		(92,709)
Property Taxes			NPT		17,000,077		7,530,333		2,139,417		128,185		2,251,403		501,392
Other Taxes					8,845,973		3,918,401		1,113,243		66,701		1,171,515		260,899
Gain Disposition of Allowances					(767)		(257)		(82)		(7)		(132)		(30)
State and Federal Income Taxes			TAXINC		89,659,334	$	19,740,109	$	19,413,920	$	830,595	$	24,418,107	$	6,134,474
Specific Assignment of Curtailable Service Rider Avoided Cost					(5,672,873)		-		-		-		-		(70,827)
Allocation of Curtailable Service Rider Credits			INTCRE		5,672,873	$	2,422,409	$	700,281	$	43,630	$	805,162	$	192,822
Total Operating Expenses		TOE		$	1,139,327,996	$	438,354,205	$	148,784,071	$	9,692,979	$	182,300,572	$	41,562,167
Net Operating Income (Unadjusted)		TOM		$	202,748,924	$	57,980,100	$	38,470,896	$	1,775,027	$	46,839,211	$	11,541,034
Net Cost Rate Base				$	3,500,935,146	$	1,543,014,453	$	439,931,146	$	26,527,156	$	466,522,028	$	103,973,077

KENTUCKY UTILITIES COMPANY
Cost of Service Study
Class Allocation
12 Months Ended March 31, 2012

Description	Ref	Name	Allocation Vector	Time of Day TOD-Secondary	Time of Day TOD-Primary	Retail Transmission RTS	Fluctuating Load FLS - Transmission	Outdoor Lighting ST & POL	Lighting Energy LE	Traffic Energy TE
<u>Cost of Service Summary -- Unadjusted</u>										
Operating Revenues										
Sales		REVUC	R01	$ 25,199,769	$ 202,384,448	$ 85,720,555	$ 14,733,900	$ 23,177,212	$ 2,251	$ 106,981
Franchise Fees and HEA			FFHEA	-	-	-	-	-	-	-
Other Accrued Revenue			R01	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Intercompany Sales		SFRS	E01	582,438	4,492,594	1,874,628	608,857	158,359	51	1,438
Off-System Sales			OSSALL	145,031	1,082,539	455,186	141,370	26,723	9	325
Brokered Sales			Energy	(7,522)	(58,017)	(24,209)	(7,863)	(2,045)	(1)	(19)
LATE PAYMENT CHARGES			LPAY	75,334	179,921	39,402	-	125	-	4
RECONNECT CHARGES			MISCSERV	2,611	99	-	125	30,585	-	-
OTHER SERVICE CHARGES			MISCSERV	861	32	-	41	10,081	-	-
RENT FROM ELEC PROPERTY			UPT	44,168	310,977	121,909	35,961	53,762	3	167
TRANSMISSION SERVICE			PLTRT	249,553	1,802,999	764,055	226,339	24,990	8	503
TAX REMITTANCE COMPENSATION			R01	334	2,681	1,136	195	307	0	1
RETURN CHECK CHARGES			MISCSERV	206	8	-	10	2,412	-	-
OTHER MISC REVENUES			MISCSERV	35	1	-	2	415	-	-
EXCESS FACILITIES CHARGES			MISCSERV	22	1	-	1	263	-	-
FORFEITED REFUNDABLE ADVANCES			R01	(70)	(564)	(239)	(41)	(65)	(0)	(0)
Unbilled Revenue		UNBREV	R01	-	-	-	-	-	-	-
Total Operating Revenues		TOR		$ 26,292,772	$ 210,197,721	$ 88,952,422	$ 15,738,896	$ 23,483,126	$ 2,322	$ 109,400
Operating Expenses										
Operation and Maintenance Expenses				$ 19,447,331	$ 145,790,692	$ 59,296,646	$ 18,926,916	$ 9,655,957	$ 1,871	$ 67,421
Depreciation and Amortization Expenses				3,471,768	24,487,872	9,654,543	2,848,821	3,956,542	225	12,570
Regulatory Credits and Accretion Expenses				(63,235)	(456,661)	(193,268)	(57,249)	(7,584)	(2)	(129)
Property Taxes			NPT	345,799	2,430,962	948,348	279,667	443,222	24	1,328
Other Taxes				179,936	1,264,948	493,472	145,524	230,630	12	691
Gain Disposition of Allowances				(20)	(151)	(63)	(20)	(5)	(0)	(0)
State and Federal Income Taxes			TAXINC	$ 605,330	$ 10,571,115	$ 5,793,961	$ (804,143)	$ 2,947,103	$ 41	$ 8,724
Specific Assignment of Curtailable Service Rider Avoided Cost				-	(190,332)	-	(5,411,714)	-	-	-
Allocation of Curtailable Service Rider Credits			INTCRE	$ 123,238	$ 891,854	$ 385,940	$ 107,319	$ -	$ -	$ 217
Total Operating Expenses		TOE		$ 24,110,146	$ 184,790,299	$ 76,379,578	$ 16,035,122	$ 17,225,865	$ 2,172	$ 90,822
Net Operating Income (Unadjusted)		TOM		$ 2,182,626	$ 25,407,421	$ 12,572,845	$ (296,226)	$ 6,257,261	$ 150	$ 18,579
Net Cost Rate Base				$ 71,592,845	$ 504,468,963	$ 197,373,814	$ 58,364,475	$ 88,886,963	$ 4,849	$ 275,377

KENTUCKY UTILITIES COMPANY
Cost of Service Study
Class Allocation
12 Months Ended March 31, 2012

Description	Ref	Name	Allocation Vector	Total System	Residential Rate RS	General Service GSS	All Electric School AES	Power Service PS-Secondary	Power Service PS-Primary
Taxable Income Unadjusted									
Total Operating Revenue				$ 1,342,076,920	$ 496,334,305	$ 187,254,967	$ 11,468,006	$ 229,139,783	$ 53,103,200
Operating Expenses				$ 1,049,668,662	$ 418,614,095	$ 129,370,150	$ 8,862,385	$ 157,882,465	$ 35,427,693
Interest Expense		INTEXP		$ 59,882,590	$ 26,525,516	$ 7,536,074	$ 451,529	$ 7,930,542	$ 1,766,148
Taxable Income		TAXINC		$ 232,525,667	$ 51,194,693	$ 50,348,743	$ 2,154,093	$ 63,326,776	$ 15,909,359

KENTUCKY UTILITIES COMPANY
Cost of Service Study
Class Allocation
12 Months Ended March 31, 2012

Description	Ref	Name	Allocation Vector	Time of Day TOD-Secondary	Time of Day TOD-Primary	Retail Transmission RTS	Fluctuating Load FLS - Transmission	Outdoor Lighting ST & POL	Lighting Energy LE	Traffic Energy TE
Taxable Income Unadjusted										
Total Operating Revenue				$ 26,292,772	$ 210,197,721	$ 88,952,422	$ 15,738,896	$ 23,483,126	$ 2,322	$ 109,400
Operating Expenses				$ 23,504,816	$ 174,219,185	$ 70,585,617	$ 16,839,265	$ 14,278,762	$ 2,131	$ 82,097
Interest Expense		INTEXP		$ 1,218,073	$ 8,563,036	$ 3,340,544	$ 985,123	$ 1,561,244	$ 84	$ 4,677
Taxable Income		TAXINC		$ 1,569,883	$ 27,415,500	$ 15,026,261	$ (2,085,492)	$ 7,643,120	$ 106	$ 22,625

KENTUCKY UTILITIES COMPANY
Cost of Service Study
Class Allocation
12 Months Ended March 31, 2012

Description	Ref	Name	Allocation Vector		Total System		Residential Rate RS		General Service GSS		All Electric School AES		Power Service PS-Secondary		Power Service PS-Primary
Cost of Service Summary -- Pro-Forma															
Operating Revenues															
Total Operating Revenue -- Actual				$	1,342,076,920	$	496,334,305	$	187,254,967	$	11,468,006	$	229,139,783	$	53,103,200
Pro-Forma Adjustments:															
Eliminate unbilled revenues			R01		5,107,000	$	1,874,680	$	717,487	$	43,930	$	878,464	$	203,405
Eliminate accrued revenues			R01		(8,438,658)	$	(3,097,666)	$	(1,185,555)	$	(72,589)	$	(1,451,548)	$	(336,101)
Mismatch in fuel cost recovery			Energy		(9,156,061)	$	(3,061,789)	$	(980,047)	$	(80,991)	$	(1,577,625)	$	(360,731)
Annualize FAC roll-in to base rates		FACRI	FAC01		2,885,839	$	882,160	$	313,854	$	27,666	$	517,040	$	153,769
Adjustment to reflect changes to FAC calculatic		FACRI	FAC01		(2,638,801)	$	(806,644)	$	(286,987)	$	(25,298)	$	(472,779)	$	(140,605)
Eliminate ECR revenues			ECRREV01		(14,710,734)	$	(5,574,888)	$	(2,594,231)	$	(124,251)	$	(2,755,268)	$	(685,530)
Adjustment to reflect Full Year of ECR Roll-in		ECRRI	ECRREV02		-	$	-	$	-	$	-	$	-	$	-
Remove off-system ECR revenues			OSSALL		(296,088)	$	(108,494)	$	(33,290)	$	(2,497)	$	(47,867)	$	(10,961)
To adjust Off-system sales margins			OSSALL		(292,995)	$	(107,361)	$	(32,942)	$	(2,471)	$	(47,367)	$	(10,846)
Eliminate brokered sales revenues			Energy		294,881	$	98,608	$	31,564	$	2,608	$	50,809	$	11,618
Eliminate DSM revenues		DSMREV	DSM01		(15,401,724)	$	(11,425,658)	$	(3,105,609)	$	(38,694)	$	(527,104)	$	(97,298)
Year end adjustment		YREND	YRE01		(3,407,542)	$	(709,927)	$	42,703	$	73,498	$	(1,561,902)	$	171,608
Customer rate switching adjustment			RS01		(8,348,788)	$	(30,891)	$	(3,346,954)	$	(20,438)	$	(1,353,663)	$	(5,386,209)
Remove Out of Period Items			RBT		23,287	$	10,264	$	2,926	$	176	$	3,103	$	692
Total Pro-Forma Operating Revenue				$	1,287,696,536	$	474,276,698	$	176,797,886	$	11,248,657	$	220,794,076	$	46,616,010

KENTUCKY UTILITIES COMPANY
Cost of Service Study
Class Allocation
12 Months Ended March 31, 2012

Description	Ref	Name	Allocation Vector	Time of Day TOD-Secondary	Time of Day TOD-Primary	Retail Transmission RTS	Fluctuating Load FLS - Transmission	Outdoor Lighting ST & POL	Lighting Energy LE	Traffic Energy TE
Cost of Service Summary -- Pro-Forma										
Operating Revenues										
Total Operating Revenue -- Actual				$ 26,292,772	$ 210,197,721	$ 88,952,422	$ 15,738,896	$ 23,483,126	$ 2,322	$ 109,400
Pro-Forma Adjustments:										
Eliminate unbilled revenues			R01	$ 99,632	$ 800,168	$ 338,913	$ 58,253	$ 91,636	$ 9	$ 423
Eliminate accrued revenues			R01	$ (164,630)	$ (1,322,174)	$ (560,011)	$ (96,256)	$ (151,416)	$ (15)	$ (699)
Mismatch in fuel cost recovery			Energy	$ (233,544)	$ (1,801,421)	$ (751,680)	$ (244,137)	$ (63,498)	$ (21)	$ (577)
Annualize FAC roll-in to base rates		FACRI	FAC01	$ 67,296	$ 541,691	$ 272,139	$ 89,538	$ 20,524	$ 6	$ 156
Adjustment to reflect changes to FAC calculatic		FACRI	FAC01	$ (61,535)	$ (495,320)	$ (248,843)	$ (81,873)	$ (18,767)	$ (6)	$ (143)
Eliminate ECR revenues			ECRREV01	$ (219,124)	$ (1,637,606)	$ (689,254)	$ (170,284)	$ (259,239)	$ (11)	$ (1,049)
Adjustment to reflect Full Year of ECR Roll-in		ECRRI	ECRREV02	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Remove off-system ECR revenues			OSSALL	$ (7,284)	$ (54,372)	$ (22,863)	$ (7,101)	$ (1,342)	$ (0)	$ (16)
To adjust Off-system sales margins			OSSALL	$ (7,208)	$ (53,804)	$ (22,624)	$ (7,026)	$ (1,328)	$ (0)	$ (16)
Eliminate brokered sales revenues			Energy	$ 7,522	$ 58,017	$ 24,209	$ 7,863	$ 2,045	$ 1	$ 19
Eliminate DSM revenues		DSMREV	DSM01	$ (70,050)	$ (137,311)	$ -	$ -	$ -	$ -	$ -
Year end adjustment		YREND	YRE01	$ 116,329	$ (1,815,382)	$ 166,915	$ -	$ 97,552	$ -	$ 11,064
Customer rate switching adjustment			RS01	$ 2,518,028	$ 3,315,076	$ (2,949,246)	$ (1,094,561)	$ -	$ -	$ 70
Remove Out of Period Items			RBT	$ 476	$ 3,356	$ 1,313	$ 388	$ 591	$ 0	$ 2
Total Pro-Forma Operating Revenue				$ 28,338,680	$ 207,598,636	$ 84,511,391	$ 14,193,700	$ 23,199,883	$ 2,284	$ 118,634

KENTUCKY UTILITIES COMPANY
Cost of Service Study
Class Allocation
12 Months Ended March 31, 2012

Description	Ref	Name	Allocation Vector	Total System	Residential Rate RS	General Service GSS	All Electric School AES	Power Service PS-Secondary	Power Service PS-Primary
Operating Expenses									
Operation and Maintenance Expenses				$ 858,787,983	$ 332,354,104	$ 104,776,257	$ 7,371,624	$ 131,503,772	$ 29,595,391
Depreciation and Amortization Expenses				167,700,749	73,444,682	20,954,020	1,273,723	22,555,226	5,040,756
Regulatory Credits and Accretion Expenses				(2,665,352)	(1,055,577)	(312,986)	(21,470)	(404,481)	(92,709)
Property Taxes			NPT	17,000,077	7,530,333	2,139,417	128,185	2,251,403	501,392
Other Taxes				8,845,973	3,918,401	1,113,243	66,701	1,171,515	260,899
Gain Disposition of Allowances				(767)	(257)	(82)	(7)	(132)	(30)
State and Federal Income Taxes			TAXINC	89,659,334	$ 19,740,109	$ 19,413,920	$ 830,595	$ 24,418,107	$ 6,134,474
Specific Assignment of Curtailable Service Rider Credit				(5,672,873)	-	-	-	-	(70,827)
Allocation of Curtailable Service Rider Credits			INTCRE	$ 5,672,873	$ 2,422,409	$ 700,281	$ 43,630	$ 805,162	$ 192,822
Adjustments to Operating Expenses:									
Eliminate mismatch in fuel cost recovery			Energy	$ (12,785,149)	$ (4,275,357)	$ (1,368,498)	$ (113,092)	$ (2,202,932)	$ (503,710)
Remove ECR expenses			ECRREV01	(9,309,387)	(3,527,954)	(1,641,706)	(78,630)	(1,743,615)	(433,824)
Adjust base expenses for full year of ECR roll-in			ECRREV02	-	-	-	-	-	-
Adjustment to reflect changes to FAC calculations			FAC01	(2,614,696)	(799,276)	(284,366)	(25,066)	(468,460)	(139,321)
Eliminate brokered sales expenses			Energy	(6,018)	(2,012)	(644)	(53)	(1,037)	(237)
Eliminate DSM expenses			DSMREV	(13,589,518)	(10,081,286)	(2,740,196)	(34,141)	(465,083)	(85,849)
Year end adjustment			YREND	(1,909,033)	(397,728)	23,924	41,176	(875,036)	96,141
Annualized depreciation expenses under current rates			DET	712,846	312,191	89,069	5,414	95,876	21,427
Labor adjustment			LBT	2,883,454	1,351,585	418,053	23,102	346,036	73,242
Pension & post retirement expense adjustment			LBT	(4,067,870)	(1,906,767)	(589,773)	(32,592)	(488,175)	(103,327)
Property insurance expense adjustment			UPT	1,079,050	475,495	135,360	8,164	143,915	32,102
Remove out of period items			RBT	(475,875)	(209,739)	(59,799)	(3,606)	(63,413)	(14,133)
Normalized storm damage expenses			SDALL	(834,318)	(559,662)	(137,742)	(4,534)	(53,635)	(7,447)
Eliminate advertising expenses			REVUC	(808,453)	(296,767)	(113,580)	(6,954)	(139,063)	(32,200)
Adjustment for transfer of ITO functions			PLTRT	(3,328,434)	(1,315,068)	(390,292)	(26,846)	(506,389)	(116,124)
Amortization of rate case expenses			OMT	(25,313)	(9,796)	(3,088)	(217)	(3,876)	(872)
Adjustment for injuries and damages FERC account 925			UPT	(1,233,028)	(543,347)	(154,676)	(9,329)	(164,452)	(36,683)
MISO exit fee regulatory asset amortization			PLTRT	(1,509,951)	(596,583)	(177,057)	(12,179)	(229,725)	(52,680)
General Management Audit regulatory asset amortization			OMT	47,507	18,385	5,796	408	7,275	1,637
Federal & State Income Tax Adjustment			ITADJ	(2,427,596)	112,475	(1,274,346)	18,236	(563,673)	(1,905,467)
Federal & State Income Tax Interest Adjustment			TAXINC	145,218	31,972	31,444	1,345	39,549	9,936
Adjustment for tax basis depreciation reduction			TAXINC	(331,159)	(72,911)	(71,706)	(3,068)	(90,189)	(22,658)
Prior income tax true-ups & adjustments			TAXINC	(436,228)	(96,043)	(94,456)	(4,041)	(118,804)	(29,847)
Total Expense Adjustments				$ (50,823,951)	$ (22,388,191)	$ (8,398,278)	$ (256,502)	$ (7,544,905)	$ (3,249,893)
Total Operating Expenses		TOE		$ 1,088,504,045	$ 415,966,014	$ 140,385,793	$ 9,436,477	$ 174,755,666	$ 38,312,274
Net Operating Income (Adjusted)				$ 199,192,491	$ 58,310,684	$ 36,412,093	$ 1,812,180	$ 46,038,409	$ 8,303,736
Net Cost Rate Base				$ 3,500,935,146	$ 1,543,014,453	$ 439,931,146	$ 26,527,156	$ 466,522,028	$ 103,973,077
ECR Plan Eliminations			PLPPT	$ (183,667,066)	$ (72,567,071)	$ (21,536,798)	$ (1,481,393)	$ (27,943,177)	$ (6,407,840)
Adjustment to Reflect Depreciation Reserve			DET	$ (712,846)	$ (312,191)	$ (89,069)	$ (5,414)	$ (95,876)	$ (21,427)
Cash Working Capital			OMLF	$ (5,709,964)	$ (2,954,346)	$ (908,487)	$ (45,307)	$ (602,915)	$ (126,906)
Adjusted Net Cost Rate Base				$ 3,310,845,270	$ 1,467,180,844	$ 417,396,792	$ 24,995,043	$ 437,880,060	$ 97,416,904
Rate of Return				**6.02%**	**3.97%**	**8.72%**	**7.25%**	**10.51%**	**8.52%**

KENTUCKY UTILITIES COMPANY
Cost of Service Study
Class Allocation
12 Months Ended March 31, 2012

Description	Ref	Name	Allocation Vector	Time of Day TOD-Secondary	Time of Day TOD-Primary	Retail Transmission RTS	Fluctuating Load FLS - Transmission	Outdoor Lighting ST & POL	Lighting Energy LE	Traffic Energy TE
Operating Expenses										
Operation and Maintenance Expenses				$ 19,447,331	$ 145,790,692	$ 59,296,646	$ 18,926,916	$ 9,655,957	$ 1,871	$ 67,421
Depreciation and Amortization Expenses				3,471,768	24,487,872	9,654,543	2,848,821	3,956,542	225	12,570
Regulatory Credits and Accretion Expenses				(63,235)	(456,661)	(193,268)	(57,249)	(7,584)	(2)	(129)
Property Taxes			NPT	345,799	2,430,962	948,348	279,667	443,222	24	1,328
Other Taxes				179,936	1,264,948	493,472	145,524	230,630	12	691
Gain Disposition of Allowances				(20)	(151)	(63)	(20)	(5)	(0)	(0)
State and Federal Income Taxes			TAXINC	$ 605,330	$ 10,571,115	$ 5,793,961	$ (804,143)	$ 2,947,103	$ 41	$ 8,724
Specific Assignment of Curtailable Service Rider Credit				-	(190,332)	-	(5,411,714)	-	-	-
Allocation of Curtailable Service Rider Credits			INTCRE	$ 123,238	$ 891,854	$ 385,940	$ 107,319	$ -	$ -	$ 217
Adjustments to Operating Expenses:										
Eliminate mismatch in fuel cost recovery			Energy	$ (326,111)	$ (2,515,431)	$ (1,049,616)	$ (340,903)	$ (88,666)	$ (29)	$ (805)
Remove ECR expenses			ECRREV01	(138,668)	(1,036,325)	(436,180)	(107,761)	(164,054)	(7)	(664)
Adjust base expenses for full year of ECR roll-in			ECRREV02	-	-	-	-	-	-	-
Adjustment to reflect changes to FAC calculations			FAC01	(60,973)	(490,795)	(246,570)	(81,125)	(18,596)	(6)	(142)
Eliminate brokered sales expenses			Energy	(154)	(1,184)	(494)	(160)	(42)	(0)	(0)
Eliminate DSM expenses			DSMREV	(61,808)	(121,155)	-	-	-	-	-
Year end adjustment			YREND	65,172	(1,017,045)	93,512	-	54,652	-	6,199
Annualized depreciation expenses under current rates			DET	14,757	104,091	41,039	12,109	16,818	1	53
Labor adjustment			LBT	51,372	353,744	134,408	41,092	90,547	5	267
Pension & post retirement expense adjustment			LBT	(72,474)	(499,049)	(189,618)	(57,971)	(127,741)	(8)	(376)
Property insurance expense adjustment			UPT	22,126	155,785	61,071	18,015	26,932	1	84
Remove out of period items			RBT	(9,731)	(68,571)	(26,829)	(7,933)	(12,082)	(1)	(37)
Normalized storm damage expenses			SDALL	(7,286)	(33,349)	-	-	(30,531)	(2)	(131)
Eliminate advertising expenses			REVUC	(15,772)	(126,669)	(53,651)	(9,222)	(14,506)	(1)	(67)
Adjustment for transfer of ITO functions			PLTRT	(79,191)	(572,148)	(242,459)	(71,824)	(7,930)	(3)	(160)
Amortization of rate case expenses			OMT	(573)	(4,297)	(1,748)	(558)	(285)	(0)	(2)
Adjustment for injuries and damages FERC account 925			UPT	(25,284)	(178,015)	(69,785)	(20,585)	(30,775)	(2)	(96)
MISO exit fee regulatory asset amortization			PLTRT	(35,925)	(259,556)	(109,992)	(32,583)	(3,597)	(1)	(72)
General Management Audit regulatory asset amortization			OMT	1,076	8,065	3,280	1,047	534	0	4
Federal & State Income Tax Adjustment			ITADJ	1,001,493	1,360,685	(862,605)	(325,887)	9,583	5	1,904
Federal & State Income Tax Interest Adjustment			TAXINC	980	17,122	9,384	(1,302)	4,773	0	14
Adjustment for tax basis depreciation reduction			TAXINC	(2,236)	(39,045)	(21,400)	2,970	(10,885)	(0)	(32)
Prior income tax true-ups & adjustments			TAXINC	(2,945)	(51,433)	(28,190)	3,912	(14,339)	(0)	(42)
Total Expense Adjustments				$ 317,846	$ (5,014,577)	$ (2,996,442)	$ (978,669)	$ (320,189)	$ (46)	$ 5,897
Total Operating Expenses		TOE		$ 24,427,992	$ 179,775,722	$ 73,383,136	$ 15,056,453	$ 16,905,675	$ 2,126	$ 96,718
Net Operating Income (Adjusted)				$ 3,910,688	$ 27,822,914	$ 11,128,256	$ (862,752)	$ 6,294,208	$ 159	$ 21,916
Net Cost Rate Base				$ 71,592,845	$ 504,468,963	$ 197,373,814	$ 58,364,475	$ 88,886,963	$ 4,849	$ 275,377
ECR Plan Eliminations			PLPPT	$ (4,369,857)	$ (31,571,854)	$ (13,379,175)	$ (3,963,359)	$ (437,592)	$ (142)	$ (8,809)
Adjustment to Reflect Depreciation Reserve			DET	$ (14,757)	$ (104,091)	$ (41,039)	$ (12,109)	$ (16,818)	$ (1)	$ (53)
Cash Working Capital			OMLF	$ (88,794)	$ (587,414)	$ (209,547)	$ (60,381)	$ (125,187)	$ (11)	$ (668)
Adjusted Net Cost Rate Base				$ 67,119,437	$ 472,205,604	$ 183,744,054	$ 54,328,626	$ 88,307,366	$ 4,694	$ 265,847
Rate of Return				**5.83%**	**5.89%**	**6.06%**	**-1.59%**	**7.13%**	**3.38%**	**8.24%**

KENTUCKY UTILITIES COMPANY
Cost of Service Study
Class Allocation
12 Months Ended March 31, 2012

Description	Ref	Name	Allocation Vector		Total System		Residential Rate RS		General Service GSS		All Electric School AES		Power Service PS-Secondary		Power Service PS-Primary
Taxable Income Pro-Forma															
Total Operating Revenue				$	1,287,696,536	$	474,276,698	$	176,797,886	$	11,248,657	$	220,794,076	$	46,616,010
Operating Expenses				$	998,844,711	$	396,225,905	$	120,971,872	$	8,605,882	$	150,337,560	$	32,177,800
Interest Expense		INTEXP		$	59,882,590	$	26,525,516	$	7,536,074	$	451,529	$	7,930,542	$	1,766,148
Interest Syncronization Adjustment			INTEXP	$	-	$	-	$	-	$	-	$	-	$	-
Taxable Income		TXINCPF		$	228,969,234	$	51,525,277	$	48,289,940	$	2,191,246	$	62,525,974	$	12,672,062

KENTUCKY UTILITIES COMPANY
Cost of Service Study
Class Allocation
12 Months Ended March 31, 2012

Description	Ref	Name	Allocation Vector	Time of Day TOD-Secondary	Time of Day TOD-Primary	Retail Transmission RTS	Fluctuating Load FLS - Transmission	Outdoor Lighting ST & POL	Lighting Energy LE	Traffic Energy TE
Taxable Income Pro-Forma										
Total Operating Revenue				$ 28,338,680	$ 207,598,636	$ 84,511,391	$ 14,193,700	$ 23,199,883	$ 2,284	$ 118,634
Operating Expenses				$ 23,822,662	$ 169,204,607	$ 67,589,175	$ 15,860,595	$ 13,958,573	$ 2,085	$ 87,994
Interest Expense		INTEXP		$ 1,218,073	$ 8,563,036	$ 3,340,544	$ 985,123	$ 1,561,244	$ 84	$ 4,677
Interest Syncronization Adjustment			INTEXP	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Taxable Income		TXINCPF		$ 3,297,945	$ 29,830,993	$ 13,581,672	$ (2,652,018)	$ 7,680,066	$ 115	$ 25,963

KENTUCKY UTILITIES COMPANY
Cost of Service Study
Class Allocation
12 Months Ended March 31, 2012

Description	Ref	Name	Allocation Vector		Total System		Residential Rate RS		General Service GSS		All Electric School AES		Power Service PS-Secondary		Power Service PS-Primary
Cost of Service Summary -- Adjusted for Proposed Increase															
Operating Revenue															
Total Operating Revenue				$	1,287,696,536	$	474,276,698	$	176,797,886	$	11,248,657	$	220,794,076	$	46,616,010
Proposed Increase				$	81,503,751	$	37,381,886	$	9,061,201	$	635,467	$	4,381,192	$	2,537,095
Increase in Miscellaneous Charges			MISCSERV	$	929,141	$	842,853	$	29,972	$	371	$	1,855	$	35,380
						$	-	$	-	$	-	$	-	$	-
Total Pro-Forma Operating Revenue				$	1,370,129,427	$	512,501,437	$	185,889,059	$	11,884,494	$	225,177,123	$	49,188,485
Operating Expenses															
Total Operating Expenses				$	1,139,327,996	$	438,354,205	$	148,784,071	$	9,692,979	$	182,300,572	$	41,562,167
Pro-Forma Adjustments				$	(50,823,951)	$	(22,388,191)	$	(8,398,278)	$	(256,502)	$	(7,544,905)	$	(3,249,893)
Incremental Income Taxes			0.367473	$	30,291,862	$	14,046,560	$	3,340,761	$	233,653	$	1,610,652	$	945,315
Total Pro-Forma Operating Expenses				$	1,118,795,907	$	430,012,574	$	143,726,553	$	9,670,130	$	176,366,318	$	39,257,589
Net Operating Income				$	251,333,520	$	82,488,863	$	42,162,506	$	2,214,365	$	48,810,805	$	9,930,896
Net Cost Rate Base				$	3,310,845,270	$	1,467,180,844	$	417,396,792	$	24,995,043	$	437,880,060	$	97,416,904
Rate of Return					**7.59%**		**5.62%**		**10.10%**		**8.86%**		**11.15%**		**10.19%**

KENTUCKY UTILITIES COMPANY
Cost of Service Study
Class Allocation
12 Months Ended March 31, 2012

Description	Ref	Name	Allocation Vector	Time of Day TOD-Secondary	Time of Day TOD-Primary	Retail Transmission RTS	Fluctuating Load FLS - Transmission	Outdoor Lighting ST & POL	Lighting Energy LE	Traffic Energy TE
Cost of Service Summary -- Adjusted for Proposed Increase										
Operating Revenue										
Total Operating Revenue				$ 28,338,680	$ 207,598,636	$ 84,511,391	$ 14,193,700	$ 23,199,883	$ 2,284	$ 118,634
Proposed Increase				$ 1,907,198	$ 12,564,145	$ 5,128,398	$ 6,632,880	$ 1,267,776	$ 124	$ 6,388
Increase in Miscellaneous Charges			MISCSERV	$ 1,462	$ 55	$ -	$ 70	$ 17,123	$ -	$ -
				$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Pro-Forma Operating Revenue				$ 30,247,340	$ 220,162,837	$ 89,639,789	$ 20,826,650	$ 24,484,783	$ 2,408	$ 125,022
Operating Expenses										
Total Operating Expenses				$ 24,110,146	$ 184,790,299	$ 76,379,578	$ 16,035,122	$ 17,225,865	$ 2,172	$ 90,822
Pro-Forma Adjustments				$ 317,846	$ (5,014,577)	$ (2,996,442)	$ (978,669)	$ (320,189)	$ (46)	$ 5,897
Incremental Income Taxes			0.367473	$ 701,381	$ 4,617,004	$ 1,884,548	$ 2,437,430	$ 472,166	$ 46	$ 2,347
Total Pro-Forma Operating Expenses				$ 25,129,373	$ 184,392,726	$ 75,267,683	$ 17,493,883	$ 17,377,841	$ 2,171	$ 99,066
Net Operating Income				$ 5,117,967	$ 35,770,110	$ 14,372,106	$ 3,332,768	$ 7,106,941	$ 237	$ 25,956
Net Cost Rate Base				$ 67,119,437	$ 472,205,604	$ 183,744,054	$ 54,328,626	$ 88,307,366	$ 4,694	$ 265,847
Rate of Return				**7.63%**	**7.58%**	**7.82%**	**6.13%**	**8.05%**	**5.05%**	**9.76%**

KENTUCKY UTILITIES COMPANY
Cost of Service Study
Class Allocation
12 Months Ended March 31, 2012

Description	Ref	Name	Allocation Vector	Total System	Residential Rate RS	General Service GSS	All Electric School AES	Power Service PS-Secondary	Power Service PS-Primary
Allocation Factors									
Energy Allocation Factors									
Energy Usage by Class		E01	Energy	1.000000	0.334400	0.107038	0.008846	0.172304	0.039398
Customer Allocation Factors									
Primary Distribution Plant -- Average Number of Custom		C08	Cust08	1.000000	0.79574	0.15542	0.00121	0.01066	0.00056
Customer Services -- Weighted cost of Services		C02		1.000000	0.475412	0.312008	0.001489	0.017124	-
Meter Costs -- Weighted Cost of Meters		C03		1.000000	0.627516	0.228780	0.005347	0.067132	0.024639
Lighting Systems -- Lighting Customers		C04	Cust04	1.000000	-	-	-	-	-
Meter Reading and Billing -- Weighted Cost		C05	Cust05	1.000000	0.64881	0.25345	0.00988	0.04347	0.00229
Marketing/Economic Development		C06	Cust06	1.000000	0.79568	0.15541	0.00121	0.01066	0.00056
Total billed revenue per Billing Determinants				1,320,340,474	481,362,814	184,154,601	11,258,851	225,868,341	52,162,115
CSR credits				(12,053,715)	$ -	$ -	$ -	$ -	$ (139,125)
Interruptible Buy Thru Charges				41,196	$ -	$ -	$ -	$ -	$ 2,843
HEA/Franchise Fees/Refundable Advances				(20,092,575)	$ (8,476,853)	$ (3,169,217)	$ (177,565)	$ (4,276,826)	$ (717,095)
Billing Determinant Revenue net of CSR & HEA		R01		1,288,235,380	472,885,961	180,985,384	11,081,286	221,591,515	51,308,738
Miscellaneous Revenue adjustment			R01	134,033	$ 49,201	$ 18,830	$ 1,153	$ 23,055	$ 5,338
Unbilled revenues not included in billing determinants			R01	(5,107,000)	$ (1,874,680)	$ (717,487)	$ (43,930)	$ (878,464)	$ (203,405)
Accrued revenues not included in billing determinants			R01	8,438,658	$ 3,097,666	$ 1,185,555	$ 72,589	$ 1,451,548	$ 336,101
Revenue per Jurisdictional Separation Study				1,291,701,071	474,158,148	181,472,282	11,111,098	222,187,654	51,446,772
Energy (at the Meter)				18,161,927,656	5,944,626,245	1,943,096,458	157,537,383	3,069,778,185	802,429,053
Energy changes due to rate switching				(131,484,040)	(454,438)	(40,427,740)	(301,217)	(6,968,747)	(79,259,287)
Net delivered energy				18,030,443,616	5,944,171,807	1,902,668,718	157,236,166	3,062,809,438	723,169,766
Energy (Loss Adjusted)(at Source)		Energy		19,319,457,806	6,460,431,335	2,067,918,123	170,892,344	3,328,818,666	761,148,808
O&M Customer Allocators									
Customers (Monthly Bills)				8,156,280	5,044,176	985,224	7,680	67,596	3,564
Average Customers (Bills/12)				679,690	420,348	82,102	640	5,633	297
Average Customers (Lighting = Lights)				679,690	420,348	82,102	640	5,633	297
Weighted Average Customers (Lighting =9 Lights per Cu		Cust05		647,872	420,348	164,204	6,400	28,165	1,485
Street Lighting		Cust04		80,975,590	-	-	-	-	-
Average Customers		Cust01		679,690	420,348	82,102	640	5,633	297
Average Customers (Lighting = 9 Lights per Cust)		Cust06		528,285	420,348	82,102	640	5,633	297
Average Secondary Customers		Cust07		527,786	420,348	82,102	640	5,633	-
Average Primary Customers		Cust08		528,249	420,348	82,102	640	5,633	297
Plant Customer Allocators									
Year End Customers				679,917	419,902	82,069	643	5,627	298
Year End Customers (Lighting = Lights)				679,917	419,902	82,069	643	5,627	298
Weighted Year End Customers (Lighting =9 Lights per C		YECust05		647,449	419,902	164,138	6,430	28,135	1,490
Street Lighting		YECust04		80,975,590	-	-	-	-	-
Year End Customers		YECust01		679,917	419,902	82,069	643	5,627	298
Year End Customers (Lighting = 9 Lights per Cust)		YECust06		527,883	419,902	82,069	643	5,627	298
Year End Secondary Customers		YECust07		527,382	419,902	82,069	643	5,627	-
Year End Primary Customers		YECust08		527,847	419,902	82,069	643	5,627	298
Demand Allocators									
Maximum Class Non-Coincident Peak Demands		NCP		4,319,251	1,750,711	536,735	50,546	592,690	147,809
Maximum Class Demands (Primary Subs)		NCPS		3,870,320	1,750,711	536,735	50,546	592,690	147,809
Maximum Class Demands (Primary Lines)		NCPL		3,870,320	1,750,711	536,735	50,546	592,690	147,809
Sum of the Individual Customer Demands (Secondary)		SICD		5,887,377	4,032,454	937,055	55,019	723,487	-
Summer Peak Period Demand Allocator		SCP		3,516,647	1,400,033	424,931	24,266	551,195	139,563
Winter Peak Period Demand Allocator		WCP		3,439,502	1,570,811	433,803	29,246	435,872	96,788
Base Demand Allocator		BDEM		2,199,392	734,855	231,912	19,314	377,518	80,508
Rate Switching Adjustment to Demand									
Sum of the Individual Customer Demands (Secondary)				-	(1,978)	4,470	(438)	(13,727)	(18,071)
Maximum Class Non-Coincident Peak Demands				-	(1,356)	(1,811)	(270)	(6,026)	(15,061)
Summer Peak Period Demand Allocator				-	(1,076)	(3,619)	(238)	(4,162)	(12,785)
Winter Peak Period Demand Allocator				-	(1,034)	(443)	(218)	(5,269)	(11,689)
Base Demand Allocator				-	(623)	(3,506)	(141)	(1,446)	(6,144)

KENTUCKY UTILITIES COMPANY
Cost of Service Study
Class Allocation
12 Months Ended March 31, 2012

Description	Ref	Name	Allocation Vector	Time of Day TOD-Secondary	Time of Day TOD-Primary	Retail Transmission RTS	Fluctuating Load FLS - Transmission	Outdoor Lighting ST & POL	Lighting Energy LE	Traffic Energy TE
Allocation Factors										
Energy Allocation Factors										
Energy Usage by Class		E01	Energy	0.025507	0.196746	0.082096	0.026664	0.006935	0.000002	0.000063
Customer Allocation Factors										
Primary Distribution Plant -- Average Number of Custom		C08	Cust08	0.00026	0.00031	-	-	0.03568	0.00000	0.00014
Customer Services -- Weighted cost of Services		C02		0.000317	-	-	-	0.192821	0.000012	0.000815
Meter Costs -- Weighted Cost of Meters		C03		0.002524	0.017829	0.024250	0.000891	-	0.000016	0.001076
Lighting Systems -- Lighting Customers		C04	Cust04	-	-	-	-	1.00000	-	-
Meter Reading and Billing -- Weighted Cost		C05	Cust05	0.00529	0.00641	0.00111	0.00008	0.02909	0.00000	0.00012
Marketing/Economic Development		C06	Cust06	0.00026	0.00031	0.00007	0.00000	0.03568	0.00000	0.00014
Total billed revenue per Billing Determinants				25,639,209	204,368,589	85,627,393	26,235,092	23,551,352	2,309	109,808
CSR credits				$ -	$ (373,866)	$ -	$ (11,540,724)	$ -	$ -	$ -
Interruptible Buy Thru Charges				$ -	$ 38,353	$ -	$ -	$ -	$ -	$ -
HEA/Franchise Fees/Refundable Advances				$ (507,052)	$ (2,191,634)	$ (136,830)	$ -	$ (436,325)	$ (64)	$ (3,114)
Billing Determinant Revenue net of CSR & HEA		R01		25,132,157	201,841,442	85,490,563	14,694,368	23,115,027	2,245	106,694
Miscellaneous Revenue adjustment			R01	$ 2,615	$ 21,000	$ 8,895	$ 1,529	$ 2,405	$ 0	$ 11
Unbilled revenues not included in billing determinants			R01	$ (99,632)	$ (800,168)	$ (338,913)	$ (58,253)	$ (91,636)	$ (9)	$ (423)
Accrued revenues not included in billing determinants			R01	$ 164,630	$ 1,322,174	$ 560,011	$ 96,256	$ 151,416	$ 15	$ 699
Revenue per Jurisdictional Separation Study				25,199,769	202,384,448	85,720,555	14,733,900	23,177,212	2,251	106,981
Energy (at the Meter)				413,123,136	3,552,305,513	1,608,310,112	546,287,246	123,275,608	40,050	1,118,667
Energy changes due to rate switching				40,279,476	59,066,890	(60,003,830)	(43,416,000)	-	-	853
Net delivered energy				453,402,612	3,611,372,403	1,548,306,282	502,871,246	123,275,608	40,050	1,119,520
Energy (Loss Adjusted)(at Source)		Energy		492,781,255	3,801,032,523	1,586,059,250	515,132,956	133,982,265	43,528	1,216,752
O&M Customer Allocators										
Customers (Monthly Bills)				1,644	1,992	432	12	2,035,740	132	8,088
Average Customers (Bills/12)				137	166	36	1	169,645	11	674
Average Customers (Lighting = Lights)				137	166	36	1	169,645	11	674
Weighted Average Customers (Lighting =9 Lights per Cu		Cust05		3,425	4,150	720	50	18,849	1	75
Street Lighting		Cust04		-	-	-	-	80,975,590	-	-
Average Customers		Cust01		137	166	36	1	169,645	11	674
Average Customers (Lighting = 9 Lights per Cust)		Cust06		137	166	36	1	18,849	1	75
Average Secondary Customers		Cust07		137	-	-	-	18,849	1	75
Average Primary Customers		Cust08		137	166	-	-	18,849	1	75
							0.39	0.61	0.00	0.00
Plant Customer Allocators							-	1.00	-	-
Year End Customers				137	167	35	1	170,307	11	720
Year End Customers (Lighting = Lights)				137	167	35	1	170,307	11	720
Weighted Year End Customers (Lighting =9 Lights per C		YECust05		3,425	4,175	700	50	18,923	1	80
Street Lighting		YECust04		-	-	-	-	80,975,590	-	-
Year End Customers		YECust01		137	167	35	1	170,307	11	720
Year End Customers (Lighting = 9 Lights per Cust)		YECust06		137	167	35	1	18,923	1	80
Year End Secondary Customers		YECust07		137	-	-	-	18,923	1	80
Year End Primary Customers		YECust08		137	167	-	-	18,923	1	80
Demand Allocators										
Maximum Class Non-Coincident Peak Demands		NCP		87,667	674,181	276,057	172,874	29,823	10	148
Maximum Class Demands (Primary Subs)		NCPS		87,667	674,181	-	-	29,823	10	148
Maximum Class Demands (Primary Lines)		NCPL		87,667	674,181	-	-	29,823	10	148
Sum of the Individual Customer Demands (Secondary)		SICD		109,367	-	-	-	29,823	10	162
Summer Peak Period Demand Allocator		SCP		86,247	573,741	241,657	74,880	-	-	133
Winter Peak Period Demand Allocator		WCP		64,825	519,768	231,577	56,678	-	-	133
Base Demand Allocator		BDEM		61,021	439,778	180,438	58,644	15,253	5	146
Rate Switching Adjustment to Demand										
Sum of the Individual Customer Demands (Secondary)				9,604	20,487	(361)	-	-	-	15
Maximum Class Non-Coincident Peak Demands				7,698	17,113	(302)	-	-	-	15
Summer Peak Period Demand Allocator				7,573	14,563	(257)	-	-	-	-
Winter Peak Period Demand Allocator				5,692	13,193	(233)	-	-	-	-
Base Demand Allocator				4,921	7,056	(124)	-	-	-	7

KENTUCKY UTILITIES COMPANY
Cost of Service Study
Class Allocation
12 Months Ended March 31, 2012

Description	Ref	Name	Allocation Vector	Total System	Residential Rate RS	General Service GSS	All Electric School AES	Power Service PS-Secondary	Power Service PS-Primary
Unadjusted Production Allocation									
Production Residual Winter Demand Allocator		PPWDRA		3,439,502	1,570,811	433,803	29,246	435,872	96,788
Production Winter Demand Costs				$ 29,353,481	$ 13,405,656	$ 3,702,175	$ 249,595	$ 3,719,831	$ 826,007
Customer Specific Assignment				$ -	-	-	0	-	-
Production Winter Demand Residual			PPWDRA	$ 29,353,481	$ 13,405,656	$ 3,702,175	$ 249,595	$ 3,719,831	$ 826,007
Production Winter Demand Total		PPWDT		$ 29,353,481	$ 13,405,656	$ 3,702,175	$ 249,595	$ 3,719,831	$ 826,007
Production Winter Demand Allocator		PPWDA	PPWDT	1.000000	0.45670	0.12612	0.00850	0.12673	0.02814
Production Residual Summer Demand Allocator		PPSDRA		3,516,647	1,400,033	424,931	24,266	551,195	139,563
Production Summer Demand Costs				$ 30,146,227	$ 12,001,691	$ 3,642,697	$ 208,018	$ 4,725,083	$ 1,196,398
Customer Specific Assignment				$ -	-	-	0	-	-
Production Summer Demand Residual			PPSDRA	$ 30,146,227	12,001,691	3,642,697	208,018	4,725,083	1,196,398
Production Summer Demand Total		PPSDT		$ 30,146,227	$ 12,001,691	$ 3,642,697	$ 208,018	$ 4,725,083	$ 1,196,398
Production Summer Demand Allocator		PPSDA	PPSDT	1.000000	0.39812	0.12083	0.00690	0.15674	0.03969
Production Residual Base Demand Allocator		PPBDRA		2,199,392	734,855	231,912	19,314	377,518	80,508
Production Base Demand Costs				$ 31,138,404					
Customer Specific Assignment				$ -	$ -	$ -	$ -	$ -	$ -
Production Base Demand Residual			PPBDRA	$ 31,138,404	$ 10,403,876	$ 3,283,352	$ 273,441	$ 5,344,803	$ 1,139,809
Production Base Demand Total		PPBDT		$ 31,138,404	$ 10,403,876	$ 3,283,352	$ 273,441	$ 5,344,803	$ 1,139,809
Production Base Demand Allocator		PPBDA	PPBDT	1.000000	0.33412	0.10544	0.00878	0.17165	0.03660
Storm Damage Allocator									
Distribution O&M		SDALL		1,071,051,206.60	718,462,461.36	176,824,936.59	5,820,423.14	68,853,021.38	9,559,947.11
Revenue Adjustment Allocators									
Remove ECR Revenues		ECRREV01		14,710,735	5,574,888	2,594,231	124,251	2,755,268	685,530
Remove Changes in ECR Roll-In		ECRREV02		-	-	-	-	-	-
Interruptible Credit Allocator		INTCRE		2,433,112,018	1,038,978,572	300,352,671	18,713,099	345,336,515	82,701,879
Year End Customers		YRE01		(3,408,969)	(710,225)	42,721	73,529	(1,562,556)	171,679
Rate Switching Allocator		RS01		(8,348,788)	(30,891)	(3,346,954)	(20,438)	(1,353,663)	(5,386,209)
Remove DSM Revenues		DSM01		15,401,444	11,425,450	3,105,553	38,693	527,094	97,296
Base Rate Revenue				1,257,574,176	458,005,465	182,158,458	10,668,266	221,396,753	51,224,549
Late Payment Revenue		LPAY		6,910,623.98	5,226,738.82	1,128,696.56	5,854.33	225,327.12	29,221.16
Franchise Fees and HEA		FFHEA		20,092,575	8,476,853	3,169,217	177,565	4,276,826	717,095
FAC Roll-In		FAC01		(3,616,226)	(1,105,429)	(393,289)	(34,668)	(647,899)	(192,686)
Revenue and Expense Adjust before IT		ITADJ		(6,606,198)	306,077	(3,467,867)	49,625	(1,533,918)	(5,185,333)
ECR Revenue in Base Rates		ECRPLAN		153,508,035	56,592,842	27,494,815	1,328,040	27,054,868	6,225,132
Operation and Maintenance Less Fuel		OMLF		246,856,793.77	127,724,167.37	39,276,303.09	1,958,720.67	26,065,618.46	5,486,500.17
Off-System Sales Allocator									
Off-System Sales			RBPPT	$ 5,895,029	$ 2,319,186	$ 689,576	$ 47,675	$ 900,176	$ 206,407
Less: Adjustment to Reallocate Expenses									
Costs allocated on Energy to be reallocated on RBPPT			Energy	$ (2,695,890)	$ (901,506)	$ (288,563)	$ (23,847)	$ (464,513)	$ (106,213)
Costs allocated on Energy reallocated on RBPPT			RBPPT	$ 2,695,890	$ 1,060,601	$ 315,354	$ 21,803	$ 411,665	$ 94,393
Net Adjustment				$ -	$ 159,094	$ 26,791	$ (2,044)	$ (52,848)	$ (11,820)
Off-System Sales Allocator		OSSALL		$ 5,895,029	$ 2,160,092	$ 662,785	$ 49,719	$ 953,024	$ 218,226
Misc Service Revenue Allocator		MISCSERV		1.00	0.91	0.03	0.00	0.00	0.04
CSR Avoided Cost									
Interruptible Demands				2,230,442					25,295
Cycle 20 Adjustment				169,275					
Avoided Cost per kW				2.75					2.80
Avoided Cost				5,672,873	-	-	-	-	70,827
Merger Surcerdit Revenue		MSCREV		(3)	-	(4)	22	(20)	-

KENTUCKY UTILITIES COMPANY
Cost of Service Study
Class Allocation
12 Months Ended March 31, 2012

Description	Ref	Name	Allocation Vector	Time of Day TOD-Secondary	Time of Day TOD-Primary	Retail Transmission RTS	Fluctuating Load FLS - Transmission	Outdoor Lighting ST & POL	Lighting Energy LE	Traffic Energy TE
Unadjusted Production Allocation										
Production Residual Winter Demand Allocator		PPWDRA		64,825	519,768	231,577	56,678	-	-	133
Production Winter Demand Costs				$ 553,228	$ 4,435,820	$ 1,976,327	$ 483,705	$ -	$ -	$ 1,138
Customer Specific Assignment				-	-	-	-	-		
Production Winter Demand Residual			PPWDRA	$ 553,228	$ 4,435,820	$ 1,976,327	$ 483,705	$ -	$ -	$ 1,138
Production Winter Demand Total		PPWDT		$ 553,228	$ 4,435,820	$ 1,976,327	$ 483,705	$ -	$ -	$ 1,138
Production Winter Demand Allocator		PPWDA	PPWDT	0.01885	0.15112	0.06733	0.01648	-	-	0.00004
Production Residual Summer Demand Allocator		PPSDRA		86,247	573,741	241,657	74,880	-	-	133
Production Summer Demand Costs				$ 739,346	$ 4,918,356	$ 2,071,589	$ 641,906	$ -	$ -	$ 1,143
Customer Specific Assignment				-	-	-	-	-		
Production Summer Demand Residual			PPSDRA	739,346	4,918,356	2,071,589	641,906	-	-	1,143
Production Summer Demand Total		PPSDT		$ 739,346	$ 4,918,356	$ 2,071,589	$ 641,906	$ -	$ -	$ 1,143
Production Summer Demand Allocator		PPSDA	PPSDT	0.02453	0.16315	0.06872	0.02129	-	-	0.00004
Production Residual Base Demand Allocator		PPBDRA		61,021	439,778	180,438	58,644	15,253	5	146
Production Base Demand Costs										
Customer Specific Assignment				$ -	$ -	$ -	$ -	$ -	$ -	$ -
Production Base Demand Residual			PPBDRA	$ 863,913	$ 6,226,262	$ 2,554,592	$ 830,273	$ 215,948	$ 70	$ 2,066
Production Base Demand Total		PPBDT		$ 863,913	$ 6,226,262	$ 2,554,592	$ 830,273	$ 215,948	$ 70	$ 2,066
Production Base Demand Allocator		PPBDA	PPBDT	0.02774	0.19995	0.08204	0.02666	0.00694	0.00000	0.00007
Storm Damage Allocator										
Distribution O&M		SDALL		9,353,410.47	42,811,857.31	-	-	39,193,816.25	3,053.26	168,279.73
Revenue Adjustment Allocators										
Remove ECR Revenues		ECRREV01		219,124	1,637,606	689,254	170,284	259,239	11	1,049
Remove Changes in ECR Roll-In		ECRREV02		-	-	-	-	-	-	-
Interruptible Credit Allocator		INTCRE		52,857,012	382,518,815	165,530,766	46,029,420	-	-	93,270
Year End Customers		YRE01		116,378	(1,816,142)	166,985	-	97,593	-	11,069
Rate Switching Allocator		RS01		2,518,028	3,315,076	(2,949,246)	(1,094,561)	-	-	70
Remove DSM Revenues		DSM01		70,049	137,309	-	-	-	-	-
Base Rate Revenue				22,889,891	184,047,357	79,886,044	24,102,240	23,087,333	2,255	105,565
Late Payment Revenue		LPAY		75,334.09	179,921.20	39,401.50	-	125.42	-	3.78
Franchise Fees and HEA		FFHEA		507,052	2,191,634	136,830	-	436,325	64	3,114
FAC Roll-In		FAC01		(84,328)	(678,789)	(341,016)	(112,199)	(25,719)	(8)	(196)
Revenue and Expense Adjust before IT		ITADJ		2,725,354	3,702,822	(2,347,399)	(886,833)	26,079	14	5,180
ECR Revenue in Base Rates		ECRPLAN		2,577,384	19,026,087	7,866,500	2,469,091	2,862,245	381	10,650
Operation and Maintenance Less Fuel		OMLF		3,838,806.64	25,395,473.47	9,059,256.82	2,610,416.73	5,412,156.55	492.60	28,881.21
Off-System Sales Allocator										
Off-System Sales			RBPPT	$ 140,537	$ 1,017,411	$ 430,938	$ 128,042	$ 14,791	$ 5	$ 285
Less: Adjustment to Reallocate Expenses										
Costs allocated on Energy to be reallocated on RBPPT			Energy	$ (68,764)	$ (530,407)	$ (221,323)	$ (71,883)	$ (18,696)	$ (6)	$ (170)
Costs allocated on Energy reallocated on RBPPT			RBPPT	$ 64,270	$ 465,278	$ 197,075	$ 58,556	$ 6,764	$ 2	$ 130
Net Adjustment				$ (4,494)	$ (65,128)	$ (24,248)	$ (13,327)	$ (11,932)	$ (4)	$ (39)
Off-System Sales Allocator		OSSALL		$ 145,031	$ 1,082,539	$ 455,186	$ 141,370	$ 26,723	$ 9	$ 325
Misc Service Revenue Allocator		MISCSERV		0.00	0.00		0.00	0.02		
CSR Avoided Cost										
Interruptible Demands					67,976		2,137,171			
Cycle 20 Adjustment					-		169,275			
Avoided Cost per kW					2.80	2.75	2.75	2.80	2.80	2.80
Avoided Cost				-	190,332	-	5,411,714	-	-	-
Merger Surcerdit Revenue		MSCREV		-	-	-	-	(1)	-	-

Conroy Exhibit C5

Zero Intercept – Overhead Conductor

Kentucky Utilities
Company

Zero Intercept Analysis
Account 365 - Overhead Conductor

March 31, 2012

Weighted Linear Regression Statistics

	Estimate		Standard Error
Size Coefficient ($ per MCM)	0.0039965		0.0004991
Zero Intercept ($ per Unit)	0.8900773		0.1479166
R-Square	0.9102948		
Plant Classification			
Total Number of Units			97,430,621
Zero Intercept			0.8900773
Zero Intercept Cost		$	86,720,783
Total Cost of Sample		$	158,902,799
Percentage of Total			0.545747358
Percentage Classified as Customer-Related			54.57%
Percentage Classified as Demand-Related			45.43%

Kentucky Utilities Company

Zero Intercept Analysis
Account 365 - Overhead Conductor

March 31, 2012

Description	Size	Cost	Quantity	Avg Cost
1 CONDUCTOR	83.69	787,710.67	115,720.00	6.80704001
1/0 CONDUCTOR	105.6	1,166,718.87	247,264.00	4.71851491
123,270 ACAR WIRE	123.27	15,545,949.30	9,048,033.00	1.71815789
195,700 ACAR WIRE	195.7	2,181,982.80	1,815,854.00	1.20162899
2/0 COPPER CONDUCTOR	133.1	683,344.27	648,440.00	1.05382806
20 M.A.W. MESSENGER WIRE	20	2,510,875.21	1,257,889.00	1.99610237
336,400 19 STR. ALL ALUMINUM	336.4	7,896,534.44	5,641,385.00	1.39975103
392,500 24/13 ACAR WIRE	392.5	1,032,139.22	882,355.00	1.16975505
4 COPPER CONDUCTOR	41.74	11,166,434.41	11,494,338.00	0.9714726
6 COPPER CONDUCTOR	26.25	6,297,126.83	14,969,991.00	0.42065001
6A COPPER CONDUCTOR	26.25	776,041.34	99,522.00	7.79768634
795 MCM ALUMINUM CONDUC	795	44,852,609.86	10,579,084.00	4.23974418
8 COPPER CONDUCTOR	16.51	572,627.12	292,367.00	1.95859013
840,200 24/13 ACAR WIRE	840.2	576,093.95	212,837.00	2.70673779
#2 CONDUCTOR	66.36	9,648,825.89	9,402,756.00	1.02616998
1/0 CABLE	105.6	38,201,146.14	22,107,346.00	1.72798427
101 MCM ACSR CONDUCTOR	101	1,181.18	250.00	4.72472
1272 MCM ACSR CONDUCTOR	1272	78,453.74	30,063.00	2.60964441
200 MCM CABLE	200	1,627.11	500.00	3.25422
3/0 CONDUCTOR	167.8	5,610,202.89	2,032,233.00	2.76061007
300 MCM COPPER CONDUCTOR	300	3,564.60	260.00	13.71
4/0 CONDUCTOR	211.6	9,192,393.32	6,532,846.00	1.40710394
520 MCM CONDUCTOR	520	98.28	30.00	3.276
600 MCM CONDUCTOR	600	90,560.30	14,160.00	6.39550141
636 MCM ALUMINUM CONDUC	636	3,083.82	190.00	16.2306316
7/C CONDUCTOR	20.92	3,543.53	500.00	7.08706
80 MCM ACSR CONDUCTOR	80	7,736.84	3,500.00	2.21052571
954 MCM ACSR CONDUCTOR	954	14,193.53	908.00	15.631641

Kentucky Utilities Company

Zero Intercept Analysis
Account 365 - Overhead Conductor

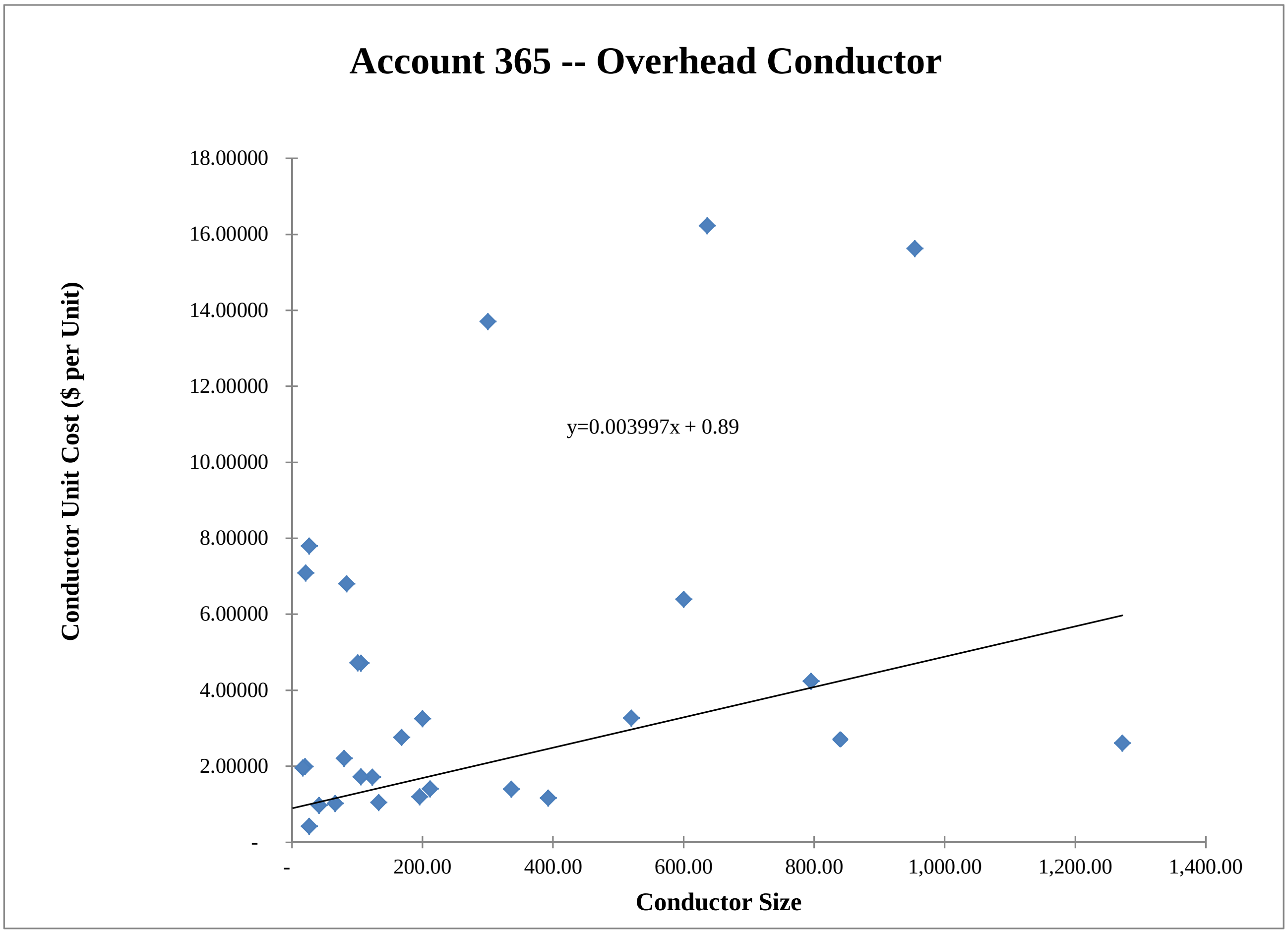
March 31, 2012

n	y	x	est y	y*n^.5	n^.5	xn^.5
115,720	6.80704	83.69	1.225	2315.594534	340.18	28469.36
247,264	4.71851	105.60	1.312	2346.312081	497.26	52510.28
9,048,033	1.71816	123.27	1.383	5168.210084	3,007.99	370795.5
1,815,854	1.20163	195.70	1.672	1619.238642	1,347.54	263712.8
648,440	1.05383	133.10	1.422	848.6031872	805.26	107179.8
1,257,889	1.99610	20.00	0.970	2238.741599	1,121.56	22431.13
5,641,385	1.39975	336.40	2.234	3324.632639	2,375.16	799003.8
882,355	1.16976	392.50	2.459	1098.794825	939.34	368690
11,494,338	0.97147	41.74	1.057	3293.612767	3,390.33	141512.4
14,969,991	0.42065	26.25	0.995	1627.539999	3,869.11	101564.1
99,522	7.79769	26.25	0.995	2459.944503	315.47	8281.116
10,579,084	4.23974	795.00	4.067	13789.98157	3,252.55	2585778
292,367	1.95859	16.51	0.956	1059.028717	540.71	8927.117
212,837	2.70674	840.20	4.248	1248.733463	461.34	387620.1
9,402,756	1.02617	66.36	1.155	3146.63875	3,066.39	203485.7
22,107,346	1.72798	105.60	1.312	8124.714126	4,701.84	496514.8
250	4.72472	101.00	1.294	74.70438253	15.81	1596.95
30,063	2.60964	1,272.00	5.974	452.4780263	173.39	220548.1
500	3.25422	200.00	1.689	72.76657134	22.36	4472.136
2,032,233	2.76061	167.80	1.561	3935.426611	1,425.56	239209.7
260	13.71000	300.00	2.089	221.0671075	16.12	4837.355
6,532,846	1.40710	211.60	1.736	3596.477836	2,555.94	540837.6
30	3.27600	520.00	2.968	17.94339098	5.48	2848.157
14,160	6.39550	600.00	3.288	761.0377958	119.00	71397.48
190	16.23063	636.00	3.432	223.723817	13.78	8766.655
500	7.08706	20.92	0.974	158.4714792	22.36	467.7854
3,500	2.21053	80.00	1.210	130.7764649	59.16	4732.864
908	15.63164	954.00	4.703	471.0288367	30.13	28746.92

Kentucky Utilities Company

Zero Intercept Analysis
Account 365 - Overhead Conductor

March 31, 2012



Kentucky Utilities Company
Pri/Sec Splits for Overhead Conductor
As of March 31, 2012

		Customer	Demand
Overhead		54.57%	45.43%
Primary	85.00%	0.4639	0.3861
Secondary	15.00%	0.0819	0.0681

Conroy Exhibit C6

Zero Intercept – Underground Conductor

Kentucky Utilities Company

Zero Intercept Analysis
Account 367 -- Underground Conductor

March 31, 2012

Weighted Linear Regression Statistics

	Estimate	Standard Error
Size Coefficient ($ per MCM)	0.0049856	0.0008547
Zero Intercept ($ per Unit)	3.0485020	0.2770197
R-Square	0.9527450	

Plant Classification

Total Number of Units	25,068,243
Zero Intercept	3.0485020
Zero Intercept Cost	$ 76,420,588
Total Cost of Sample	$ 101,609,671
Percentage of Total	0.75209955
Percentage Classified as Customer-Related	75.21%
Percentage Classified as Demand-Related	24.79%

Kentucky Utilities Company

Zero Intercept Analysis
Account 367 -- Underground Conductor

March 31, 2012

Description	Size	Cost	Quantity	Avg Cost
#12 CABLE	13.12	205,379.63	76,950	2.669001
1 CONDUCTOR	83.69	363,509.72	25,784	14.098267
1/0 CONDUCTOR	105.6	442,400.14	29,323	15.087138
1000 MCM CONDUCTOR	1000	16,663,251.48	2,053,440	8.1147983
2/0 COPPER CONDUCTOR	133.1	1,578,325.63	556,011	2.838659
250 MCM COPPER CONDUCTOI	250	238,897.61	179,098	1.3338932
4 COPPER CONDUCTOR	41.74	615,869.87	603,313	1.0208132
6 COPPER CONDUCTOR	26.25	932,008.09	315,342	2.955547
750 MCM COPPER CONDUCTOI	750	2,034,708.32	263,893	7.7103535
795 MCM ALUMINUM CONDUC	795	200,933.94	42,680	4.707918
8 COPPER CONDUCTOR	16.51	40,615.72	27,641	1.4694013
#2 CONDUCTOR	66.36	15,830,503.74	3,536,317	4.4765511
1/0 CABLE	105.6	41,903,850.41	12,165,040	3.4446126
123,270 ACAR WIRE	123.27	5,370.94	496	10.828508
2000 MCM CABLE	2000	4,904.75	90	54.497222
3/0 CONDUCTOR	167.8	322,311.91	30,870	10.440943
336,400 19 STR. ALL ALUMINUI	336.4	94,991.29	2,149	44.202555
4/0 CONDUCTOR	211.6	19,800,239.35	5104786	3.8787599
600 MCM CONDUCTOR	600	21,636.43	1634	13.241389
6A COPPER CONDUCTOR	26.25	309,784.89	53278	5.8144992
840,200 24/13 ACAR WIRE	840.2	177.03	108	1.6391667

Kentucky Utilities Company

Zero Intercept Analysis
Account 367 -- Underground Conductor

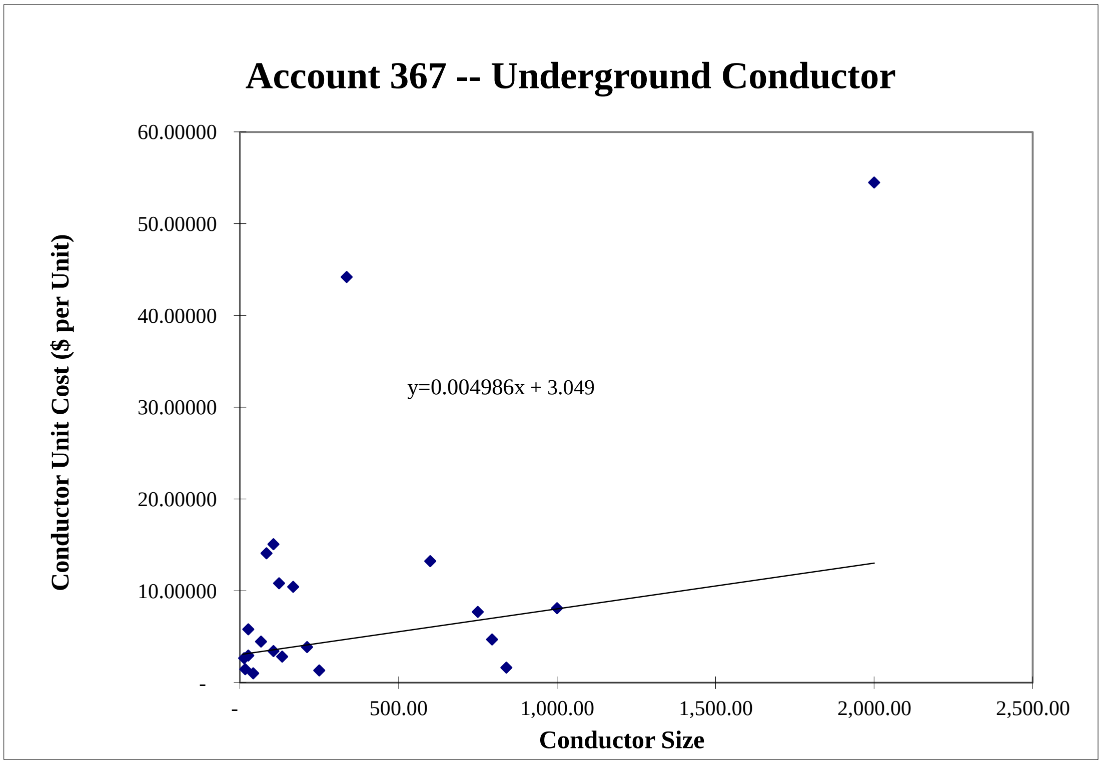
March 31, 2012

n	y	x	est y	y*n^.5	n^.5	xn^.5
76,950	2.66900	13.12	3.114	740.3772322	277.40	3639.47003
25,784	14.09827	83.69	3.466	2263.814732	160.57	13438.4356
29,323	15.08714	105.60	3.575	2583.515405	171.24	18082.9016
2,053,440	8.11480	1,000.00	8.034	11628.36727	1,432.98	1432982.9
556,011	2.83866	133.10	3.712	2116.678591	745.66	99247.5392
179,098	1.33389	250.00	4.295	564.5032374	423.20	105799.929
603,313	1.02081	41.74	3.257	792.8985361	776.73	32420.8044
315,342	2.95555	26.25	3.179	1659.696863	561.55	14740.7716
263,893	7.71035	750.00	6.788	3960.84845	513.71	385278.876
42,680	4.70792	795.00	7.012	972.6152949	206.59	164240.15
27,641	1.46940	16.51	3.131	244.2965203	166.26	2744.8837
3,536,317	4.47655	66.36	3.379	8418.198077	1,880.51	124790.628
12,165,040	3.44461	105.60	3.575	12014.2637	3,487.84	368316.088
496	10.82851	123.27	3.663	241.1623252	22.27	2745.35325
90	54.49722	2,000.00	13.020	517.0060451	9.49	18973.666
30,870	10.44094	167.80	3.885	1834.459124	175.70	29482.226
2,149	44.20255	336.40	4.726	2049.111439	46.36	15594.5984
5,104,786	3.87876	211.60	4.103	8763.582307	2,259.38	478084.247
1,634	13.24139	600.00	6.040	535.2535765	40.42	24253.6595
53,278	5.81450	26.25	3.179	1342.10432	230.82	6059.03226
108	1.63917	840.20	7.237	17.03471969	10.39	8731.61453

Kentucky Utilities Company

Zero Intercept Analysis
Account 367 -- Underground Conductor

March 31, 2012



Kentucky Utilities Company
Pri/Sec Splits for Underground Conductor
As of March 31, 2012

		Customer	Demand
Underground		75.21%	24.79%
Primary	85.00%	0.6393	0.2107
Secondary	15.00%	0.1128	0.0372

Conroy Exhibit C7

Zero Intercept – Transformers

Kentucky Utilities Company

Zero Intercept Analysis
Account 368 -- Line Transformers

March 31, 2012

Weighted Linear Regression Statistics	**Estimate**	**Standard Error**
Size Coefficient ($ per MCM)	10.4540419	0.4173453
Zero Intercept ($ per Unit)	377.9068234	49.7342315
R-Square	0.9493983	

Plant Classification

Total Number of Units	248,613
Zero Intercept	377.9068234
Zero Intercept Cost	$ 93,952,549
Total Cost of Sample	$ 203,773,079
Percentage of Total	0.461064579
Percentage Classified as Customer-Related	46.11%
Percentage Classified as Demand-Related	53.89%

Kentucky Utilities Company

Zero Intercept Analysis
Account 368 -- Line Transformers

March 31, 2012

Description	Size	Units	Cost	Ave Cost
TRANSFORMERS - OH 1P - .6 KVA	0.6	5	6350.91	1,270.18
TRANSFORMERS - OH 1P - 1 KVA	1	20	9478.16	473.91
TRANSFORMERS - OH 1P - 1.5 KVA	1.5	63	4378.94	69.51
TRANSFORMERS - OH 1P - 10 KVA	10	29886	10057915.46	336.54
TRANSFORMERS - OH 1P - 100 KVA	100	4247	5649392.01	1,330.21
TRANSFORMERS - OH 1P - 1250 KVA	1250	14	148540.75	10,610.05
TRANSFORMERS - OH 1P - 15 KVA	15	51211	24860753.53	485.46
TRANSFORMERS - OH 1P - 150 KVA	150	6	9231.17	1,538.53
TRANSFORMERS - OH 1P - 167 KVA	167	2299	4043485.49	1,758.80
TRANSFORMERS - OH 1P - 2.5 KVA	2.5	20	2246.62	112.33
TRANSFORMERS - OH 1P - 25 KVA	25	60554	36824416.84	608.13
TRANSFORMERS - OH 1P - 250 KVA	250	318	1007938.36	3,169.62
TRANSFORMERS - OH 1P - 3 KVA	3	864	93798.82	108.56
TRANSFORMERS - OH 1P - 333 KVA	333	140	485687	3,469.19
TRANSFORMERS - OH 1P - 37.5 KVA	37.5	30302	22105895.38	729.52
TRANSFORMERS - OH 1P - 5 KVA	5	6087	908509.89	149.25
TRANSFORMERS - OH 1P - 50 KVA	50	18189	14742955.81	810.54
TRANSFORMERS - OH 1P - 500 KVA	500	250	1139206.57	4,556.83
TRANSFORMERS - OH 1P - 667 KVA	667	17	92692.95	5,452.53
TRANSFORMERS - OH 1P - 7.5 KVA	7.5	21	5530.76	263.37
TRANSFORMERS - OH 1P - 75 KVA	75	6656	7404275.17	1,112.42
TRANSFORMERS - OH 1P - 833 KVA	833	31	268139.91	8,649.67
TRANSFORMERS - PM 1P - 10 KVA	10	202	154770.06	766.19
TRANSFORMERS - PM 1P - 100 KVA	100	1295	2294844.64	1,772.08
TRANSFORMERS - PM 1P - 15 KVA	15	2700	2286937.37	847.01
TRANSFORMERS - PM 1P - 150 KVA	150	13	44805.72	3,446.59
TRANSFORMERS - PM 1P - 167 KVA	167	894	1912901.1	2,139.71
TRANSFORMERS - PM 1P - 225 KVA	225	4	486.66	121.67
TRANSFORMERS - PM 1P - 25 KVA	25	8132	7743405.93	952.21
TRANSFORMERS - PM 1P - 250 KVA	250	399	1411239.77	3,536.94
TRANSFORMERS - PM 1P - 333 KVA	333	2	3901.9	1,950.95
TRANSFORMERS - PM 1P - 37.5 KVA	37.5	8648	8982169.12	1,038.64
TRANSFORMERS - PM 1P - 50 KVA	50	6904	7658471.33	1,109.28
TRANSFORMERS - PM 1P - 500 KVA	500	2	9101.56	4,550.78
TRANSFORMERS - PM 1P - 75 KVA	75	2800	3854049.83	1,376.45
TRANSFORMERS - PM 3P - 1000 KVA	1000	337	3902408.17	11,579.85
TRANSFORMERS - PM 3P - 112 KVA	112	31	85072.96	2,744.29
TRANSFORMERS - PM 3P - 112.5 KVA	112.5	229	817415.77	3,569.50
TRANSFORMERS - PM 3P - 1250 KVA	1250	2	14355.37	7,177.69
TRANSFORMERS - PM 3P - 150 KVA	150	748	2859439.73	3,822.78
TRANSFORMERS - PM 3P - 1500 KVA	1500	235	3792381.97	16,137.80
TRANSFORMERS - PM 3P - 2000 KVA	2000	107	2429199.54	22,702.80
TRANSFORMERS - PM 3P - 225 KVA	225	523	2262713.71	4,326.41
TRANSFORMERS - PM 3P - 2500 KVA	2500	149	2869977.2	19,261.59
TRANSFORMERS - PM 3P - 300 KVA	300	922	4780716.07	5,185.16
TRANSFORMERS - PM 3P - 3000 KVA	3000	14	529650.12	37,832.15
TRANSFORMERS - PM 3P - 333 KVA	333	33	117861.4	3,571.56
TRANSFORMERS - PM 3P - 45 KVA	45	119	381081.67	3,202.37
TRANSFORMERS - PM 3P - 500 KVA	500	903	6314904.33	6,993.25
TRANSFORMERS - PM 3P - 75 KVA	75	595	1779956.83	2,991.52
TRANSFORMERS - PM 3P - 750 KVA	750	468	4591625.07	9,811.16
TRANSFORMERS - PM 3P - 833 KVA	833	3	16414	5,471.33

Kentucky Utilities Company

Zero Intercept Analysis
Account 368 -- Line Transformers

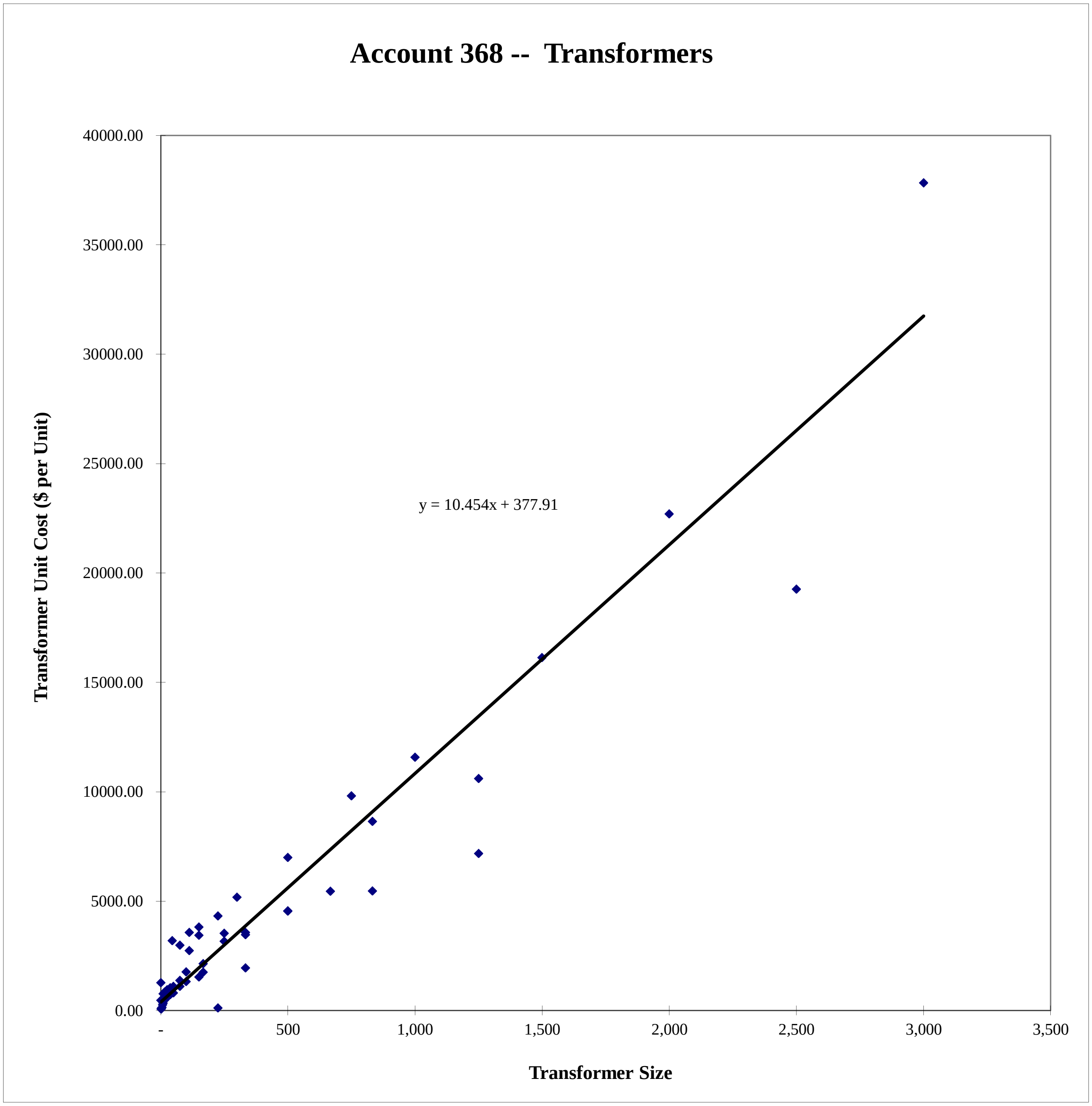
March 31, 2012

n	y	x	est y	y*n^.5	n^.5	xn^.5
5	1,270.18200	0.60	384.179	2840.213296	2.24	1.341641
20	473.90800	1.00	388.361	2119.381006	4.47	4.472136
63	69.50698	1.50	393.588	551.6945831	7.94	11.90588
29,886	336.54271	10.00	482.447	58180.04929	172.88	1728.757
4,247	1,330.20768	100.00	1,423.311	86688.31888	65.17	6516.901
14	10,610.05357	1,250.00	13,445.459	39699.18532	3.74	4677.072
51,211	485.45729	15.00	534.717	109858.2457	226.30	3394.477
6	1,538.52833	150.00	1,946.013	3768.609371	2.45	367.4235
2,299	1,758.80187	167.00	2,123.732	84330.83555	47.95	8007.297
20	112.33100	2.50	404.042	502.359504	4.47	11.18034
60,554	608.12526	25.00	639.258	149645.775	246.08	6151.931
318	3,169.61748	250.00	2,991.417	56522.37653	17.83	4458.139
864	108.56345	3.00	409.269	3191.100659	29.39	88.18163
140	3,469.19286	333.00	3,859.103	41048.04345	11.83	3940.109
30,302	729.51935	37.50	769.933	126990.8597	174.07	6527.801
6,087	149.25413	5.00	430.177	11644.69207	78.02	390.0961
18,189	810.54241	50.00	900.609	109315.099	134.87	6743.33
250	4,556.82628	500.00	5,604.928	72049.74973	15.81	7905.694
17	5,452.52647	667.00	7,350.753	22481.34256	4.12	2750.111
21	263.36952	7.50	456.312	1206.910779	4.58	34.36932
6,656	1,112.42115	75.00	1,161.960	90756.11437	81.58	6118.823
31	8,649.67452	833.00	9,086.124	48159.34952	5.57	4637.948
202	766.18842	10.00	482.447	10889.58342	14.21	142.1267
1,295	1,772.08080	100.00	1,423.311	63770.29193	35.99	3598.611
2,700	847.01384	15.00	534.717	44012.13021	51.96	779.4229
13	3,446.59385	150.00	1,946.013	12426.87084	3.61	540.8327
894	2,139.71040	167.00	2,123.732	63976.98323	29.90	4993.272
4	121.66500	225.00	2,730.066	243.33	2.00	450
8,132	952.21421	25.00	639.258	85868.39428	90.18	2254.44
399	3,536.94178	250.00	2,991.417	70650.35671	19.97	4993.746
2	1,950.95000	333.00	3,859.103	2759.05995	1.41	470.9331
8,648	1,038.64120	37.50	769.933	96588.04759	92.99	3487.298
6,904	1,109.28032	50.00	900.609	92170.44824	83.09	4154.516
2	4,550.78000	500.00	5,604.928	6435.774795	1.41	707.1068
2,800	1,376.44637	75.00	1,161.960	72834.69565	52.92	3968.627
337	11,579.84620	1,000.00	10,831.949	212577.7186	18.36	18357.56
31	2,744.28903	112.00	1,548.760	15279.55468	5.57	623.5896
229	3,569.50118	112.50	1,553.987	54016.35451	15.13	1702.434
2	7,177.68500	1,250.00	13,445.459	10150.77947	1.41	1767.767
748	3,822.78039	150.00	1,946.013	104551.4712	27.35	4102.438
235	16,137.79562	1,500.00	16,058.970	247387.7223	15.33	22994.56
107	22,702.79944	2,000.00	21,285.991	234839.5834	10.34	20688.16
523	4,326.41245	225.00	2,730.066	98941.56235	22.87	5145.568
149	19,261.59195	2,500.00	26,513.011	235117.6933	12.21	30516.39
922	5,185.15843	300.00	3,514.119	157444.4989	30.36	9109.336
14	37,832.15143	3,000.00	31,740.032	141554.9489	3.74	11224.97
33	3,571.55758	333.00	3,859.103	20517.03624	5.74	1912.939
119	3,202.36697	45.00	848.339	34933.69941	10.91	490.892
903	6,993.24953	500.00	5,604.928	210146.8576	30.05	15024.98
595	2,991.52408	75.00	1,161.960	72971.11569	24.39	1829.447
468	9,811.16468	750.00	8,218.438	212247.9439	21.63	16224.98
3	5,471.33333	833.00	9,086.124	9476.627318	1.73	1442.798

Kentucky Utilities Company

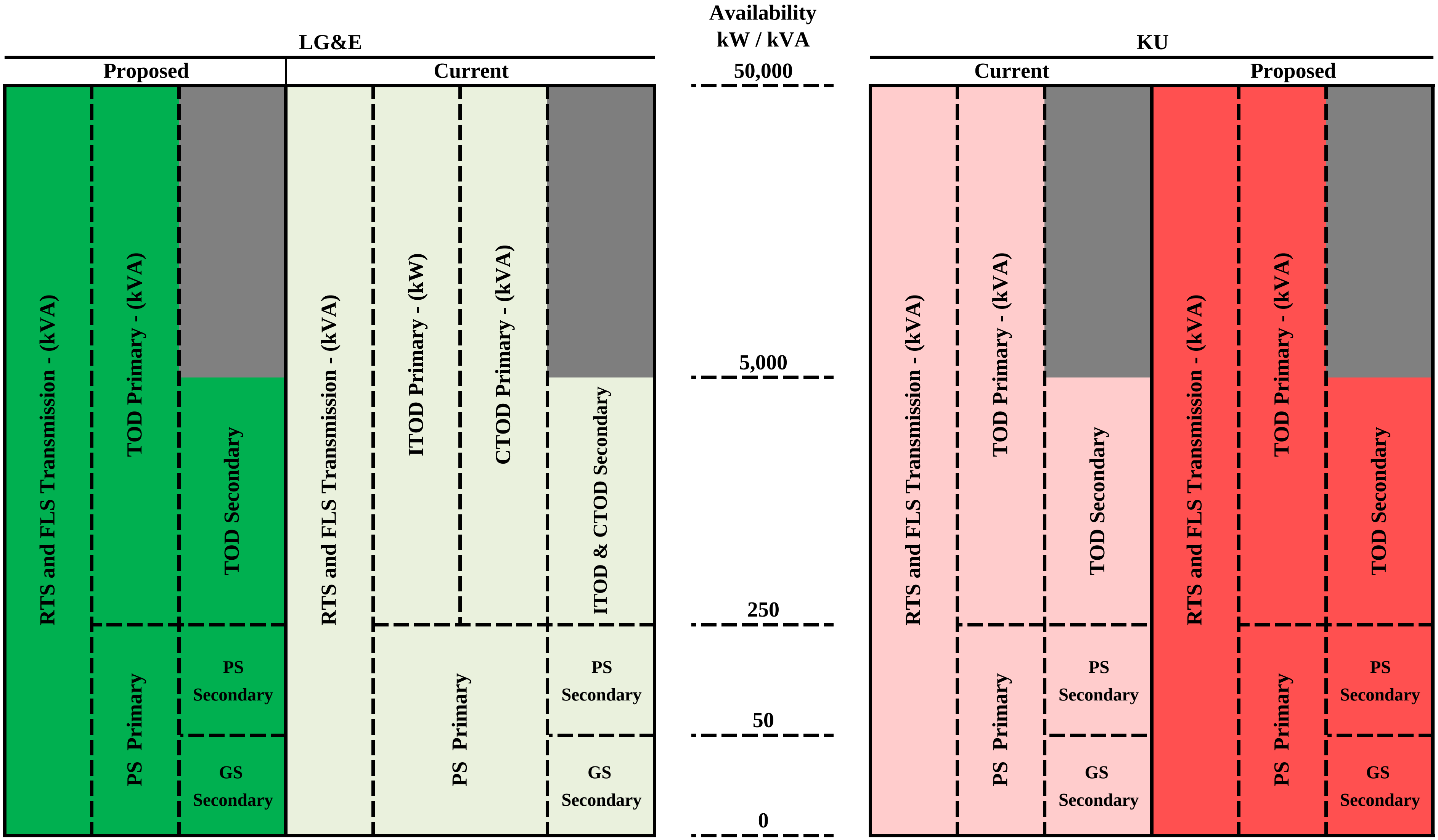
Zero Intercept Analysis
Account 368 -- Line Transformers

March 31, 2012



Conroy Exhibit R1

Visual Comparison of LG&E and KU Rate Schedules


LG&E
Proposed
Current
Availability
kW / kVA
50,000
5,000
250
50
0
KU
Current
Proposed
RTS and FLS Transmission - (kVA)
TOD Primary - (kVA)
TOD Secondary
PS Primary
PS Secondary
GS Secondary
ITOD Primary - (kW)
CTOD Primary - (kVA)
ITOD & CTOD Secondary

Conroy Exhibit R2

Residential Electric Unit Cost

Kentucky Utilities Company

Unit Cost of Service Based on the Cost of Service Study
For the 12 Months Ended March 31, 2012

Rate RS

	Production		Transmission	Distribution		Customer Service Expenses	
Description	**Demand-Related**	**Energy-Related**	**Demand-Related**	**Demand-Related**	**Customer-Related**	**Customer-Related**	**Total**
(1) Rate Base	$ 914,490,029	$ 22,130,120	$ 121,147,430	$ 181,337,903	$ 299,593,473	$ 4,315,497	$ 1,543,014,453
(2) Rate Base Adjustments	(44,943,895)	(1,087,616)	(5,953,960)	(8,912,106)	(14,723,941)	(212,091)	$ (75,833,609)
(3) Rate Base as Adjusted	$ 869,546,134	$ 21,042,505	$ 115,193,470	$ 172,425,797	$ 284,869,532	$ 4,103,406	$ 1,467,180,844
(4) Rate of Return	5.62%	5.62%	5.62%	5.62%	5.62%	5.62%	
(5) Return	$ 48,888,229	$ 1,183,066	$ 6,476,488	$ 9,694,243	$ 16,016,133	$ 230,705	$ 82,488,863
(6) Interest Expenses	$ 15,720,734	$ 380,433	$ 2,082,611	$ 3,117,328	$ 5,150,225	$ 74,186	$ 26,525,516
(7) Net Income	$ 33,167,494	$ 802,634	$ 4,393,877	$ 6,576,916	$ 10,865,908	$ 156,518	$ 55,963,347
(8) Income Taxes	$ 20,024,162	$ 484,573	$ 2,652,709	$ 3,970,672	$ 6,560,059	$ 94,494	$ 33,786,669
(9) Operation and Maintenance Expenses	$ 35,811,223	$ 204,629,937	$ 11,753,875	$ 15,171,866	$ 30,449,121	$ 34,538,081	$ 332,354,104
(10) Depreciation Expenses	$ 47,987,589	$ -	$ 4,143,897	$ 8,039,537	$ 13,273,659	$ -	$ 73,444,682
(11) Other Taxes	$ 5,720,586	$ (257)	$ 1,011,276	$ 1,381,075	$ 2,280,221	$ -	$ 10,392,900
(12) Curtailable Service Credit	$ 2,422,409						$ 2,422,409
(13) Expense Adjustments - Prod. Demand	$ (3,527,954)	$ -	$ -	$ -	$ -	$ -	$ (3,527,954)
(14) Expense Adjustments - Energy	$ -	$ (5,076,645)	$ -	$ -	$ -	$ -	$ (5,076,645)
(15) Expense Adjustments - Trans. Demand	$ -	$ -	$ (1,911,652)	$ -	$ -	$ -	$ (1,911,652)
(16) Expense Adjustments - Distribution	$ -	$ -	$ -	$ (4,012,230)	$ (6,628,718)	$ -	$ (10,640,947)
(17) Expense Adjustments - Other	$ (729,566)	$ (17,655)	$ (96,650)	$ (144,669)	$ (239,011)	$ (3,443)	$ (1,230,993)
(18) Expense Adjustments - Total	$ (4,257,520)	$ (5,094,300)	$ (2,008,301)	$ (4,156,898)	$ (6,867,729)	$ (3,443)	$ (22,388,191)
(19) Total Cost of Service	$ 156,596,678	$ 201,203,019	$ 24,029,943	$ 34,100,494	$ 61,711,464	$ 34,859,838	$ 512,501,437
(20) Less: Misc Revenue - Tran. Demand		$ -	$ (4,144,146)	$ -	$ -	$ -	$ (4,144,146)
(21) Less: Misc Revenue - Energy	$ -	$ (9,697,329)	$ -	$ -	$ -	$ -	$ (9,697,329)
(22) Less: Misc Revenue - Other	$ (4,939,670)	$ (119,537)	$ (654,385)	$ (979,507)	$ (1,618,271)	$ (23,310)	$ (8,334,681)
(23) Less: Misc Revenue - Total	$ (4,939,670)	$ (9,816,866)	$ (4,798,531)	$ (979,507)	$ (1,618,271)	$ (23,310)	$ (22,176,156)
(24) Net Cost of Service	$ 151,657,008	$ 191,386,153	$ 19,231,413	$ 33,120,987	$ 60,093,193	$ 34,836,527	$ 490,325,281
(25) Billing Units	5,944,171,807	5,944,171,807	5,944,171,807	5,944,171,807	5,044,174	5,044,174	
(26) Unit Costs	0.025513564	0.032197278	0.003235339	0.00557201	$ 11.91	$ 6.91	$ 18.82

Customer Charge	$ 18.82
Energy Charge	0.06652
Distribution Customer	$ 18.82
Distribution Customer Margin	1.06
	$ 19.88

Conroy Exhibit R3

Reconstruction of Electric Billing Determinants

Kentucky Utilities Company
Calculations to Reconstruct Test Year Billing Determinants
Based on Sales for the Twelve Months Ended March 31, 2012

	(1)	(2)	(3)	(4)	(5)	(4)	(5)	(6)	(7)	(8)	
	Revenue As Billed	FAC Billings	DSM Billings	ECR Billings	Merger Surcredit Billings	CSR Billings	Interruptible Buy Thru	Franchise Fees, HEA Charges, Other Misc Revenue	Actual Net Revenue at Base Rates	Calculated Net Revenue at Base Rates	Calculated Divided by Actual
Residential Rates RS, VFD and LEV											
Residential Service	$ 481,290,348	$ 2,592,904	$ 11,423,668	$ 14,367,955	$ -	$ -	$ -	$ 8,475,793	$ 444,430,028	$ 444,430,028	1.000000
Residential Sevice, Volunteer Fire Depts	$ 72,466	$ 353	$ 1,782	$ 2,153	$ -	$ -	$ -	$ 1,060	$ 67,118	$ 67,118	1.000000
Residential Service -- Electric Vehicle Only	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Total Residential Service	$ 481,362,814	$ 2,593,257	$ 11,425,450	$ 14,370,108	$ -	$ -	$ -	$ 8,476,853	$ 444,497,146	$ 444,497,146	1.000000
General Service Rate GS, Single and Three Pha											
General Service	$ 83,290,798	$ 416,718	$ 1,349,453	$ 2,481,897	$ (1)	$ -	$ -	$ 1,302,795	$ 77,739,936	$ 77,739,936	1.000000
General Service Three Phase	$ 100,863,803	$ 617,039	$ 1,756,100	$ 2,959,514	$ (3)	$ -	$ -	$ 1,866,422	$ 93,664,731	$ 93,664,731	1.000000
Total General Service	$ 184,154,601	$ 1,033,757	$ 3,105,553	$ 5,441,411	$ (4)	$ -	$ -	$ 3,169,217	$ 171,404,667	$ 171,404,667	1.000000
All Electric School Single and Three Phase Ser											
All Electric School	$ 805,145	$ 5,636	$ 1,984	$ 31,992	$ 22	$ -	$ -	$ 13,984	$ 751,527	$ 751,527	1.000000
All Electric School Three Phase	$ 10,453,706	$ 70,534	$ 36,709	$ 302,873	$ -	$ -	$ -	$ 163,581	$ 9,880,009	$ 9,880,009	1.000000
Total All Electric School	$ 11,258,851	$ 76,170	$ 38,693	$ 334,865	$ 22	$ -	$ -	$ 177,565	$ 10,631,536	$ 10,631,536	1.000000
Power Service Rate											
Secondary	$ 225,868,342	$ 1,728,895	$ 527,094	$ 6,481,232	$ (20)	$ -	$ -	$ 4,276,826	$ 212,854,315	$ 212,854,315	1.000000
Primary	$ 52,164,958	$ 438,178	$ 97,296	$ 1,489,519	$ -	$ -	$ 2,843	$ 717,095	$ 49,420,027	$ 49,420,027	1.000000
Total Power Service	$ 278,033,300	$ 2,167,073	$ 624,390	$ 7,970,751	$ (20)	$ -	$ 2,843	$ 4,993,921	$ 262,274,342	$ 262,274,342	1.000000
Industrial Time of Day Service											
Secondary	$ 25,639,208	$ 221,536	$ 70,049	$ 739,189	$ -	$ -	$ -	$ 507,052	$ 24,101,382	$ 24,101,382	1.000000
Primary	$ 204,406,942	$ 2,013,521	$ 137,309	$ 5,888,222	$ -	$ -	$ 38,353	$ 2,191,634	$ 194,137,903	$ 194,137,903	1.000000
Total Industrial Time of Day Service	$ 230,046,150	$ 2,235,057	$ 207,358	$ 6,627,411	$ -	$ -	$ 38,353	$ 2,698,686	$ 218,239,285	$ 218,239,285	1.000000
Retail Transmisison Service	$ 85,627,393	$ 847,670	$ -	$ 2,464,908	$ -	$ -	$ -	$ 136,830	$ 82,177,985	$ 82,177,985	1.000000
Fluctuating Load Service	$ 26,235,092	$ 296,727	$ -	$ 745,290	$ -	$ -	$ -	$ -	$ 25,193,075	$ 25,193,075	1.000000
Curtailable Service Rider	$ (12,053,715)	$ -	$ -	$ -	$ -	$ (12,053,715)	$ -	$ -	$ -	$ -	
Lighting Energy	$ 2,309	$ 17	$ -	$ 63	$ -	$ -	$ -	$ 64	$ 2,165	$ 2,165	1.000000
Traffic Energy	$ 109,808	$ 565	$ -	$ 3,101	$ -	$ -	$ -	$ 3,114	$ 103,028	$ 103,028	1.000000
Lighting Service	$ 23,551,352	$ 50,406	$ -	$ 672,786	$ (1)	$ -	$ -	$ 436,325	$ 22,391,836	$ 22,391,836	1.000000
Total	$ 1,308,327,955	$ 9,300,699	$ 15,401,444	$ 38,630,694	$ (3)	$ (12,053,715)	$ 41,196	$ 20,092,575	$ 1,236,915,065	$ 1,236,915,065	1.000000

Conroy Exhibit R4

Summary of Electric Revenue Increase

Kentucky Utilities Company
Summary of Proposed Increase
Based On Sales for the Twelve Months Ended March 31, 2012

	Revenue Adjusted to as Billed Basis	Adjustment to Remove Fuel Adjustment Clause Billings	Adjustment to Remove DSM Billings	Adjustment to Remove ECR Billings	Adjustment to Remove Merger Surcredit Billings	Adjustment to Remove HEA, Franchise Fees and Misc Revenue	Adjustment to Remove Interruptible Buy-thru Revenue	Test Year Base Revenues, As Billed	Adjustment to Reflect a Full Year of Base Rate Changes for FAC Rollin	Adjustment to Reflect a Full Year of Base Rate Changes for ECR Rollin	Test Year Base Revenues, At Current Rates
Residential Rate - RS	$ 481,362,814	$ 2,593,257	$ 11,425,450	$ 14,370,108	$ -	$ 8,476,853	$ -	$ 444,497,146	$ (1,105,429)	$ 14,613,748	$ 458,005,465
General Service Rate - GS	$ 184,154,601	$ 1,033,757	$ 3,105,553	$ 5,441,411	$ (4)	$ 3,169,217	$ -	$ 171,404,667	$ (393,289)	$ 11,147,080	$ 182,158,458
All Electric School Service Rate - AES	$ 11,258,851	$ 76,170	$ 38,693	$ 334,865	$ 22	$ 177,565	$ -	$ 10,631,536	$ (34,668)	$ 71,398	$ 10,668,266
Power Service Rate											
Power Service Rate PS - Secondary	$ 225,868,342	$ 1,728,895	$ 527,094	$ 6,481,232	$ (20)	$ 4,276,826	$ -	$ 212,854,315	$ (647,899)	$ 9,190,337	$ 221,396,753
Power Service Rate PS - Primary	$ 52,164,958	$ 438,178	$ 97,296	$ 1,489,519	$ -	$ 717,095	$ 2,843	$ 49,420,027	$ (192,686)	$ 1,997,208	$ 51,224,549
	$ 278,033,300	$ 2,167,073	$ 624,390	$ 7,970,751	$ (20)	$ 4,993,921	$ 2,843	$ 262,274,342	$ (840,585)	$ 11,187,545	$ 272,621,302
Time of Day Secondary Service TODS	$ 25,639,208	$ 221,536	$ 70,049	$ 739,189	$ -	$ 507,052	$ -	$ 24,101,382	$ (84,328)	$ (1,127,163)	$ 22,889,891
Time of Day Primary Service TODP	$ 204,406,942	$ 2,013,521	$ 137,309	$ 5,888,222	$ -	$ 2,191,634	$ 38,353	$ 194,137,903	$ (678,789)	$ (9,411,757)	$ 184,047,357
Retail Transmission Service -- RTS	$ 85,627,393	$ 847,670	$ -	$ 2,464,908	$ -	$ 136,830	$ -	$ 82,177,985	$ (341,016)	$ (1,950,925)	$ 79,886,044
Fluctuating Load Service FLS	$ 26,235,092	$ 296,727	$ -	$ 745,290	$ -	$ -	$ -	$ 25,193,075	$ (112,199)	$ (978,636)	$ 24,102,240
Curtailable Service Riders - CSR10	$ (12,053,715)	$ -	$ -	$ -	$ -	$ -	$ -	$ (12,053,715)	$ -	$ -	$ (12,053,715)
Curtailable Service Riders - CSR30	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Curtailable Service Riders	$ (12,053,715)	$ -	$ -	$ -	$ -	$ -	$ -	$ (12,053,715)	$ -	$ -	$ (12,053,715)
Lighting Energy -- LE	$ 2,309	$ 17	$ -	$ 63	$ -	$ 64	$ -	$ 2,165	$ (8)	$ 98	$ 2,255
Traffice Lighting Energy -- TE	$ 109,808	$ 565	$ -	$ 3,101	$ -	$ 3,114	$ -	$ 103,028	$ (196)	$ 2,733	$ 105,565
Dark Sky Lighting - DSK	$ 87	$ -	$ -	$ 3	$ -	$ -	$ -	$ 84	$ -	$ 1	$ 85
Street Lighting - SL	$ 10,362,100	$ 18,993	$ -	$ 291,075	$ -	$ 241,976	$ -	$ 9,810,056	$ (9,485)	$ 305,950	$ 10,106,521
Private Outdoor Lighting - POL	$ 13,189,165	$ 31,413	$ -	$ 381,708	$ (1)	$ 194,349	$ -	$ 12,581,696	$ (16,233)	$ 415,264	$ 12,980,727
Outdoor and Street Lighting, LS and RLS	$ 23,551,352	$ 50,406	$ -	$ 672,786	$ (1)	$ 436,325	$ -	$ 22,391,836	$ (25,718)	$ 721,215	$ 23,087,333
TOTAL ULTIMATE CONSUMERS	$ 1,308,327,955	$ 9,300,699	$ 15,401,444	$ 38,630,694	$ (3)	$ 20,092,575	$ 41,196	$ 1,224,861,350	$ (3,616,225)	$ 24,275,336	$1,245,520,461
Late Payment Charges	6,190,624							$ 6,190,624			$ 6,190,624
Electric Service Revenues	2,206,637							$ 2,206,637			$ 2,206,637
Rent from Electric Property	2,153,990							$ 2,153,990			$ 2,153,990
Other Miscellaneous Electric Revenue	181,175							$ 181,175			$ 181,175
TOTAL JURISDICTIONAL	$ 1,319,060,381	$ 9,300,699	$ 15,401,444	$ 38,630,694	$ (3)	$ 20,092,575	$ 41,196	$ 1,235,593,776	$ (3,616,225)	$ 24,275,336	$1,256,252,887

Kentucky Utilities Company
Summary of Proposed Increase
Based On Sales for the Twelve Months Ended March 31, 2012

	Adjustment to Reflect FAC Billings for Full Year of the Rollin	Adjustment Reflecting Year-End Number of Customers	Adjustment to Reflect Customer Billing Move to Cycle 20	Adjustment to Reflect Removal of Base Rate ECR Revenues	Adjustment to Reflect Elimination of ECR Plans	Adjustment Reflecting Rate Switching	Adjusted Billings Net of ECR at Current Rates
Residential Rate - RS	$ 4,705,954	$ (710,225)	$ -	$ (56,592,842)	$ 54,809,454	$ (30,891)	$ 460,186,915
General Service Rate - GS	$ 1,757,425	$ 42,721	$ -	$ (27,494,815)	$ 26,620,421	$ (3,346,954)	$ 179,737,256
All Electric School Service Rate - AES	$ 129,005	$ 73,529	$ -	$ (1,328,040)	$ 1,285,505	$ (20,438)	$ 10,807,827
Power Service Rate							
Power Service Rate PS - Secondary	$ 2,893,212	$ (1,562,556)	$ -	$ (27,054,868)	$ 26,179,563	$ (1,353,663)	$ 220,498,441
Power Service Rate PS - Primary	$ 759,739	$ 171,787	$ -	$ (6,225,132)	$ 6,023,730	$ (5,386,209)	$ 46,568,464
	$ 3,652,951	$ (1,390,769)	$ -	$ (33,280,000)	$ 32,203,293	$ (6,739,872)	$ 267,066,905
Time of Day Secondary Service TODS	$ 3,264,159	$ 116,378	$ -	$ (2,577,384)	$ 2,503,037	$ 2,518,028	$ 28,714,109
Time of Day Primary Service TODP	$ 371,304	$ (1,816,142)	$ (1,640,196)	$ (19,026,087)	$ 18,303,577	$ 4,955,272	$ 185,195,086
Retail Transmission Service -- RTS	$ 1,400,173	$ 166,983	$ (2,832,550)	$ (7,866,500)	$ 7,644,909	$ (116,695)	$ 78,282,364
Fluctuating Load Service FLS	$ 475,259	$ -	$ (2,008,648)	$ (2,469,091)	$ 2,410,303	$ -	$ 22,510,063
Curtailable Service Riders - CSR10	$ -	$ -	$ 914,086	$ -	$ -	$ -	$ (11,139,629)
Curtailable Service Riders - CSR30	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Curtailable Service Riders	$ -	$ -	$ 914,086	$ -	$ -	$ -	$ (11,139,629)
Lighting Energy -- LE	$ 27	$ -	$ -	$ (381)	$ 262	$ -	$ 2,163
Traffice Lighting Energy -- TE	$ 938	$ 11,068	$ -	$ (10,650)	$ 7,316	$ 70	$ 114,307
Dark Sky Lighting - DSK	$ -	$ -	$ -	$ -	$ -	$ -	
Street Lighting - SL	$ 32,546	$ -	$ -	$ -	$ -	$ -	
Private Outdoor Lighting - POL	$ 55,314	$ -	$ -	$ -	$ -	$ -	$ -
Outdoor and Street Lighting, LS and RLS	$ 87,860	$ 98,915	$ -	$ (2,862,245)	$ 2,773,810	$ -	$ 23,185,673
TOTAL ULTIMATE CONSUMERS	$ 15,845,055	$ (3,407,542)	$ (5,567,308)	$ (153,508,035)	$ 148,561,887	$ (2,781,480)	$ 1,244,663,039
Late Payment Charges							6,190,624
Electric Service Revenues							2,206,637
Rent from Electric Property							2,153,990
Other Miscellaneous Electric Revenue							181,175
TOTAL JURISDICTIONAL	$ 15,845,055	$ (3,407,542)	$ (5,567,308)	$ (153,508,035)	$ 148,561,887	$ (2,781,480)	$ 1,255,395,465

Kentucky Utilities Company
Summary of Proposed Increase
Based On Sales for the Twelve Months Ended March 31, 2012

	Adjusted Billings Net of ECR at Current Rates	Add Base ECR Revenues	ECR Billing Factor Revenues Reflecting Rollin	Adjusted Billings Including All ECR Revenue at Current Rates	Increase	Percentage Increase
Residential Rate - RS	$ 460,186,915	$ 1,783,388	$ 3,624,607	$ 465,594,910	$ 37,381,886	8.03%
General Service Rate - GS	$ 179,737,256	$ 874,394	$ 1,686,683	$ 182,298,333	$ 9,061,201	4.97%
All Electric School Service Rate - AES	$ 10,807,827	$ 42,535	$ 80,784	$ 10,931,146	$ 635,467	5.81%
Power Service Rate						
Power Service Rate PS - Secondary	$ 220,498,441	$ 875,305	$ 1,791,384	$ 223,165,130	$ 4,381,192	1.96%
Power Service Rate PS - Primary	$ 46,568,464	$ 201,402	$ 445,709	$ 47,215,575	$ 2,468,797	5.23%
	$ 267,066,905	$ 1,076,707	$ 2,237,093	$ 270,380,705	6,849,989	2.53%
Time of Day Secondary Service TODS	$ 28,714,109	$ 74,347	$ 142,467	$ 28,930,923	1,907,198	6.59%
Time of Day Primary Service TODP	$ 185,195,086	$ 722,510	$ 1,064,717	$ 186,982,312	$ 12,380,611	6.62%
Retail Transmission Service -- RTS	$ 78,282,364	$ 221,591	$ 448,130	$ 78,952,085	$ 5,128,398	6.50%
Fluctuating Load Service FLS	$ 22,510,063	$ 58,788	$ 110,713	$ 22,679,564	$ 1,417,956	6.25%
Curtailable Service Riders - CSR10	$ (11,139,629)	$ -	$ -	$ (11,139,629)	$ 5,466,756	
Curtailable Service Riders - CSR30	$ -	$ -	$ -	$ -	$ -	
Total Curtailable Service Riders	$ (11,139,629)	$ -	$ -	$ (11,139,629)	5,466,756	
Lighting Energy -- LE	$ 2,163	$ 119	$ 7	$ 2,289	$ 124	5.42%
Traffice Lighting Energy -- TE	$ 114,307	$ 3,334	$ 682	$ 118,323	$ 6,388	5.40%
	-					
Dark Sky Lighting - DSK	$ -					
Street Lighting - SL	$ -					
Private Outdoor Lighting - POL	$ -					
Outdoor and Street Lighting, LS and RLS	$ 23,185,673	$ 88,435	$ 168,549	$ 23,442,657	$ 1,267,776	5.41%
TOTAL ULTIMATE CONSUMERS	$ 1,244,663,039	$ 4,946,148	$ 9,564,432	$ 1,259,173,618	$ 81,503,751	6.47%
Late Payment Charges	6,190,624			$ 6,190,624		
Electric Service Revenues	2,206,637			$ 2,206,637		
Rent from Electric Property	2,153,990			$ 2,153,990	$ 681,722 (1)	
Other Miscellaneous Electric Revenue	181,175			$ 181,175	$ 247,419 (2)	
TOTAL JURISDICTIONAL	$ 1,255,395,465			$ 1,269,906,044	$ 82,432,892	6.49%

(1) Increase in the CATV Pole Attachment charge.
(2) Increase in the Meter Pulse Relay, Disconnect/Reconnect, and Meter Test Charges

Conroy Exhibit R5

Electric Revenue Increase by Rate Schedule

KENTUCKY UTILITIES COMPANY
Calculations of Proposed Rate Increase
Based on Sales for the 12 Months Ended March 31, 2012

(1)	(2)	(3)	(4)	(5)	(6)	(7)
	Bills	Total kWh	Present Rates	Calculated Revenue at Present Rates	Proposed Rates	Calculated Revenue at Proposed Rates
RESIDENTIAL RATE RS, inclusive of Volunteer Fire Department customers						
Basic Service Charges	5,044,089		$ 8.50	$ 42,874,757	$ 13.00	$ 65,573,157
All Energy		5,944,626,245	$ 0.06987	$ 415,351,037	$ 0.07235	$ 430,093,709
Prorated and corrected basic service charge billings				$ (217,347)		$ (217,347)
Prorated and corrected energy billings				$ (2,982)		$ (3,226)
Low Emission Vehicle Rate						
Basic Service Charges	-		$ 8.50	$ -	$ 13.00	$ -
Energy, Period 1		-	$ 0.04904	$ -	$ 0.05078	$ -
Energy, Period 2		-	$ 0.07005	$ -	$ 0.07254	$ -
Energy, Period 3		-	$ 0.13315	$ -	$ 0.13788	$ -
Total Calculated at Base Rates				**$ 458,005,465**		**$ 495,446,293**
Correction Factor				1.000000000		1.000000000
Total After Application of Correction Factor				**$ 458,005,465**		**$ 495,446,293**
Fuel Clause Billings - proforma for rollin				$ 4,705,954		4,705,954
Adjustment to Reflect Year-End Customers				(710,225)		(768,284)
Adjustment to Reflect Customers Moving To Rate				24,287		
Customer-Months Moving To Rate	618				$ 13.00	8,034
Energy Usage by Customers Moving to Rate		273,592	443		$ 0.07235	19,794
Adjustment to Reflect Customers Moving From Rate				(55,178)		
Customer-Months Moving From Rate	(533)				$ 13.00	(6,929)
Energy Usage by Customers Moving From Rate		(728,030)	1,366		$ 0.07235	(52,673)
Adjustment to Reflect Removal of Base ECR Revenues				(56,592,842)		(1,783,388)
Adjustment to Reflect Elimination of ECR Plans				54,809,454		-
Total Base Revenues Net of ECR				**$ 460,186,915**		**$ 497,568,801**
ECR Base Revenues				$ 1,783,388		$ 1,783,388
ECR Billings - proforma for rollin				$ 3,624,607		$ 3,624,607
Total Base Revenues Inclusive of ECR				**$ 465,594,910**		**$ 502,976,796**
Proposed Increase						**37,381,886**
Percentage Increase						8.03%

KENTUCKY UTILITIES COMPANY
Calculations of Proposed Rate Increase
Based on Sales for the 12 Months Ended March 31, 2012

(1)	(2)	(3)	(4)	(5)	(6)	(7)
	Bills	Total kWh	Present Rates	Calculated Revenue at Present Rates	Proposed Rates	Calculated Revenue at Proposed Rates
GENERAL SERVICE RATE GS						
Single Phase Customer Charge	779,541		$ 17.50	$ 13,641,968	$ 20.00	$ 15,590,820
Three Phase Customer Charge	204,452		$ 32.50	$ 6,644,690	$ 35.00	$ 7,155,820
All Energy		1,943,096,458	$ 0.08332	$ 161,898,797	$ 0.08678	168,621,911
Prorated and corrected basic service charge billings				$ 3,312		$ 3,714
Prorated and corrected energy billings				(30,309)		(31,568)
Total Calculated at Base Rates				**$ 182,158,458**		**$ 191,340,697**
Correction Factor				1.000000000		1.000000000
Total After Application of Correction Factor				**$ 182,158,458**		**$ 191,340,697**
Fuel Clause Billings - proforma for rollin				$ 1,757,425		$ 1,757,425
Adjustment to Reflect Year-End Customers				$ 42,721		$ 44,874
Adjustment to Reflect Customers Moving To Rate				$ 652,512		
Customer-Months Moving To Rate (single phase)	1,570				$ 20.00	$ 31,400
Energy Usage by Customers Moving to Rate		7,542,362			$ 0.08678	$ 654,526
Adjustment to Reflect Customers Moving From Rate				$ (2,299,904)		
Customer-Months Moving From Rate (single phase)	(1,252)				$ 20.00	$ (25,040)
Energy Usage by Customers Moving From Rate		(27,488,767)			$ 0.08678	$ (2,385,475)
Adjustment to Reflect Customers Moving To Rate				$ 1,683,462		
Customer-Months Moving To Rate (3 phase)	2,108				$ 35.00	$ 73,780
Energy Usage by Customers Moving to Rate		19,869,353			$ 0.08678	$ 1,724,262
Adjustment to Reflect Customers Moving From Rate				$ (3,383,024)		
Customer-Months Moving From Rate (3 phase)	(1,199)				$ 35.00	$ (41,965)
Energy Usage by Customers Moving From Rate		(40,350,688)			$ 0.08678	$ (3,501,633)
Adjustment to Reflect Removal of Base ECR Revenues				$ (27,494,815)		$ (874,394)
Adjustment to Reflect Elimination of ECR Plans				$ 26,620,421		$ -
Total Base Revenues Net of ECR				**$ 179,737,256**		**$ 188,798,457**
ECR Base Revenues				$ 874,394		$ 874,394
ECR Billings - proforma for rollin				$ 1,686,683		$ 1,686,683
Total Base Revenues Inclusive of ECR				**$ 182,298,333**		**$ 191,359,534**
Proposed Increase						**9,061,201**
						4.97%

KENTUCKY UTILITIES COMPANY
Calculations of Proposed Rate Increase
Based on Sales for the 12 Months Ended March 31, 2012

(1)	(2)	(3)	(4)	(5)	(6)	(7)
	Bills	Total kWh	Present Rates	Calculated Revenue at Present Rates	Proposed Rates	Calculated Revenue at Proposed Rates
ALL ELECTRIC SCHOOLS RATE AES						
Single Phase Customer Charge	4,564		$ 17.50	$ 79,870	$ 20.00	$ 91,280
Three Phase Customer Charge	3,131		$ 32.50	$ 101,759	$ 35.00	$ 109,585
All Energy		157,537,383	$ 0.06670	10,507,744	$ 0.07060	11,122,139
Prorated and corrected basic service charge billings				$ 392		$ 434
Prorated and corrected energy billings				(21,499)		(22,756)
Total Calculated at Base Rates				**$ 10,668,266**		**$ 11,300,682**
Correction Factor				1.000000000		1.000000000
Total After Application of Correction Factor				**$ 10,668,266**		**$ 11,300,682**
Fuel Clause Billings - proforma for rollin				$ 129,005		$ 129,005
Adjustment to Reflect Year-End Customers				$ 73,529		$ 77,888
Adjustment to Reflect Customers Moving To Rate				$ 412		
Customer-Months Moving To Rate (single phase)	3				$ 20.00	60
Energy Usage by Customers Moving to Rate		5,414			$ 0.07060	382
Adjustment to Reflect Customers Moving From Rate				$ (4,727)		
Customer-Months Moving From Rate (single phase)	(20)				$ 20.00	(400)
Energy Usage by Customers Moving From Rate		(65,871)			$ 0.07060	(4,650)
Adjustment to Reflect Customers Moving To Rate				$ 5,167		
Customer-Months Moving To Rate (3 phase)	2				$ 35.00	70
Energy Usage by Customers Moving to Rate		76,800			$ 0.07060	5,422
Adjustment to Reflect Customers Moving From Rate				$ (21,290)		
Customer-Months Moving From Rate (3 phase)	(6)				$ 35.00	(210)
Energy Usage by Customers Moving From Rate		(317,560)			$ 0.07060	(22,420)
Adjustment to Reflect Removal of Base ECR Revenues				(1,328,040)		(42,535)
Adjustment to Reflect Elimination of ECR Plans				1,285,505		-
Total Base Revenues Net of ECR				**$ 10,807,827**		**$ 11,443,294**
ECR Base Revenues				$ 42,535		42,535
ECR Billings - proforma for rollin				$ 80,784		$ 80,784
Total Base Revenues Inclusive of ECR				**$ 10,931,146**		**$ 11,566,613**
Proposed Increase						**635,467**
						5.81%

KENTUCKY UTILITIES COMPANY
Calculations of Proposed Rate Increase
Based on Sales for the 12 Months Ended March 31, 2012

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
	Customer Bills	Demand kW	Total kWh	Present Rates	Calculated Revenue at Present Rates	Proposed Rates	Calculated Revenue at Proposed Rates
POWER SERVICE RATE PS-Secondary							
Basic Service Charges	69,085			$ 90.00	$ 6,217,650	$ 90.00	$ 6,217,650
All Energy			3,069,778,185	$ 0.03300	$ 101,302,680	$ 0.03349	$ 102,806,871
Summer Demand		3,497,460		$ 13.90	$ 48,614,700	$ 14.40	$ 50,363,430
Winter Demand		4,459,854		$ 11.65	$ 51,957,297	$ 12.10	$ 53,964,231
Minimum kW and charges		958,166			$ 12,011,703		$ 12,460,256
Redundant Capacity Charges		2,025		$ 0.85	$ 1,721	$ 1.55	$ 3,139
Power factor adjustment charges					$ 1,493,329		$ 1,549,094
Prorated and corrected basic service charge billings					$ 1,642		$ 1,642
Prorated and corrected energy billings					$ 14,678		$ 14,896
Prorated and corrected demand charges					$ (218,647)		$ (226,812)
Total Calculated at Base Rates					**$ 221,396,753**		**$ 227,154,397**
Correction Factor					1.000000000		1.000000000
Total After Application of Correction Factor					**$ 221,396,753**		**$ 227,154,397**
Fuel Clause Billings - proforma for rollin					$ 2,893,212		$ 2,893,212
Adjustment to Reflect Year-End Customers					$ (1,562,556)		$ (1,603,192)
Adjustment to Reflect Rate Switching to Rate PS-Secondary					$ 3,990,897		
Customer-months Moving to Rate	1,722					$ 90.00	$ 154,980
Energy Use Moving to Rate			50,973,404			$ 0.03349	$ 1,707,099
Summer Demand for Customers Moving to Rate		95,095				$ 14.40	$ 1,369,368
Winter Demand for Customers Moving to Rate		73,247				$ 12.10	$ 886,289
Adjustment to Reflect Rate Switching From Rate PS-Secondary					$ (5,344,560)		
Customer-months Moving From Rate	(3,211)					$ 90.00	$ (288,990)
Energy Use Moving From Rate			(57,942,151)			$ 0.03349	$ (1,940,483)
Summer Demand for Customers Moving From Rate		(238,106)				$ 14.40	$ (3,428,726)
Winter Demand for Customers Moving From Rate		(94,960)				$ 12.10	$ (1,149,016)
Adjustment to Reflect Removal of Base ECR Revenues					(27,054,868)		$ (875,305)
Adjustment to Reflect Elimination of ECR Plans					$ 26,179,563		$ -
Total Base Revenues Net of ECR					**$ 220,498,441**		**$ 224,879,633**
ECR Base Revenues					$ 875,305		$ 875,305
ECR Billings - proforma for rollin					$ 1,791,384		$ 1,791,384
Total Base Revenues Inclusive of ECR					**$ 223,165,130**		**$ 227,546,322**
Proposed Increase							**4,381,192**
Percentage Increase							1.96%

KENTUCKY UTILITIES COMPANY
Calculations of Proposed Rate Increase
Based on Sales for the 12 Months Ended March 31, 2012

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
	Customer Bills	Demand kW	Total kWh	Present Rates	Calculated Revenue at Present Rates	Proposed Rates	Calculated Revenue at Proposed Rates
POWER SERVICE RATE PS-Primary							
Basic Service Charges	3,743			$ 90.00	$ 336,870	$ 125.00	$ 467,875
All Energy			802,429,053	$ 0.03300	$ 26,480,159	$ 0.03349	$ 26,873,349
Summer Demand		845,807		$ 13.72	$ 11,604,476	$ 14.75	$ 12,475,657
Winter Demand		985,114		$ 11.45	$ 11,279,551	$ 12.73	$ 12,540,497
Minimum kW and charges		35,640			$ 1,104,290		$ 1,207,178
Redundant Capacity Rider		51,285		$ 0.68	$ 34,874	$ 0.99	$ 50,772
Power factor adjustment charges					$ 429,197		$ 429,197
Prorated and corrected basic service charge billings					$ (1,126)		$ (1,564)
Prorated and corrected energy billings					$ 5,659		$ 5,743
Prorated and corrected demand charges					$ (49,401)		$ (49,401)
Total Calculated at Base Rates					**$ 51,224,549**		**$ 53,999,302**
Correction Factor					1.0000000000		1.0000000000
Total After Application of Correction Factor					**$ 51,224,549**		**$ 53,999,302**
Fuel Clause Billings - proforma for rollin					$ 759,739		$ 759,739
Adjustment to Reflect Year-End Customers					$ 171,787		$ 181,092
Adjustment to Reflect Rate Switching to Rate PS-Primary					$ 335,827		
Customer-months Moving to Rate	11					$ 125.00	$ 1,375
Energy Use Moving to Rate			5,497,600			$ 0.03349	$ 184,115
Summer Demand for Customers Moving to Rate		6,690				$ 14.75	$ 98,678
Winter Demand for Customers Moving to Rate		5,452				$ 12.73	$ 69,404
Adjustment to Reflect Rate Switching From Rate PS-Primary					$ (5,722,036)		
Customer-months Moving to Rate	(210)					$ 125.00	$ (26,250)
Energy Use Moving to Rate			(84,756,887)			$ 0.03349	$ (2,838,508)
Summer Demand for Customers Moving From Rate		(136,239)				$ 14.75	$ (2,009,525)
Winter Demand for Customers Moving From Rate		(92,754)				$ 12.73	$ (1,180,758)
Adjustment to Reflect Removal of Base ECR Revenues					$ (6,225,132)		$ (201,402)
Adjustment to Reflect Elimination of ECR Plans					$ 6,023,730		$ -
Total Base Revenues Net of ECR					**$ 46,568,464**		**$ 49,037,261**
ECR Base Revenues					$ 201,402		$ 201,402
ECR Billings - proforma for rollin					$ 445,709		$ 445,709
Total Base Revenues Inclusive of ECR					**$ 47,215,575**		**$ 49,684,372**
Proposed Increase							**2,468,797**
Percentage Increase							5.23%

KENTUCKY UTILITIES COMPANY
Calculations of Proposed Rate Increase
Based on Sales for the 12 Months Ended March 31, 2012

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
	Customer Bills Metered kVA	Minimum Demands, kVA	Total kWh	Present Rates	Calculated Revenue at Present Rates	Proposed Rates	Calculated Revenue at Proposed Rates
TIME OF DAY SECONDARY SERVICE RATE TODS							
Basic Service Charges	1,429			$ 200.00	$ 285,800	$ 200.00	$ 285,800
All Energy			413,123,136	$ 0.03490	14,417,998	$ 0.03590	14,831,121
Demand Base	831,431	88,313		$ 3.05	$ 2,535,863	$ 3.50	2,910,007
Demand Intermediate	831,643	4,385		$ 2.43	$ 2,020,892	$ 2.80	2,328,600
Demand Peak	815,180	4,566		$ 3.89	$ 3,171,050	$ 4.50	3,668,309
Minimum demand billings					$ 297,770		343,204
Redundant Capacity Rider	36,631			$ 0.85	$ 31,136	$ 1.55	56,778
Power Factor Correction Charges					$ 121,926		140,530
Prorated and corrected basic service charge billings					$ (1,311)		(1,311)
Prorated and corrected energy billings					508		523
Prorated and corrected demand billings					$ 8,259		9,519
			Total Calculated at Base Rates		**$ 22,889,891**		**$ 24,573,080**
			Correction Factor		1.000000000		1.000000000
			Total After Application of Correction Factor		**$ 22,889,891**		**$ 24,573,080**
Fuel Clause Billings - proforma for rollin					$ 3,264,159		3,264,159
Adjustment to Reflect Year-End Customers					$ 116,378		124,936
Adjustment to Reflect Rate Switching to Rate TOD-Secondary					$ 2,518,028		
Customer-months Moving to Rate	214					$ 200.00	$ 42,800
Energy Use Moving to Rate			40,279,476			$ 0.03590	$ 1,446,033
Base Demand for Customers Moving to Rate	115,245					$ 3.50	$ 403,358
Intermediate Demand for Customers Moving to Rate	115,245					$ 2.80	$ 322,686
Peak Demand for Customers Moving to Rate	115,245					$ 4.50	$ 518,603
Adjustment to Reflect Removal of Base ECR Revenues					(2,577,384)		(74,347)
Adjustment to Reflect Elimination of ECR Plans					2,503,037		-
Total Base Revenues Net of ECR					**$ 28,714,109**		**$ 30,621,307**
ECR Base Revenues					$ 74,347		$ 74,347
ECR Billings - proforma for rollin					$ 142,467		$ 142,467
Total Base Revenues Inclusive of Base ECR					**$ 28,930,923**		**$ 30,838,121**
Proposed Increase							**1,907,198**
	Percentage Increase						6.59%

KENTUCKY UTILITIES COMPANY

Calculations of Proposed Rate Increase

Based on Sales for the 12 Months Ended March 31, 2012

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
	Customer Bills Metered kVA	Minimum Demands, kVA	Total kWh	Present Rates	Calculated Revenue at Present Rates	Proposed Rates	Calculated Revenue at Proposed Rates
TIME OF DAY PRIMARY SERVICE RATE TODP							
Basic Service Charges	1,831			$ 300.00	$ 549,300	$ 300.00	$ 549,300
All Energy			3,552,305,513	$ 0.03522	$ 125,112,200	$ 0.03557	$ 126,355,507
Demand Base	8,110,339	259,295		$ 1.28	$ 10,381,235	$ 1.60	$ 12,976,542
Demand Intermediate	8,049,964	49,393		$ 2.31	$ 18,595,416	$ 2.70	$ 21,734,902
Demand Peak	7,923,350	49,057		$ 3.67	$ 29,078,693	$ 4.30	$ 34,070,403
Minimum demand biillings					$ 626,034		$ 741,702
Redundant Capcity Rider	42,074			$ 0.68	$ 28,610	$ 0.99	$ 41,653
Prorated and corrected basic service charge billings					$ (1,200)		$ (1,200)
Prorated and corrected energy billings					$ 41,617		$ 42,031
Prorated and corrected demand billings					$ (364,548)		$ (431,903)
			Total Calculated at Base Rates		**$ 184,047,357**		**$ 196,078,937**
			Correction Factor		1.000000000		1.000000000
			Total After Application of Correction Factor		**$ 184,047,357**		**$ 196,078,937**
Fuel Clause Billings - proforma for rollin					$ 371,304		$ 371,304
Adjustment to Reflect Year-End Customers					$ (1,816,142)		$ (1,934,867)
Adjustment to Reflect Rate Switching to Rate TOD-Primary					$ 4,955,272		
Customer-months Moving to Rate	181					$ 300.00	$ 54,300
Energy Use Moving to Rate			89,104,930			$ 0.03557	$ 3,169,462
Base Demand for Customers Moving to Rate	254,513					$ 1.60	$ 407,220
Intermediate Demand for Customers Moving to Rate	254,513					$ 2.70	$ 687,185
Peak Demand for Customers Moving to Rate	254,513					$ 4.30	$ 1,094,405
Adjustment to Reflect Customers Moved to Billing Cycle 20 - see Conroy Exhibit P6					$ (1,640,196)		
Customer-months Adjusted From Test Year Results	(2)					$ 300.00	$ (600)
Energy Use Adjusted From Test Year Results			(30,038,040)			$ 0.03557	$ (1,068,453)
Base Demand Adjusted From Test Year Results	(67,693)					$ 1.60	$ (108,309)
Intermediate Demand Adjusted From Test Year Results	(64,625)					$ 2.70	$ (174,488)
Peak Demand Adjusted From Test Year Results	(64,625)					$ 4.30	$ (277,889)
Adjustment to Reflect Removal of Base ECR Revenues					$ (19,026,087)		$ (722,510)
Adjustment to Reflect Elimination of ECR Plans					$ 18,303,577		$ -
Total Base Revenues Net of ECR					**$ 185,195,086**		**$ 197,575,697**
ECR Base Revenues					$ 722,510		$ 722,510
ECR Billings - proforma for rollin					$ 1,064,717		$ 1,064,717
Total Base Revenues Inclusive of Base ECR					**$ 186,982,312**		**$ 199,362,924**
Proposed Increase							**12,380,611**
	Percentage Increase						6.62%

KENTUCKY UTILITIES COMPANY
Calculations of Proposed Rate Increase
Based on Sales for the 12 Months Ended March 31, 2012

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
	Customer Bills Metered kVA	Minimum Demands, kVA	Total kWh	Present Rates	Calculated Revenue at Present Rates	Proposed Rates	Calculated Revenue at Proposed Rates
RETAIL TRANSMISSION SERVICE RATE RTS							
Basic Service Charges	432			$ 500.00	$ 216,000	$ 750.00	$ 324,000
All Energy			1,608,310,112	$ 0.03414	$ 54,907,707	$ 0.03408	$ 54,811,209
Demand Base	3,742,566	96,043		$ 0.85	$ 3,181,181	$ 1.30	$ 4,865,336
Demand Intermediate	3,689,806	8,942		$ 2.30	$ 8,486,554	$ 2.90	$ 10,700,437
Demand Peak	3,647,205	8,989		$ 3.54	$ 12,911,106	$ 3.90	$ 14,224,100
Minimum Demand Billings					$ 134,022		$ 162,436
Prorated and corrected basic service charge billings					$ (3,167)		$ (4,751)
Prorated and corrected energy billings					-		$ -
Prorated and Corrected Demand Billings					$ 52,641		$ 63,802
Total Calculated at Base Rates					**$ 79,886,044**		**$ 85,146,569**
Correction Factor					1.000000000		1.000000000
Total After Application of Correction Factor					**$ 79,886,044**		**$ 85,146,569**
Fuel Clause Billings - proforma for rollin					$ 1,400,173		$ 1,400,173
Adjustment to Reflect Year-End Customers					$ 166,983		$ 177,979
Adjustment to Reflect Customers Moving From Rate RTS					$ (116,695)		$ (116,695)
Customer-months Moving From Rate	(1)					$ 750.00	$ (750)
Energy Use Moving From Rate			(1,973,830)			$ 0.03408	$ (67,268)
Base Demand for Customers Moving From Rate	(4,335)					$ 1.30	$ (5,635)
Intermediate Demand for Customers Moving From Rate	(4,335)					$ 2.90	$ (12,570)
Peak Demand for Customers Moving From Rate	(4,335)					$ 3.90	$ (16,905)
Adjustment to Reflect Customers Moved to Billing Cycle 20					$ (2,832,550)		
Customer-months Adjusted From Test Year Results	(3)					$ 750.00	$ (2,250)
Energy Use Adjusted From Test Year Results			(58,030,000)			$ 0.03408	$ (1,977,662)
Base Demand Adjusted From Test Year Results	(110,508)					$ 1.30	$ (143,660)
Intermediate Demand Adjusted From Test Year Results	(110,203)					$ 2.90	$ (319,588)
Peak Demand Adjusted From Test Year Results	(110,099)					$ 3.90	$ (429,385)
Adjustment to Reflect Removal of Base ECR Revenues					$ (7,866,500)		$ (221,591)
Adjustment to Reflect Elimination of ECR Plans					$ 7,644,909		$ -
Total Base Revenues Net of ECR					**$ 78,282,364**		**$ 83,410,762**
ECR Base Revenues					$ 221,591		$ 221,591
ECR Billings - proforma for rollin					$ 448,130		$ 448,130
Total Base Revenues Inclusive of Base ECR					**$ 78,952,085**		**$ 84,080,483**
Proposed Increase							**5,128,398**
Percentage Increase							6.50%

KENTUCKY UTILITIES COMPANY
Calculations of Proposed Rate Increase
Based on Sales for the 12 Months Ended March 31, 2012

(1)	(2)		(3)	(4)	(5)	(6)	(7)
	Customer Bills Metered kVA	Minimum Demands, kVA	Total kWh	Present Rates	Calculated Revenue at Present Rates	Proposed Rates	Calculated Revenue at Proposed Rates
FLUCTUATING LOAD SERVICE RATE FLS							
Primary Delivery							
Basic Service Charges	-			$ 500.00	$ -	$ 750.00	$ -
All Energy			-	$ 0.03419	$ -	$ 0.03419	-
Demand Base (5-minute kVa)	-			$ 1.57	$ -	$ 1.75	$ -
Demand Intermediate (5-minute kVa)	-			$ 1.41	$ -	$ 1.44	$ -
Demand Peak (5-minute kVa)	-			$ 2.30	$ -	$ 2.40	$ -
Transmission Delivery							
Basic Service Charges	12			$ 500.00	$ 6,000	$ 750.00	$ 9,000
All Energy			546,287,246	$ 0.02947	$ 16,099,085	$ 0.03092	16,891,202
Demand Base (5-minute kVa)	2,347,234			$ 0.82	$ 1,924,732	$ 1.00	$ 2,347,234
Demand Intermediate (5-minute kVa)	2,304,105			$ 1.41	$ 3,248,788	$ 1.44	$ 3,317,911
Demand Peak (5-minute kVa)	1,227,450			$ 2.30	$ 2,823,135	$ 2.40	$ 2,945,880
Prorated and corrected basic service charge billings					$ 500		$ -
			Total Calculated at Base Rates		**$ 24,102,240**		**$ 25,511,227**
			Correction Factor		1.000000000		1.000000000
			Total After Application of Correction Factor		**$ 24,102,240**		**$ 25,511,227**
Fuel Clause Billings - proforma for rollin					$ 475,259		$ 475,259
Adjustment to Reflect Year-End Customers					$ -		$ -
Adjustment to Reflect Customers Moved to Billing Cycle 20					$ (2,008,648)		
Customer-months Adjusted From Test Year Results						$ 750.00	$ -
Energy Use Adjusted From Test Year Results			(43,416,000)			$ 0.03092	$ (1,342,423)
Base Demand Adjusted From Test Year Results	(177,320)					$ 1.00	$ (177,320)
Intermediate Demand Adjusted From Test Year Results	(177,320)					$ 1.44	$ (255,341)
Peak Demand Adjusted From Test Year Results	(93,581)					$ 2.40	$ (224,595)
Adjustment to Reflect Removal of Base ECR Revenues					$ (2,469,091)		$ (58,788)
Adjustment to Reflect Elimination of ECR Plans					$ 2,410,303		$ -
Total Base Revenues Net of ECR					**$ 22,510,063**		**$ 23,928,019**
ECR Base Revenues					$ 58,788		$ 58,788
ECR Billings - proforma for rollin					$ 110,713		$ 110,713
Total Base Revenues Inclusive of Base ECR					**$ 22,679,564**		**$ 24,097,520**
Proposed Increase							**$ 1,417,956**
	Percentage Increase						6.25%

KENTUCKY UTILITIES COMPANY
Calculations of Proposed Rate Increase
Based on Sales for the 12 Months Ended March 31, 2012

(1)	(2)	(3)	(4)	(5)	(6)	(7)
	Bills	Total kWh	Present Rates	Calculated Revenue at Present Rates	Proposed Rates	Calculated Revenue at Proposed Rates
LIGHTING ENERGY SERVICE RATE LE						
Basic Service Charges	11		$ -	$ -	$ -	$ -
All Energy		40,050	$ 0.05647	$ 2,262	$ 0.05958	$ 2,386
Prorated and corrected energy billings				(7)		(7)
Total Calculated at Base Rates				**$ 2,255**		**$ 2,379**
Correction Factor				1.000000000		1.000000000
Total After Application of Correction Factor				**$ 2,255**		**$ 2,379**
Fuel Clause Billings - proforma for rollin				$ 27		$ 27
Adjustment to Reflect Year-End Customers				$ -		$ -
Adjustment to Reflect Removal of Base ECR Revenues				$ (381)		$ (119)
Adjustment to Reflect Elimination of ECR Plans				$ 262		$ -
Total Base Revenues Net of ECR				**$ 2,163**		**$ 2,287**
ECR Base Revenues				$ 119		$ 119
ECR Billings - proforma for rollin				$ 7		$ 7
Total Base Revenues Inclusive of Base ECR				**$ 2,289**		**$ 2,413**
Proposed Increase						**124**
Percentage Increase						5.42%

KENTUCKY UTILITIES COMPANY
Calculations of Proposed Rate Increase
Based on Sales for the 12 Months Ended March 31, 2012

(1)	(2)	(3)	(4)	(5)	(6)	(7)
	Bills	Total kWh	Present Rates	Calculated Revenue at Present Rates	Proposed Rates	Calculated Revenue at Proposed Rates
TRAFFIC ENERGY SERVICE RATE TE						
Basic Service Charges	8,086		$ 3.14	$ 25,390	$ 3.25	$ 26,280
All Energy		1,118,667	$ 0.07182	$ 80,343	$ 0.07614	$ 85,175
Prorated and corrected basic service charge billings				$ (65)		$ (67)
Prorated and corrected energy billings				$ (103)		$ (109)
Total Calculated at Base Rates				**$ 105,565**		**$ 111,279**
Correction Factor				1.000000000		1.000000000
Total After Application of Correction Factor				**$ 105,565**		**$ 111,279**
Fuel Clause Billings - proforma for rollin				$ 938		$ 938
Adjustment to Reflect Year-End Customers				$ 11,068		$ 11,667
Adjustment to Reflect Customers Moving To Rate TE				$ 70		$ 70
Customer-months Moving To Rate	3				$ 3.25	$ 10
Energy Use Moving To Rate		853			$ 0.07614	$ 65
Adjustment to Reflect Removal of Base ECR Revenues				$ (10,650)		$ (3,334)
Adjustment to Reflect Elimination of ECR Plans				$ 7,316		$ -
Total Base Revenues Net of ECR				**$ 114,307**		**$ 120,695**
ECR Base Revenues				$ 3,334		$ 3,334
ECR Billings - proforma for rollin				$ 682		$ 682
Total Base Revenues Inclusive of Base ECR				**$ 118,323**		**$ 124,711**
Proposed Increase						**6,388**
	Percentage Increase					5.40%

KENTUCKY UTILITIES COMPANY
Calculations of Proposed Rate Increase
Based on Sales for the 12 Months Ended March 31, 2012

(1)	(2) Existing Tariff Sheet	(3) Existing Bill Code	(4) Total Lights	(5) Present Rates	(6) Calculated Revenue at Present Rates	(7) Proposed Bill Code	(8) Total Lights	(9) Proposed Rates	(10) Calculated Revenue at Proposed Rates
LIGHTING SERVICE -- PROPOSED RATE SHEET No. 35									
Overhead									
High Pressure Sodium									
Cobra Head, 5800 Lumen, Standard						462	**105,260**	**$ 8.33**	**$ 876,816**
5,800 Lumen HPS Std RC-462	St.Lt. 35	462	105,260	$ 7.90	$ 831,554				
Cobra Head, 5800 Lumen, Ornamental						472	**103,056**	**$ 11.32**	**$ 1,166,594**
5,800 Lumen HPS Ormtl	St.Lt. 35	472	103,056	$ 10.73	$ 1,105,791				
Cobra Head, 9500 Lumen, Standard						463	**242,538**	**$ 8.87**	**$ 2,151,312**
9,500 Lumen HPS Std	St.Lt. 35	463	242,538	$ 8.41	$ 2,039,745				
Cobra Head, 9500 Lumen, Ornamental						473	**38,154**	**$ 12.08**	**$ 460,900**
9,500 Lumen HPS Ormtl RC-473	St.Lt. 35	473	38,154	$ 11.45	$ 436,863				
Cobra Head, 22000 Lumen, Standard						464	**88,957**	**$ 13.75**	**$ 1,223,159**
22,000 Lumen HPS Std	St.Lt. 35	464	70,265	$ 13.04	$ 916,256				
22,000L Cobra Head HPS Std	P.O.L. 36	429	18,692	$ 13.04	$ 243,744				
Cobra Head, 22000 Lumen, Ornamental						474	**59,607**	**$ 16.96**	**$ 1,010,935**
22,000 Lumen HPS Ormtl RC-474	St.Lt. 35	474	59,607	$ 16.08	$ 958,481				
Cobra Head, 50000 Lumen, Standard						465	**34,927**	**$ 22.10**	**$ 771,887**
50,000 Lumen HPS Std	St.Lt. 35	465	10,551	$ 20.95	$ 221,043				
50,000L Cobra Head HPS Std RC-407	P.O.L. 36	407	24,376	$ 20.95	$ 510,677				
Cobra Head, 50000 Lumen, Ornamental						475	**5,692**	**$ 23.74**	**$ 135,128**
50,000 Lumen HPS Ormtl RC-475	St.Lt. 35	475	5,692	$ 22.51	$ 128,127				
Directional, 9500 Lumen, Standard						487	**129,370**	**$ 8.72**	**$ 1,128,106**
9,500L Directional HPS RC-487	P.O.L. 36	487	129,370	$ 8.27	$ 1,069,890				
Directional, 22000 Lumen, Standard						488	**77,504**	**$ 13.13**	**$ 1,017,628**
22,000L Directional HPS RC-488	P.O.L. 36	488	77,504	$ 12.45	$ 964,925				
Directional, 50000 Lumen, Standard						489	**95,361**	**$ 18.67**	**$ 1,780,390**
50,000L Directional HPS RC-489	P.O.L. 36	489	95,361	$ 17.70	$ 1,687,890				
Open Bottom, 9500 Lumen, Standard						428	**427,622**	**$ 7.55**	**$ 3,228,546**
9,500L Open Bottom HPS Std RC-428	P.O.L. 36	428	427,622	$ 7.16	$ 3,061,774				
Metal Halide									
Directional, 12000 Lumen, Standard						450	**7,229**	**$ 13.75**	**$ 99,399**
12,000L Fixture Only Dir-MH RC-450	P.O.L. 36.3	450	7,229	$ 13.04	$ 94,266				
Directional, 32000 Lumen, Standard						451	**55,410**	**$ 19.46**	**$ 1,078,279**
32,000L Fixture Only Dir-MH RC-451	P.O.L. 36.3	451	55,410	$ 18.45	$ 1,022,315				
Directional, 107800 Lumen, Standard						452	**12,447**	**$ 40.58**	**$ 505,099**
107,800L Fixture Only Dir-MH	P.O.L. 36.3	452	12,447	$ 38.48	$ 478,961				

KENTUCKY UTILITIES COMPANY
Calculations of Proposed Rate Increase
Based on Sales for the 12 Months Ended March 31, 2012

(1)	(2) Existing Tariff Sheet	(3) Existing Bill Code	(4) Total Lights	(5) Present Rates	(6) Calculated Revenue at Present Rates	(7) Proposed Bill Code	(8) Total Lights	(9) Proposed Rates	(10) Calculated Revenue at Proposed Rates
LIGHTING SERVICE, CONTINUED									
Underground									
High Pressure Sodium									
Colonial, 5800 Lumen, Decorative						467	**15,454**	**$ 10.47**	**$ 161,803**
5,800L Colonial HPS UG RC-467	St.Lt. 35.1	467	13,508	$ 9.93	$ 134,134				
5,800L Colonial Decor UG RC-481	P.O.L. 36.1	481	1,946	$ 9.93	$ 19,324				
Colonial, 9500 Lumen, Decorative						468	**44,225**	**$ 10.92**	**$ 482,937**
9,500L Colonial HPS UG RC-468	St.Lt. 35.1	468	23,395	$ 10.35	$ 242,138				
9,500L Colonial Decor UG RC-482	P.O.L. 36.1	482	20,830	$ 10.35	$ 215,591				
Acorn, 5800 Lumen, Smooth Pole						401	**624**	**$ 14.62**	**$ 9,123**
5,800L Acorn (D Pole) HPS UG	St.Lt. 35.1	401	420	$ 13.86	$ 5,821				
5,800L Acorn (Decorative Pole) UG RC-441	P.O.L. 36.1	441	204	$ 13.86	$ 2,827				
Acorn, 5800 Lumen, Fluted Pole						411	**1,752**	**$ 21.24**	**$ 37,212**
5,800L Acorn (Hist Pole) HPS UG	St.Lt. 35.1	411	864	$ 20.14	$ 17,401				
5,800L Acorn (Historic Pole) UG RC-445	P.O.L. 36.1	445	888	$ 20.14	$ 17,884				
Acorn, 9500 Lumen, Smooth Pole						420	**4,993**	**$ 15.18**	**$ 75,794**
9,500L Acorn (D Pole) HPS UG RC-420	St.Lt. 35.1	420	2,275	$ 14.39	$ 32,737				
9,500L Acorn (Decorative Pole) UG RC-442	P.O.L. 36.1	442	2,718	$ 14.39	$ 39,112				
Acorn, 9500 Lumen, Fluted Pole						430	**12,932**	**$ 21.92**	**$ 283,469**
9,500L Acorn (Hist Pole) HPS UG	St.Lt. 35.1	430	5,292	$ 20.78	$ 109,968				
9,500L Acorn (Historic Pole) UG RC-449	P.O.L. 36.1	449	7,640	$ 20.78	$ 158,759				
Victorian, 5800 Lumen, Fluted Pole						414	**252**	**$ 30.84**	**$ 7,772**
5,800L Coach HPS UG	P.O.L. 36.1	414	252	$ 29.24	$ 7,368				
Victorian, 9500 Lumen, Fluted Pole						415	**120**	**$ 31.27**	**$ 3,752**
9,500L Coach HPS UG RC-415	P.O.L. 36.1	415	120	$ 29.65	$ 3,558				
Contemporary Fixture and Pole, 5800 Lumen, Second Fixture						492	**6**	**$ 15.13**	**$ 91**
5,800L UG HPS Contemporary Fixture Only	P.O.L. 36.1	492	6	$ 14.35	$ 86				
Contemporary Fixture and Pole, 5800 Lumen						476	**54,631**	**$ 16.58**	**$ 905,782**
5,800L UG HPS Contemporary	St.Lt. 35.1	476	54,099	$ 15.66	$ 847,190				
5,800L Contemporary HPS UG RC-476	P.O.L. 36.1	483	532	$ 21.81	$ 11,603				
Contemporary Fixture and Pole, 9500 Lumen, Second Fixture						497	**-**	**$ 15.17**	**$ -**
9,500L Contemp Decor UG Fixture Only	P.O.L. 36.1	497	-	$ 14.38	$ -				
Contemporary Fixture and Pole, 9500 Lumen						477	**11,878**	**$ 20.87**	**$ 247,894**
9,500L Contemp Decor UG RC-484	St.Lt. 35.1	477	6,688	$ 18.19	$ 121,655				
9,500L Contemporary HPS UG RC-477	P.O.L. 36.1	484	5,190	$ 21.85	$ 113,402				
Contemporary Fixture and Pole, 22000 Lumen, Second Fixture						498	**78**	**$ 17.27**	**$ 1,347**
22,000L UG HPS Contemporary (Add Fixture	P.O.L. 36.1	498	78	$ 16.37	$ 1,277				
Contemporary Fixture and Pole, 22000 Lumen						478	**16,443**	**$ 26.55**	**$ 436,562**
22,000L Contemp Decor UG RC-485	St.Lt. 35.1	478	7,666	$ 22.11	$ 169,495				
22,000L Contemporary HPS UG RC-478	P.O.L. 36.1	485	8,777	$ 27.84	$ 244,352				
Contemporary Fixture and Pole, 50000 Lumen, Second Fixture						499	**21**	**$ 20.72**	**$ 435**
50,000L Contemp Decor UG Fixture Only	P.O.L. 36.1	499	21	$ 19.65	$ 413				
Contemporary Fixture and Pole, 50000 Lumen						479	**11,124**	**$ 32.54**	**$ 361,975**
50,000L Contemp Decor UG RC-486	St.Lt. 35.1	479	1,012	$ 28.13	$ 28,468				
50,000L Contemporary HPS UG RC-479	P.O.L. 36.1	486	10,112	$ 31.12	$ 314,685				

KENTUCKY UTILITIES COMPANY
Calculations of Proposed Rate Increase
Based on Sales for the 12 Months Ended March 31, 2012

(1)	(2) Existing Tariff Sheet	(3) Existing Bill Code	(4) Total Lights	(5) Present Rates	(6) Calculated Revenue at Present Rates	(7) Proposed Bill Code	(8) Total Lights	(9) Proposed Rates	(10) Calculated Revenue at Proposed Rates
LIGHTING SERVICE CONTINUED									
Dark Sky, 4000 Lumen						300	**4**	**$ 22.48**	**$ 90**
4,000L HPS DSK Lantern	DSK 39	300	4	$ 21.31	$ 85				
Dark Sky, 9500 Lumen						301	**-**	**$ 23.44**	**$ -**
9,500L HPS DSK Lantern	DSK 39	301	-	$ 22.22	$ -				
Granville Lights									
Pole and Fixture						360	**4,732**	**$ 53.79**	**$ 254,534**
Pole and Fixture	St.Lt. 35.1	360	4,644	$ 51.00	$ 236,844				
	P.O.L. 36.2		88	$ 51.00	$ 4,488				
Granville Accessories									
Single Crossarm Bracket	St.Lt. 35.1		-	$ 17.78	$ -		**eliminated**		
Twin Crossarm Bracket (includes 1 fixtu	St.Lt. 35.1		370	$ 19.79	$ 7,322		**370**	**$ 20.87**	**$ 7,722**
24 Inch Banner Arm	St.Lt. 35.1		288	$ 3.09	$ 890		**288**	**$ 3.26**	**$ 939**
24 Inch Clamp Banner Arm	St.Lt. 35.1		1,224	$ 4.26	$ 5,214		**1,224**	**$ 4.49**	**$ 5,496**
18 Inch Banner Arm	St.Lt. 35.1		1,248	$ 2.84	$ 3,544		**1,248**	**$ 3.00**	**$ 3,744**
18 Inch Clamp On Banner Arm	St.Lt. 35.1		-	$ 3.52	$ -		**-**	**$ 3.71**	**$ -**
Flagpole Holder	St.Lt. 35.1		432	$ 1.31	$ 566		**432**	**$ 1.38**	**$ 596**
Post-Mounted Receptacle	St.Lt. 35.1		684	$ 18.46	$ 12,627		**684**	**$ 19.47**	**$ 13,317**
Base-Mounted Receptacle	St.Lt. 35.1		-	$ 17.81	$ -		**eliminated**		
Additional Receptacles	St.Lt. 35.1		-	$ 2.52	$ -		**-**	**$ 2.66**	**$ -**
Planter	St.Lt. 35.1		648	$ 4.28	$ 2,773		**648**	**$ 4.51**	**$ 2,922**
Clamp On Planter	St.Lt. 35.1		-	$ 4.75	$ -		**-**	**$ 5.01**	**$ -**
Metal Halide									
Contemporary, 12000 Lumen, Fixture Only						490	**696**	**$ 14.99**	**$ 10,433**
12,000L Fixture Only Cont-MH RC-490	P.O.L. 36.3	490	696	$ 14.21	$ 9,890				
Contemporary, 12000 Lumen, Fixture with Smooth Pole						494	**2,573**	**$ 28.08**	**$ 72,250**
12,000L Fix With M Pole Cont-MH	P.O.L. 36.3	494	2,573	$ 26.62	$ 68,493				
Contemporary, 32000 Lumen, Fixture Only						491	**3,552**	**$ 21.22**	**$ 75,373**
32,000L Fixture Only Cont-MH RC-491	P.O.L. 36.3	491	3,552	$ 20.12	$ 71,466				
Contemporary, 32000 Lumen, Fixture with Smooth Pole						495	**7,131**	**$ 34.31**	**$ 244,665**
32,000L Fix with M Pole Cont-MH RC-495	P.O.L. 36.3	495	7,131	$ 32.53	$ 231,971				
Contemporary, 107800 Lumen, Fixture Only						493	**588**	**$ 43.98**	**$ 25,860**
107,800L Fixture Only Cont-MH RC-493	P.O.L. 36.3	493	588	$ 41.70	$ 24,520				
Contemporary, 107800 Lumen, Fixture with Smooth Pole						496	**1,969**	**$ 57.07**	**$ 112,371**
107,800L Fix With M Pole Cont-MH	P.O.L. 36.3	496	1,969	$ 54.11	$ 106,543				

KENTUCKY UTILITIES COMPANY
Calculations of Proposed Rate Increase
Based on Sales for the 12 Months Ended March 31, 2012

(1)	(2) Existing Tariff Sheet	(3) Existing Bill Code	(4) Total Lights	(5) Present Rates	(6) Calculated Revenue at Present Rates	(7) Proposed Bill Code	(8) Total Lights	(9) Proposed Rates	(10) Calculated Revenue at Proposed Rates
RESTRICTED LIGHTING SERVICE -- PROPOSED RATE SHEET No. 36									
Overhead									
High Pressure Sodium									
Cobra Head, 4000 Lumen, Fixture Only						461	**83,571**	**$ 7.31**	**$ 610,904**
4,000 Lumen HPS Std RC-461	St.Lt. 35	461	83,571	$ 6.93	$ 579,147				
Cobra Head, 4000 Lumen, Fixture and Pole						471	**45,600**	**$ 10.29**	**$ 469,224**
4,000 Lumen HPS Ormtl RC-471	St.Lt. 35	471	45,600	$ 9.76	$ 445,056				
Cobra Head, 50000 Lumen, Fixture Only						409	**1,922**	**$ 10.81**	**$ 20,777**
50,000L HPS Special Lighting RC-409	P.O.L. 36	409	1,922	$ 10.25	$ 19,701				
Open Bottom, 5800 Lumen, Fixture Only						426	**2,481**	**$ 7.09**	**$ 17,590**
5,800L Open Bottom HPS Std RC-426	P.O.L. 36	426	2,481	$ 6.72	$ 16,672				
Metal Halide									
Directional, 12000 Lumen, Flood, Fixture with Pole						454	**1,787**	**$ 18.21**	**$ 32,541**
12,000L Fix with W Pole Dir-MH RC-454	P.O.L. 36.3	454	1,787	$ 17.27	$ 30,861				
Directional, 32000 Lumen, Flood, Fixture with Pole						455	**12,283**	**$ 23.92**	**$ 293,809**
32,000L Fix with W Pole Dir-MH	P.O.L. 36.3	455	12,283	$ 22.68	$ 278,578				
Directional, 107800 Lumen, Flood, Fixture with Pole						459	**3,104**	**$ 45.05**	**$ 139,835**
107,800L Fix With W Pole Dir-MH	P.O.L. 36.3	459	3,104	$ 42.71	$ 132,572				
Mercury Vapor									
Cobra Head, 7000 Lumen, Fixture Only						446	**13,737**	**$ 9.20**	**$ 126,380**
7,000 Lumen MV Std RC-446	St.Lt. 35	446	13,737	$ 8.72	$ 119,787				
Cobra Head, 7000 Lumen, Fixture and Pole						456	**1,692**	**$ 11.54**	**$ 19,526**
7,000 Lumen MV Ormtl	St.Lt. 35	456	1,692	$ 10.94	$ 18,510				
Cobra Head, 10000 Lumen, Fixture Only						447	**9,781**	**$ 10.85**	**$ 106,124**
10,000 Lumen MV Std	St.Lt. 35	447	9,781	$ 10.29	$ 100,646				
Cobra Head, 10000 Lumen, Fixture and Pole						457	**6,043**	**$ 12.93**	**$ 78,136**
10,000 Lumen MV Ormtl	St.Lt. 35	457	6,043	$ 12.26	$ 74,087				
Cobra Head, 20000 Lumen, Fixture Only						448	**21,685**	**$ 12.19**	**$ 264,340**
20,000 Lumen MV Std RC-448	St.Lt. 35	448	17,015	$ 12.57	$ 213,879				
20,000L MV Special Lighting RC-408	P.O.L. 36	408	4,670	$ 7.85	$ 36,660				
Cobra Head, 20000 Lumen, Fixture and Pole						458	**20,913**	**$ 14.49**	**$ 303,029**
20,000 Lumen MV Ormtl	St.Lt. 35	458	15,524	$ 14.14	$ 219,509				
20,000L Cobra Head M V Std RC-405	P.O.L. 36	405	5,389	$ 12.57	$ 67,740				
Open Bottom, 7000 Lumen, Fixture Only						404	**100,442**	**$ 10.22**	**$ 1,026,517**
7,000L Open Bottom M V Std RC-404	P.O.L. 36	404	100,442	$ 9.69	$ 973,283				
Incandescent									
Tear Drop, 1000 Lumen, Fixture Only						421	**192**	**$ 3.25**	**$ 624**
1,000 Lumen Incand Std	St.Lt. 35	421	192	$ 3.08	$ 591				
Tear Drop, 2500 Lumen, Fixture Only						422	**10,185**	**$ 4.31**	**$ 43,897**
2,500 Lumen Incand Std	St.Lt. 35	422	10,185	$ 4.09	$ 41,657				
Tear Drop, 4000 Lumen, Fixture Only						424	**3,026**	**$ 6.41**	**$ 19,397**
4,000 Lumen Incand Std RC-424	St.Lt. 35	424	3,026	$ 6.08	$ 18,398				
Tear Drop, 4000 Lumen, Fixture and Pole						434	**390**	**$ 7.38**	**$ 2,878**
4,000 Lumen Incand Ormtl	St.Lt. 35	434	390	$ 7.00	$ 2,730				
Tear Drop, 6000 Lumen, Fixture Only						425	**14**	**$ 8.55**	**$ 120**
6,000 Lumen Incand Std	St.Lt. 35	425	14	$ 8.11	$ 114				

KENTUCKY UTILITIES COMPANY
Calculations of Proposed Rate Increase
Based on Sales for the 12 Months Ended March 31, 2012

(1)	(2) Existing Tariff Sheet	(3) Existing Bill Code	(4) Total Lights	(5) Present Rates	(6) Calculated Revenue at Present Rates	(7) Proposed Bill Code	(8) Total Lights	(9) Proposed Rates	(10) Calculated Revenue at Proposed Rates
RESTRICTED LIGHTING SERVICE, CONTINUED									
Underground									
Metal Halide									
Directional, 12000 Lumen, Flood, Fixture with Pole						460	**300**	**$ 26.84**	**$ 8,052**
12,000L Fix With M Pole Dir-MH	P.O.L. 36.3	460	300	$ 25.45	$ 7,635				
Directional, 32000 Lumen, Flood, Fixture with Pole						469	**3,220**	**$ 32.55**	**$ 104,811**
32,000L Fix With M Pole Dir-MH	P.O.L. 36.3	469	3,220	$ 30.86	$ 99,369				
Directional, 107800 Lumen, Flood, Fixture with Pole						470	**899**	**$ 53.67**	**$ 48,249**
107,800L Fix With M Pole Dir-MH	P.O.L. 36.3	470	899	$ 50.89	$ 45,750				
High Pressure Sodium									
Acorn, 4000 Lumen, Smooth Pole						440	**24**	**$ 13.47**	**$ 323**
4,000L Acorn (Decorative Pole) UG RC-440	P.O.L. 36.1	440	24	$ 12.77	$ 306				
Acorn, 4000 Lumen, Fluted Pole						410	**2,624**	**$ 20.21**	**$ 53,031**
4,000L Acorn (Hist Pole) HPS UG RC-410	St.Lt. 35.1	410	1,880	$ 19.16	$ 36,021				
4,000L Acorn (Historic Pole) UG RC-444	P.O.L. 36.1	444	744	$ 19.16	$ 14,255				
Colonial, 4000 Lumen, Smooth Pole						466	**9,927**	**$ 9.42**	**$ 93,512**
4,000L Colonial HPS UG RC-466	St.Lt. 35.1	466	8,928	$ 8.93	$ 79,727				
4,000L Colonial Decor UG RC-480	P.O.L. 36.1	480	999	$ 8.93	$ 8,921				
Coach, 5800 Lumen, Smooth Pole						412	**336**	**$ 30.84**	**$ 10,362**
5,800L Coach Decor UG RC-412	St.Lt. 35.1	412	336	$ 29.24	$ 9,825				
Coach, 9500 Lumen, Smooth Pole						413	**1,234**	**$ 31.27**	**$ 38,587**
9,500L Coach Decor UG RC-413	St.Lt. 35.1	413	1,234	$ 29.65	$ 36,588				
Partial Month and Prorated Bills					$ (60,028)				$ (63,312)
Total Calculated at Base Rates					$ 23,087,333				$ 24,349,701
Correction Factor					1.000000000				1.000000000
Total After Application of Correction Factor					$ 23,087,333				$ 24,349,701
Applicable to all lighting schedules:									
Fuel Clause Billings - proforma for rollin					$ 87,860				87,860
Adjustment to Reflect Year-End Customers					98,915				104,323
Adjustment to Reflect Removal of Base ECR Revenues					(2,862,245)				(88,435)
Adjustment to Reflect Elimination of ECR Plans					2,773,810				-
Total Net Base Revenues					$ 23,185,673				$ 24,453,449
ECR Base Revenues					$ 88,435				$ 88,435
ECR Billings - proforma for rollin					$ 168,549				$ 168,549
Total Base Revenues Inclusive of ECR					$ 23,442,657				$ 24,710,433
Proposed Increase									1,267,776
Percentage Increase									5.41%

Conroy Exhibit R6

Miscellaneous Charge
Revenue Increase

Kentucky Utilities Company
Summary of Increases (Decreases) to Miscellaneous Charges
Based on the 12 Months Ended March 31, 2012

Miscellaneous Charge	KU
Cable TV Charge	$ 681,722.19
Disconnect/Reconnect Charge	237,777.00
Meter Pulse Relaying	9,102.00
Meter-Test Charge	540.00
Total	$ 929,141.19

Kentucky Utilities Company
Calculation of Proposed Rate Increase
Based on Billing Units for the 12 Months Ended March 31, 2012

Cable TV Pole Attachment Charge

	Current Rate			**Proposed Rate**		
Description	**Current Actuals Annual Billing Units**	**Annual Charge**	**Actual Billings**	**Test-Year End Annual Billing Units**	**Annual Charge**	**Proposed Billings**
Cable TV Pole Attachment Charge	147,879	$ 5.40 /Yr	$ 798,547	147,879	10.01 /Yr	$ 1,480,269
Total			$ 798,547			$ 1,480,269
Increase						$ 681,722

Kentucky Utilities Company
Disconnect/Reconnect Charges
12 Months Ended March 31, 2012

Description		**Current**		**Proposed**
Regular Hours				
Disconnect/Reconnects During Test-Year		79,259		79,259
Disconnect/Reconnect Charge	$	25.00	$	28.00
Total	$	1,981,475.00	$	2,219,252.00
Increase			$	237,777.00

Kentucky Utilities Company
Meter Test Charge
12 Months Ended March 31, 2012

Description	**Current**	**Proposed**
Meter Tests During Test-Year	36	36
Meter Test Charge	$ 60.00	$ 75.00
Total	$ 2,160.00	$ 2,700.00
Increase		$ 540.00

Note: Charges would only be applicable to meters within tolerance.

Kentucky Utilities Company
Meter Pulse Relaying
12 Months Ended March 31, 2012

Description		Current		Proposed
Meter Pulse Relays During Test-Year		1,517		1,517
Meter Pulse Relay Charge	$	9.00	$	15.00
Total	$	13,653.00	$	22,755.00
Increase			$	9,102.00

Conroy Exhibit M1

Excess Facilities Charge
Cost Support

Kentucky Utilities
Excess Facilities Charges

		Assuming Customer Does Not Make Contribution In Aid of Construction	Assuming Customer Makes Contribution In Aid of Construction
1	Present Value of Replacement Plant as a Percentage of Original Cost	21.77	21.77
2	Original Cost Value	100	-
3	Total Present Value of Original and Replacement Cost Value as a Percentage of Original Cost	121.77	21.77
4	Monthly Carrying Charge Percentage (Levelized Carrying Charge Rate / 12 months)	0.00795	0.00795
5	Applicable Carrying Charge Charge Percentage (Lines 3 x 5)	0.97%	0.17%
6	O&M Percentage	0.32%	0.32%
7	Total Excess Facilities Charge	1.28%	0.49%

Kentucky Utilities

Present Value of Replacement Plant as a Percentage of Original Cost

Year (1)	30 Year R2 Iowa Curve Percent Surviving (2)	Annual Replacement Percentage (3)	Cumulative Replacement Percentage (4)	Cost Escalation Factor at a 3.00% Inflation Factor (5)	Nominal Replacement Cost (6)	Present Value Factor at a 7.00% Discount Rate (7)	Present Value of Annual Replacement Cost (8)	Cumulative Present Value of Annual Replaced Cost (9)
					(3) x (5)		(6) x (7)	
0	100.0000							
1	99.6710	0.3290	0.3290	1.0300	0.3389	0.9346	0.3167	0.3167
2	99.3034	0.3676	0.6966	1.0609	0.3900	0.8734	0.3406	0.6573
3	98.8936	0.4098	1.1064	1.0927	0.4478	0.8163	0.3655	1.0229
4	98.4380	0.4556	1.5620	1.1255	0.5128	0.7629	0.3912	1.4141
5	97.9327	0.5053	2.0673	1.1593	0.5858	0.7130	0.4177	1.8317
6	97.3737	0.5590	2.6263	1.1941	0.6675	0.6663	0.4448	2.2765
7	96.7565	0.6172	3.2435	1.2299	0.7591	0.6227	0.4727	2.7492
8	96.0767	0.6798	3.9233	1.2668	0.8612	0.5820	0.5012	3.2504
9	95.3294	0.7473	4.6706	1.3048	0.9751	0.5439	0.5304	3.7808
10	94.5095	0.8199	5.4905	1.3439	1.1019	0.5083	0.5601	4.3409
11	93.6118	0.8977	6.3882	1.3842	1.2426	0.4751	0.5904	4.9313
12	92.6306	0.9812	7.3694	1.4258	1.3990	0.4440	0.6212	5.5524
13	91.5602	1.0704	8.4398	1.4685	1.5719	0.4150	0.6523	6.2047
14	90.3943	1.1659	9.6057	1.5126	1.7635	0.3878	0.6839	6.8886
15	89.1267	1.2676	10.8733	1.5580	1.9749	0.3624	0.7158	7.6044
16	87.7508	1.3759	12.2492	1.6047	2.2079	0.3387	0.7479	8.3523
17	86.2598	1.4910	13.7402	1.6528	2.4644	0.3166	0.7802	9.1325
18	84.6471	1.6127	15.3529	1.7024	2.7455	0.2959	0.8123	9.9448
19	82.9057	1.7414	17.0943	1.7535	3.0536	0.2765	0.8443	10.7891
20	81.0292	1.8765	18.9708	1.8061	3.3892	0.2584	0.8758	11.6649
21	79.0113	2.0179	20.9887	1.8603	3.7539	0.2415	0.9066	12.5716
22	76.8463	2.1650	23.1537	1.9161	4.1484	0.2257	0.9363	13.5079
23	74.5295	2.3168	25.4705	1.9736	4.5724	0.2109	0.9645	14.4724
24	72.0573	2.4722	27.9427	2.0328	5.0255	0.1971	0.9908	15.4632
25	69.4278	2.6295	30.5722	2.0938	5.5056	0.1842	1.0144	16.4776
26	66.6411	2.7867	33.3589	2.1566	6.0098	0.1722	1.0349	17.5124
27	63.7000	2.9411	36.3000	2.2213	6.5330	0.1609	1.0514	18.5638
28	60.6101	3.0899	39.3899	2.2879	7.0695	0.1504	1.0633	19.6271
29	57.3808	3.2293	42.6192	2.3566	7.6101	0.1406	1.0697	20.6968
30	54.0251	3.3557	45.9749	2.4273	8.1452	0.1314	1.0700	21.7668

Present Value of Replacement Plant as a Percentage of Original Cost: 21.7668

Kentucky Utilities

Levelized Carrying Charge Analysis

Capital Structure:

	Percent	Rate	Weighted COC	Tax Rate	Adjusted Rate
Short Term Debt	0.00%	0.41%	0.00%		0.00%
Long Term Debt	46.30%	3.69%	1.71%	36.75%	1.08%
Common Equity	53.70%	11.00%	5.91%		5.91%
			7.62%		6.99%

Tax Depreciation Table (MACRS)

	5	10	15	20
1	20.000%	10.000%	5.000%	3.750%
2	32.000%	18.000%	9.500%	7.219%
3	19.200%	14.400%	8.550%	6.677%
4	11.520%	11.520%	7.700%	6.177%
5	11.520%	9.220%	6.930%	5.713%
6	0.000%	7.370%	6.230%	5.285%
7	0.000%	6.550%	5.900%	4.888%
8	0.000%	6.550%	5.900%	4.522%
9	0.000%	6.560%	5.910%	4.462%
10	0.000%	6.550%	5.900%	4.461%
11	0.000%	0.000%	5.910%	4.462%
12	0.000%	0.000%	5.900%	4.461%
13	0.000%	0.000%	5.910%	4.462%
14	0.000%	0.000%	5.900%	4.461%
15	0.000%	0.000%	5.910%	4.462%
16	0.000%	0.000%	2.950%	4.461%
17	0.000%	0.000%	0.000%	4.462%
18	0.000%	0.000%	0.000%	4.461%
19	0.000%	0.000%	0.000%	4.462%
20	0.000%	0.000%	0.000%	4.461%
21	0.000%	0.000%	0.000%	2.231%
22	0.000%	0.000%	0.000%	0.000%
23	0.000%	0.000%	0.000%	0.000%
24	0.000%	0.000%	0.000%	0.000%
25	0.000%	0.000%	0.000%	0.000%
26	0.000%	0.000%	0.000%	0.000%
27	0.000%	0.000%	0.000%	0.000%
28	0.000%	0.000%	0.000%	0.000%
29	0.000%	0.000%	0.000%	0.000%
30	0.000%	0.000%	0.000%	0.000%
31	0.000%	0.000%	0.000%	0.000%
31	0.000%	0.000%	0.000%	0.000%

Kentucky Utilities

Levelized Carrying Charge Analysis

Assumptions:

Investment	$ 1,000
Book Life	30
Tax Life	20
Composite Tax Rate	36.7473%
Property Tax Rate	0.00%
Levelized Revenue Requirement Years	35
O&M as Percent of Investment	0.00%

Results:

Present Value Revenue Requirement	$ 1,157	
Levelized Revenue Requirement	$95	
Levelized Carrying Charge Rate	9.54%	
Level of Investment that can be Supported by Revenue	10.48	Times Net Revenue

Year	Investment	Book Depreciation	Residual Plant	Tax Depreciation	Residual Plant	Deferred Income Tax	Accumulated Deferred Income Tax
0	$ 1,000						
1		33	967	38	963	2	2
2		33	933	72	890	14	16
3		33	900	67	824	12	28
4		33	867	62	762	10	39
5		33	833	57	705	9	47
6		33	800	53	652	7	54
7		33	767	49	603	6	60
8		33	733	45	558	4	65
9		33	700	45	513	4	69
10		33	667	45	468	4	73
11		33	633	45	424	4	77
12		33	600	45	379	4	81
13		33	567	45	335	4	85
14		33	533	45	290	4	89
15		33	500	45	245	4	94
16		33	467	45	201	4	98
17		33	433	45	156	4	102
18		33	400	45	112	4	106
19		33	367	45	67	4	110
20		33	333	45	22	4	114
21		33	300	22	(0)	(4)	110
22		33	267	-	(0)	(12)	98
23		33	233	-	(0)	(12)	86
24		33	200	-	(0)	(12)	73
25		33	167	-	(0)	(12)	61
26		33	133	-	(0)	(12)	49
27		33	100	-	(0)	(12)	37
28		33	67	-	(0)	(12)	24
29		33	33	-	(0)	(12)	12
30		33	(0)	-	(0)	(12)	(0)

Kentucky Utilities

Levelized Carrying Charge Analysis

Assumptions:

Investment	$	1,000
Book Life		30
Tax Life		20
Composite Tax Rate		36.7473%
Property Tax Rate		0.00%
Levelized Revenue Requirement Years		35
O&M as Percent of Investment		0.00%

Results:

Present Value Revenue Requirement	$	1,157	
Levelized Revenue Requirement		$95	
Levelized Carrying Charge Rate		9.54%	
Level of Investment that can be Supported by Revenue		10.48	Times Net Revenue

Year	Rate Base	Interest	Equity	Income Taxes	Annual Revenue Requirement	Present Value Interest Factor	Present Value Revenue Requirement
0	$ -	-	$ -	-	$ -	1.000000	$ -
1	965	16	57	33	140	1	130
2	918	16	54	31	135	0.863479	116
3	872	15	52	30	130	0.802376	104
4	828	14	49	28	125	0.745596	93
5	786	13	46	27	120	0.692834	83
6	746	13	44	26	116	0.643806	74
7	706	12	42	24	111	0.598248	67
8	669	11	40	23	107	0.555913	60
9	631	11	37	22	103	0.516575	53
10	594	10	35	20	99	0.480020	47
11	556	10	33	19	95	0.446051	42
12	519	9	31	18	91	0.414487	38
13	481	8	28	17	87	0.385156	33
14	444	8	26	15	82	0.357901	29
15	406	7	24	14	78	0.332574	26
16	369	6	22	13	74	0.309040	23
17	331	6	20	11	70	0.287171	20
18	294	5	17	10	66	0.266849	18
19	257	4	15	9	62	0.247966	15
20	219	4	13	8	58	0.230419	13
21	190	3	11	7	54	0.214113	12
22	169	3	10	6	52	0.198962	10
23	148	3	9	5	50	0.184882	9
24	127	2	7	4	47	0.171799	8
25	105	2	6	4	45	0.159642	7
26	84	1	5	3	43	0.148345	6
27	63	1	4	2	40	0.137848	6
28	42	1	2	1	38	0.128093	5
29	21	0	1	1	36	0.119028	4
30	(0)	(0)	(0)	(0)	33	0.110605	4
							$ 1,157

Conroy Exhibit M2

Redundant Capacity Charge
Cost Support

Kentucky Utilities Company
Redundant Capacity Charge Cost Support
Distribution Demand-Related Cost
Twelve Months Ended March 31, 2012

Secondary Service

Distribution Demand Costs					
PSS	$	9,588,794			
TODS	$	1,245,896			
Total Cost	$	10,834,690			
Billing Demand					
PSS		8,750,756			
TODS		946,676			
Total Cost		9,697,432			
Unit Cost			$	1.12	
Rate Base					
PSS	$	47,781,617			
TODS	$	7,101,683			
Total Cost	$	54,883,300			
Return	$	4,165,642			
Unit Return			$	0.43	
Capacity Charge			$	1.55	/ kW

Source: Electric Cost of Service Study, Conroy Exhibit C4

Kentucky Utilities Company
Redundant Capacity Charge Cost Support
Distribution Demand-Related Cost
Twelve Months Ended March 31, 2012

Primary Service

Distribution Demand Costs				
PSP	$	1,484,872		
TODP	$	5,617,986		
Total Cost	$	7,102,858		
Billing Demand				
PSP		1,379,179		
TODP		8,596,582		
Total Cost		9,975,761		
Unit Cost			$	0.71
Rate Base				
PSP	$	7,223,245		
TODP	$	29,715,930		
Total Cost	$	36,939,175		
Return	$	2,803,683		
Unit Return			$	0.28
Capacity Charge			$	0.99 / kW

Source: Electric Cost of Service Study, Conroy Exhibit C4

Conroy Exhibit M3

Supplemental and Standby Service
Cost Support

Kentucky Utilities Company
Supplemental / Standby Charge Cost Support

Production and Transmission Unit Demand Costs
Total System

	Reference	Total Production Cost	Total Transmission Cost	Total
Operation and Maintenance Expenses	Conroy Exhibit C4	$ 90,638,112	$ 29,749,027	$ 120,387,139
Depreciation Expenses	Conroy Exhibit C4	121,456,460	10,488,193	$ 131,944,653
Accretion Expenses	Conroy Exhibit C4	(2,647,544)	(5,404)	$ (2,652,948)
Property Taxes	Conroy Exhibit C4	11,264,737	1,687,073	$ 12,951,810
Other Taxes	Conroy Exhibit C4	5,861,594	877,867	$ 6,739,461
Gain Disposition of Allowances and other	Conroy Exhibit C4	-	-	$ -
Expense Adjustments	Conroy Exhibit C4	(13,835,798)	(5,438,023)	$ (19,273,821)
Sub-Total Expenses		$ 212,737,561	$ 37,358,733	$ 250,096,294
Adjusted Rate Base	Conroy Exhibit C4	2,188,897,801	289,975,107	2,478,872,908
Return	Rate Base x Weighted Cost of Capital %	166,694,855	22,082,967	188,777,823
Income Taxes	Rate Base x Income Tax %	75,117,102	9,951,168	85,068,270
Total Revenue Requirement	Expenses + Return + Income Taxes	$ 454,549,518	$ 69,392,868	$ 523,942,386
100% Load Factor Demand	System CP x 12 months @ 90% PF	46,888,627	46,888,627	46,888,627
Unit Cost (Single Phase)	Total Revenue Requirement / Demand	$ 9.69	$ 1.48	$ 11.17

			Weighted Cost of Capital	Income Taxes	Weighted Cost of Capital Grossed Up For Inc Taxes
Short Term Debt	0.00%	0.41%	0.00%		0.00%
Long Term Debt	46.30%	3.69%	1.71%		1.71%
Common Equity	53.70%	11.00%	5.91%	3.43%	9.34%
Total Capitalization	100.00%		7.62%		11.05%

Composite State and Fed Inc Tax Rate	36.7473%

Kentucky Utilities Company
Supplemental / Standby Charge Cost Support

Primary Distribution Unit Demand Costs
Power Service Primary & TOD Primary

	Reference	Distribution Primary Substation Cost	Distribution Primary Lines Cost	Distribution Primary Transformer Cost	Total
Operation and Maintenance Expenses	Conroy Exhibit C4	$ 1,282,565	$ 3,818,214	$ -	$ 5,100,779
Depreciation Expenses	Conroy Exhibit C4	$ 824,947	$ 1,336,113	$ -	$ 2,161,060
Accretion Expenses	Conroy Exhibit C4	$ (286)	$ (464)	$ -	$ (750)
Property Taxes	Conroy Exhibit C4	$ 93,400	$ 151,273	$ -	$ 244,673
Other Taxes	Conroy Exhibit C4	$ 48,600	$ 78,715	$ -	$ 127,315
Gain Disposition of Allowances and other	Conroy Exhibit C4	$ -	$ -	$ -	$ -
Expense Adjustments	Conroy Exhibit C4	$ (99,141)	$ (295,144)	$ -	$ (394,285)
Sub-Total Expenses		$ 2,150,084	$ 5,088,708	$ -	$ 7,238,792
Adjusted Rate Base	Conroy Exhibit C4	17,444,711	28,253,706	-	45,698,417
Return	Rate Base x Weighted Cost of Capital %	1,328,497	2,151,653	-	3,480,149
Income Taxes	Rate Base x Income Tax %	598,656	969,591	-	1,568,247
Total Revenue Requirement	Expenses + Return + Income Taxes	$ 4,077,237	$ 8,209,952	$ -	$ 12,287,189
Billing Demand	Billing Demand @ 90% PF	10,389,465	10,389,465	10,389,465	10,389,465
Unit Cost (Single Phase)	Total Revenue Requirement / Demand	$ 0.3924	$ 0.7902	$ -	$ 1.1827

			Weighted Cost of Capital	Income Taxes	Weighted Cost of Capital Grossed Up For Inc Taxes
Short Term Debt	0.00%	0.41%	0.00%		0.00%
Long Term Debt	46.30%	3.69%	1.71%		1.71%
Common Equity	53.70%	11.00%	5.91%	3.43%	9.34%
Total Capitalization	100.00%		7.62%		11.05%
Composite State and Fed Inc Tax Rate	36.7473%				

Kentucky Utilities Company
Supplemental / Standby Charge Cost Support

Secondary Distribution Unit Demand Costs
Power Service Secondary & TOD Secondary

	Reference	Distribution Secondary Substation Cost	Distribution Secondary Lines Cost	Distribution Secondary Transformer Cost	Total
Operation and Maintenance Expenses	Conroy Exhibit C4	$ 1,061,572	$ 448,807	$ 440,959	$ 1,951,338
Depreciation Expenses	Conroy Exhibit C4	$ 682,804	$ 157,052	$ 552,781	$ 1,392,637
Accretion Expenses	Conroy Exhibit C4	$ (237)	$ (54)	$ (192)	$ (483)
Property Taxes	Conroy Exhibit C4	$ 77,306	$ 17,781	$ 62,585	$ 157,673
Other Taxes	Conroy Exhibit C4	$ 40,226	$ 9,252	$ 32,566	$ 82,045
Gain Disposition of Allowances and other	Conroy Exhibit C4	$ -	$ -	$ -	$ -
Expense Adjustments	Conroy Exhibit C4	$ (334,548)	$ (140,851)	$ (138,388)	$ (613,786)
Sub-Total Expenses		$ 1,527,124	$ 491,987	$ 950,312	$ 2,969,424
Adjusted Rate Base	Conroy Exhibit C4	13,718,853	3,155,419	11,059,868	27,934,140
Return	Rate Base x Weighted Cost of Capital %	1,044,755	240,300	842,261	2,127,316
Income Taxes	Rate Base x Income Tax %	470,794	108,286	379,545	958,625
Total Revenue Requirement	Expenses + Return + Income Taxes	$ 3,042,674	$ 840,573	$ 2,172,118	$ 6,055,364
Billing Demand	Billing Demand @ 90% PF	10,758,050	10,758,050	10,758,050	10,758,050
Unit Cost (Single Phase)	Total Revenue Requirement / Demand	$ 0.2828	$ 0.0781	$ 0.2019	$ 0.5629

			Weighted Cost of Capital	Income Taxes	Weighted Cost of Capital Grossed Up For Inc Taxes
Short Term Debt	0.00%	0.41%	0.00%		0.00%
Long Term Debt	46.30%	3.69%	1.71%		1.71%
Common Equity	53.70%	11.00%	5.91%	3.43%	9.34%
Total Capitalization	100.00%		7.62%		11.05%
Composite State and Fed Inc Tax Rate	36.7473%				

Kentucky Utilities Company
Supplemental / Standby Charge Cost Support

Calculation of KU 100% Load Factor Demand

KU System Peak	(1) * 12
(1)	(2)
3,516,647	42,199,764

90% Power Factor Adjustment	(2) / (3)
(3)	(4)
90%	46,888,627

100% Load Factor Demand
46,888,627

Conroy Exhibit M4

Cable TV
Attachment Charges

KENTUCKY UTILITIES COMPANY

Calculation Of Attachment Charges for CATV

Pole Size	Quantity	Installed Cost		Average Installed Cost
Weighted Average Bare Pole Cost as of 10/31/2009				
35'	80,229	$ 18,144,593		$ 226.16
40'	132,480	83,496,635		630.26
	212,709	101,641,227		477.84
Three-User Poles				
40'	132,480	$ 83,496,635		$ 630.26
45'	61,269	54,544,545		890.25
	193,749	138,041,179		712.47

	Number of Attachments	Weighted Cost
Pole Cost (Space Factor determined from 3 user Pole)		
$712.47 x .0759 Usage Space Factor = $54.08		
$ 54.08 x .1851 Annual Carrying Charge = $10.01	147,879	1,479,871
Total	147,879	$ 1,479,871
Annual		$ 10.01

KENTUCKY UTILITIES COMPANY

Calculation Of Annual Carrying Charge

Proposed Rate of Return	7.62%
Depreciation - Sinking Fund	0.63%
Income Tax (1)	3.43%
Property Tax and Insurance	0.22%
Operation and Maintenance (Page 3)	6.61%
Total	18.51%

(1) Derived from rates of equity capital

	Capitalization Ratio	Annual Rate	Composite Rate
Short Term Debt	0.00%	0.41%	0.00%
Long Term Debt	46.30%	3.69%	1.71%
Common Equity	53.70%	11.00%	5.91%
Total Capitalization	100.00%		7.62%

Composite Federal and State Income Taxes rate = 36.75%

Income Tax = (0.3675/(1-0.3675) x 0.0591 = 3.43%

KENTUCKY UTILITIES COMPANY

Operation and Maintenance Expenses for
the 12 Months Ended October 31, 2009

(1) Labor Charged to 593001- Maint of Poles, Towers and Fixtures Subaccount	$384,792	
- Tree Trimming	734,182	
		$1,118,974
Total Labor		$135,498,603
Total Administrative and General Expenses		$93,031,576

Assignment of a Portion of A & G Expenses to Poles

($1,118,974/$135,498,603) x $93,031,576 = $768,273

Expenses Assigned to Poles

Maintenance of Poles, Towers, and Fixtures Subaccount 593001	$ 773,792
Tree Trimming of Electric Distribution Routes 593004	16,546,569
A & G Expenses Assigned to Poles	$768,273
Total	$ 18,088,634

Adder to Annual Carrying Charges for O & M Expenses

$ 18,088,634	Expenses Assigned to Poles	=	6.61%
273,798,351	Plant in Service - Account 364		

Conroy Exhibit M5

Meter Test Charge
Cost Support

Kentucky Utilities Company
Electric Meter Test
Cost Justification

Labor - One Hour	$	71.54
Vehicle - 2/3 Hour		4.59
Total Charge	$	76.13

Average hourly rate for all employees including overheads ($71.54) and vehicles ($6.89) used in the performance of this work multiplied by the time associated with performing this work including travel, test, set-up, etc.

Conroy Exhibit M6

Disconnect/Reconnect
Charge Cost Support

Kentucky Utilities Company
Disconnect/Reconnect
Cost Justification

Disconnect Service	$	14.69
Reconnect Service		14.69
Total Charge	$	29.37

Based on average cost per credit order. ($14.69) Cost per credit order consist of labor, transporation, supplies, and equipment. Front and back office service order processing expenses are not included.

Conroy Exhibit M7

Meter Relay Pulse Charge
Cost Support

Kentucky Utilities
Meter Pulse Charge

1	Present Value of Replacement Plant as a Percentage of Original Cost		38.55
2	Original Cost Basis (100)		100
3	Total Present Value of Original and Replacement Cost Value as a Percentage of Original Cost		138.55
4	Monthly Carrying Charge Percentage (Levelized Carrying Charge Rate / 12 months)		0.02047
5	Applicable Carrying Charge Charge Percentage (Lines 3 x 5)		2.84%
6	O&M Percentage		0.32%
7	Distribution O&M	$ 50,977,392	
8	Distribution Plant in Service	$ 1,348,161,065	
9	Total Monthly Revenue Requirement as Percentage of Original Cost		3.15%
10	Installed Cost of Meter Pulse Equipment		792.15
11	Monthly Charge		$ 24.97

Kentucky Utilities

Present Value of Replacement Plant as a Percentage of Original Cost

Year (1)	5-Year R3 Iowa Curve Percent Surviving (2)	Annual Replacement Percentage (3)	Cumulative Replacement Percentage (4)	Cost Escalation Factor at a 3.00% Inflation Factor (5)	Nominal Replacement Cost (6)	Present Value Factor at a 7.00% Discount Rate (7)	Present Value of Annual Replacement Cost (8)	Cumulative Present Value of Annual Replaced Cost (9)
					(3) x (5)		(6) x (7)	
0	100.0000							
1	99.2989	0.7011	0.7011	1.0300	0.7222	0.9346	0.6749	0.6749
2	96.8953	2.4035	3.1047	1.0609	2.5499	0.8734	2.2272	2.9021
3	90.7990	6.0963	9.2010	1.0927	6.6616	0.8163	5.4379	8.3400
4	78.0273	12.7718	21.9727	1.1255	14.3747	0.7629	10.9664	19.3064
5	54.7415	23.2857	45.2585	1.1593	26.9946	0.7130	19.2468	38.5531

Present Value of Replacement Plant as a Percentage of Original Cost $\boxed{38.5531}$

Kentucky Utilities

Levelized Carrying Charge Analysis

Capital Structure:

	Percent	Rate	Weighted COC	Tax Rate	Adjusted Rate
Short Term Debt	0.00%	0.41%	0.00%		0.00%
Long Term Debt	46.30%	3.69%	1.71%	36.75%	1.08%
Common Equity	53.70%	11.00%	5.91%		5.91%
			7.62%		6.99%

Tax Depreciation Table (MACRS)

	5	10	15	20
1	20.000%	10.000%	5.000%	3.750%
2	32.000%	18.000%	9.500%	7.219%
3	19.200%	14.400%	8.550%	6.677%
4	11.520%	11.520%	7.700%	6.177%
5	11.520%	9.220%	6.930%	5.713%
6	5.760%	7.370%	6.230%	5.285%
7	0.000%	6.550%	5.900%	4.888%
8	0.000%	6.550%	5.900%	4.522%
9	0.000%	6.560%	5.910%	4.462%
10	0.000%	6.550%	5.900%	4.461%
11	0.000%	0.000%	5.910%	4.462%
12	0.000%	0.000%	5.900%	4.461%
13	0.000%	0.000%	5.910%	4.462%
14	0.000%	0.000%	5.900%	4.461%
15	0.000%	0.000%	5.910%	4.462%
16	0.000%	0.000%	2.950%	4.461%
17	0.000%	0.000%	0.000%	4.462%
18	0.000%	0.000%	0.000%	4.461%
19	0.000%	0.000%	0.000%	4.462%
20	0.000%	0.000%	0.000%	4.461%
21	0.000%	0.000%	0.000%	2.231%
22	0.000%	0.000%	0.000%	0.000%
23	0.000%	0.000%	0.000%	0.000%
24	0.000%	0.000%	0.000%	0.000%
25	0.000%	0.000%	0.000%	0.000%
26	0.000%	0.000%	0.000%	0.000%
27	0.000%	0.000%	0.000%	0.000%
28	0.000%	0.000%	0.000%	0.000%
29	0.000%	0.000%	0.000%	0.000%
30	0.000%	0.000%	0.000%	0.000%
31	0.000%	0.000%	0.000%	0.000%
31	0.000%	0.000%	0.000%	0.000%

Kentucky Utilities

Levelized Carrying Charge Analysis

Assumptions:

Investment	$	1,000
Book Life		5
Tax Life		5
Composite Tax Rate		36.75%
Property Tax Rate		0.00%
Levelized Revenue Requirement Years		5
O&M as Percent of Investment		0.00%

Results:

Present Value Revenue Requirement	$	991	
Levelized Revenue Requirement		$246	
Levelized Carrying Charge Rate		24.57%	
Level of Investment that can be Supported by Revenue		4.07	Times Net Revenue

Year	Investment	Book Depreciation	Residual Plant	Tax Depreciation	Residual Plant	Deferred Income Tax	Accumulated Deferred Income Tax
0	$ 1,000						
1		200	800	200	800	-	-
2		200	600	320	480	44	44
3		200	400	192	288	(3)	41
4		200	200	115	173	(31)	10
5		200	-	115	58	(31)	(21)
6		-	-	58	-	21	-

Kentucky Utilities
Levelized Carrying Charge Analysis

Assumptions:

Investment	$	1,000
Book Life		5
Tax Life		5
Composite Tax Rate		36.75%
Property Tax Rate		0.00%
Levelized Revenue Requirement Years		5
O&M as Percent of Investment		0.00%

Results:

Present Value Revenue Requirement	$	991	
Levelized Revenue Requirement		$246	
Levelized Carrying Charge Rate		24.57%	
Level of Investment that can be Supported by Revenue		4.07	Times Net Revenue

Year	Rate Base	Interest	Equity	Income Taxes	Annual Revenue Requirement	Present Value Interest Factor	Present Value Revenue Requirement
0	$ -	-	$ -	-	$ -	1.000000	$ -
1	800	14	47	27	288	0.929236	268
2	556	9	33	19	261	0.863479	226
3	359	6	21	12	240	0.802376	192
4	190	3	11	7	221	0.745596	165
5	21	0	1	1	202	0.692834	140
6	-	-	-	-	-	0.643806	-
							$ 991

Conroy Exhibit M8

Customer Deposit Requirements

Kentucky Utilities Company

Customer Deposit Requirements

	Residential Electric -- Rate RS	
(1)	Proposed Revenue	$ 502,976,796
(2)	Customer Months	5,044,174
(3)	Residential Deposit Requirement [(1) / (2)] * 2 months	$ 199
(4)	Proposed Deposit Requirement	$ 135
	General Service -- Rate GS	
(5)	Proposed Revenue	$ 191,359,534
(6)	Customer Months	985,220
(7)	General Service Deposit Requirement [(5) / (6)] * 2 months	$ 388
(8)	Proposed Deposit Requirement	$ 220