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. 2014-00371**

In the Matter of:

APPLICATION OF LOUISVILLE GAS AND ELECTRIC COMPANY FOR AN ADJUSTMENT OF ITS ELECTRIC AND GAS RATES	**))))**	**CASE NO. 2014-00372**

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

Filed: November 26, 2014

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

A. My name is Victor A. Staffieri. I am the Chairman of the Board, Chief Executive Officer and President of Louisville Gas and Electric Company ("LG&E") and Kentucky Utilities Company ("KU") (collectively, 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 employment history, education and civic involvement.

A. I joined LG&E Energy in March 1992 as Senior Vice President, General Counsel, and Corporate Secretary. Since then, I have served in a number of positions at LG&E 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 to my testimony.

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

A. Yes. I testified before this Commission in the Companies' last four base rate cases.[1]

[1] Case No. 2012-00221, *In the Matter of: Application of Kentucky Utilities Company for an Adjustment of its Electric Rates;* Case No. 2014-00222; *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. 2009-00549, *In the Matter of: Application of Louisville Gas and Electric Company for an Adjustment of its Electric and Gas Base Rate*s 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: 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 Electric Rates, Terms and Conditions of Kentucky Utilities Company*

I have also testified in various other cases, including three proceedings regarding changes in the ownership of LG&E and KU.[2]

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, why we have elected to use a future test year, and why it is important that the increases the Companies have proposed be approved. In so doing, I will discuss changes in the industry since the Companies' 2012 rate cases and 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. I will also describe the Companies' existing programs to achieve improvements in efficiency and productivity. 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. I am also providing the attestation required by 807 KAR 5:001 Section 16(7)(e).

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

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

- Kent Blake, Chief Financial Officer - Mr. Blake will describe why the Companies' financial condition requires the requested increase in rates and

[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. 2001-00104, *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. 2000-00095, *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 for Approval of Merger.*

why the Companies chose to use a forecasted test period to support their base rate applications, and will describe the Companies' existing programs to achieve improvements in efficiency and productivity. Mr. Blake will summarize the Companies' revenue deficiencies and the associated proposed increases in revenues. Mr. Blake will also describe all factors used in preparing the Companies' base and forecast periods, including economic models, assumptions, and changes in activity levels, and will detail the Companies' Budgeting and Planning Process and capital structure. Finally, Mr. Blake will sponsor certain schedules that support the Companies' applications and are required by the Commission's rate case regulations.

- Paul W. Thompson, Chief Operating Officer – Mr. Thompson will describe the status and performance of the Companies' generation, transmission, distribution, and customer service operations. He will also describe the major capital projects associated with these operations and reflected in the forecasted test period. Mr. Thompson will discuss existing programs to achieve improvements in efficiency and productivity. In addition, Mr. Thompson will discuss safety issues and the Companies' Research and Development activities.
- David Sinclair, Vice President Energy Supply and Analysis – Mr. Sinclair will discuss the Companies' load and generation forecasts, including off-system sales, and how these forecasts were developed, as well as the support for the proposed Curtailable Service Rider Credit in this case.

- William E. Avera, President, and Adrien McKenzie, Vice President, FINCAP, Inc. – At the hearing, Dr. Avera will present the results of their analysis, which demonstrates that the range of a reasonable return on equity is from 9.60 percent to 11.40 percent. Dr. Avera will also present his recommendation that 10.64 percent is a reasonable return on common equity for both LG&E's electric and gas operations and KU's electric operations. Additionally, Dr. Avera will offer his opinion as to the appropriateness of the Companies' capital structure.
- John J. Spanos, Gannett Fleming, Inc. – Mr. Spanos will present his depreciation study and recommended depreciation rate for Cane Run Unit 7.
- Ed R. Staton, Vice President, State Regulation and Rates – Mr. Staton sponsors schedules required by the Commission's rate case regulations for a forecasted test period rate case, and describes the method of notice given to customers, the typical impact on customer bills of the proposed rate increases, and the Companies' assistance programs for low income customers.
- Dr. Martin Blake, The Prime Group, LLC – Dr. Blake discusses the cost of service studies and rate design issues for LG&E and KU.
- J. Clay Murphy, Director, Gas Management, Planning and Supply – Mr. Murphy will discuss certain changes that LG&E is proposing to its Gas Transportation Tariff terms and conditions.
- Robert M. Conroy, Director, Rates – Mr. Conroy will explain and support certain schedules that are required by the Commission's regulations for cases involving a forecasted test period, explain pro forma adjustments to the

Companies' financial forecast, and address rate design issues and the allocation of rate increases between customer classes based on cost of service study prepared by Dr. Blake.

Q. Can you describe the changes in the Companies' management since their last base rate case in 2012?

A. With the retirement Chris Hermann in 2013, Mr. Thompson, who was then Senior Vice President, Energy Delivery, was appointed to the new position of Chief Operations Officer. Mr. Thompson is now responsible for the operations of LG&E's electric and gas systems and KU's electric system.

Messrs. Blake, Chief Financial Officer, S. Bradford Rives, Chief Administrative Officer and Thompson, Chief Operations Officer report directly to me as the Chief Executive Officer.

Q. Can you briefly describe the industry changes since the 2012 rate case?

A. Certain industry changes noted in 2012 have accelerated. Specifically, the industry, and the Companies in particular, faces increasing regulatory challenges relating to U.S. Environmental Protection Agency ("EPA") regulations, North America Electric Reliability Corporation ("NERC") reliability standards, and Federal Energy Regulatory Commission ("FERC") Order 1000. For example, the new EPA regulations have dramatically impacted coal-fired generation. Nationwide, the EPA's analysis indicates that 30 to 49 GW of coal-fired capacity will become uneconomical to maintain by 2020.[3] The Companies themselves will have retired approximately 800 MW of coal-fired capacity by the end of 2016. The role of coal as a generation

[3] *Regulatory Impact Analysis for the Proposed Carbon Pollution Guidelines for Existing Power Plants and Emissions Standards for Modified and Reconstructed Power Plants,* Office of Air Quality and Standards, U. S. Environmental Protection Agency, June 2014 at p. 121.

fuel is the subject of considerable debate and at times legal and political challenges. Also, we face the need for increasing investment in information technology, both to meet regulatory requirements to maintain the security of both customer information and our own system and to meet increasing customer and industry demands for reliability and responsiveness. These issues are discussed in greater detail in the testimony of Messrs. Blake and Thompson.

Q. Can you describe the Companies' existing programs to achieve improvements in efficiency and productivity?

A. A core principle of our organization is that we always seek to be as efficient and productive as possible; we are always looking for ways to improve what we do. 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. In fact, LG&E and KU are among the most efficient utilities in the nation. As presented in greater detail in Mr. Blake's testimony, the Companies outperform industry averages in all five electric utility cost categories and rank in the top quartile in three out of five cost segments according to the Companies' benchmarking analysis of FERC data through 2013.

While the testimonies of Messrs. Blake and Thompson address an extensive number of the Companies' specific existing programs or practices to achieve efficiency and productivity, I will describe two existing initiatives that are fundamental to our utility system operations.

The Companies continually seek improvement in efficiency and productivity through their annual "bottom-up" financial planning and budgeting process. This is the most fundamental control effort to achieve efficiency and productivity within the overall management of our systems. The budgeting process provides both senior and functional business managers with a clear measure of the costs of meeting the Companies' goals and a tool for the ongoing control of costs and responding to changes in operating conditions. It further provides management a tool for internal controls, establishing a basis against which to compare actual results and measure performance. This financial control process is described in greater detail in the process documents submitted at Tab 16 to the application and in the testimonies of Messrs. Blake and Sinclair.

In addition, for years we have adopted competitive bidding as the preferred method of procurement for all materials and supplies, regardless of their price. From a good business practice standpoint, every attempt is made to create a sense of competition and supplier participation. All competitive bidding initiatives include the participation of a diverse slate of suppliers, including woman- and minority-owned businesses, where they exist. For purchases over $50,000, competitive bidding is required, except in cases where competitive bids cannot be obtained or the technical capability or availability of a particular vendor is required. In those cases, a sole-source agreement, approved by the appropriate level of management depending upon the size of the procurement, is required. This ensures that the Companies are receiving the best available price and terms in the market in each case.

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

A. The decision to file for rate increases 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 all our customers, the current economic conditions and their impact on all our 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, and continues to become ever more complex and subject to increasing regulation. The Companies have deployed and are deploying the additional debt and equity capital necessary to continue to provide safe and reliable service in this increasingly complex and demanding environment; but each new capital deployment adds to the Companies' financing costs. Due to the relatively flat sales-growth environment we have experienced in recent years and anticipate for a number of years to come, we must now adjust the Companies' rates 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 revenues.

A. LG&E is requesting a 2.7 percent, or approximately $30 million a year increase in its electric revenue, and a 4.2 percent, or approximately $14 million a year, increase in its gas revenue. The monthly impact of the requested increase in base rates will increase an average total residential electric bill by 2.73 percent, or approximately $2.75, for a customer using 984 kWh of electricity. The monthly impact of the requested increase in gas base rates will increase an average total residential gas bill by 4.2 percent, or approximately $2.62, for a customer using 5.7 Mcf of gas.

KU is requesting a 9.6 percent or approximately $153 million a year increase in its electric revenues. The monthly impact of the requested increase in base rates will increase an average residential electric bill by 9.57 percent, or approximately $11.01, for a customer using 1,200 kWh of electricity.

The testimonies of our witnesses submitted with the Companies' applications demonstrate that LG&E's and KU's requested increases in base rates are necessary for the Companies to earn a fair and reasonable return adequate to attract capital investment and provide safe and reliable high quality service to their customers.

Q What return on common equity are the Companies requesting in their applications?

A. The analysis presented by Dr. Avera demonstrates that the range of a reasonable return on equity is from 9.60 percent to 11.40 percent. In his testimony, Dr. Avera recommends a reasonable return on common equity for both LG&E's electric and gas operations and KU's electric operation is 10.64 percent. We have chosen, however, to utilize a return on equity of 10.50 percent to moderate the rate impact in some manner while striking the right balance between the interests of our customers and allowing the Companies to continue to raise capital at reasonable rates in a challenging environment. As a result, the requests for increases in their revenues by the Companies in their applications are based on 10.50 percent return on common equity.

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' excellent cost performance, customers will still receive a good value for their service if the proposed rates are approved. And as demonstrated in Mr. Staton's testimony, the proposed rates, if approved, will remain below the national average.

Q. Why did the Companies base their applications on a forecasted test period?

A. As discussed in Mr. Blake's testimony and shown in Exhibit KWB-2, between 2015 and 2019 the Companies anticipate incurring more than $5.4 billion in various capital expenditures to meet changing conditions. For example, Cane Run Unit 7 will enter service in May 2015. As described in the testimony of Mr. Thompson, the construction of this unit is on schedule and under budget. In addition to the building of Cane Run Unit 7, as noted in Mr. Thompson's testimony, LG&E is increasing the generation capacity at the Ohio River Falls hydroelectric plant on the Ohio River by 27 percent and entered into a new agreement to purchase power from Bluegrass Generation Company, LLC's unit located in Oldham County, Kentucky. In doing so, the Companies are changing their source of supply of electric power. Our use of a forecasted test period, which is permitted by statute and consistent with the practice of many other regulated Kentucky utilities, will place the Companies in a position to recover the prudent expenses of those projects in a way that enhances the Companies' ability to attract capital at the lowest possible cost.

As described in the testimonies of Messrs. Thompson and Blake, and as noted in the evidence submitted in the 2012 rate cases, because of structural changes to the

Companies' generation fleet, LG&E and KU have less base load capacity to respond to opportunities for off-system sales at prices that will clear the market on a regular basis. As a result, the Companies can no longer rely on the margins from such sales for financial support between rate cases. Additionally, as described in the testimonies of Messrs. Blake and Sinclair, the Companies continue to anticipate low growth in native system demand. In the past, the Companies have been able to rely on both off-system sales and native load growth to defray the impact of rising costs between rate cases. Because this is no longer possible, the Companies must now adjust rates to earn a reasonable return that will continue to allow LG&E and KU to raise capital at reasonable prices. Here again, use of a forecasted test period maximizes the Companies' ability to raise low-cost capital and helps the Companies respond quickly to changing market conditions.

Q. Are you sponsoring any required schedules?

A. Yes, I am sponsoring and providing the attestation required under 807 KAR 5:001 Section 16(7)(e).

Q. Can you describe the Companies' commitment to the community?

A. Yes. Our commitment to the communities we serve is a long-standing and essential part of the Companies' culture. This was recognized by the *Business First* newspaper when it presented us earlier this year the "Partners in Philanthropy Award" for being an outstanding corporate citizen for the third year in row. This award was based on being one of the area's top socially responsible organizations.

The LG&E and KU Foundation contributes to our state by supporting Kentucky nonprofits whose missions focus on education, the environment, diversity, or health and safety. Since its establishment in 1994, the Foundation has awarded more than $20 million dollars to support such benevolent endeavors across the Commonwealth. In addition to the Foundation, the Companies contribute an additional $5 million each year to various organizations. All of these contributions are funded solely by our shareholders.

In addition to our shareholders' contributions, the Companies show their civic commitment by encouraging and facilitating our employees' giving of their time, talent, and money throughout our service area to improve the quality of life in the communities in which they work and live. For example, during our 2013 annual charitable-giving campaign, Power of One, our employees donated over $1.6 million to local nonprofits throughout our service territories. This marks the seventh year in a row in which our employees have raised more than $1 million for the campaign, and it represents the highest amount ever pledged by our employees. These donations support organization such as the Crusade for Children, Fund for the Arts, and 26 United Way organizations statewide. The approximately 70 percent of LG&E and KU employees who participate through payroll deductions do so at a rate more than twice the national average.

In addition to these donations, for the last 10 years the Companies have sponsored a "Day of Caring," during which employees, typically on a Saturday and with the Companies' support, collectively volunteer at several locations across the service territories. For example, this year in Lexington employees donated and organized more than 2,500 baby items for The Nest and provided general maintenance and mulch assistance at the Arboretum. In addition, several employees helped with an annual effort to distribute more than 8,000 backpacks to local schoolchildren. In Louisville, more than 100 volunteers stuffed backpacks with school supplies or distributed those backpacks to children as part of Operation Backpack. In all, more than 3,200 backpacks were distributed.

This year and for the sixth time overall, LG&E and KU were named among the top 10 utilities in the nation for supporting economic growth within their service territories in the September 2014 issue of *Site Selection* magazine. LG&E and KU's Economic Development team was honored for helping Kentucky create more than 80 percent of the state's 12,500 new jobs in 2013. In fact, since 2000, LG&E and KU have helped create nearly 110,000 new jobs in Kentucky.

In addition, LG&E and KU together have created approximately 3,200 construction jobs as part of their ongoing $6 billion investment in environmental upgrade projects.

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

A. Like our commitment to the community, assistance to low-income customers is also an integral part of our culture. For example, LG&E and KU Energy helped found and has been involved with Project Warm since its inception in 1982. Project Warm is a nonprofit that serves elderly, disabled, and economically challenged citizens in Louisville. Each year, volunteers for the Project Warm Blitz in the LG&E service area and Winterblitz in the KU service area weatherize hundreds of homes of our low-income customers before the heating season. LG&E and KU provide the weatherization supplies for the effort, and our employees support this initiative by volunteering their time and through their donations.

As explained more fully in the testimony of Mr. Staton, the Companies currently make $1 million a year in shareholder contributions to low-income assistance programs.

Moreover, due to the delay in the distribution of Low-Income Home Energy Assistance Program ("LIHEAP") funds caused by the federal government shutdown in 2013, the Companies agreed to match $2, rather than the previous $1 match, for every $1 donated by residential customers to the Companies' heating assistance programs. And during the extreme cold of the 2014 winter season LG&E and KU jointly relaxed installment plan restrictions that helped customers defer payments from January through April 2014. As discussed in Mr. Staton's testimony, customers were issued more than 12,000 installment plans resulting in the deferment of approximately $5 million in payments. During this time, the Companies also donated more than $200,000 to various organizations that assist low-income customers in need. Customer donations and matching company funds have raised millions of dollars to help thousands of families pay their heating bills over the years.

In addition, as discussed in the testimony of Mr. Staton, LG&E and KU offer demand-side management and energy-efficiency ("DSM/EE") programs to assist low-income customers. Specifically, the Companies' Low-Income Weatherization Program ("WeCare") is an education and weatherization program designed to reduce the energy consumption of low-income customers. WeCare is now the Companies' second largest DSM/EE program by budget. This fall, LG&E, together with low income service providers, began a 24-month pilot project to increase the marketing of energy-efficiency programs to low income customers and improve the communication of energy-efficiency information with these customers.

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 that he is Chief Executive Officer of 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.

Victor A. Staffieri

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 10th day of November 2014.

(SEAL)
Notary Public

My Commission Expires:

March 29, 2018

APPENDIX

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	**)**	**CASE NO. 2014-00371**
ELECTRIC RATES	**)**	

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

Filed: November 26, 2014

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

A. My name is Kent W. Blake. I am the Chief Financial Officer for Louisville Gas and Electric Company ("LG&E") and Kentucky Utilities Company ("KU" or the "Company") and an employee of 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 40202.

Q. Please describe your educational and professional background.

A. A complete statement of my work experience and education is contained in Appendix A.

Q. Have you previously testified before this Commission?

A. Yes, I have testified before the Commission on numerous occasions, most recently for KU in the Company's last base rate case, *In the Matter of: Application of Kentucky Utilities Company for an Adjustment of its Electric Rates*, Case No. 2012-00221.

Q. What are the purposes of your testimony?

A. The purposes of my testimony are: (1) to describe why KU requires the requested increase in base rates; (2) to discuss the existing programs within the financial and administrative service groups of the Companies to achieve improvements in efficiency and productivity, including an explanation of the purpose of each program; (3) to completely describe all the factors used in preparing the forecasted test period supporting the requested increase in base rates, including the quantification, explanation and proper support for all the econometric models, variables, assumptions, escalation factors, contingency provisions, and changes in activity levels; (4) to present certain schedules required by 807 KAR 5:001 Section 16 filed with KU's application; (5) to support certain pro forma adjustments; and (6) to describe the calculation of KU's adjusted net operating income and revenue deficiency for the 12-month forecasted test period, beginning July 1, 2015 and ending June 30, 2016.

OVERVIEW

Q. Please provide an overview of KU's base rate application in this proceeding.

A. KU's application requests Commission approval of an increase of $153 million based upon a twelve-month forecasted test period, beginning July 1, 2015 and ending June 30, 2016. As explained in Mr. Staffieri's testimony, KU is requesting a 10.50 percent return on equity, which is lower than the return recommended in the testimony of Dr. William E. Avera and Adrien M. McKenzie of FINCAP, Inc. KU anticipates the Commission will suspend the proposed effective date of January 1, 2015 for this increase in rates for the full six-month suspension period through June 30, 2015. Therefore, a change in rates from this proceeding is expected to take effect July 1, 2015.

Q. Briefly state the primary reasons creating the revenue deficiency identified in KU's application.

A. Four-and-a-quarter years separate the end of the test period used in KU's last rate case from the end of the test period used in the Company's current application. Since the end of KU's last test year, the Company has or is expected to incur approximately $2.6 billion in capital expenditures, $1.4 billion of which is not the subject of any other rate mechanism and can only be recovered through a base rate proceeding. This spend has predominately been in the areas of generation, transmission, distribution and customer service, including enabling technologies, and is detailed in the table below.

KU Electric Capital Investment (millions)

Line of Business	April 1, 2012 to August 31, 2014	September 1, 2014 to June 30, 2016	April 1, 2012 to June 30, 2016
Generation	$496	$205	$701
Transmission	$119	$83	$201
Distribution	$190	$165	$355
Customer Service	$11	$14	$25
Total Operations	**$816**	**$466**	**$1,282**
Other	**$50**	**$46**	**$97**
Total KU Electric	**$866**	**$512**	**$1,378**

By the end of the forecast test period, KU and LG&E will have made significant revisions to their generation fleets and added new sources of power production to meet changing economic conditions and environmental requirements. The Companies are presently constructing a 640 MW natural gas combined cycle combustion turbine generating facility known as Cane Run Unit 7 at the Cane Run Generating Station, by far the largest single capital project in this rate case at a cost of $563 million. As discussed in Mr. Thompson's testimony, the construction of Cane Run Unit 7 is on schedule and under budget. Cane Run Unit 7 is expected to be placed in service May 2015. KU will own 78 percent of Cane Run Unit 7 with LG&E owning the remaining 22 percent. Because a historical test period ending March 31, 2012 was used to establish KU's current base rates, and construction of Cane Run Unit 7 did not commence until after that date, KU's current base rates reflect neither Cane Run Unit 7's capital costs nor its reasonable costs of depreciation, operation, and maintenance.

In addition to changes in the generation fleet, the Companies are making significant investments in transmission and distribution infrastructure and additional information technologies and programs to comply with increasing reliability and other government regulations, enhance cyber security, and facilitate customer service. As a result of the additional capital invested in these projects, KU is also incurring a corresponding increase in depreciation and associated property taxes. KU's capital budget for 2015-2019 is attached to my testimony and marked as Exhibit KWB-1.

KU'S CURRENT AND PROJECTED FINANCIAL CONDITION

Q. How would you describe KU's current and projected financial condition?

A. Since its last rate case, KU has made capital investments and incurred increased operation and maintenance expenses to provide customers with safe and reliable electric service, while also providing a positive customer experience. Given the additional costs KU will have incurred since its last rate case through the end of the forecasted test period in this case, KU does not expect to earn a reasonable rate of return. As shown in Schedule A at Tab 53, KU's electric operations are projected for the base period to have a revenue deficiency of $84,433,977 and an earned rate of return on capital of 5.71 percent. For the forecasted test period, the revenue deficiency will increase to $153,443,950 and the Company's earned rate of return on capital will fall to 4.68 percent.

To provide electric service, KU must continue to raise funds through financing, using both debt and equity. A weakened financial condition is not supportive of these efforts and is not in the interests of either KU's customers or its shareholders.

Q. Why has KU chosen to use a forecasted test period to support its application?

A. A forecasted test period allows for the establishment of rates that more accurately reflect the Company's cost of providing utility service. The use of a historical test period would not necessarily allow the Company to reflect the costs associated with the completion and placement into service of Cane Run Unit 7 because they would be outside the historical test period. As such, rates based on use of a historical test period would not reflect the Company's cost of service the moment they became effective. Our use of a forecasted test period, which is permitted by statute and consistent with the practice of many other regulated Kentucky utilities, will provide a better matching of KU's revenues and cost of service.

EXISTING PROGRAMS TO IMPROVE EFFICIENCY AND PRODUCTIVITY

Q. Can you discuss the Company's existing programs to improve efficiency and productivity?

A. Yes. As a matter of our long-standing business philosophy, we use the same criteria as that of the Commission in evaluating our practices and operations. We seek the most effective, least-cost option that will ensure the delivery of safe and reliable service. This well-established philosophy is employed in a rigorous capital project approval process that is detailed in Exhibit KWB-2, Capital and Investment Review Policy, and includes completion of an Authorization of Investment Proposal for any capital project over $2,000, completion of an Investment Proposal and Capital Evaluation Model for capital projects over $500,000 and a presentation to and approval from our Investment Committee for capital projects over $1 million. The Investment Committee consists of myself as Chair, Mr. Thompson, Mr. Sinclair, Mr.

Brad Rives (Chief Administrative Officer) and Mr. Jerry Reynolds (General Counsel). Any project overruns on an approved project follow a similar approval process.

Contracts and other disbursements go through a similar review and approval process applying the same principles used for capital projects. In addition, our long-standing policy requires that all procurement contracts be competitively bid, subject to limited exceptions. Moreover, along with making the Company more responsive to customers, its service more reliable and enhancing both customer data security and protecting the Company's critical infrastructure, our investment in information technology improves our efficiency, productivity and service. These technology investments have also provided better and timelier input into one of our most important tools for improving efficiency and productivity -- the business planning process.

Q. How is the business planning and budgeting process used to improve efficiency and productivity?

A. Our process begins with the development of our corporate objectives. Those objectives consider relevant economic, market, regulatory and legislative developments as they relate to our current performance and the Company's mission, vision and corporate values. Next, we identify operating requirements necessary to accomplish these objectives. In turn, the business planning process translates the operational requirements into the resource requirements necessary to achieve those plans.

The business planning process allows us to:

- Provide managers a tool for the ongoing control of costs and responding to changes in operating conditions;
- Project earnings, which are used to evaluate the financial viability of the Company and to determine whether modifications to plans are needed to meet market expectations;
- Provide management with a platform to present estimated costs of meeting key performance indicators and other departmental goals through the operating plan review process;
- Provide a plan for accumulating financial resources to fund operational plans; and
- Provide management a tool for internal control that provides a base against which actual results can be compared and performance measured.

Q. How does the process encourage efficiency and productivity?

A. The Company's business planning process is a "bottom-up" process, with each business unit preparing detailed five-year plans addressing its individual areas of responsibility. These five-year plans are reviewed by successive levels of management to ensure not only that they are in line with the Company's objectives, but also make efficient and productive use of the Company's resources.

Moreover, the budget and five-year plan serve as an ongoing measure to track whether the Company's objectives are being accomplished as intended, or whether adjustments are necessary. The result is ongoing attention, focus and review of the

Company's efforts to ensure that the Company is conducting its business in an efficient and productive manner.

Q. What are some of the specific changes the Company has taken to improve efficiency within its administrative and financial service functions?

A. Several programs have been undertaken to improve efficiency and productivity. For example, in anticipation of significant hiring given the demographics of our current workforce, the Human Resources Department centralized and streamlined the staffing process. The Human Resources Department prepares the posting of all new or vacant positions across the company; receives, assembles, and conducts the initial review of applicants with the hiring department; and then works closely with the hiring department on a more detailed review of the remaining applicants before making a final selection for a position. Despite the current and projected increase in hiring due to employee retirements and turnover, the Human Resources Department has not increased its headcount.

In 2013, the Companies' Information Technology group engaged an external consultant to conduct two separate engagements focused on more effective business alignment, enhanced productivity and an optimized sourcing model. The consultant noted that total information technology spending at the Companies remained lower than peers even while capital investment had increased. However, it was recognized that business and technology trends are influencing organization dynamics including alignment, cost, agility, and technology skills. The consultant recommended and the Information Technology team implemented a revised operating model anchored on plan, build, and run processes. This has enabled the group to remain cost competitive in the face of increased demands on and for automated solutions.

The use of information technology systems and software has been increased to mitigate the need for additional personnel. For example, the Company has faced additional Security and Exchange Commission reporting requirements since its return to the status of a registrant under federal securities law. It has also faced additional legal, regulatory and reporting requirements as it accesses financial markets to fund its operations and various capital projects after years of relying heavily on intercompany financing provided by its former parent, E.ON AG. The Chief Financial Officer ("CFO") group has met these increasing demands without increasing its headcount through its increasing use of information automation and the increased use of interns. The CFO group, and the Company as a whole, has encouraged the use of interns to lessen the entry-level workload on analysts, enabling full-time employees to focus on more complex work assignments and to allow greater time for necessary cross training, knowledge retention, professional development and better communication across departments. The use of interns has also provided a pipeline for full-time employment. Several recent hires in the CFO group, had previously worked as interns for the Company.

Despite efficiency and productivity efforts, certain shared service areas have had to increase their employee headcount to meet increased needs and customer expectations. Since the Company's last test year end, 53 positions have been or are projected to be added to the Information Technology group. These positions are necessary to address the increasing demands placed upon the Companies' information technology resources. The Companies' information technology infrastructure has expanded significantly as the Companies have increased their reliance upon information technology systems to ensure the reliability of service and to meet numerous regulatory requirements. We currently have 453 physical servers, 1,035 virtual servers, 853 terabytes of used storage, hundreds of miles of fiber-optic cable, thousands of networking and security devices, more than 1,300 databases, and two data centers. The Company also has expanded the mobility and accessibility of its employees through the deployment of mobile devices and applications. Additional personnel are required to service, maintain, and expand this existing network and to support critical business applications. The information technology positions are also necessary to enhance existing network security to prevent information security breaches and to enable the Companies to meet newly announced Critical Infrastructure Protection ("CIP") standards.

Other administrative service positions have been added in the areas of Environmental Affairs and Compliance to address increased regulation from the Environmental Protection Agency and other state and federal agencies. The Companies have also added personnel to more effectively communicate with customers in our service territory, including website enhancement and social media outlets. In addition to the Information Technology positions above, 17 positions have been or are projected to be added since the last test year in the Companies' administrative departments.

Q. How do the Company's costs and efficiency compare to benchmark companies?

A. Attached to my testimony as Exhibit KWB-3 is the most recent annual benchmark study, prepared under my direction and supervision, based on information in Federal Energy Regulatory Commission ("FERC") Form 1. The benchmark study shows that KU and its sister company, LG&E, are below the industry average cost in all areas of the comparison. The Companies are in the top quartile for Generation, Transmission, and Administrative and General Expenses. The Companies' rankings in Customer Service and Electric Distribution reflect additional investment in customer service and reliability to meet customer needs and regulatory expectations. In addition, as discussed below, the Companies have among the lowest-cost debt in the industry.

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

A. Yes. Exhibit KWB-3 demonstrates that KU is currently among the most cost-effective utilities in the country and that our customers receive good value. If the proposed rates are approved, KU's customers will continue to receive a good value for their utility service.

BUSINESS PLANNING PROCESS-RESULTING IN FINANCIAL FORECASTED TEST PERIOD

Q. Would you please provide a description of all business planning processes used to produce the fully forecasted test period in this case?

A. Yes. Each year the Companies prepare a five-year business plan which includes projected income statements, cash flow statements and balance sheets. The first year of that five-year plan represents the Company's budget. The basis for determining the components of the five-year financial projections and the system employed to develop those projections, including econometric models, variables, assumptions, escalation factors, contingency provisions, and changes in activity levels are described in detail in the documents attached to Filing Requirement Schedule 807 KAR 5:001 Section 16(7)(c) at Tab 16 and in my testimony and the testimony of Mr. Thompson and Mr. Sinclair.

The chart below provides a visual depiction of the business planning process:

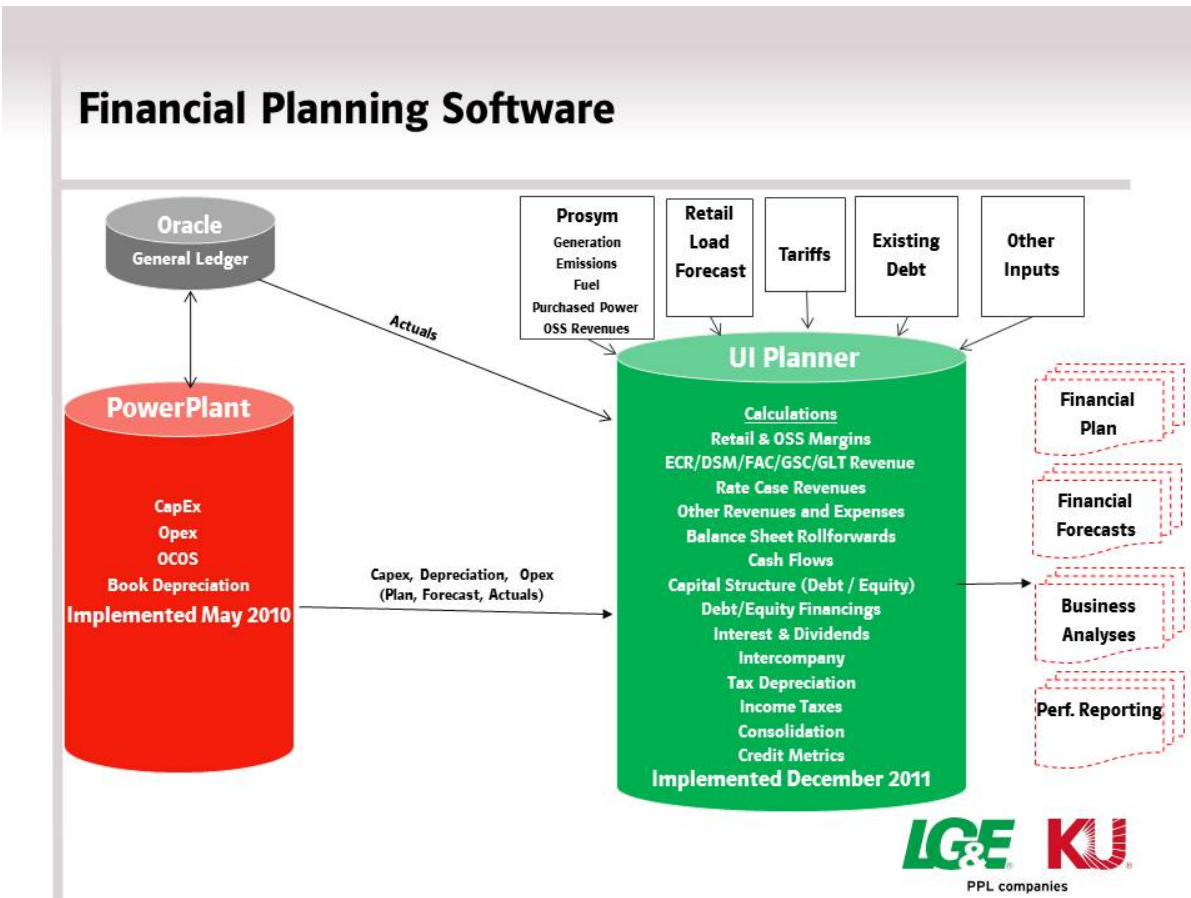

Exhibit KWB-4, Financial Summary Table, contains a list of components from the Company's income statement, balance sheet and cash flow statement, the basis to derive each item and the software system employed to arrive at each item.

Q. Has the Company prepared a list of all commercially available or in-house developed computer software, programs, and models used in the development of the schedules and work papers associated with the filing of the Application as required by 807 KAR 5:001 Section 16(7)(t)?

A. Yes. This information is located at Tab 50 of this application, and includes the software, programs, and models used in the Company's business planning process and to develop the fully forecasted test period in this case.

Q. Will you please describes the steps in the annual business planning process?

A. Yes. The process generally occurs along the following timeframe:

- May - Workforce plan finalized and labor forecast loaded into PowerPlant.
- June - Corporate burdens for employee benefits calculated and entered into PowerPlant
- July – Electric and gas sales and commodity price forecasts completed, and loaded into UIPlanner
- July-August - Capital plan prepared, reviewed, and loaded into PowerPlant
- August (first half) - Generation forecast completed. reviewed, and loaded into UIPlanner
- August (second half) - Operations and Maintenance, Costs of Sales and other expense budgets completed, reviewed, and loaded into PowerPlant
- August - PowerPlant extract imported into UIPlanner
- September - Other revenue calculations, depreciation, financing and tax calculations completed in UIPlanner
- September/October - Business Plan presentations conducted, reviews completed and necessary changes made
- October - Business Plan reviewed with Senior Officers.
- November - Business Plan reviewed with and approved by LKE Board and submitted to PPL for inclusion in PPL financial projections.

Q. Please describe the process used to develop the work force plan and labor forecast used in the business planning process.

A. The Human Resources Department works with each line of business to identify its future labor needs and its planning assumptions for employee development, retention, staffing changes, and workforce demographics. The current workforce, open positions and projected needs are analyzed. The result of this process is documented in the work force plan.

The work force plan is the starting point used to develop the labor forecast. The Companies' current labor force data is exported from PeopleSoft, the computer application that is used to perform many of the Companies' human resources functions. Wage increases, vacation hours, personal days, and sick time are applied to the PeopleSoft data which is then imported into PowerPlant. In the current financial forecast, we have assumed three percent annual wage inflation. This assumption is based on annual benchmarking studies. Those same studies are used to determine salaries for new hires. PowerPlant then produces a labor forecast that includes full-time and part-time regular employees, summarized by employee type and expenditure organization.

Q. In developing the work force plan and labor forecast, what issues are the Companies required to address?

A. Our Company's operations only continue to become more complex due to increasing regulation of the environmental, financial and operational aspects of our business. As a result, our employees must assume highly skilled roles in the workplace and be capable of adapting to significant changes in technology and the regulatory environment. Our workforce must continue to evolve to attract and retain highly skilled employees who can manage our increasingly complex operation and compliance systems.

Before any position can be filled, even if the position is contained in the approved budget or is a replacement for a departed employee, the applicable senior officer with oversight for that position must justify the position and obtain the approval of the other senior officers. The senior officers in this process consist of me, Mr. Thompson, Mr. Rives, Mr. Reynolds and Dr. Paula Pottinger, Senior Vice-President, Human Resources.

Q. Please describe the component of the business planning process for the determination of capital projects to be included in the Company's business planning and to develop the fully forecasted test period in this case.

A. Lines of business prepare a detailed list of capital projects by year, including the dollar amounts involved over time, start date and in service date. The Investment Committee mentioned earlier has established a subcommittee referred to as the Resource Allocation Committee ("RAC") to ensure capital budgets are prepared with consistent prioritization rankings with an aim towards optimizing capital spending across the enterprise. The RAC includes leaders from multiple business lines so that decisions are made based on priorities of the company as a whole. The RAC serves under the direction of, and makes recommendations to, the Investment Committee. Changes in the five-year capital plan from year to year must be based on new facts and circumstances and supported based on the need for and the cost effectiveness of the projects included therein.

Q. Briefly describe how the Companies developed their forecast of electric and gas sales, generation and off-system sales.

A. The Companies develop their electric and gas sales, generation and off-system sales forecast through the business processes presented in the Companies' integrated resource plans and in certificate of public convenience and necessity filings.

Mr. Sinclair in his testimony provides a more detailed discussion of the assumptions, software and methodology used to develop the electric and gas sales, generation and off-system sales forecasts and the results of these forecasts.

Q. Briefly describe the components of the business planning process for the determination of the operation and maintenance expenses to be included in the Company's business planning and to develop the fully forecasted test period in this case.

A. The budget for the Company's operation and maintenance expenses is prepared by each line of business using a detailed "bottoms up" approach. These expenses are budgeted to the appropriate FERC account. These expenses, along with headcount, capital and other costs, including the driving assumptions and business objectives of each group are reviewed by various levels of management and presented to and approved by the Company's senior officers. A copy of the current year presentations is included at Tab 16 of the Companies' application.

Q. Was the business planning process used to develop the fully forecasted test period ending July 1, 2016 for this application?

A. Yes. The fully forecasted test period supporting this base rate application was developed through the Company's business planning process under my supervision and direction.

Q. Did the Companies include certain assumptions concerning the cost of capital when developing the forecasted test period for this case?

A. Yes, the Companies made assumptions concerning their capital structure, cost of debt and cost of equity when developing the forecasted test period supporting their applications.

<u>Capital Structure</u>

Q. Please explain the capital structure of KU.

A. KU is firmly committed to maintaining its financial strength. One important metric of this is the level of debt compared with the Company's total capitalization. The lower the proportion of debt, the greater the likelihood a company will have sufficient cash flow to meet its interest and other debt obligations when they are due. Also, a company with lower existing debt will likely have an easier time raising additional funds when the need arises. This contributes to a higher credit rating and lower interest costs.

Since 2007, the Company's actual debt-to-capitalization ratios have been between 45.69 percent and 47.89 percent. For the forecast test period, KU has projected a debt-to-capitalization ratio of 46.98 percent. Maintaining this capital structure is consistent with our targeted bond rating of "A."

Q. How does Moody's evaluate a utility's capital structure?

A. Attached to this testimony as Exhibit KWB-5 is a copy of Moody's *Rating Methodology, Regulated Electric and Gas Utilities*, dated December 23, 2013. Under Moody's approach, four factors are considered: (1) regulatory framework, (2) ability to recover costs and earn returns, (3) diversification, and (4) financial strength.

The financial metrics Moody's uses to evaluate an entity's financial strength include the entity's debt-to-capitalization ratio. As stated by Moody's, "High debt levels in comparison to capitalization can indicate higher interest obligations, can limit the ability of a utility to raise additional financing if needed, and can lead to leverage covenant violations in credit facilities or other financing agreements."[1]

KU aims for an "A" rating from Moody's. This is consistent with a debt-to-capitalization ratio of between 35 percent and 45 percent as calculated by Moody's. But Moody's, as do other credit rating agencies, makes various adjustments in computing a company's debt. For example, long term obligations under pensions and leases are included as "debt" obligations and deferred taxes are added back to equity. Using these adjustments, KU's debt-to-capitalization ratio for the base period is at 39.9 percent; for the forecast test period it is 39.5 percent, both near the middle of Moody's range for an "A" rating.

Q. How do other rating agencies evaluate capital structure?

A. Recently, Standard & Poor's ("S&P") adopted a revised rating methodology. This methodology is described in the *S&P Corporate Methodology and Key Credit Factors for the Regulated Utilities Industry*, dated November 19, 2013. This is

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[1] Moody's *Rating Methodology, Regulated Electric and Gas Utilities*, December 23, 2013, at page 23.

attached to my testimony as Exhibit KWB-6. S&P's new methodology assigns values to the following metrics as defined by S&P's analysis: Country Risk, Industry Risk and Competitive Position, to determine a "Business Risk Profile." This is then considered along with a company's "Financial Risk Profile," which is determined by the company's cash flow in relation to its obligations. The result is then adjusted by various "modifiers," including capital structure, beyond the standard cash flow adequacy and leverage analysis, such as debt maturities, interest-rate volatility, and currency issues. Another modifier is corporate financial policy, which is S&P's view of the effect, whether positive, negative, or neutral, of the company's management that is not necessarily reflected by standard analysis of cash flow or leverage. An additional S&P modifier is a company's Liquidity, defined as a company's ability to meet its obligations in the event of declining earnings, or low probability negative events. Obviously, a company's debt-to-capitalization ratio affects both its Financial Risk Profile in terms of whether its cash flow is sufficient to meet its fixed debt obligations, as well as the Capital Structure and Liquidity modifiers. Although S&P's new methodology eliminates any direct correlation between a certain debt-to-equity ratio and a certain rating, the capital structure has a direct impact on the coverage ratios required to meet S&P's ratings guidelines. The Company's current capital structure keeps the Financial Risk Profile ratios solidly in the "Intermediate" category (using S&P's low volatility table) which, combined with the "Excellent" Business Risk Profile are consistent with our target rating of "A."

Q. Why do the credit rating agencies adjust the debt balances when determining the target capital structure?

A. The credit rating agencies view certain obligations, such as power-purchase agreements (in the case of S&P), leases, pensions, and post-retirement benefit obligations, as fixed obligations equivalent to debt. The Company accordingly makes corresponding adjustments when calculating the debt in the target capital structure for this purpose.

<u>Cost of Debt</u>

Q. Please explain how KU's cost of long-term debt was calculated.

A. KU's weighted-average cost of long-term debt at the end of the base period is projected to be 3.78 percent. It includes all components of interest expense for each bond, including the interest paid to the bondholders, amortization of bond issuance costs, amortization of pre-issuance hedging gains, 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.

KU's weighted-average cost of long-term debt for the forecast period is calculated as 4.07 percent. The forecast cost of debt includes a then current projected issuance of $500 million of secured debt in October 2015, which represents replacement of $250 million of debt maturing November 1, 2015, plus an additional $250 million of new debt. This issuance was approved by the Commission in Case

No. 2014-00082.[2] Interest on this October 2015 debt issuance was included in the forecast using then current market interest rates, projected issuance costs and hedges the Company had put in place as of that point in time in the form of forward starting swaps. The calculation of KU's cost of long-term debt is detailed on Filing Schedule J-3 required by 807 KAR 5:001 Section16(8)(j). KU expects toprovide updates on the cost of long-term debt as this case progresses.

Q. Please explain how KU's cost of short-term debt was calculated.

A. The cost of short-term debt is based on interest expense related to commercial paper issuances. For future periods, the interest rate is based on forward LIBOR curves. At the end of the base period, the rate is projected to be 0.64 percent and for the forecasted period the 13-month-average rate is calculated to be 0.91 percent. The build-up of the cost of short-term debt is shown on page 3 of Filing Schedule J-2 required by 807 KAR 5:001 Section 16(8)(j). KU expects to provide updates on the cost of the short-term debt as this case progresses.

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 on a quarterly basis. As shown in Exhibit KWB-7, KU's 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 June 30, 2014, with LG&E being the only utility in the group with a lower cost of debt.

[2] Case No. 2014-00082, *In the Matter of: Application of Kentucky Utilities Company For an Order Authorizing the Issuance of Securities and the Assumption of Obligations* (Ky. PSC June 16, 2014), *amended by* Order of June 30, 2014..

Credit Ratings

Q. What are KU's current credit ratings?

A. Filing requirement section 807 KAR 5:001 Section 16(8)(k) at Tab 63 shows the current credit ratings for KU. KU continues to maintain strong credit ratings which enable the Company to raise debt capital at very reasonable costs.

Q. Have there been any recent changes in the Company's credit rating?

A. Yes. On January 31, 2014, Moody's upgraded the ratings of both KU and LG&E from Baa1 to A3. This upgrade was based primarily on Moody's favorable view of the supportiveness of the regulatory environment in which the Companies operate in Kentucky. A copy of the news release announcing this upgrade is attached to this testimony as Exhibit KWB-8. In addition, on July 18, 2014, S&P placed KU on CreditWatch with positive implications and noted the possibility that KU's current BBB corporate credit rating could be raised by up to two notches. This reflected S&P's positive view of the possible spin-off of PPL's merchant generation business. S&P also favorably noted the credit supportive regulatory environment in Kentucky and KU's competitive rates and efficient operations. A copy of this announcement is attached as Exhibit KWB-9. KU believes that the Commission's balanced approach serves utility companies and customers well and allows Kentucky customers to receive some of the lowest-cost electricity in the United States.

Q. Does KU have sufficient access to capital?

A. Yes. KU has authority from the FERC to issue up to $500 million in short-term debt. KU maintains a $400 million 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 $350 million in commercial paper. The revolving line of credit serves as a backstop for any commercial paper issuances. In addition, by Orders dated June 16, 2014, and June 30, 2014, in Case No. 2014-00082, the Commission granted KU authority to issue up to $500 million in long term debt, secured by first-mortgage bonds before December 31, 2015.

Shareholders' Equity

Q. Can you please explain the assumptions included in your financial forecast related to dividends and equity contributions?

A. KU's dividends are based on a dividend payout ratio of 65 percent of the Company's earnings from the prior quarter. This is consistent with well-established utility industry practice as well as our own practice over the last several years. Equity contributions are made to balance the Company's capital structure as discussed earlier. During periods of extensive construction, these equity contributions can actually exceed the level of dividend payments. Exhibit KWB-10 shows equity contributions to KU compared to dividends paid by KU from 2013 through 2016. Equity contributions constitute a critical source of capital for KU as it continues to provide safe and reliable service, meet customer and regulatory expectations and maintain the target capital structure discussed above.

Q. Have you reviewed the testimony of William E. Avera and Adrien M. McKenzie of FINCAP, Inc. regarding return on common equity?

A. Yes.

Q. Do you believe Dr. Avera's proposed return on common equity is reasonable?

Yes. While I support FINCAP's recommendation, I also support KU's request of only a 10.50 percent return, rather than the 10.64 percent return that Dr. Avera recommends, for the reasons outlined in Mr. Staffieri's testimony. It is important that KU receive an adequate return on equity that considers the likely effect of regulatory lag. In the past, KU has been able to rely upon native load growth and off-system sales as revenue sources to offset rising operating costs and help mitigate the regulatory lag associated with net investment beyond its last test year. As Mr. Thompson observes in his testimony, the opportunity for off-system sales continues to be severely diminished in the current wholesale market and, as demonstrated in Mr. Sinclair's testimony, forecasted load growth continues to be limited. In the face of these conditions, KU still must incur several significant expenditures during the forecasted test period ending June 30, 2016 and beyond. Under these circumstances, KU's opportunity to earn its authorized return between rate cases is subject to significant risk even with the support of a fully forecasted test period.

SCHEDULES REQUIRED BY 807 KAR 5:001 SECTION 16

Q. Are you sponsoring certain schedules required by the Commission's regulation 807 KAR 5:001 Section 16?

A. Yes, in addition to the schedules I discuss later in my testimony required by 807 KAR 5:001 Section 16(8)(a-h and j), I am sponsoring the schedules filed with and in support of the Company's application in this case as shown on the list in Appendix B to my testimony.

FORECASTED TEST PERIOD

Q. What is the forecasted test period the Company used for supporting the requested increase in revenue in this case?

A. The forecasted test period begins July 1, 2015, and ends June 30, 2016.

Q. What is the base period the Company used for purposes of its base rate application in this case?

A. The base period is the 12-month period ending February 28, 2015 and consists of 6 months actual data from March 1, 2014 to August 31, 2014 and 6 months of estimated data from September 1, 2014 to February 28, 2015. KU expects to file updated information, any corrections and the actual data from September 1, 2014 to February 1, 2015 with the Commission no later than April 14, 2015 or 45 days after the end of the base period.

Operating Income Comparison-Electric Operations

Q. Has the Company prepared jurisdictional adjustments to operating income by major account of its electric operations for both base and forecasted test periods as required by 807 KAR 5:001 Section 16(8)(d)?

A. Yes. This information ("Schedule D") with supporting schedules is located at Tab 56 to the application. Schedule D provides the required comparisons between the base period and the forecasted test period.

Q. Please summarize Schedule D.

A. Schedule D is comprised of three schedules. Schedule D-1 shows Operating Revenue and Expenses by account, for both the base period and the forecasted period and the level of variance between the two. Certain jurisdictional pro forma adjustments are then applied to the forecast period to derive the pro forma forecast period used in Schedule C. These pro forma adjustments are detailed in Schedule D-2.1 and include the following:

- Add back the Enviromental Cost Recovery ("ECR") Surcharge costs attributed to off-system sales as such costs must be recovered through base rates rather than the ECR mechanism.
- Adjust the forecasted test period for the proposed depreciation rate to be used for Cane Run Unit 7. The details of the calculation of the Cane Run Unit 7 depreciation rate are set forth in Mr. Spanos's testimony.
- Adjust revenues for certain customer changes which occurred after preparation of the financial forecast. These changes are discussed in Mr. Conroy's testimony.
- Eliminate advertising expenses as required by 807 KAR 5:016 Section 4.
- Remove from income tax expense the tax benefit for the deduction of interest on debt capitalization associated with capital projects recovered through other rate mechanisms, predominantly ECR.

These Schedules are supported by the attached work papers showing details of the specific adjustments.

Q. Please summarize the differences in KU's jurisdictional operating revenues between the base period and pro forma forecasted period as shown on Schedule D-1.

A. Jurisdictional operating revenues are projected to increase $27.7 million or about 2 percent between the base period and pro forma forecast period. However, fuel and purchased power are projected to increase approximately $19 million during this same period. As a result, net revenues are only projected to increase $8.8 million.

Q. Please summarize the differences operating expenses between the base period and pro forma forecasted period as shown on Schedule D-1.

A. Jurisdictional operation and maintenance expenses, after removing fuel and purchased power (rows 23, 51 and 61 on Schedule D-1), are projected to increase $38 million between the base period and pro forma forecasted period. This increase has two primary drivers. First, KU's jurisdictional operating expenses in the forecasted period include $11.8 million of non-fuel operation and maintenance expenses associated with its 78 percent share of Cane Run Unit 7 that were not present in the base period. In addition, employee pension and benefits are projected to increase $17.7 million between the base period and pro forma forecasted period. Remaining jurisdictional operation and maintenance expenses are projected to increase $7.8 million or 2.5 percent between the base period and pro forma forecasted period.

Q. Why are the expenses in FERC account 926 - Employee Pension and Benefits expected to increase during the forecasted period shown on Schedule D-1?

A. The Companies' estimates for pension expense and required funding are based on an actuarial study, using the RP-2014 Mortality Improvement Scale MP-2014. The cost of the Companies' pension programs had previously been calculated using Interim Mortality Scale AA, which the Society of Actuaries ("SOA") issued in 1994. The Society of Actuaries recently issued RP-2014 Mortality Improvement Scale MP-

2014, which is intended to replace prior scales. The Internal Revenue Service ("IRS") which establishes minimum funding calculation for corporate pension plans is expected to consider the new estimates in 2016.[3] The updated tables show that people are living longer. Use of the new tables extends the assumed lifetime of plan participants, which will in turn increase the total expected benefit payments of the Companies' defined benefit plans and lengthen the plans' time horizon, and increases pension expense. The Companies are currently going through their annual process of reviewing pension assumptions with their actuary and expect to validate or update these assumptions during the course of this proceeding.

Also, the Companies project growth in medical expenses, along with additional benefit increases due to headcount growth during the forecasted period. The Companies have assumed that, with effective management and greater emphasis and funding on wellness programs, annual increases in medical insurance premiums can be limited to 4 percent with an additional 2 percent increase representing expenditures for employee wellness and health programs, as well as increased promotion of healthy lifestyle maintenance.

Q. Are there any other significant Operating Expense increases between the base period and pro forma forecasted period?

A. Yes. Depreciation expense is projected to increase by $19.8 million or 11.7 percent and property taxes are projected to increase $3.1 million or 9.7 percent. These increases are the direct product of new plant in-service and our approved depreciation

[3] Dan Fitzpatrick, Rising U.S. Life Spans Spell Likely Pain for Pension Funds: Society of Actuaries Boosts U.S. Life Expectancies by About Two Years. *Wall Street Journal* (Online). Oct. 27, 2014. http//search proquest.com/docview/1616574223?accountid=3730 (last visited Nov. 20, 2014).

rates and current property tax rates, respectively. Both increases also incorporate Cane Run Unit 7 going into service between the base period and pro forma forecasted period.

Q. Please explain why KU's federal and state income tax expense shown on Schedule D is expected to decrease during the forecasted period.

A. The decrease is due primarily to an anticipated decrease in Pretax Book Income, from $338.3 million in the base period to $281.9 million in the forecasted period. As shown on Schedule E the effective tax rate, computed as "Total Income Taxes" per row 67 divided by "Book Net Income before Income Tax & Credits" per row 3, remains relatively consistent for all periods presented at 39.4 percent for the base period, 39.0 percent for the forecasted period and 38.8 percent for the pro-forma forecasted period.

<u>Calculation of Jurisdictional Revenue Deficiency</u>

Q. Has the Company prepared a jurisdictional financial summary of its electric operations for both base and forecasted test periods as required by 807 KAR 5:001 Section 16(8)(a)?

A. Yes. This information ("Schedule A") is located at Tab 53 to the application and shows how the Company determined the amount of the requested revenue increase.

Q. Briefly describe how the jurisdictional financial summary shown in Schedule A was prepared.

A. The Company first determined the amount of required operating income by multiplying the required rate of return by the total capital allocated to the Company's jurisdictional electric operations for the forecasted test period. The total allocated capital and required rate of return are obtained from the cost of capital summary required by 807 KAR 5:001 Section 16(8)(j) ("Schedule J"). Total adjusted operating income produced by the Company's present rates, which is found in the jurisdictional operating summary required by 807 KAR 5:001 Section 16(8)(c) ("Schedule C") is then subtracted from the total required operating income. The difference is then multiplied by the gross revenue conversion factor, whose computation is required by 807 KAR 5:001 Section 16(8)(h) ("Schedule H") which takes into account the effects of various state and federal taxes and bad debt expense. This product represents the additional revenues that the Company's electric operations require to meet its reasonable operating expenses and earn a reasonable rate of return.

Q. What does the Company's financial summary on Schedule A show?

A. The financial summary shows that the Company's electric operations, at current rates, will incur a projected revenue deficiency of $153,443,950 for the forecasted test period, the 12 month period ending June 30, 2016. The projected revenue deficiency is based upon a required rate of return of 7.38 percent. During the forecasted test period, at current rates the Company's electric operations are projected to earn a rate of return of only 4.68 percent.

Q. How do the results for the forecasted test period compare to the base period?

A. For the base period, which ends February 28, 2015, the Company's electric operations are expected to have a revenue deficiency of $84,433,977 and an earned rate of return of 5.71 percent. During the forecasted test period, the revenue deficiency for the Company's electric operations is projected to increase and its earned rate of return on capital is projected to further decline.

<u>Property Valuations Presented: Capitalization and Rate Base</u>

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

A. Section 278.290 of the Kentucky Revised Statutes requires the Commission to give due consideration to three quantifiable values: original cost (rate base), 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. Which property valuation methodology has the Company chosen to support its requested rate changes in this case?

A. In keeping with the Company's approach in its four most recent base rate cases, the Company has chosen the capitalization methodology of property valuation. The Commission has approved this approach in all four of the Company's most recent base rate cases, and the methodology produces a lower revenue requirement than using the net-original-cost-rate-base methodology.

Q. Should the Commission extensively consider using the cost of reproduction as a going concern valuation methodology in this case?

A. No. While the Company had previously presented the reproduction cost of its investment in utility plant in service and the Commission has considered such methodology,[4] the Commission has consistently found such methodology was not the

[4] <u>See</u>, e.g., Case No. 8284, *General Adjustment in Electric and Gas Rates of Louisville Gas and Electric Company* (Ky. PSC Jan. 4, 1982).

most appropriate or reasonable measure for rate of return valuation.[5] This methodology typically leads to a significantly higher revenue requirement than the capitalization or rate base methodologies. Moreover, the United States Supreme Court has been critical of the use of this methodology for ratemaking purposes.[6] In light of this extensive precedent, the Company believes presenting the reproduction methodology's results and raising the methodology's use as an issue for the Commission's review and consideration in detail will not result in a productive or efficient use of the Commission's limited resources or those of any intervening party. The Commission's consideration of this evidence should be sufficient in light of this extensive precedent.

Cost of Capital Summary

Q. Has the Company prepared a cost of capital summary for both base and forecasted test periods as required by 807 KAR 5:001 Section 16(8)(j)?

A. Yes. This information ("Schedule J") is located at Tab 62 to the application. Schedule J consists of five schedules:

- J-1 Cost of Capital Summary
- J-1.1/J-1.2 Average Forecasted Period Capital Structure
- J-2 Embedded Cost of Short-Term Debt

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[5] See, e.g., Case No. 8227, *The Application of Western Kentucky Gas Company For Authority to Adjust Its Rates* (Ky. PSC Oct. 9, 1981) ("net original cost, net investment and capital structure valuation methods are still the most prudent, efficient and economical measures of reasonable rate of return valuation"). See also Case No. 90-076, *An Adjustment of the Rates of Elzie Neeley Gas Company* (Ky. PSC Dec. 7, 1990) (noting that reproduction cost appraisal inflates a utility's rate base, results in a valuation that has no economic substance, and could result in rates that are excessive in relation to the actual investment made by the owners of the utility).

[6] See, *e.g., State of Missouri ex rel. Southwestern Bell Telephone Co. v. Public Service Commission of Missouri*, 262 U.S. 276 (1923) (Brandeis, J. concurring); *St. Joseph Stock Yards Co. v. U.S.*, 298 U.S. 38 (1936); *Federal Power Commission v. Natural Gas Pipeline Co. of America*, 315 U.S. 575 (1942).

- J-3 Embedded Cost of Long-Term Debt
- B-1.1 Jurisdictional Rate Base for Capital Allocation

Schedules J-2 and J-3, and Supporting Schedule B-1.1 provide inputs to the calculations shown on Schedules J-1 and J-1.1/J-1.2.

Q. Please describe Schedule J-2.

A. Schedule J-2 consists of three pages, each of which provides the short-term debt amounts, corresponding interest rates, and weighted cost of short-term debt for the relevant time period. The first page provides the short-term debt information as of the end of the base period, February 28, 2015. The second page provides the short-term debt information as of the end of the forecasted test period, June 30, 2016. The third page provides the 13-month-average short-term debt information for the forecasted test period.

Q. Please describe Schedule J-3.

A. Schedule J-3 consists of three pages, each of which provides the long-term debt information necessary to calculate the embedded cost of long-term debt for the relevant time period, which is shown at the bottom right-hand corner of each page's data. The first page provides the long-term debt information as of the end of the base period, February 28, 2015. The second page provides the long-term debt information as of the end of the forecasted test period, June 30, 2016. The third page provides the 13-month-average long-term debt information for the forecasted test period.

Q. Please describe Supporting Schedule B-1.1.

A. Supporting Schedule B-1.1 consists of four pages, two showing the calculations of net original cost rate base and cash working capital as of the end of the base period and two showing the same calculations for the 13-month-average as of the end of the forecasted test period. The percentages shown in Line 20, "Percentage of Rate Base to Total Company Rate Base," for Column 2, "Kentucky Jurisdictional Rate Base," on pages 1 and 3 of Supporting Schedule B-1.1 are the rate-base-allocation percentages used to allocate capital in Schedules J-1 and J-1.1/J-1.2, respectively.

Q. Please describe Schedule J-1.1/J-1.2.

A. As 807 KAR 5:001 Section 16(6)(c) requires, Schedule J-1.1/J-1.2 shows the calculation of the Company's 13-month-average adjusted capitalization, as well as the weighted average cost of capital, the Company used to determine the net operating income found reasonable on Schedule A. This schedule is comparable to the Exhibit 2 the Company has filed in its recent historical-test-period base rate cases. As indicated on Schedule J-1.1/J-1.2, the requested rate of return on capitalization is 7.38 percent, based on the proposed 10.50 percent return on common equity proposed by the Company, which is within the range of returns on common equity recommended by Dr. Avera and Mr. McKenzie. Page 1 provides this calculation, while page 2 details the "Adjustment Amount" included in Column D of page 1 and page 3 details the "Jurisdictional Adjustments" included in Column H of page 1.

The adjustments on page 2 of this schedule remove KU's equity investment in Electric Energy Inc., Ohio Valley Electric Corporation, and other net non-utility investments. The adjustments on page 2 are consistent with the adjustments approved in the Commission's Orders in Case Nos. 2009-00548 and 2003-00434, and as proposed by KU in Case Nos. 2012-00221 and 2008-00251, which were resolved by settlements approved by the Commission.

The adjustments on page 3 of this schedule remove the Company's ECR Surcharge and the DSM cost-recovery mechanism rate base amounts from capitalization to be considered in this proceeding. Removing ECR and DSM rate base from the Company's capitalization is necessary because the Company recovers its ECR and DSM capital investments, and a return on those investments, through the environmental surcharge and DSM cost-recovery mechanisms. For DSM rate base, this includes removing the rate base associated with the Company's Advanced Metering Systems ("AMS") customer offering, which the Commission approved in its final order in Case No. 2014-00003.[7]

Column F on page 1 of this schedule contains the rate-base allocation factor to remove from KU's total utility capitalization all non-Kentucky-jurisdictional capital. The rate-base-allocation factor is calculated on Supporting Schedule B-1.1.

Column J shows each capital component's percentage of total capitalization, which is calculated by dividing the individual capital component's amount shown in Column I by the "Total Capital" shown at the bottom of Column I. Column K shows the cost rate for each capital component: short-term debt from Schedule J-2, long-term debt from Schedule J-3, and the return on common equity of 10.50 percent I discussed above. Finally, Column L multiplies capitalization percentages in Column J by the cost rates in Column K to obtain the 13-month-average weighted cost of each capital component. The total weighted capital cost, 7.38 percent, appears in Line 4 of Schedule A.

[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 Programs,* Case N. 2014-00003, Order (Nov. 14, 2014).

Q. Please describe Schedule J-1.

A. Schedule J-1 shows the calculation of the Company's adjusted capitalization, as well as the weighted average cost of capital, as of the end of the base and forecasted test periods. Each page of this schedule is comparable to the first page of the Exhibit 2 the Company has filed in its previous historical-test-year base-rate cases and Schedule J-1.1/J-1.2 in this proceeding, with the exceptions that (1) Schedule J-1 does not contain detailed calculations of the adjustment amounts shown in Column H of each page of the schedule and (2) the inputs the various pages of Schedule J-1 draw from Schedules J-2 and J-3, and Supporting Schedule B-1.1 differ because they address different time periods. Therefore, it is necessary to correlate the appropriate pages of Schedules J-2 and J-3, and Supporting Schedule B-1.1 with the page of Schedule J-1 the reader is using.

Jurisdictional Rate Base Summary

Q. Has the Company prepared a jurisdictional rate base summary for both base and forecasted test periods as required by 807 KAR 5:001 Section 16(8)(b)?

A. Yes. The Company has prepared a Schedule B to satisfy the requirements of 807 KAR 5:001 Section 16(8)(b); Schedule B is located at Tab 54 to the application. The information contained in Schedule B provides KU's net original cost rate base property as required under KRS 278.290. The rate base amounts calculated are for the base period (as of Feb. 28, 2015) and for a 13-month-average for the forecasted test period as required by 807 KAR 5:001 Section 16(6)(c).

Q. Please describe the components of Schedule B.

A. Schedule B consists of a summary schedule, Schedule B-1, showing KU's calculated rate base for the base period and the forecasted test period. The information contained in Schedule B-1 derives from the remaining schedules in Schedule B, which calculate the rate base components and adjustments: Plant in Service (Schedules B-2 – B-2.7), Accumulated Depreciation and Amortization (Schedules B-3 – B-3.2), Construction Work in Progress (Schedule B-4 – B-4.2), Allowance for Working Capital (Schedules B-5 – B-5.2), Deferred Credits and Accumulated Deferred Income Taxes (Schedule B-6), and Jurisdictional Percentages (Schedules B-7 – B-7.2). Also, Schedule B-8 provides comparative balance sheets for calendar years 2009-2013, as well as for the base period and for the forecasted test period. In keeping with the Company's historical-test-period base rate cases, Schedule B-5.2 computes cash working capital using the 45-day (1/8) methodology.

Q. Please explain the adjustments to base-period and forecasted-test-period rate base shown in Schedule B-2.2.

A. Schedule B-2.2 removes from the utility's rate base the portions of rate base for which the utility's other rate mechanisms provide a return of and on the utility's investment. These mechanisms are the DSM cost-recovery mechanism and the ECR surcharge. Schedule B-2.2 also reduces KU's jurisdictional rate base by the net-utility-plant amount related to its sale of Granville lights to the Lexington-Fayette Urban County Government.

Schedule B-2.2 further removes Asset Retirement Obligation ("ARO") assets from rate base, which is consistent with the Company's approach in its historical-test-year base rate cases. In Case No. 2003-00427, the Commission issued an order approving a stipulation between KU and the intervenors, 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;

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 assets, related ARO asset accumulated depreciation, ARO liabilities, and remaining regulatory assets associated with the adoption of SFAS No. 143.

In Case No. 2003-00434, KU excluded ARO assets from rate base. The Commission approved the exclusion in its June 30, 2004 Order in that proceeding. The Commission also approved the exclusion in the Company's next rate case, 2009-00548. KU similarly excluded such amounts in Case Nos. 2012-00221 and 2008-00251, which were resolved by settlements approved by the Commission.

Q. In summary, what does Schedule B show?

A. Schedule B shows that KU's jurisdictional adjusted rate base as of the end of the base period will be $3,636,964,242, which will increase to a 13-month average of $3,669,268,543 for the forecasted test period. When the adjusted operating income shown in Schedule A for the forecasted test period ($167,044,210) is divided by the 13-month-average rate base for the same period, the result is that KU's utility operation will produce a rate of return on average rate base of 4.55 percent. If the Commission approves the requested increase and KU's utility operation earns its required operating income shown in Schedule A for the forecasted test period ($263,439,015), it will earn a rate of return on rate base of 7.18 percent.

<u>Jurisdictional Operating Income Summary - Electric Operations</u>

Q. Has the Company prepared a jurisdictional operating income summary of its electric operations for both base and forecasted test periods as required by 807 KAR 5:001 Section 16(8)(c)?

A. Yes. This information ("Schedule C") is located at Tab 55 to the application.

Q. Briefly describe Schedule C.

A. Schedule C is a jurisdictional operating income summary for the base period and the forecasted period with supporting schedules that are broken down by major account group and by individual account. It consists of four schedules:

- Schedule C-1 (Jurisdictional Operating Income Summary)
- Schedule C-2 (Jurisdictional Adjusted Operating Income Statement)
- Schedule C-2.1 (Jurisdictional Operating Revenues and Expenses By Account)
- Schedule C-2.2 (Comparison of Electric Utility Activity)

Q. Please describe Schedule C-1.

A. Schedule C-1 summarizes the Company's jurisdictional operating revenues and expenses for the Company's electric operations for the base and forecasted test periods. The schedule depicts the base period level (Column 1), forecasted test period level at current rates (Column 3), and forecasted test period levels at the proposed rates (Column 5).

The amounts set forth in Schedule C-1, Column 1 reflect the Company's adjusted base period amounts as shown at pages 1-6 of Schedule C-2.1, Column 5. These amounts represent base year totals adjusted to remove revenues and expenses associated with the DSM, ECR, and the Fuel Adjustment Clause ("FAC") mechanisms, as these represent revenues and costs recovered outside of base rates. The removal of these revenues and expenses are shown on Schedule D-2. The adjustments in Schedule C-1, Column 2 are detailed in schedule D-1.

Schedule C-1, Column 4 reflects the change in revenues and expenses resulting from the implementation of the proposed rates. Revenues will increase $153,443,950, which is equal to the amount of the "Revenue Deficiency" and "Revenue Increase Requested" reported on Schedule A. Expenses will increase $57,049,146 to reflect increased taxes, bad debt expenses (included in "Operation and Maintenance Expenses") and KPSC assessments fees (included in "Taxes Other Than Income") related to the increased revenues. Note that the proposed increase in "Net Operating Income" (Column 4, line 13) is equal to the Operating Income Deficiency reported in Schedule A.

Schedule C-1, Column 5 reflects projected revenues and expenses for the forecasted test period at the Company's proposed rates.

Q. What does Schedule C-1 show?

A. For the base period, the Company projects total net operating income of $199,085,734, which results in a return on capitalization of 5.71 percent. Total net operating income during the forecasted test period is projected to decrease to $167,044,210. Because the level of capital devoted to the Company's electric operations will increase from $3,489,230,276 to $3,568,968,426, the Company's return on capitalization will decrease to 4.68 percent.

Q. Please describe Schedule C-2.

A. Schedule C-2 details the Company's adjusted jurisdictional operating statement for the base period and the forecasted test period as used in Columns 1 and 3 of Schedule C-1, and breaks down "Forecasted Adjustments at Current Rates" per Column 2 of Schedule C-1 between "Jurisdictional Adjustments to Base Period" (Column 2 of Schedule C-2) and "Jurisdictional Pro Forma Adjustments to Forecasted Period" (Column 4 of Schedule C-2).

Schedule C-2, Column 2 represents adjustments to the base period amounts to reflect forecasted test period conditions. These adjustments are shown in detail on Schedule D-1, Column 2 and are described at Schedule D-1, Column 6.

Schedule C-2, Column 4 reflects the pro forma adjustments to forecasted test period operations. These adjustments are listed in detail in Schedule D-2.1. The amounts in Schedule C-2, Column 4 correspond to the amounts at Schedule D-2.1, Column 10.

Schedule C-2, Column 5 represents the pro forma forecasted test period amount. The amounts in Column 5 correspond to those in Schedule C-1, Column 3.

Q. Please describe Schedule C-2.1.

A. Schedule C-2.1 is a statement of jurisdictional operating revenues and expense by account for the base period and for the forecasted test period. It details how the Company's jurisdictional net operating income was determined for the base period and forecast period.

Q. Please describe Schedule C-2.2.

A. Schedule C-2.2 is a comparison of the Company's electric operations on a monthly basis for the base period and for the forecasted test period. The information in this schedule is further classified by account. The information for the six months ending August 31, 2014 reflects actual operations. The remaining months of the base period and all of the forecasted test period are forecasted.

<u>**Jurisdictional Federal and State Income Tax Summary**</u>

Q. Has the Company prepared a jurisdictional federal and state income tax summary of its electric operations for both base and forecasted test periods as required by 807 KAR 5:001 Section 16(8)(e)?

A. Yes. This information ("Schedule E") is located at Tab 57 to the application.

Q. Please describe Schedule E.

A. Schedule E is in two parts, Schedule E-1 shows the Company's jurisdictional income tax at current rates for the base period and shows pro forma adjustments at both current and proposed rates for the forecasted test period. Schedule E-2 shows how the jurisdictional allocation was derived. This allocation was based on the same methodology KU has historically used in its base rate cases, and is unchanged from its last rate case, Case No. 2012-00221. The effective tax rate, computed as "Total Income Taxes" per row 67 divided by "Book Net Income before Income Tax & Credits" per row 3, remains relatively consistent for all periods presented at 39.4 percent for the base period, 39.0 percent for the forecasted period and 38.8 percent for the pro forma forecasted period.

<u>**Gross Revenue Conversion Factor**</u>

Q. Has the Company prepared a computation of a gross revenue conversion factor for the forecasted test period of its electric operations as required by 807 KAR 5:001 Section 16(8)(h)?

A. Yes. This information ("Schedule H") is located at Tab 60 to the application.

Q. Please describe Schedule H.

A. Schedule H sets forth the calculation of the gross revenue conversion factor ("GRCF"). This is the factor, or multiplier, used to gross-up the operating income deficiency to a revenue deficiency amount. This factor is designed to cover income taxes, uncollectible accounts expense and revenue-based fees assessed by the Commission on the requested revenue increase. The federal and state income tax rates are calculated as shown in the attached Workpaper WPH-1.A at Tab 60. The uncollectible accounts expense rate of 0.32 percent is based on observed trends in net write-offs and is lower than the historic 5-year average of 0.36 percent. The rate used for the KPSC assessment fee is based on the last assessment notice received by the Company. The GRCF is used on Schedule A to compute the calculated revenue deficiency based on the calculated net operating income deficiency.

Q. What is your recommendation in this proceeding?

A. I recommend the Commission authorize the changes in electric base rates that the Company has proposed in its application to recover $153,442,682 of the revenue deficiency in the forecasted period jurisdictional revenue requirement.

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 21st day of November 2014.

_________________ (SEAL)
Notary Public

My Commission Expires:

July 18, 2018

APPENDIX A

Kent W. Blake

Chief Financial Officer
LG&E and KU Energy LLC
220 West Main Street
Louisville, Kentucky 40202
Telephone: (502) 627-2573

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	2003-2007
Director, State Regulation and Rates	
Director, Regulatory Initiatives	
Director, Business Development	2002-2003
Director, Finance and Business Analysis	

Mirant Corporation (f/k/a Southern Company Energy Marketing) 1998-2002

Senior Director, Applications Development
Director, Systems Integration
Trading Controller

LG&E Energy Corp. 1997-1998

Director, Corporate Accounting and Trading Controls

Arthur Andersen LLP 1988-1997

Manager, Audit and Business Advisory Services
Senior Auditor
Audit Staff

Education

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

Professional and Community Affiliations

American Institute of Certified Public Accountants
Kentucky State Society of Certified Public Accountants
Edison Electric Institute
Financial Executives Institute
Leadership Louisville, 2007
CASA of the River Region, Chair
Metro United Way, Board Member

APPENDIX B

List of Schedules Required by 807 KAR 5:001 Section 16 Sponsored by Kent W. Blake

Application Tab	807 KAR 5:001 Section 16 Subsection	Information Required
8	(16)(6)	(a) Financial data for forecasted period presented as pro forma adjustments to base period
9	(16)(6)	(b) Forecasted adjustments limited to twelve (12) months immediately following suspension period
10	(16)(6)	(c) Capitalization and net investment rate base
11	(16)(6)	(d) No revisions to forecast
12	(16)(6)	(e) Commission may require alternative forecast
13	(16)(6)	(f) Reconciliation of rate base and capital used to determine revenue requirements
15	(16)(7)	(b) Most recent capital construction budget containing at a minimum 3-year forecast of construction expenditures
16	(16)(7)	(c) Complete description of all factors used to prepare forecast period
17	(16)(7)	(d) Annual and monthly budget for 12 months preceding filing date, base period and forecasted period
21	(16)(7)	(h) Financial forecast for each of 3 forecasted years included in capital construction budget supported by underlying assumptions made in projecting results of operations and including the following: (See Tabs 22-25, 30-33, and 38)
22	(16)(7)	(1) Operating income statement (exclusive of dividends per share or earnings per share)
23	(16)(7)	(2) Balance sheet
24	(16)(7)	(3) Statement of cash flows
25	(16)(7)	(4) Revenue requirements necessary to support forecasted rate of return
30	(16)(7)	(9) Employee level
31	(16)(7)	(10) Labor cost changes
32	(16)(7)	(11) Capital structure requirements
33	(16)(7)	(12) Rate base
38	(16)(7)	(17) Detailed explanation of any other information provided
40	(16)(7)	(j) Prospectuses of most recent stock or bond offerings
42	(16)(7)	(l) Annual report to shareholders or members and statistical supplements covering most recent 2 years from the application filing date

APPENDIX B

Application Tab	807 KAR 5:001 Section 16 Subsection	Information Required
44	(16)(7)	(n) Latest 12 months of monthly managerial reports providing financial results of operations in comparison to forecast
45	(16)(7)	(o) Complete monthly budget variance reports with narrative explanations for the 12 months immediately prior to base period, each month of base period and subsequent months, as available
46	(16)(7)	(p) SEC's annual report (Form 10-K) for most recent 2 years, any Form 8-Ks issued during past 2 years, and any Form 10-Qs issued during past 6 quarters
47	(16)(7)	(q) Independent auditor's annual opinion report
48	(16)(7)	(r) Quarterly reports to the stockholders for the most recent 5 quarters
50	(16)(7)	(t) All commercial or in-house computer software, programs and models used to develop schedules and work papers associated with application
53	(16)(8)	(a) Jurisdictional financial summary for both base and forecasted periods
54	(16)(8)	(b) Jurisdictional rate base summary for both base and forecasted periods
55	(16)(8)	(c) Jurisdictional operating income summary for both base and forecasted periods
56	(16)(8)	(d) Summary of jurisdictional adjustments to operating income by major account with supporting schedules
57	(16)(8)	(e) Jurisdictional federal and state income tax summary for both base and forecasted periods
58	(16)(8)	(f) Summary schedules for both base and forecasted periods of organization membership dues; initiation fees; expenditures for country club; charitable contributions; marketing, sales and advertising; professional services; civic and political activities; employee parties and outings; employee gifts; and rate cases
59	(16)(8)	(g) Analyses of payroll costs including schedules for wages and salaries, employees benefits, payroll taxes straight time and overtime hours, and executive compensation by title
60	(16)(8)	(h) Computation of gross revenue conversion factor

APPENDIX B

Application Tab	807 KAR 5:001 Section 16 Subsection	Information Required
		for forecasted period
61	(16)(8)	(i) Comparative income statements (exclusive of dividends per share or earnings per share), revenue statistics and sales statistics for 5 calendar years prior to application filing date, base period, forecasted period and 2 calendar years beyond forecast period
62	(16)(8)	(j) Cost of capital summary for both base and forecasted periods
63	(16)(8)	(k) Comparative financial data and earnings measures for the 10 most recent calendar years, base period and forecast period

Exhibit KWB-1

Capital Budget for 2015-2019

5 Year Capital Expenditures

LKE Capex 2015 BP
$000s

LKE:	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**
Environmental	704,824	568,613	385,260	363,134	507,833	370,343
Generating Facilities	242,810	196,949	156,031	151,287	264,622	664,577
Distribution Facilities	223,446	244,977	252,005	248,011	223,277	240,608
Transmission Facilities	77,408	59,116	53,505	83,776	72,520	88,001
Other	58,405	55,457	72,725	61,595	51,260	53,198
Total Capital Expenditures	**1,306,893**	**1,125,113**	**919,526**	**907,804**	**1,119,511**	**1,416,727**

KU:	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**
Environmental	340,366	228,075	186,595	186,509	246,750	222,372
Generating Facilities	137,899	104,825	71,445	82,052	172,667	407,238
Distribution Facilities	76,842	86,854	90,035	94,329	94,129	101,834
Transmission Facilities	42,390	43,351	41,438	58,564	55,633	67,992
Other	29,434	28,510	37,762	33,775	29,405	27,246
Total Capital Expenditures	**626,931**	**491,615**	**427,275**	**455,229**	**598,585**	**826,682**

LG&E:	2014	2015	2016	2017	2018	2019
Environmental	364,458	340,538	198,666	176,626	261,083	147,971
Generating Facilities	104,852	92,124	84,585	69,235	91,955	257,338
Distribution Facilities	146,604	158,123	161,970	153,682	129,148	138,774
Transmission Facilities	35,017	15,765	12,068	25,212	16,886	20,009
Other	26,840	25,381	34,212	27,650	21,527	25,434
Total Capital Expenditures	**677,773**	**631,931**	**491,501**	**452,405**	**520,598**	**589,527**

LKE Other:	2014	2015	2016	2017	2018	2019
Other	2,189	1,567	750	170	329	517
Total Capital Expenditures	**2,189**	**1,567**	**750**	**170**	**329**	**517**

Exhibit KWB-2

Capital and Investment Review Policy

LG&E AND KU ENERGY LLC Policy

Date: 05/01/2014

Capital and Investment Review

Policy

The primary purpose of the Capital and Investment Review Policy is to establish a uniform process for:

1. capital planning and budgeting;
2. authorizing the expenditure of funds;
3. controlling and reporting of capital expenditures;
4. developing review criteria for the authorization process;
5. recording lessons learned for future investments and decisions; and
6. determining how the investment is performing and how the returns compare to the project as sanctioned.

Further, these policies will provide management with the necessary tools to make informed business decisions. A capital expenditure includes adding, replacing or retiring units of property through the construction or acquisition process. Generally, it is inappropriate to capitalize expenditures that are part of routine or necessary maintenance programs. If a substantial improvement is made to an asset, the following two sets of criteria should be used to determine whether or not capitalization is appropriate:

The improvement must meet both of the following criteria:

1. Be a minimum of $2,000.
2. Meet the definition of a capitalizable cost under the FERC Uniform System of Accounts.

In addition, the improvement must do at least one of the following criteria:

1. Extend the original useful life of the asset.
2. Increase the throughput or capacity of the asset.
3. Increase operating efficiency.

Questions relating to the categorization of an expenditure as capital or O&M expense should be directed to Property Accounting. The Controller will have the ultimate authority of interpreting expense versus capital decisions based on generally accepted accounting principles. See Property Accounting's Home Page.

Scope

This policy applies to LG&E and KU Energy LLC ("LKE" or "the Company") and its subsidiaries.

General Requirements

LG&E AND KU ENERGY LLC Policy

Date: 05/01/2014

Capital and Investment Review

1. All capital spending that is expected to occur during the current year must be budgeted in the approved Business Plan (BP).
2. There will be no carry-over of spending capital authority from one year to the next.
3. An Authorization for Investment Proposal (AIP) must be completed in PowerPlant for all capital spending projects.
4. Projects with a total cost of $2,000 or less will be expensed.
5. An Investment Proposal (IP) and Capital Evaluation Model (CEM) must be completed for all capital spending projects greater than $500,000 unless otherwise approved by Financial Planning and Analysis (FP&A).
6. The Information Technology Department must approve all capital projects involving anything related to information technology.
7. All investment projects greater than $1,000,000 require the approval of the Investment Committee (IC).
8. The IC is required to approve any overrun of $500,000 or greater on previously approved proposals. If the previous proposal was below the IC threshold and the revised amount is over the respective IC threshold, the proposal needs to be approved by the IC regardless of the increase amount.

Capital Planning

The BP is used to inform senior management of future capital-spending projections. These plans are prepared annually on a line of business (LOB) basis and include the forecast of capital projections during the most current annual planning period. The first year of the BP, once approved, becomes the formal budget for that year.

Carry-Over Spending: During preparation of the BP, each LOB will review all current-year projects to determine if they will be completed as of the end of the year. If a project is expected to be in process at year-end, but not complete, it must be included in the following year's BP for additional funds to be approved.

Capital Approval Process

Authorization for Investment Proposal: Although specific capital projects are identified in the budgeting process, they are still subject to the Authority Limit Matrix approval requirements and all other reviews as stated on the AIP in PowerPlant. Projects are not considered approved until appropriate approvals are obtained.

The AIP is used to request the appropriate approvals for spending on capital projects. A completed AIP is subject to the following conditions:

- An AIP must be submitted and approved in PowerPlant prior to committing to or incurring any capital expenditure.

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- Approvals must be obtained up to the levels designated in the Authority Limit Matrix for the dollar amount of any project (which may include multiple projects). The combined dollar amount on multiple projects grouped together using the Budget Item field in PowerPlant is the determinant for approval levels.
- Any AIP over $500,000 must include an IP and CEM and must be submitted to FP&A for approval.
- A completed AIP must be submitted and approved prior to the disposal of any capital asset. In addition, an IP must be submitted for disposal projects of $500,000 or more.
- A revised AIP must be submitted for significant project overruns (see below).

Investment Proposal: The IP is used to explain in detail the nature and justification of the capital project. Capital projects over $500,000 on a burdened basis require the submittal of an IP and CEM along with the AIP. The following information will provide senior management with consistent documentation for evaluating capital projects. The IP template is published on the FP&A intranet website and must include the following sections at a minimum:

- Header – Include the project name, total expenditures, project number, LOB, who prepared the project and who will present the project (if applicable).
- Executive Summary (½-page length recommended) – Provide a summary explanation of the scope, purpose and necessity of the proposal. Include financial benefits, funding information and qualitative reasons why this proposal should be pursued.
- Background – Explain the history of the project that has led to the need for the project.
- Project Description – Include project scope, timeline and project cost.
- Economic Analysis and Risks – Include bid summary, assumptions, financial summary, environmental impact, risks and other alternatives considered (including their net present value revenue requirements [NPVRR] per the CEM, if applicable).
- Conclusion and recommendation.
- It is recommended that the IP not exceed 5 pages.

Unbudgeted Projects: Any capital expenditure that is not included in the original, approved budget must either be offset by a like reduction in one or more budgeted projects, approved by the Resource Allocation Committee (RAC) if subject to the RAC Tenets or have prior written approval by the LKE Chief Financial Officer (CFO) and Chief Executive Officer (CEO). FP&A must approve AIPs for unbudgeted projects (see *FP&A Approvals* below). Certain Generation Miscellaneous Projects, as described below, are exempt from being considered unbudgeted.

Under-Funded Projects: Projects that are submitted for approval that were included in the original approved budget, where the requested capital amount is greater than the budgeted amount for that project, must either be offset by a like reduction in one or more budgeted projects, approved by the RAC if subject to the its Tenets or the additional funding requires prior

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written approval by the LKE CFO and CEO. These projects are considered "unbudgeted" in PowerPlant since the full funding is not coming from the original budget for that project. FP&A must approve AIPs for under-funded projects (see *FP&A Approvals* below).

LG&E and KU Board and PPL approvals: Any budget item over $30 million requires the approval of the LG&E and KU Energy Board and the PPL CEO. Budget items over $100 million additionally require the approval of the PPL Finance Committee. Cost overruns greater than 20% on budget items approved by the PPL Finance Committee must be re-approved by the Committee before spending occurs. If an overrun on a budget item results in a total cost of $100 million or more, the proposal must be approved by the PPL Finance Committee before spending occurs.

Project Overruns: When it is apparent that the amount approved on the original AIP will be insufficient (project is expected to be 10% or $100,000 over, whichever is less, subject to a minimum of $25,000) to complete the project, **a revised AIP must be completed before the overrun occurs and the following conditions apply (see Capital Appendix):**

- If the project overrun is expected to be $500,000 or greater and the project had been approved by the IC, the revised project, including a revised IP and CEM, must be presented and re-approved by the IC.
- If project overrun is $100,000 or more, but less than $500,000, provide a clear description of the overrun in the revised AIP to FP&A. If the total project is greater than $500,000, whether it was below or above this threshold previous to the overrun, an IP and CEM are required (new or revised). If the project is $500,000 or below, no IP or CEM are required.
- If the previous project proposal was below the IC threshold and revised amount is over the IC threshold, the proposal needs to be approved by the IC regardless of the increase amount. A revised IP and CEM are required.
- Project overrun must be offset by a like reduction in one or more budgeted projects, or the overspending requires prior written approval by the LKE CFO and CEO. Project overruns of greater than $500,000 are subject to the RAC Tenets.
- Revised AIPs must be approved for the total revised dollar amount using the approval limits in the Authority Limit Matrix.

FP&A Approvals: Unbudgeted projects or those projects requiring an IP and CEM (i.e., over $500,000) must include FP&A review and approval. Unbudgeted projects less than $100,000 require FP&A manager approval, and those $100,000 and over require FP&A director approval.

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Budgeted projects less than $500,000 are approved as normally required by the Authority Limit Matrix and do not require the approval of FP&A.

Generation Miscellaneous Projects: Each Generation plant site may have one miscellaneous project not to exceed $500,000 which is budgeted to serve as a placeholder for small individual projects which arise during the year and which cannot be specifically anticipated during the budgeting process. This category of projects is different from blanket projects described elsewhere in this policy. Each Generation miscellaneous project must be budgeted, but an AIP need not be prepared for it and it will not be activated in PowerPlant. Instead, as specific work is identified, the appropriate budget coordinator must create a new project number for the charges and prepare an AIP for the new project which references the budgeted placeholder project number for funding as funds are being moved from one project to another. The new project is not considered unbudgeted to the extent that unused budget dollars are available in the budgeted placeholder project to cover it. The new project will still need to be marked as "unbudgeted" in PowerPlant and will have to be approved by FP&A.

Other Miscellaneous Projects: Several lines of business use miscellaneous projects which are budgeted to serve as a placeholder for small individual projects which arise during the year and which cannot be specifically anticipated during the budgeting process. This category of projects is different from blanket projects described elsewhere in this policy. (Examples include various facilities improvements and miscellaneous substation projects.) These projects are opened and closed on an annual basis. The projects are authorized and approved for the entire budgeted amount when they are opened. They must be set up as task level unitization within PowerPlant and are unitized by task as completed each year. For each task opened, a paper miscellaneous project AIP form must be prepared with all the pertinent information about the asset and location of the capital expenditure and sent to Property Accounting when the task is opened on the blanket project. This form can be found on Property Accounting's Home Page.

Reimbursable Projects: Projects which will have all or a portion of the spending amount reimbursed by an outside party must follow the same guidelines as non-reimbursable projects, except as noted below:

- Tax Department review indicating whether Contribution in Aid of Construction is taxable must occur prior to any reimbursement agreement greater than $25,000 being finalized and evidence of such review must be attached to the AIP. This does not apply to customer refund agreements.
- If a fully executed agreement specifying the terms of reimbursement is attached to an AIP with gross spending under $1 million, the net spending amount may be used to determine whether an IP and CEM are required.

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- Third Party jointly-owned utility projects under the specified gross spending thresholds qualify for this exception without requiring the attachment of the executed joint ownership agreement.
- For all projects, the gross spending amount must always be used to determine the appropriate approval level.

Government-Mandated/Regulatory Compliance Projects: Projects which are not reimbursable but which are mandated by governmental legislation or other governmental authority must follow the same guidelines as all other projects except that for such AIPs with gross spending under $1 million neither the IP nor the CEM are required, provided that the appropriate legislative docket numbers or applicable statute references are provided with the AIP.

Preliminary Engineering: Projects that are originally set up for preliminary engineering are treated as indirect projects and are auto approved and opened in PowerPlant. Once the preliminary engineering work is complete, the determination must be made if the project will move forward as capital or be abandoned and expensed. If the project moves forward as capital, a new project must be created in PowerPlant and must follow the approval levels based on the Authority Limit Matrix. It is the responsibility of the budget coordinator to notify Property Accounting and make the appropriate accounting transactions to move preliminary engineering charges to capital or to expense as appropriate.

Early Activation Guidelines

In order for a project to be early activated, the following criteria must be met:

1. The expenditure must be the result of a true emergency which is defined as one of the following: 1) the expenditure is needed to address an immediate safety risk; 2) the equipment has failed; or 3) a material problem has been found, requiring it to be replaced immediately in order to maintain the reliability of the system.

OR

2. The equipment vendor has provided a quote for the capital purchase that is only valid for a short period of time. The time frame would not be long enough to complete all the necessary paperwork and acquire all necessary approvals in time to place the order at the reduced price.

Process requirements for an early activated AIP are as follows:

- For each AIP that is early activated, Property Accounting must first receive email approval from the highest level of LOB authority based on the total amount of the AIP as per the AIP approval process. FP&A must also be copied on this email. Should the AIP be for an unbudgeted project, approval from FP&A will be required for the early activation.

- In the event the project has been previously approved by the IC, the above email from the highest LOB authority would not be required. Instead, verification from FP&A that the project had indeed been approved by the IC would be sufficient approval.

- The approval request email must include the following information:
    - Project number
    - Project description
    - Total project amount
    - Name of the individual whose highest level of authority is required, and any associated delegation of authority (DOA)
    - Description of the need for the early activation
    - For an unbudgeted project, the budgeted project number that will cover the unbudgeted spending.

- Additionally, for either scenario 1 or 2 above, an automated AIP must be submitted for $10,000 and approved by the project manager and budget coordinator for the project in order for the project to be moved to "open" status in PowerPlant.

- Property Accounting will maintain a log of early activated projects, and copies of the email approvals will be filed with the AIP.

- A revised AIP (for the full project amount) for all projects that are early activated must be received by Property Accounting, or FP&A if necessary, with all required approvals, as soon as possible, but no later than 30 business days after the early activation. Repeated failure to comply with this timing may require email approval by the appropriate LOB VP for early activation of all future AIPs.

Project In-Service and/or Completion

Upon project in-service and/or completion, the project manager or budget coordinator most familiar with the project is required to do the following:

1. Verify completion date (if the date is not correct, it needs to be updated in PowerPlant). Entering a completion date changes the project status to "completed".
2. Verify actual in-service date (if the date is not correct, it needs to updated in PowerPlant). Entering an in-service date without a completion date changes the project status to "in-

service". Verify actual installed costs and actual removal costs (report/explain any variances greater than 10% from the AIP to Property Accounting).

3. Verify units of property installed and units of property retired (report to Property Accounting if different from AIP).

Post Completion Audits

Budget coordinators are required to perform a post-completion audit (PCA) of projects as discussed in the guidelines below. The review must be provided to FP&A and the IC.

- Projects greater than $5,000,000 (excluding blankets) must have a PCA performed within 18 months of the project completion date unless otherwise agreed, to have a full year of financials to review.
- At the discretion of FP&A a random audit of anything less than $5,000,000 can be requested for auditing purposes.
- A PCA template is available on the FP&A website. Also, samples of PCAs are available on the website under "Examples". Transmission PCAs are not included on the website due to the Standards of Conduct.
- In case of impairment, a PCA is always required.

Leases

Prior to the execution of any new lease entered into on behalf of the Company, a review must be conducted by the budget coordinator for the appropriate LOB, Financial Accounting and Analysis and the Tax department to determine if the lease is structured as a capital or operating lease. Additional reviews by Legal and Corporate Finance may be required depending on the total amount of the lease. See the LKE Lease Policy for more details.

Blanket Capital Projects

Background: Several lines of business (primarily Distribution and Transmission) use blanket capital projects to procure routine, frequently used assets (i.e., poles, meters, transformers) or to facilitate routine work for which specific information is not available at the time the budget is prepared (i.e., Gas and Electric Distribution New Business by area). The blanket projects hold a "bucket" of budget dollars which is used to fund specific tasks under $500,000 as they are identified throughout the year. For Gas and Electric Distribution and Metering, blanket projects are not closed each year, but they are re-budgeted each year and are unitized on an "as-spent" basis. For Transmission, blanket projects are opened and closed on an annual basis. They must be set up as task level unitization within PowerPlant and are unitized by task as completed each year.

Authorization: Each December, a list of all budgeted blanket projects for the next year must be submitted to the IC for approval, along with the forecast for the current year's blanket capital spending. At the discretion of the IC, some blanket projects (e.g., Gas Leak Mitigation or Pole

Inspection and Treatment) may require an IP and PCA and will not be included in the routine blanket listing. These projects will be presented to the IC in December as separate projects. An AIP or PCA is not required for the routine blanket capital projects.

Criteria for Spending under an Existing Blanket Project: Only work and materials of a routine nature which cannot be specifically identified at the time of budget preparation may be charged to a blanket project. Individual tasks (which may consist either of individual parts or of work orders containing both labor and material) must fall below a $500,000 gross (of reimbursement) spending level. Otherwise, a separate, non-blanket capital project must be created which is subject to all requirements described elsewhere in this policy. Moreover, the same rules for spending authorization levels apply for spending under blanket capital projects as described elsewhere in this policy. Should a task on a blanket project exceed $500,000, then appropriate corrective action (i.e., AIP, CEM, etc.) and charge corrections via VOLTS and CODs to correct the charges to the correct project should be completed as soon as possible. Miscellaneous type blankets, such as small tools and transmission projects, should have a paper miscellaneous AIP prepared with all the pertinent information about the asset and location of the capital expenditure and sent to Property Accounting when the task is opened on the blanket project. This form can be found on Property Accounting's Home Page.

Criteria for Creating a New Blanket Project: New blanket capital projects require the approval of both Property Accounting and FP&A. To open new blanket projects, a partial AIP in the amount of $10,000 must go through the approval process in PowerPlant. New blanket capital projects created after the budget process is complete are always considered to be unbudgeted and are therefore subject to the same requirements for unbudgeted projects described elsewhere in this policy. The unbudgeted project authorized spending must be covered by either a budgeted blanket or a non-blanket project in accordance with the RAC Tenets.

Monthly Spending Report: The budget coordinator for each LOB incurring spending under blanket capital projects is required to prepare a monthly report listing all blanket projects (including those approved under a stand-alone IP) comparing the total year-to-date spending against the approved budget. Any substitution of non-blanket projects' budgets to cover new blanket projects' budgets must be noted on the report and tracked throughout the year. This report must be submitted to FP&A for review by the eleventh business day of the following month. FP&A, after reviewing, will send the report to Property Accounting.

Penalties for Noncompliance

Failure to comply with this policy may result in disciplinary action, up to and including discharge.

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Date: 05/01/2014

Capital and Investment Review

Reference: Authority Limit Matrix; CEM; Capital Appendix; Lease Policy; Resource Allocation Committee Tenets; FERC Uniform System of Accounts; and Investment Proposal forms.

Key Contact:

- Financial Planning & Analysis
- **Accounting Matters**: Property Accounting and Controller
- **Capital Leases**: Corporate Finance and Financial Accounting and Analysis

Administrative Responsibility: Chief Financial Officer.

Revision Dates: 12/01/07, 04/04/08, 12/31/08, 7/20/2009, 5/1/2014

CAPITAL APPENDIX

General Approval Requirements

Investment	Action Required
> $2k	• AIP required
> $500k	• Investment Proposal required • CEM required • AIP required
> $1m (for Real Property > $500k)	• Investment Committee approval and above mentioned items • LKE CFO and CEO approval needed
> $30m	• LGE and KU Energy Board approval needed • PPL CEO approval needed
> $100m	• LGE and KU Energy Board approval needed • PPL CEO approval needed • PPL Finance Committee approval needed

Note: IT approval is needed for any IT project

Project Overruns

If a project is expected to be 10% or $100k over, whichever is less, subject to a minimum of $25k, a revised AIP must be completed before the overrun occurs and the following conditions apply:

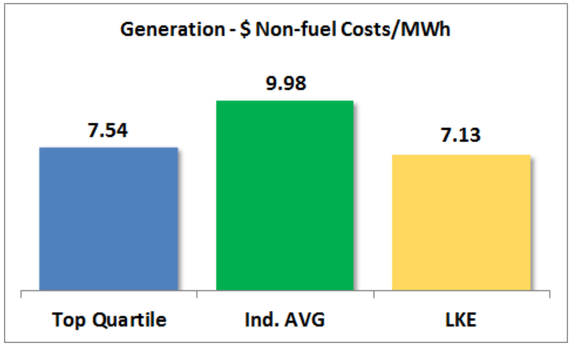
Initial Investment Amount	Increase	Action Required
< $500k	Will bring project over $500k for the first time	• Investment Proposal required • CEM required • Revised AIP
	Will bring project over IC threshold	• Investment Proposal required • CEM required • Revised AIP • IC Approval required
> $500k and Under IC Threshold	> $100k or 10%, whichever is less, subject to a minimum of $25k	• Revised IP required • Revised CEM required • Revised AIP
	Will bring project over IC threshold	• Revised IP required • Revised CEM required • Revised AIP • IC Approval required
Over IC Threshold	≥ 100k and < $500k	• Revised AIP which includes updated estimates and a clear explanation of overrun*
	≥ $500k	• Revised IP required • Revised CEM required • Revised AIP • IC approval required

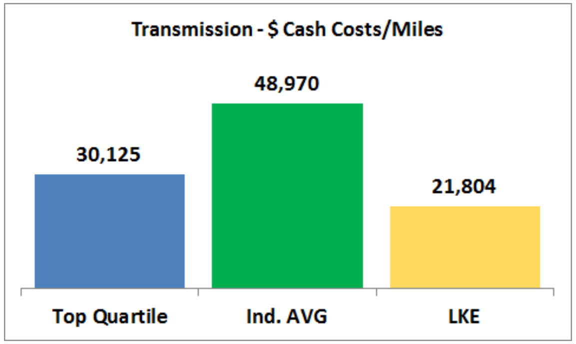
*Financial Planning and Analysis provides an annual update to the Investment Committee of project overruns between $100k and $500k. For this purpose the Lines of Business are required to provide a list of these project overruns to Financial Planning and Analysis.

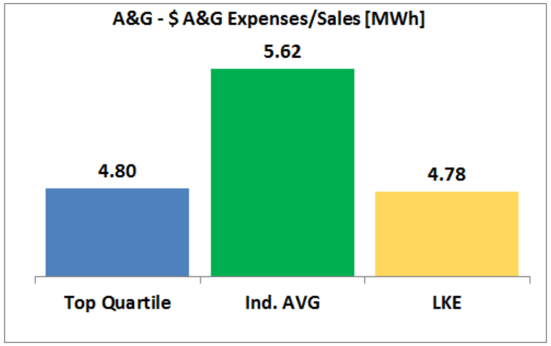
Exhibit KWB-3

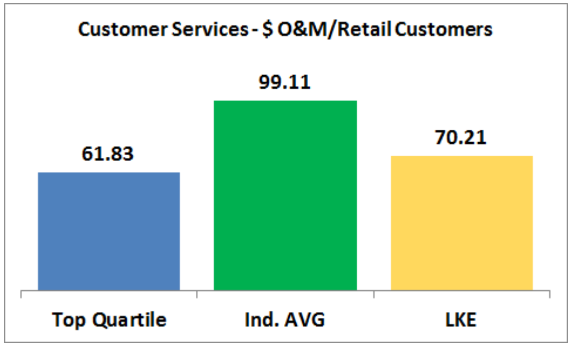
Benchmark Study by FERC USoA

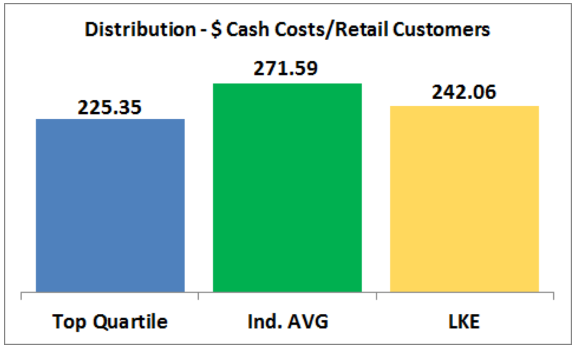
FERC Benchmarking Metric Comparisons











Key Observations:

- LKE outperforms industry averages in all five cost segments.
- LKE ranks in the top quartile in three of five cost segments.
- Spending in Cust. Services & Distribution reflects additional investment in customer service and reliability to meet customer needs and regulatory expectations.

Based on 2009-2013 FERC Form 1 Capital and Operating Expense Data.

Exhibit KWB-4

Financial Summary Table

Income Statement

Line Item	*Basis to Derive*	*System Employed*
Gross Margin Components:		
Customer Revenue	Load Forecast x Approved Tariff	UIPlanner
Demand Charge Revenue	Load Forecast x Approved Tariff	UIPlanner
Energy Revenue	Load Forecast x Approved Tariff	UIPlanner
Base Fuel Revenue	Load Forecast x Approved Tariff	UIPlanner
FAC Revenue	Difference between recoverable Fuel + Purchased Power below and Base Fuel Revenue	UIPlanner
ECR Revenue	Revenue requirement calculated using the following: rate base rolled forward for identified ECR projects using capital spend and in service dates per PowerPlant and calculated deferred income taxes; jurisdictional factor computed within UIPlanner using KY retail/total revenue ratio; cost of capital computed within UIPlanner using weighted average cost of debt, authorized ROE and target capital structure	UIPlanner PowerPlant
DSM Revenue	Revenue requirement calculated in UIPlanner based on expenses, incentive percentage, capital and lost sales volumes per DSM filing with lost sales priced using current tariffs	UIPlanner
Gas Line Tracker Revenue	Revenue requirement calculated in UIPlanner using the following: rate base rolled forward for identified GLT projects using capital spend and in service dates per PowerPlant and calculated deferred income taxes; cost of capital computed within UIPlanner using weighted average cost of debt, authorized ROE and target capital structure	UIPlanner PowerPlant
Intercompany Sales	Based on generation and load forecast relative to market prices for each utility	Prosym
Off-System Sales	Based on generation and load forecast relative to market prices	Prosym
Transmission Revenue	Projected volumes based on trends and known changes x OATT approved rate (escalated over the business plan)	EXCEL
Other Operating Revenue	Projected based on trends, incorporating any tariff changes and escalated over the business plan	EXCEL
Rate Case Impacts	Projected timing of filings based on financial projections; revenue requirement calculated within UIPlanner using projected ROE	UIPlanner
Fuel	Based on generation forecast and heat rates by plant x price curves which are a blend of contracted rates and market prices for unhedged positions	Prosym
Gas Supply	Gas load forecast priced out at contracted rates and market prices for open/indexed positions	EXCEL

Line Item	***Basis to Derive***	***System Employed***
Purchased Power	Projected in generation forecast model run using contracted capacity terms and market prices	Prosym
Other Cost of Sales	Existing contract/market prices for consumables applied to generation forecast by plant and usage rates for each plant	PowerPlant
Rate Mechanism Expenses	Projected O&M costs and depreciation by approved project	PowerPlant
Other Operating & Maintenance Expenses	Detailed “bottoms up” aggregation by department	PowerPlant
Taxes Other Than Income	Based on capital plan, classifications of property and property tax rates	EXCEL UIPlanner PowerPlant
Depreciation & Amortization	Based on capital plan, including property classifications and in service dates, and approved depreciation rates	PowerPlant
Interest Expense	Product of existing debt (accounting for debt repayments) and interest rates as well as projected debt issuances at market rates, incorporating hedges and amortization of debt issuance costs	UIPlanner
Other Income (Expense)	Projected based on trends and known changes	EXCEL
Income Tax Provision	Based on earnings, calculated permanent and timing differences and current tax laws and positions	UIPlanner
Net Income	Sum of the Above	UIPlanner

Balance Sheet

Line Item	*Basis to Derive*	*System Employed*
Cash	Derived from cash flow statement	UIPlanner
Accounts Receivable	Based on revenues and projected days of sales in receivables based on history and trends	UIPlanner
Fuels, Materials & Supplies	Fuel inventory roll forward maintained in UIPlanner based on target inventory levels, generation forecast per Prosym and contract/market prices	UIPlanner Prosym
Regulatory Assets/Liabilities	Rollforward maintained based on amortization periods, rate mechanism revenue calculations and other changes in expenses/payments as applicable	UIPlanner
Utility Plant	Rollforward maintained based on capital spend, in service and retirement dates, and depreciation	UIPlanner PowerPlant
Other Assets	Current levels only adjusted for known changes	
Accounts Payable	Function of capital and O&M spend, adjusted for some payment lag	UIPlanner
Accrued Interest	Calculated based on debt schedules	UIPlanner
Accrued Taxes	Calculated based on income tax expense calculations and payment schedules	UIPlanner
Deferred Income Taxes	Rollforward maintained based on book and tax depreciation using capital plan, current tax rates and book depreciation rates	UIPlanner PowerPlant
Accrued Pension Obligations	Based on projected expense and funding per actuarial study	UIPlanner
Other Liabilities	Current levels only adjusted for known changes	UIPlanner
Debt	Detail of existing debt supplemented with projected debt issuance and repayments	UIPlanner
Stockholder's Equity	Roll forward based on net income, dividends and equity contributions	UIPlanner

Cash Flow Statement

Line Item	*Basis to Derive*	*System Employed*
Cash From Operating Activities	Derived from income statement and balance sheet changes above	UIPlanner
Capital Expenditures	Per detailed capital plan by project, adjusted for cash payment timing	PowerPlant
Debt Issuance/Repayment	Net cash surplus (shortfall) applied to repayment (borrowing) of short-term debt until sufficient balance to issue long-term debt; other debt repayments based on existing debt terms; maintain target capital structure	UIPlanner
Dividends	Based on 65% payout ratio	UIPlanner
Equity Contributions	Projected as needed to maintain target capital structure based on other cash flow items	UIPlanner

Exhibit KWB-5

Moody's Rating Methodology

MOODY'S
INVESTORS SERVICE

RATING METHODOLOGY

Regulated Electric and Gas Utilities

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Summary

This rating methodology explains Moody's approach to assessing credit risk for regulated electric and gas utilities globally and is intended to provide general guidance that helps companies, investors, and other interested market participants understand how qualitative and quantitative risk characteristics are likely to affect rating outcomes for companies in the regulated electric and gas utility industry. This document does not include an exhaustive treatment of all factors that are reflected in Moody's ratings but should enable the reader to understand the qualitative considerations and financial information and ratios that are usually most important for ratings in this sector.

This rating methodology replaces[1] the Rating Methodology for Regulated Electric and Gas Utilities published in August 2009. While reflecting many of the same core principles as the 2009 methodology, this updated document provides a more transparent presentation of the rating considerations that are usually most important for companies in this sector and incorporates refinements in our analysis that better reflect credit fundamentals of the industry. No rating changes will result from publication of this rating methodology.

This report includes a detailed rating grid and illustrative examples that compare the mapping of rated public companies against the factors in the grid. The grid is a reference tool that can be used to approximate credit profiles within the regulated electric and gas utility sector in most cases. The grid provides summarized guidance for the factors that are generally most important in assigning ratings to companies in the regulated electric and gas utility industry. However, the grid is a summary that does not include every rating consideration. The weights shown for each factor in the grid represent an approximation of their importance for rating decisions but actual importance may vary substantially. In addition, the illustrative mapping examples in this document use historical results while ratings are based on our forward-looking expectations. As a result, the grid-indicated rating is not expected to match the actual rating of each company.

[1] This update may not be effective in some jurisdictions until certain requirements are met.

The grid contains four key factors that are important in our assessment for ratings in the regulated electric and gas utility sector, and a notching factor for structural subordination at holding companies:

1. Regulatory Framework
2. Ability to Recover Costs and Earn Returns
3. Diversification
4. Financial Strength

Some of these factors also encompass a number of sub-factors. Since an issuer's scoring on a particular grid factor or sub-factor often will not match its overall rating, in Appendix C we include a discussion of some of the grid "outliers" – companies whose grid-indicated rating for a specific sub-factor differs significantly from the actual rating – in order to provide additional insights.

This rating methodology is not intended to be an exhaustive discussion of all factors that our analysts consider in assigning ratings in this sector. We note that our analysis for ratings in this sector covers factors that are common across all industries such as ownership, management, liquidity, corporate legal structure, governance and country related risks which are not explained in detail in this document, as well as factors that can be meaningful on a company-specific basis. Our ratings consider these and other qualitative considerations that do not lend themselves to a transparent presentation in a grid format. The grid used for this methodology reflects a decision to favor a relatively simple and transparent presentation rather than a more complex grid that would map grid-indicated ratings more closely to actual ratings.

Highlights of this report include:

» An overview of the rated universe

» A summary of the rating methodology

» A discussion of the key rating factors that drive ratings

» Comments on the rating methodology assumptions and limitations, including a discussion of rating considerations that are not included in the grid

The Appendices show the full grid (Appendix A), a list of the companies included in our illustrative sample universe of issuers with their ratings, grid-indicated ratings and country of domicile (Appendix B), tables that illustrate the application of the grid to the sample universe of issuers, with explanatory comments on some of the more significant differences between the grid-implied rating for each sub-factor and our actual rating (Appendix C)[2], our approach to ratings within a utility family (Appendix D), a description of the various types of companies rated under this methodology (Appendix E), key industry issues over the intermediate term (Appendix F), regional and other considerations (Appendix G), and treatment of power purchase agreements (Appendix H).

[2] In general, the rating (or other indicator of credit strength) utilized for comparison to the grid-implied rating is the senior unsecured rating for investment-grade issuers, the Corporate Family Rating (CFR) for speculative-grade issuers and the Baseline Credit Assessment (BCA) for Government Related Issuers (GRIs). Individual debt instrument ratings also factor in decisions on notching for seniority level and collateral. Related documents that provide additional insight in this area are the rating methodologies "Loss Given Default for Speculative Grade Non-Financial Companies in the US, Canada and EMEA", published June 2009, and "Updated Summary Guidance for Notching Bonds, Preferred Stocks and Hybrid Securities of Corporate Issuers", published February 2007.

What's Changed

While incorporating many of the core principles of the 2009 version, this methodology updates how the four key rating factors are defined, and how certain sub-factors are weighted in the grid.

More specifically, this methodology introduces four equally weighted sub-factors into the two rating factors that are related to regulation –the Regulatory Framework and the Ability to Recover Costs and Earn Returns – in order to provide more granularity and transparency on the overall regulatory environment, which is the most important consideration for this sector.

The weighting of the grid indicators for diversification are unchanged, but the proposed descriptive criteria have been refined to place greater emphasis on the economic and regulatory diversity of each utility's service area rather than the diversity of operations, because we think this emphasis better distinguishes credit risk. We have refined the definitions of the Generation and Fuel Diversity sub-factor to better incorporate the full range of challenges that can affect a particular fuel type.

While the overall weighting of the Financial Strength factor is unchanged, the weighting for two sub-factors that seek to measure debt in relation to cash flow has increased. The 15% weight for CFO Pre-WC/Debt reflects our view that this is the single most predictive financial measure, followed in importance by CFO Pre-WC - Dividends/Debt with a 10% grid weighting. The additional weighting of these ratios is balanced by the elimination of a separate liquidity sub-factor that had a 10% weighting in the prior grid.

Liquidity assessment remains a key focus of our analysis. However, we consider it as a qualitative assessment outside the grid because its credit importance varies greatly over time and by issuer and accordingly is not well represented by a fixed grid weight. See “Other Rating Considerations” for insights on liquidity analysis in this sector.

Lower financial metric thresholds have been introduced for certain utilities viewed as having lower business risk, for instance many US natural gas local distribution companies (LDCs) and certain US electric transmission and distribution companies (T&Ds, which lack generation but generally retain some procurement responsibilities for customers). The low end of the scale in the methodology grid has been extended from B to Caa to better capture our views of more challenging regulatory environments and weaker performance.

We have introduced minor changes to financial metric thresholds at the lower end of the scale, primarily to incorporate this extension of the grid.

We have incorporated scorecard notching for structural subordination at holding companies. Ratings already incorporated structural subordination, but including an adjustment in the scorecard will result in a closer alignment of grid-indicated outcomes and ratings for holding companies.

Treatment of first mortgage bonds (primarily in the US), which was the subject of a Request for Comment in 2009 and adopted subsequent to the 2009 methodology, is summarized in Appendix G.

This methodology describes the analytical framework used in determining credit ratings. In some instances our analysis is also guided by additional publications which describe our approach for analytical considerations that are not specific to any single sector. Examples of such considerations include but are not limited to: the assignment of short-term ratings, the relative ranking of different classes of debt and hybrid securities, how sovereign credit quality affects non-sovereign issuers, and the assessment of credit support from other entities. Documents that describe our approach to such cross-sector methodological considerations can be found here.

About the Rated Universe

The Regulated Electric and Gas Utilities rating methodology applies to rate-regulated[3] electric and gas utilities that are not Networks[4]. Regulated Electric and Gas Utilities are companies whose predominant[5] business is the sale of electricity and/or gas or related services under a rate-regulated framework, in most cases to retail customers. Also included under this methodology are rate-regulated utilities that own generating assets as any material part of their business, utilities whose charges or bills to customers include a meaningful component related to the electric or gas commodity, utilities whose rates are regulated at a sub-sovereign level (e.g. by provinces, states or municipalities), and companies providing an independent system operator function to an electric grid. Companies rated under this methodology are primarily rate-regulated monopolies or, in certain circumstances, companies that may not be outright monopolies but where government regulation effectively sets prices and limits competition.

This rating methodology covers regulated electric and gas utilities worldwide. These companies are engaged in the production, transmission, coordination, distribution and/or sale of electricity and/or natural gas, and they are either investor owned companies, commercially oriented government owned companies or, in the case of independent system operators, not-for-profit or similar entities. As detailed in Appendix E, this methodology covers a wide variety of companies active in the sector, including vertically integrated utilities, transmission and distribution utilities with retail customers and/or sub-sovereign regulation, local gas distribution utility companies (LDCs), independent system operators, and regulated generation companies. These companies may be operating companies or holding companies.

An over-arching consideration for regulated utilities is the regulatory environment in which they operate. While regulation is also a key consideration for networks, a utility's regulatory environment is in comparison often more dynamic and more subject to political intervention. The direct relationship that a regulated utility has with the retail customer, including billing for electric or gas supply that has substantial price volatility, can lead to a more politically charged rate-setting environment. Similarly, regulation at the sub-sovereign level is often more accessible for participation by interveners, including disaffected customers and the politicians who want their votes. Our views of regulatory environments evolve over time in accordance with our observations of regulatory, political, and judicial events that affect issuers in the sector.

This methodology pertains to regulated electric and gas utilities and excludes the following types of issuers, which are covered by separate rating methodologies: Regulated Networks, Unregulated Utilities and Power Companies, Public Power Utilities, Municipal Joint Action Agencies, Electric Cooperatives, Regulated Water Companies and Natural Gas Pipelines.

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3 Companies in many industries are regulated. We use the term rate-regulated to distinguish companies whose rates (by which we also mean tariffs or revenues in general) are set by regulators.

4 Regulated Electric and Gas Networks are companies whose predominant business is purely the transmission and/or distribution of electricity and/or natural gas without involvement in the procurement or sale of electricity and/or gas; whose charges to customers thus do not include a meaningful commodity cost component; which sell mainly (or in many cases exclusively) to non-retail customers; and which are rate-regulated under a national framework.

5 We generally consider a company to be predominantly a regulated electric and gas utility when a majority of its cash flows, prospectively and on a sustained basis, are derived from regulated electric and gas utility businesses. Since cash flows can be volatile (such that a company might have a majority of utility cash flows simply due to a cyclical downturn in its non-utility businesses), we may also consider the breakdown of assets and/or debt of a company to determine which business is predominant.

Other Related Methodologies

» Regulated Electric and Gas Networks

» Unregulated Utilities and Power Companies

» Natural Gas Pipelines

» US Public Power Electric Utilities with Generation Ownership Exposure

» US Electric Generation & Transmission Cooperatives

» US Municipal Joint Action Agencies

» Government Related Issuers: Methodology Update

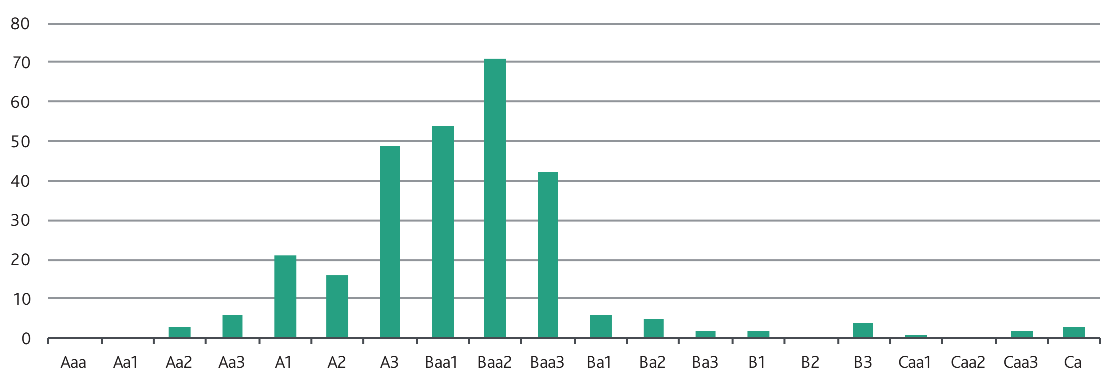
» Global Regulated Water Utilities

The rated universe includes approximately 315 entities that are either utility operating companies or a parent holding company with one or more utility company subsidiaries that operate predominantly in the electric and gas utility business. These companies account for about US$730 billion of total outstanding long-term debt instruments.

The Regulated Electric and Gas Utility sector is predominantly investment grade, reflecting the stability generally conferred by regulation that typically sets prices and also limits competition, such that defaults have been lower than in many other non-financial corporate sectors. However, the nature of regulation can vary significantly from jurisdiction to jurisdiction. Most issuers at the lower end of the ratings spectrum operate in challenging regulatory environments. Additional information about the ratings and default performance of the sector can be found in our publication "Infrastructure Default and Recovery Rates, 1983-2012H1". As shown on the following table, the ratings spectrum for issuers in the sector (both holding companies and operating companies) ranges from Aaa to Ca:

EXHIBIT 1

Regulated Electric and Gas Utilities' Senior Unsecured Ratings Distribution



Source: Moody's Investors Service, ratings as of December 2013

About this Rating Methodology

This report explains the rating methodology for regulated electric and gas utilities in seven sections, which are summarized as follows:

1. Identification and Discussion of the Rating Factors in the Grid

The grid in this rating methodology focuses on four rating factors. The four factors are comprised of sub-factors that provide further detail:

Factor / Sub-Factor Weighting - Regulated Utilities

Broad Rating Factors	Broad Rating Factor Weighting	Rating Sub-Factor	Sub-Factor Weighting
Regulatory Framework	25%	Legislative and Judicial Underpinnings of the Regulatory Framework	12.5%
		Consistency and Predictability of Regulation	12.5%
Ability to Recover Costs and Earn Returns	25%	Timeliness of Recovery of Operating and Capital Costs	12.5%
		Sufficiency of Rates and Returns	12.5%
Diversification	10%	Market Position	5%*
		Generation and Fuel Diversity	5%**
Financial Strength, Key Financial Metrics	40%		
		CFO pre-WC + Interest/ Interest	7.5%
		CFO pre-WC / Debt	15.0%
		CFO pre-WC – Dividends / Debt	10.0%
		Debt/Capitalization	7.5%
Total	**100%**		**100%**
Notching Adjustment			
		Holding Company Structural Subordination	0 to -3

*10% weight for issuers that lack generation; **0% weight for issuers that lack generation

2. Measurement or Estimation of Factors in the Grid

We explain our general approach for scoring each grid factor and show the weights used in the grid. We also provide a rationale for why each of these grid components is meaningful as a credit indicator. The information used in assessing the sub-factors is generally found in or calculated from information in company financial statements, derived from other observations or estimated by Moody's analysts.

Our ratings are forward-looking and reflect our expectations for future financial and operating performance. However, historical results are helpful in understanding patterns and trends of a company's performance as well as for peer comparisons. We utilize historical data (in most cases, an average of the last three years of reported results) in this document to illustrate the application of the rating grid. All of the quantitative credit metrics incorporate Moody's standard adjustments to income statement, cash flow statement and balance sheet amounts for restructuring, impairment, off-balance sheet accounts, receivable securitization programs, under-funded pension obligations, and recurring operating leases.

For definitions of Moody's most common ratio terms please see Moody's Basic Definitions for Credit Statistics, User's Guide (June 2011, document #78480). For a description of Moody's standard adjustments, please see Moody's Approach to Global Standard Adjustments in the Analysis of Financial Statements for Non-Financial Corporations December 2010 (128137). These documents can be found at www.moodys.com under the Research and Ratings directory.

In most cases, the illustrative examples in this document use historic financial data from a recent three year period. However, the factors in the grid can be assessed using various time periods. For example, rating committees may find it analytically useful to examine both historic and expected future performance for periods of several years or more, or for individual twelve month periods.

3. Mapping Factors to the Rating Categories

After estimating or calculating each sub-factor, the outcomes for each of the sub-factors are mapped to a broad Moody's rating category (Aaa, Aa, A, Baa, Ba, B, or Caa).

4. Mapping Issuers to the Grid and Discussion of Grid Outliers

In Appendix C, we provide a table showing how each company in the sample set of issuers maps to grid-indicated ratings for each rating sub-factor and factor. We highlight companies whose grid-indicated performance on a specific sub-factor is two or more broad rating categories higher or lower than its actual rating and discuss the general reasons for such positive and negative outliers for a particular sub-factor.

5. Assumptions, Limitations and Rating Considerations Not Included in the Grid

This section discusses limitations in the use of the grid to map against actual ratings, some of the additional factors that are not included in the grid but can be important in determining ratings, and limitations and assumptions that pertain to the overall rating methodology.

6. Determining the Overall Grid-Indicated Rating

To determine the overall grid-indicated rating, we convert each of the sub-factor ratings into a numeric value based upon the scale below.

Aaa	Aa	A	Baa	Ba	B	Caa	Ca
1	3	6	9	12	15	18	20

The numerical score for each sub-factor is multiplied by the weight for that sub-factor with the results then summed to produce a composite weighted-factor score. The composite weighted factor score is then mapped back to an alphanumeric rating based on the ranges in the table below.

Grid-Indicated Rating

Grid-Indicated Rating	Aggregate Weighted Total Factor Score
Aaa	x < 1.5
Aa1	1.5 ≤ x < 2.5
Aa2	2.5 ≤ x < 3.5
Aa3	3.5 ≤ x < 4.5
A1	4.5 ≤ x < 5.5
A2	5.5 ≤ x < 6.5
A3	6.5 ≤ x < 7.5
Baa1	7.5 ≤ x < 8.5
Baa2	8.5 ≤ x < 9.5
Baa3	9.5 ≤ x < 10.5
Ba1	10.5 ≤ x < 11.5
Ba2	11.5 ≤ x < 12.5
Ba3	12.5 ≤ x < 13.5
B1	13.5 ≤ x < 14.5
B2	14.5 ≤ x < 15.5
B3	15.5 ≤ x < 16.5
Caa1	16.5 ≤ x < 17.5
Caa2	17.5 ≤ x < 18.5
Caa3	18.5 ≤ x < 19.5
Ca	x ≥ 19.5

For example, an issuer with a composite weighted factor score of 11.7 would have a Ba2 grid-indicated rating. We used a similar procedure to derive the grid indicated ratings shown in the illustrative examples.

7. Appendices

The Appendices provide illustrative examples of grid-indicated ratings based on historical financial information and also provide additional commentary and insights on our view of credit risks in this industry.

Discussion of the Grid Factors

Moody's analysis of electric and gas utilities focuses on four broad factors:

» Regulatory Framework

» Ability to Recover Costs and Earn Returns

» Diversification

» Financial Strength

There is also a notching factor for holding company structural subordination.

Factor 1: Regulatory Framework (25%)

Why It Matters

For rate-regulated utilities, which typically operate as a monopoly, the regulatory environment and how the utility adapts to that environment are the most important credit considerations. The regulatory environment is comprised of two rating factors - the Regulatory Framework and its corollary factor, the Ability to Recover Costs and Earn Returns. Broadly speaking, the Regulatory Framework is the foundation for how all the decisions that affect utilities are made (including the setting of rates), as well as the predictability and consistency of decision-making provided by that foundation. The Ability to Recover Costs and Earn Returns relates more directly to the actual decisions, including their timeliness and the rate-setting outcomes.

Utility rates[6] are set in a political/regulatory process rather than a competitive or free-market process; thus, the Regulatory Framework is a key determinant of the success of utility. The Regulatory Framework has many components: the governing body and the utility legislation or decrees it enacts, the manner in which regulators are appointed or elected, the rules and procedures promulgated by those regulators, the judiciary that interprets the laws and rules and that arbitrates disagreements, and the manner in which the utility manages the political and regulatory process. In many cases, utilities have experienced credit stress or default primarily or at least secondarily because of a break-down or obstacle in the Regulatory Framework – for instance, laws that prohibited regulators from including investments in uncompleted power plants or plants not deemed "used and useful" in rates, or a disagreement about rate-making that could not be resolved until after the utility had defaulted on its debts.

How We Assess Legislative and Judicial Underpinnings of the Regulatory Framework for the Grid

For this sub-factor, we consider the scope, clarity, transparency, supportiveness and granularity of utility legislation, decrees, and rules as they apply to the issuer. We also consider the strength of the regulator's authority over rate-making and other regulatory issues affecting the utility, the effectiveness of the judiciary or other independent body in arbitrating disputes in a disinterested manner, and whether the utility's monopoly has meaningful or growing carve-outs. In addition, we look at how well developed the framework is – both how fully fleshed out the rules and regulations are and how well tested it is – the extent to which regulatory or judicial decisions have created a body of precedent that will help determine future rate-making. Since the focus of our scoring is on each issuer, we consider

[6] In jurisdictions where utility revenues include material government subsidy payments, we consider utility rates to be inclusive of these payments, and we thus evaluate sub-factors 1a, 1b, 2a and 2b in light of both rates and material subsidy payments. For example, we would consider the legal and judicial underpinnings and consistency and predictability of subsidies as well as rates.

how effective the utility is in navigating the regulatory framework – both the utility's ability to shape the framework and adapt to it.

A utility operating in a regulatory framework that is characterized by legislation that is credit supportive of utilities and eliminates doubt by prescribing many of the procedures that the regulators will use in determining fair rates (which legislation may show evidence of being responsive to the needs of the utility in general or specific ways), a long history of transparent rate-setting, and a judiciary that has provided ample precedent by impartially adjudicating disagreements in a manner that addresses ambiguities in the laws and rules will receive higher scores in the Legislative and Judicial Underpinnings sub-factor. A utility operating in a regulatory framework that, by statute or practice, allows the regulator to arbitrarily prevent the utility from recovering its costs or earning a reasonable return on prudently incurred investments, or where regulatory decisions may be reversed by politicians seeking to enhance their populist appeal will receive a much lower score.

In general, we view national utility regulation as being less liable to political intervention than regulation by state, provincial or municipal entities, so the very highest scoring in this sub-factor is reserved for this category. However, we acknowledge that states and provinces in some countries may be larger than small nations, such that their regulators may be equally "above-the-fray" in terms of impartial and technically-oriented rate setting, and very high scoring may be appropriate.

The relevant judicial system can be a major factor in the regulatory framework. This is particularly true in litigious societies like the United States, where disagreements between the utility and its state or municipal regulator may eventually be adjudicated in federal district courts or even by the US Supreme Court. In addition, bankruptcy proceedings in the US take place in federal courts, which have at times been able to impose rate settlement agreements on state or municipal regulators. As a result, the range of decisions available to state regulators may be effectively circumscribed by court precedent at the state or federal level, which we generally view as favorable for the credit-supportiveness of the regulatory framework.

Electric and gas utilities are generally presumed to have a strong monopoly that will continue into the foreseeable future, and this expectation has allowed these companies to have greater leverage than companies in other sectors with similar ratings. Thus, the existence of a monopoly in itself is unlikely to be a driver of strong scoring in this sub-factor. On the other hand, a strong challenge to the monopoly could cause lower scoring, because the utility can only recover its costs and investments and service its debt if customers purchase its services. There have some instances of incursions into utilities' monopoly, including municipalization, self-generation, distributed generation with net metering, or unauthorized use (beyond the level for which the utility receives compensation in rates). Incursions that are growing significantly or having a meaningful impact on rates for customers that remain with the utility could have a negative impact on scoring of this sub-factor and on factor 2 - Ability to Recover Costs and Earn Returns.

The scoring of this sub-factor may not be the same for every utility in a particular jurisdiction. We have observed that some utilities appear to have greater sway over the relevant utility legislation and promulgation of rules than other utilities – even those in the same jurisdiction. The content and tone of publicly filed documents and regulatory decisions sometimes indicates that the management team at one utility has better responsiveness to and credibility with its regulators or legislators than the management at another utility.

While the underpinnings to the regulatory framework tend to change relatively slowly, they do evolve, and our factor scoring will seek to reflect that evolution. For instance, a new framework will typically become tested over time as regulatory decisions are issued, or perhaps litigated, thereby setting a body of precedent. Utilities may seek changes to laws in order to permit them to securitize certain costs or collect interim rates, or a jurisdiction in which rates were previously recovered primarily in base rate proceedings may institute riders and trackers. These changes would likely impact scoring of sub-factor 2b - Timeliness of Recovery of Operating and Capital Costs, but they may also be sufficiently significant to indicate a change in the regulatory underpinnings. On the negative side, a judiciary that had formerly been independent may start to issue decisions that indicate it is conforming its decisions to the expectations of an executive branch that wants to mandate lower rates.

Factor 1a: Legislative and Judicial Underpinnings of the Regulatory Framework (12.5%)

Aaa	Aa	A	Baa
Utility regulation occurs under a fully developed framework that is national in scope based on legislation that provides the utility a nearly absolute monopoly (see note 1) within its service territory, an unquestioned assurance that rates will be set in a manner that will permit the utility to make and recover all necessary investments, an extremely high degree of clarity as to the manner in which utilities will be regulated and prescriptive methods and procedures for setting rates. Existing utility law is comprehensive and supportive such that changes in legislation are not expected to be necessary; or any changes that have occurred have been strongly supportive of utilities credit quality in general and sufficiently forward-looking so as to address problems before they occurred. There is an independent judiciary that can arbitrate disagreements between the regulator and the utility should they occur, including access to national courts, very strong judicial precedent in the interpretation of utility laws, and a strong rule of law. We expect these conditions to continue.	Utility regulation occurs under a fully developed national, state or provincial framework based on legislation that provides the utility an extremely strong monopoly (see note 1) within its service territory, a strong assurance, subject to limited review, that rates will be set in a manner that will permit the utility to make and recover all necessary investments, a very high degree of clarity as to the manner in which utilities will be regulated and reasonably prescriptive methods and procedures for setting rates. If there have been changes in utility legislation, they have been timely and clearly credit supportive of the issuer in a manner that shows the utility has had a strong voice in the process. There is an independent judiciary that can arbitrate disagreements between the regulator and the utility, should they occur including access to national courts, strong judicial precedent in the interpretation of utility laws, and a strong rule of law. We expect these conditions to continue.	Utility regulation occurs under a well developed national, state or provincial framework based on legislation that provides the utility a very strong monopoly (see note 1) within its service territory, an assurance, subject to reasonable prudency requirements, that rates will be set in a manner that will permit the utility to make and recover all necessary investments, a high degree of clarity as to the manner in which utilities will be regulated, and overall guidance for methods and procedures for setting rates. If there have been changes in utility legislation, they have been mostly timely and on the whole credit supportive for the issuer, and the utility has had a clear voice in the legislative process. There is an independent judiciary that can arbitrate disagreements between the regulator and the utility, should they occur, including access to national courts, clear judicial precedent in the interpretation of utility law, and a strong rule of law. We expect these conditions to continue.	Utility regulation occurs (i) under a national, state, provincial or municipal framework based on legislation that provides the utility a strong monopoly within its service territory that may have some exceptions such as greater self-generation (see note 1), a general assurance that, subject to prudency requirements that are mostly reasonable, rates will be set will be set in a manner that will permit the utility to make and recover all necessary investments, reasonable clarity as to the manner in which utilities will be regulated and overall guidance for methods and procedures for setting rates; or (ii) under a new framework where independent and transparent regulation exists in other sectors. If there have been changes in utility legislation, they have been credit supportive or at least balanced for the issuer but potentially less timely, and the utility had a voice in the legislative process. There is either (i) an independent judiciary that can arbitrate disagreements between the regulator and the utility, including access to courts at least at the state or provincial level, reasonably clear judicial precedent in the interpretation of utility laws, and a generally strong rule of law; or (ii) regulation has been applied (under a well developed framework) in a manner such that redress to an independent arbiter has not been required. We expect these conditions to continue.

Ba	B	Caa	
Utility regulation occurs (i) under a national, state, provincial or municipal framework based on legislation or government decree that provides the utility a monopoly within its service territory that is generally strong but may have a greater level of exceptions (see note 1), and that, subject to prudency requirements which may be stringent, provides a general assurance (with somewhat less certainty) that rates will be set will be set in a manner that will permit the utility to make and recover necessary investments; or (ii) under a new framework where the jurisdiction has a history of less independent and transparent regulation in other sectors. Either: (i) the judiciary that can arbitrate disagreements between the regulator and the utility may not have clear authority or may not be fully independent of the regulator or other political pressure, but there is a reasonably strong rule of law; or (ii) where there is no independent arbiter, the regulation has mostly been applied in a manner such redress has not been required. We expect these conditions to continue.	Utility regulation occurs (i) under a national, state, provincial or municipal framework based on legislation or government decree that provides the utility monopoly within its service territory that is reasonably strong but may have important exceptions, and that, subject to prudency requirements which may be stringent or at times arbitrary, provides more limited or less certain assurance that rates will be set in a manner that will permit the utility to make and recover necessary investments; or (ii) under a new framework where we would expect less independent and transparent regulation, based either on the regulator's history in other sectors or other factors. The judiciary that can arbitrate disagreements between the regulator and the utility may not have clear authority or may not be fully independent of the regulator or other political pressure, but there is a reasonably strong rule of law. Alternately, where there is no independent arbiter, the regulation has been applied in a manner that often requires some redress adding more uncertainty to the regulatory framework. There may be a periodic risk of creditor-unfriendly government intervention in utility markets or rate-setting.	Utility regulation occurs (i) under a national, state, provincial or municipal framework based on legislation or government decree that provides the utility a monopoly within its service territory, but with little assurance that rates will be set in a manner that will permit the utility to make and recover necessary investments; or (ii) under a new framework where we would expect unpredictable or adverse regulation, based either on the jurisdiction's history of in other sectors or other factors. The judiciary that can arbitrate disagreements between the regulator and the utility may not have clear authority or is viewed as not being fully independent of the regulator or other political pressure. Alternately, there may be no redress to an effective independent arbiter. The ability of the utility to enforce its monopoly or prevent uncompensated usage of its system may be limited. There may be a risk of creditor-unfriendly nationalization or other significant intervention in utility markets or rate-setting.	

Note 1: The strength of the monopoly refers to the legal, regulatory and practical obstacles for customers in the utility's territory to obtain service from another provider. Examples of a weakening of the monopoly would include the ability of a city or large user to leave the utility system to set up their own system, the extent to which self-generation is permitted (e.g. cogeneration) and/or encouraged (e.g., net metering, DSM generation). At the lower end of the ratings spectrum, the utility's monopoly may be challenged by pervasive theft and unauthorized use. Since utilities are generally presumed to be monopolies, a strong monopoly position in itself is not sufficient for a strong score in this sub-factor, but a weakening of the monopoly can lower the score.

How We Assess Consistency and Predictability of Regulation for the Grid

For the Consistency and Predictability sub-factor, we consider the track record of regulatory decisions in terms of consistency, predictability and supportiveness. We evaluate the utility's interactions in the regulatory process as well as the overall stance of the regulator toward the utility.

In most jurisdictions, the laws and rules seek to make rate-setting a primarily technical process that examines costs the utility incurs and the returns on investments the utility needs to earn so it can make investments that are required to build and maintain the utility infrastructure - power plants, electric transmission and distribution systems, and/or natural gas distribution systems. When the process remains technical and transparent such that regulators can support the financial health of the utility while balancing their public duty to assure that reliable service is provided at a reasonable cost, and when the utility is able to align itself with the policy initiatives of the governing jurisdiction, the utility will receive higher scores in this sub-factor. When the process includes substantial political intervention, which could take the form of legislators or other government officials publically second-guessing regulators, dismissing regulators who have approved unpopular rate increases, or preventing the implementation of rate increases, or when regulators ignore the laws/rules to deliver an outcome that appears more politically motivated, the utility will receive lower scores in this sub-factor.

As with the prior sub-factor, we may score different utilities in the same jurisdiction differently, based on outcomes that are more or less supportive of credit quality over a period of time. We have observed that some utilities are better able to meet the expectations of their customers and regulators, whether through better service, greater reliability, more stable rates or simply more effective regulatory outreach and communication. These utilities typically receive more consistent and credit supportive outcomes, so they will score higher in this sub-factor. Conversely, if a utility has multiple rapid rate increases, chooses to submit major rate increase requests during a sensitive election cycle or a severe economic downturn, has chronic customer service issues, is viewed as frequently providing incomplete information to regulators, or is tone deaf to the priorities of regulators and politicians, it may receive less consistent and supportive outcomes and thus score lower in this sub-factor.

In scoring this sub-factor, we will primarily evaluate the actions of regulators, politicians and jurists rather than their words. Nonetheless, words matter when they are an indication of future action. We seek to differentiate between political rhetoric that is perhaps oriented toward gaining attention for the viewpoint of the speaker and rhetoric that is indicative of future actions and trends in decision-making.

Factor 1b: Consistency and Predictability of Regulation (12.5%)

Aaa	Aa	A	Baa
The issuer's interaction with the regulator has led to a strong, lengthy track record of predictable, consistent and favorable decisions. The regulator is highly credit supportive of the issuer and utilities in general. We expect these conditions to continue.	The issuer's interaction with the regulator has a led to a considerable track record of predominantly predictable and consistent decisions. The regulator is mostly credit supportive of utilities in general and in almost all instances has been highly credit supportive of the issuer. We expect these conditions to continue.	The issuer's interaction with the regulator has led to a track record of largely predictable and consistent decisions. The regulator may be somewhat less credit supportive of utilities in general, but has been quite credit supportive of the issuer in most circumstances. We expect these conditions to continue.	The issuer's interaction with the regulator has led to an adequate track record. The regulator is generally consistent and predictable, but there may some evidence of inconsistency or unpredictability from time to time, or decisions may at times be politically charged. However, instances of less credit supportive decisions are based on reasonable application of existing rules and statutes and are not overly punitive. We expect these conditions to continue.

Ba	B	Caa	
We expect that regulatory decisions will demonstrate considerable inconsistency or unpredictability or that decisions will be politically charged, based either on the issuer's track record of interaction with regulators or other governing bodies, or our view that decisions will move in this direction. The regulator may have a history of less credit supportive regulatory decisions with respect to the issuer, but we expect that the issuer will be able to obtain support when it encounters financial stress, with some potentially material delays. The regulator's authority may be eroded at times by legislative or political action. The regulator may not follow the framework for some material decisions.	We expect that regulatory decisions will be largely unpredictable or even somewhat arbitrary, based either on the issuer's track record of interaction with regulators or other governing bodies, or our view that decisions will move in this direction. However, we expect that the issuer will ultimately be able to obtain support when it encounters financial stress, albeit with material or more extended delays. Alternately, the regulator is untested, lacks a consistent track record, or is undergoing substantial change. The regulator's authority may be eroded on frequent occasions by legislative or political action. The regulator may more frequently ignore the framework in a manner detrimental to the issuer.	We expect that regulatory decisions will be highly unpredictable and frequently adverse, based either on the issuer's track record of interaction with regulators or other governing bodies, or our view that decisions will move in this direction. Alternately, decisions may have credit supportive aspects, but may often be unenforceable. The regulator's authority may have been seriously eroded by legislative or political action. The regulator may consistently ignore the framework to the detriment of the issuer.	

Factor 2: Ability to Recover Costs and Earn Returns (25%)

Why It Matters

This rating factor examines the ability of a utility to recover its costs and earn a return over a period of time, including during differing market and economic conditions. While the Regulatory Framework looks at the transparency and predictability of the rules that govern the decision-making process with respect to utilities, the Ability to Recover Costs and Earn Returns evaluates the regulatory elements that directly impact the ability of the utility to generate cash flow and service its debt over time. The ability to recover prudently incurred costs on a timely basis and to attract debt and equity capital are crucial credit considerations. The inability to recover costs, for instance if fuel or purchased power costs ballooned during a rate freeze period, has been one of the greatest drivers of financial stress in this sector, as well as the cause of some utility defaults. In a sector that is typically free cash flow negative (due to large capital expenditures and dividends) and that routinely needs to refinance very large maturities of long-term debt, investor concerns about a lack of timely cost recovery or the sufficiency of rates can, in an extreme scenario, strain access to capital markets and potentially lead to insolvency of the utility (as was the case when “used and useful” requirements threatened some utilities that experienced years of delay in completing nuclear power plants in the 1980s). While our scoring for the Ability to Recover Costs and Earn Returns may primarily be influenced by our assessment of the regulatory relationship, it can also be highly impacted by the management and business decisions of the utility.

How We Assess Ability to Recover Costs and Earn Returns

The timeliness and sufficiency of rates are scored as separate sub-factors; however, they are interrelated. Timeliness can have an impact on our view of what constitutes sufficient returns, because a strong assurance of timely cost recovery reduces risk. Conversely, utilities may have a strong assurance that they will earn a full return on certain deferred costs until they are able to collect them, or their generally strong returns may allow them to weather some rate lag on recovery of construction-related capital expenditures. The timeliness of cost recovery is particularly important in a period of rapidly rising costs. During the past five years, utilities have benefitted from low interest rates and generally decreasing fuel costs and purchased power costs, but these market conditions could easily reverse. For example, fuel is a large component of total costs for vertically integrated utilities and for natural gas utilities, and fuel prices are highly volatile, so the timeliness of fuel and purchased power cost recovery is especially important.

While Factors 1 and 2 are closely inter-related, scoring of these factors will not necessarily be the same. We have observed jurisdictions where the Regulatory Framework caused considerable credit concerns – perhaps it was untested or going through a transition to de-regulation, but where the track record of rate case outcomes was quite positive, leading to a higher score in the Ability to Recover Costs and Earn Returns. Conversely, there have been instances of strong Legislative and Judicial Underpinnings of the Regulatory Framework where the commission has ignored the framework (which would affect Consistency and Predictability of Regulation as well as Ability to Recover Costs and Earn Returns) or has used extraordinary measures to prevent or defer an increase that might have been justifiable from a cost perspective but would have caused rate shock.

One might surmise that Factors 2 and 4 should be strongly correlated, since a good Ability to Recover Costs and Earn Returns would normally lead to good financial metrics. However, the scoring for the Ability to Recover Costs and Earn Returns sub-factor places more emphasis on our expectation of timeliness and sufficiency of rates over time; whereas financial metrics may be impacted by one-time events, market conditions or construction cycles - trends that we believe could normalize or even reverse.

How We Assess Timeliness of Recovery of Operating and Capital Costs for the Grid

The criteria we consider include provisions and cost recovery mechanisms for operating costs, mechanisms that allow actual operating and/or capital expenditures to be trued-up periodically into rates without having to file a rate case (this may include formula rates, rider and trackers, or the ability to periodically adjust rates for construction work in progress) as well as the process and timeframe of general tariff/base rate cases – those that are fully reviewed by the regulator, generally in a public format that includes testimony of the utility and other stakeholders and interest groups. We also look at the track record of the utility and regulator for timeliness. For instance, having a formula rate plan is positive, but if the actual process has included reviews that are delayed for long periods, it may dampen the benefit to the utility. In addition, we seek to estimate the lag between the time that a utility incurs a major construction expenditures and the time that the utility will start to recover and/or earn a return on that expenditure.

How We Assess Sufficiency of Rates and Returns for the Grid

The criteria we consider include statutory protections that assure full cost recovery and a reasonable return for the utility on its investments, the regulatory mechanisms used to determine what a reasonable return should be, and the track record of the utility in actually recovering costs and earning returns. We examine outcomes of rate cases/tariff reviews and compare them to the request submitted by the utility, to prior rate cases/tariff reviews for the same utility and to recent rate/tariff decisions for a peer group of comparable utilities. In this context, comparable utilities are typically utilities in the same or similar jurisdiction. In cases where the utility is unique or nearly unique in its jurisdiction, comparison will be made to other peers with an adjustment for local differences, including prevailing rates of interest and returns on capital, as well as the timeliness of rate-setting. We look at regulatory disallowances of costs or investments, with a focus on their financial severity and also on the reasons given by the regulator, in order to assess the likelihood that such disallowances will be repeated in the future.

Factor 2a: Timeliness of Recovery of Operating and Capital Costs (12.5%)

Aaa	Aa	A	Baa
Tariff formulas and automatic cost recovery mechanisms provide full and highly timely recovery of all operating costs and essentially contemporaneous return on all incremental capital investments, with statutory provisions in place to preclude the possibility of challenges to rate increases or cost recovery mechanisms. By statute and by practice, general rate cases are efficient, focused on an impartial review, quick, and permit inclusion of fully forward-looking costs.	Tariff formulas and automatic cost recovery mechanisms provide full and highly timely recovery of all operating costs and essentially contemporaneous or near-contemporaneous return on most incremental capital investments, with minimal challenges by regulators to companies' cost assumptions. By statute and by practice, general rate cases are efficient, focused on an impartial review, of a very reasonable duration before non-appealable interim rates can be collected, and primarily permit inclusion of forward-looking costs.	Automatic cost recovery mechanisms provide full and reasonably timely recovery of fuel, purchased power and all other highly variable operating expenses. Material capital investments may be made under tariff formulas or other rate-making permitting reasonably contemporaneous returns, or may be submitted under other types of filings that provide recovery of cost of capital with minimal delays. Instances of regulatory challenges that delay rate increases or cost recovery are generally related to large, unexpected increases in sizeable construction projects. By statute or by practice, general rate cases are reasonably efficient, primarily focused on an impartial review, of a reasonable duration before rates (either permanent or non-refundable interim rates) can be collected, and permit inclusion of important forward-looking costs.	Fuel, purchased power and all other highly variable expenses are generally recovered through mechanisms incorporating delays of less than one year, although some rapid increases in costs may be delayed longer where such deferrals do not place financial stress on the utility. Incremental capital investments may be recovered primarily through general rate cases with moderate lag, with some through tariff formulas. Alternately, there may be formula rates that are untested or unclear. Potentially greater tendency for delays due to regulatory intervention, although this will generally be limited to rates related to large capital projects or rapid increases in operating costs.
Ba	**B**	**Caa**	
There is an expectation that fuel, purchased power or other highly variable expenses will eventually be recovered with delays that will not place material financial stress on the utility, but there may be some evidence of an unwillingness by regulators to make timely rate changes to address volatility in fuel, or purchased power, or other market-sensitive expenses. Recovery of costs related to capital investments may be subject to delays that are somewhat lengthy, but not so pervasive as to be expected to discourage important investments.	The expectation that fuel, purchased power or other highly variable expenses will be recovered may be subject to material delays due to second-guessing of spending decisions by regulators or due to political intervention. Recovery of costs related to capital investments may be subject to delays that are material to the issuer, or may be likely to discourage some important investment.	The expectation that fuel, purchased power or other highly variable expenses will be recovered may be subject to extensive delays due to second-guessing of spending decisions by regulators or due to political intervention. Recovery of costs related to capital investments may be uncertain, subject to delays that are extensive, or that may be likely to discourage even necessary investment.	

Note: Tariff formulas include formula rate plans as well as trackers and riders related to capital investment.

Factor 2b: Sufficiency of Rates and Returns (12.5%)

Aaa	Aa	A	Baa
Sufficiency of rates to cover costs and attract capital is (and will continue to be) unquestioned.	Rates are (and we expect will continue to be) set at a level that permits full cost recovery and a fair return on all investments, with minimal challenges by regulators to companies' cost assumptions. This will translate to returns (measured in relation to equity, total assets, rate base or regulatory asset value, as applicable) that are strong relative to global peers.	Rates are (and we expect will continue to be) set at a level that generally provides full cost recovery and a fair return on investments, with limited instances of regulatory challenges and disallowances. In general, this will translate to returns (measured in relation to equity, total assets, rate base or regulatory asset value, as applicable) that are generally above average relative to global peers, but may at times be average.	Rates are (and we expect will continue to be) set at a level that generally provides full operating cost recovery and a mostly fair return on investments, but there may be somewhat more instances of regulatory challenges and disallowances, although ultimate rate outcomes are sufficient to attract capital without difficulty. In general, this will translate to returns (measured in relation to equity, total assets, rate base or regulatory asset value, as applicable) that are average relative to global peers, but may at times be somewhat below average.
Ba	**B**	**Caa**	
Rates are (and we expect will continue to be) set at a level that generally provides recovery of most operating costs but return on investments may be less predictable, and there may be decidedly more instances of regulatory challenges and disallowances, but ultimate rate outcomes are generally sufficient to attract capital. In general, this will translate to returns (measured in relation to equity, total assets, rate base or regulatory asset value, as applicable) that are generally below average relative to global peers, or where allowed returns are average but difficult to earn. Alternately, the tariff formula may not take into account all cost components and/or remuneration of investments may be unclear or at times unfavorable.	We expect rates will be set at a level that at times fails to provide recovery of costs other than cash costs, and regulators may engage in somewhat arbitrary second-guessing of spending decisions or deny rate increases related to funding ongoing operations based much more on politics than on prudency reviews. Return on investments may be set at levels that discourage investment. We expect that rate outcomes may be difficult or uncertain, negatively affecting continued access to capital. Alternately, the tariff formula may fail to take into account significant cost components other than cash costs, and/or remuneration of investments may be generally unfavorable.	We expect rates will be set at a level that often fails to provide recovery of material costs, and recovery of cash costs may also be at risk. Regulators may engage in more arbitrary second-guessing of spending decisions or deny rate increases related to funding ongoing operations based primarily on politics. Return on investments may be set at levels that discourage necessary maintenance investment. We expect that rate outcomes may often be punitive or highly uncertain, with a markedly negative impact on access to capital. Alternately, the tariff formula may fail to take into account significant cash cost components, and/or remuneration of investments may be primarily unfavorable.	

Factor 3: Diversification (10%)

Why It Matters

Diversification of overall business operations helps to mitigate the risk that economic cycles, material changes in a single regulatory regime or commodity price movements will have a severe impact on cash flow and credit quality of a utility. While utilities' sales volumes have lower exposure to economic recessions than many non-financial corporate issuers, some sales components, including industrial sales, are directly affected by economic trends that cause lower production and/or plant closures. In addition, economic activity plays a role in the rate of customer growth in the service territory and (absent energy efficiency and conservation) can often impact usage per customer. The economic strength or weakness of the service territory can affect the political and regulatory environment for rate increase requests by the utility. For utilities in areas prone to severe storms and other natural disasters, the utility's geographic diversity or concentration can be a key determinant for creditworthiness. Diversity among regulatory regimes can mitigate the impact of a single unfavorable decision affecting one part of the utility's footprint.

For utilities with electric generation, fuel source diversity can mitigate the impact (to the utility and to its rate-payers) of changes in commodity prices, hydrology and water flow, and environmental or other regulations affecting plant operations and economics. We have observed that utilities' regulatory environments are most likely to become unfavorable during periods of rapid rate increases (which are more important than absolute rate levels) and that fuel diversity leads to more stable rates over time. For that reason, fuel diversity can be important even if fuel and purchased power expenses are an automatic pass-through to the utility's ratepayers. Changes in environmental, safety and other regulations have caused vulnerabilities for certain technologies and fuel sources during the past five years. These vulnerabilities have varied widely in different countries and have changed over time.

How We Assess Market Position for the Grid

Market position is comprised primarily of the economic diversity of the utility's service territory and the diversity of its regulatory regimes. We also consider the diversity of utility operations (e.g., regulated electric, gas, water, steam) when there are material operations in more than one area. Economic diversity is a typically a function of the population, size and breadth of the territory and the businesses that drive its GDP and employment. For the size of the territory, we typically consider the number of customers and the volumes of generation and/or throughput. For breadth, we consider the number of sizeable metropolitan areas served, the economic diversity and vitality in those metropolitan areas, and any concentration in a particular area or industry. In our assessment, we may consider various information sources. For example, in the US, information sources on the diversity and vitality of economies of individual states and metropolitan areas may include Moody's Economy.com. We also look at the mix of the utility's sales volumes among customer types, as well as the track record of volume sales and any notable payment patterns during economic cycles. For diversity of regulatory regimes, we typically look at the number of regulators and the percentages of revenues and utility assets that are under the purview of each. While the highest scores in the Market Position sub-factor are reserved for issuers regulated in multiple jurisdictions, when there is only one regulator, we make a differentiation of regimes perceived as having lower or higher volatility.

Issuers with multiple supportive regulatory jurisdictions, a balanced sales mix among residential, commercial, industrial and governmental customers in a large service territory with a robust and diverse economy will generally score higher in this sub-factor. An issuer with a small service territory economy that has a high dependence on one or two sectors, especially highly cyclical industries, will generally score lower in this sub-factor, as will issuers with meaningful exposure to economic dislocations caused by natural disasters.

For issuers that are vertically integrated utilities having a meaningful amount of generation, this sub-factor has a weighting of 5%. For electric transmission and distribution utilities without meaningful generation and for natural gas local distribution companies, this sub-factor has a weighting of 10%.

How We Assess Generation and Fuel Diversity for the Grid

Criteria include the fuel type of the issuer's generation and important power purchase agreements, the ability of the issuer to economically shift its generation and power purchases when there are changes in fuel prices, the degree to which the utility and its rate-payers are exposed to or insulated from changes in commodity prices, and exposure to Challenged Source and Threatened Sources (see the explanations for how we generally characterize these generation sources in the table below). A regulated utility's capacity mix may not in itself be an indication of fuel diversity or the ability to shift fuels, since utilities may keep old and inefficient plants (e.g., natural gas boilers) to serve peak load. For this reason, we do not incorporate set percentages reflecting an "ideal" or "sub-par" mix for capacity or even generation. In addition to looking at a utility's generation mix to evaluate fuel diversity, we consider the efficiency of the utility's plants, their placement on the regional dispatch curve, and the demonstrated ability/inability of the utility to shift its generation mix in accordance with changing commodity prices.

Issuers having a balanced mix of hydro, coal, natural gas, nuclear and renewable energy as well as low exposure to challenged and threatened sources of generation will score higher in this sub-factor. Issuers that have concentration in one or two sources of generation, especially if they are threatened or challenged sources, will score lower.

In evaluating an issuer's degree of exposure to challenged and threatened sources, we will consider not only the existence of those plants in the utility's portfolio, but also the relevant factors that will determine the impact on the utility and on its rate-payers. For instance, an issuer that has a fairly high percentage of its generation from challenged sources could be evaluated very differently if its peer utilities face the same magnitude of those issues than if its peers have no exposure to challenged or threatened sources. In evaluating threatened sources, we consider the utility's progress in its plan to replace those sources, its reserve margin, the availability of purchased power capacity in the region, and the overall impact of the replacement plan on the issuer's rates relative to its peer group. Especially if there are no peers in the same jurisdiction, we also examine the extent to which the utility's generation resources plan is aligned with the relevant government's fuel/energy policy.

Factor 3: Diversification (10%)

Weighting 10%	Sub-Factor Weighting	Aaa	Aa	A	Baa
Market Position	5% *	A very high degree of multinational and regional diversity in terms of regulatory regimes and/or service territory economies.	Material operations in three or more nations or substantial geographic regions providing very good diversity of regulatory regimes and/or service territory economies.	Material operations in two to three nations, states, provinces or regions that provide good diversity of regulatory regimes and service territory economies. Alternately, operates within a single regulatory regime with low volatility, and the service territory economy is robust, has a very high degree of diversity and has demonstrated resilience in economic cycles.	May operate under a single regulatory regime viewed as having low volatility, or where multiple regulatory regimes are not viewed as providing much diversity. The service territory economy may have some concentration and cyclicality, but is sufficiently resilient that it can absorb reasonably foreseeable increases in utility rates.
Generation and Fuel Diversity	5% **	A high degree of diversity in terms of generation and/or fuel sources such that the utility and rate-payers are well insulated from commodity price changes, no generation concentration, and very low exposures to Challenged or Threatened Sources (see definitions below).	Very good diversification in terms of generation and/or fuel sources such that the utility and rate-payers are affected only minimally by commodity price changes, little generation concentration, and low exposures to Challenged or Threatened Sources.	Good diversification in terms of generation and/or fuel sources such that the utility and rate-payers have only modest exposure to commodity price changes; however, may have some concentration in a source that is neither Challenged nor Threatened. Exposure to Threatened Sources is low. While there may be some exposure to Challenged Sources, it is not a cause for concern.	Adequate diversification in terms of generation and/or fuel sources such that the utility and rate-payers have moderate exposure to commodity price changes; however, may have some concentration in a source that is Challenged. Exposure to Threatened Sources is moderate, while exposure to Challenged Sources is manageable.

	Sub-Factor Weighting	Ba	B	Caa	Definitions
Market Position	5% *	Operates in a market area with somewhat greater concentration and cyclicality in the service territory economy and/or exposure to storms and other natural disasters, and thus less resilience to absorbing reasonably foreseeable increases in utility rates. May show somewhat greater volatility in the regulatory regime(s).	Operates in a limited market area with material concentration and more severe cyclicality in service territory economy such that cycles are of materially longer duration or reasonably foreseeable increases in utility rates could present a material challenge to the economy. Service territory may have geographic concentration that limits its resilience to storms and other natural disasters, or may be an emerging market. May show decided volatility in the regulatory regime(s).	Operates in a concentrated economic service territory with pronounced concentration, macroeconomic risk factors, and/or exposure to natural disasters.	"Challenged Sources" are generation plants that face higher but not insurmountable economic hurdles resulting from penalties or taxes on their operation, or from environmental upgrades that are required or likely to be required. Some examples are carbon-emitting plants that incur carbon taxes, plants that must buy emissions credits to operate, and plants that must install environmental equipment to continue to operate, in each where the taxes/credits/upgrades are sufficient to have a material impact on those plants' competitiveness relative to other generation types or on the utility's rates, but where the impact is not so severe as to be likely require plant closure.
Generation and Fuel Diversity	5% **	Modest diversification in generation and/or fuel sources such that the utility or rate-payers have greater exposure to commodity price changes. Exposure to Challenged and Threatened Sources may be more pronounced, but the utility will be able to access alternative sources without undue financial stress.	Operates with little diversification in generation and/or fuel sources such that the utility or rate-payers have high exposure to commodity price changes. Exposure to Challenged and Threatened Sources may be high, and accessing alternate sources may be challenging and cause more financial stress, but ultimately feasible.	Operates with high concentration in generation and/or fuel sources such that the utility or rate-payers have exposure to commodity price shocks. Exposure to Challenged and Threatened Sources may be very high, and accessing alternate sources may be highly uncertain.	"Threatened Sources" are generation plants that are not currently able to operate due to major unplanned outages or issues with licensing or other regulatory compliance, and plants that are highly likely to be required to de-activate, whether due to the effectiveness of currently existing or expected rules and regulations or due to economic challenges. Some recent examples would include coal fired plants in the US that are not economic to retro-fit to meet mercury and air toxics standards, plants that cannot meet the effective date of those standards, nuclear plants in Japan that have not been licensed to re-start after the Fukushima Dai-ichi accident, and nuclear plants that are required to be phased out within 10 years (as is the case in some European countries).

*10% weight for issuers that lack generation **0% weight for issuers that lack generation

Factor 4: Financial Strength (40%)

Why It Matters

Electric and gas utilities are regulated, asset-based businesses characterized by large investments in long-lived property, plant and equipment. Financial strength, including the ability to service debt and provide a return to shareholders, is necessary for a utility to attract capital at a reasonable cost in order to invest in its generation, transmission and distribution assets, so that the utility can fulfill its service obligations at a reasonable cost to rate-payers.

How We Assess It for the Grid

In comparison to companies in other non-financial corporate sectors, the financial statements of regulated electric and gas utilities have certain unique aspects that impact financial analysis, which is further complicated by disparate treatment of certain elements under US Generally Accepted Accounting Principles (GAAP) versus International Financial Reporting Standards (IFRS). Regulatory accounting may permit utilities to defer certain costs (thereby creating regulatory assets) that a non-utility corporate entity would have to expense. For instance, a regulated utility may be able to defer a substantial portion of costs related to recovery from a storm based on the general regulatory framework for those expenses, even if the utility does not have a specific order to collect the expenses from ratepayers over a set period of time. A regulated utility may be able to accrue and defer a return on equity (in addition to capitalizing interest) for construction-work-in-progress for an approved project based on the assumption that it will be able to collect that deferred equity return once the asset comes into service. For this reason, we focus more on a utility's cash flow than on its reported net income. Conversely, utilities may collect certain costs in rates well ahead of the time they must be paid (for instance, pension costs), thereby creating regulatory liabilities. Many of our metrics focus on Cash Flow from Operations Before Changes in Working Capital (CFO Pre-WC) because, unlike Funds from Operations (FFO), it captures the changes in long-term regulatory assets and liabilities. However, under IFRS the two measures are essentially the same. In general, we view changes in working capital as less important in utility financial analysis because they are often either seasonal (for example, power demand is generally greatest in the summer) or caused by changes in fuel prices that are typically a relatively automatic pass-through to the customer. We will nonetheless examine the impact of working capital changes in analyzing a utility's liquidity (see Other Rating Considerations – Liquidity).

Given the long-term nature of utility assets and the often lumpy nature of their capital expenditures, it is important to analyze both a utility's historical financial performance as well as its prospective future performance, which may be different from backward-looking measures. Scores under this factor may be higher or lower than what might be expected from historical results, depending on our view of expected future performance. In the illustrative mapping examples in this document, the scoring grid uses three year averages for the financial strength sub-factors. Multi-year periods are usually more representative of credit quality because utilities can experience swings in cash flows from one-time events, including such items as rate refunds, storm cost deferrals that create a regulatory asset, or securitization proceeds that reduce a regulatory asset. Nonetheless, we also look at trends in metrics for individual periods, which may influence our view of future performance and ratings.

For this scoring grid, we have identified four key ratios that we consider the most consistently useful in the analysis of regulated electric and gas utilities. However, no single financial ratio can adequately convey the relative credit strength of these highly diverse companies. Our ratings consider the overall financial strength of a company, and in individual cases other financial indicators may also play an important role.

CFO Pre-Working Capital Plus Interest/Interest or Cash Flow Interest Coverage

The cash flow interest coverage ratio is an indicator for a utility's ability to cover the cost of its borrowed capital. The numerator in the ratio calculation is the sum of CFO Pre-WC and interest expense, and the denominator is interest expense.

CFO Pre-Working Capital / Debt

This important metric is an indicator for the cash generating ability of a utility compared to its total debt. The numerator in the ratio calculation is CFO Pre-WC, and the denominator is total debt.

CFO Pre-Working Capital Minus Dividends / Debt

This ratio is an indicator for financial leverage as well as an indicator of the strength of a utility's cash flow after dividend payments are made. Dividend obligations of utilities are often substantial, quasi-permanent outflows that can affect the ability of a utility to cover its debt obligations, and this ratio can also provide insight into the financial policies of a utility or utility holding company. The higher the level of retained cash flow relative to a utility's debt, the more cash the utility has to support its capital expenditure program. The numerator of this ratio is CFO Pre-WC minus dividends, and the denominator is total debt.

Debt/Capitalization

This ratio is a traditional measure of balance sheet leverage. The numerator is total debt and the denominator is total capitalization. All of our ratios are calculated in accordance with Moody's standard adjustments[7], but we note that our definition of total capitalization includes deferred taxes in addition to total debt, preferred stock, other hybrid securities, and common equity. Since the presence or absence of deferred taxes is a function of national tax policy, comparing utilities using this ratio may be more meaningful among utilities in the same country or in countries with similar tax policies. High debt levels in comparison to capitalization can indicate higher interest obligations, can limit the ability of a utility to raise additional financing if needed, and can lead to leverage covenant violations in bank credit facilities or other financing agreements[8]. A high ratio may result from a regulatory framework that does not permit a robust cushion of equity in the capital structure, or from a material write-off of an asset, which may not have impacted current period cash flows but could affect future period cash flows relative to debt.

There are two sets of thresholds for three of these ratios based on the level of the issuer's business risk – the Standard Grid and the Lower Business Risk (LBR) Grid. In our view, the different types of utility entities covered under this methodology (as described in Appendix E) have different levels of business risk.

Generation utilities and vertically integrated utilities generally have a higher level of business risk because they are engaged in power generation, so we apply the Standard Grid. We view power generation as the highest-risk component of the electric utility business, as generation plants are typically the most expensive part of a utility's infrastructure (representing asset concentration risk) and are subject to the greatest risks in both construction and operation, including the risk that incurred costs will either not be recovered in rates or recovered with material delays.

7 In certain circumstances, analysts may also apply specific adjustments.

8 We also examine debt/capitalization ratios as defined in applicable covenants (which typically exclude deferred taxes from capitalization) relative to the covenant threshold level.

Other types of utilities may have lower business risk, such that we believe that they are most appropriately assessed using the LBR Grid, due to factors that could include a generally greater transfer of risk to customers, very strong insulation from exposure to commodity price movements, good protection from volumetric risks, fairly limited capex needs and low exposure to storms, major accidents and natural disasters. For instance, we tend to view many US natural gas local distribution companies (LDCs) and certain US electric transmission and distribution companies (T&Ds, which lack generation but generally retain some procurement responsibilities for customers), as typically having a lower business risk profile than their vertically integrated peers. In cases of T&Ds that we do not view as having materially lower risk than their vertically integrated peers, we will apply the Standard grid. This could result from a regulatory framework that exposes them to energy supply risk, large capital expenditures for required maintenance or upgrades, a heightened degree of exposure to catastrophic storm damage, or increased regulatory scrutiny due to poor reliability, or other considerations. The Standard Grid will also apply to LDCs that in our view do not have materially lower risk; for instance, due to their ownership of high pressure pipes or older systems requiring extensive gas main replacements, where gas commodity costs are not fully recovered in a reasonably contemporaneous manner, or where the LDC is not well insulated from declining volumes.

The four key ratios, their weighting in the grid, and the Standard and LBR scoring thresholds are detailed in the following table.

Factor 4: Financial Strength

Weighting 40%	Sub-Factor Weighting		Aaa	Aa	A	Baa	Ba	B	Caa
CFO pre-WC + Interest / Interest	7.5%		≥ 8x	6x - 8x	4.5x - 6x	3x - 4.5x	2x - 3x	1x - 2x	< 1x
CFO pre-WC / Debt	15%	Standard Grid	≥ 40%	30% - 40%	22% - 30%	13% - 22%	5% - 13%	1% - 5%	< 1%
		Low Business Risk Grid	≥ 38%	27% - 38%	19% - 27%	11% - 19%	5% - 11%	1% - 5%	< 1%
CFO pre-WC - Dividends / Debt	10%	Standard Grid	≥ 35%	25% - 35%	17% - 25%	9% - 17%	0% - 9%	(5%) - 0%	< (5%)
		Low Business Risk Grid	≥ 34%	23% - 34%	15% - 23%	7% - 15%	0% - 7%	(5%) - 0%	< (5%)
Debt / Capitalization	7.5%	Standard Grid	< 25%	25% - 35%	35% - 45%	45% - 55%	55% - 65%	65% - 75%	≥ 75%
		Low Business Risk Grid	< 29%	29% - 40%	40% - 50%	50% - 59%	59% - 67%	67% - 75%	≥ 75%

Notching for Structural Subordination of Holding Companies

Why It Matters

A typical utility company structure consists of a holding company ("HoldCo") that owns one or more operating subsidiaries (each an "OpCo"). OpCos may be regulated utilities or non-utility companies. A HoldCo typically has no operations – its assets are mostly limited to its equity interests in subsidiaries, and potentially other investments in subsidiaries that are structured as advances, debt, or even hybrid securities.

Most HoldCos present their financial statements on a consolidated basis that blurs legal considerations about priority of creditors based on the legal structure of the family, and grid scoring is thus based on consolidated ratios. However, HoldCo creditors typically have a secondary claim on the group's cash flows and assets after OpCo creditors. We refer to this as structural subordination, because it is the corporate legal structure, rather than specific subordination provisions, that causes creditors at each of the utility and non-utility subsidiaries to have a more direct claim on the cash flows and assets of their respective OpCo obligors. By contrast, the debt of the HoldCo is typically serviced primarily by dividends that are up-streamed by the OpCos[9]. Under normal circumstances, these dividends are made from net income, after payment of the OpCo's interest and preferred dividends. In most non-financial corporate sectors where cash often moves freely between the entities in a single issuer family, this distinction may have less of an impact. However, in the regulated utility sector, barriers to movement of cash among companies in the corporate family can be much more restrictive, depending on the regulatory framework. These barriers can lead to significantly different probabilities of default for HoldCos and OpCos. Structural subordination also affects loss given default. Under most default[10] scenarios, an OpCo's creditors will be satisfied from the value residing at that OpCo before any of the OpCo's assets can be used to satisfy claims of the HoldCo's creditors. The prevalence of debt issuance at the OpCo level is another reason that structural subordination is usually a more serious concern in the utility sector than for investment grade issuers in other non-financial corporate sectors.

The grids for factors 1-4 are primarily oriented to OpCos (and to some degree for HoldCos with minimal current structural subordination; for example, there is no current structural subordination to debt at the operating company if all of the utility family's debt and preferred stock is issued at the HoldCo level, although there is structural subordination to other liabilities at the OpCo level). The additional risk from structural subordination is addressed via a notching adjustment to bring grid outcomes (on average) closer to the actual ratings of HoldCos.

How We Assess It

Grid-indicated ratings of holding companies may be notched down based on structural subordination. The risk factors and mitigants that impact structural subordination are varied and can be present in different combinations, such that a formulaic approach is not practical and case-by-case analyst judgment of the interaction of all pertinent factors that may increase or decrease its importance to the credit risk of an issuer are essential.

Some of the potentially pertinent factors that could increase the degree and/or impact of structural subordination include the following:

» Regulatory or other barriers to cash movement from OpCos to HoldCo

» Specific ring-fencing provisions

» Strict financial covenants at the OpCo level

» Higher leverage at the OpCo level

» Higher leverage at the HoldCo level[11]

» Significant dividend limitations or potential limitations at an important OpCo

» HoldCo exposure to subsidiaries with high business risk or volatile cash flows

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9 The HoldCo and OpCo may also have intercompany agreements, including tax sharing agreements, that can be another source of cash to the HoldCo.

10 Actual priority in a default scenario will be determined by many factors, including the corporate and bankruptcy laws of the jurisdiction, the asset value of each OpCo, specific financing terms, inter-relationships among members of the family, etc.

11 While higher leverage at the HoldCo does not increase structural subordination per se, it exacerbates the impact of any structural subordination that exists

» Strained liquidity at the HoldCo level

» The group's investment program is primarily in businesses that are higher risk or new to the group

Some of the potentially mitigating factors that could decrease the degree and/or impact of structural subordination include the following:

» Substantial diversity in cash flows from a variety of utility OpCos

» Meaningful dividends to HoldCo from unlevered utility OpCos

» Dependable, meaningful dividends to HoldCo from non-utility OpCos

» The group's investment program is primarily in strong utility businesses

» Inter-company guarantees - however, in many jurisdictions the value of an upstream guarantee may be limited by certain factors, including by the value that the OpCo received in exchange for granting the guarantee

Notching for structural subordination within the grid may range from 0 to negative 3 notches. Instances of extreme structural subordination are relatively rare, so the grid convention does not accommodate wider differences, although in the instances where we believe it is present, actual ratings do reflect the full impact of structural subordination.

A related issue is the relationship of ratings within a utility family with multiple operating companies, and sometimes intermediate holding companies. Some of the key issues are the same, such as the relative amounts of debt at the holding company level compared to the operating company level (or at one OpCo relative to another), and the degree to which operating companies have credit insulation due to regulation or other protective factors. Appendix D has additional insights on ratings within a utility family.

Rating Methodology Assumptions and Limitations, and Other Rating Considerations

The grid in this rating methodology represents a decision to favor simplicity that enhances transparency and to avoid greater complexity that would enable the grid to map more closely to actual ratings. Accordingly, the four rating factors and the notching factor in the grid do not constitute an exhaustive treatment of all of the considerations that are important for ratings of companies in the regulated electric and gas utility sector. In addition, our ratings incorporate expectations for future performance, while the financial information that is used to illustrate the mapping in the grid in this document is mainly historical. In some cases, our expectations for future performance may be informed by confidential information that we can't disclose. In other cases, we estimate future results based upon past performance, industry trends, competitor actions or other factors. In either case, predicting the future is subject to the risk of substantial inaccuracy.

Assumptions that may cause our forward-looking expectations to be incorrect include unanticipated changes in any of the following factors: the macroeconomic environment and general financial market conditions, industry competition, disruptive technology, regulatory and legal actions.

Key rating assumptions that apply in this sector include our view that sovereign credit risk is strongly correlated with that of other domestic issuers, that legal priority of claim affects average recovery on different classes of debt, sufficiently to generally warrant differences in ratings for different debt classes of the same issuer, and the assumption that access to liquidity is a strong driver of credit risk.

In choosing metrics for this rating methodology grid, we did not explicitly include certain important factors that are common to all companies in any industry such as the quality and experience of management, assessments of corporate governance and the quality of financial reporting and information disclosure. Therefore ranking these factors by rating category in a grid would in some cases suggest too much precision in the relative ranking of particular issuers against all other issuers that are rated in various industry sectors.

Ratings may include additional factors that are difficult to quantify or that have a meaningful effect in differentiating credit quality only in some cases, but not all. Such factors include financial controls, exposure to uncertain licensing regimes and possible government interference in some countries. Regulatory, litigation, liquidity, technology and reputational risk as well as changes to consumer and business spending patterns, competitor strategies and macroeconomic trends also affect ratings. While these are important considerations, it is not possible to precisely express these in the rating methodology grid without making the grid excessively complex and significantly less transparent. Ratings may also reflect circumstances in which the weighting of a particular factor will be substantially different from the weighting suggested by the grid.

This variation in weighting rating considerations can also apply to factors that we choose not to represent in the grid. For example, liquidity is a consideration frequently critical to ratings and which may not, in other circumstances, have a substantial impact in discriminating between two issuers with a similar credit profile. As an example of the limitations, ratings can be heavily affected by extremely weak liquidity that magnifies default risk. However, two identical companies might be rated the same if their only differentiating feature is that one has a good liquidity position while the other has an extremely good liquidity position.

Other Rating Considerations

Moody's considers other factors in addition to those discussed in this report, but in most cases understanding the considerations discussed herein should enable a good approximation of our view on the credit quality of companies in the regulated electric and gas utilities sector. Ratings consider our assessment of the quality of management, corporate governance, financial controls, liquidity management, event risk and seasonality. The analysis of these factors remains an integral part of our rating process.

Liquidity and Access to Capital Markets

Liquidity analysis is a key element in the financial analysis of electric and gas utilities, and it encompasses a company's ability to generate cash from internal sources as well as the availability of external sources of financing to supplement these internal sources. Liquidity and access to financing are of particular importance in this sector. Utility assets can often have a very long useful life- 30, 40 or even 60 years is not uncommon, as well as high price tags. Partly as a result of construction cycles, the utility sector has experienced prolonged periods of negative free cash flow – essentially, the sum of its dividends and its capital expenditures for maintenance and growth of its infrastructure frequently exceeds cash from operations, such that a portion of capital expenditures must routinely be debt financed. Utilities are among the largest debt issuers in the corporate universe and typically require consistent access to the capital markets to assure adequate sources of funding and to maintain financial flexibility. Substantial portions of capex are non-discretionary (for example, maintenance, adding customers to the network, or meeting environmental mandates); however, utilities were swift to cut or defer discretionary spending during the 2007-2009 recession. Dividends represent a quasi-permanent outlay, since utilities will typically only rarely cut their dividend. Liquidity is also important to meet maturing obligations, which often occur in large chunks, and to meet collateral calls under any hedging agreements.

Due to the importance of liquidity, incorporating it as a factor with a fixed weighting in the grid would suggest an importance level that is often far different from the actual weight in the rating. In normal circumstances most companies in the sector have good access to liquidity. The industry generally requires, and for the most part has, large, syndicated, multi-year committed credit facilities. In addition, utilities have demonstrated strong access to capital markets, even under difficult conditions. As a result, liquidity has generally not been an issue for most utilities and a utility with very strong liquidity may not warrant a rating distinction compared to a utility with strong liquidity. However, when there is weakness in liquidity or liquidity management, it can be the dominant consideration for ratings.

Our assessment of liquidity for regulated utilities involves an analysis of total sources and uses of cash over the next 12 months or more, as is done for all corporates. Using our financial projections of the utility and our analysis of its available sources of liquidity (including an assessment of the quality and reliability of alternate liquidity such as committed credit facilities), we evaluate how its projected sources of cash (cash from operations, cash on hand and existing committed multi-year credit facilities) compare to its projected uses (including all or most capital expenditures, dividends, maturities of short and long-term debt, our projection of potential liquidity calls on financial hedges, and important issuer-specific items such as special tax payments). We assume no access to capital markets or additional liquidity sources, no renewal of existing credit facilities, and no cut to dividends. We examine a company's liquidity profile under this scenario, its ability to make adjustments to improve its liquidity position, and any dependence on liquidity sources with lower quality and reliability.

Management Quality and Financial Policy

The quality of management is an important factor supporting the credit strength of a regulated utility or utility holding company. Assessing the execution of business plans over time can be helpful in assessing management's business strategies, policies, and philosophies and in evaluating management performance relative to performance of competitors and our projections. A record of consistency provides Moody's with insight into management's likely future performance in stressed situations and can be an indicator of management's tendency to depart significantly from its stated plans and guidelines.

We also assess financial policy (including dividend policy and planned capital expenditures) and how management balances the potentially competing interests of shareholders, fixed income investors and other stakeholders. Dividends and discretionary capital expenditures are the two primary components over which management has the greatest control in the short term. For holding companies, we consider the extent to which management is willing stretch its payout ratio (through aggressive increases or delays in needed decreases) in order to satisfy common shareholders. For a utility that is a subsidiary of a parent company with several utility subsidiaries, dividends to the parent may be more volatile depending on the cash generation and cash needs of that utility, because parents typically want to assure that each utility maintains the regulatory debt/equity ratio on which its rates have been set. The effect we have observed is that utility subsidiaries often pay higher dividends when they have lower capital needs and lower dividends when they have higher capital expenditures or other cash needs. Any dividend policy that cuts into the regulatory debt/equity ratio is a material credit negative.

Size – Natural Disasters, Customer Concentration and Construction Risks

The size and scale of a regulated utility has generally not been a major determinant of its credit strength in the same way that it has been for most other industrial sectors. While size brings certain economies of scale that can somewhat affect the utility's cost structure and competitiveness, rates are more heavily impacted by costs related to fuel and fixed assets. Particularly in the US, we have not observed material differences in the success of utilities' regulatory outreach based on their size. Smaller utilities have sometimes been better able to focus their attention on meeting the expectations of a single regulator than their multi-state peers.

However, size can be a very important factor in our assessment of certain risks that impact ratings, including exposure to natural disasters, customer concentration (primarily to industrial customers in a single sector) and construction risks associated with large projects. While the grid attempts to incorporate the first two of these into Factor 3, for some issuers these considerations may be sufficiently important that the rating reflects a greater weight for these risks. While construction projects always carry the risk of cost over-runs and delays, these risks are materially heightened for projects that are very large relative to the size of the utility.

Interaction of Utility Ratings with Government Policies and Sovereign Ratings

Compared to most industrial sectors, regulated utilities are more likely to be impacted by government actions. Credit impacts can occur directly through rate regulation, and indirectly through energy, environmental and tax policies. Government actions affect fuel prices, the mix of generating plants, the certainty and timing of revenues and costs, and the likelihood that regulated utilities will experience financial stress. While our evolving view of the impact of such policies and the general economic and financial climate is reflected in ratings for each utility, some considerations do not lend themselves to incorporation in a simple ratings grid.[12]

Diversified Operations at the Utility

A small number of regulated utilities have diversified operations that are segments within the utility company, as opposed to the more common practice of housing such operations in one or more separate affiliates. In general, we will seek to evaluate the other businesses that are material in accordance with the appropriate methodology and the rating will reflect considerations from such methodologies. There may be analytical limitations in evaluating the utility and non-utility businesses when segment financial results are not fully broken out and these may be addressed through estimation based on available information. Since regulated utilities are a relatively low risk business compared to other corporate sectors, in most cases diversified non-utility operations increase the business risk profile of a utility. Reflecting this tendency, we note that assigned ratings are typically lower than grid-indicated ratings for such companies.

Event Risk

We also recognize the possibility that an unexpected event could cause a sudden and sharp decline in an issuer's fundamental creditworthiness. Typical special events include mergers and acquisitions, asset sales, spin-offs, capital restructuring programs, litigation and shareholder distributions.

[12] See also the cross-sector methodology How Sovereign Credit Quality May Affect Other Ratings, February 2012.

Corporate Governance

Among the areas of focus in corporate governance are audit committee financial expertise, the incentives created by executive compensation packages, related party transactions, interactions with outside auditors, and ownership structure.

Investment and Acquisition Strategy

In our credit assessment we take into consideration management's investment strategy. Investment strategy is benchmarked with that of the other companies in the rated universe to further verify its consistency. Acquisitions can strengthen a company's business. Our assessment of a company's tolerance for acquisitions at a given rating level takes into consideration (1) management's risk appetite, including the likelihood of further acquisitions over the medium term; (2) share buy-back activity; (3) the company's commitment to specific leverage targets; and (4) the volatility of the underlying businesses, as well as that of the business acquired. Ratings can often hold after acquisitions even if leverage temporarily climbs above normally acceptable ranges. However, this depends on (1) the strategic fit; (2) pro-forma capitalization/leverage following an acquisition; and (3) our confidence that credit metrics will be restored in a relatively short timeframe.

Financial Controls

We rely on the accuracy of audited financial statements to assign and monitor ratings in this sector. Such accuracy is only possible when companies have sufficient internal controls, including centralized operations, the proper tone at the top and consistency in accounting policies and procedures.

Weaknesses in the overall financial reporting processes, financial statement restatements or delays in regulatory filings can be indications of a potential breakdown in internal controls.

Conclusion: Summary of the Grid-Indicated Rating Outcomes

For the 45 representative utilities shown in the illustrative mapping examples, the grid-indicated ratings map to current assigned ratings as follows (see Appendix B for the details):

» 33% or 15 companies map to their assigned rating

» 49% or 22 companies have grid-indicated ratings that are within one alpha-numeric notch of their assigned rating

» 16% or 7 companies have grid-indicated ratings that are within two alpha-numeric notches of their assigned rating

» 2% or 1 company has a grid-indicated rating that is within three alpha-numeric notches of its assigned rating

Grid Indicated Rating Outcomes

Map to Assigned Rating	Map to Within One Notch
American Electric Power Company, Inc.	Appalachian Power Company
China Longyuan Power Group Corporation Ltd.	Arizona Public Service Company
Chubu Electric Power Company, Incorporated	China Resources Gas Group Limited
Entergy Corporation	Duke Energy Corporation
FortisBC Holdings Inc.	Florida Power & Light Company
Great Plains Energy Incorporated	Georgia Power Company
Hokuriku Electric Power Company	Hawaiian Electric Industries, Inc.
Madison Gas & Electric	Idaho Power Company
MidAmerican Energy Company	Kansai Electric Power Company, Incorporated
Mississippi Power Company	Korea Electric Power Corporation
Newfoundland Power Inc.	MidAmerican Energy Holdings Co.
Oklahoma Gas and Electric Company	Niagara Mohawk Power Corporation
Osaka Gas Co., Ltd.	Northern States Power Minnesota
Saudi Electricity	Okinawa Electric Power Company, Incorporated
Wisconsin Public Service Corporation	PacifiCorp
	Pennsylvania Electric Company
	PNG Companies
	Public Service Company of New Mexico
	SCANA
	Southwestern Public Service Company
	UGI Utilities, Inc.
	Virginia Electric Power Company

Map to Within Two Notches	Map to Within Three or More Notches
Ameren Illinois Company	Western Mass Electric Co.
Consumers Energy Company	
Distribuidora de Electricidad La Paz S.A.	
Empresa Electrica de Guatemala, S.A. (EEGSA)	
Gail (India) Ltd	
Gas Natural Ban, S.A.	
Ohio Power Company	

Appendix A: Regulated Electric and Gas Utilities Methodology Factor Grid

Factor 1a: Legislative and Judicial Underpinnings of the Regulatory Framework (12.5%)

Aaa	Aa	A	Baa
Utility regulation occurs under a fully developed framework that is national in scope based on legislation that provides the utility a nearly absolute monopoly (see note 1_ within its service territory, an unquestioned assurance that rates will be set in a manner that will permit the utility to make and recover all necessary investments, an extremely high degree of clarity as to the manner in which utilities will be regulated and prescriptive methods and procedures for setting rates. Existing utility law is comprehensive and supportive such that changes in legislation are not expected to be necessary; or any changes that have occurred have been strongly supportive of utilities credit quality in general and sufficiently forward-looking so as to address problems before they occurred. There is an independent judiciary that can arbitrate disagreements between the regulator and the utility should they occur, including access to national courts, very strong judicial precedent in the interpretation of utility laws, and a strong rule of law. We expect these conditions to continue.	Utility regulation occurs under a fully developed national, state or provincial framework based on legislation that provides the utility an extremely strong monopoly (see note 1) within its service territory, a strong assurance, subject to limited review, that rates will be set in a manner that will permit the utility to make and recover all necessary investments, a very high degree of clarity as to the manner in which utilities will be regulated and reasonably prescriptive methods and procedures for setting rates. If there have been changes in utility legislation, they have been timely and clearly credit supportive of the issuer in a manner that shows the utility has had a strong voice in the process. There is an independent judiciary that can arbitrate disagreements between the regulator and the utility, should they occur including access to national courts, strong judicial precedent in the interpretation of utility laws, and a strong rule of law. We expect these conditions to continue.	Utility regulation occurs under a well developed national, state or provincial framework based on legislation that provides the utility a very strong monopoly (see note 1) within its service territory, an assurance, subject to reasonable prudency requirements, that rates will be set in a manner that will permit the utility to make and recover all necessary investments, a high degree of clarity as to the manner in which utilities will be regulated, and overall guidance for methods and procedures for setting rates. If there have been changes in utility legislation, they have been mostly timely and on the whole credit supportive for the issuer, and the utility has had a clear voice in the legislative process. There is an independent judiciary that can arbitrate disagreements between the regulator and the utility, should they occur, including access to national courts, clear judicial precedent in the interpretation of utility law, and a strong rule of law. We expect these conditions to continue.	Utility regulation occurs (i) under a national, state, provincial or municipal framework based on legislation that provides the utility a strong monopoly within its service territory that may have some exceptions such as greater self-generation (see note 1), a general assurance that, subject to prudency requirements that are mostly reasonable, rates will be set will be set in a manner that will permit the utility to make and recover all necessary investments, reasonable clarity as to the manner in which utilities will be regulated and overall guidance for methods and procedures for setting rates; or (ii) under a new framework where independent and transparent regulation exists in other sectors. If there have been changes in utility legislation, they have been credit supportive or at least balanced for the issuer but potentially less timely, and the utility had a voice in the legislative process. There is either (i) an independent judiciary that can arbitrate disagreements between the regulator and the utility, including access to courts at least at the state or provincial level, reasonably clear judicial precedent in the interpretation of utility laws, and a generally strong rule of law; or (ii) regulation has been applied (under a well developed framework) in a manner such that redress to an independent arbiter has not been required. We expect these conditions to continue.

Ba	B	Caa	
Utility regulation occurs (i) under a national, state, provincial or municipal framework based on legislation or government decree that provides the utility a monopoly within its service territory that is generally strong but may have a greater level of exceptions (see note 1), and that, subject to prudency requirements which may be stringent, provides a general assurance (with somewhat less certainty) that rates will be set will be set in a manner that will permit the utility to make and recover necessary investments; or (ii) under a new framework where the jurisdiction has a history of less independent and transparent regulation in other sectors. Either: (i) the judiciary that can arbitrate disagreements between the regulator and the utility may not have clear authority or may not be fully independent of the regulator or other political pressure, but there is a reasonably strong rule of law; or (ii) where there is no independent arbiter, the regulation has mostly been applied in a manner such redress has not been required. We expect these conditions to continue.	Utility regulation occurs (i) under a national, state, provincial or municipal framework based on legislation or government decree that provides the utility monopoly within its service territory that is reasonably strong but may have important exceptions, and that, subject to prudency requirements which may be stringent or at times arbitrary, provides more limited or less certain assurance that rates will be set in a manner that will permit the utility to make and recover necessary investments; or (ii) under a new framework where we would expect less independent and transparent regulation, based either on the regulator's history in other sectors or other factors. The judiciary that can arbitrate disagreements between the regulator and the utility may not have clear authority or may not be fully independent of the regulator or other political pressure, but there is a reasonably strong rule of law. Alternately, where there is no independent arbiter, the regulation has been applied in a manner that often requires some redress adding more uncertainty to the regulatory framework. There may be a periodic risk of creditor-unfriendly government intervention in utility markets or rate-setting.	Utility regulation occurs (i) under a national, state, provincial or municipal framework based on legislation or government decree that provides the utility a monopoly within its service territory, but with little assurance that rates will be set in a manner that will permit the utility to make and recover necessary investments; or (ii) under a new framework where we would expect unpredictable or adverse regulation, based either on the jurisdiction's history of in other sectors or other factors. The judiciary that can arbitrate disagreements between the regulator and the utility may not have clear authority or is viewed as not being fully independent of the regulator or other political pressure. Alternately, there may be no redress to an effective independent arbiter. The ability of the utility to enforce its monopoly or prevent uncompensated usage of its system may be limited. There may be a risk of creditor-unfriendly nationalization or other significant intervention in utility markets or rate-setting.	

Note 1: The strength of the monopoly refers to the legal, regulatory and practical obstacles for customers in the utility's territory to obtain service from another provider. Examples of a weakening of the monopoly would include the ability of a city or large user to leave the utility system to set up their own system, the extent to which self-generation is permitted (e.g. cogeneration) and/or encouraged (e.g., net metering, DSM generation). At the lower end of the ratings spectrum, the utility's monopoly may be challenged by pervasive theft and unauthorized use. Since utilities are generally presumed to be monopolies, a strong monopoly position in itself is not sufficient for a strong score in this sub-factor, but a weakening of the monopoly can lower the score.

Factor 1b: Consistency and Predictability of Regulation (12.5%)

Aaa	Aa	A	Baa
The issuer's interaction with the regulator has led to a strong, lengthy track record of predictable, consistent and favorable decisions. The regulator is highly credit supportive of the issuer and utilities in general. We expect these conditions to continue.	The issuer's interaction with the regulator has a led to a considerable track record of predominantly predictable and consistent decisions. The regulator is mostly credit supportive of utilities in general and in almost all instances has been highly credit supportive of the issuer. We expect these conditions to continue.	The issuer's interaction with the regulator has led to a track record of largely predictable and consistent decisions. The regulator may be somewhat less credit supportive of utilities in general, but has been quite credit supportive of the issuer in most circumstances. We expect these conditions to continue.	The issuer's interaction with the regulator has led to an adequate track record. The regulator is generally consistent and predictable, but there may some evidence of inconsistency or unpredictability from time to time, or decisions may at times be politically charged. However, instances of less credit supportive decisions are based on reasonable application of existing rules and statutes and are not overly punitive. We expect these conditions to continue.
Ba	**B**	**Caa**	
We expect that regulatory decisions will demonstrate considerable inconsistency or unpredictability or that decisions will be politically charged, based either on the issuer's track record of interaction with regulators or other governing bodies, or our view that decisions will move in this direction. The regulator may have a history of less credit supportive regulatory decisions with respect to the issuer, but we expect that the issuer will be able to obtain support when it encounters financial stress, with some potentially material delays. The regulator's authority may be eroded at times by legislative or political action. The regulator may not follow the framework for some material decisions.	We expect that regulatory decisions will be largely unpredictable or even somewhat arbitrary, based either on the issuer's track record of interaction with regulators or other governing bodies, or our view that decisions will move in this direction. However, we expect that the issuer will ultimately be able to obtain support when it encounters financial stress, albeit with material or more extended delays. Alternately, the regulator is untested, lacks a consistent track record, or is undergoing substantial change. The regulator's authority may be eroded on frequent occasions by legislative or political action. The regulator may more frequently ignore the framework in a manner detrimental to the issuer.	We expect that regulatory decisions will be highly unpredictable and frequently adverse, based either on the issuer's track record of interaction with regulators or other governing bodies, or our view that decisions will move in this direction. Alternately, decisions may have credit supportive aspects, but may often be unenforceable. The regulator's authority may have been seriously eroded by legislative or political action. The regulator may consistently ignore the framework to the detriment of the issuer.	

Factor 2a: Timeliness of Recovery of Operating and Capital Costs (12.5%)

Aaa	Aa	A	Baa
Tariff formulas and automatic cost recovery mechanisms provide full and highly timely recovery of all operating costs and essentially contemporaneous return on all incremental capital investments, with statutory provisions in place to preclude the possibility of challenges to rate increases or cost recovery mechanisms. By statute and by practice, general rate cases are efficient, focused on an impartial review, quick, and permit inclusion of fully forward -looking costs.	Tariff formulas and automatic cost recovery mechanisms provide full and highly timely recovery of all operating costs and essentially contemporaneous or near-contemporaneous return on most incremental capital investments, with minimal challenges by regulators to companies' cost assumptions. By statute and by practice, general rate cases are efficient, focused on an impartial review, of a very reasonable duration before non-appealable interim rates can be collected, and primarily permit inclusion of forward-looking costs.	Automatic cost recovery mechanisms provide full and reasonably timely recovery of fuel, purchased power and all other highly variable operating expenses. Material capital investments may be made under tariff formulas or other rate-making permitting reasonably contemporaneous returns, or may be submitted under other types of filings that provide recovery of cost of capital with minimal delays. Instances of regulatory challenges that delay rate increases or cost recovery are generally related to large, unexpected increases in sizeable construction projects. By statute or by practice, general rate cases are reasonably efficient, primarily focused on an impartial review, of a reasonable duration before rates (either permanent or non-refundable interim rates) can be collected, and permit inclusion of important forward -looking costs.	Fuel, purchased power and all other highly variable expenses are generally recovered through mechanisms incorporating delays of less than one year, although some rapid increases in costs may be delayed longer where such deferrals do not place financial stress on the utility. Incremental capital investments may be recovered primarily through general rate cases with moderate lag, with some through tariff formulas. Alternately, there may be formula rates that are untested or unclear. Potentially greater tendency for delays due to regulatory intervention, although this will generally be limited to rates related to large capital projects or rapid increases in operating costs.

Ba	B	Caa	
There is an expectation that fuel, purchased power or other highly variable expenses will eventually be recovered with delays that will not place material financial stress on the utility, but there may be some evidence of an unwillingness by regulators to make timely rate changes to address volatility in fuel, or purchased power, or other market-sensitive expenses. Recovery of costs related to capital investments may be subject to delays that are somewhat lengthy, but not so pervasive as to be expected to discourage important investments.	The expectation that fuel, purchased power or other highly variable expenses will be recovered may be subject to material delays due to second-guessing of spending decisions by regulators or due to political intervention. Recovery of costs related to capital investments may be subject to delays that are material to the issuer, or may be likely to discourage some important investment.	The expectation that fuel, purchased power or other highly variable expenses will be recovered may be subject to extensive delays due to second-guessing of spending decisions by regulators or due to political intervention. Recovery of costs related to capital investments may be uncertain, subject to delays that are extensive, or that may be likely to discourage even necessary investment.	

Note: Tariff formulas include formula rate plans as well as trackers and riders related to capital investment.

Factor 2b: Sufficiency of Rates and Returns (12.5%)

Aaa	Aa	A	Baa
Sufficiency of rates to cover costs and attract capital is (and will continue to be) unquestioned.	Rates are (and we expect will continue to be) set at a level that permits full cost recovery and a fair return on all investments, with minimal challenges by regulators to companies' cost assumptions. This will translate to returns (measured in relation to equity, total assets, rate base or regulatory asset value, as applicable) that are strong relative to global peers.	Rates are (and we expect will continue to be) set at a level that generally provides full cost recovery and a fair return on investments, with limited instances of regulatory challenges and disallowances. In general, this will translate to returns (measured in relation to equity, total assets, rate base or regulatory asset value, as applicable) that are generally above average relative to global peers, but may at times be average.	Rates are (and we expect will continue to be) set at a level that generally provides full operating cost recovery and a mostly fair return on investments, but there may be somewhat more instances of regulatory challenges and disallowances, although ultimate rate outcomes are sufficient to attract capital without difficulty. In general, this will translate to returns (measured in relation to equity, total assets, rate base or regulatory asset value, as applicable) that are average relative to global peers, but may at times be somewhat below average.

Ba	B	Caa
Rates are (and we expect will continue to be) set at a level that generally provides recovery of most operating costs but return on investments may be less predictable, and there may be decidedly more instances of regulatory challenges and disallowances, but ultimate rate outcomes are generally sufficient to attract capital. In general, this will translate to returns (measured in relation to equity, total assets, rate base or regulatory asset value, as applicable) that are generally below average relative to global peers, or where allowed returns are average but difficult to earn. Alternately, the tariff formula may not take into account all cost components and/or remuneration of investments may be unclear or at times unfavorable.	We expect rates will be set at a level that at times fails to provide recovery of costs other than cash costs, and regulators may engage in somewhat arbitrary second-guessing of spending decisions or deny rate increases related to funding ongoing operations based much more on politics than on prudency reviews. Return on investments may be set at levels that discourage investment. We expect that rate outcomes may be difficult or uncertain, negatively affecting continued access to capital. Alternately, the tariff formula may fail to take into account significant cost components other than cash costs, and/or remuneration of investments may be generally unfavorable.	We expect rates will be set at a level that often fails to provide recovery of material costs, and recovery of cash costs may also be at risk. Regulators may engage in more arbitrary second-guessing of spending decisions or deny rate increases related to funding ongoing operations based primarily on politics. Return on investments may be set at levels that discourage necessary maintenance investment. We expect that rate outcomes may often be punitive or highly uncertain, with a markedly negative impact on access to capital. Alternately, the tariff formula may fail to take into account significant cash cost components, and/or remuneration of investments may be primarily unfavorable.

Factor 3: Diversification (10%)

Weighting 10%	Sub-Factor Weighting	Aaa	Aa	A	Baa
Market Position	5% *	A very high degree of multinational and regional diversity in terms of regulatory regimes and/or service territory economies.	Material operations in three or more nations or substantial geographic regions providing very good diversity of regulatory regimes and/or service territory economies.	Material operations in two to three nations, states, provinces or regions that provide good diversity of regulatory regimes and service territory economies. Alternately, operates within a single regulatory regime with low volatility, and the service territory economy is robust, has a very high degree of diversity and has demonstrated resilience in economic cycles.	May operate under a single regulatory regime viewed as having low volatility, or where multiple regulatory regimes are not viewed as providing much diversity. The service territory economy may have some concentration and cyclicality, but is sufficiently resilient that it can absorb reasonably foreseeable increases in utility rates.
Generation and Fuel Diversity	5% **	A high degree of diversity in terms of generation and/or fuel sources such that the utility and rate-payers are well insulated from commodity price changes, no generation concentration, and very low exposures to Challenged or Threatened Sources (see definitions below).	Very good diversification in terms of generation and/or fuel sources such that the utility and rate-payers are affected only minimally by commodity price changes, little generation concentration, and low exposures to Challenged or Threatened Sources.	Good diversification in terms of generation and/or fuel sources such that the utility and rate-payers have only modest exposure to commodity price changes; however, may have some concentration in a source that is neither Challenged nor Threatened. Exposure to Threatened Sources is low. While there may be some exposure to Challenged Sources, it is not a cause for concern.	Adequate diversification in terms of generation and/or fuel sources such that the utility and rate-payers have moderate exposure to commodity price changes; however, may have some concentration in a source that is Challenged. Exposure to Threatened Sources is moderate, while exposure to Challenged Sources is manageable.

	Sub-Factor Weighting	Ba	B	Caa	Definitions
Market Position	5% *	Operates in a market area with somewhat greater concentration and cyclicality in the service territory economy and/or exposure to storms and other natural disasters, and thus less resilience to absorbing reasonably foreseeable increases in utility rates. May show somewhat greater volatility in the regulatory regime(s).	Operates in a limited market area with material concentration and more severe cyclicality in service territory economy such that cycles are of materially longer duration or reasonably foreseeable increases in utility rates could present a material challenge to the economy. Service territory may have geographic concentration that limits its resilience to storms and other natural disasters, or may be an emerging market. May show decided volatility in the regulatory regime(s).	Operates in a concentrated economic service territory with pronounced concentration, macroeconomic risk factors, and/or exposure to natural disasters.	Challenged Sources are generation plants that face higher but not insurmountable economic hurdles resulting from penalties or taxes on their operation, or from environmental upgrades that are required or likely to be required. Some examples are carbon-emitting plants that incur carbon taxes, plants that must buy emissions credits to operate, and plants that must install environmental equipment to continue to operate, in each where the taxes/credits/upgrades are sufficient to have a material impact on those plants' competitiveness relative to other generation types or on the utility's rates, but where the impact is not so severe as to be likely require plant closure.
Generation and Fuel Diversity	5% **	Modest diversification in generation and/or fuel sources such that the utility or rate-payers have greater exposure to commodity price changes. Exposure to Challenged and Threatened Sources may be more pronounced, but the utility will be able to access alternative sources without undue financial stress.	Operates with little diversification in generation and/or fuel sources such that the utility or rate-payers have high exposure to commodity price changes. Exposure to Challenged and Threatened Sources may be high, and accessing alternate sources may be challenging and cause more financial stress, but ultimately feasible.	Operates with high concentration in generation and/or fuel sources such that the utility or rate-payers have exposure to commodity price shocks. Exposure to Challenged and Threatened Sources may be very high, and accessing alternate sources may be highly uncertain.	Threatened Sources are generation plants that are not currently able to operate due to major unplanned outages or issues with licensing or other regulatory compliance, and plants that are highly likely to be required to de-activate, whether due to the effectiveness of currently existing or expected rules and regulations or due to economic challenges. Some recent examples would include coal fired plants in the US that are not economic to retro-fit to meet mercury and air toxics standards, plants that cannot meet the effective date of those standards, nuclear plants in Japan that have not been licensed to re-start after the Fukushima Dai-ichi accident, and nuclear plants that are required to be phased out within 10 years (as is the case in some European countries).

* 10% weight for issuers that lack generation **0% weight for issuers that lack generation

Factor 4: Financial Strength

Weighting 40%	Sub-Factor Weighting		Aaa	Aa	A	Baa	Ba	B	Caa
CFO pre-WC + Interest / Interest	7.5%		≥ 8x	6x - 8x	4.5x - 6x	3x - 4.5x	2x - 3x	1x - 2x	< 1x
CFO pre-WC / Debt	15%	Standard Grid	≥ 40%	30% - 40%	22% - 30%	13% - 22%	5% - 13%	1% - 5%	< 1%
		Low Business Risk Grid	≥ 38%	27% - 38%	19% - 27%	11% - 19%	5% - 11%	1% - 5%	< 1%
CFO pre-WC - Dividends / Debt	10%	Standard Grid	≥ 35%	25% - 35%	17% - 25%	9% - 17%	0% - 9%	(5%) - 0%	< (5%)
		Low Business Risk Grid	≥ 34%	23% - 34%	15% - 23%	7% - 15%	0% - 7%	(5%) - 0%	< (5%)
Debt / Capitalization	7.5%	Standard Grid	< 25%	25% - 35%	35% - 45%	45% - 55%	55% - 65%	65% - 75%	≥ 75%
		Low Business Risk Grid	< 29%	29% - 40%	40% - 50%	50% - 59%	59% - 67%	67% - 75%	≥ 75%

Appendix B: Regulated Electric and Gas Utilities – Assigned Ratings and Grid-Indicated Ratings for a Selected Cross-Section of Issuers

	Issuer	Outlook	Actual Rating	*BCA / Rating Before Uplift*[13]	Grid Indicated Rating	Country
1	Ameren Illinois Company	RUR-Up	Baa2	-	A3	USA
2	American Electric Power Company, Inc.	RUR-Up	Baa2	-	Baa2	USA
3	Appalachian Power Company	RUR-Up	Baa2	-	Baa1	USA
4	Arizona Public Service Company	RUR-Up	Baa1	-	A3	USA
5	China Longyuan Power Group Corporation	Stable	Baa3	*Ba1*	Ba1	China
6	China Resources Gas Group Ltd.	Stable	Baa1	*Baa2*	Baa1	China
7	Chubu Electric Power Company, Inc.	Negative	A3	*Baa2*	Baa2	Japan
8	Consumers Energy Company	RUR-Up	(P)Baa1	-	A2	USA
9	Distribuidora de Electricidad La Paz S.A.	Stable	Ba3	-	Ba1	Bolivia
10	Duke Energy Corporation	RUR-Up	Baa1	-	Baa2	USA
11	Empresa Electrica de Guatemala, S.A.	Positive	Ba2	-	Baa3	Guatemala
12	Entergy Corporation	Stable	Baa3	-	Baa3	USA
13	Florida Power & Light Company	RUR-Up	A2	-	A1	USA
14	FortisBC Holdings Inc.	Negative	Baa2	-	Baa2	Canada
15	Gail (India) Ltd	Stable	Baa2	*Baa2*	A3	India
16	Gas Natural BAN, S.A.	Negative	B3	-	B1	Argentina
17	Georgia Power Company	Stable	A3	-	A2	USA
18	Great Plains Energy Incorporated	RUR-Up	Baa3	-	Baa3	USA
19	Hawaiian Electric Industries, Inc.	RUR-Up	Baa2	-	Baa1	USA
20	Hokuriku Electric Power Company	Negative	A3	*Baa2*	Baa2	Japan
21	Idaho Power Company	RUR-Up	Baa1	-	A3	USA
22	Kansai Electric Power Company, Inc.	Negative	A3	*Baa2*	Baa3	Japan
23	Korea Electric Power Corporation	Stable	A1	*Baa2*	Baa3	Korea
24	Madison Gas & Electric	RUR-Up	A1	-	A1	USA
25	MidAmerican Energy Company	RUR-Up	A2	-	A2	USA
26	MidAmerican Energy Holdings Co.	RUR-Up	Baa1	-	A3	USA
27	Mississippi Power Company	Stable	Baa1	-	Baa1	USA
28	Niagara Mohawk Power Corporation	RUR-Up	A3	-	A2	USA
29	Newfoundland Power Inc.	Stable	Baa1	-	Baa1	Canada
30	Northern States Power Minnesota	RUR-Up	A3	-	A2	USA
31	Ohio Power Company	Stable	Baa1	-	A2	USA
32	Okinawa Electric Power Company, Inc.	Stable	Aa3	*A2*	A3	Japan
33	Oklahoma Gas & Electric Company	RUR-Up	A2	-	A2	USA
34	Osaka Gas Co., Ltd.	Stable	Aa3	*A1*	A1	Japan

[13] BCA means a Baseline Credit Assessment for a government related issuer. Please see Government Related Issuers: Methodology Update, July 2010. In addition, certain companies in Japan receive a ratings uplift due to country-specific considerations. Please see "Support system for large corporate entities in Japan can provide ratings uplift, with limits" in Appendix G.

	Issuer	Outlook	Actual Rating	*BCA / Rating Before Uplift*[13]	Grid Indicated Rating	Country
35	PacifiCorp	RUR-Up	Baa1	-	A3	USA
36	Pennsylvania Electric Company	Stable	Baa2	-	Baa1	USA
37	PNG Companies LLC	RUR-Up	Baa3	-	Baa2	USA
38	Public Service Company of New Mexico	RUR-Up	Baa3	-	Baa2	USA
39	Saudi Electricity Company	Stable	A1	*Baa1*	Baa1	Saudi Arabia
40	SCANA Corporation	Stable	Baa3	-	Baa2	USA
41	Southwestern Public Service Company	RUR-Up	Baa2	-	Baa1	USA
42	UGI Utilities, Inc.	RUR-Up	A3	-	A2	USA
43	Virginia Electric and Power Company	RUR-Up	A3	-	A2	USA
44	Western Massachusetts Electric Company	RUR-Up	Baa2	-	A2	USA
45	Wisconsin Public Service Corporation	RUR-Up	A2	-	A2	USA

Appendix C: Regulated Electric and Gas Utility Grid Outcomes and Outlier Discussion

In the table below positive or negative "outliers" for a given sub-factor are defined as issuers whose grid sub-factor score is at least two broad rating categories higher or lower than a company's rating (e.g. a B-rated company whose rating on a specific sub-factor is in the Baa-rating category is flagged as a positive outlier for that sub-factor). Green is used to denote a positive outlier, whose grid-indicated performance for a sub-factor is two or more broad rating categories higher than Moody's rating. Red is used to denote a negative outlier, whose grid-indicated performance for a sub-factor is two or more broad rating categories lower than Moody's rating.

Grid-Indicated Ratings

		Actual Rating / *BCA or Rating Before Uplift*	Indicated Rating	Indicated Factor 1 Rating	Factor 1a 12.50 %	Factor 1b 12.50 %	Indicated Factor 2 Rating	Factor 2a 12.50 %	Factor 2b 12.50 %	Indicated Factor 3 Rating	Factor 3a 5.00 %	Factor 3b 5.00 %	Indicated Factor 4 Rating	Factor 4a 7.50 %	Factor 4b 15.00 %	Factor 4c 10.00 %	Factor 4d 7.50 %	Hold-Co Notching for Structural Subor-dination
1	Ameren Illinois Company	Baa2	A3	Baa	A	Baa	Baa	Aa	Ba	Baa	Baa	-	A	Baa	A	Baa	Aa	n/a
2	American Electric Power Company, Inc.	Baa2	Baa2	A	A	A	Baa	A	Baa	Baa	Baa	Baa	Baa	Baa	Baa	Baa	Baa	-1
3	Appalachian Power Company	Baa2	Baa1	A	A	A	Baa	Baa	Baa	Baa	Baa	Baa	Baa	Baa	Baa	Baa	Baa	n/a
4	Arizona Public Service Company	Baa1	A3	A	A	A	Baa	A	Baa	Baa	Baa	Baa	A	A	A	A	A	n/a
5	China Longyuan Power Group Corporation Ltd.	Baa3 / *Ba1*	Ba1	Ba	Ba	Baa	A	Baa	A	Baa	Baa	A	Ba	Ba	Ba	Baa	B	-1
6	China Resources Gas Group Limited	Baa1 / *Baa2*	Baa1	Ba	Ba	Baa	Ba	Ba	Baa	Baa	Baa	-	A	Aaa	A	A	A	n/a
7	Chubu Electric Power Company, Incorporated	A3 / *Baa2*	Baa2	A	Aa	Baa	Baa	Ba	A	Baa	A	Ba	Ba	Aa	Ba	Ba	B	n/a
8	Consumers Energy Company	Baa1	A2	A	A	Aa	A	Aa	A	Ba	Baa	Ba	A	A	A	A	Baa	n/a
9	Distribuidora de Electricidad La Paz S.A.	Ba3	Ba1	B	B	Ba	B	B	Ba	B	B	-	A	Baa	A	A	A	n/a
10	Duke Energy Corp.	Baa1	Baa2	A	A	Aa	Baa	A	Baa	A	A	A	Baa	A	Baa	Baa	A	-2
11	Empresa Electrica de Guatemala, S.A. (EEGSA)	Ba2	Baa3	Ba	Ba	Ba	Ba	Ba	Ba	Ba	Ba	-	Baa	A	Aa	B	A	n/a
12	Entergy Corp	Baa3	Baa3	Baa	A	Baa	Baa	Baa	Baa	A	A	Baa	A	A	A	A	Baa	-2
13	Florida Power & Light Company	A2	A1	A	A	Aa	A	Aa	Baa	A	A	A	Aa	Aaa	Aa	Aa	Aa	n/a
14	FortisBC Holdings Inc.	Baa2	Baa2	A	A	A	A	A	A	A	A	-	Ba	Ba	Ba	Ba	Ba	0
15	Gail (India) Ltd	Baa2 / *Baa2*	A3	Ba	Ba	Ba	Baa	Baa	Baa	Ba	Ba	-	Aa	Aaa	Aaa	Aaa	Aa	n/a
16	Gas Natural Ban, S.A.	B3	B1	Caa	Caa	Caa	Caa	Caa	Caa	B	B	-	A	Ba	A	Baa	Aaa	n/a

Grid-Indicated Ratings

		Actual Rating / *BCA or Rating Before Uplift*	Indicated Rating	Indicated Factor 1 Rating	Factor 1a 12.50 %	Factor 1b 12.50 %	Indicated Factor 2 Rating	Factor 2a 12.50 %	Factor 2b 12.50 %	Indicated Factor 3 Rating	Factor 3a 5.00 %	Factor 3b 5.00 %	Indicated Factor 4 Rating	Factor 4a 7.50 %	Factor 4b 15.00 %	Factor 4c 10.00 %	Factor 4d 7.50 %	Hold-Co Notching for Structural Subor-dination
17	Georgia Power Company	A3	A2	Aa	Aa	Aa	A	Aa	Baa	Baa	Baa	Baa	A	Aa	A	Baa	A	n/a
18	Great Plains Energy Incorporated	Baa3	Baa3	A	A	A	Ba	Baa	Ba	Ba	Baa	Ba	Baa	Baa	Baa	Baa	Baa	-1
19	Hawaiian Electric Industries, Inc.	Baa2	Baa1	A	A	A	A	Aa	A	Ba	Baa	Ba	Baa	A	Baa	Baa	Baa	-1
20	Hokuriku Electric Power Company	A3 / *Baa2*	Baa2	A	Aa	Baa	Baa	Ba	A	Ba	Baa	Ba	Ba	Aa	Ba	Ba	B	n/a
21	Idaho Power Company	Baa1	A3	A	A	A	A	Aa	Baa	Baa	Baa	A	Baa	Baa	Baa	Baa	A	n/a
22	Kansai Electric Power Company, Incorporated	A3 / *Baa2*	Baa3	A	Aa	Baa	Baa	Ba	A	Baa	A	Ba	B	Ba	B	Ba	Caa	n/a
23	Korea Electric Power Corporation	A1 / *Baa2*	Baa3	Baa	Baa	Baa	Ba	Ba	Ba	A	A	A	Ba	Ba	Ba	Ba	Baa	n/a
24	Madison Gas & Electric	A1	A1	A	A	Aa	A	Aa	Baa	Baa	Baa	Baa	Aa	Aa	Aa	Aa	A	n/a
25	MidAmerican Energy Company	A2	A2	A	A	Aa	Ba	Ba	Baa	Baa	Baa	A	A	Aa	A	Aa	A	n/a
26	MidAmerican Energy Holdings Co.	Baa1	A3	A	A	A	Baa	Baa	Baa	A	A	Baa	Baa	Baa	Baa	A	Baa	0
27	Mississippi Power Company	Baa1	Baa1	A	A	A	A	Aa	Baa	Ba	Baa	Ba	Baa	A	Baa	Baa	Baa	n/a
28	Niagara Mohawk Power Corporation	A3	A2	A	A	A	A	Aa	Baa	Baa	Baa	-	A	Aa	A	A	Aa	n/a
29	Newfoundland Power Inc.	Baa1	Baa1	A	A	A	A	A	A	Baa	Baa	Baa	Baa	Baa	Baa	Baa	Baa	n/a
30	Northern States Power Minnesota	A3	A2	A	A	A	A	Aa	Baa	Baa	Baa	Baa	A	A	A	A	A	n/a
31	Ohio Power Company	Baa1	A2	A	A	A	Baa	Baa	A	Ba	Baa	B	A	A	Aa	A	A	n/a
32	Okinawa Electric Power Company, Incorporated	Aa3 / *A2*	A3	Aa	Aa	Aa	A	A	A	Ba	Ba	Ba	Baa	Aaa	Ba	Baa	B	n/a
33	Oklahoma Gas and Electric Company	A2	A2	A	A	Aa	Baa	Baa	A	Baa	Baa	Baa	A	A	A	A	A	n/a
34	Osaka Gas Co., Ltd.	Aa3 / *A1*	A1	Aa	Aa	Aa	A	A	A	A	A	-	A	Aaa	A	A	A	n/a
35	PacifiCorp	Baa1	A3	A	A	A	Baa	Aa	Ba	Baa	A	Baa	A	A	A	Baa	A	n/a
36	Pennsylvania Electric Company	Baa2	Baa1	A	A	A	Baa	A	Baa	Baa	Baa	-	Baa	Baa	Baa	Ba	A	n/a

Grid-Indicated Ratings

		Actual Rating / *BCA or Rating Before Uplift*	Indicated Rating	Indicated Factor 1 Rating	Factor 1a 12.50 %	Factor 1b 12.50 %	Indicated Factor 2 Rating	Factor 2a 12.50 %	Factor 2b 12.50 %	Indicated Factor 3 Rating	Factor 3a 5.00 %	Factor 3b 5.00 %	Indicated Factor 4 Rating	Factor 4a 7.50 %	Factor 4b 15.00 %	Factor 4c 10.00 %	Factor 4d 7.50 %	Hold-Co Notching for Structural Subor-dination
37	PNG Companies	Baa3	Baa2	A	A	A	Ba	Baa	Ba	Baa	Baa	-	Ba	Ba	Ba	Ba	Baa	n/a
38	Public Service Company of New Mexico	Baa3	Baa2	Baa	A	Baa	Ba	Baa	Ba	Baa	Baa	Baa	Baa	A	Baa	A	Baa	n/a
39	Saudi Electricity	A1 / *Baa1*	Baa1	Baa	Baa	A	Ba	Baa	Ba	A	Baa	Aaa	A	Aaa	A	A	Baa	n/a
40	SCANA	Baa3	Baa2	Aa	Aa	Aa	Baa	Baa	Baa	Ba	Baa	Ba	Baa	Baa	Baa	Baa	Baa	-1
41	Southwestern Public Service Company	Baa2	Baa1	A	A	A	Baa	A	Baa	Ba	Ba	Baa	Baa	Baa	Baa	Baa	A	n/a
42	UGI Utilities, Inc.	A3	A2	A	A	A	A	A	A	Baa	Baa	-	A	A	A	A	A	n/a
43	Virginia Electric Power Company	A3	A2	Aa	Aa	Aa	A	Aa	Baa	Baa	Baa	Baa	A	A	A	A	A	n/a
44	Western Mass Electric Co.	Baa2	A2	A	A	Aa	A	A	A	Ba	Ba	-	A	Aa	A	A	A	n/a
45	Wisconsin Public Service Corporation	A2	A2	A	A	Aa	A	Aa	Baa	Baa	Baa	Baa	A	Aa	A	A	A	n/a

Outliers in Legislative and Judicial Underpinnings of the Regulatory Framework

For Chubu Electric Power Company, Hokuriku Electric Power Company, Kansai Electric Power Company, and Okinawa Electric Power Company, our ratings consider the credit-supportive underpinnings in the Electric Utility Industries Law that have been balanced against higher leverage and lower returns than global peers.

For SCANA Corporation, the South Carolina Base Load Review Act provides strong credit support for companies engaging in nuclear new-build, which also affects the scoring for consistency and predictability of regulation. However, SCANA's rating also considers the size and complexity of the nuclear construction project, which is out of scale to the size of the company, as well as structural subordination.

Outliers in Consistency and Predictability of Regulation

Consumers Energy Company has benefitted from increasingly predictable regulatory decisions in Michigan, as well as improved timeliness due to forward test years and the ability to implement interim rates. However, the substantial debt at its parent, CMS Energy Corporation (Baa3, RUR-up), has weighed on the ratings.

Duke Energy Corporation has received generally consistent and predictable rate treatment at it subsidiary operating companies, but parent debt has impacted financial metrics

The shift in business mix at Western Massachusetts Electric Company will place a greater percentage of its rate base under the jurisdiction of the FERC, generally viewed as having greater consistency and predictability, which is somewhat tempered by its financial metrics.

Outliers in Timeliness of Recovery of Operating and Capital Costs

Ameren Illinois Company has a formula rate plan that has a positive impact on timeliness, balanced against rate decisions that have been somewhat below average.

Hawaiian Electric Industries, Inc.'s timeliness has improved considerably due to the introduction in rate-making of a de-coupling mechanism, forward test year and an investment tracker at its utility subsidiary.

For Mississippi Power Company, a fully forward test year and the ability to recover some construction-work-in-progress in rates lead to strong scoring for timeliness. Ratings also consider risks associated with construction of a power plant that will utilize lignite and integrated gasification combined cycle technology, that has experienced material costs overruns and that represents a high degree of asset concentration for the utility.

For MidAmerican Energy Company, the absence of a fuel cost pass-through mechanism at the time of this writing results in its relatively low scoring on timeliness. However, the company has proposed a fuel clause in its current rate case, and the regulatory framework has generally been quite credit supportive, which has helped the utility generate good financial metrics.

The primary utility divisions of PacifiCorp have forward test years that have a positive impact on timeliness, balanced against rate decisions that have been somewhat below average.

Outliers in Sufficiency of Rates and Returns

China Longyuan Power Group Corporation Ltd. has benefitted from a higher benchmark tariff for its wind power generation, balanced against a less well developed regulatory framework.

Outliers in Market Position

Okinawa Electric Power Company, Incorporated's service territory is a group of small islands with limited economic diversity, which negatively impacts its market position. Generation is highly dependent on coal and oil. These factors are balanced against a strong regulatory framework.

Outliers in Generation and Fuel Diversity

Ohio Power Company has been highly dependent on coal-fired generation but will be divesting generation assets in accordance with regulatory initiatives.

Outliers in Financial Strength

Distribuidora de Electricidad La Paz S.A. has strong historical financial metrics that are balanced against the somewhat unpredictable regulatory framework and the risk of government intervention in its business.

Gail (India) Limited has strong historical financial metrics that are balanced against higher business risk in its diversified, non-rate-regulated operations, including in oil and gas exploration and production. Financial metrics are expected to weaken somewhat relative to historical levels due to debt funded capex and are thus expected to be more in line with its rating going forward.

Gas Natural BAN S.A. has strong historical financial metrics that are expected to deteriorate due to frozen tariff positions, reflected in weak scores for the regulatory environment. Its ratings are also impacted by debt maturities that are concentrated in the short term and the Government of Argentina's B3 negative rating.

Appendix D: Approach to Ratings within a Utility Family

Typical Composition of a Utility Family

A typical utility company structure consists of a holding company ("HoldCo") that owns one or more operating subsidiaries (each an "OpCo"). OpCos may be regulated utilities or non-utility companies. Financing of these entities varies by region, in part due to the regulatory framework. A HoldCo typically has no operations – its assets are mostly limited to its equity interests in subsidiaries, and potentially other investments in subsidiaries or minority interests in other companies. However, in certain cases there may be material operations at the HoldCo level. Financing can occur primarily at the OpCo level, primarily at the HoldCo level, or at both HoldCo and OpCos in varying proportions. When a HoldCo has multiple utility OpCos, they will often be located in different regulatory jurisdictions. A HoldCo may have both levered and unlevered OpCos.

General Approach to a Utility Family

In our analysis, we generally consider the stand-alone credit profile of an OpCo and the credit profile of its ultimate parent HoldCo (and any intermediate HoldCos), as well as the profile of the family as a whole, while acknowledging that these elements can have cross-family credit implications in varying degrees, principally based on the regulatory framework of the OpCos and the financing model (which has often developed in response to the regulatory framework).

In addition to considering individual OpCos under this (or another applicable) methodology, we typically[14] approach a HoldCo rating by assessing the qualitative and quantitative factors in this methodology for the consolidated entity and each of its utility subsidiaries. Ratings of individual entities in the issuer family may be pulled up or down based on the interrelationships among the companies in the family and their relative credit strength.

In considering how closely aligned or how differentiated ratings should be among members of a utility family, we assess a variety of factors, including:

» Regulatory or other barriers to cash movement among OpCos and from OpCos to HoldCo

» Differentiation of the regulatory frameworks of the various OpCos

» Specific ring-fencing provisions at particular OpCos

» Financing arrangements – for instance, each OpCo may have its own financing arrangements, or the sole liquidity facility may be at the parent; there may be a liquidity pool among certain but not all members of the family; certain members of the family may better be able to withstand a temporary hiatus of external liquidity or access to capital markets

» Financial covenants and the extent to which an Event of Default by one OpCo limits availability of liquidity to another member of the family

» The extent to which higher leverage at one entity increases default risk for other members of the family

» An entity's exposure to or insulation from an affiliate with high business risk

[14] See paragraph at the end of this section for approaches to Hybrid HoldCos.

» Structural features or other limitations in financing agreements that restrict movements of funds, investments, provision of guarantees or collateral, etc.

» The relative size and financial significance of any particular OpCo to the HoldCo and the family

See also those factors noted in Notching for Structural Subordination of Holding Companies.

Our approach to a Hybrid HoldCo (see definition in Appendix E) depends in part on the importance of its non-utility operations and the availability of information on individual businesses. If the businesses are material and their individual results are fully broken out in financial disclosures, we may be able to assess each material business individually by reference to the relevant Moody's methodologies to arrive at a composite assessment for the combined businesses. If non-utility operations are material but are not broken out in financial disclosures, we may look at the consolidated entity under more than one methodology. When non-utility operations are less material but could still impact the overall credit profile, the difference in business risks and our estimation of their impact on financial performance will be qualitatively incorporated in the rating.

Higher Barriers to Cash Movement with Financing Predominantly at the OpCos

Where higher barriers to cash movement exist on an OpCo or OpCos due the regulatory framework or debt structural features, ratings among family members are likely to be more differentiated. For instance, for utility families with OpCos in the US, where regulatory barriers to free cash movement are relatively high, greater importance is generally placed on the stand-alone credit profile of the OpCo.

Our observation of major defaults and bankruptcies in the US sector generally corroborates a view that regulation creates a degree of separateness of default probability. For instance, Portland General Electric (Baa1 RUR-up) did not default on its securities, even though its then-parent Enron Corp. entered bankruptcy proceedings. When Entergy New Orleans (Ba2 stable) entered into bankruptcy, the ratings of its affiliates and parent Entergy Corporation (Baa3 stable) were unaffected. PG&E Corporation (Baa1 stable) did not enter bankruptcy proceedings despite bankruptcies of two major subsidiaries - Pacific Gas & Electric Company (A3 stable) in 2001 and National Energy Group in 2003.

The degree of separateness may be greater or smaller and is assessed on a case by case basis, because situational considerations are important. One area we consider is financing arrangements. For instance, there will tend to be greater differentiation if each member of a family has its own bank credit facilities and difficulties experienced by one entity would not trigger events of default for other entities. While the existence of a money pool might appear to reduce separateness between the participants, there may be regulatory barriers within money pools that preserve separateness. For instance, non-utility entities may have access to the pool only as a borrower, only as a lender, and even the utility entities may have regulatory limits on their borrowings from the pool or their credit exposures to other pool members. If the only source of external liquidity for a money pool is borrowings by the HoldCo under its bank credit facilities, there would be less separateness, especially if the utilities were expected to depend on that liquidity source. However, the ability of an OpCo to finance itself by accessing capital markets must also be considered. Inter-company tax agreements can also have an impact on our view of how separate the risks of default are.

For a HoldCo, the greater the regulatory, economic, and geographic diversity of its OpCos, the greater its potential separation from the default probability of any individual subsidiary. Conversely, if a HoldCo's actions have made it clear that the HoldCo will provide support for an OpCo encountering some financial stress (for instance, due to delays and/or cost over-runs on a major construction project), we would be likely to perceive less separateness.

Even where high barriers to cash movement exist, onerous leverage at a parent company may not only give rise to greater notching for structural subordination at the parent, it may also pressure an OpCo's rating, especially when there is a clear dependence on an OpCo's cash flow to service parent debt. While most of the regulatory barriers to cash movement are very real, they are not absolute. Furthermore, while it is not usually in the interest of an insolvent parent or its creditors to bring an operating utility into a bankruptcy proceeding, such an occurrence is not impossible.

The greatest separateness occurs where strong regulatory insulation is supplemented by effective ring-fencing provisions that fully separate the management and operations of the OpCo from the rest of the family and limit the parent's ability to cause the OpCo to commence bankruptcy proceedings as well as limiting dividends and cash transfers. Currently, most entities in US utility families (including HoldCos and OpCos) are rated within 3 notches of each other. However, Energy Future Holdings Corp. (Caa3 senior unsecured) and its T&D subsidiary Oncor Electric Delivery Company LLC (Baa3 senior secured) have much wider notching due to the combination of regulatory imperatives and strong ring-fencing that includes a significant minority shareholder who must agree to important corporate decisions, including a voluntary bankruptcy filing.

Lower Barriers to Cash Movement with Financing Predominantly at the OpCos

Our approach to rating issuers within a family where there are lower regulatory barriers to movement of cash from OpCos to HoldCos (e.g., many parts of Asia and Europe) places greater emphasis on the credit profile of the consolidated group. Individual OpCos are considered based on their individual characteristics and their importance to the family, and their assigned ratings are typically banded closely around the consolidated credit profile of the group due to the expectation that cash will transit relatively freely among family entities.

Some utilities may have OpCos in jurisdictions where cash movement among certain family members is more restricted by the regulatory framework, while cash movement from and/or among OpCos in other jurisdictions is less restricted. In these situations, OpCos with more restrictions may vary more widely from the consolidated credit profile while those with fewer restrictions may be more tightly banded around the other entities in the corporate family group.

Appendix E: Brief Descriptions of the Types of Companies Rated Under This Methodology

The following describes the principal categories of companies rated under this methodology:

Vertically Integrated Utility: Vertically integrated utilities are regulated electric or combination utilities (see below) that own generation, distribution and (in most cases) electric transmission assets. Vertically integrated utilities are generally engaged in all aspects of the electricity business. They build power plants, procure fuel, generate power, build and maintain the electric grid that delivers power from a group of power plants to end-users (including high and low voltage lines, transformers and substations), and generally meet all of the electric needs of the customers in a specific geographic area (also called a service territory). The rates or tariffs for all of these monopolistic activities are set by the relevant regulatory authority.

Transmission & Distribution Utility: Transmission & Distribution utilities (T&Ds) typically operate in deregulated markets where generation is provided under a competitive framework. T&Ds own and operate the electric grid that transmits and/or distributes electricity within a specific state or region. T&Ds provide electrical transportation and distribution services to carry electricity from power plants and transmission lines to retail, commercial, and industrial customers. T&Ds are typically responsible for billing customers for electric delivery and/or supply, and most have an obligation to provide a standard supply or provider-of-last-resort (POLR) service to customers that have not switched to a competitive supplier. These factors distinguish T&Ds from Networks, whose customers are retail electric suppliers and/or other electricity companies. In a smaller number of cases, T&Ds rated under this methodology may not have an obligation to provide POLR services, but are regulated in sub-sovereign jurisdictions. The rates or tariffs for these monopolistic T&D activities are set by the relevant regulatory authority.

Local Gas Distribution Company: Distribution is the final step in delivering natural gas to customers. While some large industrial, commercial, and electric generation customers receive natural gas directly from high capacity pipelines that carry gas from gas producing basins to areas where gas is consumed, most other users receive natural gas from their local gas utility, also called a local distribution company (LDC). LDCs are regulated utilities involved in the delivery of natural gas to consumers within a specific geographic area. Specifically, LDCs typically transport natural gas from delivery points located on large-diameter pipelines (that usually operate at fairly high pressure) to households and businesses through thousands of miles of small-diameter distribution pipe (that usually operate at fairly low pressure). LDCs are typically responsible for billing customers for gas delivery and/or supply, and most also have the responsibility to procure gas for at least some of their customers, although in some markets gas supply to all customers is on a competitive basis. These factors distinguish LDCs from gas networks, whose customers are retail gas suppliers and/or other natural gas companies. The rates or tariffs for these monopolistic activities are set by the relevant regulatory authority.

Integrated Gas Utility: Integrated gas regulated utilities are regulated utilities that deliver gas to all end users in a particular service territory by sourcing the commodity; operating transport infrastructure that often combines high pressure pipelines with low pressure distribution systems and, in some cases, gas storage, re-gasification or other related facilities; and performing other supply-related activities, such as customer billing and metering. The rates or tariffs for the totality of these activities are set by the relevant regulatory authority. Many integrated gas utilities are national in scope.

Combination Utility: Combination utilities are those that combine an LDC or Integrated Gas Utility with either a vertically integrated utility or a T&D utility. The rates or tariffs for these monopolistic activities are set by the relevant regulatory authority.

Regulated Generation Utility: Regulated generation utilities (Regulated Gencos) are utilities that almost exclusively have generation assets, but their activities are generally regulated like those of vertically integrated utilities. In the US, this means that the purchasers of their output (typically other investor-owned, municipal or cooperative utilities) pay a regulated rate based on the total allowed costs of the Regulated Genco, including a return on equity based on a capital structure designated by the regulator (primarily FERC). Companies that have been included in this group include certain generation companies (including in Korea and China) that are not rate regulated in the usual sense of recovering costs plus a regulated rate of return on either equity or asset value. Instead, we have looked at a combination of governmental action with respect to setting feed-in tariffs and directives on how much generation will be built (or not built) in combination with a generally high degree of government ownership, and we have concluded that these companies are currently best rated under this methodology. Future evolution in our view of the operating and/or regulatory environment of these companies could lead us to conclude that they may be more appropriately rated under a related methodology (for example, Unregulated Utilities and Power Companies).

Independent System Operator: An Independent System Operator (ISO) is an organization formed in certain regional electricity markets to act as the sole chief coordinator of an electric grid. In the areas where an ISO is established, it coordinates, controls and monitors the operation of the electrical power system to assure that electric supply and demand are balanced at all times, and, to the extent possible, that electric demand is met with the lowest-cost sources. ISOs seek to assure adequate transmission and generation resources, usually by identifying new transmission needs and planning for a generation reserve margin above expected peak demand. In regions where generation is competitive, they also seek to establish rules that foster a fair and open marketplace, and they may conduct price-setting auctions for energy and/or capacity. The generation resources that an ISO coordinates may belong to vertically integrated utilities or to independent power producers. ISOs may not be rate-regulated in the traditional sense, but fall under governmental oversight. All participants in the regional grid are required to pay a fee or tariff (often volumetric) to the ISO that is designed to recover its costs, including costs of investment in systems and equipment needed to fulfill their function. ISOs may be for profit or not-for-profit entities.

In the US, most ISOs were formed at the direction or recommendation of the Federal Energy Regulatory Commission (FERC), but the ISO that operates solely in Texas falls under state jurisdiction. Some US ISOs also perform certain additional functions such that they are designated as Regional Transmission Organizations (or RTOs).

Transmission-Only Utility: Transmission-only utilities are solely focused on owning and operating transmission assets. The transmission lines these utilities own are typically high-voltage and allow energy producers to transport electric power over long distances from where it is generated (or received) to the transmission or distribution system of a T&D or vertically integrated utility. Unlike most of the other utilities rated under this methodology, transmission-only utilities primarily provide services to other utilities and ISOs. Transmission-only utilities in most parts of the world other than the US have been rated under the Regulated Networks methodology, and we expect that FERC-regulated transmission-only utilities in the US will also transition to the Regulated Networks when that methodology is updated (expected in 2014).

Utility Holding Company (Utility HoldCo): As detailed in Appendix D, regulated electric and gas utilities are often part of corporate families under a parent holding company. The operating subsidiaries of Utility Holdcos are overwhelmingly regulated electric and gas utilities.

Hybrid Holding Company (Hybrid HoldCo): Some utility families contain a mix of regulated electric and gas utilities and other types of companies, but the regulated electric and gas utilities represent the majority of the consolidated cash flows, assets and debt. The parent company is thus a Hybrid HoldCo.

Appendix F: Key Industry Issues Over the Intermediate Term

Political and Regulatory Issues

As highly regulated monopolistic entities, regulated utilities continually face political and regulatory risk, and managing these risks through effective outreach to key customers as well as key political and regulatory decision-makers is, or at least should be, a core competency of companies in this sector. However, larger waves of change in the political, regulatory or economic environment have the potential to cause substantial changes in the level of risk experienced by utilities and their investors in somewhat unpredictable ways.

One of the more universal risks faced by utilities currently is the compression of allowed returns. A long period of globally low interest rates, held down by monetary stimulus policies, has generally benefitted utilities, since reductions in allowed returns have been slower than reductions in incurred capital costs. Essentially all regulated utilities face a ratcheting down of allowed and/or earned returns. More difficult to predict is how regulators will respond when monetary stimulus reverses, and how well utilities will fare when fixed income investors require higher interest rates and equity investors require higher total returns and growth prospects.

The following global snapshot highlights that regulatory frameworks evolve over time. On an overall basis in the US over the past several years, we have noted some incremental positive regulatory trends, including greater use of formula rates, trackers and riders, and (primarily for natural gas utilities) de-coupling of returns from volumetric sales. In Canada, the framework has historically been viewed as predictable and stable, which has helped offset somewhat lower levels of equity in the capital structure, but the compression of returns has been relatively steep in recent years. In Japan, the regulatory authorities are working through the challenges presented by the decision to shut down virtually all of the country's nuclear generation capacity, leading to uncertainty regarding the extent to which increased costs will be reflected in rate increases sufficient to permit returns on capital to return to prior levels. China's regulatory framework has continued to evolve, with fairly low transparency and some time-to-time shifts in favored versus less-favored generation sources balanced by an overall state policy of assuring sustainability of the sector, adequate supply of electricity and affordability to the general public. Singapore and Hong Kong have fairly well developed and supportive regulatory frameworks despite a trend towards lower returns, whereas Malaysia, Korea and Thailand have been moving towards a more transparent regulatory framework. The Philippines is in the process of deregulating its power market, while Indian power utilities continue to grapple with structural challenges. In Latin America, there is a wide dispersion among frameworks, ranging from the more stable, long established and predictable framework in Chile to the decidedly unpredictable framework in Argentina. Generally, as Latin American economies have evolved to more stable economic policies, regulatory frameworks for utilities have also shown greater stability and predictability.

All of the other issues discussed in this section have a regulatory/political component, either as the driver of change or in reaction to changes in economic environments and market factors.

Economic and Financial Market Conditions

As regulated monopolies, electric and gas utilities have generally been quite resistant to unsettled economic and financial market conditions for several reasons. Unlike many companies that face direct market-based competition, their rates do not decrease when demand decreases. The elasticity of demand for electricity and gas is much lower than for most products in the consumer economy. When financial markets are volatile, utilities often have greater capital market access than industrial companies in competitive sectors, as was the case in the 2007-2009 recession. However, regulated electric and gas utilities are by no means immune to a protracted or severe recession.

Severe economic malaise can negatively affect utility credit profiles in several ways. Falling demand for electricity or natural gas may negatively impact margins and debt service protection measures, especially when rates are designed such that a substantial portion of fixed costs is in theory recovered through volumetric charges. The decrease in demand in the 2007-2009 recession was notable in comparison to prior recessions, especially in the residential sector. Poor economic conditions can make it more difficult for regulators to approve needed rate increases or provide timely cost recovery for utilities, resulting in higher cost deferrals and longer regulatory lag. Finally, recessions can coincide with a lack of confidence in the utility sector that impacts access to capital markets for a period of time. For instance, in the Great Depression and (to a lesser extent) in the 2001 recession, access for some issuers was curtailed due to the sector's generally higher leverage than other corporate sectors, combined with a concerns over a lack of transparency in financial reporting.

Fuel Price Volatility and the Global Impact of Shale Gas

The ability of most utilities to pass through their fuel costs to end users may insulate a utility from exposure to price volatility of these fuels, but it does not insulate consumers. Consumers and regulators complained vociferously about utility rates during the run-up in hydro-carbon prices in 2005-2008 (oil, natural gas and, to a lesser extent, coal). The steep decline in US natural gas prices since 2009, caused in large part by the development of shale gas and shale oil resources, has been a material benefit to US utilities, because many have been able to pass through substantial base rate increases during a period when all-in rates were declining. Shale hydro-carbons have also had a positive impact, albeit one that is less immediate and direct, on non-US utilities. In much of the eastern hemisphere, natural gas prices under long-term contracts have generally been tied to oil prices, but utilities and other industrial users have started to have some success in negotiating to de-link natural gas from oil. In addition, increasing US production of oil has had a noticeable impact on world oil prices, generally benefitting oil and gas users.

Not all utilities will benefit equally. Utilities that have locked in natural gas under high-priced long-term contracts that they cannot re-negotiate are negatively impacted if they cannot pass through their full contracted cost of gas, or if the high costs cause customer dissatisfaction and regulatory backlash. Utilities with large coal fleets or utilities constructing nuclear power plants may also face negative impacts on their regulatory environment, since their customers will benefit less from lower natural gas prices.

Distributed Generation Versus the Central Station Paradigm

The regulation and the financing of electric utilities are based on the premise that the current model under which electricity is generated and distributed to customers will continue essentially unchanged for many decades to come. This model, called the central station paradigm (because electricity is generated in large, centrally located plants and distributed to a large number of customers, who may in fact be hundreds of miles away), has been in place since the early part of the 20th century. The model has worked because the economies of scale inherent to very large power plants has more than offset the cost and inefficiency (through power losses) inherent to maintaining a grid for transmitting and distributing electricity to end users.

Despite rate structures that only allow recovery of invested capital over many decades (up to 60 years), utilities can attract capital because investors assume that rates will continue to be collected for at least that long a period. Regulators and politicians assume that taxes and regulatory charges levied on electricity usage will be paid by a broad swath of residences and businesses and will not materially discourage usage of electricity in a way that would decrease the amount of taxes collected. A corollary assumption is that the number of customers taking electricity from the system during that period will continue to be high enough such that rates will be reasonable and generally more attractive than other alternatives. In the event that consumers were to switch en masse to alternate sources of generating or receiving power (for instance distributed generation), rates for remaining customers would either not cover the utility's costs, or rates would need to be increased so much that more customers may be incentivized to leave the system. This scenario has been experienced in the regulated US copper wire telephone business, where rates have increased quite dramatically for users who have not switched to digital or wireless telephone service. While this scenario continues to be unlikely for the electricity sector, distributed generation, especially from solar panels, has made inroads in certain regions.

Distributed generation is any retail-scale generation, differentiated from self-generation, which generally describes a large industrial plant that builds its own reasonably large conventional power plant to meet its own needs. While some residential property owners that install distributed generation may choose to sever their connection to the local utility, most choose to remain connected, generating power into the grid when it is both feasible and economic to do so, and taking power from the grid at other times. Distributed generation is currently concentrated in roof-top photovoltaic solar panels, which have benefitted from varying levels of tax incentives in different jurisdictions. Regulatory treatment has also varied, but some rate structures that seek to incentivize distributed renewable energy are decidedly credit negative for utilities, in particular net metering.

Under net metering, a customer receives a credit from the utility for all of its generation at the full (or nearly full) retail rate and pays only for power taken, also at the retail rate, resulting in a materially reduced monthly bill relative to a customer with no distributed generation. The distributed generation customer has no obligation to generate any particular amount of power, so the utility must stand ready to generate and deliver that customer's full power needs at all times. Since most utility costs, including the fixed costs of financing and maintaining generation and delivery systems, are currently collected through volumetric rates, a customer owning distributed generation effectively transfers a portion of the utility's costs of serving that customer to other customers with higher net usage, notably to customers that do not own distributed generation. The higher costs may incentivize more customers to install solar panels, thereby shifting the utility's fixed costs to an even smaller group of rate-payers. California is an example of a state employing net solar metering in its rate structure, whereas in New Jersey, which has the second largest residential solar program in the US, utilities buy power at a price closer to their blended cost of generation, which is much lower than the retail rate.

To date, solar generation and net metering have not had a material credit impact on any utilities, but ratings could be negatively impacted if the programs were to grow and if rate structures were not amended so that each customer's monthly bill more closely approximated the cost of serving that customer.

In our current view, the possibility that there will be a widespread movement of electric utility customers to sever themselves from the grid is remote. However, we acknowledge that new technologies, such as the development of commercially viable fuel cells and/or distributed electric storage, could materially disrupt the central station paradigm and the credit quality of the utility sector.

Nuclear Issues

Utilities with nuclear generation face unique safety, regulatory, and operational issues. The nuclear disaster at Fukushima Daiichi had a severely negative credit impact on its owner, Tokyo Electric Power Company, Incorporated (Ba3, negative), as well as all the nuclear utilities in the country. Japan previously generated about 30% of its power from 50 reactors, but all are currently either idled or shut down, and utilities in the country face materially higher costs of replacement power, a credit negative. Japan also created a new Nuclear Regulation Authority (NRA), under the Ministry of the Environment to replace the Nuclear Safety Commission, which had been under the Ministry of Economy, Trade and Industry. The NRA has not yet set any schedule for completing safety checks at idled plants.

Fukushima Daiichi also had global consequences. Germany's response was to require that all nuclear power plants in the country be shut by 2022. Switzerland opted for a phase-out by 2031. (Most European nuclear plants are owned by companies rated under other the Unregulated Utilities and Power Companies methodology.) Even in countries where the regulatory response was more moderate, increased regulatory scrutiny has raised operating costs, a credit negative, especially in the US, where low natural gas prices have rendered certain primarily smaller nuclear plants uneconomic. Nuclear license renewal decisions in the US are currently on hold until the Nuclear Regulatory Commission comes to a determination on the safety of spent fuel storage in the absence of a permanent repository. Nonetheless, we view robust and independent nuclear safety regulation as a credit-positive for the industry.

Other general issues for nuclear operators include higher costs and lower reliability related to the increasing age of the fleet. In 2013, Duke Energy Florida, Inc. (Baa1, RUR-up) decided to permanently shut Crystal River Unit 3 after it determined that a de-lamination (or separation) in the concrete of the outer wall of the containment building was uneconomic to repair. San Onofre Nuclear Generating Station was permanently closed in 2013 after its owners, including Southern California Edison Company (A3, RUR-up) and San Diego Gas & Electric Company (A2, RUR-up), decided not to pursue a re-start in light of operating defects in two steam generators that had been replaced in 2010 and 2011.

Korea Hydro and Nuclear Power Company Limited (KHNP, A1 stable) and its parent Korea Electric Power Corporation (KEPCO, A1 stable), face a scandal related to alleged corruption and acceptance of falsified safety documents provided by its parts suppliers for nuclear plants. Korean prosecutors' widening probe into KHNP's use of substandard parts at many of its 23 nuclear power plants caused three plants to be temporarily shut down starting in May 2013 and raises the risk the Korean public will lose confidence in nuclear power. However, more than 80% of substandard parts in the idled plants have been replaced, and a restart is expected in late 2013 or early 2014.

Appendix G: Regional and Other Considerations

Notching Considerations for US First Mortgage Bonds

In most regions, our approach to notching between different debt classes of the same regulated utility issuer follows the guidance in the publication Updated Summary Guidance for Notching Bonds, Preferred Stocks and Hybrid Securities of Corporate Issuers, February 2007), including a one notch differential between senior secured and senior unsecured debt. However, in most cases we have two notches between the first mortgage bonds and senior unsecured debt of regulated electric and gas utilities in the US.

Wider notching differentials between debt classes may also be appropriate in speculative grade. Additional insights for speculative grade issuers are provided in the publication Loss Given Default for Speculative-Grade Non-Financial Companies in the US, Canada and EMEA, June 2009).

First mortgage bond holders in the US generally benefit from a first lien on most of the fixed assets used to provide utility service, including such assets as generating stations, transmission lines, distribution lines, switching stations and substations, and gas distribution facilities, as well as a lien on franchise agreements. In our view, the critical nature of these assets to the issuers and to the communities they serve has been a major factor that has led to very high recovery rates for this class of debt in situations of default, thereby justifying a two notch uplift. The combination of the breadth of assets pledged and the bankruptcy-tested recovery experience has been unique to the US.

In some cases, there is only a one notch differential between US first mortgage bonds and the senior unsecured rating. For instance, this is likely when the pledged property is not considered critical infrastructure for the region, or if the mortgage is materially weakened by carve-outs, lien releases or similar creditor-unfriendly terms.

Securitization

The use of securitization, a financing technique utilizing a discrete revenue stream (typically related to recovery of specifically defined expenses) that is dedicated to servicing specific securitization debt, has primarily been used in the US, where it has been quite pervasive in the past two decades. The first generation of securitization bonds were primarily related to recovery of the negative difference between the market value of utilities' generation assets and their book value when certain states switched to competitive electric supply markets and utilities sold their generation (so-called stranded costs). This technique was then used for significant storm costs (especially hurricanes) and was eventually broadened to include environmental related expenditures, deferred fuel costs, or even deferred miscellaneous expenses. States that have implemented securitization frameworks include Arkansas, California, Connecticut, Illinois, Louisiana, Maryland, Massachusetts, Mississippi, New Hampshire, New Jersey, Ohio, Pennsylvania, Texas and West Virginia. In its simplest form, a securitization isolates and dedicates a stream of cash flow into a separate special purpose entity (SPE). The SPE uses that stream of revenue and cash flow to provide annual debt service for the securitized debt instrument. Securitization is typically underpinned by specific legislation to segregate the securitization revenues from the utility's revenues to assure their continued collection, and the details of the enabling legislation may vary from state to state. The utility benefits from the securitization because it receives an immediate source of cash (although it gives up the opportunity to earn a return on the corresponding asset), and ratepayers benefit because the cost of the securitized debt is lower than the utility's cost of debt and much lower than its all-in cost of capital, which reduces the revenue requirement associated with the cost recovery.

In the presentation of US securitization debt in published financial ratios, Moody's makes its own assessment of the appropriate credit representation but in most cases follows the accounting in audited statements under US Generally Accepted Accounting Principles (GAAP), which is in turn considers the terms of enabling legislation. As a result, accounting treatment may vary. In most states utilities have been required to consolidate securitization debt under GAAP, even though it is technically non-recourse.

In general, we view securitization debt of utilities as being on-credit debt, in part because the rates associated with it reduce the utility's headroom to increase rates for other purposes while keeping all-in rates affordable to customers. Thus, where accounting treatment is off balance sheet, we seek to adjust the company's ratios by including the securitization debt and related revenues for our analysis. Where the securitized debt is on balance sheet, our credit analysis also considers the significance of ratios that exclude securitization debt and related revenues. Since securitization debt amortizes mortgage-style, including it makes ratios look worse in early years (when most of the revenue collected goes to pay interest) and better in later years (when most of the revenue collected goes to pay principal).

Strong levels of government ownership in Asia Pacific (ex-Japan) provide rating uplift

Strong levels of government ownership have dominated the credit profiles of utilities in Asia Pacific (excluding Japan), generally leading to ratings that are a number of notches above the Baseline Credit Assessment. Regulated electric and gas utilities with significant government ownership are rated using this methodology in conjunction with the Joint Default Analysis approach in our methodology for Government-Related Issuers.

Support system for large corporate entities in Japan can provide ratings uplift, with limits

Moody's ratings for large corporate entities in Japan reflect the unique nature of the country's support system, and they are higher than they would otherwise be if such support were disregarded. This is reflected in the tendency for ratings of Japanese utilities to be higher than their grid implied ratings (currently higher on average by about 2 notches), while utilities globally tend to be more evenly distributed above and below their actual ratings. However, even for large prominent companies, our ratings consider that support will not be endless and is less likely to be provided when a company has questionable viability rather than being in need of temporary liquidity assistance.

Appendix H: Treatment of Power Purchase Agreements ("PPAs")

Although many utilities own and operate power stations, some have entered into PPAs to source electricity from third parties to satisfy retail demand. The motivation for these PPAs may be one or more of the following: to outsource operating risks to parties more skilled in power station operation, to provide certainty of supply, to reduce balance sheet debt, to fix the cost of power, or to comply with regulatory mandates regarding power sourcing, including renewable portfolio standards. While Moody's regards PPAs that reduce operating or financial risk as a credit positive, some aspects of PPAs may negatively affect the credit of utilities. The most conservative treatment would be to treat a PPA as a debt obligation of the utility as, by paying the capacity charge, the utility is effectively providing the funds to service the debt associated with the power station. At the other end of the continuum, the financial obligations of the utility could also be regarded as an ongoing operating cost, with no long-term capital component recognized.

Under most PPAs, a utility is obliged to pay a capacity charge to the power station owner (which may be another utility or an Independent Power Producer – IPP); this charge typically covers a portion of the IPP's fixed costs in relation to the power available to the utility. These fixed payments usually help to cover the IPP's debt service and are made irrespective of whether the utility calls on the IPP to generate and deliver power. When the utility requires generation, a further energy charge, to cover the variable costs of the IPP, will also typically be paid by the utility. Some other similar arrangements are characterized as tolling agreements, or long-term supply contracts, but most have similar features to PPAs and are thus analyzed by Moody's as PPAs.

PPAs are recognized qualitatively to be a future use of cash whether or not they are treated as debt-like obligations in financial ratios

The starting point of our analysis is the issuer's audited financial statements – we consider whether the utility's accountants determine that the PPA should be treated as a debt equivalent, a capitalized lease, an operating lease, or in some other manner. PPAs have a wide variety of operational and financial terms, and it is our understanding that accountants are required to have a very granular view into the particular contractual arrangements in order to account for these PPAs in compliance with applicable accounting rules and standards. However, accounting treatment for PPAs may not be entirely consistent across US GAAP, IFRS or other accounting frameworks. In addition, we may consider that factors not incorporated into the accounting treatment may be relevant (which may include the scale of PPA payments, their regulatory treatment including cost recovery mechanisms, or other factors that create financial or operational risk for the utility that is greater, in our estimation, than the benefits received). When the accounting treatment of a PPA is a debt or lease equivalent (such that it is reported on the balance sheet, or disclosed as an operating lease and thus included in our adjusted debt calculation), we generally do not make adjustments to remove the PPA from the balance sheet. However, in relevant circumstances we consider making adjustments that impute a debt equivalent to PPAs that are off-balance sheet for accounting purposes.

Regardless of whether we consider that a PPA warrants or does not warrant treatment as a debt obligation, we assess the totality of the impact of the PPA on the issuer's probability of default. Costs of a PPA that cannot be recovered in retail rates creates material risk, especially if they also cannot be recovered through market sales of power.

Additional considerations for PPAs

PPAs have a wide variety of financial and regulatory characteristics, and each particular circumstance may be treated differently by Moody's. Factors which determine where on the continuum Moody's treats a particular PPA include the following:

» Risk management: An overarching principle is that PPAs have normally been used by utilities as a risk management tool and Moody's recognizes that this is the fundamental reason for their existence. Thus, Moody's will not automatically penalize utilities for entering into contracts for the purpose of reducing risk associated with power price and availability. Rather, we will look at the aggregate commercial position, evaluating the risk to a utility's purchase and supply obligations. In addition, PPAs are similar to other long-term supply contracts used by other industries and their treatment should not therefore be fundamentally different from that of other contracts of a similar nature.

» Pass-through capability: Some utilities have the ability to pass through the cost of purchasing power under PPAs to their customers. As a result, the utility takes no risk that the cost of power is greater than the retail price it will receive. Accordingly Moody's regards these PPA obligations as operating costs with no long-term debt-like attributes. PPAs with no pass-through ability have a greater risk profile for utilities. In some markets, the ability to pass through costs of a PPA is enshrined in the regulatory framework, and in others can be dictated by market dynamics. As a market becomes more competitive or if regulatory support for cost recovery deteriorates, the ability to pass through costs may decrease and, as circumstances change, Moody's treatment of PPA obligations will alter accordingly.

» Price considerations: The price of power paid by a utility under a PPA can be substantially above or below the market price of electricity. A below-market price will motivate the utility to purchase power from the IPP in excess of its retail requirements, and to sell excess electricity in the spot market. This can be a significant source of cash flow for some utilities. On the other hand, utilities that are compelled to pay capacity payments to IPPs when they have no demand for the power or at an above-market price may suffer a financial burden if they do not get full recovery in retail rates. Moody's will particularly focus on PPAs that have mark-to-market losses, which typically indicates that they have a material impact on the utility's cash flow.

» Excess Reserve Capacity: In some jurisdictions there is substantial reserve capacity and thus a significant probability that the electricity available to a utility under PPAs will not be required by the market. This increases the risk to the utility that capacity payments will need to be made when there is no demand for the power. We may determine that all of a utility's PPAs represent excess capacity, or that a portion of PPAs are needed for the utility's supply obligations plus a normal reserve margin, while the remaining portion represents excess capacity. In the latter case, we may impute debt to specific PPAs that are excess or we take a proportional approach to all of the utility's PPAs.

» Risk-sharing: Utilities that own power plants bear the associated operational, fuel procurement and other risks. These must be balanced against the financial and liquidity risk of contracting for the purchase of power under a PPA. Moody's will examine on a case-by case basis the relative credit risk associated with PPAs in comparison to plant ownership.

» Purchase requirements: Some PPAs are structured with either options or requirements to purchase the asset at the end of the PPA term. If the utility has an economically meaningful requirement to purchase, we would most likely consider it to be a debt obligation. In most such cases, the obligation would already receive on-balance sheet treatment under relevant accounting standards.

» Default provisions: In most cases, the remedies for default under a PPA do not include acceleration of amounts due, and in many cases PPAs would not be considered as debt in a bankruptcy scenario and could potentially be cancelled. Thus, PPAs may not materially increase Loss Given Default for the utility. In addition, PPAs are not typically considered debt for cross-default provisions under a utility's debt and liquidity arrangements. However, the existence of non-standard default provisions that are debt-like would have a large impact on our treatment of a PPA. In addition, payments due under PPAs are senior unsecured obligations, and any inability of the utility to make them materially increases default risk.

Each of these factors will be considered by Moody's analysts and a decision will be made as to the importance of the PPA to the risk analysis of the utility.

Methods for estimating a liability amount for PPAs

According to the weighting and importance of the PPA to each utility and the level of disclosure, Moody's may approximate a debt obligation equivalent for PPAs using one or more of the methods discussed below. In each case we look holistically at the PPA's credit impact on the utility, including the ability to pass through costs and curtail payments, the materiality of the PPA obligation to the overall business risk and cash flows of the utility, operational constraints that the PPA imposes, the maturity of the PPA obligation, the impact of purchased power on market-based power sales (if any) that the utility will engage in, and our view of future market conditions and volatility.

» Operating Cost: If a utility enters into a PPA for the purpose of providing an assured supply and there is reasonable assurance that regulators will allow the costs to be recovered in regulated rates, Moody's may view the PPA as being most akin to an operating cost. Provided that the accounting treatment for the PPA is, in this circumstance, off-balance sheet, we will most likely make no adjustment to bring the obligation onto the utility's balance sheet.

» Annual Obligation x 6: In some situations, the PPA obligation may be estimated by multiplying the annual payments by a factor of six (in most cases). This method is sometimes used in the capitalization of operating leases. This method may be used as an approximation where the analyst determines that the obligation is significant but cannot otherwise be quantified otherwise due to limited information.

» Net Present Value: Where the analyst has sufficient information, Moody's may add the NPV of the stream of PPA payments to the debt obligations of the utility. The discount rate used will be our estimate of the cost of capital of the utility.

» Debt Look-Through: In some circumstances, where the debt incurred by the IPP is directly related to the off-taking utility, there may be reason to allocate the entire debt (or a proportional part related to share of power dedicated to the utility) of the IPP to that of the utility.

» Mark-to-Market: In situations in which Moody's believes that the PPA prices exceed the market price and thus will create an ongoing liability for the utility, we may use a net mark-to-market method, in which the NPV of the utility's future out-of-the-money net payments will be added to its total debt obligations.

» Consolidation: In some instances where the IPP is wholly dedicated to the utility, it may be appropriate to consolidate the debt and cash flows of the IPP with that of the utility. If the utility purchases only a portion of the power from the IPP, then that proportion of debt might be consolidated with the utility.

If we have determined to impute debt to a PPA for which the accounting treatment is not on-balance sheet, we will in some circumstances use more than one method to estimate the debt equivalent obligations imposed by the PPA, and compare results. If circumstances (including regulatory treatment or market conditions) change over time, the approach that is used may also vary.

Moody's Related Research

Industry Outlooks:

» US Regulated Utilities: Regulation Provides Stability as Business Model Faces Challenges, July 2013 (156754)

» Asian Power Utilities (ex-Japan): Broad Stable Outlook; India an Outlier, March 2013 (149101)

Rating Methodologies:

» US Electric Generation & Transmission Cooperatives, April 2013, (151814)

» How Sovereign Credit Quality May Affect Other Ratings, February 2012 (139495)

» Unregulated Utilities and Power Companies, August 2009 (118508)

» Regulated Electric and Gas Networks, August 2009 (118786)

» Natural Gas Pipelines, November 2012 (146415)

» US Public Power Electric Utilities with Generation Ownership Exposure, November 2011 (135299)

» US Electric Generation & Transmission Cooperatives, April 2013 (151814)

» US Municipal Joint Action Agencies, October 2012 (145899)

» Government Related Issuers: Methodology Update, July 2010 (126031)

» Global Regulated Water Utilities, December 2009 (121311)

To access any of these reports, click on the entry above. Note that these references are current as of the date of publication of this report and that more recent reports may be available. All research may not be available to all clients.

The credit ratings assigned in this sector are primarily determined by this credit rating methodology. Certain broad methodological considerations (described in one or more secondary or cross-sector credit rating methodologies) may also be relevant to the determination of credit ratings of issuers and instruments in this sector. Potentially related secondary and cross-sector credit rating methodologies can be found here.

For data summarizing the historical robustness and predictive power of credit ratings assigned using this credit rating methodology, see link.

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MOODY'S
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Report Number: 157160

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Exhibit KWB-6

S&P Corporate Methodology and Key Credit Factors

STANDARD & POOR'S RATINGS SERVICES
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Table Of Contents

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Criteria | Corporates | General:

Corporate Methodology

1. Standard & Poor's Ratings Services is updating its criteria for rating corporate industrial companies and utilities. The criteria organize the analytical process according to a common framework and articulate the steps in developing the stand-alone credit profile (SACP) and issuer credit rating (ICR) for a corporate entity.

2. This article is related to our criteria article "Principles Of Credit Ratings," which we published on Feb. 16, 2011.

SUMMARY OF THE CRITERIA

3. The criteria describe the methodology we use to determine the SACP and ICR for corporate industrial companies and utilities. Our assessment reflects these companies' business risk profiles, their financial risk profiles, and other factors that may modify the SACP outcome (see "General Criteria: Stand-Alone Credit Profiles: One Component Of A Rating," published Oct. 1, 2010, for the definition of SACP). The criteria provide clarity on how we determine an issuer's SACP and ICR and are more specific in detailing the various factors of the analysis. The criteria also provide clear guidance on how we use these factors as part of determining an issuer's ICR. Standard & Poor's intends for these criteria to provide the market with a framework that clarifies our approach to fundamental analysis of corporate credit risks.

4. The business risk profile comprises the risk and return potential for a company in the markets in which it participates, the competitive climate within those markets (its industry risk), the country risks within those markets, and the competitive advantages and disadvantages the company has within those markets (its competitive position). The business risk profile affects the amount of financial risk that a company can bear at a given SACP level and constitutes the foundation for a company's expected economic success. We combine our assessments of industry risk, country risk, and competitive position to determine the assessment for a corporation's business risk profile.

5. The financial risk profile is the outcome of decisions that management makes in the context of its business risk profile and its financial risk tolerances. This includes decisions about the manner in which management seeks funding for the company and how it constructs its balance sheet. It also reflects the relationship of the cash flows the organization can achieve, given its business risk profile, to the company's financial obligations. The criteria use cash flow/leverage analysis to determine a corporate issuer's financial risk profile assessment.

6. We then combine an issuer's business risk profile assessment and its financial risk profile assessment to determine its anchor (see table 3). Additional rating factors can modify the anchor. These are: diversification/portfolio effect, capital structure, financial policy, liquidity, and management and governance. Comparable ratings analysis is the last analytical factor under the criteria to determine the final SACP on a company.

7. These criteria are complemented by industry-specific criteria called Key Credit Factors (KCFs). The KCFs describe the industry risk assessments associated with each sector and may identify sector-specific criteria that supersede certain sections of these criteria. As an example, the liquidity criteria state that the relevant KCF article may specify different standards than those stated within the liquidity criteria to evaluate companies that are part of exceptionally stable or

volatile industries. The KCFs may also define sector-specific criteria for one or more of the factors in the analysis. For example, the analysis of a regulated utility's competitive position is different from the methodology to evaluate the competitive position of an industrial company. The regulated utility KCF will describe the criteria we use to evaluate those companies' competitive positions (see "Key Credit Factors For The Regulated Utility Industry," published Nov. 19, 2013).

SCOPE OF THE CRITERIA

8. This methodology applies to nonfinancial corporate issuer credit ratings globally. Please see "Criteria Guidelines For Recovery Ratings On Global Industrial Issuers' Speculative-Grade Debt," published Aug. 10, 2009, and "2008 Corporate Criteria: Rating Each Issue," published April 15, 2008, for further information on our methodology for determining issue ratings. This methodology does not apply to the following sectors, based on the unique characteristics of these sectors, which require either a different framework of analysis or substantial modifications to one or more factors of analysis: project finance entities, project developers, transportation equipment leasing, auto rentals, commodities trading, investment holding companies and companies that maximize their returns by buying and selling equity holdings over time, Japanese general trading companies, corporate securitizations, nonprofit and cooperative organizations, master limited partnerships, general partnerships of master limited partnerships, and other entities whose cash flows are primarily derived from partially owned equity holdings.

IMPACT ON OUTSTANDING RATINGS

9. We expect about 5% of corporate industrial companies and utilities ratings within the scope of the criteria to change. Of that number, we expect approximately 90% to receive a one-notch change, with the majority of the remainder receiving a two-notch change. We expect the ratio of upgrades to downgrades to be around 3:1.

EFFECTIVE DATE AND TRANSITION

10. These criteria are effective immediately on the date of publication. We intend to complete our review of all affected ratings within the next six months.

METHODOLOGY

A. Corporate Ratings Framework

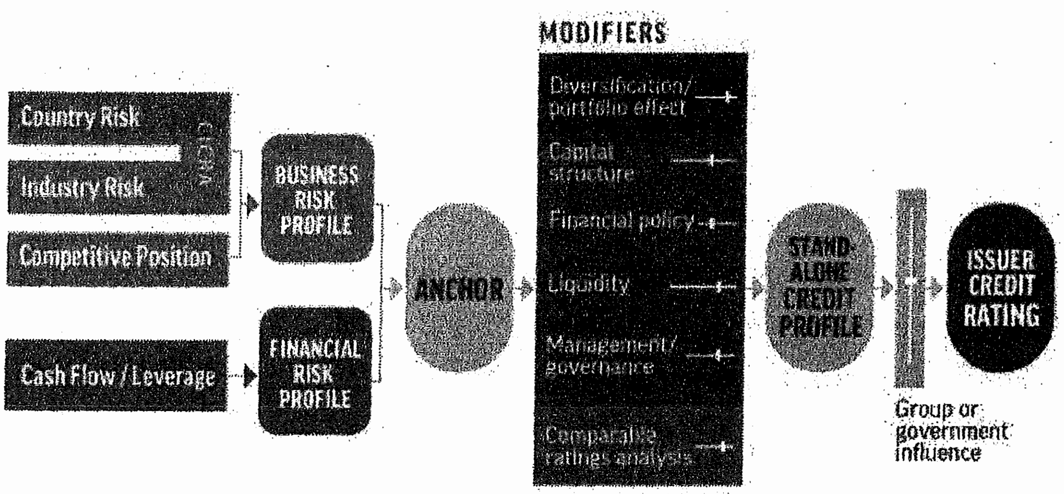
11. The corporate analytical methodology organizes the analytical process according to a common framework, and it divides the task into several factors so that Standard & Poor's considers all salient issues. First we analyze the company's business risk profile, then evaluate its financial risk profile, then combine those to determine an issuer's anchor. We then analyze six factors that could potentially modify our anchor conclusion.

12. To determine the assessment for a corporate issuer's business risk profile, the criteria combine our assessments of industry risk, country risk, and competitive position. Cash flow/leverage analysis determines a company's financial risk profile assessment. The analysis then combines the corporate issuer's business risk profile assessment and its financial risk profile assessment to determine its anchor. In general, the analysis weighs the business risk profile more heavily for investment-grade anchors, while the financial risk profile carries more weight for speculative-grade anchors.

13. After we determine the anchor, we use additional factors to modify the anchor. These factors are: diversification/portfolio effect, capital structure, financial policy, liquidity, and management and governance. The assessment of each factor can raise or lower the anchor by one or more notches--or have no effect. These conclusions take the form of assessments and descriptors for each factor that determine the number of notches to apply to the anchor.

14. The last analytical factor the criteria call for is comparable ratings analysis, which may raise or lower the anchor by one notch based on a holistic view of the company's credit characteristics.

Corporate Criteria Framework



15. The three analytic factors within the business risk profile generally are a blend of qualitative assessments and quantitative information. Qualitative assessments distinguish risk factors, such as a company's competitive advantages, that we use to assess its competitive position. Quantitative information includes, for example, historical cyclicality of revenues and profits that we review when assessing industry risk. It can also include the volatility and level of profitability we consider in order to assess a company's competitive position. The assessments for business risk profile are: 1, excellent; 2, strong; 3, satisfactory; 4, fair; 5, weak; and 6, vulnerable.

16. In assessing cash flow/leverage to determine the financial risk profile, the analysis focuses on quantitative measures. The assessments for financial risk profile are: 1, minimal; 2, modest; 3, intermediate; 4, significant; 5, aggressive; and 6, highly leveraged.

17. The ICR results from the combination of the SACP and the support framework, which determines the extent of the difference between the SACP and the ICR, if any, for group or government influence. Extraordinary influence is then captured in the ICR. Please see "Group Rating Methodology," published Nov. 19, 2013, and "Rating Government-Related Entities: Methodology And Assumptions," published Dec. 9, 2010, for our methodology on group and government influence.

18. Ongoing support or negative influence from a government (for government-related entities), or from a group, is factored into the SACP (see "SACP criteria"). While such ongoing support/negative influence does not affect the industry or country risk assessment, it can affect any other factor in business or financial risk. For example, such support or negative influence can affect: national industry analysis, other elements of competitive position, financial risk profile, the liquidity assessment, and comparable ratings analysis.

19. The application of these criteria will result in an SACP that could then be constrained by the relevant sovereign rating and transfer and convertibility (T&C) assessment affecting the entity when determining the ICR. In order for the final ICR to be higher than the applicable sovereign rating or T&C assessment, the entity will have to meet the conditions established in "Ratings Above The Sovereign--Corporate And Government Ratings: Methodology And Assumptions," published Nov. 19, 2013.

1. Determining the business risk profile assessment

20. Under the criteria, the combined assessments for country risk, industry risk, and competitive position determine a company's business risk profile assessment. A company's strengths or weaknesses in the marketplace are vital to its credit assessment. These strengths and weaknesses determine an issuer's capacity to generate cash flows in order to service its obligations in a timely fashion.

21. Industry risk, an integral part of the credit analysis, addresses the relative health and stability of the markets in which a company operates. The range of industry risk assessments is: 1, very low risk; 2, low risk; 3, intermediate risk; 4, moderately high risk; 5, high risk; and 6, very high risk. The treatment of industry risk is in section B.

22. Country risk addresses the economic risk, institutional and governance effectiveness risk, financial system risk, and payment culture or rule of law risk in the countries in which a company operates. The range of country risk assessments is: 1, very low risk; 2, low risk; 3, intermediate risk; 4, moderately high risk; 5, high risk; and 6, very high risk. The treatment of country risk is in section C.

23. The evaluation of an enterprise's competitive position identifies entities that are best positioned to take advantage of key industry drivers or to mitigate associated risks more effectively--and achieve a competitive advantage and a stronger business risk profile than that of entities that lack a strong value proposition or are more vulnerable to industry risks. The range of competitive position assessments is: 1, excellent; 2, strong; 3, satisfactory; 4, fair; 5, weak; and 6, vulnerable. The full treatment of competitive position is in section D.

24. The combined assessment for country risk and industry risk is known as the issuer's Corporate Industry and Country Risk Assessment (CICRA). Table 1 shows how to determine the combined assessment for country risk and industry risk.

Table 1

Determining The CICRA

	--Country risk assessment--					
Industry risk assessment	**1 (very low risk)**	**2 (low risk)**	**3 (intermediate risk)**	**4 (moderately high risk)**	**5 (high risk)**	**6 (very high risk)**
1 (very low risk)	1	1	1	2	4	5
2 (low risk)	2	2	2	3	4	5
3 (intermediate risk)	3	3	3	3	4	6
4 (moderately high risk)	4	4	4	4	5	6
5 (high risk)	5	5	5	5	5	6
6 (very high risk)	6	6	6	6	6	6

25. The CICRA is combined with a company's competitive position assessment in order to create the issuer's business risk profile assessment. Table 2 shows how we combine these assessments.

Table 2

Determining The Business Risk Profile Assessment

	--CICRA--					
Competitive position assessment	**1**	**2**	**3**	**4**	**5**	**6**
1 (excellent)	1	1	1	2	3*	5
2 (strong)	1	2	2	3	4	5
3 (satisfactory)	2	3	3	3	4	6
4 (fair)	3	4	4	4	5	6
5 (weak)	4	5	5	5	5	6
6 (vulnerable)	5	6	6	6	6	6

*See paragraph 26.

26. A small number of companies with a CICRA of 5 may be assigned a business risk profile assessment of 2 if all of the following conditions are met:

- The company's competitive position assessment is 1.
- The company's country risk assessment is no riskier than 3.
- The company produces significantly better-than-average industry profitability, as measured by the level and volatility of profits.
- The company's competitive position within its sector transcends its industry risks due to unique competitive advantages with its customers, strong operating efficiencies not enjoyed by the large majority of the industry, or scale/scope/diversity advantages that are well beyond the large majority of the industry.

27. For issuers with multiple business lines, the business risk profile assessment is based on our assessment of each of the factors--country risk, industry risk, and competitive position--as follows:

- Country risk: We use the weighted average of the country risk assessments for the company across all business lines that generate more than 5% of sales or where more than 5% of fixed assets are located.

- Industry risk: We use the weighted average of the industry risk assessments for all business lines representing more than 20% of the company's forecasted earnings, revenues or fixed assets, or other appropriate financial measures if earnings, revenue, or fixed assets do not accurately reflect the exposure to an industry.
- Competitive position: We assess all business lines identified above for the components competitive advantage, scope/scale/diversity, and operating efficiency (see section D). They are then blended using a weighted average of revenues, earnings, or assets to form the preliminary competitive position assessment. The level of profitability and volatility of profitability are then assessed based on the consolidated financials for the enterprise. The preliminary competitive position assessment is then blended with the profitability assessment, as per section D.5, to assess competitive position for the enterprise.

2. Determining the financial risk profile assessment

28. Under the criteria, cash flow/leverage analysis is the foundation for assessing a company's financial risk profile. The range of assessments for a company's cash flow/leverage is 1, minimal; 2, modest; 3, intermediate; 4, significant; 5, aggressive; and 6, highly leveraged. The full treatment of cash flow/leverage analysis is the subject of section E.

3. Merger of financial risk profile and business risk profile assessments

29. An issuer's business risk profile assessment and its financial risk profile assessment are combined to determine its anchor (see table 3). If we view an issuer's capital structure as unsustainable or if its obligations are currently vulnerable to nonpayment, and if the obligor is dependent upon favorable business, financial, and economic conditions to meet its commitments on its obligations, then we will determine the issuer's SACP using "Criteria For Assigning 'CCC+', 'CCC', 'CCC-', And 'CC' Ratings," published Oct. 1, 2012. If the issuer meets the conditions for assigning 'CCC+', 'CCC', 'CCC-', and 'CC' ratings, we will not apply Table 3.

Table 3

Combining The Business And Financial Risk Profiles To Determine The Anchor

	--Financial risk profile--					
Business risk profile	**1 (minimal)**	**2 (modest)**	**3 (intermediate)**	**4 (significant)**	**5 (aggressive)**	**6 (highly leveraged)**
1 (excellent)	aaa/aa+	aa	a+/a	a-	bbb	bbb-/bb+
2 (strong)	aa/aa-	a+/a	a-/bbb+	bbb	bb+	bb
3 (satisfactory)	a/a-	bbb+	bbb/bbb-	bbb-/bb+	bb	b+
4 (fair)	bbb/bbb-	bbb-	bb+	bb	bb-	b
5 (weak)	bb+	bb+	bb	bb-	b+	b/b-
6 (vulnerable)	bb-	bb-	bb-/b+	b+	b	b-

30. When two anchor outcomes are listed for a given combination of business risk profile assessment and financial risk profile assessment, an issuer's anchor is determined as follows:

- When a company's financial risk profile is 4 or stronger (meaning, 1-4), its anchor is based on the comparative strength of its business risk profile. We consider our assessment of the business risk profile for corporate issuers to be points along a possible range. Consequently, each of these assessments that ultimately generate the business risk profile for a specific issuer can be at the upper or lower end of such a range. Issuers with stronger business risk profiles for the range of anchor outcomes will be assigned the higher anchor. Those with a weaker business risk profile for the range of anchor outcomes will be assigned the lower anchor.
- When a company's financial risk profile is 5 or 6, its anchor is based on the comparative strength of its financial risk

profile. Issuers with stronger cash flow/leverage ratios for the range of anchor outcomes will be assigned the higher anchor. Issuers with weaker cash flow/leverage ratios for the range of anchor outcomes will be assigned the lower anchor. For example, a company with a business risk profile of (1) excellent and a financial risk profile of (6) highly leveraged would generally be assigned an anchor of 'bb+' if its ratio of debt to EBITDA was 8x or greater and there were no offsetting factors to such a high level of leverage.

4. Building on the anchor

31. The analysis of diversification/portfolio effect, capital structure, financial policy, liquidity, and management and governance may raise or lower a company's anchor. The assessment of each modifier can raise or lower the anchor by one or more notches--or have no effect in some cases (see tables 4 and 5). We express these conclusions using specific assessments and descriptors that determine the number of notches to apply to the anchor. However, this notching in aggregate can't lower an issuer's anchor below 'b-' (see "Criteria For Assigning 'CCC+', 'CCC', 'CCC-', And 'CC' Ratings," published Oct. 1, 2012, for the methodology we use to assign 'CCC' and 'CC' category SACPs and ICRs to issuers).

32. The analysis of the modifier diversification/portfolio effect identifies the benefits of diversification across business lines. The diversification/portfolio effect assessments are 1, significant diversification; 2, moderate diversification; and 3, neutral. The impact of this factor on an issuer's anchor is based on the company's business risk profile assessment and is described in Table 4. Multiple earnings streams (which are evaluated within a firm's business risk profile) that are less-than-perfectly correlated reduce the risk of default of an issuer (see Appendix D). We determine the impact of this factor based on the business risk profile assessment because the benefits of diversification are significantly reduced with poor business prospects. The full treatment of diversification/portfolio effect analysis is the subject of section F.

Table 4

Modifier Step 1: Impact Of Diversification/Portfolio Effect On The Anchor

	--Business risk profile assessment--					
Diversification/portfolio effect	**1 (excellent)**	**2 (strong)**	**3 (satisfactory)**	**4 (fair)**	**5 (weak)**	**6 (vulnerable)**
1 (significant diversification)	+2 notches	+2 notches	+2 notches	+1 notch	+1 notch	0 notches
2 (moderate diversification)	+1 notch	+1 notch	+1 notch	+1 notch	0 notches	0 notches
3 (neutral)	0 notches	0 notches	0 notches	0 notches	0 notches	0 notches

33. After we adjust for the diversification/portfolio effect, we determine the impact of the other modifiers: capital structure, financial policy, liquidity, and management and governance. We apply these four modifiers in the order listed in Table 5. As we go down the list, a modifier may (or may not) change the anchor to a new range (one of the ranges in the four right-hand columns in the table). We'll choose the appropriate value from the new range, or column, to determine the next modifier's effect on the anchor. And so on, until we get to the last modifier on the list—management and governance. For example, let's assume that the anchor, after adjustment for diversification/portfolio effect but before adjusting for the other modifiers, is 'a'. If the capital structure assessment is very negative, the indicated anchor drops two notches, to 'bbb+'. So, to determine the impact of the next modifier—financial policy—we go to the column 'bbb+ to bbb-' and find the appropriate assessment—in this theoretical example, positive. Applying that assessment moves the anchor up one notch, to the 'a- and higher' category. In our example, liquidity is strong, so the impact is zero notches and the anchor remains unchanged. Management and governance is satisfactory, and thus the anchor remains 'a-' (see chart following table 5).

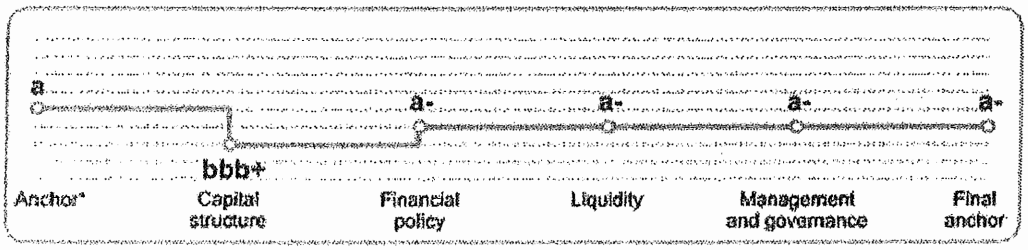
Table 5

Modifier Step 2: Impact Of Remaining Modifier Factors On The Anchor

	--Anchor range--			
	'a-' and higher	**'bbb+' to 'bbb-'**	**'bb+' to 'bb-'**	**'b+' and lower**
Factor/Assessment				
Capital structure (see section G)				
1 (Very positive)	2 notches	2 notches	2 notches	2 notches
2 (Positive)	1 notch	1 notch	1 notch	1 notch
3 (Neutral)	0 notches	0 notches	0 notches	0 notches
4 (Negative)	-1 notch	-1 notch	-1 notch	-1 notch
5 (Very negative)	-2 or more notches	-2 or more notches	-2 or more notches	-2 notches
Financial policy (FP; see section H)				
1 (Positive)	+1 notch if M&G is at least satisfactory	+1 notch if M&G is at least satisfactory	+1 notch if liquidity is at least adequate and M&G is at least satisfactory	+1 notch if liquidity is at least adequate and M&G is at least satisfactory
2 (Neutral)	0 notches	0 notches	0 notches	0 notches
3 (Negative)	-1 to -3 notches(1)	-1 to -3 notches(1)	-1 to -2 notches(1)	-1 notch
4 (FS-4, FS-5, FS-6, FS-6 [minus])	N/A(2)	N/A(2)	N/A(2)	N/A(2)
Liquidity (see section I)				
1 (Exceptional)	0 notches	0 notches	0 notches	+1 notch if FP is positive, neutral, FS-4, or FS-5 (3)
2 (Strong)	0 notches	0 notches	0 notches	+1 notch if FP is positive, neutral, FS-4, or FS-5 (3)
3 (Adequate)	0 notches	0 notches	0 notches	0 notches
4 (Less than adequate [4])	N/A	N/A	-1 notch(5)	0 notches
5 (Weak)	N/A	N/A	N/A	'b-' cap on SACP
Management and governance (M&G; see section J)				
1 (Strong)	0 notches	0 notches	0, +1 notches(6)	0, +1 notches(6)
2 (Satisfactory)	0 notches	0 notches	0 notches	0 notches
3 (Fair)	-1 notch	0 notches	0 notches	0 notches
4 (Weak)	-2 or more notches(7)	-2 or more notches(7)	-1 or more notches(7)	-1 or more notches(7)

(1) Number of notches depends on potential incremental leverage. (2) See "Assessing Financial Policy," section H.2. (3) Additional notch applies only if we expect liquidity to remain exceptional or strong. (4) See "Methodology And Assumptions: Liquidity Descriptors For Global Corporate Issuers," published Nov. 19, 2013. SACP is capped at 'bb+.' (5) If issuer SACP is 'bb+' due to cap, there is no further notching. (6) This adjustment is one notch if we have not already captured benefits of strong management and governance in the analysis of the issuer's competitive position. (7) Number of notches depends upon the degree of negative effect to the enterprise's risk profile.

Example: How Remaining Modifiers Can Change The Anchor



*After adjusting for diversification/portfolio effect. See paragraph 33.

34. Our analysis of a firm's capital structure assesses risks in the firm's capital structure that may not arise in the review of its cash flow/leverage. These risks include the currency risk of debt, debt maturity profile, interest rate risk of debt, and an investments subfactor. We assess a corporate issuer's capital structure on a scale of 1, very positive; 2, positive; 3, neutral; 4, negative; and 5, very negative. The full treatment of capital structure is the subject of section G.

35. Financial policy serves to refine the view of a company's risks beyond the conclusions arising from the standard assumptions in the cash flow/leverage, capital structure, and liquidity analyses. Those assumptions do not always reflect or adequately capture the long-term risks of a firm's financial policy. The financial policy assessment is, therefore, a measure of the degree to which owner/managerial decision-making can affect the predictability of a company's financial risk profile. We assess financial policy as 1) positive, 2) neutral, 3) negative, or as being owned by a financial sponsor. We further identify financial sponsor-owned companies as "FS-4", "FS-5", "FS-6", or "FS-6 (minus)." The full treatment of financial policy analysis is the subject of section H.

36. Our assessment of liquidity focuses on the monetary flows--the sources and uses of cash--that are the key indicators of a company's liquidity cushion. The analysis also assesses the potential for a company to breach covenant tests tied to declines in earnings before interest, taxes, depreciation, and amortization (EBITDA). The methodology incorporates a qualitative analysis that addresses such factors as the ability to absorb high-impact, low-probability events, the nature of bank relationships, the level of standing in credit markets, and the degree of prudence of the company's financial risk management. The liquidity assessments are 1, exceptional; 2, strong; 3, adequate; 4, less than adequate; and 5, weak. An SACP is capped at 'bb+' for issuers whose liquidity is less than adequate and 'b-' for issuers whose liquidity is weak, regardless of the assessment of any modifiers or comparable ratings analysis. (For the complete methodology on assessing corporate issuers' liquidity, see "Methodology And Assumptions: Liquidity Descriptors For Global Corporate Issuers," published Nov. 19, 2013.)

37. The analysis of management and governance addresses how management's strategic competence, organizational effectiveness, risk management, and governance practices shape the company's competitiveness in the marketplace, the strength of its financial risk management, and the robustness of its governance. The range of management and governance assessments is: 1, strong; 2, satisfactory; 3, fair; and 4, weak. Typically, investment-grade anchor outcomes reflect strong or satisfactory management and governance, so there is no incremental benefit. Alternatively, a fair or weak assessment of management and governance can lead to a lower anchor. Also, a strong assessment for management and governance for a weaker entity is viewed as a favorable factor, under the criteria, and can have a

positive impact on the final SACP outcome. For the full treatment of management and governance, see "Methodology: Management And Governance Credit Factors For Corporate Entities And Insurers," published Nov. 13, 2012.

5. Comparable ratings analysis

38. The anchor, after adjusting for the modifiers, could change one notch up or down in order to arrive at an issuer's SACP based on our comparable ratings analysis, which is a holistic review of a company's stand-alone credit risk profile, in which we evaluate an issuer's credit characteristics in aggregate. A positive assessment leads to a one-notch improvement, a negative assessment leads to a one-notch reduction, and a neutral assessment indicates no change to the anchor. The application of comparable ratings analysis reflects the need to 'fine-tune' ratings outcomes, even after the use of each of the other modifiers. A positive or negative assessment is therefore likely to be common rather than exceptional.

B. Industry Risk

39. The analysis of industry risk addresses the major factors that Standard & Poor's believes affect the risks that entities face in their respective industries. (See "Methodology: Industry Risk," published Nov. 19, 2013.)

C. Country Risk

40. The analysis of country risk addresses the major factors that Standard & Poor's believes affect the country where entities operate. Country risks, which include economic, institutional and governance effectiveness, financial system, and payment culture/rule of law risks, influence overall credit risks for every rated corporate entity. (See "Country Risk Assessment Methodology And Assumptions," published Nov. 19, 2013.)

1. Assessing country risk for corporate issuers

41. The following paragraphs explain how the criteria determine the country risk assessment for a corporate entity. Once it's determined, we combine the country risk assessment with the issuer's industry risk assessment to calculate the issuer's CICRA (see section A, table 1). The CICRA is one of the factors of the issuer's business risk profile. If an issuer has very low to intermediate exposure to country risk, as represented by a country risk assessment of 1, 2, or 3, country risk is neutral to an issuer's CICRA. But if an issuer has moderately high to very high exposure to country risk, as represented by a country risk assessment of 4, 5, or 6, the issuer's CICRA could be influenced by its country risk assessment.

42. Corporate entities operating within a single country will receive a country risk assessment for that jurisdiction. For entities with exposure to more than one country, the criteria prospectively measure the proportion of exposure to each country based on forecasted EBITDA, revenues, or fixed assets, or other appropriate financial measures if EBITDA, revenue, or fixed assets do not accurately reflect the exposure to that jurisdiction.

43. Arriving at a company's blended country risk assessment involves multiplying its weighted-average exposures for each country by each country's risk assessment and then adding those numbers. For the weighted-average calculation, the criteria consider countries where the company generates more than 5% of its sales or where more than 5% of its fixed assets are located, and all weightings are rounded to the nearest 5% before averaging. We round the assessment to the

nearest integer, so a weighted assessment of 2.2 rounds to 2, and a weighted assessment of 2.6 rounds to 3 (see table 6).

Table 6

Hypothetical Example Of Weighted-Average Country Risk For A Corporate Entity

Country	Weighting (% of business*)	Country risk§	Weighted country risk
Country A	45	1	0.45
Country B	20	2	0.4
Country C	15	1	0.15
Country D	10	4	0.4
Country E	10	2	0.2
Weighted-average country risk assessment (rounded to the nearest whole number)	--	--	2

*Using EBITDA, revenues, fixed assets, or other financial measures as appropriate. §On a scale from 1-6, lowest to highest risk.

44. A weak link approach, which helps us calculate a blended country risk assessment for companies with exposure to more than one country, works as follows: If fixed assets are based in a higher-risk country but products are exported to a lower-risk country, the company's exposure would be to the higher-risk country. Similarly, if fixed assets are based in a lower-risk country but export revenues are generated from a higher-risk country and cannot be easily redirected elsewhere, we measure exposure to the higher-risk country. If a company's supplier is located in a higher-risk country, and its supply needs cannot be easily redirected elsewhere, we measure exposure to the higher-risk country. Conversely, if the supply chain can be re-sourced easily to another country, we would not measure exposure to the higher risk country.

45. Country risk can be mitigated for a company located in a single jurisdiction in the following narrow case. For a company that exports the majority of its products overseas and has no direct exposure to a country's banking system that would affect its funding, debt servicing, liquidity, or ability to transfer payments from or to its key counterparties, we could reduce the country risk assessment by one category (e.g., 5 to 4) to determine the adjusted country risk assessment. This would only apply for countries where we considered the financial system risk subfactor a constraint on the overall country risk assessment for that country. For such a company, other country risks are not mitigated: Economic risk still applies, albeit less of a risk than for a company that sells domestically (potential currency volatility remains a risk for exporters); institutional and governance effectiveness risk still applies (political risk may place assets at risk); and payment culture/rule of law risk still applies (legal risks may place assets and cross-border contracts at risk).

46. Companies will often disclose aggregated information for blocks of countries, rather than disclosing individual country information. If the information we need to estimate exposure for all countries is not available, we use regional risk assessments. Regional risk assessments are calculated as averages of the unadjusted country risk assessments, weighted by gross domestic product of each country in a defined region. The criteria assess regional risk on a 1-6 scale (strongest to weakest). Please see Appendix A, Table 26, which lists the constituent countries of the regions.

47. If an issuer does not disclose its country-level exposure or regional-level exposure, individual country risk exposures or regional exposures will be estimated.

2. Adjusting the country risk assessment for diversity

48. We will adjust the country risk assessment for a company that operates in multiple jurisdictions and demonstrates a high degree of diversity of country risk exposures. As a result of this diversification, the company could have less exposure to country risk than the rounded weighted average of its exposures might indicate. Accordingly, the country risk assessment for a corporate entity could be adjusted if an issuer meets the conditions outlined in paragraph 49.

49. The preliminary country risk assessment is raised by one category to reflect diversity if all of the following four conditions are met:

- If the company's head office, as defined in paragraph 51, is located in a country with a risk assessment stronger than the preliminary country risk assessment;
- If no country, with a country risk assessment equal to or weaker than the company's preliminary country risk assessment, represents or is expected to represent more than 20% of revenues, EBITDA, fixed assets, or other appropriate financial measures;
- If the company is primarily funded at the holding level, or through a finance subsidiary in a similar or stronger country risk environment than the holding company, or if any local funding could be very rapidly substituted at the holding level; and
- If the company's industry risk assessment is '4' or stronger.

50. The country risk assessment for companies that have 75% or more exposure to one jurisdiction cannot be improved and will, in most instances, equal the country risk assessment of that jurisdiction. But the country risk assessment for companies that have 75% or more exposure to one jurisdiction can be weakened if the balance of exposure is to higher risk jurisdictions.

51. We consider the location of a corporate head office relevant to overall risk exposure because it influences the perception of a company and its reputation--and can affect the company's access to capital. We determine the location of the head office on the basis of 'de facto' head office operations rather than just considering the jurisdiction of incorporation or stock market listing for public companies. De facto head office operations refers to the country where executive management and centralized high-level corporate activities occur, including strategic planning and capital raising. If such activities occur in different countries, we take the weakest country risk assessment applicable for the countries in which those activities take place.

D. Competitive Position

52. Competitive position encompasses company-specific factors that can add to, or partly offset, industry risk and country risk--the two other major factors of a company's business risk profile.

53. Competitive position takes into account a company's: 1) competitive advantage, 2) scale, scope, and diversity, 3) operating efficiency, and 4) profitability. A company's strengths and weaknesses on the first three components shape its competitiveness in the marketplace and the sustainability or vulnerability of its revenues and profit. Profitability can either confirm our initial assessment of competitive position or modify it, positively or negatively. A stronger-than-industry-average set of competitive position characteristics will strengthen a company's business risk profile. Conversely, a weaker-than-industry-average set of competitive position characteristics will weaken a

company's business risk profile.

54. These criteria describe how we develop a competitive position assessment. They provide guidance on how we assess each component based on a number of subfactors. The criteria define the weighting rules applied to derive a preliminary competitive position assessment. And they outline how this preliminary assessment can be maintained, raised, or lowered based on a company's profitability. Standard & Poor's competitive position analysis is both qualitative and quantitative.

1. The components of competitive position

55. A company's competitive position assessment can be: 1, excellent; 2, strong; 3, satisfactory; 4, fair; 5, weak; or 6, vulnerable.

56. The analysis of competitive position includes a review of:

- Competitive advantage;
- Scale, scope, and diversity;
- Operating efficiency; and
- Profitability.

57. We follow four steps to arrive at the competitive position assessment. First, we separately assess competitive advantage; scale, scope, and diversity; and operating efficiency (excluding any benefits or risks already captured in the issuer's CICRA assessment). Second, we apply weighting factors to these three components to derive a weighted-average assessment that translates into a preliminary competitive position assessment. Third, we assess profitability. Finally, we combine the preliminary competitive position assessment and the profitability assessment to determine the final competitive position assessment. Profitability can confirm, or influence positively or negatively, the competitive position assessment.

58. We assess the relative strength of each of the first three components by reviewing a variety of subfactors (see table 7). When quantitative metrics are relevant and available, we use them to evaluate these subfactors. However, our overall assessment of each component is qualitative. Our evaluation is forward-looking; we use historical data only to the extent that they provide insight into future trends.

59. We evaluate profitability by assessing two subcomponents: level of profitability (measured by historical and projected nominal levels of return on capital, EBITDA margin, and/or sector-specific metrics) and volatility of profitability (measured by historically observed and expected fluctuations in EBITDA, return on capital, EBITDA margin, or sector specific metrics). We assess both subcomponents in the context of the company's industry.

Table 7

Competitive Position Components And Subfactors

Component	Explanation	Subfactors
1. Competitive advantage (see Appendix B, section 1)	The strategic positioning and attractiveness to customers of a company's products or services, and the fragility or sustainability of its business model	• Strategy • Differentiation/uniqueness/product positioning/bundling • Brand reputation and marketing • Product and/or service quality • Barriers to entry and customers' switching costs • Technological advantage and capabilities and vulnerability to/ability to drive technological displacement • Asset base characteristics
2. Scale, scope, and diversity (see Appendix B, section 2)	The concentration or diversification of business activities	• Diversity of products or services • Geographic diversity • Volumes, size of markets and revenues, and market share • Maturity of products or services
3. Operating efficiency (see Appendix B, section 3)	The quality and flexibility of a company's asset base and its cost management and structure	• Cost structure • Manufacturing processes • Working capital management • Technology
4. Profitability		• Level of profitability (historical and projected return on capital, EBITDA margin, and/or sector-relevant measure) • Volatility of profitability

2. Assessing competitive advantage, scale, scope, and diversity, and operating efficiency

60. We assess competitive advantage; scale, scope, and diversity; and operating efficiency as: 1, strong; 2, strong/adequate; 3, adequate; 4, adequate/weak; or 5, weak. Tables 8, 9, and 10 provide guidance for assessing each component.

61. In assessing the components' relative strength, we place significant emphasis on comparative analysis. Peer comparisons provide context for evaluating the subfactors and the resulting component assessment. We review company-specific characteristics in the context of the company's industry, not just its narrower subsector. (See list of industries and subsectors in Appendix B, table 27.) For example, when evaluating an airline, we will benchmark the assessment against peers in the broader transportation-cyclical industry (including the marine and trucking subsectors), and not just against other airlines. Likewise, we will compare a home furnishing manufacturer with other companies in the consumer durables industry, including makers of appliances or leisure products. We might occasionally extend the comparison to other industries if, for instance, a company's business lines cross several industries, or if there are a limited number of rated peers in an industry, subsector, or region.

62. An assessment of strong means that the company's strengths on that component outweigh its weaknesses, and that the combination of relevant subfactors results in lower-than-average business risk in the industry. An assessment of adequate means that the company's strengths and weaknesses with respect to that component are balanced and that the relevant subfactors add up to average business risk in the industry. A weak assessment means that the company's weaknesses on that component override any strengths and that its subfactors, in total, reveal higher-than-average business risk in the industry.

63. Where a component is not clearly strong or adequate, we may assess it as strong/adequate. A component that is not clearly adequate or weak may end up as adequate/weak.

64. Although we review each subfactor, we don't assess each individually--and we seek to understand how they may reinforce or weaken each other. A component's assessment combines the relative strengths and importance of its subfactors. For any company, one or more subfactors can be unusually important--even factors that aren't common in the industry. Industry KCF articles identify subfactors that are consistently more important, or happen not to be relevant, in a given industry.

65. Not all subfactors may be equally important, and a single one's strength or weakness may outweigh all the others. For example, if notwithstanding a track record of successful product launches and its strong brand equity, a company's strategy doesn't appear adaptable, in our view, to changing competitive dynamics in the industry, we will likely not assess its competitive advantage as strong. Similarly, if its revenues came disproportionately from a narrow product line, we might view this as compounding its risk of exposure to a small geographic market and, thus, assess its scale, scope, and diversity component as weak.

66. From time to time companies will, as a result of shifting industry dynamics or strategies, expand or shrink their product or service lineups, alter their cost structures, encounter new competition, or have to adapt to new regulatory environments. In such instances, we will reevaluate all relevant subfactors (and component assessments).

Table 8

Competitive Advantage Assessment

Qualifier	What it means	Guidance
Strong	• The company has a major competitive advantage due to one or a combination of factors that supports revenue and profit growth, combined with lower-than-average volatility of profits. • There are strong prospects that the company can sustain this advantage over the long term. • This should enable the company to withstand economic downturns and competitive and technological threats better than its competitors can. • Any weaknesses in one or more subfactors are more than offset by strengths in other subfactors that produce sustainable and profitable revenue growth.	• The company's business strategy is highly consistent with, and adaptable to, industry trends and conditions and supports its leadership in the marketplace. • It consistently develops and markets well-differentiated products or services, aligns products with market demand, and enhances the attractiveness or uniqueness of its value proposition through bundling. • Its superior track record of product development, service quality, and customer satisfaction and retention support its ability to maintain or improve its market share. • Its products or services command a clear price premium relative to its competitors' thanks to its brand equity, technological leadership, or quality of service; it is able to sustain this advantage with innovation and effective marketing. • It benefits from barriers to entry from regulation, market characteristics, or intrinsic benefits (such as patents, technology, or customer relationships) that effectively reduce the threat of new competition. • It has demonstrated a commitment and ability to effectively reinvest in its asset base, as evidenced by a continuous pipeline of new products and/or improvement in key capabilities, such as employee retention, customer care, distribution, and supplier relations. These tangible and intangible assets support long term prospects of sustainable and profitable growth.
Adequate	• The company has some competitive advantages, but not so large as to create a superior business model or durable benefit compared to its peers'. • It has some but not all drivers of competitiveness. Certain factors support the business' long-term viability and should result in average profitability and average profit volatility during recessions or periods of increased competition. However, these drivers are partially offset by the company's disadvantages or lack of sustainability of other factors.	• The company's strategy is well adapted to marketplace conditions, but it is not necessarily a leader in setting industry trends. • It exhibits neither superior nor subpar abilities with respect to product or service differentiation and positioning. • Its products command no price premium or advantage relative to competing brands as a result of its brand equity or its technological positioning. • It may enjoy some barriers to entry that provide some defense against competitors but don't overpower them. It faces some risk of product/service displacement or substitution longer term. • Its metrics of product or service quality and customer satisfaction or retention are in line with its industry's average. The company could lose customers to competitors if it makes operational missteps. • Its asset profile does not exhibit particularly superior or inferior characteristics compared to other industry participants. These assets generate consistent revenue and profit growth although long-term prospects are subject to some uncertainty.

Weak	• The company has few, if any, competitive advantages and a number of competitive disadvantages. • Because the company lacks many competitive advantages, its long-term prospects are uncertain, and its profit volatility is likely to be higher than average for its industry. • The company is less likely than its competitors to withstand economic, competitive, or technological threats. • Alternatively, the company has weaknesses in one or more subfactors that could keep its profitability below average and its profit volatility above average during economic downturns or periods of increased competition.	• The company's strategy is inconsistent with, or not well adapted to, marketplace trends and conditions. • There is evidence of little innovation, slowness in developing and marketing new products, an inability to raise prices, and/or ineffective bundling. • Its products generally enjoy no price premium relative to competing brands and it often has to sell its products at a lower price than its peers can command. • It has suffered or is at risk of suffering customer defections due to falling quality and because customers perceive its products or services to be less valuable than those of its competitors. • Its revenues and market shares are vulnerable to aggressive pricing by existing or new competitors or to technological displacement risks over the near to medium term. • Its metrics of product or service quality and customer satisfaction or retention are weaker than the industry average. • Its reinvestment in its business is lower than its peers', its ability to retain operational talent is limited, its distribution network is inefficient, and its revenue could stagnate or decline as result.

Table 9

Scale, Scope, And Diversity

Qualifier	What it means	Guidance
Strong	• The company's overall scale, scope, and diversity supports stable revenues and profits by rendering it essentially invulnerable to all but the most disruptive combinations of adverse factors, events, or trends. • Its significant advantages in scale, scope, and diversity enable it to withstand economic, regional, competitive, and technological threats better than its competitors can.	• The company's range of products or services is among the most comprehensive in its sector. It derives its revenue and profits from a broader set of products or services than the industry average. • Its products and services enjoy industry-leading market shares relative to other participants in its industry. • It does not rely on a particular customer or small group of customers. If it does, the customer(s) is/are of high credit quality, their demand is highly sustainable, or the company and its customer(s) have significant interdependence. • It does not depend on any particular supplier or related group of suppliers that it could not easily replace. If it does, the supplier(s) is/are of high credit quality, or the company and its supplier(s) have significant interdependence. • It enjoys broader geographic diversity than its peers and doesn't overly depend on a single regional or local market. If it does, the market is local, often for regulatory reasons. The company's production or service centers are diversified across several locations. • It holds a strategic investment that provides positive business diversification.
Adequate	• The company's overall scale, scope, and diversity is comparable to its peers'. • Its ability to withstand economic, competitive, or technological threats is comparable to the ability of others within its sector.	• The company has a broad range of products or services compared with its competitors and doesn't depend on a particular product or service for the majority of its revenues and profits. • Its market share is average compared with that of its competitors. • Its dependence on or concentration of key customers is no higher than the industry average, and the loss of a top customer would be unlikely to pose a high risk to its business stability. • It isn't overly dependent on any supplier or regional group of suppliers that it couldn't easily replace. • It doesn't depend excessively on a single local or regional market, and its geographic footprint of production and revenue compares with that of other industry participants.

Weak	• The company's lack of scale, scope, and diversity compromises the stability and sustainability of its revenues and profits. • The company's vulnerability to, or reliance on, various elements of scale, scope, and diversity leaves it less likely than its competitors to withstand economic, competitive, or technological threats.	• The company's product or service lineup is somewhat limited compared to those of its sector peers. The company derives its profits from a narrow group of products or services, and has not achieved significant market share compared with its peers. • Demand for its products or services is lower than for its competitors', and this trend isn't improving. • It relies heavily on a particular customer or small group of customers, and the characteristics of the customer base do not mitigate this risk. • It depends on a particular supplier or group of suppliers, which it would not be able to easily replace without incurring high switching costs. • It depends disproportionately on a single local or regional economy for selling its goods or services, and the company's industry is global. • Key production assets are concentrated by location, and the company has limited ability to quickly replace them without incurring high costs relative to its profits.

Table 10

Operating Efficiency Assessment

Qualifier	What it means	Guidance
Strong	• The company maximizes revenues and profits via intelligent use of assets and by minimizing costs and increasing efficiency. • The company's cost structure should enable it to withstand economic downturns better than its peers.	• The company has a lower cost structure than its peers resulting in higher profits or margins even if capacity utilization or demand are well below ideal levels and during down economic and industry cycles. • It has demonstrated its ability to efficiently manage fixed and variable costs in cyclical downturns, and has a history of successful and often ongoing cost reductions programs. • Its capacity utilization is close to optimal at the peak of the industry cycle and outperforms the industry average over the cycle. • It has demonstrated that it can pass along increases in input costs and we expect this will continue. • It has a very high ability to adjust production and labor costs in response to changes in demand without repercussions for product quality, or has demonstrated the ability to operate very profitably in a more costly or less flexible labor environment. • Its suppliers have demonstrated an ability to meet swings in demand without causing bottlenecks or quality issues, and can absorb all but the most severe supply chain disruptions. • It has superior working capital management, as evidenced by a consistently better-than-average "cash conversion cycle" and other working capital metrics, supporting higher cash flow and lower funding costs. • Its investments in technology are likely to increase revenue growth and/or improve its cost structure and operating efficiency.

Adequate	• A combination of cost structure and efficiency should support sustainable profits with average profit volatility relative to the company's peers. Its cost structure is similar to its peers'.	• The company has demonstrated the ability to manage some fixed and most variable costs except during periods of extremely weak demand, and has some history of cutting costs in good and bad times. • Its cost structure permits some profitability even if capacity utilization or customer demand is well below ideal levels. The company can at least break even during most of the industry/demand cycle. • Its cost structure is in line with its peers'. For example, its selling, general, and administrative (SG&A) expense as a percent of revenue is similar to its peers' and is likely to be stable. • It has demonstrated an ability to adjust labor costs in most scenarios without hurting product output and quality, or can operate profitability in a more costly or less flexible labor environment; it has some success passing on input cost increases, although perhaps only partially or with time lag. • Its suppliers have met typical swings in demand without causing widespread bottlenecks or quality issues, and the company has some capacity to withstand limited supply chain disruptions. • It has good working capital management, evidenced by its cash conversion cycle and working capital metrics that are on par with its peers'. • Its investments in technology are likely to help it at least maintain its cost structure and current level of operating efficiency.
Weak	• The company's operating efficiency leaves it with lower profitability than its peers' due to lower asset utilization and/or a higher, less flexible cost structure.	• The company's cost structure permits better-than-marginal profitability only if capacity utilization is at the top of the cycle or during periods of strong demand. The company needs solid and sustained industry conditions to generate fair profitability. • It has limited success or capability of managing fixed costs and even most typically variable costs are fixed in the next two to three years. • It has a limited track record of successful cost reductions, such as reducing labor costs in the face of swings in demand, or it has limited ability to pass along increases in input costs. • Its costs are higher than its peers'. For example, the company's SG&A expense as a percent of revenue is above that of its peers, and likely to remain so. • Its suppliers may face bottlenecks or quality issues in the event of modest swings in demand, or have limited technological capabilities. There is evidence that a limited supply chain disruption would make it difficult for suppliers to meet their commitments to the company. • Its working capital management is weak, as evidenced by working capital metrics that are significantly worse than those of its peers, resulting in lower cash flow and higher funding costs. • It lacks investments in technology, which could hurt is revenue growth and/or result in a higher cost structure and less efficient operations relative to its peers'.

3. Determining the preliminary competitive position assessment: Competitive position group profile and category weightings

67. After assessing competitive advantage; scale, scope, and diversity; and operating efficiency, we determine a company's preliminary competitive position assessment by ascribing a specific weight to each component. The weightings depend on the company's Competitive Position Group Profile (CPGP).

68. There are six possible CPGPs: 1) services and product focus, 2) product focus/scale driven, 3) capital or asset focus, 4) commodity focus/cost driven, 5) commodity focus/scale driven, and 6) national industry and utilities (see table 11 for definitions and characteristics).

Table 11

Competitive Position Group Profile (CPGP)

	Definition and characteristics	Examples
Services and product focus	Brands, product quality or technology, and service reputation are typically key differentiating factors for competing in the industry. Capital intensity is typically low to moderate, although supporting the brand often requires ongoing reinvestment in the asset base.	Typically, these are companies in consumer-facing light manufacturing or service industries. Examples include branded drug manufacturers, software companies, and packaged food.
Product focus/scale driven	Product and geographic diversity, as well as scale and market position are key differentiating factors. Sophisticated technology and stringent quality controls heighten risk of product concentration. Product preferences or sales relationships are more important than branding or pricing. Cost structure is relatively unimportant.	The sector most applicable is medical device/equipment manufacturers, particularly at the higher end of the technology scale. These companies largely sell through intermediaries, as opposed to directly to the consumer.
Capital or asset focus	Sizable capital investments are generally required to sustain market position in the industry. Brand identification is of limited importance, although product and service quality often remain differentiating factors.	Heavy manufacturing industries typically fall into this category. Examples include telecom infrastructure manufacturers and semiconductor makers.
Commodity focus/cost driven	Cost position and efficiency of production assets are more important than size, scope, and diversification. Brand identification is of limited importance	Typically, these are companies that manufacture products from natural resources that are used as raw materials by other industries. Examples include forest and paper products companies that harvest timber or produce pulp, packaging paper, or wood products.
Commodity focus/scale driven	Pure commodity companies have little product differentiation, and tend to compete on price and availability. Where present, brand recognition or product differences are secondary or of less importance.	Examples range from pure commodity producers and most oil and gas upstream producers, to some producers with modest product or brand differentiation, such as commodity foods.
National industries and utilities	Government policy or control, regulation, and taxation and tariff policies significantly affect the competitive dynamics of the industry (see paragraphs 72-73).	An example is a water-utility company in an emerging market.

69. The nature of competition and key success factors are generally prescribed by industry characteristics, but vary by company. Where service, product quality, or brand equity are important competitive factors, we'll give the competitive advantage component of our overall assessment a higher weighting. Conversely, if the company produces a commodity product, differentiation comes less into play, and we will more heavily weight scale, scope, and diversity as well as operating efficiency (see table 12).

Table 12

Competitive Position Group Profiles (CPGPs) And Category Weightings

Component	--(%)--					
	Services and product focus	**Product focus/scale driven**	**Capital or asset focus**	**Commodity focus/cost driven**	**Commodity focus/scale driven**	**National industries and utilities**
1. Competitive advantage	45	35	30	15	10	60
2. Scale, scope, and diversity	30	50	30	35	55	20
3. Operating efficiency	25	15	40	50	35	20
Total	100	100	100	100	100	100
Weighted-average assessment*	1.0-5.0	1.0-5.0	1.0-5.0	1.0-5.0	1.0-5.0	1.0-5.0

*1 (strong), 2 (strong/adequate), 3 (adequate), 4 (adequate/weak), 5 (weak).

70. We place each of the defined industries (see Appendix B, table 27) into one of the six CPGPs (see above and Appendix B, table 27). This is merely a starting point for the analysis, since we recognize that some industries are less homogenous than others, and that company-specific strategies do affect the basis of competition.

71. In fact, the criteria allow for flexibility in selecting a company's group profile (with its category weightings). Reasons for selecting a profile different than the one suggested in the guidance table could include:

- The industry is heterogeneous, meaning that the nature of competition differs from one subsector to the next, and possibly even within subsectors. The KCF article for the industry will identify such circumstances.
- A company's strategy could affect the relative importance of its key factors of competition.

72. For example, the standard CPGP for the telecom and cable industry is services and product focus. While this may be an appropriate group profile for carriers and service providers, an infrastructure provider may be better analyzed under the capital or asset focus group profile. Other examples: In the capital goods industry, a construction equipment rental company may be analyzed under the capital or asset focus group profile, owing to the importance of efficiently managing the capital spending cycle in this segment of the industry, whereas a provider of hardware, software, and services for industrial automation might be analyzed under the services and product focus group profile, if we believe it can achieve differentiation in the marketplace based on product performance, technology innovation, and service.

73. In some industries, the effects of government policy, regulation, government control, and taxation and tariff policies can significantly alter the competitive dynamics, depending on the country in which a company operates. That can alter our assessment of a company's competitive advantage; scale, size, and diversity; or operating efficiency. When industries in given countries have risks that differ materially from those captured in our global industry risk profile and assessment (see "Methodology: Industry Risk," published Nov. 19, 2013, section B), we will weight competitive advantage more heavily to capture the effect, positive or negative, on competitive dynamics. The assessment of competitive advantage; scale, size, and diversity; and operating efficiency will reflect advantages or disadvantages based on these national industry risk factors. Table 13 identifies the circumstances under which national industry risk factors are positive or negative.

Table 13

National Industry Risk Factors	
National industry risk factors are positive	• Government policy including regulation, ownership, and taxation is supportive and has a good track record of mitigating risks to the stability of industry margins. • Any government ownership, tariff, and taxation policy supports growth prospects for revenues and profit generation. • There is very little discernible risk of negative policy, regulatory, ownership, or taxation changes that could threaten business stability.
National industry risk factors are negative	• Government policy and regulation has a weak track record of stabilizing margins and reducing industry risks. • Any government ownership, tariff, and taxation policy undermine growth prospects for revenues and profit generation. • There is an increasing risk of negative policy, ownership, and taxation changes that could undermine industry stability.

74. When national industry risk factors are positive for a company, typically they support revenue growth, profit growth, higher EBITDA margins, and/or lower-than-average volatility of profits. Often, these benefits provide barriers to entry that impede or even bar new market entrants, which should be reflected in the competitive advantage assessment. These benefits may also include risk mitigants that enable a company to withstand economic downturns and competitive and technological threats better in its local markets than its global competitors can. The scale, scope, and diversity assessment might also benefit from these policies if the company is able to withstand economic, regional, competitive, and technological threats better than its global competitors can. Likewise, the company's operating efficiency assessment may improve if, as a result, it is better able than its global competitors to withstand economic downturns, taking into account its cost structure.

75. Conversely, when national industry risk factors are negative for a company, typically they detract from revenue growth and profit growth, shrink EBITDA margins, and/or increase the average volatility of profits. The company may also have less protection against economic downturns and competitive and technological threats within its local markets than its global competitors do. We may also adjust the company's scale, scope, and diversity assessment lower if, as a result of these policies, it is less able to withstand economic, regional, competitive, and technological threats than its global competitors can. Likewise, we may adjust its operating efficiency assessment lower if, as a result of these policies, it is less able to withstand economic downturns, taking into account the company's cost structure.

76. An example of when we might use a national industry risk factor would be for a telecommunications network owner that benefits from a monopoly network position, supported by substantial capital barriers to entry, and as a result is subject to regulated pricing for its services. Accordingly, in contrast to a typical telecommunications company, our analysis of the company's competitive position would focus more heavily on the monopoly nature of its operations, as well as the nature and reliability of the operator's regulatory framework in supporting future revenue and earnings. If we viewed the regulatory framework as being supportive of the group's future earnings stability, and we considered its

monopoly position to be sustainable, we would assess these national industry risk factors as positive in our assessment of the group's competitive position.

77. The weighted average assessment translates into the preliminary competitive position assessment on a scale of 1 to 6, where one is best. Table 14 describes the matrix we use to translate the weighted average assessment of the three components into the preliminary competitive position assessment.

Table 14

Translation Table For Converting Weighted-Average Assessments Into Preliminary Competitive Position Assessments

Weighted average assessment range	Preliminary competitive position assessment
1.00 – 1.50	1
>1.50 – 2.25	2
>2.25 – 3.00	3
>3.00 – 3.75	4
>3.75 – 4.50	5
>4.50 – 5.00	6

4. Assessing profitability

78. We assess profitability on the same scale of 1 to 6 as the competitive position assessment.

79. The profitability assessment consists of two subcomponents: level of profitability and the volatility of profitability, which we assess separately. We use a matrix to combine these into the final profitability assessment.

a) Level of profitability

80. The level of profitability is assessed in the context of the company's industry. We most commonly measure profitability using return on capital (ROC) and EBITDA margins, but we may also use sector-specific ratios. Importantly, as with the other components of competitive position, we review profitability in the context of the industry in which the company operates, not just in its narrower subsector. (See list of industries and subsectors in Appendix B, table 27.)

81. We assess level of profitability on a three-point scale: above average, average, and below average. Industry KCF articles may establish numeric guidance, for instance by stating that an ROC above 12% is considered above average, between 8%-12% is average, and below 8% is below average for the industry, or by differentiating between subsectors in the industry. In the absence of numeric guidance, we compare a company against its peers across the industry.

82. We calculate profitability ratios generally based on a five-year average, consisting of two years of historical data, our projections for the current year (incorporating any reported year-to-date results and estimates for the remainder of the year), and the next two financial years. There may be situations where we consider longer or shorter historical results or forecasts, depending on such factors as availability of financials, transformational events (such as mergers or acquisitions [M&A]), cyclical distortion (such as peak or bottom of the cycle metrics that we do not deem fully representative of the company's level of profitability), and we take into account improving or deteriorating trends in profitability ratios in our assessment.

b) Volatility of profitability

83. We base the volatility of profitability on the standard error of the regression (SER) for a company's historical EBITDA, EBITDA margins, or return on capital. The KCF articles provide guidance on which measures are most appropriate for a given industry or set of companies. For each of these measures, we divide the standard error by the average of that measure over the time period in order to ensure better comparability across companies.

84. The SER is a statistical measure that is an estimate of the deviation around a 'best fit' linear trend line. We regress the company's EBITDA, EBITDA margins, or return on capital against time. A key advantage of SER over standard deviation or coefficient of variation is that it doesn't view upwardly trending data as inherently more volatile. At the same time, we recognize that SER, like any statistical measure, may understate or overstate expected volatility and thus we will make qualitative adjustments where appropriate (see paragraphs 86-90). Furthermore, we only calculate SER when companies have at least seven years of historical annual data and have not significantly changed their line of business during the timeframe, to ensure that the results are meaningful.

85. As with the level of profitability, we evaluate a company's SER in the context of its industry group. For most industries, we establish a six-point scale with 1 capturing the least volatile companies, i.e., those with the lowest SERs, and 6 identifying companies whose profits are most volatile. We have established industry-specific SER parameters using the most recent seven years of data for companies within each sector. We believe that seven years is generally an adequate number of years to capture a business cycle. (See Appendix B, section 4 for industry-specific SER parameters.) For companies whose business segments cross multiple industries, we evaluate the SER in the context of the organization's most dominant industry--if that industry represents at least two-thirds of the organization's EBITDA, sales, or other relevant metric. If the company is a conglomerate and no dominant industry can be identified, we will evaluate its profit volatility in the context of SER guidelines for all nonfinancial companies.

86. In certain circumstances, the SER derived from historical information may understate--or overstate--expected future volatility, and we may adjust the assessment downward or upward. The scope of possible adjustments depends on certain conditions being met as described below.

87. We might adjust the SER-derived volatility assessment to a worse assessment (i.e., to a higher assessment for greater volatility) by up to two categories if the expected level of volatility isn't apparent in historical numbers, and the company either:

- Has a weighted country risk assessment of 4 or worse, which may, notwithstanding past performance, result in a less stable business environment going forward;
- Operates in a subsector of the industry that may be prone to higher technology or regulation changes, or other potential disruptive risks that have not emerged over the seven year period;
- Is of limited size and scope, which will often result in inherently greater vulnerability to external changes; or
- Has pursued material M&A or internal growth projects that obscure the company's underlying performance trend line. As an example, a company may have consummated an acquisition during the trough of the cycle, masking what would otherwise be a significant decline in performance.

88. The choice of one or two categories depends on the degree of likelihood that the related risks will materialize and our view of the likely severity of these risks.

89. Conversely, we may adjust the SER-derived volatility assessment to a better assessment (i.e., to a lower assessment reflecting lower volatility) by up to two categories if we observe that the conditions historically leading to greater volatility have receded and are misrepresentative. This will be the case when:

- The company grew at a moderately faster, albeit more uneven, pace relative to the industry. Since we measure volatility around a linear trend line, a company growing at a constant percentage of moderate increase (relative to the industry) or an uneven pace (e.g., due to "lumpy" capital spending programs) could receive a relatively unfavorable assessment on an unadjusted basis, which would not be reflective of the company's performance in a steady state. (Alternatively, those companies that grow at a significantly higher-than-average industry rate often do so on unsustainable rates of growth or by taking on high-risk strategies. Companies with these high-risk growth strategies would not receive a better assessment and could be adjusted to a worse assessment;)
- The company's geographic, customer, or product diversification has increased in scope as a result of an acquisition or rapid expansion (e.g. large, long-term contracts wins), leading to more stability in future earnings in our view; or
- The company's business model is undergoing material change that we expect will benefit earnings stability, such as a new regulatory framework or major technology shift that is expected to provide a significant competitive hedge and margin protection over time.

90. The choice of one or two categories depends on the degree of likelihood that the related risks will materialize and our view of the likely severity of these risks.

91. If the company either does not have at least seven years of annual data or has materially changed its business lines or undertaken abnormally high levels of M&A during this time period, then we do not use its SER to assess the volatility of profitability. In these cases, we use a proxy to establish the volatility assessment. If there is a peer company that has, and is expected to continue having, very similar profitability volatility characteristics, we use the SER of that peer entity as a proxy.

92. If no such matching peer exists, or one cannot be identified with enough confidence, we perform an assessment of expected volatility based on the following rules:

- An assessment of 3 if we expect the company's profitability, supported by available historical evidence, will exhibit a volatility pattern in line with, or somewhat less volatile than, the industry average.
- An assessment of 2 based on our confidence, supported by available historical evidence, that the company will exhibit lower volatility in profitability metrics than the industry's average. This could be underpinned by some of the factors listed in paragraph 89, whereas those listed in paragraph 87 would typically not apply.
- An assessment of 4 or 5 based on our expectation that profitability metrics will exhibit somewhat higher (4), or meaningfully higher (5) volatility than the industry, supported by available historical evidence, or because of the applicability of possible adjustment factors listed in paragraph 87.
- Assessments of either 1 or 6 are rarely assigned and can only be achieved based on a combination of data evidence and very high confidence tests. For an assessment of 1, we require strong evidence of minimal volatility in profitability metrics compared with the industry, supported by at least five years of historical information, combined with a very high degree of confidence that this will continue in the future, including no country risk, subsector risk or size considerations that could otherwise warrant a worse assessment as per paragraph 87. For an assessment of 6 we require strong evidence of very high volatility in profitability metrics compared with the industry, supported by at least five years of historical information and very high confidence that this will continue in the future.

93. Next, we combine the level of profitability assessment with the volatility assessment to determine the final profitability

assessment using the matrix in Table 15.

Table 15

Profitability Assessment

	--Volatility of profitability assessment--					
Level of profitability assessment	**1**	**2**	**3**	**4**	**5**	**6**
Above average	1	1	2	3	4	5
Average	1	2	3	4	5	6
Below average	2	3	4	5	6	6

5. Combining the preliminary competitive position assessment with profitability

94. The fourth and final step in arriving at a competitive position assessment is to combine the preliminary competitive position assessment with the profitability assessment. We use the combination matrix in Table 16, which shows how the profitability assessment can confirm, strengthen, or weaken (by up to one category) the overall competitive position assessment.

Table 16

Combining The Preliminary Competitive Position Assessment And Profitability Assessment

	--Preliminary competitive position assessment--					
Profitability assessment	**1**	**2**	**3**	**4**	**5**	**6**
1	1	2	2	3	4	5
2	1	2	3	3	4	5
3	2	2	3	4	4	5
4	2	3	3	4	5	5
5	2	3	4	4	5	6
6	2	3	4	5	5	6

95. We generally expect companies with a strong preliminary competitive position assessment to exhibit strong and less volatile profitability metrics. Conversely, companies with a relatively weaker preliminary competitive position assessment will generally have weaker and/or more volatile profitability metrics. Our analysis of profitability helps substantiate whether management is translating any perceived competitive advantages, diversity benefits, and cost management measures into higher earnings and more stable return on capital and return on sales ratios than the averages for the industry. When profitability differs markedly from what the preliminary/anchor competitive position assessment would otherwise imply, we adjust the competitive position assessment accordingly.

96. Our method of adjustment is biased toward the preliminary competitive position assessment rather than toward the profitability assessment (e.g., a preliminary competitive assessment of 6 and a profitability assessment of 1 will result in a final assessment of 5).

E. Cash Flow/Leverage

97. The pattern of cash flow generation, current and future, in relation to cash obligations is often the best indicator of a company's financial risk. The criteria assess a variety of credit ratios, predominately cash flow-based, which

complement each other by focusing on the different levels of a company's cash flow waterfall in relation to its obligations (i.e., before and after working capital investment, before and after capital expenditures, before and after dividends), to develop a thorough perspective. Moreover, the criteria identify the ratios that we think are most relevant to measuring a company's credit risk based on its individual characteristics and its business cycle.

98. For the analysis of companies with intermediate or stronger cash flow/leverage assessments (a measure of the relationship between the company's cash flows and its debt obligations as identified in paragraphs 106 and 124), we primarily evaluate cash flows that reflect the considerable flexibility and discretion over outlays that such companies typically possess. For these entities, the starting point in the analysis is cash flows before working capital changes plus capital investments in relation to the size of a company's debt obligations in order to assess the relative ability of a company to repay its debt. These "leverage" or "payback" cash flow ratios are a measure of how much flexibility and capacity the company has to pay its obligations.

99. For entities with significant or weaker cash flow/leverage assessments (as identified in paragraphs 105 and 124), the criteria also call for an evaluation of cash flows in relation to the carrying cost or interest burden of a company's debt. This will help us assess a company's relative and absolute ability to service its debt. These "coverage"- or "debt service"-based cash flow ratios are a measure of a company's ability to pay obligations from cash earnings and the cushion the company possesses through stress periods. These ratios, particularly interest coverage ratios, become more important the further a company is down the credit spectrum.

1. Assessing cash flow/leverage

100. Under the criteria, we assess cash flow/leverage as 1, minimal; 2, modest; 3, intermediate; 4, significant; 5, aggressive; or 6, highly leveraged. To arrive at these assessments, the criteria combine the assessments of a variety of credit ratios, predominately cash flow-based, which complement each other by focusing attention on the different levels of a company's cash flow waterfall in relation to its obligations. For each ratio, there is an indicative cash flow/leverage assessment that corresponds to a specified range of values in one of three given benchmark tables (see tables 17, 18, and 19). We derive the final cash flow/leverage assessment for a company by determining the relevant core ratios, anchoring a preliminary cash flow assessment based on the relevant core ratios, determining the relevant supplemental ratio(s), adjusting the preliminary cash flow assessment according to the relevant supplemental ratio(s), and, finally, modifying the adjusted cash flow/leverage assessment for any material volatility.

2. Core and supplemental ratios

a) Core ratios

101. For each company, we calculate two core credit ratios--funds from operations (FFO) to debt and debt to EBITDA--in accordance with Standard & Poor's ratios and adjustments criteria (see "Corporate Methodology: Ratios And Adjustments," published Nov. 19, 2013). We compare these payback ratios against benchmarks to derive the preliminary cash flow/leverage assessment for a company. These ratios are also useful in determining the relative ranking of the financial risk of companies.

b) Supplemental ratios

102. The criteria also consider one or more supplemental ratios (in addition to the core ratios) to help develop a fuller understanding of a company's financial risk profile and fine-tune our cash flow/leverage analysis. Supplemental ratios

could either confirm or adjust the preliminary cash flow/leverage assessment. The confirmation or adjustment of the preliminary cash flow/leverage assessment will depend on the importance of the supplemental ratios as well as any difference in indicative cash flow/leverage assessment between the core and supplemental ratios as described in section E.3.b.

103. The criteria typically consider five standard supplemental ratios, although the relevant KCF criteria may introduce additional supplemental ratios or focus attention on one or more of the standard supplemental ratios. The standard supplemental ratios include three payback ratios--cash flow from operations (CFO) to debt, free operating cash flow (FOCF) to debt, and discretionary cash flow (DCF) to debt--and two coverage ratios, FFO plus interest to cash interest and EBITDA to interest.

104. The criteria provide guidelines as to the relative importance of certain ratios if a company exhibits characteristics such as high leverage, working capital intensity, capital intensity, or high growth.

105. If the preliminary cash flow/leverage assessment is significant or weaker (see section E.3), then two coverage ratios, FFO plus interest to cash interest and EBITDA to interest, will be given greater importance as supplemental ratios. For the purposes of calculating the coverage ratios, "cash interest" includes only cash interest payments (i.e., interest excludes noncash interest payable on, for example, payment-in-kind [PIK] instruments) and does not include any Standard & Poor's adjusted interest on such items as leases, while "interest" is the income statement figure plus Standard & Poor's adjustments to interest (see "Corporate Methodology: Ratios And Adjustments," published Nov. 19, 2013).

106. If the preliminary cash flow/leverage assessment is intermediate or stronger, the criteria first apply the three standard supplemental ratios of CFO to debt, FOCF to debt, and DCF to debt. When FOCF to debt and DCF to debt indicate a cash flow/leverage assessment that is lower than the other payback-ratio-derived cash flow/leverage assessments, it signals that the company has either larger than average capital spending or other non-operating cash distributions (including dividends). If these differences persist and are consistent with a negative trend in overall ratio levels, which we believe is not temporary, then these supplemental leverage ratios will take on more importance in the analysis.

107. If the supplemental ratios indicate a cash flow/leverage assessment that is different than the preliminary cash flow/leverage assessment, it could suggest an unusual debt service or fixed charge burden, working capital or capital expenditure profile, or unusual financial activity or policies. In such cases, we assess the sustainability or persistence of these differences. For example, if either working capital or capital expenditures are unusually low, leading to better indicated assessments, we examine the sustainability of such lower spending in the context of its impact on the company's longer term competitive position. If there is a deteriorating trend in the company's asset base, we give these supplemental ratios less weight. If either working capital or capital expenditures are unusually high, leading to weaker indicated assessments, we examine the persistence and need for such higher spending. If elevated spending levels are required to maintain a company's competitive position, for example to maintain the company's asset base, we give more weight to these supplemental ratios.

108. For capital-intensive companies, EBITDA and FFO may overstate financial strength, whereas FOCF may be a more accurate reflection of their cash flow in relation to their financial obligations. The criteria generally consider a

capital-intensive company as having ongoing capital spending to sales of greater than 10%, or depreciation to sales of greater than 8%. For these companies, the criteria place more weight on the supplementary ratio of FOCF to debt. Where we place more analytic weight on FOCF to debt, we also seek to estimate the amount of maintenance or full cycle capital required (see Appendix C) under normal conditions (we estimate maintenance or full-cycle capital expenditure required because this is not a reported number). The FOCF figure may be adjusted by adding back estimated discretionary capital expenditures. The adjusted FOCF to debt based on maintenance or full cycle capital expenditures often helps determine how much importance to place on this ratio. If both the FOCF to debt and the adjusted (for estimated discretionary capital spending) FOCF to debt derived assessments are different from the preliminary cash/flow leverage assessment, then these supplemental leverage ratios take on more importance in the analysis.

109. For working-capital-intensive companies, EBITDA and FFO may also overstate financial strength, and CFO may be a more accurate measure of the company's cash flow in relation to its financial risk profile. Under the criteria, if a company has a working capital-to-sales ratio that exceeds 25% or if there are significant seasonal swings in working capital, we generally consider it to be working-capital-intensive. For these companies, the criteria place more emphasis on the supplementary ratio of CFO to debt. Examples of companies that have working-capital-intensive characteristics can be found in the capital goods, metals and mining downstream, or the retail and restaurants industries. The need for working capital in those industries reduces financial flexibility and, therefore, these supplemental leverage ratios take on more importance in the analysis.

110. For all companies, when FOCF to debt or DCF to debt is negative or indicates materially lower cash flow/leverage assessments, the criteria call for an examination of management's capital spending and cash distribution strategies. For high-growth companies, typically the focus is on FFO to debt instead of FOCF to debt because the latter ratio can vary greatly depending on the growth investment the company is undergoing. The criteria generally consider a high-growth company one that exhibits real revenue growth in excess of 8% per year. Real revenue growth excludes price or foreign exchange related growth, under these criteria. In cases where FOCF or DCF is low, there is a greater emphasis on monitoring the sustainability of margins and return on capital and the overall financing mix to assess the likely trend of future debt ratios. In addition, debt service ratio analysis will be important in such situations. For companies with more moderate growth, the focus is typically on FOCF to debt unless the capital spending is short term or is not funded with debt.

111. For companies that have ongoing and well entrenched banking relationships we can reflect these relationships in our cash flow/leverage analysis through the use of the interest coverage ratios as supplemental ratios. These companies generally have historical links and a strong ongoing relationship with their main banks, as well as shareholdings by the main banks, and management influence and interaction between the main banks and the company. Based on their bank relationships, these companies often have lower interest servicing costs than peers, even if the macro economy worsens. In such cases, we generally use the interest coverage ratios as supplemental ratios. This type of banking relationship occurs in Japan, for example, where companies that have the type of bank relationship described in this paragraph tend to have a high socioeconomic influence within their country by way of their revenue size, total debt quantum, number of employees, and the relative importance of the industry.

c) Time horizon and ratio calculation

112. A company's credit ratios may vary, often materially, over time due to economic, competitive, technological, or investment cycles, the life stage of the company, and corporate or strategic actions. Thus, we evaluate credit ratios on a time series basis with a clear forward-looking bias. The length of the time series is dependent on the relative credit risk of the company and other qualitative factors and the weighting of the time series varies according to transformational events. A transformational event is any event that could cause a material change in a company's financial profile, whether caused by changes to the company's capital base, capital structure, earnings, cash flow profile, or financial policies. Transformational events can include mergers, acquisitions, divestitures, management changes, structural changes to the industry or competitive environment, and/or product development and capital programs. This section provides guidance on the timeframe and weightings the criteria apply to calculate the indicative ratios.

113. The criteria generally consider the company's credit ratios for the previous one to two years, current-year forecast, and the two subsequent forecasted financial years. There may be situations where longer--or even shorter--historical results or forecasts are appropriate, depending on such factors as availability of financials, transformational events, or relevance. For example, a utility company with a long-term capital spending program may lend itself to a longer-term forecast, whereas for a company experiencing a near-term liquidity squeeze even a two-year forecast will have limited value. Alternatively, for most commodities-based companies we emphasize credit ratios based on our forward-looking view of market conditions, which may differ materially from the historical period.

114. Historical patterns in cash flow ratios are informative, particularly in understanding past volatility, capital spending, growth, accounting policies, financial policies, and business trends. Our analysis starts with a review of these historical patterns in order to assess future expected credit quality. Historical patterns can also provide an indication of potential future volatility in ratios, including that which results from seasonality or cyclicality. A history of volatility could result in a more conservative assessment of future cash flow generation if we believe cash flow will continue to be volatile.

115. The forecast ratios are based on an expected base-case scenario developed by Standard & Poor's, incorporating current and near-term economic conditions, industry assumptions, and financial policies. The prospective cyclical and longer-term volatility associated with the industry in which the issuer operates is addressed in the industry risk criteria (see section B) and the longer-term directional influence or event risk of financial policies is addressed in our financial policy criteria (see section H).

116. The criteria generally place greater emphasis on forecasted years than historical years in the time series of credit ratios when calculating the indicative credit ratio. For companies where we have five years of ratios as described in section E.3, generally we calculate the indicative ratio by weighting the previous two years, the current year, and the forecasted two years as 10%, 15%, 25%, 25%, and 25%, respectively.

117. This weighting changes, however, to place even greater emphasis on the current and forecast years when:

- The issuer meets the characteristics described in paragraph 113, and either shorter- or longer-term forecasts are applicable. The weights applied will generally be quite forward weighted, particularly if a company is undergoing a transformational event and there is moderate or better cash flow certainty.
- The issuer is forecast to generate negative cash flow available for debt repayment, which we believe could lead to

deteriorating credit metrics. Forecast negative cash flows could be generated from operating activities as well as capital expenditures, share buybacks, dividends, or acquisitions, as we forecast these uses of cash based on the company's track record, market conditions, or financial policy. The weights applied will generally be 30%, 40%, and 30% for the current and two subsequent years, respectively.

- The issuer is in an industry that is prospectively volatile or that has a high degree of cash flow uncertainty. Industries that are prospectively volatile are industries whose competitive risk and growth assessments are either high risk (5) or very high risk (6) or whose overall industry risk assessments are either high risk (5) or very high risk (6). The weights applied will generally be 50% for the current year and 50% for the first subsequent forecast year.

118. When the indicative ratio(s) is borderline (i.e., less than 10% different from the threshold in relative terms) between two assessment thresholds (as described in section E.3 and tables 17, 18, and 19) and the forecast points to a switch in the ratio between categories during the rating timeframe, we will weigh the forecast even more heavily in order to prospectively capture the trend.

119. For companies undergoing a transformational event, the weighting of the time series could vary significantly.

120. For companies undergoing a transformational event and with significant or weaker cash flow/leverage assessments, we place greater weight on near-term risk factors. That's because overemphasis on longer-term (inherently less predictable) issues could lead to some distortion when assessing the risk level of a speculative-grade company. We generally analyze a company using the arithmetic mean of the credit ratios expected according to our forecasts for the current year (or pro forma current year) and the subsequent financial year. A common example of this is when a private equity firm acquires a company using additional debt leverage, which makes historical financial ratios meaningless. In this scenario, we weight or focus the majority of our analysis on the next one or two years of projected credit measures.

3. Determining the cash flow/leverage assessment

a) Identifying the benchmark table

121. Tables 17, 18, and 19 provide benchmark ranges for various cash flow ratios we associate with different cash flow/leverage assessments for standard volatility, medial volatility, and low volatility industries. The tables of benchmark ratios differ for a given ratio and cash flow/leverage assessment along two dimensions: the starting point for the ratio range and the width of the ratio range.

122. If an industry exhibits low volatility, the threshold levels for the applicable ratios to achieve a given cash flow/leverage assessment are less stringent than those in the medial or standard volatility tables, although the range of the ratios is narrower. Conversely, if an industry exhibits medial or standard levels of volatility, the threshold for the applicable ratios to achieve a given cash flow/leverage assessment are elevated, albeit with a wider range of values.

123. The relevant benchmark table for a given company is based on our assessment of the company's associated industry and country risk volatility, or the CICRA (see section A, table 1). The low volatility table (table 19) will generally apply when a company's CICRA is 1, unless otherwise indicated in a sector's KCF criteria. The medial volatility table (table 18) will be used under certain circumstances for companies with a CICRA of 1 or 2. Those circumstances are described in the respective sectors' KCF criteria. The standard volatility table (table 17) serves as the relevant benchmark table for companies with a CICRA of 2 or worse, and we will always use it for companies with a CICRA of 1 or 2 and whose competitive position is assessed 5 or 6. Although infrequent, we will use the low volatility table when

a company's CICRA is 2 for companies that exhibit or are expected to exhibit low levels of volatility. The choice of volatility tables for companies with a CICRA of 2 is addressed in the respective sector's KCF article.

Table 17

Cash Flow/Leverage Analysis Ratios--Standard Volatility	--Core ratios--		--Supplementary coverage ratios--		--Supplementary payback ratios--		
	FFO/debt (%)	Debt/EBITDA (x)	FFO/cash interest(x)	EBITDA/interest (x)	CFO/debt (%)	FOCF/debt (%)	DCF/debt (%)
Minimal	60+	Less than 1.5	More than 13	More than 15	More than 50	40+	25+
Modest	45-60	1.5-2	9-13	10-15	35-50	25-40	15-25
Intermediate	30-45	2-3	6-9	6-10	25-35	15-25	10-15
Significant	20-30	3-4	4-6	3-6	15-25	10-15	5-10
Aggressive	12-20	4-5	2-4	2-3	10-15	5-10	2-5
Highly leveraged	Less than 12	Greater than 5	Less than 2	Less than 2	Less than 10	Less than 5	Less than 2

Table 18

Cash Flow/Leverage Analysis Ratios--Medial Volatility	--Core ratios--		--Supplementary coverage ratios--		--Supplementary payback ratios--		
	FFO/debt (%)	Debt/EBITDA (x)	FFO/cash interest (x)	EBITDA/interest (x)	CFO/debt (%)	FOCF/debt (%)	DCF/debt (%)
Minimal	50+	less than 1.75	10.5+	14+	40+	30+	18+
Modest	35-50	1.75-2.5	7.5-10.5	9-14	27.5-40	17.5-30	11-18
Intermediate	23-35	2.5-3.5	5-7.5	5-9	18.5-27.5	9.5-17.5	6.5-11
Significant	13-23	3.5-4.5	3-5	2.75-5	10.5-18.5	5-9.5	2.5-6.5
Aggressive	9-13	4.5-5.5	1.75-3	1.75-2.75	7-10.5	0-5	(11)-2.5
Highly leveraged	Less than 9	Greater than 5.5	Less than 1.75	Less than 1.75	Less than 7	Less than 0	Less than (11)

Table 19

Cash Flow/Leverage Analysis Ratios--Low Volatility	--Core ratios--		--Supplementary coverage ratios--		--Supplementary payback ratios--		
	FFO/debt (%)	Debt/EBITDA (x)	FFO/cash interest (x)	EBITDA/interest (x)	CFO/debt (%)	FOCF/debt (%)	DCF/debt (%)
Minimal	35+	Less than 2	More than 8	More than 13	More than 30	20+	11+
Modest	23-35	2-3	5-8	7-13	20-30	10-20	7-11
Intermediate	13-23	3-4	3-5	4-7	12-20	4-10	3-7
Significant	9-13	4-5	2-3	2.5-4	8-12	0-4	0-3
Aggressive	6-9	5-6	1.5-2	1.5-2.5	5-8	(10)-0	(20)-0
Highly leveraged	Less than 6	Greater than 6	Less than 1.5	Less than 1.5	Less than 5	Less than (10)	Less than (20)

b) Aggregating the credit ratio assessments

124. To determine the final cash flow/leverage assessment, we make these calculations:
1) First, calculate a time series of standard core and supplemental credit ratios, select the relevant benchmark table, and determine the appropriate time weighting of the credit ratios.

- Calculate the two standard core credit ratios and the five standard supplemental credit ratios over a five-year time horizon.
- Consult the relevant industry KCF article (if applicable), which may identify additional supplemental ratio(s). The relevant benchmark table for a given company is based on our assessment of the company's associated industry and country risk volatility, or the CICRA.
- Calculate the appropriate weighted average cash flow/leverage ratios. If the company is undergoing a transformational event, then the core and supplemental ratios will typically be calculated based on Standard & Poor's projections for the current and next one or two financial years.

2) Second, we use the core ratios to determine the preliminary cash flow assessment.

- Compare the core ratios (FFO to debt and debt to EBITDA) to the ratio ranges in the relevant benchmark table.
- If the core ratios result in different cash flow/leverage assessments, we will select the relevant core ratio based on which provides the best indicator of a company's future leverage.

3) Third, we review the supplemental ratio(s).

- Determine the importance of standard or KCF supplemental ratios based on company-specific characteristics, namely, leverage, capital intensity, working capital intensity, growth rate, or industry.

4) Fourth, we calculate the adjusted cash flow/leverage assessment.

- If the cash flow/leverage assessment(s) indicated by the important supplemental ratio(s) differs from the preliminary cash flow/leverage assessment, we might adjust the preliminary cash flow/leverage assessment by one category in the direction of the cash flow/leverage assessment indicated by the supplemental ratio(s) to derive the adjusted cash flow/leverage assessment. We will make this adjustment if, in our view, the supplemental ratio provides the best indicator of a company's future leverage.
- If there is more than one important supplemental ratio and they result in different directional deviations from the preliminary cash flow/leverage assessment, we will select one as the relevant supplemental ratio based on which, in our opinion, provides the best indicator of a company's future leverage. We will then make the adjustment outlined above if the selected supplemental ratio differs from the preliminary cash flow/leverage assessment and the selected supplemental ratio provides the best overall indicator of a company's future leverage.

5) Lastly, we determine the final cash flow/leverage assessment based on the volatility adjustment.

- We classify companies as stable for these cash flow criteria if cash flow/leverage ratios are expected to move up by one category during periods of stress based on their business risk profile. The final cash flow/leverage assessment for these companies will not be modified from the adjusted cash flow/leverage assessment.
- We classify companies as volatile for these cash flow criteria if cash flow/leverage ratios are expected to move one or two categories worse during periods of stress based on their business risk profiles. Typically, this is equivalent to EBITDA declining about 30% from its current level. The final cash flow/leverage assessment for these companies will be modified to one category weaker than the adjusted cash flow/leverage assessment; the adjustment will be eliminated if cash flow/leverage ratios, as evaluated, include a moderate to high level of stress already.
- We classify companies as highly volatile for these cash flow criteria if cash flow/leverage ratios are expected to move two or three categories worse during periods of stress, based on their business risk profiles. Typically, this is equivalent to EBITDA declining about 50% from its current level. The final cash flow/leverage assessment for these companies will be modified to two categories weaker than the adjusted cash flow/leverage assessment; the adjustment will be eliminated or reduced to one category if cash flow/leverage ratios, as evaluated, include a moderate to high level of stress already.

125. The volatility adjustment is the mechanism by which we factor a "cushion" of medium-term variance to current financial performance not otherwise captured in either the near-term base-case forecast or the long-term business risk

assessment. We make this adjustment based on the following:

- The expectation of any potential cash flow/leverage ratio movement is both prospective and dependent on the current business or economic conditions.
- Stress scenarios include, but are not limited to, a recessionary economic environment, technology or competitive shifts, loss or renegotiation of major contracts or customers, and key product or input price movements, as typically defined in the company's industry risk profile and competitive position assessment.
- The volatility adjustment is not static and is company specific. At the bottom of an economic cycle or during periods of stressed business conditions, already reflected in the general industry risk or specific competitive risk profile, the prospect of weakening ratios is far less than at the peak of an economic cycle or business conditions.
- The expectation of prospective ratio changes may be formed by observed historical performance over an economic, business, or product cycle by the company or by peers.
- The assessment of which classification to use when evaluating the prospective number of scoring category moves will be guided by how close the current ratios are to the transition point (i.e. "buffer" in the current scoring category) and the corresponding amount of EBITDA movement at each scoring transition.

F. Diversification/Portfolio Effect

126. Under the criteria, diversification/portfolio effect applies to companies that we regard as conglomerates. They are companies that have multiple core business lines that may be operated as separate legal entities. For the purpose of these criteria, a conglomerate would have at least three business lines, each contributing a material source of earnings and cash flow.

127. The criteria aim to measure how diversification or the portfolio effect could improve the anchor of a company with multiple business lines. This approach helps us determine how the credit strength of a corporate entity with a given mix of business lines could improve based on its diversity. The competitive position factor assesses the benefits of diversity within individual lines of business. This factor also assesses how poorly performing businesses within a conglomerate affect the organization's overall business risk profile.

128. Diversification/portfolio effect could modify the anchor depending on how meaningful we think the diversification is, and on the degree of correlation we find in each business line's sensitivity to economic cycles. This assessment will have either a positive or neutral impact on the anchor. We capture any potential factor that weakens a company's diversification, including poor management, in our management and governance assessment.

129. We define a conglomerate as a diversified company that is involved in several industry sectors. Usually the smallest of at least three distinct business segments/lines would contribute at least 10% of either EBITDA or FOCF and the largest would contribute no more than 50% of EBITDA or FOCF, with the long-term aim of increasing shareholder value by generating cash flow. Industrial conglomerates usually hold a controlling stake in their core businesses, have highly identifiable holdings, are deeply involved in the strategy and management of their operating companies, generally do not frequently roll over or reshuffle their holdings by buying and selling companies, and therefore have high long-term exposure to the operating risks of their subsidiaries.

130. In rating a conglomerate, we first assess management's commitment to maintain the diversified portfolio over a

longer-term horizon. These criteria apply only if the company falls within our definition of a conglomerate.

1. Assessing diversification/portfolio effect

131. A conglomerate's diversification/portfolio effect is assessed as 1, significant diversification; 2, moderate diversification; or 3, neutral. An assessment of moderate diversification or significant diversification potentially raises the issuer's anchor. To achieve an assessment of significant diversification, an issuer should have uncorrelated diversified businesses whose breadth is among the most comprehensive of all conglomerates'. This assessment indicates that we expect the conglomerate's earnings volatility to be much lower through an economic cycle than an undiversified company's. To achieve an assessment of moderate diversification, an issuer typically has a range of uncorrelated diversified businesses that provide meaningful benefits of diversification with the expectation of lower earnings volatility through an economic cycle than an undiversified company's.

132. We expect that a conglomerate will also benefit from diversification if its core assets consistently produce positive cash flows over our rating horizon. This supports our assertion that the company diversifies to take advantage of allocating capital among its business lines. To this end, our analysis focuses on a conglomerate's track record of successfully deploying positive discretionary cash flow into new business lines or expanding capital-hungry business lines. We assess companies that we do not expect to achieve these benefits as neutral.

2. Components of correlation and how it is incorporated into our analysis

133. We determine the assessment for this factor based on the number of business lines in separate industries (as described in table 27) and the degree of correlation between these business lines as described in table 20. There is no rating uplift for an issuer with a small number of business lines that are highly correlated. By contrast, a larger number of business lines that are not closely correlated provide the maximum rating uplift.

Table 20

Assessing Diversification/Portfolio Effect

	--Number of business lines--		
Degree of correlation of business lines	**3**	**4**	**5 or more**
High	Neutral	Neutral	Neutral
Medium	Neutral	Moderately diversified	Moderately diversified
Low	Moderately diversified	Significantly diversified	Significantly diversified

134. The degree of correlation of business lines is high if the business lines operate within the same industry, as defined by the industry designations in Appendix B, table 27. The degree of correlation of business lines is medium if the business lines operate within different industries, but operate within the same geographic region (for further guidance on defining geographic regions, see Appendix A, table 26). An issuer has a low degree of correlation across its business lines if these business lines are both a) in different industries and b) either operate in different regions or operate in multiple regions.

135. If we believe that a conglomerate's various industry exposures fail to provide a partial hedge against the consolidated entity's volatility because they are highly correlated through an economic cycle, then we assess the diversification/portfolio effect as neutral.

G. Capital Structure

136. Standard & Poor's uses its capital structure criteria to assess risks in a company's capital structure that may not show up in our standard analysis of cash flow/leverage. These risks may exist as a result of maturity date or currency mismatches between a company's sources of financing and its assets or cash flows. These can be compounded by outside risks, such as volatile interest rates or currency exchange rates.

1. Assessing capital structure

137. Capital structure is a modifier category, which adjusts the initial anchor for a company after any modification due to diversification/portfolio effect. We assess a number of subfactors to determine the capital structure assessment, which can then raise or lower the initial anchor by one or more notches--or have no effect in some cases. We assess capital structure as 1, very positive; 2, positive; 3, neutral; 4, negative; or 5, very negative. In the large majority of cases, we believe that a firm's capital structure will be assessed as neutral. To assess a company's capital structure, we analyze four subfactors:

- Currency risk associated with debt,
- Debt maturity profile (or schedule),
- Interest rate risk associated with debt, and
- Investments.

138. Any of these subfactors can influence a firm's capital structure assessment, although some carry greater weight than others, based on a tiered approach:

- Tier one risk subfactors: Currency risk of debt and debt maturity profile, and
- Tier two risk subfactor: Interest rate risk of debt.

139. The initial capital structure assessment is based on the first three subfactors (see table 21). We may then adjust the preliminary assessment based on our assessment of the fourth subfactor, investments.

Table 21

Preliminary Capital Structure Assessment

Preliminary capital structure assessment	Subfactor assessments
Neutral	No tier one subfactor is negative.
Negative	One tier one subfactor is negative, and the tier two subfactor is neutral.
Very negative	Both tier one subfactors are negative, or one tier one subfactor is negative and the tier two subfactor is negative.

140. Tier one subfactors carry the greatest risks, in our view, and, thus, could have a significant impact on the capital structure assessment. This is because, in our opinion, these factors have a greater likelihood of affecting credit metrics and potentially causing liquidity and refinancing risk. The tier two subfactor is important in and of itself, but typically less so than the tier one subfactors. In our view, in the majority of cases, the tier two subfactor in isolation has a lower likelihood of leading to liquidity and default risk than do tier one subfactors.

141. The fourth subfactor, investments, as defined in paragraph 153, quantifies the impact of a company's investments on

its overall financial risk profile. Although not directly related to a firm's capital structure decisions, certain investments could provide a degree of asset protection and potential financial flexibility if they are monetized. Thus, the fourth subfactor could modify the preliminary capital structure assessment (see table 22). If the subfactor is assessed as neutral, then the preliminary capital structure assessment will stand. If investments is assessed as positive or very positive, we adjust the preliminary capital structure assessment upward (as per table 22) to arrive at the final assessment.

Table 22

Final Capital Structure Assessment

	--Investments subfactor assessment--		
Preliminary capital structure assessment	**Neutral**	**Positive**	**Very positive**
Neutral	Neutral	Positive	Very positive
Negative	Negative	Neutral	Positive
Very negative	Very negative	Negative	Negative

2. Capital structure analysis: Assessing the subfactors

a) Subfactor 1: Currency risk of debt

142. Currency risk arises when a company borrows without hedging in a currency other than the currency in which it generates revenues. Such an unhedged position makes the company potentially vulnerable to fluctuations in the exchange rate between the two currencies, in the absence of mitigating factors. We determine the materiality of any mismatch by identifying situations where adverse exchange-rate movements could weaken cash flow and/or leverage ratios. We do not include currency mismatches under the following scenarios:

- The country where a company generates its cash flows has its currency pegged to the currency in which the company has borrowed, or vice versa (or the currency of cash flows has a strong track record and government policy of stability with the currency of borrowings), examples being the Hong Kong dollar which is pegged to the U.S. dollar, and the Chinese renminbi which is managed in a narrow band to the U.S. dollar (and China's foreign currency reserves are mainly in U.S. dollars). Moreover, we expect such a scenario to continue for the foreseeable future;
- A company has the proven ability, through regulation or contract, to pass through changes in debt servicing costs to its customers; or
- A company has a natural hedge, such as where it may sell its product in a foreign currency and has matched its debt in that same currency.

143. We also recognize that even if an entity generates insufficient same-currency cash flow to meet foreign currency-denominated debt obligations, it could have substantial other currency cash flows it can convert to meet these obligations. Therefore, the relative amount of foreign denominated debt as a proportion of total debt is an important factor in our analysis. If foreign denominated debt, excluding fully hedged debt principal, is 15% or less of total debt, we assess the company as neutral on currency risk of debt. If foreign-denominated debt, excluding fully hedged debt principal, is greater than 15% of total debt, and debt to EBITDA is greater than 3.0x, we evaluate currency risks through further analysis.

144. If an entity's foreign-denominated debt in a particular currency represents more than 15% of total debt, and if its debt to EBITDA ratio is greater than 3.0x, we identify whether a currency-specific interest coverage ratio indicates potential

currency risk. The coverage ratio divides forecasted operating cash flow in each currency by interest payments over the coming 12 months for that same currency. It is often easier to ascertain the geographic breakdown of EBITDA as opposed to operating cash flow. So in situations where we don't have sufficient cash flow information, we may calculate an EBITDA to interest expense coverage ratio in the relevant currencies. If neither cash flow nor EBITDA information is disclosed, we estimate the relevant exposures based on available information.

145. In such an instance, our assessment of this subfactor is negative if we believe any appropriate interest coverage ratio will fall below 1.2x over the next 12 months.

b) Subfactor 2: Debt maturity profile

146. A firm's debt maturity profile shows when its debt needs to be repaid, or refinanced if possible, and helps determine the firm's refinancing risk. Lengthier and more evenly spread out debt maturity schedules reduce refinancing risk, compared with front-ended and compressed ones, since the former give an entity more time to manage business- or financial market-related setbacks.

147. In evaluating debt maturity profiles, we measure the weighted average maturity (WAM) of bank debt and debt securities (including hybrid debt) within a capital structure, and make simplifying assumptions that debt maturing beyond year five matures in year six. WAM = (Maturity1/Total Debt)*tenor1 + (Maturity2/Total Debt)* tenor2 +... (Thereafter/Total Debt)* tenor6

148. In evaluating refinancing risk, we consider risks in addition to those captured under the 12-month to 24-month time-horizons factored in our liquidity criteria (see "Methodology And Assumptions: Liquidity Descriptors For Global Corporate Issuers," published Nov. 19, 2013). While we recognize that investment-grade companies may have more certain future business prospects and greater access to capital than speculative-grade companies, all else being equal, we view a company with a shorter maturity schedule as having greater refinancing risk compared to a company with a longer one. In all cases, we assess a company's debt maturity profile in conjunction with its liquidity and potential funding availability. Thus, a short-dated maturity schedule alone is not a negative if we believe the company can maintain enough liquidity to pay off debt that comes due in the near term.

149. Our assessment of this subfactor is negative if the WAM is two years or less, and the amount of these near-term maturities is material in relation to the issuer's liquidity so that under our base-case forecast, we believe the company's liquidity assessment will become less than adequate or weak over the next two years due to these maturities. In certain cases, we may assess a debt maturity profile as negative regardless of whether or not the company passes the aforementioned test. We expect such instances to be rare, and will include scenarios where we believed a concentration of debt maturities within a five-year time horizon poses meaningful refinancing risk, either due to the size of the maturities in relation to the company's liquidity sources, the company's leverage profile, its operating trends, lender relationships, and/or credit market standings.

c) Subfactor 3: Interest rate risk of debt

150. The interest rate risk of debt subfactor analyzes the company's mix of fixed-rate and floating-rate debt. Generally, a higher proportion of fixed-rate debt leads to greater predictability and stability of interest expense and therefore cash flows. The exception would be companies whose operating cash flows are to some degree correlated with interest rate movements--for example, a regulated utility whose revenues are indexed to inflation--given the typical correlation

between nominal interest rates and inflation.

151. The mix of fixed versus floating-rate debt is usually not a significant risk factor for companies with intermediate or better financial profiles, strong profitability, and high interest coverage. In addition, the interest rate environment at a given point in time will play a role in determining the impact of interest rate movements. Our assessment of this subcategory will be negative if a 25% upward shift (e.g., from 2.0% to 2.5%) or a 100 basis-point upward shift (e.g., 2% to 3%) in the base interest rate of the floating rate debt will result in a breach of interest coverage covenants or interest coverage rating thresholds identified in the cash flow/leverage criteria (see section E.3).

152. Many loan agreements for speculative-grade companies contain a clause requiring a percentage of floating-rate debt to be hedged for a period of two to three years to mitigate this risk. However, in many cases the loan matures after the hedge expires, creating a mismatched hedge. We consider only loans with hedges that match the life of the loan to be--effectively--fixed-rate debt.

d) Subfactor 4: Investments

153. For the purposes of the criteria, investments refer to investments in unconsolidated equity affiliates, other assets where the realizable value isn't currently reflected in the cash flows generated from those assets (e.g. underutilized real-estate property), we do not expect any additional investment or support to be provided to the affiliate, and the investment is not included within Standard & Poor's consolidation scope and so is not incorporated in the company's business and financial risk profile analysis. If equity affiliate companies are consolidated, then the financial benefits and costs of these investments will be captured in our cash flow and leverage analysis. Similarly, where the company's ownership stake does not qualify for consolidation under accounting rules, we may choose to consolidate on a pro rata basis if we believe that the equity affiliates' operating and financing strategy is influenced by the rated entity. If equity investments are strategic and provide the company with a competitive advantage, or benefit a company's scale, scope, and diversity, these factors will be captured in our competitive position criteria and will not be used to assess the subfactor investments as positive. Within the capital structure criteria, we aim to assess nonstrategic financial investments that could provide a degree of asset protection and financial flexibility in the event they are monetized. These investments must be noncore and separable, meaning that a potential divestiture, in our view, has no impact on the company's existing operations.

154. In many instances, the cash flows generated by an equity affiliate, or the proportional share of the associate company's net income, might not accurately reflect the asset's value. This could occur if the equity affiliate is in high growth mode and is currently generating minimal cash flow or net losses. This could also be true of a physical asset, such as real estate. From a valuation standpoint, we recognize the subjective nature of this analysis and the potential for information gaps. As a result, in the absence of a market valuation or a market valuation of comparable companies in the case of minority interests in private entities, we will not ascribe value to these assets.

155. We assess this subfactor as positive or very positive if three key characteristics are met. First, an estimated value can be ascribed to these investments based on the presence of an existing market value for the firm or comparable firms in the same industry. Second, there is strong evidence that the investment can be monetized over an intermediate timeframe--in the case of an equity investment, our opinion of the marketability of the investment would be enhanced by the presence of an existing market value for the firm or comparable firms, as well as our view of market liquidity.

Third, monetization of the investment, assuming proceeds would be used to repay debt, would be material enough to positively move existing cash flow and leverage ratios by at least one category and our view on the company's financial policy, specifically related to financial discipline, supports the assessment that the potential proceeds would be used to pay down debt. This subfactor is assessed as positive if debt repayment from the investment sale has the potential to improve cash flow and leverage ratios by one category. We assess investments as very positive if proceeds upon sale of the investment have the potential to improve cash flow and leverage ratios by two or more categories. If the three characteristics are not met, this subfactor will be assessed as neutral and the preliminary capital structure assessment will stand.

156. We will not assess the investments subfactor as positive or very positive when the anchor is 'b+' or lower unless the three conditions described in paragraph 155 are met, and:

- For issuers with less than adequate or weak liquidity, the company has provided a credible near-term plan to sell the investment.
- For issuers with adequate or better liquidity, we believe that the company, if needed, could sell the investment in a relatively short timeframe.

H. Financial Policy

157. Financial policy refines the view of a company's risks beyond the conclusions arising from the standard assumptions in the cash flow/leverage assessment (see section E). Those assumptions do not always reflect or entirely capture the short-to-medium term event risks or the longer-term risks stemming from a company's financial policy. To the extent movements in one of these factors cannot be confidently predicted within our forward-looking evaluation, we capture that risk within our evaluation of financial policy. The cash flow/leverage assessment will typically factor in operating and cash flows metrics we observed during the past two years and the trends we expect to see for the coming two years based on operating assumptions and predictable financial policy elements, such as ordinary dividend payments or recurring acquisition spending. However, over that period and, generally, over a longer time horizon, the firm's financial policies can change its financial risk profile based on management's or, if applicable, the company's controlling shareholder's (see Appendix E, paragraphs 254-257) appetite for incremental risk or, conversely, plans to reduce leverage. We assess financial policy as 1) positive, 2) neutral, 3) negative, or as being owned by a financial sponsor. We further identify financial sponsor-owned companies as "FS-4", "FS-5", "FS-6", or "FS-6 (minus)" (see section H.2).

1. Assessing financial policy

158. First, we determine if a company is owned by a financial sponsor. Given the intrinsic characteristics and aggressive nature of financial sponsor's strategies (i.e. short- to intermediate-term holding periods and the use of debt or debt-like instruments to maximize shareholder returns), we assign a financial risk profile assessment to a firm controlled by a financial sponsor that reflects the likely impact on leverage due to these strategies and we do not separately analyze management's financial discipline or financial policy framework.

159. If a company is not controlled by a financial sponsor, we evaluate management's financial discipline and financial policy framework. Management's financial discipline measures its tolerance for incremental financial risk or,

conversely, its willingness to maintain the same degree of financial risk or to lower it compared with recent cash flow/leverage metrics and our projected ratios for the next two years. The company's financial policy framework assesses the comprehensiveness, transparency, and sustainability of the entity's financial policies. We do not assess these factors for financial sponsor controlled firms.

160. The financial discipline assessments can have a positive or negative influence on an enterprise's overall financial policy assessment, or can have no net effect. Conversely, the financial policy framework assessment cannot positively influence the overall financial policy assessment. It can constrain the overall financial policy assessment to no greater than neutral.

161. The separate assessments of a company's financial policy framework and financial discipline determine the financial policy adjustment.

162. We assess management's financial discipline as 1, positive; 2, neutral; or 3, negative. We determine the assessment by evaluating the predictability of an entity's expansion plans and shareholder return strategies. We take into account, generally, management's tolerance for material and unexpected negative changes in credit ratios or, instead, its plans to rapidly decrease leverage and keep credit ratios within stated boundaries.

163. A company's financial policy framework assessment is: 1, supportive or 2, non-supportive. We make the determination by assessing the comprehensiveness of a company's financial policy framework and whether financial targets are clearly communicated to a large number of stakeholders, and are well defined, achievable, and sustainable.

Table 23

Financial Policy Assessments

Assessment	What it means	Guidance
Positive	Indicates that we expect management's financial policy decisions to have a positive impact on credit ratios over the time horizon, beyond what can be reasonably built in our forecasts on the basis of normalized operating and cash flow assumptions. An example would be when a credible management team commits to dispose of assets or raise equity over the short to medium term in order to reduce leverage. A company with a 1 financial risk profile will not be assigned a positive assessment.	If financial discipline is positive, and the financial policy framework is supportive
Neutral	Indicates that, in our opinion, future credit ratios won't differ materially over the time horizon beyond what we have projected, based on our assessment of management's financial policy, recent track record, and operating forecasts for the company. A neutral financial policy assessment effectively reflects a low probability of "event risk," in our view.	If financial discipline is positive, and the financial policy framework is non-supportive. Or when financial discipline is neutral, regardless of the financial policy framework assessment.
Negative	Indicates our view of a lower degree of predictability in credit ratios, beyond what can be reasonably built in our forecasts, as a result of management's financial discipline (or lack of it). It points to high event risk that management's financial policy decisions may depress credit metrics over the time horizon, compared with what we have already built in our forecasts based on normalized operating and cash flow assumptions.	If financial discipline is negative, regardless of the financial policy framework assessment
Financial Sponsor*	We define a financial sponsor as an entity that follows an aggressive financial strategy in using debt and debt-like instruments to maximize shareholder returns. Typically, these sponsors dispose of assets within a short to intermediate time frame. Accordingly, the financial risk profile we assign to companies that are controlled by financial sponsors ordinarily reflects our presumption of some deterioration in credit quality in the medium term. Financial sponsors include private equity firms, but not infrastructure and asset-management funds, which maintain longer investment horizons.	We define financial sponsor-owned companies as companies that are owned 40% or more by a financial sponsor or a group of three or less financial sponsors and where we consider that the sponsor(s) exercise control of the company solely or together.

*Assessed as FS-4, FS-5, FS-6, or FS-6 (minus).

2. Financial sponsor-controlled companies

164. We define a financial sponsor as an entity that follows an aggressive financial strategy in using debt and debt-like instruments to maximize shareholder returns. Typically, these sponsors dispose of assets within a short-to-intermediate time frame. Financial sponsors include private equity firms, but not infrastructure and asset-management funds, which maintain longer investment horizons.

165. We define financial sponsor-owned companies as companies that are owned 40% or more by a financial sponsor or a group of three or less financial sponsors and where we consider that the sponsor(s) exercise control of the company solely or together.

166. We differentiate between financial sponsors and other types of controlling shareholders and companies that do not have controlling shareholders based on our belief that short-term ownership--such as exists in private equity sponsor-owned companies--generally entails financial policies aimed at achieving rapid returns for shareholders typically through aggressive debt leverage.

167. Financial sponsors often dictate policies regarding risk-taking, financial management, and corporate governance for the companies that they control. There is a common pattern of these investors extracting cash in ways that increase the companies' financial risk by utilizing debt or debt like instruments. Accordingly, the financial risk profile we assign to companies that are controlled by financial sponsors ordinarily reflect our presumption of some deterioration in credit quality or steadily high leverage in the medium term.

168. We assess the influence of financial sponsor ownership as "FS-4", "FS-5", "FS-6", and "FS-6 (minus)" depending on how aggressive we assume the sponsor will be and assign a financial risk profile accordingly (see table 24).

169. Generally, financial sponsor-owned issuers will receive an assessment of "FS-6" or "FS-6 (minus)", leading to a financial risk profile assessment of '6', under the criteria. A "FS-6" assessment indicates that, in our opinion, forecasted credit ratios in the medium term are likely be to be consistent with a '6' financial risk profile, based on our assessment of the financial sponsor's financial policy and track record. A "FS-6 (minus)" will likely be applied to companies that we forecast to have near-term credit ratios consistent with a '6' financial risk profile, but we believe the financial sponsor to be very aggressive and that leverage could increase materially even further from our forecasted levels.

170. In a small minority of cases, a financial sponsor-owned entity could receive an assessment of "FS-5". This assessment will apply only when we project that the company's leverage will be consistent with a '5' (aggressive) financial risk profile (see tables 17, 18, and 19), we perceive that the risk of releveraging is low based on the company's financial policy and our view of the owner's financial risk appetite, and liquidity is at least adequate.

171. In even rarer cases, we could assess the financial policy of a financial sponsor-owned entity as "FS-4". This assessment will apply only when all of the following conditions are met: other shareholders own a material (generally, at least 20%) stake, we expect the sponsor to relinquish control over the intermediate term, we project that leverage is currently consistent with a '4' (significant) financial risk profile (see tables 17, 18, and 19), the company has said it will maintain leverage at or below this level, and liquidity is at least adequate.

Table 24

Financial Risk Profile Implications For Sponsor-Owned Issuers

Assessment	What It Means	Guidance
FS-4	Financial risk profile set at '4'	Issuer must meet all of the following conditions: • Other shareholders must own a material (no less than 20%) stake; • We anticipate that the sponsor will relinquish control over the medium term; • For issuers subject to Table 17 (standard volatility), debt to EBITDA is less than 4x, and we estimate that it will remain less than 4x. For issuers that are subject to Table 18 (medial volatility), debt to EBITDA is below 4.5x and we forecast it to remain below that level. Or for issuers subject to Table 19 (low volatility), debt to EBITDA is less than 5x and our estimation is it will remain below that level; • The company has indicated a financial policy stipulating a level of leverage consistent with a significant or better financial risk profile (that is, debt to EBITDA of less than 4x when applying standard volatility tables, 4.5x when applying medial volatility tables, or less than 5x when applying low volatility tables) and • We assess liquidity to be at least adequate, with adequate covenant headroom.
FS-5	Financial risk profile set at '5'	Issuer must meet all of the following conditions: • For issuers subject to the standard volatility table, debt to EBITDA is less than 5x, and we estimate that it will remain less than 5x. For issuers that are subject to the medial volatility table, debt to EBITDA is below 5.5x and we forecast it to remain below that level. Or for issuers subject to the low volatility table, debt to EBITDA is less than 6x and our estimation is it will remain below that level; • We believe the risk of releveraging beyond 5x (standard volatility issuer), 5.5x (medial volatility issuer), or 6x (low volatility issuer) is low; and • We assess liquidity to be at least adequate, with adequate covenant headroom.
FS-6	Financial risk profile set at '6'	Standard & Poor's debt to EBITDA is greater than 5x (when applying the standard volatility table), greater than 5.5x (when applying the medial volatility table), or greater than 6x (when applying the low volatility table). However, we believe leverage is unlikely to increase meaningfully beyond these levels.
FS-6 (minus)	Financial risk profile set at '6', and rating reduced by one notch (unless this results in a final rating below 'B-')	In determining the anchor rating the financial risk profile is a '6', but we believe the track record of the financial sponsor indicates that leverage could increase materially from already high levels.

3. Companies not controlled by a financial sponsor

172. For companies not controlled by a financial sponsor we evaluate management's financial discipline and financial policy framework to determine the influence on an entity's financial risk profile beyond what is implied by recent credit ratios and our cash flow and leverage forecasts. This influence can be positive, neutral, or negative.

173. We do not distinguish between management and a controlling shareholder that is not a financial sponsor when assessing these subfactors, as the controlling shareholder usually has the final say on financial policy.

a) Financial discipline

174. The financial discipline assessment is based on management's leverage tolerance and the likelihood of event risk. The criteria evaluate management's potential appetite to incur unforeseen, higher financial risk over a prolonged period and the associated impact on credit measures. We also assess management's capacity and commitment to rapidly decrease debt leverage to levels consistent with its credit ratio targets.

175. This assessment therefore seeks to determine whether unforeseen actions by management to increase, maintain, or reduce financial risk are likely to occur during the next two to three years, with either a negative or positive effect, or none at all, on our baseline forecasts for the period.

176. This assessment is based on the leverage tolerance of a company's management, as reflected in its plans or history of acquisitions, shareholder remuneration, and organic growth strategies (see Appendix E, paragraphs 258 to 263).

177. We assess financial discipline as positive, neutral, or negative, based on its potential impact on our forward-looking assessment of a firm's cash flow/leverage, as detailed in table 25. For example, a neutral assessment for leverage tolerance reflects our expectation that management's financial policy will unlikely lead to significant deviation from current and forecasted credit ratios. A negative assessment acknowledges a significant degree of event risk of increased leverage relative to our base-case forecast, resulting from the company's acquisition policy, its shareholder remuneration policy, or its organic growth strategy. A positive assessment indicates that the company is likely to take actions to reduce leverage, but we cannot confidently incorporate these actions into our baseline forward-looking assessment of cash flow/leverage.

178. A positive assessment indicates that management is committed and has the capacity to reduce debt leverage through the rapid implementation of credit enhancing measures, such as asset disposals, rights issues, or reductions in shareholder returns. In addition, management's track record over the past five years shows that it has taken actions to rapidly reduce unforeseen increases in debt leverage and that there have not been any prolonged periods when credit ratios were weaker than our expectations for the rating. Management, even if new, also has a track record of successful execution. Conversely, a negative assessment indicates management's financial policy allows for significant increase in leverage compared with both current levels and our forward-looking forecast under normal operating/financial conditions or does not have observable time limits or stated boundaries. Management has a track record of allowing for significant and prolonged peaks in leverage and there is no commitment or track record of management using mitigating measures to rapidly return to credit ratios consistent with our expectations.

179. As evidence of management's leverage tolerance, we evaluate its track record and plans regarding acquisitions, shareholder remuneration, and organic growth strategies (see Appendix E, paragraphs 258 to 263). Acquisitions could increase the risk that leverage will be higher than our base-case forecast if we view management's strategy as opportunistic or if its financial policy (if it exists) provides significant headroom for debt-financed acquisitions. Shareholder remuneration could also increase the risk of leverage being higher than our base-case forecast if management's shareholder reward policies are not particularly well defined or have no clear limits, management has a tolerance for shareholder returns exceeding operating cash flow, or has a track record of sustained cash returns despite weakening operating performance or credit ratios. Organic growth strategies can also result in leverage higher than our base-case forecast if these plans have no clear focus or investment philosophy, capital spending is fairly unpredictable,

or there is a track record of overspending or unexpected or rapid shifts in plans for new markets or products.

180. We also take into account management's track record and level of commitment to its stated financial policies, to the extent a company has a stated policy. Historical evidence and any deviations from stated policies are key elements in analyzing a company's leverage tolerance. Where material and unexpected deviation in leverage may occur (for example, on the back of operating weakness or acquisitions), we also assess management's plan to restore credit ratios to levels consistent with previous expectations through rapid and proactive non-organic measures. Management's track record to execute its deleveraging plan, its level of commitment, and the scope and timeframe of debt mitigating measures will be key differentiators in assessing a company's financial policy discipline.

Table 25

Assessing Financial Discipline

Descriptor	What it means	Guidance
Positive	Management is likely to take actions that result in leverage that is lower than our base-case forecast, but can't be confidently included in our base-case assumptions. Event risk is low.	Management is committed and has capacity to reduce debt leverage and increase financial headroom through the rapid implementation of credit enhancing measures, in line with its stated financial policy, if any. This relates primarily to management's careful and moderate policy with regard to acquisitions and shareholder remuneration as well as to its organic growth strategy. The assessments are supported by historical evidence over the past five years of not showing any prolonged weakening in the company's credit ratios, or relative to our base-case credit metrics' assumptions. Management, even if new, has a track record of successful execution.
Neutral	Leverage is not expected to deviate materially from our base-case forecast. Event risk is moderate.	Management's financial discipline with regard to acquisitions, shareholder remuneration, as well as its organic growth strategy does not result in significantly different leverage as defined in its stated financial policy framework.
Negative	Leverage could become materially higher than our base-case forecast. Event risk is high.	Management's financial policy framework does not explicitly rule out a significant increase in leverage compared to our base-case assumptions, possibly reflecting a greater event risk with regard to its M&A and shareholder remuneration policy as well as to its organic growth strategy. These points are supported by historical evidence over the past five years of allowing for significant and prolonged peaks in leverage, which remained unmitigated by credit supporting measures by management.

b) Financial policy framework

181. The company's financial policy framework assesses the comprehensiveness, transparency, and sustainability of the entity's financial policies (see Appendix E, paragraphs 264-268). This will help determine whether there is a satisfactory degree of visibility into the issuer's future financial risk profile. Companies that have developed and sustained a comprehensive set of financial policies are more likely to build long-term, sustainable credit quality than those that do not.

182. We will assess a company's financial policy framework as supportive or non-supportive based on evidence that supports the characteristics listed below. In order for an entity to receive a supportive assessment for financial policy framework, there must be sufficient evidence of management's financial policies to back that assessment.

183. A company assessed as supportive will generally exhibit the following characteristics:

- Management has a comprehensive set of financial policies covering key areas of financial risk, including debt leverage and liability management. Financial targets are well defined and quantifiable.
- Management's financial policies are clearly articulated in public forums (such as public listing disclosures and investor presentations) or are disclosed to a limited number of key stakeholders such as main creditors or to the credit rating agencies. The company's adherence to these policies is satisfactory.

- Management's articulated financial policies are considered achievable and sustainable. This assessment takes into consideration historical adherence to articulated policies, existing financial risk profile, capacity to sustain capital structure through nonorganic means, demands of key stakeholders, and the stability of financial policy parameters over time.

184. A company receives a non-supportive assessment if it does not meet all the conditions for a supportive assessment. We expect a non-supportive assessment to be uncommon.

I. Liquidity

185. Our assessment of liquidity focuses on monetary flows--the sources and uses of cash--that are the key indicators of a company's liquidity cushion. The analysis assesses the potential for a company to breach covenant tests related to declines in EBITDA, as well as its ability to absorb high-impact, low-probability events, the nature of the company's bank relationships, its standing in credit markets, and how prudent (or not) we believe its financial risk management to be (see "Methodology And Assumptions: Liquidity Descriptors For Global Corporate Issuers," published Nov. 19, 2013).

J. Management And Governance

186. The analysis of management and governance addresses how management's strategic competence, organizational effectiveness, risk management, and governance practices shape the issuer's competitiveness in the marketplace, the strength of its financial risk management, and the robustness of its governance. Stronger management of important strategic and financial risks may enhance creditworthiness (see "Methodology: Management And Governance Credit Factors For Corporate Entities And Insurers," published Nov. 13, 2012).

K. Comparable Ratings Analysis

187. The comparable ratings analysis is our last step in determining a SACP on a company. This analysis can lead us to raise or lower our anchor, after adjusting for the modifiers, on a company by one notch based on our overall assessment of its credit characteristics for all subfactors considered in arriving at the SACP. This involves taking a holistic review of a company's stand-alone credit risk profile, in which we evaluate an issuer's credit characteristics in aggregate. A positive assessment leads to a one-notch upgrade, a negative assessment leads to a one-notch downgrade, and a neutral assessment indicates no change to the anchor.

188. The application of comparable ratings analysis reflects the need to "fine-tune" ratings outcomes, even after the use of each of the other modifiers. A positive or negative assessment is therefore likely to be common rather than exceptional.

189. We consider our assessments of each of the underlying subfactors to be points within a possible range. Consequently, each of these assessments that ultimately generate the SACP can be at the upper or lower end, or at the mid-point, of such a range:

- A company receives a positive assessment if we believe, in aggregate, its relative ranking across the subfactors typically to be at the higher end of the range;
- A company receives a negative assessment if we believe, in aggregate, its relative ranking across the subfactors typically to be at the lower end of the range;
- A company receives a neutral assessment if we believe, in aggregate, its relative ranking across the subfactors typically to be in line with the middle of the range.

190. The most direct application of the comparable ratings analysis is in the following circumstances:

- Business risk assessment. If we expect a company to sustain a position at the higher or lower end of the ranges for the business risk category assessment, the company could receive a positive or negative assessment, respectively.
- Financial risk assessment and financial metrics. If a company's actual and forecasted metrics are just above (or just below) the financial risk profile range, as indicated in its cash flow/leverage assessment, we could assign a positive or negative assessment.

191. We also consider additional factors not already covered, or existing factors not fully captured, in arriving at the SACP. Such factors will generally reflect less frequently observed credit characteristics, may be unique, or may reflect unpredictability or uncertain risk attributes, both positive and negative.

192. Some examples that we typically expect could lead to a positive or negative assessment using comparable ratings analysis include:

- Short operating track record. For newly formed companies or companies that have experienced transformational events, such as a significant acquisition, a lack of an established track record of operating and financial performance could lead to a negative assessment until such a track record is established.
- Entities in transition. A company in the midst of changes that we anticipate will strengthen or weaken its creditworthiness and that are not already fully captured elsewhere in the criteria could receive a positive or negative assessment. Such a transition could occur following major divestitures or acquisitions, or during a significant overhaul of its strategy, business, or financial structure.
- Industry or macroeconomic trends. When industry or macroeconomic trends indicate a strengthening or weakening of the company's financial condition that is not already fully captured elsewhere in the criteria, the company could receive a positive or negative assessment, respectively.
- Unusual funding structures. A company with exceptional financial resources that the criteria do not capture in the traditional ratio or liquidity analysis, or in capital structure analysis, could receive a positive assessment.
- Contingent risk exposures. How well (or not) a company identifies, manages, and reserves for contingent risk exposures that can arise if guarantees are called, derivative contract break clauses are activated, or substantial lawsuits are lost could lead to a negative assessment.

SUPERSEDED CRITERIA FOR ISSUERS WITHIN THE SCOPE OF THESE CRITERIA

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- 2008 Corporate Criteria: Analytical Methodology, April 15, 2008
- Credit FAQ: Knowing The Investors In A Company's Debt And Equity, April 4, 2006

RELATED CRITERIA

- Methodology: Industry Risk, Nov. 19, 2013
- Corporate Criteria: Ratios And Adjustments, Nov. 19, 2013
- Country Risk Assessment Methodology And Assumptions, Nov. 19, 2013
- Ratings Above The Sovereign--Corporate And Government Ratings: Methodology And Assumptions, Nov. 19, 2013
- Methodology And Assumptions: Liquidity Descriptors For Global Corporate Issuers, Nov. 19, 2013
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- Criteria Guidelines For Recovery Ratings On Global Industrial Issuers' Speculative-Grade Debt, Aug. 10, 2009
- 2008 Corporate Criteria: Rating Each Issue, April 15, 2008

APPENDIXES

A. Country Risk

Table 26

Country And Regional Risk		
Region		
Western Europe		
Southern Europe		
Western + Southern Europe		
East Europe		
Central Europe		
Eastern Europe and Central Asia		
Middle East		
Africa		
North America		
Central America		
Latin America		
The Caribbean		
Asia-Pacific		
Central Asia		
East Asia		
Australia NZ		
Country	**Region**	**GDP weighting (%)**
South Africa	Africa	30.2
Egypt	Africa	28.0
Nigeria	Africa	23.5
Morocco	Africa	8.9

Table 26

Country And Regional Risk (cont.)		
Tunisia	Africa	5.4
Senegal	Africa	1.4
Mozambique	Africa	1.4
Zambia	Africa	1.2
Indonesia	Asia-Pacific	27.1
Taiwan	Asia-Pacific	20.1
Thailand	Asia-Pacific	14.4
Malaysia	Asia-Pacific	11.0
Philippines	Asia-Pacific	9.5
Vietnam	Asia-Pacific	7.1
Bangladesh	Asia-Pacific	6.8
Sri Lanka	Asia-Pacific	2.8
Laos	Asia-Pacific	0.4
Papua New Guinea	Asia-Pacific	0.4
Mongolia	Asia-Pacific	0.3
Australia	Australia NZ	88.2
New Zealand	Australia NZ	11.8
Guatemala	Central America	40.5
Costa Rica	Central America	30.2
Panama	Central America	29.3
India	Central Asia	86.5
Pakistan	Central Asia	9.3
Kazakhstan	Central Asia	4.2
Poland	Central Europe	46.3
Czech Republic	Central Europe	16.6
Hungary	Central Europe	11.3
Slovakia	Central Europe	7.7
Bulgaria	Central Europe	6.0
Croatia	Central Europe	4.6
Lithuania	Central Europe	3.8
Latvia	Central Europe	2.1
Estonia	Central Europe	1.6
China	East Asia	64.5
Japan	East Asia	23.6
Korea	East Asia	8.4
Hong Kong	East Asia	1.9
Singapore	East Asia	1.7
Greece	East Europe	77.5
Slovenia	East Europe	16.0
Cyprus	East Europe	6.5
Russia	Eastern Europe and Central Asia	80.4
Ukraine	Eastern Europe and Central Asia	10.8

Table 26

Country And Regional Risk (cont.)		
Belarus	Eastern Europe and Central Asia	4.8
Azerbaijan	Eastern Europe and Central Asia	3.2
Georgia	Eastern Europe and Central Asia	0.9
Brazil	Latin America	35.3
Mexico	Latin America	26.3
Argentina	Latin America	11.1
Colombia	Latin America	7.5
Venezuela	Latin America	6.0
Peru	Latin America	4.9
Chile	Latin America	4.8
Ecuador	Latin America	2.0
Uruguay	Latin America	0.8
El Salvador	Latin America	0.7
Paraguay	Latin America	0.6
Belize	Latin America	0.0
Turkey	Middle East	42.8
Saudi Arabia	Middle East	28.2
Israel	Middle East	9.4
Qatar	Middle East	7.2
Kuwait	Middle East	6.3
Oman	Middle East	3.4
Jordan	Middle East	1.5
Bahrain	Middle East	1.2
United States	North America	91.5
Canada	North America	8.5
Italy	Southern Europe	52.6
Spain	Southern Europe	40.4
Portugal	Southern Europe	7.0
Dominican Republic	The Caribbean	75.4
Jamaica	The Caribbean	19.2
Barbados	The Caribbean	5.4
Germany	Western Europe	28.7
United Kingdom	Western Europe	21.3
France	Western Europe	20.7
Netherlands	Western Europe	6.5
Belgium	Western Europe	3.9
Sweden	Western Europe	3.6
Switzerland	Western Europe	3.3
Austria	Western Europe	3.3
Norway	Western Europe	2.6
Denmark	Western Europe	1.9
Finland	Western Europe	1.8

Table 26

Country And Regional Risk (cont.)		
Ireland	Western Europe	1.8
Luxembourg	Western Europe	0.4
Iceland	Western Europe	0.1
Malta	Western Europe	0.1

B. Competitive Position

Table 27

List Of Industries, Subsectors, And Standard Competitive Position Group Profiles

Industry	Subsector	Competitive position group profile
Transportation cyclical	Airlines	Capital or asset focus
	Marine	Capital or asset focus
	Trucking	Capital or asset focus
Auto OEM	Automobile and truck manufacturers	Capital or asset focus
Metals and mining downstream	Aluminum	Commodity focus/cost driven
	Steel	Commodity focus/cost driven
Metals and mining upstream	Coal and consumable fuels	Commodity focus/cost driven
	Diversified metals and mining	Commodity focus/cost driven
	Gold	Commodity focus/cost driven
	Precious metals and minerals	Commodity focus/cost driven
Homebuilders and developers	Homebuilding	Capital or asset focus
Oil and gas refining and marketing	Oil and gas refining and marketing	Commodity focus/scale driven
Forest and paper products	Forest products	Commodity focus/cost driven
	Paper products	Commodity focus/cost driven
Building Materials	Construction materials	Capital or asset focus
Oil and gas integrated, exploration and production	Integrated oil and gas	Commodity focus/scale driven
	Oil and gas exploration and production	Commodity focus/scale driven
Agribusiness and commodity foods	Agricultural products	Commodity focus/scale driven
Real estate investment trusts (REITs)	Diversified REITs	Real-estate specific*
	Health care REITS	Real-estate specific*
	Industrial REITs	Real-estate specific*
	Office REITs	Real-estate specific*
	Residential REITs	Real-estate specific*
	Retail REITs	Real-estate specific*
	Specialized REITs	Not appplicable**
	Self-storage REITs	Real-estate specific*
	Net lease REITs	Real-estate specific*
	Real estate operating companies	Real-estate specific*
Leisure and sports	Casinos and gaming	Services and product focus
	Hotels, resorts, and cruise lines	Services and product focus

Table 27

List Of Industries, Subsectors, And Standard Competitive Position Group Profiles (cont.)		
	Leisure facilities	Services and product focus
Commodity chemicals	Commodity chemicals	Commodity focus/cost driven
	Diversified chemicals	Commodity focus/cost driven
	Fertilizers and agricultural chemicals	Commodity focus/cost driven
Auto suppliers	Auto parts and equipment	Capital or asset focus
	Tires and rubber	Capital or asset focus
	Vehicle-related suppliers	Capital or asset focus
Aerospace and defense	Aerospace and defense	Services and product focus
Technology hardware and semiconductors	Communications equipment	Capital or asset focus
	Computer hardware	Capital or asset focus
	Computer storage and peripherals	Capital or asset focus
	Consumer electronics	Capital or asset focus
	Electronic equipment and instruments	Capital or asset focus
	Electronic components	Capital or asset focus
	Electronic manufacturing services	Capital or asset focus
	Technology distributors	Capital or asset focus
	Office electronics	Capital or asset focus
	Semiconductor equipment	Capital or asset focus
	Semiconductors	Capital or asset focus
Specialty Chemicals	Industrial gases	Capital or asset focus
	Specialty chemicals	Capital or asset focus
Capital Goods	Electrical components and equipment	Capital or asset focus
	Heavy equipment and machinery	Capital or asset focus
	Industrial componentry and consumables	Capital or asset focus
	Construction equipment rental	Capital or asset focus
	Industrial distributors	Services and product focus
Engineering and construction	Construction and engineering	Services and product focus
Railroads and package express	Railroads	Capital or asset focus
	Package express	Services and product focus
	Logistics	Services and product focus
Business and consumer services	Consumer services	Services and product focus
	Distributors	Services and product focus
	Facilities services	Services and product focus
	General support services	Services and product focus
	Professional services	Services and product focus
Midstream energy	Oil and gas storage and transportation	Commodity focus/scale driven
Technology software and services	Internet software and services	Services and product focus
	IT consulting and other services	Services and product focus
	Data processing and outsourced services	Services and product focus
	Application software	Services and product focus
	Systems software	Services and product focus
	Consumer software	Services and product focus

Table 27

List Of Industries, Subsectors, And Standard Competitive Position Group Profiles (cont.)		
Consumer durables	Home furnishings	Services and product focus
	Household appliances	Services and product focus
	Housewares and specialties	Services and product focus
	Leisure products	Services and product focus
	Photographic products	Services and product focus
	Small appliances	Services and product focus
Containers and packaging	Metal and glass containers	Capital or asset focus
	Paper packaging	Capital or asset focus
Media and entertainment	Ad agencies and marketing services companies	Services and product focus
	Ad-supported internet content platforms	Services and product focus
	Broadcast TV networks	Services and product focus
	Cable TV networks	Services and product focus
	Consumer and trade magazines	Services and product focus
	Data/professional publishing	Services and product focus
	Directories	Services and product focus
	E-Commerce (services)	Services and product focus
	Educational publishing	Services and product focus
	Film and TV programming production	Capital or asset focus
	Miscellaneous media and entertainment	Services and product focus
	Motion picture exhibitors	Services and product focus
	Music publishing	Services and product focus
	Music recording	Services and product focus
	Newspapers	Services and product focus
	Outdoor advertising	Services and product focus
	Printing	Commodity focus/scale driven
	Radio broadcasters	Services and product focus
	Trade shows	Services and product focus
	TV stations	Services and product focus
Oil and gas drilling, equipment and services	Onshore contract drilling	Commodity focus/scale driven
	Offshore contract drilling	Capital or Asset Focus
	Oil and gas equipment and services (oilfield services)	Commodity focus/scale driven
Retail and restaurants	Catalog retail	Services and product focus
	Internet retail	Services and product focus
	Department stores	Services and product focus
	General merchandise stores	Services and product focus
	Apparel retail	Services and product focus
	Computer and electronics retail	Services and product focus
	Home improvement retail	Services and product focus
	Specialty stores	Services and product focus
	Automotive retail	Services and product focus
	Home furnishing retail	Services and product focus

Table 27

List Of Industries, Subsectors, And Standard Competitive Position Group Profiles (cont.)		
Health care services	Health care services	Commodity focus/scale driven
Transportation infrastructure	Airport services	National industries and utilities
	Highways	National industries and utilities
	Railtracks	National industries and utilities
	Marine ports and services	National industries and utilities
Environmental services	Environmental and facilities services	Services and product focus
Regulated utilities	Electric utilities	National industries and utilities
	Gas utilities	National industries and utilities
	Multi-utilities	National industries and utilities
	Water utilities	National industries and utilities
Unregulated power and gas	Independent power producers and energy traders	Capital or asset focus
	Merchant power	Capital or asset focus
Pharmaceuticals	Branded pharmaceuticals	Services and product focus
	Generic pharmaceuticals	Commodity focus/scale driven
Health care equipment	High-tech health care equipment	Product focus/scale driven
	Low-tech health care equipment	Commodity focus/scale driven
Branded nondurables	Brewers	Services and product focus
	Distillers and vintners	Services and product focus
	Soft drinks	Services and product focus
	Packaged foods and meats	Services and product focus
	Tobacco	Services and product focus
	Household products	Services and product focus
	Apparel, footwear, accessories, and luxury goods	Services and product focus
	Personal products	Services and product focus
Telecommunications and cable	Cable and satellite	Services and product focus
	Alternative carriers	Services and product focus
	Integrated telecommunication services	Services and product focus
	Wireless towers	Capital or asset focus
	Data center operators	Capital or asset focus
	Fiber-optic carriers	Capital or asset focus
	Wireless telecommunication services	Services and product focus

*See "Key Credit Factors For The Real Estate Industry," published Nov. 19, 2013. **For specialized REITs, there is no standard CPGP, as the CPGP will vary based on the underlying industry exposure (e.g. a forest and paper products REIT).

1. Analyzing subfactors for competitive advantage

193. Competitive advantage is the first component of our competitive position analysis. Companies that possess a sustainable competitive advantage are able to capitalize on key industry factors or mitigate associated risks more effectively. When a company operates in more than one business, we analyze each segment separately to form an overall view of its competitive advantage. In assessing competitive advantage, we evaluate the following subfactors:

- Strategy;
- Differentiation/uniqueness, product positioning/bundling;

- Brand reputation and marketing;
- Product/service quality;
- Barriers to entry, switching costs;
- Technological advantage and capabilities, technological displacement; and
- Asset profile.

a) Strategy

194. A company's business strategy will enhance or undermine its market entrenchment and business stability. Compelling business strategies can create a durable competitive advantage and thus a relatively stronger competitive position. We form an opinion as to the source and sustainability (if any) of the company's competitive advantage relative to its peers'. The company may have a differentiation advantage (i.e., brand, technology, regulatory) or a cost advantage (i.e., lower cost producer/servicer at the same quality level), or a combination.

195. Our assessment of a company's strategy is informed by a company's historical performance and how realistic we view its forward-looking business objectives to be. These may include targets for market shares, the percentage of revenues derived from new products, price versus the competition's, sales or profit growth, and required investment levels. We evaluate these objectives in the context of industry dynamics and the attractiveness of the markets in which the company participates.

b) Differentiation/uniqueness, product positioning/bundling

196. The attributes of product or service differentiation vary by sector, and may include product or services features, performance, durability, reliability, delivery, and comprehensiveness, among other measures. The intensity of competition may be lower where buyers perceive the product or service to be highly differentiated or to have few substitutes. Conversely, products and services that lack differentiation, or offer little value-added in the eyes of customers, are generally commodity-type products that primarily compete on price. Competition intensity will often be highest where limited or moderate investment (R&D, capital expenditures, or advertising) or low employee skill levels (for service businesses) are required to compete. Independent market surveys, media commentaries, market share trends, and evidence of leading or lagging when it comes to raising or lowering prices can indicate varying degrees of product differentiation.

197. Product positioning influences how companies are able to extend or protect market shares by offering popular products or services. A company's abilities to replace aging products with new ones, or to launch product extensions, are important elements of product positioning. In addition, the ability to sell multiple products or services to the same customer, known as bundling or cross-selling, (for instance, offering an aftermarket servicing contract together with the sale of a new appliance) can create a competitive advantage by increasing customers' switching costs and fostering loyalty.

c) Brand reputation and marketing

198. Brand equity measures the price premium a company receives based on its brand relative to the generic equivalent. High brand equity typically translates into customer loyalty, built partially via marketing campaigns. One measure of advertising effectiveness can be revenue growth compared with the increase in advertising expenses.

199. We also analyze re-investment and advertising strategies to anticipate potential strengthening or weakening of a

company's brand. A company's track record of boosting market share and delivering attractive margins could indicate its ability to build and maintain brand reputation.

d) Product/service level quality

200. The strength and consistency of a value proposition is an important factor contributing to a sustainable competitive advantage. Value proposition encompasses the key features of a product or a service that convince customers that their purchase has the right balance between price and quality. Customers generally perceive a product or a service to be good if their expectations are consistently met. Quality, both actual and perceived, can help a company attract and retain customers. Conversely, poor product and service quality may lead to product recalls, higher-than-normal product warnings, or service interruptions, which may reduce demand. Measures of customer satisfaction and retention, such as attrition rates and contract renewal rates, can help trace trends in product/service quality.

201. Maintaining the value proposition requires consistency and adaptability around product design, marketing, and quality-related operating controls. This is pertinent where product differentiation matters, as is the case in most noncommodity industries, and especially so where environmental or human health (concerns for the chemical, food, and pharmaceutical industries) adds a liability dimension to the quality and value proposition. Similarly, regulated utilities (which often do not set their own prices) typically focus on delivering uninterrupted service, often to meet the standards set by their regulator.

e) Barriers to entry, switching costs

202. Barriers to entry can reduce or eliminate the threat of new market entrants. Where they are effective, these barriers can lead to more predictable revenues and profits, by limiting pricing pressures and customer losses, lowering marketing costs, and improving operating efficiency. While barriers to entry may enable premium pricing, a dominant player may rationally choose pricing restraint to further discourage new entrants.

203. Barriers to entry can be one or more of: a natural or regulatory monopoly; supportive regulation; high transportation costs; an embedded customer base that would incur high switching costs; a proprietary product or service; capital or technological intensiveness.

204. A natural monopoly may result from unusually high requirements for capital and operating expenditures that make it uneconomic for a market to support more than a single, dominant provider. The ultimate barrier to entry is found among regulated utilities, which provide an essential service in their 'de juris' monopolies and receive a guaranteed rate of return on their investments. A supportive regulatory regime can include rules and regulations with high hurdles that discourage competitors, or mandate so many obligations for a new entrant as to make market entry financially unviable.

205. In certain industrial sectors, proprietary access to a limited supply of key raw materials or skilled labor, or zoning laws that effectively preclude a new entrant, can provide a strong barrier to entry. Factors such as relationships, long-term contracts or maintenance agreements, or exclusive distribution agreements can result in a high degree of customer stickiness. A proprietary product or service that's protected by a copyright or patent can pose a significant hurdle to new competitors.

f) Technological advantage and capabilities, technological displacement

206. A company may benefit from a proprietary technology that enables it to offer either a superior product or a commodity-type product at a materially lower cost. Proven research and development (R&D) capabilities can deliver a differentiated, superior product or service, as in the pharmaceutical or high tech sectors. However, optimal R&D strategies or the importance or effectiveness of patent protection differ by industry, stage of product development, and product lifecycle.

207. Technological displacement can be a threat in many industries; new technologies or extensions of current ones can effectively displace a significant portion of a company's products or services.

g) Asset profile

208. A company's asset profile is a reflection of its reinvestment, which creates tangible or intangible assets, or both. Companies in similar sectors and industries usually have similar reinvestment options and, thus, their asset profiles tend to be comparable. The reinvestment in "heavy" industries, such as oil and gas, metals and mining, and automotive, tends to produce more tangible assets, whereas the reinvestment in certain "light" industries, such as services, media and entertainment, and retail, tends to produce more intangible assets.

209. We evaluate how a company's asset profile supports or undermines its competitive advantage by reviewing its manufacturing or service creation capabilities and investment requirements, its distribution capabilities, and its track record and commitment to reinvesting in its asset base. This may include a review of the company's ability to attract and retain a talented workforce; its degree of vertical integration and how that may help or hinder its ability to secure supply sources, control the value-added part of its production chain, or adjust to technological developments; or its ability develop a broad and strong distribution network.

2. Analyzing subfactors for scale, scope, and diversity

210. In assessing the relative strength of this component, we evaluate four subfactors:

- Diversity of product or service range;
- Geographic diversity;
- Volumes, size of markets and revenues, and market shares; and
- Maturity of products or services.

211. In a given industry, entities with a broader mix of business activities are typically lower risk, and entities with a narrower mix are higher risk. High concentration of business volumes by product, customer, or geography, or a concentration in the production footprint or supplier base, can lead to less stable and predictable revenues and profits. Comparatively broader diversity helps a company withstand economic, competitive, or technological threats better than its peers.

212. There is no minimum size criterion, although size often provides a measure of diversification. Size and scope of operations is important relative to those of industry peers, though not in absolute terms. While relatively smaller companies can enjoy a high degree of diversification, they will likely be, almost by definition, more concentrated in terms of product, number of customers, or geography than their larger peers in the same industry.

213. Successful and continuing diversification supports a stronger competitive position. Conversely, poor diversification

weakens overall competitive position. For example, a company will weaken its overall business position if it enters new product lines and countries where it has limited expertise and lacks critical mass to be a real competitor to the incumbent market leaders. The weakness is greater when the new products or markets are riskier than the traditional core business.

214. Where applicable, we also include under scale, scope, and diversity an assessment of the potential benefits derived from unconsolidated (or partially consolidated) investments in strategic assets. The relative significance of such an investment and whether it is in an industry that exhibits high or, conversely, low correlation with the issuer's businesses would be considered in determining its potential benefits to scale, scope, and diversity. This excludes nonstrategic, financial investments, the analysis of which does not fall under the competitive position criteria but, instead, under the capital structure criteria.

a) Diversity of product or service range

215. The concentration of business volumes or revenues in a particular or comparatively small set of products or services can lead to less stable revenues and profits. Even if this concentration is in an attractive product or service, it may be a weakness. Likewise, the concentration of business volumes with a particular customer or a small group of customers, or the reliance on one or a few suppliers, can expose the company to a potentially greater risk of losing and having to replace related revenues and profits. On the other hand, successful diversification across products, customers, and/or suppliers can lead to more stable and predictable revenues and profits, which supports a stronger assessment of scale, scope, and diversity.

216. The relative contribution of different products or services to a company's revenues or profits helps us gauge its diversity. We also evaluate the correlation of demand between product or services lines. High correlation in demand between seemingly different product or service lines will accentuate volume declines during a weak part of the business cycle.

217. In most sectors, the share of revenue a company receives from its largest five to 10 customers or counterparties reveals how diversified its customer base is. However, other considerations such as the stability and credit quality of that customer base, and the company's ability to retain significant customers, can be mitigating or accentuating factors in our overall evaluation. Likewise, supplier dependency can often be measured based on a supplier's share of a company's operating or capital costs. However, other factors, such as the degree of interdependence between the company and its supplier(s), the substitutability of key supply sources, and the company's presumed ability to secure alternative supply without incurring substantial switching costs, are important considerations. Low switching costs (i.e. limited impact on input price, quality, or delivery times as a result of having to adapt to a new supply chain partner) can mitigate a high level of concentration.

b) Geographic diversity

218. We assess geographic diversity both from the standpoint of the breadth of the company's served or addressable markets, and from the standpoint of how geographically concentrated its facilities are.

219. The concentration of business volumes and revenues within a particular region can lead to greater exposure to economic factors affecting demand for a company's goods or services in that region. Even if the company's volumes and revenues are concentrated in an attractive region, it may still be vulnerable to a significant drop in demand for its

goods and services. Conversely, a company that serves multiple regions may benefit from different demand conditions in each, possibly resulting in greater revenue stability and more consistent profitability than a more focused peer's. That said, we consider geographic diversification in the context of the industry and the size of the local or regional economy. For instance, companies operating in local industries (such as food retailers) may benefit from a well-entrenched local position.

220. Generally, though, geographically concentrated production or service operations can expose a company to the risk of disruption, and damage revenues and profitability. Even when country risks don't appear significant, a company's vulnerability to exogenous factors (for example, natural disasters, labor or political unrest) increases with geographic concentration.

c) Volumes, size of markets and revenues, market share

221. Absolute sales or unit volumes and market share do not, by themselves, support a strong assessment of scale, scope, and diversity. Yet superior market share is a positive, since it may indicate a broad range of operations, products, or services.

222. We view volume stability (relative to peers') as a positive especially when: a company has demonstrated it during an economic downturn; if it has been achieved without relying on greater price concessions than competitors have made; and when it is likely to be sustained in the future. However, volume stability combined with shrinking market share could be evidence of a company's diminishing prospects for future profitability. We assess the predictability of business volumes and the likely degree of future volume stability by analyzing the company's performance relative to peers' on several industry factors: cyclicality; ability to adapt to technological and regulatory threats; the profile of the customer base (stickiness); and the potential life cycle of the company's products or services.

223. Depending on the industry sector, we measure a company's relative size and market share based on unit sales; the absolute amount of revenues; and the percentage of revenues captured from total industry revenues. We also adjust for industry and company specific qualitative considerations. For example, if an industry is particularly fragmented and has a number of similarly sized participants, none may have a particular advantage or disadvantage with respect to market share.

d) Maturity of products or services

224. The degree of maturity and the relative position on the lifecycle curve of the company's product or service portfolio affect the stability and sustainability of its revenues and margins. It is important to identify the stage of development of a company's products or services in order to measure the life cycle risks that may be associated with key products or services.

225. Mature products or services (e.g. consumer products or broadcast programming) are not necessarily a negative, in our view, if they still contribute reliable profits. If demand is declining for a company's product or service, we examine its track record on introducing new products with staying power. Similarly, a company's track record with product launches is particularly relevant.

3. Analyzing subfactors for operating efficiency

226. In assessing the relative strength of this component, we consider four subfactors:

- Cost structure,
- Manufacturing processes,
- Working capital management, and
- Technology.

227. To the extent a company has high operating efficiency, it should be able to generate better profit margins than peers that compete in the same markets, whatever the prevailing market conditions. The ability to minimize manufacturing and other operational costs and thus maximize margins and cash flow--for example, through manufacturing excellence, cost control, and diligent working capital management--will provide the funds for research and development, marketing, and customer service.

a) Cost structure

228. Companies that are well positioned from a cost standpoint will typically enjoy higher capacity utilization and be more profitable over the course of the business cycle. Cost structure and cost control are keys to generating strong profits and cash flow, particularly for companies that produce commodities, operate in mature industries, or face pricing pressures. It is important to consider whether a company or any of its competitors has a sustainable cost advantage, which can be based on access to cheaper energy, favorable manufacturing locations, or lower and more flexible labor costs, for example.

229. Where information is available, we examine a company's fixed versus variable cost mix as an indication of operating leverage, a measure of how revenue growth translates into growth in operating income. A company with significant operating leverage may witness dramatic declines in operating profit if unit volumes fall, as during cyclical downturns. Conversely, in an upturn, once revenues pass the breakeven point, a substantial percentage of incremental revenues typically becomes profit.

b) Manufacturing process

230. Capital intensity characterizes many heavy manufacturing sectors that require minimum volumes to produce acceptable profits, cash flow, and return on assets. We view capacity utilization through the business cycle (combined with the cost base) as a good indication of manufacturers' ability to maintain profits in varying economic scenarios. Our capacity utilization assessment is based on a company's production capacity across its manufacturing footprint. In addition, we consider the direction of a company's capacity utilization in light of our unit sales expectations, as opposed to analyzing it plant-by-plant.

231. Labor relations remain an important focus in our analysis of operating efficiency for manufacturers. Often, a company's labor cost structure is driven by its history of contractual negotiations and the countries in which it operates. We examine the rigidity or flexibility of a company's labor costs and the extent to which it relies on labor rather than automation. We analyze labor cost structure by assessing the extent of union representation, wage and benefit costs as a share of cost of goods sold (when available), and by assessing the balance of capital equipment vs. labor input in the manufacturing process. We also incorporate trends in a company's efforts to transfer labor costs from high-cost to low-cost regions.

c) Working capital management

232. Working capital management--of current or short-term assets and liabilities--is a key factor in our evaluation of operating efficiency. In general, companies with solid working capital management skills exhibit shorter cash conversion cycles (defined as days' investment in inventory and receivables less days' investment in accounts payable) than their lower-skilled peers. Short cash-conversion cycles could, for instance, demonstrate that a company has a stronger position in the supply chain (for example, requiring suppliers or dealers to hold more of its inventory). This allows a company to direct more capital than its peers can to other areas of investment.

d) Technology

233. Technology can play an important role in achieving superior operating efficiency through effective yield management (by improving input/output ratios), supply chain automation, and cost optimization.

234. Achieving high yield management is particularly important in industries with limited inventory and high fixed costs, such as transportation, lodging, media, and retail. The most efficient airlines can achieve higher revenue per available seat mile than their peers, while the most efficient lodging companies can achieve a higher revenue per available room than their peers. Both industries rely heavily on technology to effectively allocate inventory (seats and rooms) to maximize sales and profitability.

235. Effective supply chain automation systems enable companies to reduce investments in inventory and better forecast future orders based on current trends. By enabling electronic data interchange between supplier and retailer, such systems help speed orders and reorders for goods by quickly pinpointing which merchandise is selling well and needs restocking. They also identify slow moving inventory that needs to be marked down, making space available for fresh merchandise.

236. Effective use of technology can also help hold down costs by improving productivity via automation and workflow management. This can reduce selling, general, and administrative costs, which usually represent a substantial portion of expenditures for industries with high fixed costs, thus boosting earnings.

4. Industry-specific SER parameters

Table 28

SER Calibration By Industry Based On EBITDA

	--Volatility of profitability assessment*--					
	1	2	3	4	5	6
Transportation cyclical	=<10%	>10%-14%	>14%-22%	>22%-33%	>33%-76%	>76%
Auto OEM	=<25%	>25%-33%	>33%-35%	>35%-40%	>40%-46%	>46%
Metals and mining downstream	=<16%	>16%-31%	>31%-42%	>42%-53%	>53%-82%	>82%
Metals and mining upstream	=<16%	>16%-23%	>23%-28%	>28%-34%	>34%-59%	>59%
Homebuilders and developers	=<19%	>19%-33%	>33%-46%	>46%-65%	>65%-95%	>95%
Oil and gas refining and marketing	=<14%	>14%-21%	>21%-35%	>35%-46%	>46%-82%	>82%
Forest and paper products	=<9%	>9%-18%	>18%-26%	>26%-51%	>51%-114%	>114%
Building materials	=<9%	>9%-16%	>16%-19%	>19%-24%	>24%-33%	>33%
Oil and gas integrated, exploration and production	=<12%	>12%-19%	>19%-22%	>22%-28%	>28%-38%	>38%
Agribusiness and commodity foods	=<12%	>12%-19%	>19%-25%	>25%-39%	>39%-57%	>57%

Table 28

SER Calibration By Industry Based On EBITDA (cont.)

Real estate investment trusts (REITs)	=<5%	>5%-9%	>9%-13%	>13%-20%	>20%-32%	>32%
Leisure and sports	=<5%	>5%-9%	>9%-12%	>12%-16%	>16%-24%	>24%
Commodity chemicals	=<14%	>14%-19%	>19%-28%	>28%-37%	>37%-51%	>51%
Auto suppliers	=<15%	>15%-20%	>20%-26%	>26%-32%	>32%-45%	>45%
Aerospace and defense	=<6%	>6%-9%	>9%-15%	>15%-24%	>24%-41%	>41%
Technology hardware and semiconductors	=<11%	>11%-15%	>15%-22%	>22%-31%	>31%-58%	>58%
Specialty chemicals	=<5%	>5%-10%	>10%-14%	>14%-23%	>23%-36%	>36%
Capital goods	=<12%	>12%-16%	>16%-21%	>21%-30%	>30%-45%	>45%
Engineering and construction	=<9%	>9%-14%	>14%-20%	>20%-28%	>28%-39%	>39%
Railroads and package express	=<5%	>5%-8%	>8%-10%	>10%-13%	>13%-22%	>22%
Business and consumer services	=<4%	>4%-8%	>8%-11%	>11%-16%	>16%-30%	>30%
Midstream energy	=<5%	>5%-9%	>9%-11%	>11%-15%	>15%-31%	>31%
Technology software and services	=<4%	>4%-9%	>9%-14%	>14%-19%	>19%-33%	>33%
Consumer durables	=<7%	>7%-10%	>10%-13%	>13%-19%	>19%-35%	>35%
Containers and packaging	=<5%	>5%-7%	>7%-12%	>12%-18%	>18%-26%	>26%
Media and entertainment	=<6%	>6%-10%	>10%-14%	>14%-20%	>20%-29%	>29%
Oil and gas drilling, equipment and services	=<16%	>16%-22%	>22%-28%	>28%-44%	>44%-62%	>62%
Retail and restaurants	=<4%	>4%-8%	>8%-11%	>11%-16%	>16%-26%	>26%
Health care services	=<4%	>4%-5%	>5%-9%	>9%-12%	>12%-19%	>19%
Transportation infrastructure	=<2%	>2%-4%	>4%-7%	>7%-12%	>12%-19%	>19%
Environmental services	=<5%	>5%-9%	>9%-13%	>13%-22%	>22%-29%	>29%
Regulated utilities	=<4%	>4%-7%	>7%-9%	>9%-14%	>14%-26%	>26%
Unregulated power and gas	=<7%	>7%-16%	>16%-20%	>20%-29%	>29%-47%	>47%
Pharmaceuticals	=<5%	>5%-8%	>8%-11%	>11%-17%	>17%-32%	>32%
Health care equipment	=<3%	>3%-5%	>5%-6%	>6%-10%	>10%-25%	>25%
Branded nondurables	=<4%	>4%-7%	>7%-10%	>10%-15%	>15%-43%	>43%
Telecommunications and cable	=<3%	>3%-6%	>6%-9%	>9%-13%	>13%-23%	>23%
Overall	=<5%	>5%-9%	>9%-15%	>15%-23%	>23%-43%	>43%

*The data ranges include the values up to and including the upper bound. As an example, for a range of 5%-9%, a value of 5% is excluded, while a value of 9% is included; the numbers are rounded to the nearest whole number for presentation purposes.

Table 29

SER Calibration By Industry Based On EBITDA Margin

	--Volatility of profitability assessment*--					
	1	2	3	4	5	6
Transportation cyclical	=<4%	>4%-8%	>8%-16%	>16%-28%	>28%-69%	>69%
Auto OEM	=<15%	>15%-19%	>19%-29%	>29%-31%	>31%-45%	>45%
Metals and mining downstream	=<10%	>10%-18%	>18%-26%	>26%-36%	>36%-56%	>56%
Metals and mining upstream	=<8%	>8%-10%	>10%-14%	>14%-19%	>19%-31%	>31%
Homebuilders and developers	=<10%	>10%-18%	>18%-30%	>30%-56%	>56%-114%	>114%
Oil and gas refining and marketing	=<12%	>12%-22%	>22%-28%	>28%-42%	>42%-71%	>71%
Forest and paper products	=<8%	>8%-13%	>13%-21%	>21%-41%	>41%-117%	>117%
Building materials	=<4%	>4%-8%	>8%-13%	>13%-18%	>18%-23%	>23%

Table 29

SER Calibration By Industry Based On EBITDA Margin (cont.)						
Oil and gas integrated, exploration and production	=<4%	>4%-6%	>6%-8%	>8%-13%	>13%-22%	>22%
Agribusiness and commodity foods	=<9%	>9%-14%	>14%-18%	>18%-27%	>27%-100%	>100%
Real estate investment trusts (REITs)	=<2%	>2%-5%	>5%-8%	>8%-13%	>13%-34%	>34%
Leisure and sports	=<3%	>3%-5%	>5%-6%	>6%-9%	>9%-18%	>18%
Commodity chemicals	=<9%	>9%-14%	>14%-18%	>18%-25%	>25%-37%	>37%
Auto suppliers	=<9%	>9%-13%	>13%-18%	>18%-23%	>23%-40%	>40%
Aerospace and defense	=<3%	>3%-6%	>6%-7%	>7%-12%	>12%-24%	>24%
Technology hardware and semiconductors	=<7%	>7%-10%	>10%-15%	>15%-21%	>21%-62%	>62%
Specialty chemicals	=<3%	>3%-6%	>6%-10%	>10%-19%	>19%-28%	>28%
Capital goods	=<6%	>6%-9%	>9%-13%	>13%-20%	>20%-33%	>33%
Engineering and construction	=<6%	>6%-8%	>8%-12%	>12%-17%	>17%-26%	>26%
Railroads and package express	=<2%	>2%-6%	>6%-8%	>8%-10%	>10%-17%	>17%
Business and consumer services	=<3%	>3%-5%	>5%-7%	>7%-12%	>12%-22%	>22%
Midstream energy	=<3%	>3%-6%	>6%-9%	>9%-14%	>14%-28%	>28%
Technology software and services	=<3%	>3%-6%	>6%-10%	>10%-15%	>15%-30%	>30%
Consumer durables	=<4%	>4%-8%	>8%-11%	>11%-15%	>15%-26%	>26%
Containers and packaging	=<5%	>5%-7%	>7%-9%	>9%-15%	>15%-22%	>22%
Media and entertainment	=<4%	>4%-6%	>6%-9%	>9%-14%	>14%-24%	>24%
Oil and gas drilling, equipment and services	=<6%	>6%-12%	>12%-16%	>16%-22%	>22%-32%	>32%
Retail and restaurants	=<3%	>3%-5%	>5%-7%	>7%-12%	>12%-21%	>21%
Health care services	=<3%	>3%-5%	>5%-6%	>6%-8%	>8%-15%	>15%
Transportation infrastructure	=<1%	>1%-3%	>3%-5%	>5%-7%	>7%-15%	>15%
Environmental services	=<3%	>3%-4%	>4%-6%	>6%-10%	>10%-24%	>24%
Regulated utilities	=<4%	>4%-7%	>7%-9%	>9%-14%	>14%-24%	>24%
Unregulated power and gas	=<6%	>6%-10%	>10%-15%	>15%-23%	>23%-41%	>41%
Pharmaceuticals	=<4%	>4%-5%	>5%-7%	>7%-10%	>10%-21%	>21%
Health care equipment	=<2%	>2%-4%	>4%-5%	>5%-10%	>10%-16%	>16%
Branded nondurables	=<3%	>3%-6%	>6%-9%	>9%-13%	>13%-28%	>28%
Telecommunications and cable	=<2%	>2%-4%	>4%-5%	>5%-7%	>7%-13%	>13%
Overall	=<3%	>3%-6%	>6%-10%	>10%-16%	>16%-32%	>32%

*The data ranges include the values up to and including the upper bound. As an example, for a range of 5%-9%, a value of 5% is excluded, while a value of 9% is included; the numbers are rounded to the nearest whole number for presentation purposes.

Table 30

SER Calibration By Industry Based On Return On Capital						
	--Volatility of profitability assessment*--					
	1	**2**	**3**	**4**	**5**	**6**
Transportation cyclical	=<14%	>14%-28%	>28%-39%	>39%-53%	>53%-156%	>156%
Auto OEM	=<42%	>42%-64%	>64%-74%	>74%-86%	>86%-180%	>180%
Metals and mining downstream	=<25%	>25%-32%	>32%-43%	>43%-53%	>53%-92%	>92%
Metals and mining upstream	=<22%	>22%-30%	>30%-38%	>38%-45%	>45%-93%	>93%
Homebuilders and developers	=<12%	>12%-31%	>31%-50%	>50%-70%	>70%-88%	>88%

Table 30

SER Calibration By Industry Based On Return On Capital (cont.)						
Oil and gas refining and marketing	=<14%	>14%-30%	>30%-48%	>48%-67%	>67%-136%	>136%
Forest and paper products	=<10%	>10%-22%	>22%-40%	>40%-89%	>89%-304%	>304%
Building materials	=<13%	>13%-20%	>20%-26%	>26%-36%	>36%-62%	>62%
Oil and gas integrated, exploration and production	=<16%	>16%-22%	>22%-31%	>31%-43%	>43%-89%	>89%
Agribusiness and commodity foods	=<12%	>12%-15%	>15%-29%	>29%-55%	>55%-111%	>111%
Real estate investment trusts (REITs)	=<8%	>8%-14%	>14%-20%	>20%-26%	>26%-116%	>116%
Leisure and sports	=<11%	>11%-17%	>17%-26%	>26%-34%	>34%-64%	>64%
Commodity chemicals	=<19%	>19%-28%	>28%-41%	>41%-50%	>50%-73%	>73%
Auto suppliers	=<20%	>20%-39%	>39%-50%	>50%-67%	>67%-111%	>111%
Aerospace and defense	=<7%	>7%-13%	>13%-19%	>19%-27%	>27%-61%	>61%
Technology hardware and semiconductors	=<8%	>8%-21%	>21%-34%	>34%-49%	>49%-113%	>113%
Specialty chemicals	=<5%	>5%-18%	>18%-28%	>28%-43%	>43%-64%	>64%
Capital goods	=<15%	>15%-24%	>24%-31%	>31%-45%	>45%-121%	>121%
Engineering and construction	=<12%	>12%-21%	>21%-23%	>23%-33%	>33%-54%	>54%
Railroads and package express	=<3%	>3%-11%	>11%-17%	>17%-20%	>20%-27%	>27%
Business and consumer services	=<9%	>9%-17%	>17%-23%	>23%-40%	>40%-87%	>87%
Midstream energy	=<5%	>5%-11%	>11%-17%	>17%-22%	>22%-34%	>34%
Technology software and services	=<8%	>8%-21%	>21%-35%	>35%-65%	>65%-105%	>105%
Consumer durables	=<8%	>8%-13%	>13%-20%	>20%-35%	>35%-60%	>60%
Containers and packaging	=<6%	>6%-14%	>14%-23%	>23%-35%	>35%-52%	>52%
Media and entertainment	=<9%	>9%-17%	>17%-26%	>26%-40%	>40%-86%	>86%
Oil and gas drilling, equipment and services	=<25%	>25%-33%	>33%-45%	>45%-65%	>65%-90%	>90%
Retail and restaurants	=<6%	>6%-14%	>14%-18%	>18%-26%	>26%-69%	>69%
Health care services	=<6%	>6%-10%	>10%-15%	>15%-25%	>25%-44%	>44%
Transportation infrastructure	=<5%	>5%-9%	>9%-12%	>12%-16%	>16%-27%	>27%
Environmental Services	=<7%	>7%-12%	>12%-24%	>24%-35%	>35%-72%	>72%
Regulated utilities	=<6%	>6%-9%	>9%-13%	>13%-20%	>20%-36%	>36%
Unregulated power and gas	=<14%	>14%-19%	>19%-29%	>29%-55%	>55%-117%	>117%
Pharmaceuticals	=<6%	>6%-8%	>8%-15%	>15%-20%	>20%-33%	>33%
Health care equipment	=<4%	>4%-8%	>8%-19%	>19%-31%	>31%-81%	>81%
Branded nondurables	=<6%	>6%-10%	>10%-17%	>17%-29%	>29%-63%	>63%
Telecommunications and cable	=<7%	>7%-13%	>13%-19%	>19%-26%	>26%-60%	>60%
Overall	=<7%	>7%-15%	>15%-23%	>23%-38%	>38%-81%	>81%

*The data ranges include the values up to and including the upper bound. As an example, for a range of 5%-9%, a value of 5% is excluded, while a value of 9% is included; the numbers are rounded to the nearest whole number for presentation purposes.

C. Cash Flow/Leverage Analysis

1. The merits and drawbacks of each cash flow measure

a) EBITDA

237. EBITDA is a widely used, and therefore a highly comparable, indicator of cash flow, although it has significant limitations. Because EBITDA derives from the income statement entries, it can be distorted by the same accounting issues that limit the use of earnings as a basis of cash flow. In addition, interest can be a substantial cash outflow for speculative-grade companies and therefore EBITDA can materially overstate cash flow in some cases. Nevertheless, it serves as a useful and common starting point for cash flow analysis and is useful in ranking the financial strength of different companies.

b) Funds from operations (FFO)

238. FFO is a hybrid cash flow measure that estimates a company's inherent ability to generate recurring cash flow from its operations independent of working capital fluctuations. FFO estimates the cash flow available to the company before working capital, capital spending, and discretionary items such as dividends, acquisitions, etc.

239. Because cash flow from operations tends to be more volatile than FFO, FFO is often used to smooth period-over-period variation in working capital. We consider it a better proxy of recurring cash flow generation because management can more easily manipulate working capital depending on its liquidity or accounting needs. However, we do not generally rely on FFO as a guiding cash flow measure in situations where assessing working capital changes is important to judge a company's cash flow generating ability and general creditworthiness. For example, for working-capital-intensive industries such as retailing, operating cash flow may be a better indicator than FFO of the firm's actual cash generation.

240. FFO is a good measure of cash flow for well-established companies whose long-term viability is relatively certain (i.e., for highly rated companies). For such companies, there can be greater analytical reliance on FFO and its relation to the total debt burden. FFO remains very helpful in the relative ranking of companies. In addition, more established, healthier companies usually have a wider array of financing possibilities to cover potential short-term liquidity needs and to refinance upcoming maturities. For marginal credit situations, the focus shifts more to free operating cash flow--after deducting the various fixed uses such as working capital investment and capital expenditures--as this measure is more directly related to current debt service capability.

c) Cash flow from operations (CFO)

241. The measurement and analysis of CFO forms an important part of our ratings assessment, in particular for companies that operate in working-capital-intensive industries or industries in which working capital flows can be volatile. CFO is distinct from FFO as it is a pure measure of cash flow calculated after accounting for the impact on earnings of changes in operating assets and liabilities. CFO is cash flow that is available to finance items such as capital expenditures, repay borrowing, and pay for dividends and share buybacks.

242. In many industries, companies shift their focus to cash flow generation in a downturn. As a result, even though they typically generate less cash from ordinary business activities because of low capacity utilization and relatively low fixed-cost absorption, they may generate cash by reducing inventories and receivables. Therefore, although FFO is likely to be lower in a downturn, the impact on CFO may not be as great. In times of strong growth the opposite will be true, and consistently lower CFO compared to FFO without a corresponding increase in revenue and profitability can indicate an untenable situation.

243. Working capital is a key element of a company's cash flow generation. While there tends to be a need to build up working capital and therefore to consume cash in a growth or expansion phase, changes in working capital can also act as a buffer in case of a downturn. Many companies will sell off inventories and invest a lower amount in raw materials because of weaker business activities, both of which reduce the amount of capital and cash that is tied up in working capital. Therefore, working capital fluctuations can occur both in periods of revenue growth and contraction and analyzing a company's near-term working capital needs is crucial for estimating future cash flow developments.

244. Often, businesses that are capital intensive are not working-capital-intensive: most of the capital commitment is upfront in equipment and machinery, while asset-light businesses may have to invest proportionally more in inventories and receivables. That also affects margins, because capital-intensive businesses tend to have proportionally lower operating expenses (and therefore higher EBITDA margins), while working-capital-intensive businesses usually report lower EBITDA margins. The resulting cash flow volatility can be significant: because all investment is made upfront in a capital-intensive business, there is usually more room to absorb subsequent EBITDA volatility because margins are higher. For example, a capital-intensive company may remain reasonably profitable even if its EBITDA margin declines from 30% to 20%. By contrast, a working-capital-intensive business with a lower EBITDA margin (due to higher operating expenses) of 8% can post a negative EBITDA margin if EBITDA volatility is large.

d) Free operating cash flow (FOCF)

245. By deducting capital expenditures from CFO, we arrive at FOCF, which can be used as a proxy for a company's cash generated from core operations. We may exclude discretionary capital expenditures for capacity growth from the FOCF calculation, but in practice it is often difficult to discriminate between spending for expansion and replacement. And, while companies have some flexibility to manage their capital budgets to weather down cycles, such flexibility is generally temporary and unsustainable in light of intrinsic requirements of the business. For example, companies can be compelled to increase their investment programs because of strong demand growth or technological changes. Regulated entities (for example, telecommunications companies) might also face significant investment requirements related to their concession contracts (the understanding between a company and the host government that specifies the rules under which the company can operate locally).

246. Positive FOCF is a sign of strength and helpful in distinguishing between two companies with the same FFO. In addition, FOCF is helpful in differentiating between the cash flows generated by more and less capital-intensive companies and industries.

247. In highly capital-intensive industries (where maintenance capital expenditure requirements tend to be high) or in other situations in which companies have little flexibility to postpone capital expenditures, measures such as FFO to debt and debt to EBITDA may provide less valuable insight into relative creditworthiness because they fail to capture potentially meaningful capital expenditures. In such cases, a ratio such as FOCF to debt provides greater analytical insight.

248. A company serving a low-growth or declining market may exhibit relatively strong FOCF because of diminishing fixed and working capital needs. Growth companies, in contrast, exhibit thin or even negative FOCF because of the investment needed to support growth. For the low-growth company, credit analysis weighs the positive, strong current cash flow against the danger that this high level of cash flow might not be sustainable. For the high-growth company,

the opposite is true: weighing the negatives of a current cash deficit against prospects of enhanced cash flow once current investments begin yielding cash benefits. In the latter case, if we view the growth investment as temporary and not likely to lead to increased leverage over the long-term, we'll place greater analytical importance on FFO to debt rather than on FOCF to debt. In any event, we also consider the impact of a company's growth environment in our business risk analysis, specifically in a company's industry risk analysis (see section B).

e) Discretionary cash flow (DCF)

249. For corporate issuers primarily rated in the investment-grade universe, DCF to debt can be an important barometer of future cash flow adequacy as it more fully reflects a company's financial policy, including decisions regarding dividend payouts. In addition, share buybacks and potential M&A, both of which can represent very significant uses of cash, are important components in cash flow analysis.

250. The level of dividends depends on a company's financial strategy. Companies with aggressive dividend payout targets might be reluctant to reduce dividends even under some liquidity pressure. In addition, investment-grade companies are less likely to reduce dividend payments following some reversals--although dividends ultimately are discretionary. DCF is the truest reflection of excess cash flow, but it is also the most affected by management decisions and, therefore, does not necessarily reflect the potential cash flow available.

D. Diversification/Portfolio Effect

1. Academic research

251. Academic research recently concluded that, during the global financial crisis of 2007-2009, conglomerates had the advantage over single sector-focused firms because they had better access to the credit markets as a result of their debt co-insurance and used the internal capital markets more efficiently (i.e., their core businesses had stronger cash flows). Debt co-insurance is the view that the joining-together of two or more firms whose earnings streams are less-than-perfectly correlated reduces the risk of default of the merged firms (i.e., the co-insurance effect) and thereby increases the "debt capacity" or "borrowing ability" of the combined enterprise. These financing alternatives became more valuable during the crisis. (Source: "Does Diversification Create Value In The Presence Of External Financing Constraints? Evidence From The 2007-2009 Financial Crisis," Venkat Kuppuswamy and Belen Villalonga, Harvard Business School, Aug. 19, 2011.)

252. In addition, fully diversified, focused companies saw more narrow credit default swap spreads from 2004-2010 vs. less diversified firms. This highlighted that lenders were differentiating for risk and providing these companies with easier and cheaper access to capital. (Source: "The Power of Diversified Companies During Crises," The Boston Consulting Group and Leipzig Graduate School of Management, January 2012.)

253. Many rated conglomerates are either country- or region-specific; only a small percentage are truly global. The difference is important when assessing the country and macroeconomic risk factors. Historical measures for each region, based on volatility and correlation, reflect regional trends that are likely to change over time.

E. Financial Policy

1. Controlling shareholders

254. Controlling shareholder(s)--if they exist--exert significant influence over a company's financial risk profile, given their ability to use their direct or indirect control of the company's financial policies for their own benefit. Although the criteria do not associate the presence of controlling shareholder(s) to any predefined negative or positive impact, we assess the potential medium- to long-term implications for a company's credit standing of these strategies. Long-term ownership--such as exists in many family-run businesses--is often accompanied by financial discipline and reluctance to incur aggressive leverage. Conversely, short-term ownership--such as exists in private equity sponsor-owned companies--generally entails financial policies aimed at achieving rapid returns for shareholders typically through aggressive debt leverage.

255. The criteria define controlling shareholder(s) as:

- A private shareholder (an individual or a family) with majority ownership or control of the board of directors;
- A group of shareholders holding joint control over the company's board of directors through a shareholder agreement. The shareholder agreement may be comprehensive in scope or limited only to certain financial aspects; and
- A private equity firm or a group of private equity firms holding at least 40% in a company or with majority control of its board of directors.

256. A company is not considered to have a controlling shareholder if it is publicly listed with more than 50% of voting interest listed or when there is no evidence of a particular shareholder or group of shareholders exerting 'de facto' control over a company.

257. Companies that have as their controlling shareholder governments or government-related entities, infrastructure and asset-management funds, and diversified holding companies and conglomerates are assessed in separate criteria.

2. Financial discipline

a) Leverage influence from acquisitions

258. Companies may employ more or less acquisitive growth strategies based on industry dynamics, regulatory changes, market opportunities, and other factors. We consider management teams with disciplined, transparent acquisition strategies that are consistent with their financial policy framework as providing a high degree of visibility into the projected evolution of cash flow and credit measures. Our assessment takes into account management's track record in terms of acquisition strategy and the related impact on the company's financial risk profile. Historical evidence of limited management tolerance for significant debt-funded acquisitions provides meaningful support for the view that projected credit ratios would not significantly weaken as a result of the company's acquisition policy. Conversely, management teams that pursue opportunistic acquisition strategies, without well-defined parameters, increase the risks that the company's financial risk profile may deteriorate well beyond our forecasts.

259. Acquisition funding policies and management's track record in this respect also provide meaningful insight in terms of credit ratio stability. In the criteria, we take into account management's willingness and capacity to mobilize all funding resources to restore credit quality, such as issuing equity or disposing of assets, to mitigate the impact of sizable

acquisitions on credit ratios. The financial policy framework and related historical evidence are key considerations in our assessment.

b) Leverage influence from shareholder remuneration policies

260. A company's approach to rewarding shareholders demonstrates how it balances the interests of its various stakeholders over time. Companies that are consistent and transparent in their shareholder remuneration policies, and exhibit a willingness to adjust shareholder returns to mitigate adverse operating conditions, provide greater support to their long-term credit quality than other companies. Conversely, companies that prioritize cash returns to shareholders in periods of deteriorating economic, operating, or share price performance can significantly undermine long-term credit quality and exacerbate the credit impact of adverse business conditions. In assessing a company's shareholder remuneration policies, the criteria focus on the predictability of shareholder remuneration plans, including how a company builds shareholder expectations, its track record in executing shareholder return policies over time, and how shareholder returns compare with industry peers'.

261. Shareholder remuneration policies that lack transparency or deviate meaningfully from those of industry peers introduce a higher degree of event risk and volatility and will be assessed as less predictable under the criteria. Dividend and capital return policies that function primarily as a means to distribute surplus capital to shareholders based on transparent and stable payout ratios--after satisfying all capital requirements and leverage objectives of the company, and that support stable to improving leverage ratios--are considered the most supportive of long term credit quality.

c) Leverage influence from plans regarding investment decisions or organic growth strategies

262. The process by which a company identifies, funds, and executes organic growth, such as expansion into new products and/or new markets, can have a significant impact on its long-term credit quality. Companies that have a disciplined, coherent, and manageable organic growth strategy, and have a track record of successful execution are better positioned to continue to attract third-party capital and maintain long-term credit quality. By contrast, companies that allocate significant amounts of capital to numerous, unrelated, large and/or complex projects and often incur material overspending against the original budget can significantly increase their credit risk.

263. The criteria assess whether management's organic growth strategies are transparent, comprehensive, and measurable. We seek to evaluate the company's mid- to long-term growth objectives--including strategic rationales and associated execution risks--as well as the criteria it uses to allocate capital. Effective capital allocation is likely to include guidelines for capital deployment, including minimum return hurdles, competitor activity analysis, and demand forecasting. The company's track record will provide key data for this assessment, including how well it executes large and/or complex projects against initial budgets, cost overruns, and timelines.

3. Financial policy framework

a) Comprehensiveness of financial policy framework

264. Financial policies that are clearly defined, unambiguous, and provide a tight framework around management behavior are the most reliable in determining an issuer's future financial risk profile. We assess as consistent with a supportive assessment, policies that are clear, measurable, and well understood by all key stakeholders. Accordingly, the financial policy framework must include well-defined parameters regarding how the issuer will manage its cash flow protection

strategies and debt leverage profile. This includes at least one key or a combination of financial ratio constraints (such as maximum debt to EBITDA threshold) and the latter must be relevant with respect to the issuer's industry and/or capital structure characteristics.

265. By contrast, the absence of established financial policies, policies that are vague or not quantifiable, or historical evidence of significant and unexpected variation in management's long-term financial targets could contribute to an overall assessment of a non-supportive financial policy.

b) Transparency of financial policies

266. We assess as supportive financial policy objectives that are transparent and well understood by all key stakeholders and we view them as likely to influence an issuer's financial risk profile over time. Alternatively, financial policies, if they exist, that are not communicated to key stakeholders and/or where there is limited historical evidence to support the company's commitment to these policies, are non-supportive, in our view. We consider the variety of ways in which a company communicates its financial policy objectives, including public disclosures, investor presentation materials, and public commentary.

267. In some cases, however, a company may articulate its financial policy objectives to a limited number of key stakeholders, such as its main creditors or to credit rating agencies. In these situations, a company may still receive a supportive classification if we assess that there is a sufficient track record (more than three years) to demonstrate a commitment to its financial policy objectives.

c) Achievability and sustainability of financial policies

268. To assess the achievability and sustainability of a company's financial policies, we consider a variety of factors, including the entity's current and historical financial risk profile; the demands of its key stakeholders (including dividend and capital return expectations of equity holders); and the stability of the company's financial policies that we have observed over time. If there is evidence that the company is willing to alter its financial policy framework because of adverse business conditions or growth opportunities (including M&A), this could support an overall assessment of non-supportive.

4. Financial policy adjustments--examples

269. Example 1: A moderately leveraged company has just been sold to a new financial sponsor. The financial sponsor has not leveraged the company yet and there is no stated financial policy at the outset. We expect debt leverage to increase upon refinancing, but we are not able to factor it precisely in our forecasts yet.
Likely outcome: FS-6 financial policy assessment, implying that we expect the new owner to implement an aggressive financial policy in the absence of any other evidence.

270. Example 2: A company has two owners—a family owns 75%, a strategic owner holds the remaining 25%. Although the company has provided Standard & Poor's with some guidance on long-term financial objectives, the overall financial policy framework is not sufficiently structured nor disclosed to a sufficient number of stakeholders to qualify for a supportive assessment. Recent history, however, does not provide any evidence of unexpected, aggressive financial transactions and we believe event risk is moderate.
Likely outcome: Neutral financial policy impact, including an assessment of neutral for financial discipline. Although the company's financial framework does not support long-term visibility, historical evidence and stability of management suggest that event risk is not significant. The unsupportive financial framework assessment, however,

prevents the company from qualifying for an overall positive financial policy assessment, should the conditions for positive financial discipline be met.

271. Example 3: A company (not owned by financial sponsors) has stated leverage targets equivalent to a significant financial risk profile assessment. The company continues to make debt-financed acquisitions yet remains within its leverage targets, albeit at the weaker end of these. Our forecasts are essentially built on expectations that excess cash flow will be fully used to fund M&A or, possibly pay share repurchases, but that management will overall remain within its leverage targets.
Likely outcome: Neutral financial policy impact. Although management is fairly aggressive, the company consistently stays within its financial policy targets. We think our forecasts provide a realistic view of the evolution of the company's credit metrics over the next two years. No event risk adjustment is needed.

272. Example 4: A company (not owned by a financial sponsor) has just made a sizable acquisition (consistent with its long-term business strategy) that has brought its credit ratios out of line. Management expressed its commitment to rapidly improve credit ratios back to its long-term ratio targets—representing an acceptable range for the SACP--through asset disposals or a rights issue. We see their disposal plan (or rights issue) as realistic but precise value and timing are uncertain. At the same time, management has a supportive financial policy framework, a positive track record of five years, and assets are viewed as fairly easily tradable.
Likely outcome: Positive financial policy impact. Although forecast credit ratios will remain temporarily depressed, as we cannot fully factor in asset disposals (or rights issue) due to uncertainty on timing/value, or without leaking confidential information, the company's credit risk should benefit from management's positive track record and a satisfactory financial policy framework. The anchor will be better by one notch if management and governance is at least satisfactory and liquidity is at least adequate.

273. Example 5: A company (not owned by a financial sponsor) has very solid financial ratios, providing it with meaningful flexibility for M&A when compared with management's long-term stated financial policy. Also, its stock price performance is somewhat below that of its closest industry peers. Although we have no recent evidence of any aggressive financial policy steps, we fundamentally believe that, over the long-term term, the company will end up using its financial flexibility for the right M&A opportunity, or alternatively return cash to shareholders.
Likely outcome: Negative financial policy impact. Long-term event risk derived from M&A cannot be built into forecasts nor shareholder returns (share buybacks or one-off dividends) be built into forecasts to attempt aligning projected ratios with stated long-term financial policy levels. This is because our forecasts are based on realistic and reasonably predictable assumptions for the medium term. The anchor will be adjusted down, by one notch or more, because of the negative financial policy assessment.

F. Corporate Criteria Glossary

Anchor: The combination of an issuer's business risk profile assessment and its financial risk profile assessment determine the anchor. Additional rating factors can then modify the anchor to determine the final rating or SACP.

Asset profile: A descriptive way to look at the types and quality of assets that comprise a company (examples can include tangible versus intangible assets, those assets that require large and continuing maintenance, upkeep, or reinvestment, etc.).

Business risk profile: This measure comprises the risk and return potential for a company in the market in which it participates, the country risks within those markets, the competitive climate, and the competitive advantages and disadvantages the company has. The criteria combine the assessments for Corporate Industry and Country Risk Assessment (CICRA), and competitive position to determine a company's business risk profile assessment.

Capital-intensive company: A company exhibiting large ongoing capital spending to sales, or a large amount of depreciation to sales. Examples of capital-intensive sectors include oil production and refining, telecommunications, and transportation sectors such as railways and airlines.

Cash available for debt repayment: Forecast cash available for debt repayment is defined as the net change in cash for the period before debt borrowings and debt repayments. This includes forecast discretionary cash flow adjusted for our expectations of: share buybacks, net of any share issuance, and M&A. Discretionary cash flow is defined as cash flow from operating activities less capital expenditures and total dividends.

Competitive position: Our assessment of a company's: 1) competitive advantage; 2) operating efficiency; 3) scale, scope, and diversity; and 4) profitability.

- Competitive advantage--The strategic positioning and attractiveness to customers of the company's products or services, and the fragility or sustainability of its business model.
- Operating efficiency--The quality and flexibility of the company's asset base and its cost management and structure.
- Scale, scope, and diversity--The concentration or diversification of business activities.
- Profitability--Our assessment of both the company's level of profitability and volatility of profitability.

Competitive Position Group Profile (CPGP): Used to determine the weights to be assigned to the four components of competitive position. While industries are assigned to one of the six profiles, individual companies and industry subsectors can be classified into another CPGP because of unique characteristics. Similarly, national industry risk factors can affect the weighing. The six CPGPs are:

- Services and product focus,
- Product focus/scale driven,
- Capital or asset focus,
- Commodity focus/cost driven,
- Commodity focus/scale driven, and
- National industry and utilities.

Conglomerate: Companies that have at least three distinct business segments, each contributing between 10%-50% of EBITDA or FOCF. Such companies may benefit from the diversification/portfolio effect.

Controlling shareholders: Equity owners who are able to affect decisions of varying effect on operations, leverage, and shareholder reward without necessarily being a majority of shareholders.

Corporate Industry and Country Risk Assessment (CICRA): The result of the combination of an issuer's country risk assessment and industry risk assessment.

Debt co-insurance: The view that the joining-together of two or more firms whose earnings streams are less-than-perfectly correlated reduces the risk of default of the merged firms (i.e., the co-insurance effect) and thereby increases the "debt capacity" or "borrowing ability" of the combined enterprise. These financing alternatives became more valuable during the global financial crisis of 2007-2009.

Financial headroom: Measure of deviation tolerated in financial metrics without moving outside or above a pre-designated band or limit typically found in loan covenants (as in a debt to EBITDA multiple that places a constraint on leverage). Significant headroom would allow for larger deviations.

Financial risk profile: The outcome of decisions that management makes in the context of its business risk profile and its financial risk tolerances. This includes decisions about the manner in which management seeks funding for the company and how it constructs its balance sheet. It also reflects the relationship of the cash flows the organization can achieve, given its business risk profile, to its financial obligations. The criteria use cash flow/leverage analysis to determine a corporate issuer's financial risk profile assessment.

Financial sponsor: An entity that follows an aggressive financial strategy in using debt and debt-like instruments to maximize shareholder returns. Typically, these sponsors dispose of assets within a short to intermediate time frame. Financial sponsors include private equity firms, but not infrastructure and asset-management funds, which maintain longer investment horizons.

Profitability ratio: Commonly measured using return on capital and EBITDA margins but can be measured using sector-specific ratios. Generally calculated based on a five-year average, consisting of two years of historical data, and our projections for the current year and the next two financial years.

Shareholder remuneration policies: Management's stated shareholder reward plans (such as a buyback or dividend amount, or targeted payout ratios).

Stand-alone credit profile (SACP): Standard & Poor's opinion of an issue's or issuer's creditworthiness, in the absence of extraordinary intervention or support from its parent, affiliate, or related government or from a third-party entity such as an insurer.

Transfer and convertibility assessment: Standard & Poor's view of the likelihood of a sovereign restricting nonsovereign access to foreign exchange needed to satisfy the nonsovereign's debt service obligations.

Unconsolidated equity affiliates: Companies in which an issuer has an investment, but which are not consolidated in an issuer's financial statements. Therefore, the earnings and cash flows of the investees are not included in our primary metrics unless dividends are received from the investees.

Upstream/midstream/downstream: Referring to exploration and production, transport and storage, and refining and distributing, respectively, of natural resources and commodities (such as metals, oil, gas, etc.).

Volatility of profitability/SER: We base the volatility of profitability on the standard error of the regression (SER) for a company's historical EBITDA. The SER is a statistical measure that is an estimate of the deviation around a 'best fit' trend line. We combine it with the profitability ratio to determine the final profitability assessment. We only calculate

SER when companies have at least seven years of historical annual data, to ensure that the results are meaningful.

Working-capital-intensive companies: Generally a company with large levels of working capital in relation to its sales in order to meet seasonal swings in working capital. Examples of working-capital-intensive sectors include retail, auto manufacturing, and capital goods.

These criteria represent the specific application of fundamental principles that define credit risk and ratings opinions. Their use is determined by issuer- or issue-specific attributes as well as Standard & Poor's Ratings Services' assessment of the credit and, if applicable, structural risks for a given issuer or issue rating. Methodology and assumptions may change from time to time as a result of market and economic conditions, issuer- or issue-specific factors, or new empirical evidence that would affect our credit judgment.

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Key Credit Factors For The Regulated Utilities Industry

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Key Credit Factors For The Regulated Utilities Industry

(Editor's Note: *This criteria article supersedes "Key Credit Factors: Business And Financial Risks In The Investor-Owned Utilities Industry," published Nov. 26, 2008, "Assessing U.S. Utility Regulatory Environments," Nov. 7, 2007, and "Revised Methodology For Adjusting Amounts Reported By U.K. GAAP Water Companies For Infrastructure Renewals Accounting," Jan. 27, 2010.)*

1. Standard & Poor's Ratings Services is refining and adapting its methodology and assumptions for its Key Credit Factors: Criteria For Regulated Utilities. We are publishing these criteria in conjunction with our corporate criteria (see "Corporate Methodology, published Nov. 19, 2013). This article relates to our criteria article, "Principles Of Credit Ratings," Feb. 16, 2011.

2. This criteria article supersedes "Key Credit Factors: Business And Financial Risks In The Investor-Owned Utilities Industry," Nov. 26, 2008, "Criteria: Assessing U.S. Utility Regulatory Environments," Nov. 7, 2007, and "Revised Methodology For Adjusting Amounts Reported By U.K. GAAP Water Companies For Infrastructure Renewals Accounting," Jan. 27, 2010.

SCOPE OF THE CRITERIA

3. These criteria apply to entities where regulated utilities represent a material part of their business, other than U.S. public power, water, sewer, gas, and electric cooperative utilities that are owned by federal, state, or local governmental bodies or by ratepayers. A regulated utility is defined as a corporation that offers an essential or near-essential infrastructure product, commodity, or service with little or no practical substitute (mainly electricity, water, and gas), a business model that is shielded from competition (naturally, by law, shadow regulation, or by government policies and oversight), and is subject to comprehensive regulation by a regulatory body or implicit oversight of its rates (sometimes referred to as tariffs), service quality, and terms of service. The regulators base the rates that they set on some form of cost recovery, including an economic return on assets, rather than relying on a market price. The regulated operations can range from individual parts of the utility value chain (water, gas, and electricity networks or "grids," electricity generation, retail operations, etc.) to the entire integrated chain, from procurement to sales to the end customer. In some jurisdictions, our view of government support can also affect the final rating outcome, as per our government-related entity criteria (see "General Criteria: Rating Government-Related Entities: Methodology and Assumptions," Dec. 9, 2010).

SUMMARY OF THE CRITERIA

4. Standard & Poor's is updating its criteria for analyzing regulated utilities, applying its corporate criteria. The criteria for evaluating the competitive position of regulated utilities amend and partially supersede the "Competitive Position" section of the corporate criteria when evaluating these entities. The criteria for determining the cash flow leverage

assessment partially supersede the "Cash Flow/Leverage" section of the corporate criteria for the purpose of evaluating regulated utilities. The section on liquidity for regulated utilities partially amends existing criteria. All other sections of the corporate criteria apply to the analysis of regulated utilities.

IMPACT ON OUTSTANDING RATINGS

5. These criteria could affect the issuer credit ratings of about 5% of regulated utilities globally due primarily to the introduction of new financial benchmarks in the corporate criteria. Almost all ratings changes are expected to be no more than one notch, and most are expected to be in an upward direction.

EFFECTIVE DATE AND TRANSITION

6. These criteria are effective immediately on the date of publication.

METHODOLOGY

Part I--Business Risk Analysis

Industry risk

7. Within the framework of Standard & Poor's general criteria for assessing industry risk, we view regulated utilities as a "very low risk" industry (category '1'). We derive this assessment from our view of the segment's low risk ('2') cyclicality and very low risk ('1') competitive risk and growth assessment.

8. In our view, demand for regulated utility services typically exhibits low cyclicality, being a function of such key drivers as employment growth, household formation, and general economic trends. Pricing is non-cyclical, since it is usually based in some form on the cost of providing service.

Cyclicality

9. We assess cyclicality for regulated utilities as low risk ('2'). Utilities typically offer products and services that are essential and not easily replaceable. Based on our analysis of global Compustat data, utilities had an average peak-to-trough (PTT) decline in revenues of about 6% during recessionary periods since 1952. Over the same period, utilities had an average PTT decline in EBITDA margin of about 5% during recessionary periods, with PTT EBITDA margin declines less severe in more recent periods. The PTT drop in profitability that occurred in the most recent recession (2007-2009) was less than the long-term average.

10. With an average drop in revenues of 6% and an average profitability decline of 5%, utilities' cyclicality assessment calibrates to low risk ('2'). We generally consider that the higher the level of profitability cyclicality in an industry, the higher the credit risk of entities operating in that industry. However, the overall effect of cyclicality on an industry's risk profile may be mitigated or exacerbated by an industry's competitive and growth environment.

Competitive risk and growth

11. We view regulated utilities as warranting a very low risk ('1') competitive risk and growth assessment. For competitive risk and growth, we assess four sub-factors as low, medium, or high risk. These sub-factors are:

- Effectiveness of industry barriers to entry;
- Level and trend of industry profit margins;
- Risk of secular change and substitution by products, services, and technologies; and
- Risk in growth trends.

Effectiveness of barriers to entry--low risk

12. Barriers to entry are high. Utilities are normally shielded from direct competition. Utility services are commonly naturally monopolistic (they are not efficiently delivered through competitive channels and often require access to public thoroughfares for distribution), and so regulated utilities are granted an exclusive franchise, license, or concession to serve a specified territory in exchange for accepting an obligation to serve all customers in that area and the regulation of its rates and operations.

Level and trend of industry profit margins--low risk

13. Demand is sometimes and in some places subject to a moderate degree of seasonality, and weather conditions can significantly affect sales levels at times over the short term. However, those factors even out over time, and there is little pressure on margins if a utility can pass higher costs along to customers via higher rates.

Risk of secular change and substitution of products, services, and technologies--low risk

14. Utility products and services are not overly subject to substitution. Where substitution is possible, as in the case of natural gas, consumer behavior is usually stable and there is not a lot of switching to other fuels. Where switching does occur, cost allocation and rate design practices in the regulatory process can often mitigate this risk so that utility profitability is relatively indifferent to the substitutions.

Risk in industry growth trends--low risk

15. As noted above, regulated utilities are not highly cyclical. However, the industry is often well established and, in our view, long-range demographic trends support steady demand for essential utility services over the long term. As a result, we would expect revenue growth to generally match GDP when economic growth is positive.

B. Country risk

16. In assessing "country risk" for a regulated utility, our analysis uses the same methodology as with other corporate issuers (see "Corporate Methodology").

C. Competitive position

17. In the corporate criteria, competitive position is assessed as ('1') excellent, ('2') strong, ('3') satisfactory, ('4') fair, ('5') weak, or ('6') vulnerable.

18. The analysis of competitive position includes a review of:

- Competitive advantage,
- Scale, scope, and diversity,
- Operating efficiency, and
- Profitability.

19. In the corporate criteria we assess the strength of each of the first three components. Each component is assessed as either: (1) strong, (2) strong/adequate, (3) adequate, (4) adequate/weak, or (5) weak. After assessing these components, we determine the preliminary competitive position assessment by ascribing a specific weight to each component. The applicable weightings will depend on the company's Competitive Position Group Profile. The group profile for regulated utilities is "National Industries & Utilities," with a weighting of the three components as follows: competitive advantage (60%), scale, scope, and diversity (20%), and operating efficiency (20%). Profitability is assessed by combining two sub-components: level of profitability and the volatility of profitability.

20. "Competitive advantage" cannot be measured with the same sub-factors as competitive firms because utilities are not primarily subject to influence of market forces. Therefore, these criteria supersede the "competitive advantage" section of the corporate criteria. We analyze instead a utility's "regulatory advantage" (section 1 below).

Assessing regulatory advantage

21. The regulatory framework/regime's influence is of critical importance when assessing regulated utilities' credit risk because it defines the environment in which a utility operates and has a significant bearing on a utility's financial performance.

22. We base our assessment of the regulatory framework's relative credit supportiveness on our view of how regulatory stability, efficiency of tariff setting procedures, financial stability, and regulatory independence protect a utility's credit quality and its ability to recover its costs and earn a timely return. Our view of these four pillars is the foundation of a utility's regulatory support. We then assess the utility's business strategy, in particular its regulatory strategy and its ability to manage the tariff-setting process, to arrive at a final regulatory advantage assessment.

23. When assessing regulatory advantage, we first consider four pillars and sub-factors that we believe are key for a utility to recover all its costs, on time and in full, and earn a return on its capital employed:

24. Regulatory stability:

- Transparency of the key components of the rate setting and how these are assessed
- Predictability that lowers uncertainty for the utility and its stakeholders
- Consistency in the regulatory framework over time

25. Tariff-setting procedures and design:

- Recoverability of all operating and capital costs in full
- Balance of the interests and concerns of all stakeholders affected
- Incentives that are achievable and contained

26. Financial stability:

- Timeliness of cost recovery to avoid cash flow volatility
- Flexibility to allow for recovery of unexpected costs if they arise
- Attractiveness of the framework to attract long-term capital
- Capital support during construction to alleviate funding and cash flow pressure during periods of heavy investments

27. Regulatory independence and insulation:

- Market framework and energy policies that support long-term financeability of the utilities and that is clearly enshrined in law and separates the regulator's powers
- Risks of political intervention is absent so that the regulator can efficiently protect the utility's credit profile even during a stressful event

28. We have summarized the key characteristics of the assessments for regulatory advantage in table 1.

Table 1

Preliminary Regulatory Advantage Assessment

Qualifier	What it means	Guidance
Strong	The utility has a major regulatory advantage due to one or a combination of factors that support cost recovery and a return on capital combined with lower than average volatility of earnings and cash flows.	The utility operates in a regulatory climate that is transparent, predictable, and consistent from a credit perspective.
	There are strong prospects that the utility can sustain this advantage over the long term.	The utility can fully and timely recover all its fixed and variable operating costs, investments and capital costs (depreciation and a reasonable return on the asset base).
	This should enable the utility to withstand economic downturns and political risks better than other utilities.	The tariff set may include a pass-through mechanism for major expenses such as commodity costs, or a higher return on new assets, effectively shielding the utility from volume and input cost risks.
		Any incentives in the regulatory scheme are contained and symmetrical.
		The tariff set includes mechanisms allowing for a tariff adjustment for the timely recovery of volatile or unexpected operating and capital costs.
		There is a track record of earning a stable, compensatory rate of return in cash through various economic and political cycles and a projected ability to maintain that record.
		There is support of cash flows during construction of large projects, and pre-approval of capital investment programs and large projects lowers the risk of subsequent disallowances of capital costs.
		The utility operates under a regulatory system that is sufficiently insulated from political intervention to efficiently protect the utility's credit risk profile even during stressful events.
Adequate	The utility has some regulatory advantages and protection, but not to the extent that it leads to a superior business model or durable benefit.	It operates in a regulatory environment that is less transparent, less predictable, and less consistent from a credit perspective.
	The utility has some but not all drivers of well-managed regulatory risk. Certain regulatory factors support the business's long-term stability and viability but could result in periods of below-average levels of profitability and greater profit volatility. However, overall these regulatory drivers are partially offset by the utility's disadvantages or lack of sustainability of other factors.	The utility is exposed to delays or is not, with sufficient certainty, able to recover all of its fixed and variable operating costs, investments, and capital costs (depreciation and a reasonable return on the asset base) within a reasonable time.
		Incentive ratemaking practices are asymmetrical and material, and could detract from credit quality.
		The utility is exposed to the risk that it doesn't recover unexpected or volatile costs in a full or less than timely manner due to lack of flexible reopeners or annual revenue adjustments.
		There is an uneven track record of earning a compensatory rate of return in cash through various economic and political cycles and a projected ability to maintain that record.

Table 1

Preliminary Regulatory Advantage Assessment (cont.)		
		There is little or no support of cash flows during construction, and investment decisions on large projects (and therefore the risk of subsequent disallowances of capital costs) rest mostly with the utility.
		The utility operates under a regulatory system that is not sufficiently insulated from political intervention and is sometimes subject to overt political influence.
Weak	The utility suffers from a complete breakdown of regulatory protection that places the utility at a significant disadvantage.	The utility operates in an opaque regulatory climate that lacks transparency, predictability, and consistency.
	The utility's regulatory risk is such that the long-term cost recovery and investment return is highly uncertain and materially delayed, leading to volatile or weak cash flows. There is the potential for material stranded assets with no prospect of recovery.	The utility cannot fully and/or timely recover its fixed and variable operating costs, investments, and capital costs (depreciation and a reasonable return on the asset base).
		There is a track record of earning minimal or negative rates of return in cash through various economic and political cycles and a projected inability to improve that record sustainably.
		The utility must make significant capital commitments with no solid legal basis for the full recovery of capital costs.
		Ratemaking practices actively harm credit quality.
		The utility is regularly subject to overt political influence.

29. After determining the preliminary regulatory advantage assessment, we then assess the utility's business strategy. Most importantly, this factor addresses the effectiveness of a utility's management of the regulatory risk in the jurisdiction(s) where it operates. In certain jurisdictions, a utility's regulatory strategy and its ability to manage the tariff-setting process effectively so that revenues change with costs can be a compelling regulatory risk factor. A utility's approach and strategies surrounding regulatory matters can create a durable "competitive advantage" that differentiates it from peers, especially if the risk of political intervention is high. The assessment of a utility's business strategy is informed by historical performance and its forward-looking business objectives. We evaluate these objectives in the context of industry dynamics and the regulatory climate in which the utility operates, as evaluated through the factors cited in paragraphs 24-27.

30. We modify the preliminary regulatory advantage assessment to reflect this influence positively or negatively. Where business strategy has limited effect relative to peers, we view the implications as neutral and make no adjustment. A positive assessment improves the preliminary regulatory advantage assessment by one category and indicates that management's business strategy is expected to bolster its regulatory advantage through favorable commission rulings beyond what is typical for a utility in that jurisdiction. Conversely, where management's strategy or businesses decisions result in adverse regulatory outcomes relative to peers, such as failure to achieve typical cost recovery or allowed returns, we adjust the preliminary regulatory advantage assessment one category worse. In extreme cases of poor strategic execution, the preliminary regulatory advantage assessment is adjusted by two categories worse (when possible; see table 2) to reflect management decisions that are likely to result in a significantly adverse regulatory outcome relative to peers.

Table 2

Determining The Final Regulatory Advantage Assessment

	--Strategy modifier--			
Preliminary regulatory advantage score	**Positive**	**Neutral**	**Negative**	**Very negative**
Strong	Strong	Strong	Strong/Adequate	Adequate
Strong/Adequate	Strong	Strong/Adequate	Adequate	Adequate/Weak
Adequate	Strong/Adequate	Adequate	Adequate/Weak	Weak
Adequate/Weak	Adequate	Adequate/Weak	Weak	Weak
Weak	Adequate/Weak	Weak	Weak	Weak

Scale, scope, and diversity

31. We consider the key factors for this component of competitive position to be primarily operational scale and diversity of the geographic, economic, and regulatory foot prints. We focus on a utility's markets, service territories, and diversity and the extent that these attributes can contribute to cash flow stability while dampening the effect of economic and market threats.

32. A utility that warrants a Strong or Strong/Adequate assessment has scale, scope, and diversity that support the stability of its revenues and profits by limiting its vulnerability to most combinations of adverse factors, events, or trends. The utility's significant advantages enable it to withstand economic, regional, competitive, and technological threats better than its peers. It typically is characterized by a combination of the following factors:

- A large and diverse customer base with no meaningful customer concentration risk, where residential and small to medium commercial customers typically provide most operating income.
- The utility's range of service territories and regulatory jurisdictions is better than others in the sector.
- Exposure to multiple regulatory authorities where we assess preliminary regulatory advantage to be at least Adequate. In the case of exposure to a single regulatory regime, the regulatory advantage assessment is either Strong or Strong/Adequate.
- No meaningful exposure to a single or few assets or suppliers that could hurt operations or could not easily be replaced.

33. A utility that warrants a Weak or Weak/Adequate assessment lacks scale, scope, and diversity such that it compromises the stability and sustainability of its revenues and profits. The utility's vulnerability to, or reliance on, various elements of this sub-factor is such that it is less likely than its peers to withstand economic, competitive, or technological threats. It typically is characterized by a combination of the following factors:

- A small customer base, especially if burdened by customer and/or industry concentration combined with little economic diversity and average to below-average economic prospects;
- Exposure to a single service territory and a regulatory authority with a preliminary regulatory advantage assessment of Adequate or Adequate/Weak; or
- Dependence on a single supplier or asset that cannot easily be replaced and which hurts the utility's operations.

34. We generally believe a larger service territory with a diverse customer base and average to above-average economic growth prospects provides a utility with cushion and flexibility in the recovery of operating costs and ongoing investment (including replacement and growth capital spending), as well as lessening the effect of external shocks (i.e.,

extreme local weather) since the incremental effect on each customer declines as the scale increases.

35. We consider residential and small commercial customers as having more stable usage patterns and being less exposed to periodic economic weakness, even after accounting for some weather-driven usage variability. Significant industrial exposure along with a local economy that largely depends on one or few cyclical industries potentially contributes to the cyclicality of a utility's load and financial performance, magnifying the effect of an economic downturn.

36. A utility's cash flow generation and stability can benefit from operating in multiple geographic regions that exhibit average to better than average levels of wealth, employment, and growth that underpin the local economy and support long-term growth. Where operations are in a single geographic region, the risk can be ameliorated if the region is sufficiently large, demonstrates economic diversity, and has at least average demographic characteristics.

37. The detriment of operating in a single large geographic area is subject to the strength of regulatory assessment. Where a utility operates in a single large geographic area and has a strong regulatory assessment, the benefit of diversity can be incremental.

Operating efficiency

38. We consider the key factors for this component of competitive position to be:

- Compliance with the terms of its operating license, including safety, reliability, and environmental standards;
- Cost management; and
- Capital spending: scale, scope, and management.

39. Relative to peers, we analyze how successful a utility management achieves the above factors within the levels allowed by the regulator in a manner that promotes cash flow stability. We consider how management of these factors reduces the prospect of penalties for noncompliance, operating costs being greater than allowed, and capital projects running over budget and time, which could hurt full cost recovery.

40. The relative importance of the above three factors, particularly cost and capital spending management, is determined by the type of regulation under which the utility operates. Utilities operating under robust "cost plus" regimes tend to be more insulated given the high degree of confidence costs will invariably be passed through to customers. Utilities operating under incentive-based regimes are likely to be more sensitive to achieving regulatory standards. This is particularly so in the regulatory regimes that involve active consultation between regulator and utility and market testing as opposed to just handing down an outcome on a more arbitrary basis.

41. In some jurisdictions, the absolute performance standards are less relevant than how the utility performs against the regulator's performance benchmarks. It is this performance that will drive any penalties or incentive payments and can be a determinant of the utilities' credibility on operating and asset-management plans with its regulator.

42. Therefore, we consider that utilities that perform these functions well are more likely to consistently achieve determinations that maximize the likelihood of cost recovery and full inclusion of capital spending in their asset bases. Where regulatory resets are more at the discretion of the utility, effective cost management, including of labor, may allow for more control over the timing and magnitude of rate filings to maximize the chances of a constructive outcome such as full operational and capital cost recovery while protecting against reputational risks.

43. A regulated utility that warrants a Strong or Strong/Adequate assessment for operating efficiency relative to peers generates revenues and profits through minimizing costs, increasing efficiencies, and asset utilization. It typically is characterized by a combination of the following:

- High safety record;
- Service reliability is strong, with a track record of meeting operating performance requirements of stakeholders, including those of regulators. Moreover, the utility's asset profile (including age and technology) is such that we have confidence that it could sustain favorable performance against targets;
- Where applicable, the utility is well-placed to meet current and potential future environmental standards;
- Management maintains very good cost control. Utilities with the highest assessment for operating efficiency have shown an ability to manage both their fixed and variable costs in line with regulatory expectations (including labor and working capital management being in line with regulator's allowed collection cycles); or
- There is a history of a high level of project management execution in capital spending programs, including large one-time projects, almost invariably within regulatory allowances for timing and budget.

44. A regulated utility that warrants an Adequate assessment for operating efficiency relative to peers has a combination of cost position and efficiency factors that support profit sustainability combined with average volatility. Its cost structure is similar to its peers. It typically is characterized by a combination of the following factors:

- High safety performance;
- Service reliability is satisfactory with a track record of mostly meeting operating performance requirements of stakeholders, including those of regulators. We have confidence that a favorable performance against targets can be mostly sustained;
- Where applicable, the utility may be challenged to comply with current and future environmental standards that could increase in the medium term;
- Management maintains adequate cost control. Utilities that we assess as having adequate operating efficiency mostly manage their fixed and variable costs in line with regulatory expectations (including labor and working capital management being mostly in line with regulator's allowed collection cycles); or
- There is a history of adequate project management skills in capital spending programs within regulatory allowances for timing and budget.

45. A regulated utility that warrants a weak or weak/adequate assessment for operating efficiency relative to peers has a combination of cost position and efficiency factors that fail to support profit sustainability combined with below-average volatility. Its cost structure is worse than its peers. It typically is characterized by a combination of the following:

- Poor safety performance;
- Service reliability has been sporadic or non-existent with a track record of not meeting operating performance requirements of stakeholders, including those of regulators. We do not believe the utility can consistently meet performance targets without additional capital spending;
- Where applicable, the utility is challenged to comply with current environmental standards and is highly vulnerable to more onerous standards;
- Management typically exceeds operating costs authorized by regulators;
- Inconsistent project management skills as evidenced by cost overruns and delays including for maintenance capital spending; or
- The capital spending program is large and complex and falls into the weak or weak/adequate assessment, even if

operating efficiency is generally otherwise considered adequate.

Profitability

46. A utility with above-average profitability would, relative to its peers, generally earn a rate of return at or above what regulators authorize and have minimal exposure to earnings volatility from affiliated unregulated business activities or market-sensitive regulated operations. Conversely, a utility with below-average profitability would generally earn rates of return well below the authorized return relative to its peers or have significant exposure to earnings volatility from affiliated unregulated business activities or market-sensitive regulated operations.

47. The profitability assessment consists of "level of profitability" and "volatility of profitability."

Level of profitability

48. Key measures of general profitability for regulated utilities commonly include ratios, which we compare both with those of peers and those of companies in other industries to reflect different countries' regulatory frameworks and business environments:

- EBITDA margin,
- Return on capital (ROC), and
- Return on equity (ROE).

49. In many cases, EBITDA as a percentage of sales (i.e., EBITDA margin) is a key indicator of profitability. This is because the book value of capital does not always reflect true earning potential, for example when governments privatize or restructure incumbent state-owned utilities. Regulatory capital values can vary with those of reported capital because regulatory capital values are not inflation-indexed and could be subject to different assumptions concerning depreciation. In general, a country's inflation rate or required rate of return on equity investment is closely linked to a utility company's profitability. We do not adjust our analysis for these factors, because we can make our assessment through a peer comparison.

50. For regulated utilities subject to full cost-of-service regulation and return-on-investment requirements, we normally measure profitability using ROE, the ratio of net income available for common stockholders to average common equity. When setting rates, the regulator ultimately bases its decision on an authorized ROE. However, different factors such as variances in costs and usage may influence the return a utility is actually able to earn, and consequently our analysis of profitability for cost-of-service-based utilities centers on the utility's ability to consistently earn the authorized ROE.

51. We will use return on capital when pass-through costs distort profit margins--for instance congestion revenues or collection of third-party revenues. This is also the case when the utility uses accelerated depreciation of assets, which in our view might not be sustainable in the long run.

Volatility of profitability

52. We may observe a clear difference between the volatility of actual profitability and the volatility of underlying regulatory profitability. In these cases, we could use the regulatory accounts as a proxy to judge the stability of earnings.

53. We use actual returns to calculate the standard error of regression for regulated utility issuers (only if there are at least

seven years of historical annual data to ensure meaningful results). If we believe recurring mergers and acquisitions or currency fluctuations affect the results, we may make adjustments.

Part II--Financial Risk Analysis

D. Accounting

54. Our analysis of a company's financial statements begins with a review of the accounting to determine whether the statements accurately measure a company's performance and position relative to its peers and the larger universe of corporate entities. To allow for globally consistent and comparable financial analyses, our rating analysis may include quantitative adjustments to a company's reported results. These adjustments also align a company's reported figures with our view of underlying economic conditions and give us a more accurate portrayal of a company's ongoing business. We discuss adjustments that pertain broadly to all corporate sectors, including this sector, in "Corporate Methodology: Ratios And Adjustments." Accounting characteristics and analytical adjustments unique to this sector are discussed below.

Accounting characteristics

55. Some important accounting practices for utilities include:

- For integrated electric utilities that meet native load obligations in part with third-party power contracts, we use our purchased power methodology to adjust measures for the debt-like obligation such contracts represent (see below).
- Due to distortions in leverage measures from the substantial seasonal working-capital requirements of natural gas distribution utilities, we adjust inventory and debt balances by netting the value of inventory against outstanding short-term borrowings. This adjustment provides an accurate view of the company's balance sheet by reducing seasonal debt balances when we see a very high certainty of near-term cost recovery (see below).
- We deconsolidate securitized debt (and associated revenues and expenses) that has been accorded specialized recovery provisions (see below).
- For water utilities that report under U.K. GAAP, we adjust ratios for infrastructure renewals accounting, which permits water companies to capitalize the maintenance spending on their infrastructure assets (see below). The adjustments aim to make those water companies that report under U.K. GAAP more comparable to those that report under accounting regimes that do not permit infrastructure renewals accounting.

56. In the U.S. and selectively in other regions, utilities employ "regulatory accounting," which permits a rate-regulated company to defer some revenues and expenses to match the timing of the recognition of those items in rates as determined by regulators. A utility subject to regulatory accounting will therefore have assets and liabilities on its books that an unregulated corporation, or even regulated utilities in many other global regions, cannot record. We do not adjust GAAP earnings or balance-sheet figures to remove the effects of regulatory accounting. However, as more countries adopt International Financial Reporting Standards (IFRS), the use of regulatory accounting will become more scarce. IFRS does not currently provide for any recognition of the effects of rate regulation for financial reporting purposes, but it is considering the use of regulatory accounting. We do not anticipate altering our fundamental financial analysis of utilities because of the use or non-use of regulatory accounting. We will continue to analyze the effects of regulatory actions on a utility's financial health.

Purchased power adjustment

57. We view long-term purchased power agreements (PPA) as creating fixed, debt-like financial obligations that represent substitutes for debt-financed capital investments in generation capacity. By adjusting financial measures to incorporate PPA fixed obligations, we achieve greater comparability of utilities that finance and build generation capacity and those that purchase capacity to satisfy new load. PPAs do benefit utilities by shifting various risks to the electricity generators, such as construction risk and most of the operating risk. The principal risk borne by a utility that relies on PPAs is recovering the costs of the financial obligation in rates. (See "Standard & Poor's Methodology For Imputing Debt for U.S. Utilities' Power Purchase Agreements," May 7, 2007, for more background and information on the adjustment.)

58. 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 the same as the one used in the operating lease adjustment, i.e., 7%. For U.S. companies, notes to the financial statements enumerate capacity payments for the coming five years, and a thereafter period. Company forecasts show the detail underlying the thereafter amount, or we divide the amount reported as thereafter by the average of the capacity payments in the preceding five years to get an approximation of annual payments after year five.

59. We also consider new contracts that will start during the forecast period. The company provides us the information regarding these contracts. 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. The projected PPA debt is included in projected ratios as a current rating factor, even though it is not included in the current-year ratio calculations.

60. The PV is adjusted to reflect regulatory or legislative cost-recovery mechanisms when present. Where there is no explicit regulatory or legislative recovery of PPA costs, as in most European countries, the PV may be adjusted for other mitigating factors that reduce the risk of the PPAs to the utility, such as a limited economic importance of the PPAs to the utility's overall portfolio.The adjustment reduces the debt-equivalent amount by multiplying the PV by a specific risk factor.

61. Risk factors based on regulatory or legislative cost recovery 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 regulatory or legislative support. A 0% risk factor indicates that the burden of the contractual payments rests solely with ratepayers, as when the utility merely acts as a conduit for the delivery of a third party's electricity. These utilities 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. We employ a 50% risk factor in cases where regulators use base rates for the recovery of the fixed PPA costs. If a regulator has established a separate adjustment mechanism for recovery of all prudent PPA costs, a risk factor of 25% is employed. 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. Specialized, legislatively created cost-recovery mechanisms may 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 also exclude short-term PPAs where they serve merely as gap fillers, pending either the construction of new capacity or the execution of long-term PPAs.

62. Where there is no explicit regulatory or legislative recovery of PPA costs, the risk factor is generally 100%. We may use a lower risk factor if mitigating factors reduce the risk of the PPAs on the utility. Mitigating factors include a long position in owned generation capacity relative to the utility's customer supply needs that limits the importance of the PPAs to the utility or the ability to resell power in a highly liquid market at minimal loss. A utility with surplus owned generation capacity would be assigned a risk factor of less than 100%, generally 50% or lower, because we would assess its reliance on PPAs as limited. For fixed capacity payments under PPAs related to renewable power, we use a risk factor of less than 100% if the utility benefits from government subsidies. The risk factor reflects the degree of regulatory recovery through the government subsidy.

63. 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 may 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.

64. Some PPAs are treated as operating leases for accounting purposes--based on the tenor of the PPA or the residual value of the asset on the PPA's expiration. We accord PPA treatment to those obligations, in lieu of lease treatment; rather, the PV of the stream of capacity payments associated with these PPAs is reduced to reflect the applicable risk factor.

65. Long-term transmission contracts can also substitute for new generation, and, accordingly, may fall under our PPA methodology. We sometimes 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.

66. Adjustment procedures:

- Data requirements:
- Future capacity payments obtained from the financial statement footnotes or from management.
- Discount rate: 7%.
- 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.
- Property, plant, and equipment 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 determined by multiplying the discount rate by the amount of imputed debt (or average PPA imputed debt, if there is fluctuation of the level), and is added to interest expense.
- We impute a depreciation component to PPAs. The depreciation component is determined 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.
- The cost amount attributed to depreciation is reclassified as capital spending, thereby increasing operating cash flow and funds from operations (FFO).
- 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 determine 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 depreciation and amortization (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.

Natural gas inventory adjustment

67. In jurisdictions where a pass-through mechanism is used to recover purchased natural gas costs of gas distribution utilities within one year, we adjust for seasonal changes in short-debt tied to building inventories of natural gas in non-peak periods for later use to meet peak loads in peak months. Such short-term debt is not considered to be part of the utility's permanent capital. Any history of non-trivial disallowances of purchased gas costs would preclude the use of this adjustment. The accounting of natural gas inventories and associated short-term debt used to finance the purchases must be segregated from other trading activities.

68. Adjustment procedures:

- Data requirements:
- Short-term debt amount associated with seasonal purchases of natural gas devoted to meeting peak-load needs of captive utility customers (obtained from the company).

- Calculations:
- Adjustment to debt--we subtract the identified short-term debt from total debt.

Securitized debt adjustment

69. For regulated utilities, we deconsolidate debt (and associated revenues and expenses) that the utility issues as part of a securitization of costs that have been segregated for specialized recovery by the government entity constitutionally authorized to mandate such recovery if the securitization structure contains a number of protective features:

- An irrevocable, non-bypassable charge and an absolute transfer and first-priority security interest in transition property;
- Periodic adjustments ("true-up") of the charge to remediate over- or under-collections compared with the debt service obligation. The true-up ensures collections match debt service over time and do not diverge significantly in the short run; and,
- Reserve accounts to cover any temporary short-term shortfall in collections.

70. Full cost recovery is in most instances mandated by statute. Examples of securitized costs include "stranded costs" (above-market utility costs that are deemed unrecoverable when a transition from regulation to competition occurs) and unusually large restoration costs following a major weather event such as a hurricane. If the defined features are present, the securitization effectively makes all consumers responsible for principal and interest payments, and the utility is simply a pass-through entity for servicing the debt. We therefore remove the debt and related revenues and expenses from our measures. (See "Securitizing Stranded Costs," Jan. 18, 2001, for background information.)

71. Adjustment procedures:

- Data requirements:
- Amount of securitized debt on the utility's balance sheet at period end;
- Interest expense related to securitized debt for the period; and
- Principal payments on securitized debt during the period.

- Calculations:
- Adjustment to debt: We subtract the securitized debt from total debt.
- Adjustment to revenues: We reduce revenue allocated to securitized debt principal and interest. The adjustment is the sum of interest and principal payments made during the year.
- Adjustment to operating income after depreciation and amortization (D&A) and EBIT: We reduce D&A related to the securitized debt, which is assumed to equal the 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 remove the interest expense of the securitized debt from total interest expense.

- 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.

Infrastructure renewals expenditure

72. In England and Wales, water utilities can report under either IFRS or U.K. GAAP. Those that report under U.K. GAAP are allowed to adopt infrastructure renewals accounting, which enables the companies to capitalize the maintenance spending on their underground assets, called infrastructure renewals expenditure (IRE). Under IFRS, infrastructure renewals accounting is not permitted and maintenance expenditure is charged to earnings in the year incurred. This difference typically results in lower adjusted operating cash flows for those companies that report maintenance expenditure as an operating cash flow under IFRS, than for those that report it as capital expenditure under U.K. GAAP. We therefore make financial adjustments to amounts reported by water issuers that apply U.K. GAAP, with the aim of making ratios more comparable with those issuers that report under IFRS and U.S. GAAP. For example, we deduct IRE from EBITDA and FFO.

73. IRE does not always consist entirely of maintenance expenditure that would be expensed under IFRS. A portion of IRE can relate to costs that would be eligible for capitalization as they meet the recognition criteria for a new fixed asset set out in International Accounting Standard 16 that addresses property, plant, and equipment. In such cases, we may refine our adjustment to U.K. GAAP companies so that we only deduct from FFO the portion of IRE that would not be capitalized under IFRS. However, the information to make such a refinement would need to be of high quality, reliable, and ideally independently verified by a third party, such as the company's auditor. In the absence of this, we assume

that the entire amount of IRE would have been expensed under IFRS and we accordingly deduct the full expenditure from FFO.

74. Adjustment procedures:

- Data requirements:
- U.K. GAAP accounts typically provide little information on the portion of capital spending that relates to renewals accounting, or the related depreciation, which is referred to as the infrastructure renewals charge. The information we use for our adjustments is, however, found in the regulatory cost accounts submitted annually by the water companies to the Water Services Regulation Authority, which regulates all water companies in England and Wales.

- Calculations:
- EBITDA: Reduced by the value of IRE that was capitalized in the period.
- EBIT: Adjusted for the difference between the adjustment to EBITDA and the reduction in the depreciation expense, depending on the degree to which the actual cash spending in the current year matches the planned spending over the five-year regulatory review period.
- Cash flow from operations and FFO: Reduced by the value of IRE that was capitalized in the period.
- Capital spending: Reduced by the value of infrastructure renewals spending that we reclassify to cash flow from operations.
- Free operating cash flow: No impact, as the reduction in operating cash flows is exactly offset by the reduction in capital spending.

E. Cash flow/leverage analysis

75. In assessing the cash flow adequacy of a regulated utility, our analysis uses the same methodology as with other corporate issuers (see "Corporate Methodology"). We assess cash flow/leverage on a six-point scale ranging from ('1') minimal to ('6') highly leveraged. These scores are determined by aggregating the assessments of a range of credit ratios, predominantly cash flow-based, which complement each other by focusing attention on the different levels of a company's cash flow waterfall in relation to its obligations.

76. The corporate methodology provides benchmark ranges for various cash flow ratios we associate with different cash flow leverage assessments for standard volatility, medial volatility, and low volatility industries. The tables of benchmark ratios differ for a given ratio and cash flow leverage assessment along two dimensions: the starting point for the ratio range and the width of the ratio range.

77. If an industry's volatility levels are low, the threshold levels for the applicable ratios to achieve a given cash flow leverage assessment are less stringent, although the width of the ratio range is narrower. Conversely, if an industry has standard levels of volatility, the threshold levels for the applicable ratios to achieve a given cash flow leverage assessment may be elevated, but with a wider range of values.

78. We apply the "low-volatility" table to regulated utilities that qualify under the corporate criteria and with all of the following characteristics:

- A vast majority of operating cash flows come from regulated operations that are predominantly at the low end of the utility risk spectrum (e.g., a "network," or distribution/transmission business unexposed to commodity risk and with very low operating risk);
- A "strong" regulatory advantage assessment;

- An established track record of normally stable credit measures that is expected to continue;
- A demonstrated long-term track record of low funding costs (credit spread) for long-term debt that is expected to continue; and
- Non-utility activities that are in a separate part of the group (as defined in our group rating methodology) that we consider to have "nonstrategic" group status and are not deemed high risk and/or volatile.

79. We apply the "medial volatility" table to companies that do not qualify under paragraph 78 with:

- A majority of operating cash flows from regulated activities with an "adequate" or better regulatory advantage assessment; or
- About one-third or more of consolidated operating cash flow comes from regulated utility activities with a "strong" regulatory advantage and where the average of its remaining activities have a competitive position assessment of '3' or better.

80. We apply the "standard-volatility" table to companies that do not qualify under paragraph 79 and with either:

- About one-third or less of its operating cash flow comes from regulated utility activities, regardless of its regulatory advantage assessment; or
- A regulatory advantage assessment of "adequate/weak" or "weak."

Part III--Rating Modifiers

F. Diversification/portfolio effect

81. In assessing the diversification/portfolio effect on a regulated utility, our analysis uses the same methodology as with other corporate issuers (see "Corporate Methodology").

G. Capital structure

82. In assessing the quality of the capital structure of a regulated utility, we use the same methodology as with other corporate issuers (see "Corporate Methodology").

H. Liquidity

83. In assessing a utility's liquidity/short-term factors, our analysis is consistent with the methodology that applies to corporate issuers (See "Methodology And Assumptions: Liquidity Descriptors For Global Corporate Issuers," Nov. 19, 2013) except for the standards for "adequate" liquidity set out in paragraph 84 below.

84. The relative certainty of financial performance by utilities operating under relatively predictable regulatory monopoly frameworks make these utilities attractive to investors even in times of economic stress and market turbulence compared to conventional industrials. For this reason, utilities with business risk profiles of at least "satisfactory" meet our definition of "adequate" liquidity based on a slightly lower ratio of sources to uses of funds of 1.1x compared with the standard 1.2x. Also, recognizing the cash flow stability of regulated utilities we allow more discretion when calculating covenant headroom. We consider that utilities have adequate liquidity if they generate positive sources over uses, even if forecast EBITDA declines by 10% (compared with the 15% benchmark for corporate issuers) before covenants are breached.

I. Financial policy

85. In assessing financial policy on a regulated utility, our analysis uses the same methodology as with other corporate issuers (see "Corporate Methodology").

J. Management and governance

86. In assessing management and governance on a regulated utility, our analysis uses the same methodology as with other corporate issuers (see "Corporate Methodology").

K. Comparable ratings analysis

87. In assessing the comparable ratings analysis on a regulated utility, our analysis uses the same methodology as with other corporate issuers (see "Corporate Methodology").

Appendix--Frequently Asked Questions

Does Standard & Poor's expect that the business strategy modifier to the preliminary regulatory advantage will be used extensively?

88. Globally, we expect management's influence will be neutral in most jurisdictions. Where the regulatory assessment is "strong," it is less likely that a negative business strategy modifier would be used due to the nature of the regulatory regime that led to the "strong" assessment in the first place. Utilities in "adequate/weak" and "weak" regulatory regimes are challenged to outperform due to the uncertainty of such regulatory regimes. For a positive use of the business strategy modifier, there would need to be a track record of the utility consistently outperforming the parameters laid down under a regulatory regime, and we would need to believe this could be sustained. The business strategy modifier is most likely to be used when the preliminary regulatory advantage assessment is "strong/adequate" because the starting point in the assessment is reasonably supportive, and a utility has shown it manages regulatory risk better or worse than its peers in that regulatory environment and we expect that advantage or disadvantage will persist. An example would be a utility that can consistently earn or exceed its authorized return in a jurisdiction where most other utilities struggle to do so. If a utility is treated differently by a regulator due to perceptions of poor customer service or reliability and the "operating efficiency" component of the competitive position assessment does not fully capture the effect on the business risk profile, a negative business strategy modifier could be used to accurately incorporate it into our analysis. We expect very few utilities will be assigned a "very negative" business strategy modifier.

Does a relatively strong or poor relationship between the utility and its regulator compared with its peers in the same jurisdiction necessarily result in a positive or negative adjustment to the preliminary regulatory advantage assessment?

89. No. The business strategy modifier is used to differentiate a company's regulatory advantage within a jurisdiction where we believe management's business strategy has and will positively or negatively affect regulatory outcomes beyond what is typical for other utilities in that jurisdiction. For instance, in a regulatory jurisdiction where allowed returns are negotiated rather than set by formula, a utility that is consistently authorized higher returns (and is able to earn that return) could warrant a positive adjustment. A management team that cannot negotiate an approved capital spending program to improve its operating performance could be assessed negatively if its performance lags behind peers in the same regulatory jurisdiction.

What is your definition of regulatory jurisdiction?

90. A regulatory jurisdiction is defined as the area over which the regulator has oversight and could include single or multiple subsectors (water, gas, and power). A geographic region may have several regulatory jurisdictions. For example, the Office of Gas and Electricity Markets and the Water Services Regulation Authority in the U.K. are considered separate regulatory jurisdictions. In Ontario, Canada, the Ontario Energy Board represents a single jurisdiction with regulatory oversight for power and gas. Also, in Australia, the Australian Energy Regulator would be considered a single jurisdiction given that it is responsible for both electricity and gas transmission and distribution networks in the entire country, with the exception of Western Australia.

Are there examples of different preliminary regulatory advantage assessments in the same country or jurisdiction?

91. Yes. In Israel we rate a regulated integrated power utility and a regulated gas transmission system operator (TSO). The power utility's relationship with its regulator is extremely poor in our view, which led to significant cash flow volatility in a stress scenario (when terrorists blew up the gas pipeline that was then Israel's main source of natural gas, the utility was unable to negotiate compensation for expensive alternatives in its regulated tariffs). We view the gas TSO's relationship with its regulator as very supportive and stable. Because we already reflected this in very different preliminary regulatory advantage assessments, we did not modify the preliminary assessments because the two regulatory environments in Israel differ and were not the result of the companies' respective business strategies.

How is regulatory advantage assessed for utilities that are a natural monopoly but are not regulated by a regulator or a specific regulatory framework, and do you use the regulatory modifier if they achieve favorable treatment from the government as an owner?

92. The four regulatory pillars remain the same. On regulatory stability we look at the stability of the setup, with more emphasis on the historical track record and our expectations regarding future changes. In tariff-setting procedures and design we look at the utility's ability to fully recover operating costs, investments requirements, and debt-service obligations. In financial stability we look at the degree of flexibility in tariffs to counter volume risk or commodity risk. The flexibility can also relate to the level of indirect competition the utility faces. For example, while Nordic district heating companies operate under a natural monopoly, their tariff flexibility is partly restricted by customers' option to change to a different heating source if tariffs are significantly increased. Regulatory independence and insulation is mainly based on the perceived risk of political intervention to change the setup that could affect the utility's credit profile. Although political intervention tends to be mostly negative, in certain cases political ties due to state ownership might positively influence tariff determination. We believe that the four pillars effectively capture the benefits from the close relationship between the utility and the state as an owner; therefore, we do not foresee the use of the regulatory modifier.

In table 1, when describing a "strong" regulatory advantage assessment, you mention that there is support of cash flows during construction of large projects, and preapproval of capital investment programs and large projects lowers the risk of subsequent disallowances of capital costs. Would this preclude a "strong" regulatory advantage assessment in jurisdictions where those practices are absent?

93. No. The table is guidance as to what we would typically expect from a regulatory framework that we would assess as "strong." We would expect some frameworks with no capital support during construction to receive a "strong" regulatory advantage assessment if in aggregate the other factors we analyze support that conclusion.

RELATED CRITERIA AND RESEARCH

- Corporate Methodology, Nov. 19, 2013
- Group Rating Methodology, Nov. 19, 2013
- Methodology: Industry Risk, Nov. 19, 2013
- Corporate Methodology: Ratios And Adjustments, Nov. 19, 2013
- Ratings Above The Sovereign--Corporate And Government Ratings: Methodology And Assumptions, Nov. 19, 2013
- Methodology And Assumptions: Liquidity Descriptors For Global Corporate Issuers, Nov. 19, 2013
- Collateral Coverage And Issue Notching Rules For '1+' And '1' Recovery Ratings On Senior Bonds Secured By Utility Real Property, Feb. 14, 2013
- Methodology: Management And Governance Credit Factors For Corporate Entities and Insurers, Nov. 13, 2012
- General Criteria: Principles Of Credit Ratings, Feb. 16, 2011
- General Criteria: Rating Government-Related Entities: Methodology And Assumptions, Dec. 9, 2010

These criteria represent the specific application of fundamental principles that define credit risk and ratings opinions. Their use is determined by issuer- or issue-specific attributes as well as Standard & Poor's Ratings Services' assessment of the credit and, if applicable, structural risks for a given issuer or issue rating. Methodology and assumptions may change from time to time as a result of market and economic conditions, issuer- or issue-specific factors, or new empirical evidence that would affect our credit judgment.

(And watch the related CreditMatters TV segment titled, "Standard & Poor's Highlights The Key Credit Factors For Rating Regulated Utilities," dated Nov. 21, 2013.)

Exhibit KWB-7

Utility Peer Group Cost of Debt Comparison (June 2014)

Utilty Cost of Debt Comparison 12 Months Ending June 2014		
Rank	Company	Per Public Data
-		
1.	**LG&E**	**3.533%**
2.	**KU**	**3.565%**
3.	Duke Energy Ohio	3.753%
4.	Dayton Power and Light	3.820%
5.	AEP Texas North Company	4.246%
6.	Public Service Electric and Gas Company	4.388%
7.	AEP Texas Central Company	4.440%
8.	Indiana Michigan Power Company	4.543%
9.	Duke Energy Indiana Inc.	4.616%
10.	DTE Electric Company	4.738%
11.	PECO Energy Company	4.827%
12.	Union Electric Company	4.845%
13.	Ohio Power Company	4.849%
14.	Commonwealth Edison	4.983%
15.	PPL Electric Utilities	4.985%
16.	NiSource	4.988%
17.	Appalachian Power Company	5.177%
18.	Jersey Central Power & Light Co.	5.502%
19.	Metropolitan Edison Company	5.607%
20.	Kentucky Power Company	5.833%
21.	Pennsylvania Electric Company	6.028%
22.	DTE Gas Company	6.349%
23.	Toledo Edison Company	6.463%
24.	Ameren Illinois Company	7.264%
25.	Ohio Edison Company	7.841%

Exhibit KWB-8

News Release re: Moody’s Upgrade

MOODY'S
INVESTORS SERVICE

Moody's upgrades the ratings of PPL US utility subsidiaries and confirms the rating of PPL Corp. and LKE; rating outlook stable.

31 Jan 2014

Approximately $10.8 Billion of Debt Affected

New York, January 31, 2014 -- Moody's Investors Service today upgraded the ratings of PPL Corporation's US utility operating subsidiaries: the rating of PPL Electric Utilities (PPLEU) was upgraded to Baa1 from Baa2 and the ratings of Louisville Gas & Electric Company (LGE) and Kentucky Utilities (KU) were upgraded to A3 from Baa1. Moody's confirmed the senior unsecured ratings of PPL Corporation (PPL) at Baa3 and of LG&E and KU Energy LLC (LKE) at Baa2. This rating action completes our review of PPL and its regulated operations initiated on November 8, 2013. The outlook for all PPL entities is stable.

The primary driver of today's positive rating action on PPL's US utility operating companies was Moody's more favorable view of the relative credit supportiveness of the US regulatory environment, as detailed in our September 2013 Request for Comment titled "Proposed Refinements to the Regulated Utilities Rating Methodology and our Evolving View of US Utility Regulation."

The review, however, did not result in a corresponding upgrade for the parent holding company PPL because the upgrades of PPL's US regulated utilities, which represent 31% of earnings, did not shift PPL's consolidated credit profile sufficiently. PPL's consolidated financial metrics are also weak for its rating category. LKE did not receive an upgrade because of the high debt level at LKE relative to the consolidated LKE. Moreover, because there is free movement of cash between PPL and LKE, PPL has a constraining effect on LKE's ratings.

RATINGS RATIONALE

The ratings of PPL and its utility subsidiaries are underpinned by regulatory environments that, while they may vary somewhat from jurisdiction to jurisdiction, are generally supportive of utility credit quality and by an energy commodity market that has alleviated some of the pressure on rates generally. Additionally, PPL's rating is reflective of the consolidated credit profile which has been transformed from a heavily merchant commodity driven and regionally focused operation, to a more diversified and mostly rate regulated platform. These positive factors are balanced against financial metrics on a consolidated basis that have been on the lower end of the range for benchmarks established for regulated utilities. As of end of third quarter 2013, PPL's CFO Pre-WC/debt averaged over the past three years is 15.5%, while the benchmark for regulated utilities in the Baa category is between 13% and 22%.

Rating Outlook

The stable outlook for PPL reflects our view that PPL's credit quality has been fortified through the growing share of its regulated business. The stable outlook also incorporates a view that the company's large capital investment will be prudently financed, to include if needed, the issuance of common equity. The unregulated generation assets' cash flow generating capacity is expected to be lower over the next several years but further downsides are moderated by hedging and its declining share to the consolidated cash flow.

What Could Change the Rating -- Up

Potential for upgrade is currently limited by its financial metrics which are weak for its ratings. Upgrade is possible if exposure to unregulated activity continue to decline while cash flow to debt ratio improves 20% or above on a sustained basis.

What Could Change the Rating - Down

While we do not foresee any particular event that would result in a negative rating action, the company's cash flow to debt credit metrics are expected to be weaker going forward due to the declining cash flow coming from its unregulated operations. As a result, the company has a smaller margin of error for a negative rating action.

The principal methodology used in this rating was Regulated Electric and Gas Utilities published in December 2013. Please see the Credit Policy page on www.moodys.com for a copy of this methodology.

Issuer: PPL Corporation

Outlook revised to stable from RUR-UP

Confirmed:

LT Issuer Rating: Baa3

Pref. Shelf ratings: (P)Ba2

Issuer: PPL Electric Utilities Corporation

Outlook revised to stable from RUR-UP

Upgraded:

LT Issuer Rating to Baa1 from Baa2

Senior unsecured to Baa1 from Baa2

Senior secured to A2 from A3

First Mortgage Bonds to A2 from A3

Preference Shelf to (P)Baa3 from (P)Ba1

Senior Secured Shelf to (P)A2 from (P)A3

Affirmed:

Commercial paper rating of P-2

Issuer: LG&E and KU Energy LLC

Outlook revised to stable from RUR-UP

Confirmed:

LT Issuer Rating: Baa2

Senior unsecured: Baa2

Senior unsecured Self: (P)Baa2

Issuer: Louisville Gas & Electric Company

Outlook revised to stable from RUR-UP

Upgraded:

LT Issuer Rating to A3 from Baa1

Senior unsecured to A3 from Baa1

Senior secured to A1 from A2

Senior secured Shelf to (P)A1 from (P)A2

Affirmed:

Commercial Paper ratings: P-2

Issuer: Kentucky Utilities Co.

Outlook revised to stable from RUR-UP

Upgraded:

LT Issuer Rating to A3 from Baa1

Senior unsecured to A3 from Baa1

Senior secured to A1 from A2

Senior secured Shelf to (P)A1 from (P)A2

Affirmed:

Commercial Paper rating: P-2

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MOODY'S
INVESTORS SERVICE

Exhibit KWB-9

S&P Announcement

STANDARD & POOR'S
RATINGS SERVICES
McGRAW HILL FINANCIAL

Research

PPL Corp. And Subsidiaries 'BBB' Issuer Credit Rating On CreditWatch Positive On Spin-Off Plan

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- PPL Corp. (PPL) announced that it intends to spin off its unregulated power generation subsidiary PPL Energy Supply LLC (PPLES).
- We are placing our 'BBB' issuer credit ratings (ICR) on PPL, PPL Electric Utilities Corp. (PPLEU), LG&E and KU Energy LLC (LKE), Kentucky Utilities Co. (KU), and Louisville Gas and Electric Co. (LG&E) on CreditWatch with positive implications. We based the CreditWatch placement on the expected improvement in PPL's business risk profile after the spin-off of PPLES and sufficient credit measures that could result in a ratings upgrade.
- Based on the preliminary terms of the transaction, we believe the ICRs on PPL and its U.S. regulated utility subsidiaries could be raised to 'A-', subject to satisfactory regulated approvals and operating results remaining in line with our expectations.
- We are affirming the 'A-2' short-term ratings.

NEW YORK (Standard & Poor's) June 10, 2014--Standard & Poor's Ratings Services today placed its 'BBB' issuer credit ratings on PPL Corp. and utility subsidiaries PPL Electric Utilities Corp., Kentucky Utilities Co., and Louisville Gas and Electric Co., as well as intermediate holding company LG&E and KU Energy LLC on CreditWatch with positive implications. At the same time, we affirmed the 'A-2' short-term ratings on the companies.

"Our CreditWatch placement reflects our expectation that PPL's credit profile will strengthen after the spin-off of the unregulated power generation subsidiary PPL Energy Supply LLC," said Standard & Poor's credit analyst Gerrit Jepsen.

Based on our medial volatility financial ratio benchmarks, we expect to assess PPL's financial risk profile as "significant", with projected credit protection measures being mostly near the lower end of the category. PPL currently has "adequate" liquidity, as our criteria define the term.

Standard & Poor's bases its ICR on PPL on the consolidated group credit profile (GCP) and application of our group ratings methodology. PPL, as the parent company, currently has an ICR equal to the 'bbb' GCP, which we will reassess as part of the CreditWatch resolution. Under our group rating methodology, we consider all of PPL's U.S. regulated utilities and their intermediate holding companies core subsidiaries of the PPL group because we believe the utilities are integral to PPL's long-term strategy. The ICRs for these subsidiaries are therefore most likely to remain equal to the GCP established for PPL.

The CreditWatch placement will remain until the transaction closing, with periodic updates. Upon the transaction's completion, we could raise the issuer credit ratings and issue ratings on PPL, LKE, LG&E, KU, and PPLEU by up to two notches depending on the credit measures of the consolidated PPL group after the PPLES divestiture. Material changes to the financial measures in our base and cash flow generation capability of the pro forma group could affect the ultimate financial risk profile.

RELATED CRITERIA AND RESEARCH

- Criteria - Corporates - General: Methodology And Assumptions: Liquidity Descriptors For Global Corporate Issuers, Jan. 2, 2014
- Criteria - Corporates - Utilities: Key Credit Factors For The Regulated Utilities Industry, Nov. 19, 2013
- General Criteria: Group Rating Methodology, Nov. 19, 2013
- General Criteria: Methodology: Industry Risk, Nov. 19, 2013
- Criteria - Corporates - General: Corporate Methodology, Nov. 19, 2013
- General Criteria: Methodology: Industry Risk, Nov. 19, 2013
- Criteria - Corporates - General: Corporate Methodology: Ratios And Adjustments, Nov. 19, 2013
- Criteria - Corporates - Utilities: Collateral Coverage And Issue Notching Rules For '1+' And '1' Recovery Ratings On Senior Bonds Secured By Utility Real Property, Feb. 14, 2013
- General Criteria: Methodology: Management And Governance Credit Factors For Corporate Entities And Insurers, Nov. 13, 2012
- General Criteria: Stand-Alone Credit Profiles: One Component Of A Rating, Oct. 1, 2010
- Use of CreditWatch and Outlooks, Sept. 14, 2009
- Criteria - Corporates - Utilities: Notching Of U.S. Investment-Grade Investor-Owned Utility Unsecured Debt Now Better Reflects Anticipated Absolute Recovery, Nov. 10, 2008
- 2008 Corporate Criteria: Rating Each Issue, April 15, 2008
- Criteria - Corporates - General: 2008 Corporate Criteria: Commercial Paper , April 15, 2008

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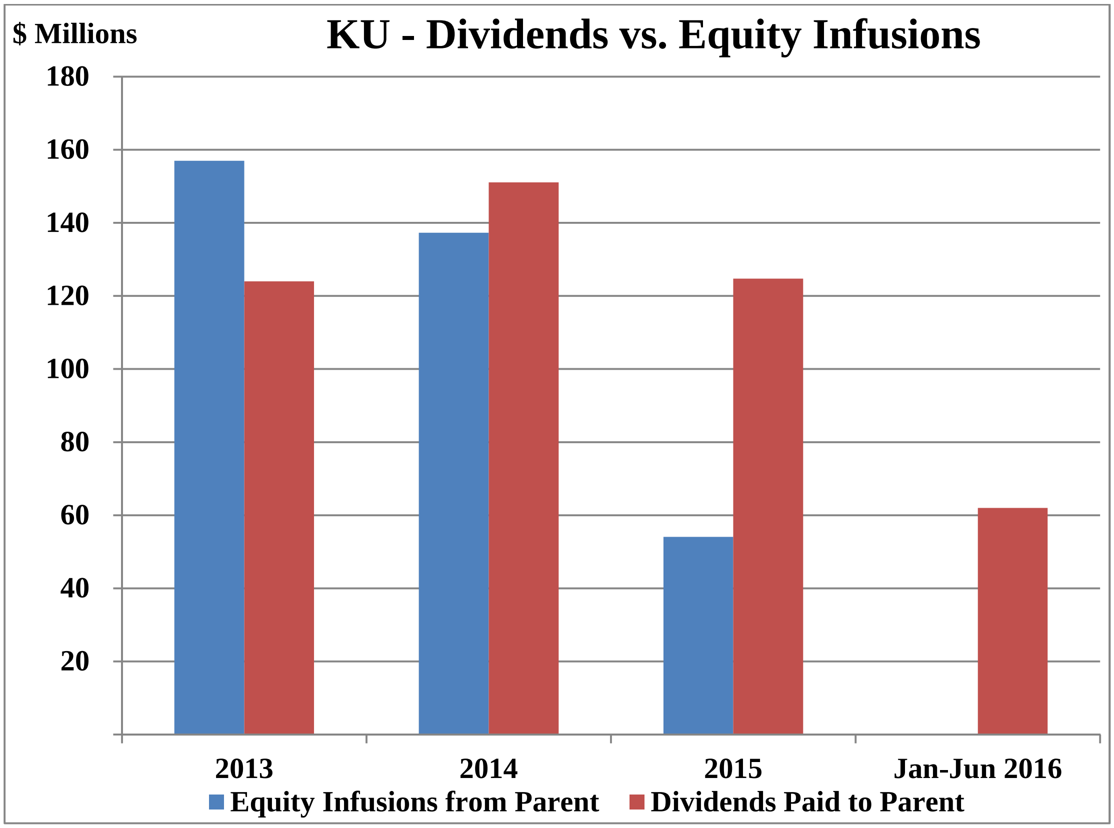
Exhibit KWB-10

Dividend vs. Equity Infusions


$ Millions
KU - Dividends vs. Equity Infusions
180
160
140
120
100
80
60
40
20
2013
2014
2015
Jan-Jun 2016
Equity Infusions from Parent
Dividends Paid to Parent

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. 2014-00371**

In the Matter of:

APPLICATION OF LOUISVILLE GAS AND ELECTRIC COMPANY FOR AN ADJUSTMENT OF ITS ELECTRIC AND GAS RATES	))))	**CASE NO. 2014-00372**

TESTIMONY OF
PAUL W. THOMPSON
CHIEF OPERATING OFFICER
LOUISVILLE GAS AND ELECTRIC COMPANY
AND
KENTUCKY UTILITIES COMPANY

Filed: November 26, 2014

TABLE OF CONTENTS

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

A. My name is Paul W. Thompson. I am the Chief Operating Officer 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, which provides services to the Companies. 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 job duties as Chief Operating Officer.

A. As Chief Operating Officer, I am responsible for power generation functions, engineering and construction, energy supply and analysis, electric distribution and transmission, gas distribution and storage, and customer service.

Q. When did you become Chief Operating Officer?

A. I was named Chief Operating Officer in February 2013. Previously, I served as Senior Vice President of Energy Services. In that role, I oversaw generation, transmission, and energy supply and analysis activities. The Companies created the Chief Operating Officer position around the time of Chris Hermann's retirement. Mr.

Hermann had served as Senior Vice President of Energy Delivery, which means he oversaw gas and electric distribution and customer service operations. The Chief Operating Officer position combines these two former positions.

Q. Have other organizational changes occurred since the last rate case?

A. Around the same time I was named Chief Operating Officer, LG&E created a new position titled Vice President of Gas Distribution. The various gas distribution functions were consolidated under this new position. The Vice President of Gas Distribution is responsible for the safe, reliable, and strategic operation of LG&E's natural gas transmission and distribution systems and for the low-cost delivery of gas to customers. Lonnie Bellar was named Vice President of Gas Distribution and continues in that role today.

Q. Have you previously testified before this Commission?

A. Yes, I have testified in the Companies' last four base rate cases.[1] I testified in the proceeding involving the early termination of the lease between Western Kentucky Energy Corporation and Big Rivers Electric Corporation[2] and in the Commission's investigation of the Companies' membership in the Midwest Independent

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

[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.

Transmission System Operator, Inc.[3] I also testified when the Companies sought and received approval to construct a natural gas combined-cycle combustion turbine.[4] Most recently, I testified in Case No. 2014-00002 involving the Companies' request for a certificate of public convenience and necessity ("CPCN") to construct a solar photovoltaic facility at the E.W. Brown Generating Station.[5]

Q. What is the purpose of your testimony?

A. My testimony describes the operational side of the Companies, including how the Companies continue to provide safe and reliable service to our customers, make significant capital and operation and maintenance expenditures to improve utility plant, and maintain our commitment to safety and customer service. These efforts have come with increased costs despite our work to increase productivity and achieve efficiencies. While Kent Blake and others explain the specific reasons why the Companies seek a rate increase, my testimony provides context and detail to the operational reasons behind the request.

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[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*, Case No. 2011-00375.

[5] *In the Matter of: Joint Application of Louisville Gas and Electric Company and Kentucky Utilities Company for Certificates of Public Convenience and Necessity for the Construction of a Combined Cycle Combustion Turbine at the Green River Generating Station and a Solar Photovoltaic Facility at the E.W. Brown Generating Station*, Case No. 2014-00002. The Companies are no longer seeking a CPCN for the generating unit at Green River.

OVERVIEW

Operating Stress Test

Q. Have the Companies faced any operational challenges since their last rate cases?

A. Yes. The electric and gas industries face continual and ever-changing challenges, including increasing regulatory constraints, unpredictable severe weather events, and difficult economic conditions. These challenges have resulted in increased operating complexity and expense. LG&E and KU meet the operational challenges of this complex environment in part by employing, training, and retaining a sophisticated workforce capable of doing whatever is reasonably necessary to meet customer need, be it implementing the latest regulatory requirements, restoring power following significant storms, or assessing the least-cost option for new generation needs.

Perhaps the most significant event since the Companies' last rate cases involved the polar vortex experienced in early 2014. The consistently cold temperatures in January and February 2014 were among the coldest on record. January 2014 was the third-coldest January in the last twenty years; February 2014 was the fourth-coldest February in the last twenty years. On January 6, 2014, and January 7, 2014, the Companies set several new peak energy demand records, including their highest ever combined system winter peak demand of 7,114 MW on January 6. KU also experienced its highest peak demand ever at the hour ending 9:00 a.m. EST on January 7, 2014, when demand was 5,068 MW. That same day, the Companies set a record for the most energy provided in a day by providing 153,967 MWh to their customers. LG&E's gas business set an all-time record for natural gas sendout on January 6 by providing 557,000 Mcf.

I am proud to say the Companies' utility systems met the demands placed on them by such highly adverse conditions. While other utility companies experienced challenges ranging from generators not starting to issues with securing natural gas, the Companies safely delivered energy to their customers in a time of operational stress and critical customer need. When our customers' needs were greatest, our systems delivered the energy customers needed to stay warm, have lighting, and operate their businesses.

That said, the Companies' good past performance does not preclude future improvement. To that end, the Companies are carefully reviewing the North American Electric Reliability Corporation's ("NERC") *Polar Vortex Review*, which NERC issued in September 2014 in response to certain performance shortcomings experienced by utilities during the extreme weather. NERC, working with the utility industry, identified possible improvements to the power industry's cold-weather operations and changes to the natural gas industry's scheduling process. The Companies will make all prudent performance-enhancing procedural changes or investments indicated by the Companies' analysis of the *Polar Vortex Review*, though the Companies' preliminary review indicates they are performing to expectations.

Programs and Practices to Achieve Efficiency and Productivity

Q. Do you agree with Mr. Staffieri's testimony that the Companies have programs and practices in place to achieve improvements in efficiency and productivity?

A. Absolutely. The Companies have many existing programs and practices across all areas to achieve improvements in efficiency and productivity. While specific advantages vary—such as streamlining a process, reducing unplanned maintenance costs, or automating a task—all benefits inure to our customers through the efficient delivery of reliable electric and gas service. My testimony will further describe the many programs and practices that Power Generation, Transmission, Electric Distribution, Gas Distribution, and Customer Services use to enhance their efficiency and productivity.

One program of particular importance to the Companies is the written policy regarding our Competitive Bid Process. The electric and gas industries involve significant capital investment and operation and maintenance spending. We take seriously our obligation to provide safe, reliable, and low-cost energy to our customers. Therefore, we competitively bid materials, supplies, and projects involving the expenditure of more than $50,000 unless competitive bids cannot be obtained or competitive bidding is not reasonable under the circumstances. The Companies do not competitively bid where the technical capability or availability of a particular vendor is required, such as when a boiler modification or repair is made and the original equipment manufacturer is the best source due to their knowledge of design and engineering specifications. These situations are, however, the exception rather than the rule; and many purchases under the $50,000 threshold are competitively bid.

The Companies' Competitive Bid Process policy is spelled out within the Companies' *Purchasing Guidelines*. The process entails up to eight steps from the initial development and publication of a request for proposals through execution of a contract. The overall goal of the process is to secure the best overall value while treating all suppliers fairly and consistently. For example, the Companies develop bid-evaluation criteria prior to bid opening. The Companies make it a point to include woman- and minority-owned businesses in the bidding process when possible and have had success in doing so.

One particularly topical example of the Companies' Competitive Bid Process is the construction of Cane Run Unit 7 ("CR7"), which is discussed in greater detail below. Initially, the Companies projected the cost of CR7 to be $583 million. Current figures project the final cost to be $563 million. The Companies believe the Competitive Bid Process contributed to these savings.

Operating Changes Supporting an Increase in Base Rates

Q. Why is a rate increase needed at this time?

A. The Companies have made and are continuing to make significant capital investments needed to serve customers and comply with new and upcoming environmental regulations. Since the close of the test period for the Companies' last rate cases,[6] they have invested approximately $1.5 billion in capital projects to serve customers (excluding capital investments recovered through rate mechanisms). This includes approximately $755 million for generation-related projects, $212 million for transmission, $337 million for electric distribution, $79 million for gas distribution, and $25 million for customer services. The following tables show actual capital investments by company and operational line of business from April 1, 2012 (the end of the prior test period), through August 31, 2014; forecasted amounts from September 1, 2014, through June 30, 2016; and comprehensive amounts from the end

[6] The Companies last filed base rate cases in 2012 based on an historical test year. The test year in the prior case was April 1, 2011, through March 31, 2012. *See 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.

of the prior test period through the end of the forecasted test period (April 1, 2012, through June 30, 2016):

LG&E Electric Capital Investment (millions)[7]

Line of Business	April 1, 2012 to August 31, 2014	September 1, 2014 to June 30, 2016	April 1, 2012 to June 30, 2016
Generation	$259	$184	$443
Transmission	$93	$39	$132
Distribution	$147	$144	$291
Customer Service	$7	$6	$12
Total	**$506**	**$373**	**$878**

LG&E Gas Capital Investment (millions)

Line of Business	April 1, 2012 to August 31, 2014	September 1, 2014 to June 30, 2016	April 1, 2012 to June 30, 2016
Distribution	$79	$54	$133
Customer Service	$7	$6	$14
Total	**$87**	**$60**	**$148**

KU Electric Capital Investment (millions)

Line of Business	April 1, 2012 to August 31, 2014	September 1, 2014 to June 30, 2016	April 1, 2012 to June 30, 2016
Generation	$496	$205	$701
Transmission	$119	$83	$201
Distribution	$190	$165	$355
Customer Service	$11	$14	$25
Total	**$816**	**$466**	**$1,282**

Much of this capital investment through August 31, 2014 (over $480 million), relates to construction of CR7, a natural gas combined-cycle unit expected to begin commercial operation in May 2015. The construction of this unit is on schedule and under budget. Other significant capital projects since the last rate case include both nonrecurring investments, such as the ongoing renovation at LG&E's Ohio Falls Generating Station—which is explained in more detail below—and recurring

[7] These tables are not comprehensive and do not include certain expenditures or services that are shared between the Companies, such as information technology, finance, and human resources. Slight differences may exist due to rounding.

investment, such as work on generating unit boilers and tubing and pole replacements.

Although significant, these capital investments are not over. The Companies anticipate making additional capital investments of $486 million during the forecasted test period. The investment during the test period will occur across all lines of business. Significant capital projects during the forecasted test period include circuit hardening and the replacement of utility poles to improve reliability, construction of a solar facility at Brown to increase renewable-resource generating capacity, and demolition of the retired coal-fired units at Paddy's Run Generating Station to increase safety.

Capital investment alone is not the only reason an increase in rates is needed. Operation and maintenance expenses also have increased. As discussed throughout my testimony, the Companies have a full suite of programs and practices to create efficiencies and increase productivity. Nonetheless, economic and regulatory changes have increased expenses. These increased costs are due to many factors, such as the cost to maintain a competitive and skilled workforce, more equipment and operating complexity requiring more employees, general inflation, and additional pension expense due to updated actuarial standards the IRS is anticipated to adopt. My testimony describes how customer needs, regulatory requirements, capital projects, and future retirements will require additional employees throughout each line of business by the end of the forecasted test period.

Ultimately, customers deserve safe and reliable service, and we do our best to deliver. Providing this essential service requires the commitment of financial and human resources, and the Companies strive to do so at the lowest reasonable cost. Despite the best efforts of our employees, though, we must seek to increase base rates to recover the cost of capital invested and operational expenditures made to meet our customers' energy needs.

GENERATION SYSTEMS

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

A. LG&E owns and operates approximately 3,221 MW of summer net generating capacity with a net book value of approximately $1.2 billion. LG&E's generating system consists primarily of three coal-fired generating stations: Cane Run, 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 base load supply subject to river flow constraints. LG&E also purchases power from the Ohio Valley Electric Corporation ("OVEC") through a long-existing Inter-Company Power Agreement and anticipates purchasing power from Bluegrass Generation Company, LLC ("Bluegrass"), located in Oldham County, Kentucky, in the near future as described below.

Q. Please describe KU's generation system.

A. KU owns and operates approximately 4,693 MW of summer net generating capacity with a net book value of approximately $3 billion. KU's generating system primarily consists of four generating stations: Ghent in Carroll County, E.W. Brown in Mercer County, Trimble County, and Green River in Muhlenberg County. The last operational generating unit at Tyrone in Woodford County was retired in 2013. 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. KU also purchases power from OVEC through the same long-existing Inter-Company Power Agreement.

Q. Do LG&E and KU engage in joint planning of their generation 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 Companies' combined eighteen coal-fired units, eleven hydro units, and twenty simple-cycle combustion turbines continues to produce efficiencies through joint dispatch capabilities and intercompany sales of power. Once commercially operational, CR7 will be included in this joint dispatch, as will the power purchased from Bluegrass.

Q. As a result of this joint planning, do LG&E and KU jointly own certain generating units and combustion turbines?

A. Yes. KU and LG&E, together with the Illinois Municipal Electric Agency ("IMEA") and the Indiana Municipal Power Association ("IMPA"), jointly own Trimble County Unit 2 ("TC2")[8]; KU's ownership share is 60.75 percent, LG&E's ownership share is 14.25 percent, and IMEA and IMPA together hold a 25 percent share. LG&E and KU also jointly own several peaking units: Trimble County Units 5 through 10, E.W. Brown Units 5 through 7, and Paddy's Run Unit 13.

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[8] LG&E owns 75 percent of Trimble County Unit 1, with IMEA and IMPA owning the remaining 25 percent.

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

A. LG&E and KU have a history of reliable and efficient generation performance. This is evidenced through the Companies' 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 2013 was 7.7 percent, while its five-year average from 2009 through 2013 was 6.5 percent. The most recent three-year national average for EFOR (through 2012) across all electric utilities was 8.3 percent. These comparisons demonstrate that the Companies' performance is comparable to reliable generating units nationwide.

Generation Efficiency and Productivity Programs and Practices

Q. Can you please describe the efficiency and productivity programs and practices that Power Generation uses in generating electricity?

A. Certainly. One of the most significant practices is predictive maintenance, which is fully integrated into the Companies' six generating stations. The purpose is to provide the generating stations and facilities with strategy, expertise, information, and services essential to optimize maintenance and operating decisions based on measured equipment condition. It does so through four technologies at each generating station: vibration analysis, oil analysis, thermal imaging, and motor testing. These technologies provide for the early detection of machine issues, such as imbalances and gearing defects. The information received from these technologies allows the Companies to establish maintenance practices that reduce the number of unexpected component failures and unnecessary equipment changes. For example, one of the units at Paddy's Run Generating Station was able to forego time-based oil changes this year because the predictive maintenance oil analyses showed the change was unnecessary, thereby reducing maintenance costs without negatively affecting reliability.

Power Generation also uses remote performance monitoring to detect early anomalies that could indicate emerging issues with plant equipment and systems. Remote performance monitoring initially began as a pilot in 2010 at two coal-fired plants and was later extended to the entire coal-fired fleet and combustion turbines at the Brown and Trimble County generating stations. The program collects data from the plants' Distributed Control System, which is then sent to Black and Veatch for monitoring and analysis based on models that track normal operating ranges to look for data points that fall outside these ranges. Black and Veatch alerts the Companies to any anomalous parameters and provides information to help diagnose the issue and return the parameter to normal operational values. This early detection allows LG&E and KU to avoid costly failures while keeping equipment operating in a reliable manner.

Q. Does Power Generation have efficiency and productivity practices in place with respect to its boilers?

A. Yes, LG&E and KU have two such practices. First, the Companies improve reliability and preserve life of boiler pressure parts through utilizing best practices for inspection, repairs, and replacement. This practice allows the Companies to assess the current condition of boiler components through planned outages, which allows not only for immediate repairs, but informed corrective actions and future repair plans.

Second, the Companies engage in corrosion fatigue mitigation efforts. The Companies systematically identify, remove, and prevent future occurrences of corrosion fatigue in their boilers. Since 2007, eight boilers have been inspected. The information gleaned from these inspections helps prevent boiler component failures and allows the Companies to refine their corrosion-removal methodologies.

Q. Are there other efficiency and productivity practices that Power Generation employs?

A. Yes, there are two other efficiency and productivity practices I should discuss. First, the Companies utilize three-dimensional analytical software to perform stress analyses on all high energy piping in the Companies' plants. The software allows the Companies to prioritize repair and inspection needs and estimate the remaining life of components.

The Companies also utilize a catalyst management program on its selective catalytic reduction ("SCR") equipment to implement guidelines to protect and monitor this important equipment. SCR equipment consists of a large box containing multiple layers of nitrogen oxide ("NO_x") reduction catalyst. Catalyst reactivity degrades over time and must be replaced to maintain the requisite NO_x removal efficiency. The Catalyst Management Program provides clear direction to all affected departments regarding their SCR management responsibilities. This ensures the equipment is properly and efficiently maintained.

These programs and others have led to the Companies spending on average $7.13 per MWh on non-fuel generation costs from 2009–2013. This compares favorably to the $9.98 national average and places the Companies in the top quartile nationwide according to Federal Energy Regulatory Commission ("FERC") benchmarking data.

Cane Run 7 and Other New Generation Resources

Q. Please provide an update on CR7.

A. On May 3, 2012, the Commission granted the Companies a CPCN to construct CR7.[9] CR7 is a natural gas, combined-cycle combustion turbine unit that utilizes state-of-the-art technology to minimize environmental impact while maximizing efficiency. CR7 will have a net summer generation capacity of 640 MW. Construction of CR7 is approaching its final phases.

As part of constructing CR7, the Companies also installed an approximately 8-mile, 20" natural gas transmission line from a new city gate station adjacent to LG&E's Penile Road city gate station to the Cane Run Generation Station. Work on the natural gas transmission line began in January 2014. The work is now complete and the line is in service.

Q. Will CR7 be jointly owned?

A. Yes. Following appropriate analysis and Commission approval, KU will own 78 percent of CR7 with LG&E owning the remaining 22 percent. CR7 will be jointly and economically dispatched according to need.

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[9] *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. Prior to filing their application for a CPCN for CR7, the Companies' issued a request for proposals to 116 potential energy suppliers in an effort to meet a projected capacity shortfall. The Companies received 18 responses containing 50 offers. The construction of CR7 was part of the least-cost alternative for meeting their capacity and energy needs.

Q. Is CR7 the most significant ongoing new generation investment in base rates?

A. Yes, though as explained below, CR7 is not the only ongoing generation investment. Through August 2014, the Companies have invested $484 million in the construction of CR7. The current total projected cost to construct CR7 is approximately $563 million (including the natural gas transmission pipeline), which is less than the $583 million projected cost when the Companies filed for a CPCN for CR7. The construction of CR7 has been cost efficient and reflects the benefits of our competitive bid policy. The cost of the unit per kW, when compared to its generation capacity, is projected to be $879 per kW based on a 640 MW summer capacity.

Q. Please describe how CR7 will achieve efficiency while minimizing environmental impact.

A. CR7 will be the Companies' first non-coal baseload and intermediate load generating unit, although the Companies have significant experience with other combustion turbines used for peak load. It is well established that environmental regulatory requirements over the last several years have made it more difficult and costly to construct and operate coal-fired generating units. When combined with current and projected natural gas prices, the Companies' analysis showed that a natural gas combined-cycle generating unit would be the least-cost option to comply with environmental requirements and replace a significant portion of the 797 MW of coal-fired generation that has been, or will be, retired as part of the environmental compliance plan.

When compared to existing facilities at the Cane Run Generation Station, CR7 will greatly reduce the emission of particulate matter and NO_x, while emissions of sulfur dioxide ("SO_2") will be virtually eliminated. In addition, CR7 will not produce any combustion by-products that would require landfill needs.

Q. Are the Companies expending funds for other generation projects?

A. Yes. One of the most significant is a new power-purchase agreement with Bluegrass. The Commission previously approved the Companies' proposed acquisition of Bluegrass's generating facility, but the acquisition was not consummated because of conditions FERC imposed on the transaction.[10] The Companies now have determined that entrance into the Capacity Purchase and Tolling Agreement dated August 26, 2014, (the "Agreement") with Bluegrass presents a favorable opportunity for meeting a portion of LG&E's capacity and power supply requirements to maintain a reliable reserve margin at time of system peak. At present, the Companies are allocating 100 percent of the purchased power to LG&E, although the Agreement allows the Companies to change the allocation based on future system demands.

On September 19, 2014, the Companies filed an application seeking Commission approval for their entry into the Agreement.[11] Assuming approval, the Companies will be entitled to 165 MW of firm generation capacity and output from Bluegrass Unit 3 beginning May 1, 2015. The Agreement lasts through April 30, 2019. The Agreement requires the Companies to pay capacity charges, operating-

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[10] *In the Matter of: Joint Application of Louisville Gas and Electric Company and Kentucky Utilities Company for a Certificate of 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, Order (May 3, 2012).

[11] *In the Matter of: Verified Application of Louisville Gas and Electric Company and Kentucky Utilities Company for a Declaratory Order and Approval Pursuant to KRS 278.300 for a Capacity Purchase and Tolling Agreement*, Case No. 2014-00321.

and-maintenance charges, and start-up charges. The Companies expect annual total fixed charges, based on a full year, of approximately $9.6 million.

The Companies also plan to invest about $4 million each in capital during the forecasted test period on blackstart generation capability. Generally speaking, a blackstart generating unit is one that can start without an outside electric supply. Blackstart units are used following a total grid shutdown to get other generating units up and running. Modern generating units such as TC2 and CR7 require new or enhanced blackstart capability as these higher capacity units require more power for system start-up.

Q. Please provide an update on the solar-power project at Brown Generating Station.

A. On January 17, 2014, the Companies submitted a CPCN application for the construction of a new 10 MW solar photovoltaic facility at the Brown Generating Station.[12] If approved, ownership of the solar facility will be allocated 61 percent to KU and 39 percent to LG&E. The Companies anticipate the project will cost $36 million, much of which will be expended during the forecasted test period. The Companies and all but one intervenor submitted an Agreement, Stipulation and Recommendation to the Commission on October 1, 2014. On November 24, 2014, the Commission conducted a hearing and the matter is now under Commission consideration.

[12] *In the Matter of: Joint Application of Louisville Gas and Electric Company and Kentucky Utilities Company for Certificates of Public Convenience and Necessity for the Construction of a Combined Cycle Combustion Turbine at the Green River Generating Station and a Solar Photovoltaic Facility at the E.W. Brown Generating Station*, Case No. 2014-00002.

Investment in Existing Generation Assets

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

A. Yes. As described above in my testimony regarding efficiency and productivity programs and practices, the Companies continuously assess methods to improve reliability and reduce risk, then act accordingly. The Companies' reliability activities can generally be categorized in one of several categories: controls, transformers/generators, turbines, boilers, and hydroelectric. Several recent projects are described below.

The Companies added control technologies to allow for tighter control of key operating parameters and provide integrated systems optimization not previously available with analog controls. Hardware upgrades were installed on the distributed control systems on Mill Creek 1 and 4 and Trimble County 1. Additionally, the Companies have improved the controls on some steam turbines, including electrohydraulic controls upgrades on Mill Creek Units 1, 3, and 4.

As for transformers and generators, generator rewind/refurbishment was completed on Brown 3 and voltage regulators on Ghent 1, 2, and 3 were replaced. The planned installation of generator stator bars on Mill Creek 4 in 2014 and Mill Creek 1 and 2 in 2015 will maintain existing reliability and ensure minimal downtime and continued operation into the future. The Companies have also improved reliability by purchasing spare Generator Step Up transformers. As replacement transformers can take months for manufacturing and delivery, having these spare transformers on hand assists with faster unit restoration should an existing transformer fail.

Investments have also been made for turbines. Major steam turbine overhauls were completed recently on Mill Creek 1 and 2, Ghent 2, and Brown 3. The overhauls included repairing or refurbishing components to ensure reliability. Additionally, diesel generators were purchased for the combustion turbines at the Trimble and Brown Generating Stations and Paddy's Run Unit 12. The Trimble and Brown diesel generators maintain power to the existing auxiliary systems for the combustion turbines. The Paddy's Run Unit 12 diesel generator ensures the unit is available for a blackstart.

The Companies have also completed boiler tube studies utilizing inspections and the latest software modeling tools to identify boiler sections in need of replacement. These efforts continue to ensure boiler availability and reliability.

As for the Companies' hydroelectric sites, a complete renovation is ongoing at the Ohio Falls Station and is a part of the FERC relicensing process. The project includes new wicket gates, impellers, generator rewinds, and new unit controls and instrumentation. The rehabilitation project will increase each unit's rated nameplate capacity and will increase the energy produced from the available water, since the upgraded units are more efficient. The project is scheduled for completion in 2017, though five of the eight Ohio Falls units have been renovated and placed back into service. From the close of the test period in the last base rate case through the close of the forecasted test period, LG&E anticipates investing nearly $63 million on this project, $15 million of which will be expended in the test period.

As for Dix Dam, the rehabilitation project on all three units is complete and the available capacity from those units was increased from 24 MW to 32 MW. The project included refurbishment of the turbines, generators, and wicket gates, while work was also done to remediate leakage through the dam's face-slab joints.

Q. Please provide an update on TC2's performance.

A. TC2 is a complex, supercritical coal-fired unit with a full suite of environmental controls, including SCR, flue gas desulfurization, dry and wet electrostatic precipitators, and baghouse equipment. TC2 is typically one of the first base load generating units economically dispatched due to its low-heat rate and fuel cost. Consequently, the Companies dispatch as much of TC2's generating capacity as possible. TC2 has proven to be the cost-efficient unit the Companies anticipated, even though the unit's original burners had design issues that had to be remedied.

During 2013, TC2 had one planned outage to make an interim change to the burners so they would last until a final design fix could be implemented. TC2 also had an outage extension to correct issues related to its turbine oil system. TC2 was available and performed during the critically important peak summer months (July and August) and during January 2014 when the Companies' generation systems were pressed to meet new peak load conditions during unusually cold weather conditions.

TC2 underwent a fifteen-week outage in the spring of 2014 for complete burner replacement. This included repositioning the burner throat openings, installing new oil igniters, adding additional over-fire air ports, repositioning the coal supply pipes, and re-commissioning the combustion-system controls. Additional work included replacing the bags in the fabric filter, replacing transition connections in the boiler roof, reconditioning the grinding systems, and replacing the chains and sprockets in the submerged scraper conveyor. TC2 came back online on May 28,

2014. An additional two-week outage occurred over the summer caused by a malfunction in the main turbine steam valves. The malfunction was caused by TC2's electro-hydraulic control system. The system was flushed, tested, and returned to service and is working as intended. Additional improvements to the system are planned for TC2's next scheduled outage.

TC2 has performed well since these outages. In October of 2014, the new burners and combustion system successfully completed testing on a variety of coals as specified in the original design criteria. The combustion system performance issues now appear to have been resolved, and the new burners are operating under a new warranty period. We continue to believe TC2 will provide good value to our customers in the future.

Q. Please provide an update on the retirement of generating units at the Cane Run, Green River, and Tyrone Generating Stations.

A. The Companies currently plan to retire the coal-fired units at Cane Run Generating Station when CR7 achieves commercial operation. As for the Green River Generating Station units, the Companies plan to request permission from the Kentucky Division of Air Quality in December of this year to extend operation of the units to April 2016. An additional one-year extension through April 2017 is possible under the Mercury and Air Toxics Standards if grid reliability concerns are present. The last unit operating at Tyrone was retired in 2013. Thus, the Companies will have retired 797 MW of coal-fired capacity by April 2016. Lastly, the Companies anticipate beginning the demolition of the retired units at the Paddy's Run and Canal Generating Stations.

Q. Please provide a brief update on the Companies' overall environmental compliance.

A. The Companies continue to make significant investments in infrastructure aimed toward complying with ever tighter environmental requirements. Our compliance plans and associated capital investments in environmental controls are described in detail in other proceedings before the Commission and are subject to the Commission's continuous oversight and review. Through the years, emissions of criteria pollutants such as SO_2 and NO_x have fallen even though generation output has increased. For example, from 1997 through our forecast for 2018, SO_2 emission levels will have dropped by 83 percent, and NO_x emission rates will have dropped by 74 percent although our customers' energy needs will have risen by over 21 percent.

<u>Generation Workforce</u>

Q. Do the Companies anticipate a change in headcount for Generation operations through the end of the forecasted test period?

A. Yes. From April 1, 2012, through the end of the forecasted test period, the Companies anticipate Generation headcount will increase by 50 positions, or 5 percent.

Q. Please explain the cause for Generation's increased headcount.

A. The primary drivers are equipment additions associated with capital projects and the need to retain core skills and knowledge. First, the Companies are currently engaged in several-billion-dollars' worth of capital projects, including CR7 and environmental control equipment. These significant construction projects impact staffing needs.

Second, the Companies face multiple issues on the core skill building and knowledge retention and transfer front. These include the large number of contractors traditionally used by the Companies. The Companies have identified several key positions that they believe should be filled by Company employees to ensure core skills and knowledge are retained.

Off-System Sales

Q. Please describe off-system sales.

A. The Companies build or acquire generation resources to serve their native load customers and maintain an adequate reserve margin. When the load demands of native load customers do not require this generation, the Companies attempt to sell this power for a profit in the wholesale power market. The sales are made only when the demand of native load customers does not require the Companies' full generation resources and when the market price is above our marginal cost.

Q. What is the current status of the off-system sales market?

A. The off-system sales market continues to experience low pricing. A weak economy and current low natural gas prices have decreased power market prices, which in turn have caused a decrease in opportunities for off-system sales. These factors make the off-system sales market unreliable for producing revenue. Even with lower prices in the off-system sales market, the Companies' use of their generating units to provide energy to their customers remains a lower-cost option than purchasing power in the off-system sales market. Additionally, customers get the reliability associated with the Companies having generation units dedicated to meeting their load demand, as evidenced by numerous peak records set during the early 2014 polar vortex.

Q. Have the Companies' experienced significant off-system sales in the recent past?

A. No. The Companies make every effort to sell excess power to others in the wholesale power market when their generation facilities are not needed to serve native load customers and a profit is expected. The energy produced by coal-fired units, which have a lower cost of operation compared to other types of units, is now utilized almost exclusively by native-load customers. This makes opportunities scarce in the current market for making off-system sales. The table below shows the Companies' off-system sales margins since 2005.

Year	Margin (in millions)	Volume (in GWh)
2005	$116.0	4,441
2006	$60.0	4,953
2007	$27.1	3,092
2008	$38.5	5,723
2009	$4.1	1,398
2010	$3.0	540
2011	$10.9	1,644
2012	$2.1	418
2013	$4.6	503
2014 (through August)	$10.0	365
Forecasted Test Period	$3.3	390

The amount of off-system sales margins included in the forecasted test period is discussed in detail in Mr. Sinclair's testimony. As these figures demonstrate, a distinction exists between the off-system sales market as it existed in 2008 and before versus 2009 and after. Off-system sales margins for 2005 through 2008 averaged over $60 million per year. Even eliminating 2005, off-system sales margins averaged nearly $42 million per year in 2006 through 2008. Off-system sales margins have averaged approximately $5 million per year for the years 2009 through 2013. The Companies have experienced an uptick in off-system sales for 2014, mostly due to an approximately two-month period during the past winter in which they saw an increase in profit on off-system sales. During this January–February 2014 period, the Companies' off-system sales margin was $6.4 million; $4.4 million of this amount came on just eight days during extremely cold weather throughout the country. The

Companies were able to leverage the strong performance of their generation fleet during this time of high energy demand (and concomitantly, high energy prices) in the off-system sales market. Through the end of August, the Companies have sold 365 GWh of energy at a margin of $10.0 million this year. Such sales cannot reasonably be expected to continue. Disregarding the apparent outliers in off-system sales for 2011 and 2014 reduces the average to approximately $3.5 million.

Q. Do the Companies anticipate off-system sales increasing in the near future?

A. No. Off-system sales experienced a drop off in 2009 and have now been relatively stable at these lower levels for a number of years. Abundant domestic supplies, the continued sluggish economy, and weak annual electric load growth have contributed to this change and are anticipated to continue. Therefore, the Companies do not anticipate a change in this downward trend for the foreseeable future.

Additionally, important structural changes have occurred to the Companies' generating fleet over the past several years. First, the Companies have less base load capacity to respond to opportunities for off-system sales. More of the Companies' base load capacity now goes to serving native load customers during periods when off-system sales were typically made. This change has occurred for a variety of reasons, including the termination of the Companies' power supply agreements with Electric Energy, Inc. and Owensboro Municipal Utilities. The Companies no longer have the sustained available capacity to offer competitively priced power in the off-system sales market even if it becomes more robust.

Second, the margin made on off-system sales has declined due to abundant supplies of natural gas. This increased supply has lowered the price of natural gas.

While the Companies will be positioned to take advantage of lower natural gas prices in operating CR7, the prices have negatively affected spot wholesale power prices.

Simply stated, the Companies can no longer rely upon the off-system sales market to provide revenue between rate cases by which the Companies can offset rising operating costs. The Companies do not have the generating capacity to achieve such sales and, in any event, the market does not support prices for such sales.

Generation Capital Investment Summary

Q. Will you briefly summarize the investment made in generation facilities from the last rate case until the end of the forecasted test period?

A. In sum, the Companies anticipate spending over $1.1 billion in generation capital investments from April 1, 2012, through June 30, 2016, about half of which is related to CR7. Other significant investments will occur for projects ranging from boiler work on generating units to environmental facilities that are not recovered through the ECR mechanism. Significant projects during the forecasted test period include the demolition of Paddy's Run units, the construction of a Brown solar unit, costs related to retiring the coal-fired units at Cane Run, and a gas pipeline for Paddy's Run. The following chart breaks investment out by Company from April 1, 2012, through June 30, 2016, the end of the last test period through the end of the forecasted test period.

DESCRIPTION	LG&E	KU	TOTAL
CR7	$124 million	$435 million	$559 million[13]
Ohio Falls	$63 million	n/a	$63 million
Other Generation Projects	$66 million	$37 million	$103 million
Investment in Existing Generation	$190 million	$229 million	$419 million
TOTAL	$443 million	$701 million	$1.14 billion

TRANSMISSION SYSTEMS

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

A. LG&E serves approximately 397,000 electricity customers over its transmission and distribution network in nine Kentucky counties. LG&E's transmission plant covers approximately 916 circuit miles and has a net book value of approximately $191 million.

Q. Please describe KU's transmission system.

A. KU serves approximately 543,000 electricity customers over a transmission and distribution network in seventy-seven Kentucky counties. KU's transmission plant covers approximately 4,372 circuit miles and has a net book value of approximately $420 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 and planning as a single interconnected and centrally controlled system and have operated jointly since the Companies merged in 1998.

[13] CR7 is anticipated to cost $563 million, about $4 million of which was spent before April 1, 2012.

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

A. The Companies' transmission operations are performing well, though the cost of maintaining the Companies' emphasis on reliability is increasing. FERC continues to develop mandatory standards and regulations and augment its oversight of the electric utility industry, 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 continued strong performance, but at an increased cost.

As an important anecdote, the Companies track their overall electric transmission expenditures per mile of transmission line and compare their performance to other electric utilities. Based on 2009–2013 FERC benchmarking data, the Companies' $21,804 per mile total expenditure ranks in the top quartile of electric utilities and is well below the $48,970 national average.

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

A. Yes. Portions of the Companies' transmission systems date to the mid-20th century and NERC continually enhances its reliability standards. The Companies' constantly work to address these and other transmission challenges and requirements. In addition, environmental regulations and other factors are driving the retirement of coal-generation units and altering the resource mix within the industry, which presents challenges to the transmission grid as changes to system flows alter system constraints, which must be mitigated through new investments.

Transmission Efficiency and Productivity Programs and Practices

Q. Does the Transmission line of business utilize efficiency and productivity programs and practices?

A. Yes, it does. One of the principal information system programs that Transmission utilizes is the Cascade work management program. The program provides a centralized repository for substation assets and maintenance records and equipment ratings. The program also facilitates tracking and reporting of both routine and NERC-required testing and maintenance data and triggering of predictive maintenance based on asset condition and operating history. The technology allows field technicians to remotely access maintenance history, asset data, and inspection records. The Cascade work management program, instituted in 2011, minimizes duplication through consolidating information and simplifying data analysis and maintenance work order generation.

Transmission is also implementing a substation control house replacement program. A control house is an enclosure that contains protective relays, communication equipment, batteries, and other necessary components to ensure that the electric grid functions in a desired state. Replacement of an entire control house as a prebuilt package enables the Companies to install, test, and commission new equipment at a lower cost and with shorter system downtime than traditional replacement.

The Companies have also invested in new transmission technology systems. This includes new software that allows the Companies' air patrol to input data while in flight and later upload the information to the air patrol database, software that allows event logging and outage analysis that will facilitate enhanced reliability analysis, and installing a protection and control laboratory that allows testing of strategies to address critical infrastructure protection. Transmission also proactively replaces facilities based on risk criteria, as further described below.

Transmission Workforce

Q. Do the Companies anticipate a change in headcount for Transmission operations through the end of the forecasted test period?

A. Yes. From April 1, 2012, through the end of the forecasted test period, the Companies anticipate Transmission headcount will increase by 19 positions, or 14 percent.

Q. Please explain the cause for Transmission's increased headcount.

A. Most new Transmission positions result from the Companies' need to retain core skills and knowledge as certain positions that have previously been contracted out are now being brought in-house. Changes in technology, and increased compliance and regulatory requirements, such as Critical Infrastructure Protection and reliability standards, are also driving the need for additional headcount.

Investment in New and Existing Transmission Facilities

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

A. The Companies have invested significant dollars into several improvements to their transmission facilities since their last rate cases. In 2013 alone, the Companies invested approximately $59 million in ongoing capital projects to upgrade their transmission infrastructure. The Companies' investment has continued to strengthen the transmission system through various modernizing and hardening projects, including the proactive replacement of transmission facilities. The Companies target certain assets for proactive replacement based on risk criteria. These assets include breakers, control houses, protective relays, wood poles, and supervisory control and data acquisition equipment.

Also, the Companies periodically review their transformer and breaker inventory to determine if additional spare equipment is needed. Because transformers and breakers are not always readily available in the event of immediate need, the Companies have added spare transformers and spare breakers to their inventory. Having these spare transformers and breakers on hand assists with rapid system restoration when these components are needed.

The total investment in transmission facilities since the last rate case through August 2014 is over $93 million by LG&E and $119 million by KU. Between September 2014 and the end of the forecasted test period, LG&E anticipates investing nearly $39 million in ongoing capital projects for transmission while KU anticipates investing nearly $83 million. This will include investments to upgrade transmission infrastructure to meet forecasted power flows, reliability improvement projects, and the aforementioned proactive replacement of transmission facilities, which together represent a significant portion of anticipated investment.

Q. Has CR7 required any new investment for transmission facilities?

A. Yes, the Companies constructed a new substation that has been energized while also making a number of other system modifications to accommodate the power flows expected from CR7 when it is placed in service. The Companies anticipate these transmission upgrades will cost approximately $24 million and are separate expenditures from the generation capital project previously discussed in my testimony.

Q. What other transmission-related expenditures support a rate increase?

A. Many projects are identified in the annual transmission expansion plan, which studies changes in power flows on the transmission grid. The plan identifies projects whose installation will prevent system or component overload conditions. Some projects, such as the addition of a new transmission substation located in western Kentucky, are large undertakings, while others, such as line reconductoring, are part of the ordinary course of business. Seven transformers have been or will be installed since the last rate case, including one in the Middletown, Kentucky area as part of a significant substation upgrade costing nearly $17 million that will strengthen the transmission system in the Louisville area. The Companies also will have expended nearly $25 million on a project to strengthen the transmission system by tying into the Duke Indiana transmission system in the New Albany, Indiana area.

Q. Have the Companies incurred any expenses related to FERC and NERC compliance?

A. Yes. Since 2013, the Companies have expended well over $8 million to comply with NERC's transmission-related Critical Infrastructure Protection and Order 693 requirements. This includes over $5 million in operations and maintenance expense on an ongoing basis. The Companies also invested nearly $35 million in response to line-rating and clearance-requirement alerts issued by NERC from the last rate case through August 2014 on transmission line modifications. The transmission line and structure upgrades resulting from these projects ensure the Companies' transmission lines meet verified maximum operating temperature ratings. Additionally, the forecasted test period includes recurring expenditures to survey transmission lines rated 100kV and above to ensure line ratings are maintained.

FERC has also approved NERC's Critical Infrastructure Protection Version 5 Reliability Standards ("CIP V5"). CIP V5 is a complex revision to the current standards and adopts new cybersecurity controls while extending the scope of systems that the CIP standards are designed to protect. CIP V5 requires compliance by April 2016 and will result in some incremental costs during the forecasted test year.

Transmission Capital Investment Summary

Q. Would you briefly summarize the investment the Companies will have made in their transmission facilities since the last rate case until the end of the forecasted test period?

A. Yes. In sum, the Companies anticipate spending over $333 million in transmission capital investments from April 1, 2012, through June 30, 2016. Of this, $132 million will be invested by LG&E and $201 million will be invested by KU.

DISTRIBUTION OF RELIABLE ELECTRIC SERVICE

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

A. LG&E's electric distribution business serves approximately 397,000 customers in Jefferson and 8 surrounding counties. LG&E's service area covers approximately 700 square miles. The electric distribution facilities we operate include 97 substations (32 of which are shared with transmission), 3,908 miles of overhead electric lines, and 2,390 miles of underground electric lines. This plant has a net book value of approximately $680 million.

Q. Please describe KU's distribution business.

A. KU's distribution business serves approximately 543,000 customers in 77 counties in Kentucky. KU's service area covers approximately 4,800 noncontiguous square miles. The electric distribution facilities we operate include 479 substations (58 of which are shared with transmission), 12,970 miles of overhead electric lines in Kentucky, and approximately 2,263 miles of underground electric lines in Kentucky. This plant has a net book value of approximately $970 million.

Q. How do LG&E and KU measure their 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"), System Average Interruption Frequency Index ("SAIFI"), and Customer Average Interruption Duration Index ("CAIDI"). SAIDI measures the average electric service interruption duration in minutes per customer for the specified period and system. SAIFI measures the average electric service interruption frequency per customer for the specified period and system. CAIDI measures the average time required to restore service to interrupted customers.

The Companies' distribution performance continues to be strong and is trending toward further improvement. For example, in 2013, the Companies achieved a distribution system SAIDI of 81.6 and a SAIFI of 0.84, excluding major events. This places the Companies within the top quartile in the Southeastern Electric Exchange's 2013 benchmarking study. The Companies believe their improvement in system performance is attributed to their reliability programs, including the Hazard Tree Program, circuit hardening, and pole inspection and treatment.

The Companies also track their overall electric distribution expenditures per customer and compare their performance to other electric utilities. Based on FERC 2009–2013 data, the Companies' $242 per customer expenditure is well below the $272 nationwide average.

Distribution Efficiency and Productivity Practices

Q. Please describe the productivity and efficiency practices that Distribution employs to improve its performance.

A. Distribution has implemented a number of productivity and efficiency practices that improve performance. For example, the Companies participate in several mutual assistance organizations under which other utilities' employees and contractors will aid the Companies during large-scale outage events. The Companies have successfully leveraged these relationships to efficiently respond to significant ice events and windstorms in the last decade. Relatedly, LG&E and KU have implemented an incident command system that assists with responding to emergencies and outage events in a timely and effective manner based on a structured chain of command and designated reporting relationships.

On a different note, the Companies use faulted circuit indicators to identify and isolate faulted line and cable sections without requiring the Companies to test cable segments one at a time, thus speeding the restoration process. The Companies have recently implemented new software called Mobile Workforce Management ("MWM") and Mobile Damage Assessment ("MDA"). These mobile applications support the Companies' restoration processes and enhance the efficiency and timeliness of critical outage information exchange between customers, field personnel, and the Distribution Control Center. The MWM application enables mobile assignment of repair, operations, and maintenance tasks to truck laptop computers. Employees complete work tasks electronically, thus allowing for efficient and timely processing by back-office personnel.

In addition to the MWM and MDA mobile platforms, the Companies also utilize software called Asset and Resource Management ("ARM") for Electric Distribution and Cascade for Substation asset and work management. The ARM system ensures efficiency, consistency, and accuracy with high-volume work management, including resource integration and tracking, documentation, and reporting. Cascade provides a central repository for substation asset data and is a mobile solution, thus allowing field technicians to access maintenance records via laptop computer. All inspection and test data is entered electronically and is automatically processed and tabulated by the software. Cascade allows for condition and reliability based maintenance, thereby enhancing productivity by prioritizing maintenance where it will be most effective. Cascade triggers, tracks, and reports on all substation maintenance, including routine and emergency, preventive and corrective, as well as NERC-required testing and inspection.

Q. Do LG&E and KU have grid projects that increase efficiencies?

A. Yes, such as the Downtown Network Load Flow Modeling endeavor that LG&E began this year. Installation of advanced metering technologies in the Louisville downtown network will be used to gather detailed time coincidental load data. The load data will link directly into an electric planning model. This initiative will improve LG&E's capability to optimize planned investments while enhancing safety, reliability, and performance in the downtown Louisville network electrical system.

A related project LG&E has started in downtown Louisville uses supervisory control and data acquisition technology to provide real time monitoring and control of critical network equipment. In addition to providing information that allows the network to operate more efficiently, this endeavor enhances worker safety by enabling the remote operation of network protectors, which means that workers no longer have to stand in close proximity while operating equipment inside a vault.

The Companies are also expanding the use of telemetry in approximately 380 KU substations throughout the state to obtain real time substation load data. This will increase the efficiency and timeliness of data collection used for planning of system maintenance, contingency switching, and substation and circuit enhancements.

Q. Has Distribution implemented programs that improve the infrastructure and electric reliability of its distribution system?

A. Yes, the umbrella program for these efforts is System Hardening, under which the Companies identify assets that can be replaced or modified to improve the distribution system's ability to withstand extreme weather conditions and events. System Hardening is comprised of three sub-programs: Hazard Tree Removal; Circuits Identified for Improvement; and Distribution Ground Line Pole Inspection, Treatment, and Replacement.

Under the circuits identified for improvement practice, reliability performance of all distribution circuits is analyzed annually and ranked based on a five-year average performance. The circuits identified for improvement are selected based on statistical analyses focused on reducing the number of circuits whose performance deviates substantially from the system mean. Solutions such as vegetation management, circuit hardening, and animal outage mitigation are employed as needed.

The Distribution Ground Line Pole Inspection, Treatment, and Replacement program enables the Companies to inspect, treat, and replace poles across LG&E's and KU's service territories. The program helps reduce outages due to failed poles, extends the serviceable life of the assets, and improves system integrity through inspection for ground line decay, pole top damage, or other defects. Identification of wood poles near the end of their lives helps to develop a mitigation plan to replace or structurally modify those poles to address the identified problems. The Companies will inspect approximately 500,000 distribution wood poles during this program. Since the program began in 2010, LG&E and KU have inspected approximately 270,000 poles, treated 91,000 poles, and replaced or reinforced approximately 18,400 poles.

In addition to System Hardening, the Companies are also investing in a number of other reliability and infrastructure initiatives. Major projects include the multi-year replacement of approximately 70 miles of Paper Insulated Lead Covered Cable in the Louisville Downtown Network and replacement and life extension of infrastructure in substations such as power transformers, power circuit breakers, and protective relays.

Q. Do the Companies anticipate any new plans that will further improve the infrastructure and electric reliability of its distribution system?

A. Yes. The Companies plan to implement a rear easement hardening program to improve overhead lines that are in difficult-to-access rear easements. This will increase the resiliency of the lines by reducing the number of conductor failures caused by vegetation contact and ice loading, especially in adverse weather conditions.

In addition, the Companies plan to implement an initiative related to substations. Under the initiative, the Companies will replace substation underground exit cables. When these cables fail, a large number of customers often experience service interruptions. Through this initiative, the Companies will improve reliability and levelize future failure costs. Absent these proactive efforts, the number of failures would likely increase.

<u>Vegetation Management for the Distribution System</u>

Q. Please provide an update on the Companies' Hazard Tree Program.

A. The Companies' Hazard Tree Program was implemented in October 2010 consistent with the recommendations in the Commission's report related to the 2008 windstorm and 2009 ice storm. The plan includes the removal of dead, dying, and diseased trees outside of the Companies' right of way to decrease the likelihood of tree damage to electrical infrastructure during severe weather events.

Since the Hazard Tree Program was implemented, LG&E has removed over 13,000 hazard trees and KU has removed over 50,000 hazard trees. The Companies have seen improvement in tree-related SAIDI and SAIFI since the program took effect. LG&E's tree-related SAIDI has been reduced more than 46 percent, while its tree-related SAIFI has fallen more than 47 percent. KU's tree-related SAIDI has been reduced more than 30 percent, while its tree-related SAIFI has fallen 36 percent.

The Companies have expended over $12 million in operation and maintenance costs for the Hazard Tree Program since the test period for the last rate case ended and anticipate spending an additional $5.6 million in the forecasted test period.

Q. Do the Companies foresee any additional vegetation management issues over the coming years?

A. Yes, and one in particular is potentially significant. In May 2009, the Emerald Ash Borer ("EAB") was discovered in two Kentucky counties—Jessamine and Shelby. The EAB is an exotic beetle that causes damage to ash trees. Ultimately, many ash trees succumb to the EAB's actions.

Kentucky is estimated to have over 266 million ash trees. Current projections anticipate that the EAB will be present in every Kentucky County by 2022. The Companies are estimated to have nearly 54,000 ash trees along their distribution corridors that are currently of sufficient height to impact distribution facilities should the tree succumb to the EAB. The customer impact of such potential ash tree decimation is estimated to be an additional 16,370 tree-caused outages over the next ten years, which would impact nearly one million customers.

The Companies began addressing the EAB in 2014, and they now seek to include the costs that will be incurred in base rates. In part due to the EAB's presence, the Companies are extending the Hazard Tree Program beyond its originally scheduled termination date. In this case, being reactive rather than proactive will be more costly and will lead to increased service disruptions for our customers.

Distribution Workforce

Q. Do the Companies anticipate a change in headcount for Electric Distribution operations through the end of the forecasted test period?

A. Yes. From April 1, 2012, through the end of the forecasted test period, the Companies anticipate Electric Distribution headcount will increase by 53 positions, or 8 percent.

Q. Please explain the cause for Electric Distribution's increased headcount.

A. Each of the positions created in Electric Distribution will assist with retaining core skills and knowledge. Many of the new Electric Distribution positions will involve a corresponding contractor offset.

Investment in New and Existing Distribution Facilities

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 approximately $337 million in electric system distribution reliability and infrastructure to ensure that our customers benefit from a safe and reliable distribution system. This includes $147 million by LG&E and $190 million by KU. Investments include projects targeted toward specific circuits identified for improvement and replacement and life extension of infrastructure such as power transformers, circuit breakers, protective relays, overhead and underground conductors, and utility poles. Over $36 million has been spent since April 2012 to replace aging or inferior utility poles alone. In fact, the Companies have replaced approximately 12,000 utility poles since April 2012.

During the forecasted test period, the Companies anticipate expending approximately $170 million in electric distribution-related projects. This includes

$79 million by LG&E and $91 million by KU. Much of this investment will be necessary for broader distribution of service to customers throughout our service territory and replacement of meters. Specific major projects during the forecasted test period include targeted circuits identified for improvement, the pole inspection and treatment program, downtown Louisville underground network cable replacement, major substation and circuit work in the Lexington area, work to the Lakeshore and Innovation Drive substations in Lexington, and extensive substation and circuit work in the Manslick Road area of Louisville. New projects for 2015 include rear easement hardening, replacement of substation underground exit cables, and circuit upgrades, transformer additions, and other distribution system enhancements to add contingency for substation transformer failures or outages.

Electric Distribution Capital Investment Summary

Q. Would you briefly summarize the investment the Companies will have made in their electric distribution facilities since the last rate case until the end of the forecasted test period?

A. Yes. In sum, the Companies anticipate spending approximately $645 million in electric distribution capital investments from April 1, 2012, through June 30, 2016. Of this, $290 million is attributable to LG&E and $355 million attributable to KU.

DISTRIBUTION OF RELIABLE GAS SERVICE

Q. Please describe LG&E's gas distribution business.

A. LG&E's gas distribution business serves approximately 318,000 customers in Jefferson and 16 surrounding counties. The gas distribution facilities we operate include approximately 4,306 miles of gas distribution pipe, 387 miles of transmission pipe, and five underground gas storage fields, which are the Muldraugh field in

Meade County; the Doe Run field along the Ohio River in Meade County and into Harrison County, Indiana; the Magnolia Upper and Magnolia Deep fields in parts of LaRue, Green, and Hart counties; and the Center field in parts of Metcalfe, Green, and Barren counties. LG&E's gas plant has a net book value of approximately $649 million.

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

A. Yes. LG&E has invested approximately $175 million in capital in its natural gas infrastructure from April 2012 through August 2014. About $96 million of these expenditures relate to previously approved reliability initiatives, including the leak mitigation program, main replacement activity, and the gas riser replacement program, recovered through mechanisms. In 2013 alone, though, LG&E made over $26 million in capital project investment *outside* of the gas tracker mechanism, a number that rises to about $79 million since April 1, 2012. LG&E anticipates investing $29 million in capital during the forecasted test period for gas operations. Of this, two of the most significant projects involve a city gate station upgrade and a gas transmission pipeline in the Mt. Washington / Lebanon Junction area.

Gas Distribution Efficiency and Productivity Programs and Practices

Q. Does Gas Distribution utilize some of the same programs and practices that improve productivity and efficiency as Electric Distribution?

A. Yes. Gas Distribution utilizes several of the same programs as Electric Distribution, including the incident command and mutual assistance programs. Gas Distribution has expanded its use of telemetry as well. These programs provide the same improvements in productivity and efficiency as they do for Electric Distribution.

LG&E Gas, like Electric Distribution, also recently implemented the aforementioned ARM software system and uses Service Suite. Service Suite allows the Company to dispatch work to employees on a mobile platform leading to more consistent and detailed information for employees about their assignments. Employees also complete work requests electronically, thus making the information available on a timelier basis to back-office personnel. In addition, dispatch employees can see when crews are available for work to be assigned. The ARM system helps manage resources required to serve new business and work requiring design resources. Customers benefit through Service Suite and ARM because they provide detailed and consistent information about service requests allowing us to more efficiently meet our customers' needs.

Q. Are there additional programs and practices unique to Gas Distribution that enhance productivity and efficiency?

A. Yes, including LG&E's proactive replacement of gas mains. LG&E began a program to replace older gas mains in 1996 and expanded the initiative in 2004 for a broader leak mitigation program. This program involves the replacement of the cast iron, wrought iron, and bare steel gas mains and associated services with modern materials. The replacement increases the safety and reliability of the gas system by utilizing modern industry standard materials, which also provide operational benefits—such as reduced water intrusion—that decrease service issues. Performing these replacements in an intentional and large-scale manner has resulted in fewer restorations to property, roadways, and sidewalks than if the mains were replaced in smaller sections.

To date, LG&E has installed 598 miles of replacement piping for gas distribution. Of these 598 miles, 89 miles have been installed since LG&E's last rate case at an investment of $51 million. An estimated 87 percent of planned replacements are complete, and the project should be finalized by 2017.

In addition to the large-scale programs, LG&E has invested approximately $13 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. Please provide an update on LG&E's program to replace and assume ownership of certain gas service risers.

A. In the last rate gas, LG&E received Commission approval to implement a new program to replace and assume ownership of certain gas risers, thereby continuing to ensure that customers receive safe and reliable natural gas service. LG&E started the 5-year gas service riser replacement program in 2013. Under the program, LG&E replaces certain gas service risers that have a compression-type mechanical coupling that do not incorporate an anti-pull out design. LG&E has replaced and taken ownership of approximately 66,000 gas service risers as of August 31, 2014.

By performing this work on a large scale systematic basis, LG&E is able to complete the inspections and replacements more efficiently. For example, LG&E can prep multiple replacements at once, which allows the replacements to be completed more quickly. Also, because LG&E is buying materials for a significant number of replacements, it can leverage its economies of scale and utilize competitive bidding.

Q. How does LG&E recover the costs associated with the gas riser replacement program and leak mitigation program?

A. Costs for these two programs occur through the gas line tracker approved by the Commission in LG&E's last rate case. The primary costs recovered through this mechanism include investments made for the gas service riser replacement program, the leak mitigation program, and costs associated with taking ownership of customer service lines. LG&E periodically completes and submits filings to the Commission for the gas line tracker in accordance with a prescribed schedule.

Q. Has does LG&E measure efficiency with respect to Gas Trouble Call response time?

A. LG&E tracks Gas Trouble Call response time by measuring the elapsed time to dispatch a technician[14] to a location of a potential gas trouble situation. LG&E's average response time in 2013 was 41.8 minutes while responding to 10,175 gas trouble calls, which is consistent with the average response time over the previous five years.

Gas Distribution Workforce

Q. Does LG&E anticipate a change in headcount for Gas Distribution operations through the end of the forecasted test period?

A. Yes. From April 1, 2012, through the end of the forecasted test period, LG&E anticipates Gas Distribution headcount will increase by 42 positions, or 19 percent.

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[14] The time measured begins when Gas Dispatch receives the trouble call information and ends when the technician arrives at the location of the potential gas trouble situation.

Q. Please explain the cause for Gas Distribution's increased headcount.

A. The additional 42 Gas Distribution positions are driven primarily by the need to retain core skills and knowledge and the need to meet regulatory, compliance, and safety requirements.

LG&E's Gas Distribution operations have also faced increased regulatory requirements over the past few years, which in part led to the creation of a Vice President for Gas Distribution position in 2013. Ongoing compliance and efforts to increase overall distribution system integrity are driving additional headcount.

<u>Investment in New and Existing Gas Distribution Facilities</u>

Q. Has LG&E taken other actions to maintain or improve the safety and reliability of its gas system?

A. Yes. LG&E's gas transmission business must comply with the Pipeline Safety Improvement Act of 2002. LG&E has already identified all High Consequence Areas in its gas transmission lines, conducted risk analyses of those pipeline segments, and completed the initial baseline integrity assessments of covered pipeline segments. Now, ongoing reassessments have begun. LG&E has invested almost $4 million dollars since its last rate case to modify its gas transmission system to enable in-line inspections using high-resolution magnetic flux leakage tools capable of identifying pipeline defects such as wall losses, dents, and third-party damages. Currently, about 85 percent of LG&E's gas transmission system, excluding pipelines related to gas storage fields, is capable of in-line inspections. By mid-2015, about 93 percent of LG&E's gas transmission system, excluding gas storage field related pipelines, will be capable of in-line inspections. An additional $15 million has been invested in pipeline enhancements and replacements, including amounts spent to automate valves on the gas transmission system.

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. Most of the expenditures under this program are related to the gas main replacement program and the riser replacement program. LG&E also completed a ten-year gas service regulator program in 2012. All of these programs help ensure the safe, reliable delivery of gas supply to LG&E's customers.

Additionally, LG&E has invested nearly $43 million since its last rate case to replace and upgrade equipment in compressor stations and storage fields to ensure the safe and reliable operation of the underground gas storage system. With respect to compressor stations, this work has included gas compressor installations and upgrades to control equipment, gas processing systems, station piping and valves, and auxiliary systems. With respect to gas storage fields, this work has included replacement of field pipelines, gas storage well upgrades, and drilling gas storage wells. Finally, LG&E has invested in projects related to ensuring it is operating within maximum allowable operating pressure in its gas lines.

<u>Gas Distribution Capital Investment Summary</u>

Q. Would you briefly summarize the investment LG&E will have made in its gas distribution facilities since the last rate case until the end of the forecasted test period?

A. Yes. In sum, LG&E anticipates spending over $133 million in gas distribution capital investments from April 1, 2012, through June 30, 2016.

CUSTOMER SERVICE

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

A. The Companies' "Customer Experience" objective is to provide superior and innovative customer service. The Companies continue to meet this objective by expanding relationships with customers and delivering outstanding customer experiences that create value for the customer and build trust. In doing so, the Companies employ their core values (safety and health, customer focus, employee commitment and diversity, integrity and openness, performance excellence, and corporate citizenship) to ensure these objectives are accomplished in a safe, effective, and efficient manner.

Q. Please provide examples of how the "Customer Experience" helps improve customer satisfaction.

A. Through our many customer satisfaction surveys, the Companies have useful data on customer satisfaction drivers. The Companies utilize this information when training and educating their employees and in developing tactics and initiatives to serve customers. For example, one session in the day-long, mandatory "New Employee Orientation" is on the Customer Experience. The Companies' strategy and expectations are addressed, and employees are asked to consider the impact of every decision on customers. Employees are also asked to serve as ambassadors for the Companies and to bring any customer concern from friends, neighbors, relatives, and others to the Customer Commitment Department for prompt research, follow up, and resolution.

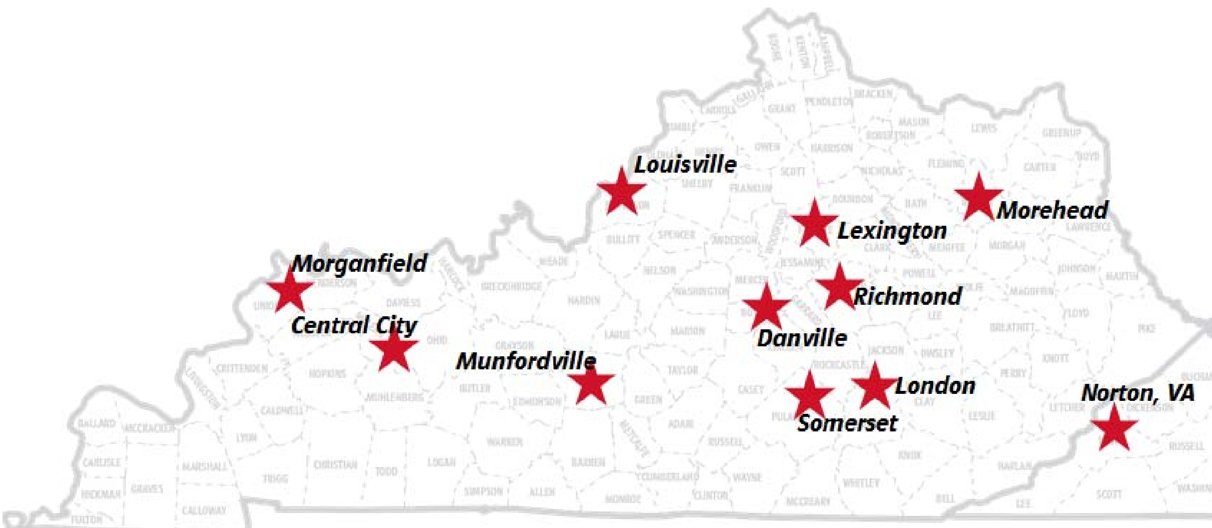
Another example involves a program called the "Customer Experience Kick-off" session. The Companies implemented this initiative in March 2012 with the start of a LG&E natural gas transmission line replacement project and have continued it with numerous other customer-impacting projects, including the gas riser replacement program, the CR7 easement clearing and gas line construction project, the 345 kv transmission tie-in to Duke Indiana, and the inclusion of new energy efficiency ("EE") program vendors. During these expectation-setting sessions, a number of senior managers from the Companies, along with their counterparts from business partners involved on the relevant project, bring together and address the workers who will complete the projects. Topics, including "respectful relationships," "property management," and "empowerment," are discussed to drive home the expectation that we must conduct ourselves as "guests" on customers' property, delivering the highest levels of positive customer experience every time.

<u>Customer Services: Stakeholder Input</u>

Q. Have the Companies engaged customer groups to gain insight into their energy needs?

A. Yes. The Companies utilize three distinct customer groups to solicit collaborative input on actions being taken to meet overall customer needs—the Consumer Advisory Panel, Customer Commitment Advisory Forum, and the Energy Efficiency Advisory Group.

The Consumer Advisory Panel meets quarterly to discuss customer-related issues. These issues include environmental matters impacting our Companies, advancing customer service offerings and contact channels, low-income customer programs, research and development, and emerging technology. The panel consists of approximately 20 members. Membership includes representatives from the counties served by LG&E and KU and consists of both rural and urban customers. Additionally, elected officials at the state and local level are often invited to discuss regional issues. The Vice President of Customer Services chairs this panel and I routinely attend meetings. The map below highlights the current member areas supported.



The Customer Commitment Advisory Forum provides a platform for discussion between the Companies and their low-income-advocate stakeholders. The purpose of the Advisory Forum is to elevate collaboration, provide a venue for open discussion, and broaden general understanding of the issues facing the communities we serve. Our aim for the Advisory Forum is to ultimately provide guidance to LG&E and KU regarding policies and practices that relate to the provision of electric and gas service to customers in need.

Organizations participating, listed in alphabetic order, include:

Affordable Energy Corporation	Lexington-Fayette Urban County Government
Association of Community Ministries	Louisville Metro Housing Authority
Bluegrass Community Action Plan	Louisville Metro Human Services
Chrysalis House – Lexington	Metropolitan Housing Coalition
Community Action Council	Multi-Purpose Community Action Agency
Community Action Kentucky	Office of the Attorney General
Community Action Partnership	People Organized and Working for Energy Reform and Affordable Energy
Habitat for Humanity	Project Warm
Kentucky River Foothills Community Action Agency	Shively Area Ministries
Legal Aid Society	Urban League of Louisville

The Energy Efficiency Advisory Group provides a forum for customer groups to discuss the Companies' existing DSM/Energy Efficiency programs and development of future programs. Currently, there are 22 participant organizations that represent the residential and commercial sectors. Organizations participating, listed in alphabetic order, include:

Association of Community Ministries	Kroger
Community Action Council for Lexington-Fayette, Bourbon, Harrison and Nicholas Counties	Legal Aid Society
Community Action Kentucky	Louisville Metro Air Pollution Control District
Department for Energy Development and Independence	Metro Louisville
Kentucky Association of Home Builders	Metropolitan Housing Council
Kentucky Community Action Council	Midwest Energy Efficiency Alliance
Kentucky Division of Air Quality	Office of the Attorney General
Kentucky Industrial Utilities Customers	Partnership for a Green City
Kentucky National Energy Education Development Project	Shelby County School Board Association
Kentucky Resources Council	University of Kentucky
Kentucky School Board Association	West Louisville Community Ministries

Customer Services: Resources to Assist Customers

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 2012 rate cases to better reflect customers' preferences across several new or enhanced contact channels including walk-in business offices, business and residential contact centers, web self-service, integrated voice response systems, e-mail, and an outage map application. Customers can receive information and complete transactions across these channels at their discretion. In addition to assessing operational performance across every customer contact channel, LG&E and KU utilize a third-party research firm to conduct transactional studies following customer interactions to measure how customers evaluate the Companies' performance. Ratings for each contact channel have been excellent. The contact channels continue to routinely meet or exceed the 8.5 mean target score on a 10-point scale.

Q. Please describe the call centers' operational performance.

A. Both the Residential Service Centers' and the Business Service Centers' operational performance continues to be excellent, answering at least 80 percent of all calls within 30 seconds. Of equal significance, the Companies have maintained or exceeded the goal of resolving at least 80 percent of all customer issues during the first phone call. Lastly, customer experience ratings continue to routinely meet or exceed the 8.5 mean target score on a 10-point scale.

Q. Please provide an overview of the Companies' initiatives with regard to customer self-service and productivity and efficiency programs.

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, start or stop service, view energy usage, and register for many customer programs including automatic bank draft, budget billing, and energy efficiency offerings. In 2013, customers average over 179,000 online transactions per month. In 2010, LG&E and KU developed a portal for low-income assistance agencies. 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 2013–14 heating season, approximately 54,000 LIHEAP customer pledges and payments were processed electronically, which resulted in higher satisfaction with the agencies, customers, and company employees.

Also in 2010, LG&E and KU began offering landlords and property managers a portal where the landlord or owner of multiple properties could register and manage all their accounts online by using a single email address. In 2014, the Companies transitioned to a new electronic payment vendor that allows customers to pay their bills online or over the phone with a debit or credit card. In addition, new functions have been added to the LG&E and KU website that allow customers who are not registered through My Account to make electronic check payments with no fee. Electronic payments in general are increasing. Since 2007, electronic payments have increased from 29 percent of total payments to 49 percent. Lastly, the customer experience ratings for residential and business customers who utilize web self-service options continues to routinely meet or exceed the 8.5 mean target score on a 10-point scale.

The Companies also update their website on a continual basis in an effort to make it as user-friendly as possible. Today, with only one click on the "Customer Service" ribbon homepage, customers have access to twelve frequently accessed pages, including information about bill payment, bill management, outages, public safety, starting and stopping service, tree management and powerline clearance, ways to manage the customer's bill, a guide to energy usage at home, customer handbooks, rates and tariffs, and a "contact us" link.

Q. Please provide an overview of the Companies' Interactive Voice Response system?

A. The Companies' Interactive Voice Response ("IVR") system uses the most current technology to simplify customer pathing (e.g., "bill payment as easy as 1-2-3") and improve the customer experience. IVR allows customers to interact with the Companies' system via a telephone keypad, after which they can service their own inquiries by following prompts. The percentage of residential callers resolving their issue or question while staying within the IVR system continues to increase. Today, approximately 40 percent of "non-outage" calls per month, or approximately 1.5 million calls annually, are fully contained within the IVR. For comparison, the IVR system fully contained about 8 percent of calls when first introduced and between 32-34 percent of calls, or approximately 1,000,000 calls annually, leading up to the Companies' last rate cases. In addition, customer satisfaction with IVR is continually measured through third-party telephone surveys and continues to routinely meet or exceed the 8.5 mean target score on a 10-point scale.

Q. Please provide an update as to the Companies' efforts to improve meter reading accuracy.

A. The Companies strive to provide the most accurate meter readings possible not only because meter reads form the foundation for invoicing our customers, but also because meter reads are an important component of our customers' trust and confidence in our billing process. Therefore, the Companies implemented a series of recommendations beginning in 2011 to improve meter reading accuracy. To date, the Companies have: conducted an "all hands" meeting with all meter reading employees and executives from our contract partners to stress the importance of accuracy; analyzed industry data to determine utility companies that excel at accuracy and discuss best practices with them; reviewed internal processes and procedures related to meter reading and implement corrective actions; begun field quality audits; tightened tolerances for consumption changes; re-evaluated performance standards; and improved communications with meter reading employees.

The Companies make every attempt to meet or exceed a 99.9 percent meter reading accuracy target. Since the last rate case, the Companies have averaged approximately 99.9 percent meter reading accuracy.

Q. Do the Companies offer programs to help customers pay their bills?

A. Yes. LG&E and KU offer a variety of billing and payment options designed to suit the needs of their diverse customer population. Budget Payment Plan helps alleviate the swings in monthly utility bills in the cold winter and hot summer months by calculating an average billing amount and making adjustments periodically to keep the monthly payment due amount more predictable for customers. In the Companies' last rate case, the "time to pay without penalty" was increased from 12 calendar days to at least 22 calendar days. Survey feedback from customers indicates this lengthening of time has increased satisfaction. For customers on a fixed or limited income, the Companies provide a program referred to as FLEX that provides customers 30 days to pay. Customer need for this program has slowed since the time to pay without penalty was increased in the last rate case. Also in the last rate case, the late payment charge for residential customers was decreased from 5 percent to 3 percent. Again, customer survey responses indicate this change has had a positive impact on customer satisfaction.

The Companies continue to offer a multitude of ways customers can pay their bills: in-person at a walk-in business office; after-hours drop box; at an authorized pay-agent location; on the phone through an IVR or live agent at the Companies' third-party payment vendor; on-line with an electronic check, credit card, or debit card; recurring payments through automated deduction from a bank account; through the customer's own bank website; or by mailing a payment.

The Companies have worked closely with Community Action Kentucky to develop and implement a portal for the various Community Action Agencies' use to post pledges to pay on customer accounts.

<u>Customer Service Efficiency and Productivity Programs and Practices</u>

Q. Do the Companies utilize programs that enhance productivity and efficiency with respect to their customer service?

A. Yes, the Companies have a number of programs and technologies that are designed to aid in the efficient performance of customer service. Since 2009, the Companies have invested in new technologies that provide customers with online self-service options; real-time automated payment processing; enhancements to serve visually impaired customers; enhancements to serve Spanish-speaking customers; and web portals to assist agencies providing assistance to low-income customers and property management professionals. Relatedly, the Companies also redesigned their website to allow customers to transact business more easily, including from their mobile devices. All of these technologies allow our customers to make payments and interact with the Companies more efficiently. These technologies and others also allow the Companies to maintain low overall operation and maintenance cost. In 2013, the Companies' operation and maintenance cost per customer was $77, well below the $105 mean of electric utilities.

Q. Do the Companies continue to support DSM and EE programs?

A. Yes; in fact, the Commission recently approved the Companies' joint application to review, modify, continue, and add certain DSM and EE programs.[15] The Companies' application responded to the Commission's expressed desire to encourage more conservation, EE, and DSM programs[16] and the Commission's directive that the Companies study the potential for additional demand and energy savings through DSM and EE programs.[17] The Commission's order approving the Companies' most recent DSM-EE application will make possible additional energy and cost savings for our customers over the next several years.

The Companies have a long history of advancing DSM-EE programs in Kentucky. The Companies' first DSM and EE programs were implemented in 1994; since then, the Companies have worked with numerous customer-stakeholder groups to obtain additional approval for DSM and EE programs in 1996, 1998, 2001, 2008, 2011, and 2014.

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[15] *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*, Case No. 2014-00003, Order at 13 (Nov. 14, 2014).

[16] *See, e,g., In the Matter of: Application of Meade County Rural Electric Cooperative Corporation to Adjust Electric Rates*¸ Case No. 2010-00222, Order at 15-16 (Feb. 17, 2011).

[17] *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 Combustion Turbine Facilities from Bluegrass Generation Company, LLC in LaGrange, Kentucky*¸ Case No. 2011-00375, Order at 18-21 (May 3, 2012).

Importantly, the Companies project that the effect of all of their past and current DSM and EE programs, as well as those proposed in their recently approved DSM-EE application, will be a cumulative demand reduction of 500 MW and cumulative energy and gas savings of 1.6 million MWh and nearly 13.4 million Ccf of natural gas by 2018. Our efforts have led to impressive accomplishments, including the Companies receiving a 2013 ENERGY STAR Partner of the Year – Sustained Excellence Award.

These programs also improve productivity and efficiency. For example, demand conservation enables the Companies to use their power plants more efficiently—and delay the addition of new ones—by placing a device on air conditioning units to help reduce summer peak demand by as much as 181 MW to date. The Companies also perform energy analyses for its residential and commercial customers, as well as weatherization services for its low-income customers. The suite of programs—in addition to the customer education information the Companies provide on its website, in advertisements, and other mediums—enable the Companies and customers to use energy more efficiently.

The Companies have created such demand and energy savings, and have improved productivity and efficiency as a result, by proposing and implementing DSM-EE programs only after careful cost-benefit analysis of all programs anticipated to create demand or energy savings. In particular, the proposals contained in the Companies' applications have used the industry-standard and Commission-required California Standard Practice Manual cost-benefit tests to ensure that all programs designed to produce savings will do so economically. Taking this disciplined analytical approach, rather than including items such as "non-energy factors and benefits" that the Commission has rejected as "not yet fully known," has ensured that the Companies' customers have enjoyed economical demand and energy savings through the Companies' DSM-EE programs.[18]

Customer Service Workforce

Q. Do the Companies anticipate a change in headcount for Customer Service operations through the end of the forecasted test period?

A. Yes. From April 1, 2012, through the end of the forecasted test period, the Companies anticipate Customer Service headcount will increase by 93 positions, or 16 percent.

Q. Please explain the cause for Customer Service's increased headcount.

A. The increased headcount for Customer Service operations is due to customer service needs, the need to retain core skills and knowledge, and regulatory compliance. First, the Companies added a call center in Morganfield, Kentucky, in 2011 to meet customer expectations and improve service. The addition of this call center has helped improve customer service. Second, while contractors are helpful to meet customer service demands, the Companies want to ensure internal skill building and knowledge retention for customer service functions. Hence, contractor offsets are a part of the increase. Finally, the Companies must meet strict NERC CIP cyber security standards, including in Customer Service operations, thus necessitating additional employees.

[18] *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*, Case No. 2014-00003, Order at 26 (Nov. 14, 2014).

<u>Customer Service Capital Investment Summary</u>

Q. Would you briefly summarize the investment the Companies will have made in their customer service operations since the last rate case until the end of the forecasted test period?

A. Yes. The Companies anticipate spending over $50 million in customer service capital investments (inclusive of projects within the operational lines of business) from April 1, 2012, through June 30, 2016. Of this, LG&E is anticipated to expend approximately $26 million and KU is anticipated to expend approximately $25 million. During the forecasted test year, the most significant project will be upgrading KU's rural customer service locations.

<u>ADJUSTMENTS TO SCHEDULE D-1</u>

Q. Have the Companies prepared a schedule of their jurisdictional adjustments to operating income by major account with supporting schedules for individual adjustments and jurisdictional factors as required by 807 KAR 5:001, Section 16(8)(d)?

A. Yes, they have. This information, which is sponsored by Kent Blake, is set forth in Schedule D-1. The schedule lists each pro forma adjustment to operating income in the forecasted test period that the Companies have made.

Q. Are several of the adjustments made by both KU and LG&E Electric attributable to the commercial operation of CR7 during the forecasted test period?

A. Yes, the following adjustments, primarily falling under "Other Generation" expenses, are directly attributable to CR7 being in commercial operation during the forecasted test period: FERC account 547 – Other Fuel; FERC account 549 – Miscellaneous

Other Power Generation Expenses; FERC account 553 – Maintenance of Generating and Electric Plant; FERC account 554 – Maintenance of Miscellaneous Other Power Generation Plant; and FERC account 924 – Property Insurance. The most monetarily significant of these adjustments is the increase in Account 547 – Other Fuel, which relates to the increase in natural gas fuel purchases that will be required for CR7. CR7's expected commercial operation date is in May 2015. The adjustments are allocated between KU and LG&E based on the unit's ownership percentages.

Q. Why did KU make an adjustment to FERC account 506 – Miscellaneous Steam Power Expenses?

A. The principal reason KU made an adjustment to this account is the increased volume of commodities TC2 is expected to use during the forecasted test period. Moving forward, the unit is expected to consume increased amounts of ammonia, activated carbon, and hydrated lime. During portions of the base period, the consumption of hydrated lime, or the injection rate, was 3,000 pounds per hour, which is lower than the amount expected to be used moving forward, which is 8,000 pounds per hour. Furthermore, an outage occurred at TC2 from February 8, 2014, to May 28, 2014, to replace the burners. The forecasted test period assumes TC2 will be operational for the entire period.

Q. Are several of the adjustments made by LG&E Electric attributable to the retirement of the steam generation units at the Cane Run Generating Station?

A. Yes, several adjustments under the "Steam Generation" category of expenses are made. These adjustments are directly attributable to the remaining coal-fired units at the Cane Run Generating Station being retired during the forecasted test period:

FERC account 500 – Steam Operation Supervision and Engineering; FERC account 501 – Fuel; FERC account 502 – Steam Expenses; FERC account 505 – Electric Expenses; FERC account 506 – Miscellaneous Steam Power Expenses; FERC account 509 – Allowances; FERC account 510 – Maintenance Supervision and Engineering; FERC account 511 – Maintenance of Structures; FERC account 512 – Maintenance of Boiler Plant; FERC account 513 – Maintenance of Electric Plant; and FERC account 514 – Maintenance of Electric Plant. Of these, the adjustment for Account 501 – Fuel is by far the most significant and results from the decrease in coal purchases during the forecasted test period.

Q. Has LG&E Gas made an adjustment to FERC account 863 – Maintenance of Mains?

A. Yes, this expense is expected to increase in the forecasted test period due to an increased number of inline inspections that will be performed. Inline inspections are performed when a tool, known as a "pig," is sent into a pipeline propelled by the pressure of the product flow in the pipeline itself to inspect the condition of the pipeline walls. In the base year, one inline inspection was performed, but three will be performed during the forecasted test period. Two of the inspections are required for regulatory compliance issued by the Pipeline & Hazardous Materials Safety Administration and the third will be performed to assess the integrity of an important segment of pipeline.

RESEARCH AND DEVELOPMENT

Q. Please describe the Companies' recent research and development activities.

A. The Companies continue their longstanding support of collaborative research with the Electric Power Research Institute, which accounted for nearly $9 million in investment since the last rate case to support research for generation, environmental, transmission, and renewable energy projects. In addition, the Companies continue to support the University of Kentucky's Center for Applied Energy Research ("CAER") through both funding and infrastructure support. For example, the Companies participated in a ribbon-cutting ceremony at the Brown Generating Station on July 21, 2014, with Governor Beshear, Kentucky Energy and Environment Cabinet Secretary Len Peters, representatives from the U.S. Department of Energy, and other dignitaries for Kentucky's first megawatt-scale carbon capture project approved and jointly funded by the Energy Department. The Companies originally committed $1.5 million to CAER in 2006 and now provide annual funding of $200,000. The project at Brown calls for the construction of a 2-megawatt thermal post-combustion carbon dioxide capture pilot system, which is scheduled for completion in the first quarter of 2015. The pilot project will then conduct testing through at least mid-2016, after which key discoveries will be determined.

In addition to internal research and development, the Companies also commit $75,000 per year to the University of Texas's Carbon Management Project and Carbon Capture Pilot Plant Project and nearly $50,000 per year to Georgia Tech University's National Electric Energy Testing, Research & Applications Center.

SAFETY PERFORMANCE AND RECOGNITION

Q. Please discuss the Companies' commitment to safety.

A. LG&E and KU's priority and core business value is the safety of employees, contractors, and the general public. The Companies' safety goal is simply to achieve zero injuries because we have a sincere concern about the well-being of all involved in our product and services. That is why our safety approach is quite simply "No

Compromises" and "Not in Our House!" Excellent safety performance also is the hallmark of a successful, cost-efficient, and operationally excellent company. Safe work substantially contributes to a strong financial foundation by reducing injury-related costs. These include, but are not limited to, investigation time, Worker's Compensation, medical and liability insurance costs, employee time off, and lost productivity. Fewer injuries and less absenteeism also increase employees' morale, productivity, pride and their ability to provide reliable gas and electric service and superior customer service.

To further the Companies' safety goals, all safety areas were recently merged into a single organization known as Safety and Technical Training. We believe this consolidation integrates safety processes, efficiencies, and best practices Company-wide while strengthening the Companies' safety culture. In addition, the Companies have added or will be adding 8 new positions within the Safety and Technical Training area by June 30, 2016. These new hires will be focused strictly on ensuring a safe workplace environment for our employees and customers.

Q. Please provide examples of the Companies' safety achievements.

A. The Companies' commitment to safety is exemplified by a long list of safety awards and milestones. A complete list is too long to detail in my testimony, so I have attached as Exhibit PWT-1 a document showing the Companies' more significant safety awards and recognitions since 2012. Among the more notable are those from the Edison Electric Institute, Southern Gas Association, American Gas Association, Kentucky Gas Association, Southeastern Electric Exchange, and National Highway

Traffic Safety Administration and nine Kentucky Governor's Safety and Health Awards.

LG&E and KU gauge safety success by the positive behavior of employees and contractors, measured primarily by recordable and lost-time injury rates, which have dropped substantially over the last decade. For example, employees' 2013 year-end recordable injury rate was 1.29, lower than the 2012 rate of 1.35. Contractors' recordable rate was 1.26, compared to 1.39 in 2012. These rates are far below the national average recordable injury rates of 3.5 for the utility industry and 3.8 for the general industry.

CONCLUSION

Q. Please summarize why a rate increase is needed.

A. The Companies have invested and will continue to invest significant amounts into infrastructure, technology, and programs to ensure that our customers receive safe, reliable, and low-cost energy when they need it. The Companies' efforts have resulted in increased capital and operating and maintenance expenditures that will continue into the future. As shown in the testimony of Mr. Kent Blake, Chief Financial Officer, these necessary and prudent expenditures need to be included in base rates to allow the Companies to recover the costs, including the cost of capital, of meeting our customers' energy needs safely and reliably. This will ensure the Companies' ability to attract the necessary capital investment.

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 19th day of November 2014.

(SEAL)
Notary Public

My Commission Expires:

July 11, 2018

APPENDIX A

Paul W. Thompson

Chief Operating Officer
LG&E and KU Services Company
220 West Main Street
Louisville, KY 40202
(502) 627-3324

Industry Affiliations

Center for Applied Energy Research, Advisory Board Member
Electric Energy Inc., Board Member
Ohio Valley Electric Corporation, Board Member
Prior Affiliations:
FutureGen Industrial Alliance, Board Member and former Chairman of the Board

Civic Activities

Greater Louisville Inc. Board
Louisville Downtown Development Corporation Board, Chairman
Louisville Free Public Library Foundation Board, Advocacy Committee Chairman
Chairman (2006–2012)
Chair, Annual Appeal (2002–2003)
Co-Chair, Annual Children's Reading Appeal (1999–2001)
Jefferson County Public Education Foundation Board (2008–2013)
University of Kentucky College of Engineering, Project Lead The Way, Council Member (2007–2012)
March of Dimes, Honorary Chair (1997–1998)
Habitat for Humanity, Representing LG&E as co-sponsor
Friends of the Waterfront Board (1998–2002)
Leadership Louisville (1997–1998)

Education

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

Previous Positions

Senior Vice President, Energy Services (2000–12)
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– 991 – 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

LG&E and KU Safety Awards

2012

- Edison Electric Institute Safety Achievement Award
- Southern Gas Association Accident Prevention Award
- Southern Gas Association Video Excellence Award
- Kentucky Emergency Services Conference Award
- Southern Gas Association Safety Achievement Award
- Kentucky Gas Association Accident Prevention Award (for the 13th consecutive year)
- Five Kentucky Governor’s Safety and Health Awards

2013

- Kentucky Gas Association Accident Prevention Award for Safety Excellence
- Edison Electric Institute Safety Excellence Award
- Two Kentucky Governor’s Safety and Health Awards
- The Kentucky Safety and Health Network President’s Award
- National Safety Council Rising Star Award
- The Southern Gas Association Meritorious Service Award
- The Southern Gas Association Video Excellence Award
- The National Highway Traffic Safety Administration Outstanding Service Award

2014

- Two Kentucky Governor’s Safety and Health Awards
- Edison Electric Institute Safety Achievement Award
- American Gas Association Safety Achievement Award
- Southeastern Electric Exchange’s Top Performance in Fleet Safety Award
- Southern Gas Association Service Award
- Southern Gas Association Safety Video Excellence Award
- Utility Communicators International Better Communications Award for Safety Communications

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. 2014-00371**

In the Matter of:

APPLICATION OF LOUISVILLE GAS AND ELECTRIC COMPANY FOR AN ADJUSTMENT OF ITS ELECTRIC AND GAS RATES	**))))**	**CASE NO. 2014-00372**

TESTIMONY OF
DAVID S. SINCLAIR
VICE PRESIDENT, ENERGY SUPPLY AND ANALYSIS
LOUISVILLE GAS AND ELECTRIC COMPANY
KENTUCKY UTILITIES COMPANY

Filed: November 26, 2014

Table of Contents

<u>Section 1 – Introduction and Overview</u>

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

A. My name is David S. Sinclair. I am Vice President, Energy Supply and Analysis 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. Have you previously testified before the Kentucky Public Service Commission ("the Commission")?

A. Yes. I previously testified before the Commission in the following cases:

- Case No. 2003-00266, *In the Matter of: Investigation into the Membership of Louisville Gas and Electric Company and Kentucky Utilities Company in the Midwest Independent Transmission System Operator*;
- Case No. 2004-00507, *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 a Site Compatibility Certificate for the Expansion of the Trimble County Generating Station*;
- Case No. 2011-00161, *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* and Case No. 2011-00162, *In the Matter of: The Application of Louisville Gas and Electric Company for Certificates of Public Convenience and Necessity and Approval of Its 2011 Compliance Plan for Recovery By Environmental Surcharge*;

- Case No. 2011-00375, *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 a 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 La Grange, Kentucky*;
- Case No. 2012-00428, *In the Matter of: Consideration of the Implementation of Smart Grid and Smart Meter Technologies*; and
- Case No. 2014-00002, *In the Matter of: Joint Application of Louisville Gas and Electric Company and Kentucky Utilities Company for a Certificate of Public Convenience and Necessity for the Construction of a Combined Cycle Combustion Turbine at the Green River Generating Station and a Solar Photovoltaic Facility at the E.W. Brown Generating Station.*

Q. Please describe your job responsibilities.

A. I have four primary areas of responsibility: (i) fuel procurement (coal and natural gas) for the Companies' generating stations, (ii) real time dispatch optimization of the generating stations to meet the Companies' native load obligations, (iii) wholesale market activities, and (iv) sales and market analysis and generation planning. As pertains to this proceeding, the Sales Analysis and Forecasting group prepared the electric and gas load forecasts and the Generation Planning group prepared the forecast of generation and off-system sales ("OSS") as well as the analysis of the Curtailable Service Rider. All of this work was done under my direction.

Q. What are the purposes of your testimony?

A. The purposes of my testimony are to: (1) support certain exhibits required by the Commission's regulations; (2) describe the Companies load forecast, including factors used in preparing that forecast: econometric models, variables, assumptions, escalation factors, contingency provisions, and changes in activity levels; (3) explain the Companies' forecast of generation and OSS; (4) explain changes from the base period to the forecasted test period for operating revenues, sales for resale, and purchased power; and (5) describe the Companies' Curtailable Service Rider ("CSR") and how it factors into the Companies' requests in this case.

Q. Are you supporting any exhibits and schedules that are required by the Commission's regulation 807 KAR 5:001 Rules of Procedure?

A. Yes, I am sponsoring the following exhibits and schedules for the corresponding filing requirements in 807 KAR 5:001 Rules of Procedure:

• Factors Used in Forecast	Section 16(7)(c)	Tab 16
• Load Forecast Including Energy and Demand (electric)	Section 16(7)(h)5	Tab 26
• Mix of Generation (electric)	Section 16(7)(h)7	Tab 28
• Customer Forecast (gas)	Section 16(7)(h)14	Tab 35
• Sales Volume Forecast – cubic feet (gas)	Section 16(7)(h)15	Tab 36

- All commercial or in-house computer software, programs and models used to develop schedules and work papers — Section 16(7)(t) — Tab 50

Q. Please identify the documents attached at Tab 16 of the Companies' Applications you are sponsoring.

A. I am sponsoring the following documents that are among those attached at Tab 16 of the Companies' Applications and relate to the Companies' forecasting: (1) Annual Electric Sales & Demand Forecast Process; (2) 2015 Business Plan Electric Sales Forecast; (3) Annual Natural Gas Volume Forecast Process; (4) 2015 Business Plan Gas Volume Forecast; (5) Annual Generation & Off-System Sales Forecast Process; and (6) 2015 Business Plan Generation and OSS Forecast.

Q. Are you sponsoring any exhibits to your testimony?

A. Yes. I am sponsoring the following exhibits to my direct testimony:

Exhibit DSS-1	Comparison of LG&E Electric Customers, Billing Demand, and Energy: Base Period vs. Forecasted Test Period
Exhibit DSS-2	Comparison of KU Electric Customers, Billing Demand, and Energy: Base Period vs. Forecasted Test Period
Exhibit DSS-3	Comparison of LG&E Gas Customers and Volume: Base Period vs. Forecasted Test Period
Exhibit DSS-4	Economic Inputs to Electric and Gas Forecasts
Exhibit DSS-5	Comparison of Generation Volume by Unit, Base Period vs. Forecasted Test Period

Section 2 – Overview of Electric Load Forecast

Q. Please describe the Companies' electric load forecast process.

A. Each year, the Companies prepare a 30-year demand and energy forecast with the first 6 years being used to prepare the Companies' business plan. The electric load forecast process is essentially the same for both LG&E and KU and is described in the document at Tab 16 to the Companies' Applications entitled "Annual Electric Sales & Demand Forecast Process." Essentially the forecast process involves:

- Using historical data to develop models that relate the Companies' electricity usage, demand, sales and number of customers by rate classes to exogenous factors such as economic activity, demographic trends and weather conditions, and
- Using the models in combination with forecasts of the exogenous factors to forecast the Companies' electricity usage, demand, sales and number of customers for the various rate classes.[1]

The Companies' approach to electric load forecasting is widely accepted in the industry and can readily accommodate the influences of national, regional and local (service territory) drivers of utility sales. The modeling of residential and small commercial sales also incorporates elements of end-use forecasting – covering base load, heating and cooling components of sales – which recognize expectations with regard to appliance saturation trends, efficiencies, and price or income effects.

While the forecasting approach is generally based on econometric modeling, it also incorporates specific intelligence on the prospective energy needs of the Companies' largest customers. Sales for several large customers for both KU and LG&E are forecasted using their recent history and information provided by the customers to the Companies regarding their outlook. These customers are referred to

[1] A detailed description of the methodologies used to create the electric load forecasts can be found in Volume II, Technical Appendix, of the 2014 IRP, Case No. 2014-00131. The methodology has not materially changed since the 2014 IRP.

as "Major Accounts." This process allows for market intelligence to be directly incorporated into the sales forecast.

Q. Does the Companies' load forecast reflect the impact of the Companies' demand side management ("DSM") programs?

A. Yes. The Companies have a number of DSM programs that reduce the peak demand and energy usage of residential and commercial customers.[2] The forecasts produced by the models are adjusted to reflect the forecasted impact of these programs.

Q. You said that weather is used in preparing the electric load forecast. Does the weather forecast reflect the potential for more frequent extreme events due to climate change?

A. No. As discussed in Annual Electric Sales & Demand Forecast Process at Tab 16, the Companies assume that future weather will be the average of the weather experienced over the last 20 years. The Companies have used this approach for many years in Integrated Resource Plan ("IRP"), Environmental Cost Recovery ("ECR"), and Certificate of Public Convenience and Necessity ("CPCN") filings and it is consistent with industry practice of utilizing the average of historical weather as the basis for determining the "normal" weather used in preparing a load forecast. This helps ensure that there is an approximately equal chance that actual weather will be warmer or cooler than the normal period, thereby avoiding weather bias from the forecast.

The methods used to prepare the 2015 Load Forecast are not materially different from those discussed in Section 7 of the 2011 IRP. In the 2011 IRP case, Commission Staff stated, "LG&E/KU's load forecasting approach … is both

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[2] *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,* Case No. 2011-00134.

thorough and well documented. The load forecasting model and its results are reasonable ….”[3] Commission Staff also stated:

> The continued enhancements in the Companies' load forecasting processes are an important aspect of improving and refining the planning, both short-term and long-term, that is necessary to meet customers' load requirements, and service expectations, in the future. The scope and depth of their reserve margin analysis, as well as the supply-side and demand-side screening analyses, are well developed and informative.[4]

These are the same methods used to prepare the 2014 IRP that was filed in April.

Q. You stated that the Companies prepare a 30-year load forecast each year. When was the load forecast prepared that was used in preparing the 2015 business plan?

A. The load forecast that was used in preparing the 2015 business plan was completed in the late summer of 2014 ("2015 LF"). The electric load forecasts for LG&E and KU that were used in the 2015 business plan are attached at Tab 26 to the Applications.

<u>Section 3 – LG&E Electric Load Forecast</u>

Q. Please provide an overview of the 2015 LF for LG&E.

A. As can be seen in Exhibit DSS-1, from the Base Period (March 2014 through February 2015) to the Forecasted Test Period (July 2015 through June 2016), electric sales increase by 305 GWh (2.6 percent) and total customers increase by 3,815 (0.9

[3] Commission Staff's Report, p. 14, which is attached to the Commission's March 13, 2013 Order in *In the Matter of: 2011 Joint Integrated Resource Plan of Louisville Gas and Electric Company and Kentucky Utilities Company*, Case No. 2011-00140.

[4] *Id., p. 44.*

percent). At the total company level, these changes are very consistent with what one would expect given the economic and other assumptions underlying the forecast.[5]

Q. Does weather explain any of the difference between the sales in the Base Period and the Forecasted Test Period?

A. Yes. The Base Period consists of actual billed data for the first six months and, therefore, reflects the actual weather during that time. On the other hand, sales in the last six months of the Base Period and the entire Forecasted Test Period are based on 20-year normal weather for the LG&E service area as described in Annual Electric Sales & Demand Forecast Process at Tab 16. Table 1 compares the actual monthly heating degree days ("HDDs") and cooling degree days ("CDDs") to their 20-year normal values. As you can see, the Base Period winter was much colder than average based on higher than average HDDs, while the Base Period summer was milder than average with less than average CDDs. As shown in Exhibit DSS-1, energy in the residential ("RS") rate class is 151 GWh (4 percent) higher in the Forecasted Test Period compared to the Base Period. In addition, the General Service ("GS") rate class is 24 GWh (2 percent) higher. These rate classes are highly sensitive to weather, but LG&E also has a high saturation of natural gas customers. Therefore, the colder than average winter weather in the Base Period had less of an impact on electric sales, but the milder than average summer weather in the Base Period reduced electric sales driven by air conditioning load as compared to the Forecasted Test Period.

[5] See Exhibit DSS-4 for detailed assumptions for the Forecasted Test Period.

Table 1 - Comparison of Actual and 20-year Average Weather for the LG&E Service Area

	Actual	Average	Difference
March (HDD)	678	568	110
April (HDD)	202	251	(49)
May (CDD)	176	119	57
June (CDD)	361	301	60
July (CDD)	306	414	(108)
August (CDD)	380	395	(15)

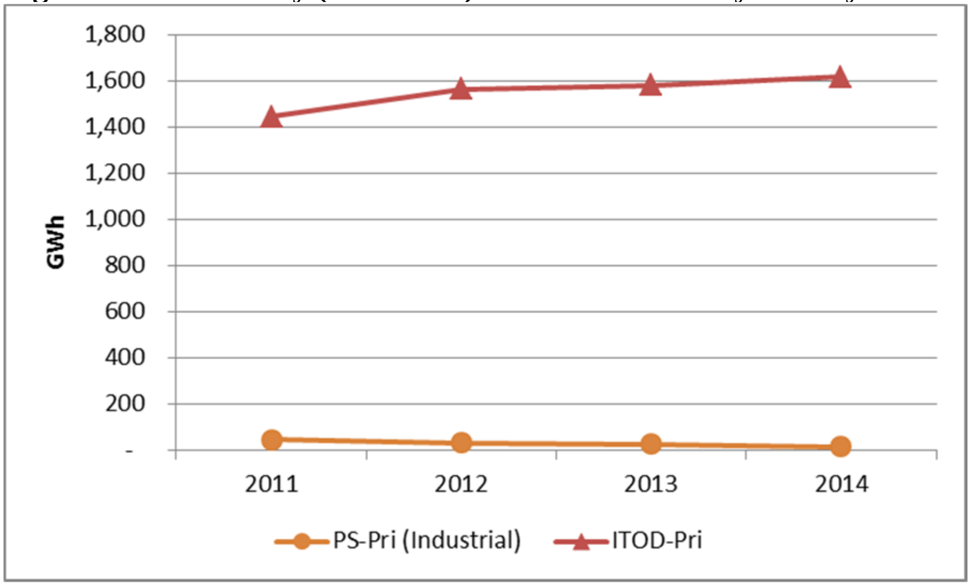
Q. Besides the differences in weather, are there any other aspects of the Forecasted Test Period compared to the Base Period that are of interest?

A. Yes. In Exhibit DSS-1, one can see that for the majority of rate classes, sales, customers, and demand are increasing from the Base Period to the Forecasted Test Period. This trend is consistent with modestly improving economic conditions since the 2007-2009 recession which are forecasted to continue.

Q. Are there any rate classes that show rather large changes, either positive or negative, between the Base Period and the Forecasted Test Period?

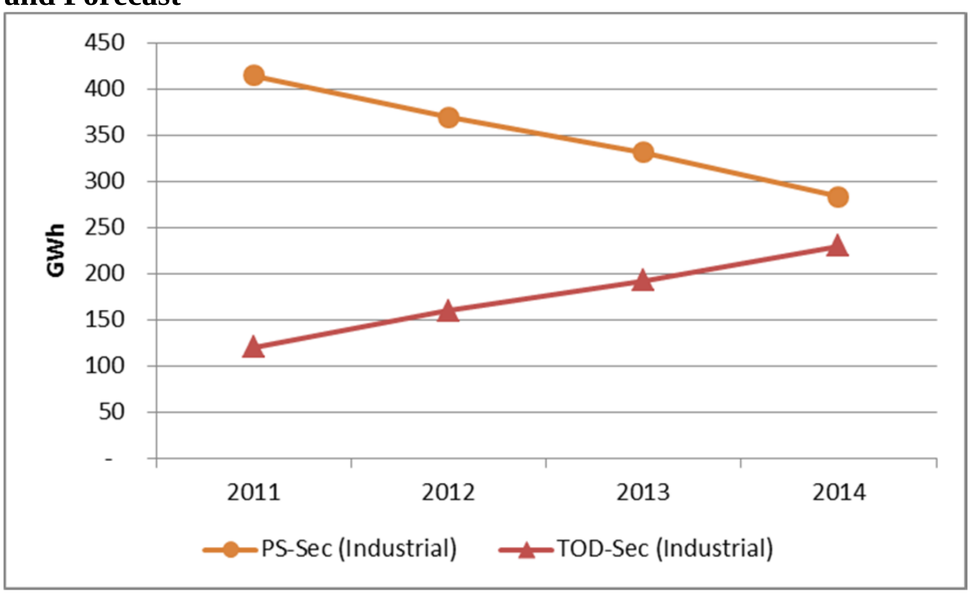
A. Yes. While not affecting LG&E's total sales, as shown in Exhibit DSS-1, we are seeing some customers migrating from Power Service ("PS") rate classes to Time-of-Day ("TOD") rate classes. For example, the PS-Primary (Industrial) and PS-Secondary (Industrial) rate classes are experiencing declines in sales over the last few years, but this is more than offset by sales increases in the ITOD-Primary and TOD-Secondary (Industrial) rate classes (see Figures 1 and 2).

Figure 1: PS-Primary (Industrial) and ITOD-Primary History and Forecast



Note: 2014 is 8 months of actual and 4 months of forecast.

Figure 2: PS-Secondary (Industrial) and TOD-Secondary (Industrial) History and Forecast



Note: 2014 is 8 months of actual and 4 months of forecast.

Q. Are there any large differences in individual Major Account customers between the Base Period and the Forecasted Test Period that would explain changes in a particular rate class forecast and how were these forecasts developed?

A. As described in Annual Electric Sales & Demand Forecast Process at Tab 16, the forecast process for certain major accounts is based largely on input from the customer itself. As can be seen in Exhibit DSS-1, energy sales and billed demand to Special Contract 1 are forecasted to decline over time. Special Contract 1 is installing natural gas and solar generation and has a long term goal to be energy independent. As a result of this, their energy declines in the Forecasted Test Period by 50 GWh (31 percent) and the sum of the monthly billed demands declines by 120 MW (43 percent). In contrast to Special Contract 1, several Major Account customers are forecasted to experience growth based on input from the customer. As shown in Exhibit DSS-1, the RTS rate class is 49 GWh (6 percent) higher in the Forecasted Test Period driven by forecasted energy usage by certain Major Account customers. In addition, the sum of monthly billing demand volumes in the Base and Intermediate periods is approximately 105 MVA (6 percent) higher in the Forecasted Test Period while the sum of the monthly Peak period demand is forecasted to decline by 62 MVA because one Major Account customer which has been operating in the Peak demand period has indicated that it will not continue to do so. The ITOD-Primary rate class is 61 GWh (4 percent) higher in the Forecasted Test Period driven by the customer movement mentioned earlier as well as forecasted growth at another Major Account customer.

Q. Do you believe the forecasted billing determinants for the Forecasted Test Period are a reasonable basis for developing revenue forecasts?

A. Yes. The forecast process is one that has been employed for many years and has been reviewed by the Commission in the context of IRPs, CPCNs, and ECR filings. It reflects the best data available, and the output is reasonable both in a historical context and given the underlying input assumptions.

Section 4 – KU Electric Load Forecast

Q. Please provide an overview of the 2015 LF for KU.

A. As shown in Exhibit DSS-2, from the Base Period (March 2014 through February 2015) to the Forecasted Test Period (July 2015 through June 2016), electric sales increase by 207 GWh (1.1 percent) and total customers increase by 4,055 (0.8 percent). At the total company level, these changes are very consistent with what one would expect given the economic and other assumptions underlying the forecast.[6]

Q. Does weather explain any of the difference between the sales in the Base Period and the Forecasted Test Period?

A. Yes. The Base Period consists of actual billed data for the first six months and, therefore, reflects the actual weather during that time. On the other hand, sales in the last six months of the Base Period and the entire Forecasted Test Period are based on 20-year normal weather for the KU service area as described in Annual Electric Sales & Demand Forecast Process at Tab 16. Table 2 compares the actual monthly HDDs and CDDs to their 20-year normal values. As you can see, the Base Period winter was much colder than average based on higher than average HDDs, while the Base Period summer was milder than average with less than average CDDs. KU has a higher saturation of electric heat compared to LG&E; therefore, weather also has a significant impact during the winter.

[6] See Exhibit DSS-4 for detailed assumptions for the Forecasted Test Period.

As shown in Exhibit DSS-2, energy in the residential ("RS") rate class is 37 GWh (1 percent) higher in the Forecasted Test Period. In addition, the General Service ("GS") rate class is 49 GWh (3 percent) higher. These rate classes are highly sensitive to weather, therefore the colder than average winter weather in the Base Period was partially offset by the milder than average Base Period summer weather.

Table 2 - Comparison of Actual and 20-year Average Weather for the KU Service Area

	Actual	Average	Difference
March (HDD)	717	619	98
April (HDD)	206	296	(90)
May (CDD)	146	89	57
June (CDD)	305	245	60
July (CDD)	270	352	(82)
August (CDD)	345	333	12

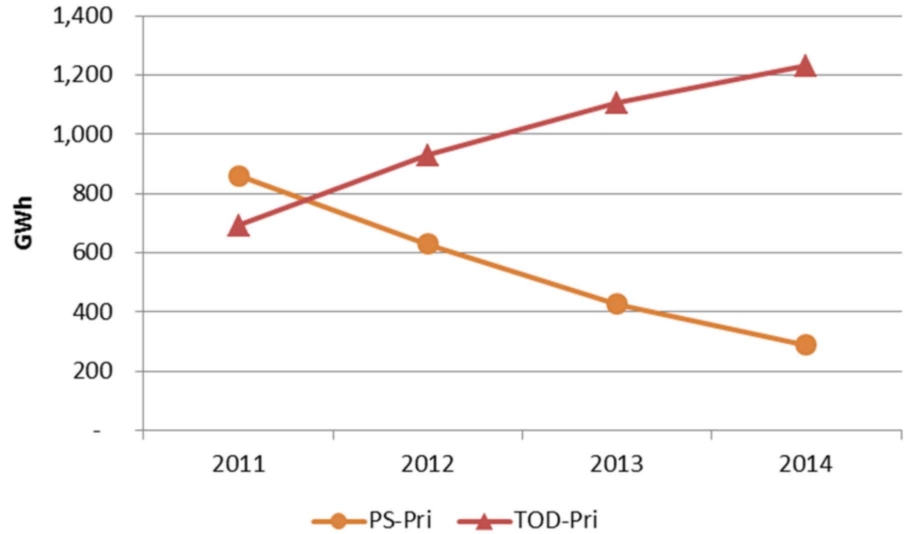
Q. Besides the differences in weather, are there any other aspects of the Forecasted Test Period compared to the Base Period that are of interest?

A. Yes. In Exhibit DSS-2, one can see that sales, customers, and demand are increasing for the majority of rate classes from the Base Period to the Forecasted Test Period. This trend is consistent with modestly improving economic conditions since the 2007-2009 recession that are forecasted to continue.

Q. Are there any rate classes that show rather large changes, either positive or negative, between the Base Period and the Forecasted Test Period?

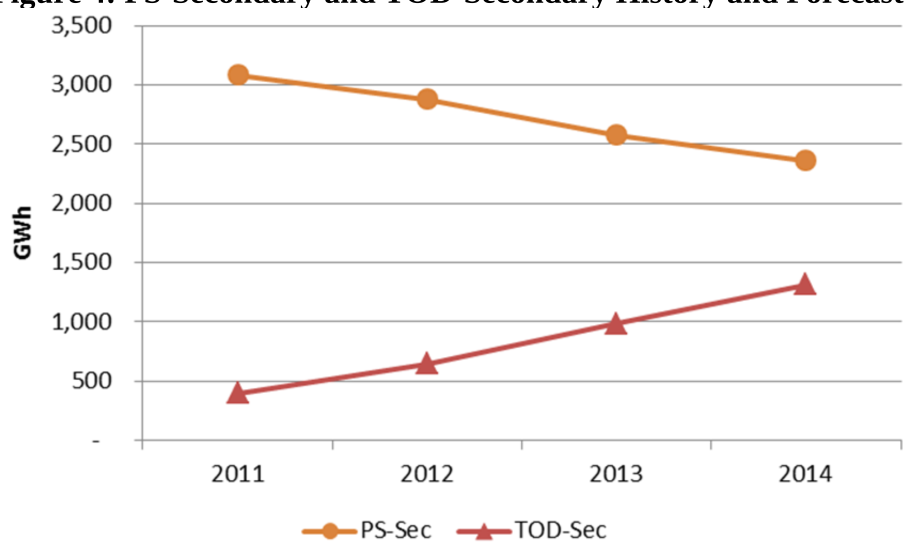
A. Yes. Some large industrial customers are expected to see growth, but the eastern Kentucky coal mining sector is expected to see declines. As shown in Exhibit DSS-2, the RTS rate class is expected to show little to no growth, 2 GWh (0 percent) in the Forecasted Test Period. The RTS rate class is comprised of a significant portion of coal mining customers located in eastern Kentucky which are forecasted to decrease energy usage, thus offsetting growth from customers in other industries. Customers have migrated towards the Time-of-Day ("TOD") rate classes from the power service ("PS") rate classes over the last few years, and this is forecasted to continue (see Figures 3 and 4). The PS-Secondary rate class declines 177 GWh (8 percent) while the TOD-Secondary rate class increases 237 GWh (17 percent) in the Forecasted Test Period. Additionally, the PS-Primary rate class declines 25 GWh (9 percent) while the TOD-Primary rate class increases 28 GWh (2 percent) in the Forecasted Test Period.

Figure 3: PS-Primary and TOD-Primary History and Forecast



Note: 2014 is 8 months of actual and 4 months of forecast.

Figure 4: PS-Secondary and TOD-Secondary History and Forecast



Note: 2014 is 8 months of actual and 4 months of forecast.

Q. Are there any large differences in individual Major Account customers between the Base Period and the Forecasted Test Period that would explain changes in a particular rate class forecast and how were these forecasts developed?

A. As described in Annual Electric Sales & Demand Forecast Process at Tab 16, the forecast process for certain major accounts is based largely on input from the customer itself. As shown in Exhibit DSS-2, the customer on the Fluctuating Load Service ("FLS") rate has been experiencing a high level of demand in the peak period over the last few months which is not forecasted to continue. Billed demand in the peak period declines by approximately 14 MVA per month on average. This translates into a decline of 173 MVA (12 percent) in the Forecasted Test Period.

The Large Time-of-Day (LTOD-Pri) rate class is 58 GWh (2 percent) higher in the Forecasted Test Period. This is driven by expected growth in several individually forecasted Major Account customers.

Q. Do you believe the forecasted billing determinants for the Forecasted Test Period are a reasonable basis for developing revenue forecasts?

A. Yes. As I said before, the forecast process is one that has been employed for many years and has been reviewed by the Commission in the context of IRPs, CPCNs, and ECR filings. It reflects the best data available, and the output is reasonable both in a historical context and given the underlying input assumptions.

<u>Section 5 – LG&E Natural Gas Forecast</u>

Q. Please provide an overview of the 2015 LF of natural gas volumes for LG&E.

A. As discussed in document entitled "Annual Natural Gas Volume Forecast Process" at Tab 16 of the Companies' Applications, the natural gas volume forecast consists of two broad types of customers: sales to consumers and transportation to customers who procure their own natural gas. From the Base Period (March 2014 through

February 2015) to the Forecasted Test Period (July 2015 through June 2016), natural gas sales decline by 1,739,105 Mcf (5.2 percent) and total customers increase by 216 (0.1 percent). Similarly, comparing the same time periods, volumes for transportation customers increase by 339,727 Mcf (2.8 percent). Weather is the primary reason for the decline from the Base Period to the Forecasted Test Period.

Q. Why do you believe that weather is the primary explanation for the difference in volumes between the Base Period and the Forecasted Test Period?

A. As I have stated previously, the Base Period consists of actual billed data for the first six months and, therefore, reflects the actual weather during that time. Because the vast majority of natural gas demand occurs in the winter, the fact that the actual months in the Base Period reflect billed data in March and April of 2014 when weather was colder than normal results in a period-to-period decline. Furthermore, as discussed in Annual Natural Gas Volume Forecast Process at Tab 16, billed data reflects volumes used in the prior month as well. As shown in Table 3, the total HDDs in February through April 2014 were significantly greater than the 30-year normal values used in developing the billed forecast volumes for the same months in the Forecasted Test Period.[7]

Table 3 - Comparison of Actual and 30-year Average Weather for the LG&E Service Area

	Actual	Average	Difference
February (HDD)	894	743	151
March (HDD)	648	544	104
April (HDD)	176	244	(68)

[7] The 30-year period is used for gas forecasts to be consistent with the methodology used in the Weather Normalization Adjustment Clause for Residential Gas Service (“RGS”) and Firm Commercial Gas Service (“CGS”) rates.

Q. Besides the differences in weather, are there any other aspects of the Forecasted Test Period compared to the Base Period that are of interest?

A. Yes. In Exhibit DSS-3, one can see that, although the weather impact is clearly evident in the 3.3 percent decrease for total gas volumes, total customer growth shows a very slight increase of 0.1 percent. The number of net customers is increasing slightly (0.1 percent) as economic conditions have improved since the 2007-2009 recession although no substantial increase in customer growth rates is expected.

Q. Are there any rate classes that show noteworthy changes, either positive or negative, between the Base Period and the Forecasted Test Period?

A. Yes. As shown in Exhibit DSS-3, Gas Transport Service FT, Industrial shows a slight increase (2 percent) despite any weather influence based on input from individually forecasted customers. For Gas Special Contracts – LG&E (-16 percent), as of September 2014, the Cane Run Generating Station is taking gas directly from the Texas Gas Transmission interstate pipeline at a new interconnection point built for the Cane Run Unit 7 natural gas combined cycle unit and is no longer being served by the LG&E Gas Business.

Q. Are there any large differences in individual Major Account customers between the Base Period and the Forecasted Test Period that would explain changes in a particular rate class forecast and how were these forecasts developed?

A. As described in Annual Natural Gas Volume Forecast Process at Tab 16, the forecast process for an individually forecasted major account is based largely on input from the customer itself. As shown in Exhibit DSS-3, the "Gas Transport Service, FT

Industrial" rate class increased by 252,248 Mcf (2 percent) in the Forecasted Test Period. This is driven primarily by an expansion of a single Major Account customer which will consume additional gas volumes of approximately 180,000 Mcf annually starting in late 2015.

Q. Do you believe the forecasted billing determinants for the Forecasted Test Period are a reasonable basis for developing revenue forecasts?

A. Yes. The forecast process is one that has been employed for many years, reflects the best data available, and the output is reasonable both in a historical context and given the underlying input assumptions. The natural gas forecast process uses many of the same methodologies and forecasting techniques as the electric forecast which has been reviewed by the Commission in the context of IRPs, CPCNs, and ECR filings.

<u>Section 6 – Electric and Gas Forecast Summary</u>

Q. Please summarize your thoughts on the 2015 electric and natural gas forecasts.

A. As I have stated, both the electric and natural gas forecasts were prepared using methods that have been in place for many years. These are the same methods that have been used to prepare forecasts that have been presented by the Companies in numerous proceedings at this Commission. The 2015 electric and natural gas forecasts were prepared using updated models and information and, as I explained, the resulting forecasts are reasonable.

Q. How do the Companies ensure their electric and gas load forecasts are reasonable?

A. The Companies seek to ensure their load forecasts are prepared using sound methods by people who are qualified professionals. There are three practices that the Companies employ to help produce the most reasonable forecast possible:

1. Build and rigorously test statistically and economically sound mathematical models of the load forecast variables;
2. Use quality forecasts of future macroeconomic events, both nationally and in the service territory, that influence the load forecast variables; and
3. Thoroughly review and analyze the model output to ensure the results make sense based on historical trends and the forecaster's own sense and understanding of long-term trends in electricity and natural gas usage.

The end result is the best forecast that can be produced by experienced professionals using the best available methods, models, and data.

Q. In your professional opinion, is the 2015 LF a reasonable forecast that can be relied upon in the development of the 2015 business plan?

A. Yes. I have been involved in economic forecasting for 30 years and first began performing utility load forecasts in 1986 so I have prepared and reviewed many forecasts in my career. It is my opinion that the 2015 LF fully meets the criteria I just discussed and is a reasonable forecast upon which to base the business plan.

<u>Section 7 – Generation and OSS Forecasts</u>

Q. Please describe how the generation and OSS forecasts are prepared.

A. A software program called PROSYM is used to simulate the dispatch of the Companies' generation fleet. The model uses a forecast of hourly energy requirements for the combined LG&E and KU system (including load in Virginia and wholesale requirements contracts) along with information on the Companies' generation fleet (unit capacity, heat rate, fuel cost, variable O&M, emissions, maintenance schedules, forced outage rate, etc.) and market conditions (spot wholesale electricity prices, transmission availability) to first optimize the cost of serving native load and then to sell any economic generation into the market. This process is described in detail in the document entitled "Annual Generation & Off-System Sales Forecast Process" attached at Tab 16 of the Companies' Applications.

Q. What are the primary reasons for differences in the generation volumes in the Forecasted Test Period compared to the Base Period?

A. Not surprisingly, the difference in the overall generation volume in the Forecasted Test Period compared to the Base Period is much the same as the difference in the Kentucky retail sales that I previously discussed. This is because sales to Kentucky retail customers make up approximately 92 percent of the Companies' native load (which also includes retail sales in Virginia and Tennessee and wholesale sales to twelve cities in Kentucky). However, as can be seen in Exhibit DSS-5, the generation volume from a particular unit can vary greatly from the Base Period to the Forecasted Test Period. The primary reasons for these differences are: (i) timing and duration of routine maintenance outages, (ii) outages for tie-in of newly constructed environmental equipment, (iii) the retirement of the Cane Run coal units, (iv) the new natural gas combined cycle (Cane Run Unit 7) that is being commissioned, (v) differences between actual forced outage events and forecasted forced out rates, and (vi) changes in fuel costs.

Q. What are OSS volume and margin expected to be in the Forecasted Test Period and how do they compare to the Base Period amounts?

A. Table 4 and Table 5 contain a comparison of OSS volume and margin between the Base Period and the Forecasted Test Period for LG&E and KU, respectively.[8] Compared to the Base Period, LG&E's OSS volume and margin in the Forecasted Test Period are expected to be lower by 94 GWh and $3.3 million, respectively. KU's OSS volume is expected to increase by 46 GWh but its OSS margin is expected to decrease by $0.1 million.

Table 4 - Comparison of OSS Volumes and Margins – LG&E

	Base Period			Forecasted Test Period			Difference		
Month	**Price ($/ MWh)**	**OSS Vol. (GWh)**	**OSS Margin ($M)**	**Price ($/ MWh)**	**OSS Vol. (GWh)**	**OSS Margin ($M)**	**Price ($/ MWh)**	**OSS Vol. (GWh)**	**OSS Margin ($M)**
Mar	56	53	1.5	38	34	0.3	(18)	(19)	(1.2)
Apr	37	1	0.0	35	4	0.0	(3)	2	0.0
May	42	39	0.8	32	6	0.0	(10)	(33)	(0.8)
Jun	38	42	0.5	35	3	0.0	(3)	(39)	(0.5)
Jul	32	11	0.1	44	7	0.1	12	(3)	(0.0)
Aug	32	33	0.3	40	4	0.0	7	(29)	(0.3)
Sep	34	43	0.3	30	7	0.0	(4)	(37)	(0.3)
Oct	34	7	0.1	30	2	0.0	(4)	(5)	(0.1)
Nov	35	5	0.0	31	4	0.0	(5)	(1)	(0.0)
Dec	41	38	0.4	35	38	0.1	(6)	(0)	(0.3)
Jan	55	58	0.9	50	70	0.7	(4)	12	(0.2)
Feb	50	68	1.0	50	126	1.5	1	58	0.5
Total		**399**	**6.0**		**305**	**2.7**		**(94)**	**(3.3)**

[8] OSS volumes and margins are for sales to third parties and do not include intercompany sales between LG&E and KU.

Table 5 - Comparison of OSS Volumes and Margins - KU

	Base Period			Forecasted Test Period			Difference		
Month	**Price ($/ MWh)**	**OSS Vol. (GWh)**	**OSS Margin ($M)**	**Price ($/ MWh)**	**OSS Vol. (GWh)**	**OSS Margin ($M)**	**Price ($/ MWh)**	**OSS Vol. (GWh)**	**OSS Margin ($M)**
Mar	56	0	0.0	38	8	0.1	(18)	8	0.0
Apr	37	0	0.0	35	1	0.0	(3)	1	0.0
May	42	5	0.1	32	20	0.1	(10)	16	(0.0)
Jun	38	4	0.1	35	5	0.0	(3)	1	(0.0)
Jul	32	4	0.1	44	13	0.1	12	9	0.0
Aug	32	8	0.1	40	8	0.0	7	0	(0.1)
Sep	34	4	0.1	30	10	0.0	(4)	6	(0.1)
Oct	34	5	0.1	30	0	0.0	(4)	(5)	(0.1)
Nov	35	0	0.0	31	0	0.0	(5)	(0)	(0.0)
Dec	41	1	0.0	35	5	0.0	(6)	4	(0.0)
Jan	55	2	0.0	50	10	0.1	(4)	8	0.1
Feb	50	8	0.1	50	6	0.1	1	(1)	(0.0)
Total		**40**	**0.7**		**86**	**0.5**		**46**	**(0.1)**

For the shoulder months of April, October, and November, the differences in OSS margin between the Base Period and Forecasted Test Period are immaterial. OSS volumes are typically limited in shoulder months due to planned maintenance (which reduces the availability of generation for OSS) and mild weather which often results in lower wholesale prices. For the remaining months, the differences in OSS margin between the Base Period and Forecasted Test Period are explained primarily by differences in wholesale electricity prices and native load energy requirements. When native load energy requirements are lower, generation that would otherwise be needed for native load is available for OSS (all other things equal). Likewise (all other things equal), as wholesale electricity prices increase, generation that would otherwise not be economic for OSS becomes economic.

For LG&E, with the exception of July and August, the change in OSS margin for the non-shoulder months is explained by the change in wholesale electricity prices. In July and August, the impact of higher electricity prices is slightly more than offset by the impact of higher native load energy requirements. As I mentioned previously, the Base Period reflects actual weather for March through August and 'normal' weather for September through February. Due to the significantly milder than normal weather in July and August of 2014, energy requirements in the Base Period for these months are much lower than energy requirements in the Forecasted Test Period, which is based on a 'normal' weather forecast.

The same factors explain monthly differences in OSS margin for KU. However, due to KU's relatively low OSS volumes, the differences in OSS margin between the Base Period and Forecasted Test Period are immaterial.

Q. In your professional opinion, are the 2015 generation and OSS forecasts reasonable and can they be relied upon in the development of the 2015 business plan?

A. Yes. Both of these forecasts were developed using processes and software that have been utilized by the Companies for many years and have been the basis for information provided to the Commission in numerous IRPs, CPCNs, and ECR cases. Using sound models and assumptions will produce reasonable forecasts. As I discussed, the differences between generation volumes and OSS in the Forecasted Test Period and the Base Period are reasonable given the underlying differences in native load energy requirements and wholesale electricity prices.

Section 8 – Schedule D-1 Support

Q. Does your testimony support the Jurisdictional Adjustments to Base Period for Operating Revenues from Sales of Electricity in Schedule D-1?

A. Yes. For the reasons I have stated, the volumetric changes to both KU's and LG&E's electric and gas load forecasts serve as a driver for the differences in Operating Revenues from Sales of Electricity (Account No's. 440, 442.2, 442.3, 444, and 445) between the Base Period and the Forecasted Test Period.

Q. In Schedule D-1, what revenues and expenses are included in Sales for Resale (Account No. 447) and Purchased Power (Account No. 555)?

A. Sales for Resale contains intercompany sales revenue and OSS revenue. Purchased Power contains intercompany purchased power expense, market economy purchased power expense, OVEC purchase power expense, and (for LG&E) non-fuel expenses associated with the Bluegrass tolling agreement. Intercompany sales revenue for one company in Account No. 447 equals the intercompany purchased power expense for the other company in Account No. 555.

Q. What are the differences in Sales for Resale and Purchased Power between the Base Period and the Forecasted Test Period?

A. Compared to the Base Period, LG&E's Sales for Resale in the Forecasted Test Period are expected to decrease by $33 million, from $105 million to $72 million; KU's Sales for Resale are expected to increase by $11 million, from $14 million to $25 million. The retirement of the Cane Run coal units (owned by LG&E) and the commissioning of Cane Run Unit 7 (78 percent owned by KU) are the primary drivers of these differences. Both events are scheduled to take place between the Base Period and the Forecasted Test Period. After these events, even with 78 percent of Cane Run Unit 7 owned by KU, LG&E will continue to sell the majority of energy sold between the Companies.

Compared to the Base Period, LG&E's Purchased Power in the Forecasted Test Period is expected to be higher by $22 million; KU's Purchased Power is expected to be lower by $23 million. For KU, the change is explained almost entirely by the reduction in intercompany purchased power expense associated with the retirement of the Cane Run coal units and the commissioning of Cane Run Unit 7. These events explain roughly half of the increase in Purchased Power for LG&E. The other half of the increase is explained by the addition of non-fuel expenses associated with the Bluegrass tolling agreement.

<u>Section 9 – Curtailable Service Rider</u>

Q. Please explain what the Curtailable Service Rider ("CSR") is and why the Companies offer it.

A. The CSR is a tariff that provides a credit against a customer's demand charge in exchange for allowing the Companies to curtail (interrupt) service for a given volume and limited number of hours during the year. By being able to interrupt service, the Companies are able to avoid procuring capacity, thereby reducing revenue requirements for the system. The Companies have incorporated this process in their system modeling for previous IRP and CPCN filings.

Q. Please describe the Companies' existing CSR tariffs and the proposed changes to them.

A. The CSR terms are the same for both LG&E and KU. Table 6 shows some of the major terms in the existing CSR tariffs along with the proposed changes that are being filed in this case. As you can see, the Companies are proposing to simplify the

CSR tariffs by eliminating the "buy through" option and eliminating the limitation on the ability to call for curtailment for only "system reliability events."

Table 6 - Overview of Proposed Changes to CSR Tariffs

	Existing Tariffs	Proposed Tariffs
Total Hours of Curtailment	375	100
Buy through option	Yes – 275 hours	None
Limitation on curtailment request	Only during "system reliability events"	None
Certification of curtailment volume	None	Customer must annually demonstrate or certify its ability to comply with a physical curtailment request

Q. Why are the Companies proposing to eliminate the "buy through" provision?

A. As I said before, the primary purpose of the CSR is to reduce the need for the Companies to obtain generating assets to serve load. The "buy through" provision did nothing to alter the Companies' obligation to serve, and thus, the need for generating assets to meet load. All it did was effectively change the energy price for a customer on the CSR tariff to be equivalent to a simple cycle gas-fired combustion turbine ("CT").

Q. Why are the Companies proposing to eliminate the "system reliability events" limitation on when they can ask for a curtailment?

A. From a system planning point of view, the ability to curtail load for a limited number of hours under the CSR is supposed to substitute for a peaking generation asset like a CT. In fact, the demand credit the CSR customer receives is very similar to the annualized fixed cost of a CT. The Companies have no such "system reliability events" limitation on the use of their CTs and, from a dispatch operations perspective, limiting the ability to call for a curtailment until a "system reliability event" occurs reduces their ability to dispatch the system in a least-cost manner. By eliminating the "system reliability events" limitation, the Companies are putting the CSR tariff on equal footing with its other peaking resources while, at the same time, keeping the 100 hour annual limitation on curtailable events ensures that it will be used effectively during system peak conditions. This increased flexibility will result in making the CSR a more effective resource.

Q. Why are the Companies proposing that a CSR customer annually certify or demonstrate its ability to physically curtail its load?

A. As I said, the purpose of offering a CSR tariff is to avoid the need to acquire generation assets. From a resource planning perspective, the load of a CSR customer is assumed to be curtailed during times of system peak. Therefore, should a CSR customer not perform when called upon, it puts the reliability of the system in jeopardy. While the Companies can, and do, assess a financial penalty to a CSR customer that fails to perform, this after-the-fact remedy does nothing to ensure the reliability of the system at the time a curtailment was requested. By requiring a customer who wants to be on the CSR tariff to annually certify or demonstrate their ability to implement their physical curtailment plan, the Companies are helping to ensure that the CSR tariff is a reliable resource that can be counted on during peak system conditions.

Q. Given the proposed changes, why are the Companies not proposing to change the amount of the CSR credit?

A. The Generation Planning department analyzed the value of being able to interrupt load compared to the cost of new generating capacity and determined that the current capacity credit contained within CSR10 and CSR30 fall within the range of reasonableness. Therefore, no change to the monetary value of the credit is being proposed.

Q. Does this conclude your testimony?

A. Yes, it does.

VERIFICATION

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

The undersigned, **David S. Sinclair**, being duly sworn, deposes and says that he is Vice President, Energy Supply and Analysis 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.

David S Sinclair
David S. Sinclair

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 11th day of November 2014.

Judy Schooler (SEAL)
Notary Public

My Commission Expires:

July 11, 2018

APPENDIX A

David S. Sinclair

Vice President, Energy Supply and Analysis
LG&E and KU Energy, LLC
220 West Main Street
Louisville, Kentucky 40202
(502) 627-4653

Education

Arizona State University, M.B.A -1991
Arizona State University, M.S. in Economics – 1984
University of Missouri, Kansas City, B.A. in Economics - 1982

Professional Experience

LG&E and KU Energy, LLC
2008-present – Vice President, Energy Supply and Analysis
2000-2008 – Director, Energy Planning, Analysis and Forecasting

LG&E Energy Marketing, Louisville, Kentucky
1997-1999 – Director, Product Management
1997-1997 (4th Quarter) – Product Development Manager
1996-1996 – Risk Manager

LG&E Power Development, Fairfax Virginia
1994-1995 – Business Developer

Salt River Project, Tempe, Arizona
1992-1994 – Analyst, Corporate Planning Department

Arizona Public Service, Phoenix, Arizona
1989-1992 – Analyst, Financial Planning Department
1986-1989 – Analyst, Forecasts Department

State of Arizona, Phoenix, Arizona
1983-1986 – Economist, Arizona Department of Economic Security

Affiliations

Consensus Forecasting Group (2013-present) - nonpartisan group of economists that monitor Kentucky's revenues and the economy on behalf of the governor and legislature.

Civic Activities

Serve on the Board of Junior Achievement of Kentuckiana

Graduate of Leadership Louisville (2008) and Bingham Fellows (2011)

Exhibit DSS-1

LG&E Electric Base Period vs. Forecasted Test Period

Comparison of LG&E Electric Customers, Billing Demand, and Energy: Base Period vs. Forecasted Test Period

Rate	Category	Values		Period	Mar '14 - Feb '15	Jul '15 - Jun '16	Delta	% Delta
PS-Pri (Commercial)	Customers	Avg Number of Customers			54	52	(2)	-3%
	Demand	Sum of Volume	MW	Base	360	363	4	1%
	Energy	Sum of Volume	GWh		150	150	(0)	0%
PS-Sec (Commercial)	Customers	Avg Number of Customers			2,585	2,582	(3)	0%
	Demand	Sum of Volume	MW	Base	4,416	4,293	(122)	-3%
	Energy	Sum of Volume	GWh		1,717	1,728	11	1%
CTOD-Pri	Customers	Avg Number of Customers			35	39	4	12%
	Demand	Sum of Volume	MVA	Base	868	887	19	2%
			MVA	Intermediate	807	822	15	2%
			MVA	Peak	790	804	15	2%
	Energy	Sum of Volume	GWh		372	373	1	0%
TOD-Sec (Commercial)	Customers	Avg Number of Customers			213	221	9	4%
	Demand	Sum of Volume	MW	Base	1,595	1,716	120	8%
			MW	Intermediate	1,504	1,625	121	8%
			MW	Peak	1,476	1,595	119	8%
	Energy	Sum of Volume	GWh		718	781	62	9%
Special Contract 1	Customers	Avg Number of Customers			1	1	-	0%
	Demand	Sum of Volume	MW	Base	280	160	(120)	-43%
	Energy	Sum of Volume	GWh		160	110	(50)	-31%
GS	Customers	Avg Number of Customers			44,385	44,597	212	0%
	Energy	Sum of Volume	GWh		1,361	1,385	24	2%
PS-Pri (Industrial)	Customers	Avg Number of Customers			22	21	(1)	-3%
	Demand	Sum of Volume	MW	Base	56	48	(7)	-13%
	Energy	Sum of Volume	GWh		14	13	(0)	-2%
PS-Sec (Industrial)	Customers	Avg Number of Customers			236	213	(22)	-9%
	Demand	Sum of Volume	MW	Base	831	749	(82)	-10%
	Energy	Sum of Volume	GWh		272	238	(34)	-12%
ITOD-Pri	Customers	Avg Number of Customers			66	70	4	7%
	Demand	Sum of Volume	MVA	Base	3,842	4,104	263	7%
			MVA	Intermediate	3,598	3,726	128	4%
			MVA	Peak	3,543	3,676	133	4%
	Energy	Sum of Volume	GWh		1,610	1,670	61	4%
TOD-Sec (Industrial)	Customers	Avg Number of Customers			81	98	17	21%
	Demand	Sum of Volume	MW	Base	593	649	56	9%
			MW	Intermediate	557	604	47	8%
			MW	Peak	543	588	44	8%
	Energy	Sum of Volume	GWh		232	260	27	12%
Special Contract 2	Customers	Avg Number of Customers			2	2	-	0%
	Demand	Sum of Volume	MW	Base	114	113	(1)	-1%
	Energy	Sum of Volume	GWh		57	58	0	0%
RS	Customers	Avg Number of Customers			357,916	361,519	3,603	1%
	Energy	Sum of Volume	GWh		4,116	4,267	151	4%
RTS	Customers	Avg Number of Customers			12	12	-	0%
	Demand	Sum of Volume	MVA	Base	1,812	1,918	105	6%
			MVA	Intermediate	1,740	1,844	104	6%
			MVA	Peak	1,220	1,158	(62)	-5%
	Energy	Sum of Volume	GWh		828	877	49	6%
Lighting	Customers	Avg Number of Customers			1,069	1,061	(8)	-1%
	Energy	Sum of Volume	GWh		120	123	3	3%
Total LGE Energy					11,727	12,032	305	2.6%
Total LGE Customers					406,675	410,490	3,815	0.9%

Exhibit DSS-2

KU Electric Base Period vs. Forecasted Test Period

Comparison of KU Electric Customers, Billing Demand, and Energy: Base Period vs. Forecasted Test Period

Rate	Category	Values	Unit	Period	Mar '14 - Feb '15	Jul '15 - Jun '16	Delta	% Delta
AES	Customers	Avg Number of Customers			625	634	9	2%
	Energy	Sum of Volume	GWh		148	152	4	3%
FLS	Customers	Avg Number of Customers			1	1	-	0%
	Demand	Sum of Volume	MVA	Base	2,231	2,222	(10)	0%
			MVA	Intermediate	2,231	2,222	(10)	0%
			MVA	Peak	1,390	1,217	(173)	-12%
	Energy	Sum of Volume			565	561	(4)	-1%
GS	Customers	Avg Number of Customers			81,930	82,105	175	0%
	Energy	Sum of Volume	GWh		1,856	1,905	49	3%
LTOD-Pri	Customers	Avg Number of Customers			53	52	(1)	-2%
	Demand	Sum of Volume	MVA	Base	6,178	6,342	165	3%
			MVA	Intermediate	5,919	6,071	152	3%
			MVA	Peak	5,836	5,988	152	3%
	Energy	Sum of Volume	GWh		2,971	3,029	58	2%
PS-Pri	Customers	Avg Number of Customers			227	198	(30)	-13%
	Demand	Sum of Volume	MW	Base	715	683	(32)	-5%
	Energy	Sum of Volume	GWh		263	238	(25)	-9%
PS-Sec	Customers	Avg Number of Customers			4,997	4,656	(341)	-7%
	Demand	Sum of Volume	MW	Base	7,143	6,977	(165)	-2%
	Energy	Sum of Volume	GWh		2,286	2,109	(177)	-8%
RS	Customers	Avg Number of Customers			426,154	430,354	4,200	1%
	Energy	Sum of Volume	GWh		6,161	6,197	37	1%
RTS	Customers	Avg Number of Customers			32	32	-	0%
	Demand	Sum of Volume	MVA	Base	3,635	3,652	17	0%
			MVA	Intermediate	3,507	3,507	0	0%
			MVA	Peak	3,427	3,428	1	0%
	Energy	Sum of Volume	GWh		1,603	1,606	2	0%
TOD-Pri	Customers	Avg Number of Customers			172	202	30	18%
	Demand	Sum of Volume	MVA	Base	3,199	3,276	77	2%
			MVA	Intermediate	3,070	3,136	67	2%
			MVA	Peak	3,003	3,068	65	2%
	Energy	Sum of Volume			1,240	1,268	28	2%
TOD-Sec	Customers	Avg Number of Customers			454	467	12	3%
	Demand	Sum of Volume	MW	Base	3,404	3,967	563	17%
			MW	Intermediate	3,138	3,654	515	16%
			MW	Peak	3,072	3,577	504	16%
	Energy	Sum of Volume	GWh		1,372	1,609	237	17%
Lighting	Customers	Avg Number of Customers			748	747	(1)	0%
	Energy	Sum of Volume	GWh		121	119	(2)	-2%
Total KU Energy					18,586	18,793	207	1.1%
Total KU Customers					515,393	519,448	4,055	0.8%

Exhibit DSS-3

LG&E Gas Base Period vs. Forecasted Test Period

Comparison of LG&E Gas Customers and Volume: Base Period vs. Forecasted Test Period

Rate	Category	Sales/Transport	Values	Mar '14 - Feb '15	Jul '15 - Jun '16	Delta	% Delta
As-Available Gas Service, Commercial	Gas Volumes	Sales	Volume (Mcf)	76,182	54,585	(21,597)	-28%
	Customers	Sales	Average Number of Customers	3	3	-	0%
As-Available Gas Service, Industrial	Gas Volumes	Sales	Volume (Mcf)	236,865	191,784	(45,081)	-19%
	Customers	Sales	Average Number of Customers	4	3	(1)	-31%
Special Contract 1	Gas Volumes	Transport	Volume (Mcf)	533,513	593,147	59,635	11%
	Customers	Transport	Average Number of Customers	1	1	-	0%
Firm Commercial Gas Service	Gas Volumes	Sales	Volume (Mcf)	10,929,771	10,433,869	(495,902)	-5%
	Customers	Sales	Average Number of Customers	24,265	23,697	(568)	-2%
Firm Industrial Gas Service	Gas Volumes	Sales	Volume (Mcf)	1,197,133	1,198,353	1,220	0%
	Customers	Sales	Average Number of Customers	247	252	5	2%
Gas Special Contracts - LG&E	Gas Volumes	LGE	Volume (Mcf)	449,637	376,106	(73,531)	-16%
	Customers	LGE	Average Number of Customers	2	1	(1)	-33%
Gas Transport Service, FT Commercial	Gas Volumes	Transport	Volume (Mcf)	625,746	573,119	(52,626)	-8%
	Customers	Transport	Average Number of Customers	10	10	-	0%
Gas Transport Service, FT Industrial	Gas Volumes	Transport	Volume (Mcf)	10,728,874	10,981,122	252,248	2%
	Customers	Transport	Average Number of Customers	68	69	1	2%
Gas Transport Service, Paddy's Run	Gas Volumes	Paddy's	Volume (Mcf)	1,482,475	1,398,150	(84,325)	-6%
	Customers	Paddy's	Average Number of Customers	1	1	-	0%
Residential Gas Service	Gas Volumes	Sales	Volume (Mcf)	21,162,816	19,985,071	(1,177,745)	-6%
	Customers	Sales	Average Number of Customers	293,835	294,616	781	0%
TS-2: Gas Trans/Firm Balancing (AAGS In)	Gas Volumes	Transport	Volume (Mcf)	56,004	152,455	96,451	172%
	Customers	Transport	Average Number of Customers	1	2	1	50%
TS-2: Gas Transport/Firm Balancing (IGS)	Gas Volumes	Transport	Volume (Mcf)	153,053	137,073	(15,980)	-10%
	Customers	Transport	Average Number of Customers	3	2	(1)	-25%
Total Gas Volumes				47,632,067	46,074,833	(1,557,234)	-3.3%
Total Customers				318,440	318,656	217	0.1%
Total Gas Volumes		Sales		33,602,766	31,863,661	(1,739,105)	-5.2%
Total Customers		Sales		318,354	318,570	216	0.1%
Total Gas Volumes		Transport		12,097,189	12,436,916	339,727	2.8%
Total Customers		Transport		83	84	1	1.4%

Exhibit DSS-4

Economic Inputs

Economic Inputs to Electric and Gas Forecasts

	Gross Domestic Product Billions of Chained 2009 Dollars, SAAR	Real Gross State Product (GSP) Millions of 2005 US$, SAAR	Employment, Retail Trade (NAICS 44-45) Thousand
2005 Q1	14,100.20	137,807.62	212.67
2005 Q2	14,177.20	138,253.80	212.13
2005 Q3	14,292.90	139,169.66	212.40
2005 Q4	14,372.00	139,856.92	211.80
2006 Q1	14,546.40	142,391.37	212.77
2006 Q2	14,591.60	142,005.01	212.03
2006 Q3	14,604.40	141,190.43	210.60
2006 Q4	14,718.40	141,541.18	211.80
2007 Q1	14,728.10	140,691.47	214.03
2007 Q2	14,841.50	141,199.25	214.27
2007 Q3	14,941.50	141,349.44	213.00
2007 Q4	14,996.10	141,719.84	212.97
2008 Q1	14,895.40	141,660.24	212.93
2008 Q2	14,969.20	142,387.02	211.63
2008 Q3	14,895.10	141,253.71	210.50
2008 Q4	14,574.60	137,423.04	207.47
2009 Q1	14,372.10	133,860.22	203.27
2009 Q2	14,356.90	134,080.51	202.07
2009 Q3	14,402.50	135,385.25	201.30
2009 Q4	14,540.20	137,394.01	200.40
2010 Q1	14,597.70	139,199.22	200.07
2010 Q2	14,738.00	141,469.53	200.40
2010 Q3	14,839.30	142,860.20	200.67
2010 Q4	14,942.40	144,379.05	201.10
2011 Q1	14,894.00	143,533.74	201.07
2011 Q2	15,011.30	144,271.94	201.00
2011 Q3	15,062.10	144,917.17	200.90
2011 Q4	15,242.10	146,393.14	201.67
2012 Q1	15,381.60	147,011.32	202.53
2012 Q2	15,427.70	146,825.20	203.07
2012 Q3	15,534.00	146,965.48	202.57
2012 Q4	15,539.60	146,333.63	202.90
2013 Q1	15,583.90	146,721.04	202.73
2013 Q2	15,679.70	147,577.83	203.00
2013 Q3	15,839.30	149,378.86	203.30
2013 Q4	15,965.60	149,434.99	201.60
2014 Q1	16,041.24	150,497.40	199.76
2014 Q2	16,132.46	151,452.54	200.01
2014 Q3	16,240.25	152,322.14	200.02
2014 Q4	16,369.77	153,124.74	200.29
2015 Q1	16,512.53	154,201.84	200.21
2015 Q2	16,652.33	155,453.57	200.46
2015 Q3	16,798.83	156,931.08	200.45
2015 Q4	16,940.26	158,250.94	200.33
2016 Q1	17,077.34	159,483.64	200.45
2016 Q2	17,219.18	160,735.24	200.54
2016 Q3	17,364.12	162,084.12	200.50
2016 Q4	17,511.88	163,408.09	200.40
2017 Q1	17,633.90	164,442.17	200.49
2017 Q2	17,764.02	165,633.41	200.74
2017 Q3	17,899.31	166,850.21	200.92
2017 Q4	18,036.48	168,242.59	201.01

Economic Inputs tc

	Employment, Wholesale Trade (NAICS 42)	Industrial Production Index, Total	Industrial Production Index, Fabricated Metal Products	Real Personal Income
	Thousand	(2007=100)	(2007=100)	Millions of 2005 US$, SAAR
2005 Q1	74.40	95.12	89.36	120,747.54
2005 Q2	74.43	95.83	90.18	121,787.57
2005 Q3	74.70	95.10	91.33	122,875.32
2005 Q4	74.60	96.98	93.26	122,986.11
2006 Q1	75.20	97.85	95.67	125,676.02
2006 Q2	76.10	97.97	95.90	125,762.55
2006 Q3	76.07	98.01	95.51	125,542.70
2006 Q4	76.57	98.03	96.61	127,081.29
2007 Q1	77.13	98.98	97.41	127,653.51
2007 Q2	77.27	100.31	98.74	128,151.30
2007 Q3	77.00	100.42	101.85	128,388.96
2007 Q4	76.63	100.28	102.03	128,497.49
2008 Q1	76.93	100.22	102.27	130,453.78
2008 Q2	76.57	98.97	99.81	130,303.55
2008 Q3	76.20	95.30	95.17	128,753.70
2008 Q4	75.50	90.91	88.49	130,049.61
2009 Q1	73.50	85.45	76.76	128,495.47
2009 Q2	72.40	83.41	70.11	129,154.59
2009 Q3	71.73	84.41	69.63	128,029.92
2009 Q4	71.80	85.75	70.60	128,748.67
2010 Q1	71.73	86.99	72.40	127,757.65
2010 Q2	71.60	89.27	75.78	130,193.67
2010 Q3	71.70	90.72	78.91	130,814.29
2010 Q4	71.80	91.43	80.64	131,125.05
2011 Q1	71.77	91.33	81.54	133,245.83
2011 Q2	71.67	91.29	83.28	133,237.92
2011 Q3	72.43	92.73	85.18	134,280.58
2011 Q4	72.27	94.11	86.52	134,068.31
2012 Q1	72.43	95.53	88.39	135,642.99
2012 Q2	72.70	96.70	90.77	135,898.34
2012 Q3	72.87	98.46	92.78	135,218.09
2012 Q4	73.07	98.59	92.40	136,760.60
2013 Q1	73.73	99.28	95.06	136,336.96
2013 Q2	74.07	99.81	93.89	136,873.60
2013 Q3	74.23	100.85	93.80	137,471.27
2013 Q4	74.03	100.97	94.76	137,587.64
2014 Q1	75.18	100.59	95.26	137,874.60
2014 Q2	75.45	101.64	96.40	138,975.28
2014 Q3	75.60	102.40	97.33	139,785.18
2014 Q4	75.77	103.17	98.18	140,647.64
2015 Q1	76.02	104.28	99.22	142,520.22
2015 Q2	76.34	105.21	100.26	143,723.30
2015 Q3	76.68	106.34	101.37	144,698.68
2015 Q4	77.07	107.23	102.58	145,817.37
2016 Q1	77.29	108.00	103.32	147,816.34
2016 Q2	77.64	108.87	104.66	148,875.98
2016 Q3	77.91	109.80	105.90	149,939.30
2016 Q4	78.20	110.67	107.16	151,056.80
2017 Q1	78.55	111.28	108.11	152,596.57
2017 Q2	78.90	111.91	108.93	153,768.94
2017 Q3	79.24	112.58	109.67	154,945.46
2017 Q4	79.53	113.18	110.36	156,043.99

Economic Inputs tc

	Population Thousand	Households, Total Thousand	Household Average Size Persons
2005 Q1	4,173.55	1,654.71	2.52
2005 Q2	4,182.74	1,657.96	2.52
2005 Q3	4,191.84	1,657.65	2.53
2005 Q4	4,200.95	1,657.35	2.53
2006 Q1	4,210.09	1,657.04	2.54
2006 Q2	4,219.24	1,656.74	2.55
2006 Q3	4,228.57	1,657.90	2.55
2006 Q4	4,237.91	1,659.06	2.55
2007 Q1	4,247.28	1,660.22	2.56
2007 Q2	4,256.67	1,661.38	2.56
2007 Q3	4,264.95	1,669.17	2.56
2007 Q4	4,273.24	1,677.01	2.55
2008 Q1	4,281.55	1,684.88	2.54
2008 Q2	4,289.88	1,692.78	2.53
2008 Q3	4,296.66	1,694.96	2.53
2008 Q4	4,303.45	1,697.15	2.54
2009 Q1	4,310.26	1,699.33	2.54
2009 Q2	4,317.07	1,701.52	2.54
2009 Q3	4,324.50	1,707.50	2.53
2009 Q4	4,331.93	1,713.64	2.53
2010 Q1	4,339.36	1,719.97	2.52
2010 Q2	4,347.70	1,722.13	2.52
2010 Q3	4,352.49	1,719.08	2.53
2010 Q4	4,357.28	1,716.02	2.54
2011 Q1	4,362.08	1,712.97	2.55
2011 Q2	4,366.87	1,709.92	2.55
2011 Q3	4,370.08	1,718.64	2.54
2011 Q4	4,373.29	1,727.36	2.53
2012 Q1	4,376.51	1,736.07	2.52
2012 Q2	4,379.73	1,744.79	2.51
2012 Q3	4,383.62	1,752.74	2.50
2012 Q4	4,387.51	1,759.65	2.49
2013 Q1	4,391.40	1,765.50	2.49
2013 Q2	4,395.30	1,770.28	2.48
2013 Q3	4,399.47	1,774.10	2.48
2013 Q4	4,403.95	1,777.83	2.48
2014 Q1	4,408.77	1,782.34	2.47
2014 Q2	4,413.75	1,787.16	2.47
2014 Q3	4,418.93	1,791.33	2.47
2014 Q4	4,424.29	1,795.89	2.46
2015 Q1	4,429.80	1,800.60	2.46
2015 Q2	4,435.43	1,805.41	2.46
2015 Q3	4,441.19	1,810.01	2.45
2015 Q4	4,447.04	1,814.71	2.45
2016 Q1	4,452.93	1,819.24	2.45
2016 Q2	4,458.88	1,823.77	2.44
2016 Q3	4,464.93	1,828.38	2.44
2016 Q4	4,471.07	1,832.99	2.44
2017 Q1	4,477.27	1,837.62	2.44
2017 Q2	4,483.47	1,842.22	2.43
2017 Q3	4,489.69	1,846.82	2.43
2017 Q4	4,495.91	1,851.44	2.43

Exhibit DSS-5

Generation Differences by Unit, Base Period vs. Forecasted Test Period

Comparison of Generation Volume by Unit, Base Period vs. Forecasted Test Period

KU

GWh	**Base Period**	**Forecasted Test Period**	**Difference**	**%Difference**
Coal				
Brown 1	364	216	(148)	-41%
Brown 2	688	487	(201)	-29%
Brown 3	1,302	920	(382)	-29%
Cane Run 4	NA	NA		
Cane Run 5	NA	NA		
Cane Run 6	NA	NA		
Ghent 1	3,304	3,122	(182)	-6%
Ghent 2	3,461	2,631	(830)	-24%
Ghent 3	3,086	3,169	83	3%
Ghent 4	2,887	3,103	216	7%
Green River 3	327	192	(135)	-41%
Green River 4	681	474	(207)	-30%
Mill Creek 1	NA	NA		
Mill Creek 2	NA	NA		
Mill Creek 3	NA	NA		
Mill Creek 4	NA	NA		
OVEC	262	256	(6)	-2%
Trimble County 1	NA	NA		
Trimble County 2	2,390	3,079	689	29%
SCCT				
Brown 5	4	1	(3)	-67%
Brown 6	76	38	(37)	-49%
Brown 7	75	65	(10)	-13%
Brown 8	7	17	10	143%
Brown 9	5	2	(3)	-60%
Brown 10	5	2	(3)	-60%
Brown 11	6	5	(1)	-17%
Cane Run 11	NA	NA		
Haefling	0	0	0	0%
LS Power PPA	NA	NA		
Paddys Run 11	NA	NA		
Paddys Run 12	NA	NA		
Paddys Run 13	50	59	8	17%
Trimble County 5	160	191	31	20%
Trimble County 6	138	163	25	18%
Trimble County 7	99	113	14	15%
Trimble County 8	20	23	3	16%
Trimble County 9	95	91	(4)	-5%
Trimble County 10	27	14	(13)	-49%
Zorn	NA	NA		
NGCC				
Cane Run 7	295	3,150	2,856	969%
Hydro				
Dix Dam	76	74	(2)	-3%
Ohio Falls	NA	NA		
Total Coal	18,752	17,649	(1,104)	-6%
Total SCCT	767	785	18	2%
Total NGCC	295	3,150	2,856	969%
Total Hydro	76	74	(2)	-3%
Grand Total	19,890	21,658	1,768	9%

Note: The generation volumes above are from KU's ownership share of the unit. "NA" is shown for units with no KU ownership share.

LG&E

GWh	**Base Period**	**Forecast Period**	**Difference**	**%Difference**
Coal				
Brown 1	NA	NA		
Brown 2	NA	NA		
Brown 3	NA	NA		
Cane Run 4	628	0	(628)	-100%
Cane Run 5	857	0	(857)	-100%
Cane Run 6	522	0	(522)	-100%
Ghent 1	NA	NA		
Ghent 2	NA	NA		
Ghent 3	NA	NA		
Ghent 4	NA	NA		
Green River 3	NA	NA		
Green River 4	NA	NA		
Mill Creek 1	2,107	2,000	(107)	-5%
Mill Creek 2	1,974	1,862	(112)	-6%
Mill Creek 3	2,617	2,191	(426)	-16%
Mill Creek 4	2,311	2,922	611	26%
OVEC	593	587	(6)	-1%
Trimble County 1	2,529	2,176	(353)	-14%
Trimble County 2	561	722	162	29%
SCCT				
Brown 5	5	2	(3)	-67%
Brown 6	46	24	(23)	-49%
Brown 7	46	40	(6)	-13%
Brown 8	NA	NA		
Brown 9	NA	NA		
Brown 10	NA	NA		
Brown 11	NA	NA		
Cane Run 11	0	0	0	0%
Haefling	NA	NA		
LS Power PPA	0	71	71	0%
Paddys Run 11	0	0	0	0%
Paddys Run 12	0	0	0	0%
Paddys Run 13	57	66	10	17%
Trimble County 5	65	78	13	20%
Trimble County 6	57	67	10	18%
Trimble County 7	58	67	9	15%
Trimble County 8	11	13	2	16%
Trimble County 9	56	53	(3)	-5%
Trimble County 10	16	8	(8)	-49%
Zorn	0	0	0	0%
NGCC				
Cane Run 7	83	889	805	969%
Hydro				
Dix Dam	NA	NA		
Ohio Falls	262	245	(17)	-6%
Total Coal	14,699	12,460	(2,239)	-15%
Total SCCT	417	488	71	17%
Total NGCC	83	889	805	969%
Total Hydro	262	245	(17)	-6%
Grand Total	15,461	14,082	(1,379)	-9%

Note: The generation volumes above are from LG&E’s ownership share of the unit. “NA” is shown for units with no LG&E ownership share.

Combined Company

GWh	Base Period	Forecast Period	Difference	%Difference
Coal				
Brown 1	364	216	(148)	-41%
Brown 2	688	487	(201)	-29%
Brown 3	1,302	920	(382)	-29%
Cane Run 4	628	0	(628)	-100%
Cane Run 5	857	0	(857)	-100%
Cane Run 6	522	0	(522)	-100%
Ghent 1	3,304	3,122	(182)	-6%
Ghent 2	3,461	2,631	(830)	-24%
Ghent 3	3,086	3,169	84	3%
Ghent 4	2,887	3,103	216	7%
Green River 3	327	192	(135)	-41%
Green River 4	681	474	(207)	-30%
Mill Creek 1	2,107	2,000	(106)	-5%
Mill Creek 2	1,974	1,862	(112)	-6%
Mill Creek 3	2,617	2,191	(426)	-16%
Mill Creek 4	2,311	2,922	611	26%
OVEC	854	844	(11)	-1%
Trimble County 1	2,529	2,176	(352)	-14%
Trimble County 2	2,951	3,801	850	29%
SCCT				
Brown 5	9	3	(6)	-68%
Brown 6	122	62	(60)	-49%
Brown 7	121	105	(16)	-13%
Brown 8	7	17	11	154%
Brown 9	5	2	(3)	-63%
Brown 10	5	2	(3)	-67%
Brown 11	6	5	(1)	-10%
Cane Run 11	0	0	0	0%
Haefling	0	0	0	0%
LS Power PPA	0	71	71	0%
Paddys Run 11	0	0	(0)	0%
Paddys Run 12	0	0	(0)	0%
Paddys Run 13	107	125	18	17%
Trimble County 5	225	269	43	19%
Trimble County 6	195	230	35	18%
Trimble County 7	157	180	23	14%
Trimble County 8	31	36	5	17%
Trimble County 9	151	144	(7)	-5%
Trimble County 10	43	22	(21)	-49%
Zorn	0	0	0	0%
NGCC				
Cane Run 7	378	4,039	3,661	967%
Hydro				
Dix Dam	76	74	(2)	-3%
Ohio Falls	262	245	(18)	-7%
Total Coal	33,449	30,109	(3,340)	-10%
Total SCCT	1,184	1,274	89	8%
Total NGCC	378	4,039	3,661	967%
Total Hydro	339	319	(20)	-6%
Grand Total	35,350	35,741	391	1%

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

APPLICATION OF KENTUCKY	**)**	
UTILITIES COMPANY FOR AN	**)**	**CASE NO. 2014-00371**
ADJUSTMENT OF ITS ELECTRIC	**)**	
RATES	**)**	

TESTIMONY OF

WILLIAM E. AVERA
AND
ADRIEN M. MCKENZIE

on behalf of

KENTUCKY UTILITIES COMPANY

Filed: November 26, 2014

DIRECT TESTIMONY OF

WILLIAM E. AVERA

AND

ADRIEN M. MCKENZIE

TABLE OF CONTENTS

I. INTRODUCTION

Q1. PLEASE STATE YOUR NAMES AND BUSINESS ADDRESS.

A1. Our names are William E. Avera and Adrien M. McKenzie. Our business address is 3907 Red River, Austin, Texas.

Q2. IN WHAT CAPACITY ARE YOU EMPLOYED?

A2. We are financial, economic, and policy consultants to business and government.

Q3. PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND AND PROFESSIONAL EXPERIENCE.

A3. A description of our background and qualifications, including resumes containing the details of our experience, is attached as Exhibit No. 1.

Q4. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A4. The purpose of our testimony is to present to the Kentucky Public Service Commission ("KPSC") our 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, we also examined the reasonableness of KU's capital structure, considering both the specific risks faced by the Company, as well as other industry guidelines.

Q5. WHICH OF YOU INTENDS TO APPEAR IN THE EVENT OF A HEARING IN THIS PROCEEDING?

A5. We anticipate that Dr. Avera will appear to sponsor our joint testimony and respond to cross examination in any future hearings before the KPSC in this proceeding.

Q6. PLEASE SUMMARIZE THE INFORMATION AND MATERIAL YOU RELIED ON TO SUPPORT THE OPINIONS AND CONCLUSIONS CONTAINED IN YOUR TESTIMONY.

A6. We referenced information from a variety of sources that would normally be relied upon by a person in our capacity. In connection with the present filing, we considered and relied upon corporate disclosures, publicly available financial reports and filings, and other published information relating to KU. We also reviewed information relating generally to capital market conditions and specifically to investor perceptions, requirements, and expectations for utilities. These sources, coupled with our experience in the fields of finance and utility regulation, have given us a working knowledge of the issues relevant to investors' required return for KU, and they form the basis of our analyses and conclusions.

Q7. HOW IS YOUR TESTIMONY ORGANIZED?

A7. After first summarizing our conclusions and recommendations, we briefly reviewed KU's operations and finances. We then examined current conditions in the capital markets and their implications in evaluating a fair ROE for KU. With this as a background, we conducted well-accepted quantitative analyses to estimate the current cost of equity for a reference group of comparable-risk electric utilities. These included the discounted cash flow ("DCF") model, the empirical form of Capital Asset Pricing Model ("ECAPM"), and an equity risk premium approach based on allowed ROEs, which are all methods that are commonly relied on in regulatory proceedings. Based on the cost of equity estimates indicated by our analyses, a fair ROE for KU was evaluated taking into account the specific risks and requirements for financial strength that provides benefits to customers, as well as flotation costs, which are properly considered in setting a fair ROE.

Finally, we tested our recommended ROE for KU based on the results of alternative ROE benchmarks, including reference to applications of the traditional

Capital Asset Pricing Model ("CAPM") and expected rates of return for utilities. Further, we corroborated our utility quantitative analyses by applying the DCF model to a group of extremely low risk non-utility firms.

II. RETURN ON EQUITY FOR KU

Q8. WHAT IS THE PURPOSE OF THIS SECTION?

A8. This section presents our conclusions regarding the 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.

A. Summary of Conclusions

Q9. WHAT ARE YOUR FINDINGS REGARDING THE FAIR RATE OF RETURN ON EQUITY FOR KU?

A9. Based on the results of our analyses and the economic requirements necessary to support continuous access to capital, we recommend an ROE for KU of 10.64%.

Q10. PLEASE SUMMARIZE THE RESULTS OF THE QUANTITATIVE ANALYSES ON WHICH YOUR CONCLUSIONS WERE BASED.

A10. In order to reflect the risks and prospects associated with KU's jurisdictional utility operations, our analyses focused on a proxy group of 20 other utilities with both gas and electric utility operations. The cost of common equity estimates produced by the DCF, ECAPM, and risk premium analyses described subsequently are presented on page 1 of Exhibit No. 2, and summarized below:

- Based on our evaluation of the strengths and weaknesses of the DCF, ECAPM, and risk premium methods, we concluded that a fair ROE for the proxy group of utilities is in the 9.74 to 11.54% range;
- In evaluating the results of the DCF model, we considered the relative merits of the alternative growth rates, giving little weight to the internal, "br+sv" growth measures;

- The forward-looking ECAPM estimates suggested an ROE in the range of 11.1% to 12.2%;
- The utility risk premium approach implies an ROE estimate on the order of 10.1% to 11.2%;
- Widespread expectations for higher interest rates emphasize the implication of considering the impact of projected bond yields in evaluating the results of the ECAPM and risk premium methods;
- Taken together, these results indicated that the "bare bones cost of equity," that is, the cost of equity before flotation costs, falls within a range of 9.6% to 11.4%;
- Adding a flotation cost adjustment of 14 basis points to this bare bones cost of equity range resulted in an ROE range for the proxy group of 9.74% to 11.54%;
- An ROE of 10.64% is equal to the midpoint of the proxy group range.

Q11. WHAT DID THE RESULTS OF ALTERNATIVE ROE BENCHMARKS INDICATE WITH RESPECT TO YOUR RECOMMENDED ROE?

A11. The results of the traditional CAPM analyses, a review of expected earned rates of return, and DCF results for a select, low risk group of non-utility firms[1] are shown on page 2 of Exhibit No. 2 and summarized below. These benchmark tests of reasonableness confirm that a 10.64% ROE falls in the reasonable range to maintain KU's financial integrity, provide a return commensurate with investments of comparable risk, and support the Company's ability to attract capital:

- Applying the traditional CAPM approach implied a current cost of equity of 10.4% to 11.6%;
- Expected returns for the proxy group of comparable risk utilities suggested an ROE of 10.8%; and,
- Application of the DCF model to a select group of low-risk firms in the non-utility sector resulted in average ROE estimates ranging from 10.3% to 11.0%.

[1] As discussed subsequently, the average risk measures for the group of non-utility firms suggest that they have less investment risk than KU or the proxy group of utilities.

Apart from the expected upward trend in capital costs, a cost of equity of 10.64% is consistent with the need to support financial integrity and fund capital investment even under adverse circumstances.

B. Other Factors

Q12. ARE THERE REGULATORY MECHANISMS THAT AFFECT KU'S RATES FOR UTILITY SERVICE?

A12. Yes. Kentucky Revised Statute 278.183 notes, in part, that "… a utility shall be entitled to the current recovery of its costs of complying with the Federal Clean Air Act as amended and those federal, state, or local environmental requirements which apply to coal combustion wastes and by-products from facilities utilized for production of energy from coal …" Consistent with this statutory provision, the KPSC has approved an environmental cost recovery mechanism ("ECR") for the Company that allows for recovery of related costs. In addition, KU 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.

Q13. DOES THE FACT THAT KU OPERATES UNDER CERTAIN REGULATORY MECHANISMS WARRANT ANY ADJUSTMENT IN YOUR EVALUATION OF A FAIR ROE?

A13. No. Investors recognize that KU is exposed to significant risks associated with the ability to recover rising costs and investment on a timely basis, and concerns over these risks have become increasingly pronounced in the industry. The KPSC's rate adjustment mechanisms are a tool to address these risks, but they do not eliminate them. In addition, investors also recognize that the heightened scrutiny associated with trackers exposes the Company to increased risk for retroactive reviews and disallowances.

While the regulatory mechanisms approved for KU partially attenuate exposure to attrition in an era of rising costs and investment, this leveling of the playing field only serves to address factors that could otherwise impair the Company's opportunity to earn its authorized return, as required by established regulatory standards. Similarly, KU's election to employ a future test year would be supportive of the Company's financial integrity, but it would not constitute a dramatic change in the investment risk that investors associate with KU.

Q14. DO THESE MECHANISMS SET KU APART FROM OTHER FIRMS OPERATING IN THE UTILITY INDUSTRY?

A14. No. Adjustment mechanisms, cost trackers, and reliance on forward-looking test periods have been increasingly prevalent in the utility industry in recent years. In response to the increasing risk sensitivity of investors to uncertainty over fluctuations in costs and the importance of advancing other public interest goals such as reliability, energy conservation, and safety, utilities and their regulators have sought to mitigate some of the cost recovery uncertainty and align the interest of utilities and their customers through a variety of regulatory mechanisms.

Q15. HAVE YOU SUMMARIZED THE VARIOUS REGULATORY MECHANISMS AVAILABLE TO THE OTHER UTILITIES IN THE UTILITY GROUP?

A15. Yes. We evaluated the regulatory mechanisms approved for the proxy group utilities using data reported in the most recent Form 10-K reports filed with the Securities and Exchange Commission, which is publicly available and free of charge.[2] Reflective of industry trends, the companies in the Utility Group operate under a variety of regulatory adjustment mechanisms. As summarized on Exhibit No. 3, these mechanisms are ubiquitous and wide ranging. For example, fourteen of the

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[2] Because this information is widely referenced by the investment community, it is also directly relevant to an evaluation of the risks and prospects that determine the cost of equity.

twenty firms benefit from mechanisms that allow for cost recovery of infrastructure investment outside a formal rate proceeding. Many of these utilities operate under revenue decoupling and other mechanisms that insulate the utility from volatility related to fluctuations in sales volumes, as well as the ability to implement periodic rate adjustments to reflect changes in a diverse range of operating and capital costs, including expenditures related to environmental mandates, conservation programs, transmission costs, and storm recovery efforts.

Q16. IS THE USE OF A FUTURE TEST YEAR ALSO A COMMON FEATURE ON THE REGULATORY LANDSCAPE?

A16. Yes. With respect to future test years, a 2010 study by the Edison Electric Institute concluded that sixteen regulatory jurisdictions "use forward test years routinely," while four other states use "hybrid" test years and an additional 13 states make varying use of future test years or extraordinary adjustments to historical test year data.[3] KU's election to utilize a future test year is consistent with state statute and the treatment afforded other utilities operating in Kentucky, and it does not distinguish the Company from other utilities across the nation.

Q17. WHAT IS YOUR CONCLUSION REGARDING THE IMPACT OF REGULATORY MECHANISMS IN EVALUATING A FAIR ROE FOR KU?

A17. Investors recognize that the use of adjustment mechanisms and future test years is widely prevalent in the utility industry, and the relative impact is already considered in the data for our proxy group. As a result, any mitigation in risks associated with KU's ability to attenuate regulatory lag through adjustment mechanisms or its election of a future test year is already reflected in the results of the quantitative methods presented in our testimony. The KPSC's adjustment mechanisms and KU's election to use a future test year act to level the playing field, placing the Company

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[3] *Forward Test Years for US Electric Utilities*, Edison Electric Institute (August 2010).

on equal footing with its peers in the industry. As a result, no adjustment to the ROE is justified or warranted.

Q18. WHAT IS YOUR CONCLUSION AS TO THE REASONABLENESS OF THE COMPANY'S CAPITAL STRUCTURE?

A18. Based on our evaluation, we concluded that a common equity ratio of 53.02% 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 well within the range of capitalizations maintained by the firms in the proxy group of utilities and is consistent with the capitalization maintained by other electric utility operating companies based on data at year-end 2013 and near-term expectations; 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.

III. FUNDAMENTAL ANALYSES

Q19. WHAT IS THE PURPOSE OF THIS SECTION?

A19. As a predicate to subsequent quantitative analyses, this section briefly reviews the operations and finances of KU. In addition, it examines 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

Q20. BRIEFLY DESCRIBE KU.

A20. Along with Louisville Gas and Electric Company ("LGE"), KU is a wholly owned subsidiary of PPL Corporation ("PPL"). Headquartered in Lexington, Kentucky, KU is principally engaged in providing regulated electric utility service. In addition to serving approximately 514,000 retail customers in central, southeastern, and western Kentucky, KU also provides service to approximately 29,000 customers in Virginia.[1]

Although KU and LGE are separate operating subsidiaries, they are operated as a single, fully integrated system. The Company's utility facilities include over 4,700 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 2013. 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 20,500 miles of lines. As of December 31, 2013, the Company had total assets of $7.2 billion, with annual revenues totaling approximately $1.6 billion. KU's retail electric operations are subject to the jurisdiction of the KPSC, the Virginia State Corporation Commission, and the Tennessee Regulatory Authority, with the Federal Energy Regulatory Commission ("FERC") regulating the Company's interstate transmission and wholesale operations.

Q21. HOW ARE FLUCTUATIONS IN THE COMPANY'S OPERATING EXPENSES CAUSED BY VARYING ENERGY MARKET CONDITIONS ACCOMMODATED IN ITS RATES?

A21. 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

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[1] KU also serves a limited number of customers in Tennessee.

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.

Q22. WHERE DOES KU OBTAIN THE CAPITAL USED TO FINANCE ITS INVESTMENT IN UTILITY PLANT?

A22. 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.

Q23. DOES KU ANTICIPATE THE NEED FOR ADDITIONAL CAPITAL GOING FORWARD?

A23. Yes. KU will require capital investment to provide for necessary maintenance and replacements of its utility infrastructure, as well as to fund investment in new facilities. Moody's informed investors that:

> Capital expenditures for KU are expected to remain at elevated levels from 2013-2017. Total capital expenditures are expected to be $3.1 billion, with $1.2 billion related to environmental. The total estimated amount represents about 56% of its net book value of property, plant and equipment …[4]

Moody's noted the challenges associated with the Company's "[l]arge capital expenditure program," and "[h]igh coal concentration."[5] 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.

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[4] Moody's Investors Service, "Credit Opinion: Kentucky Utilities Company.," *Global Credit Research* (Dec. 8, 2013).

[5] *Id.*

Q24. WHAT CREDIT RATINGS ARE ASSIGNED TO KU?

A24. Currently, KU is assigned a corporate credit rating of BBB by S&P.[6] Moody's has assigned the Company an issuer rating of A3, while Fitch Ratings Ltd. ("Fitch") has assigned KU an "A-" issuer default rating.

B. Outlook for Capital Costs

Q25. DO CURRENT CAPITAL MARKET CONDITIONS PROVIDE A REPRESENTATIVE BASIS ON WHICH TO EVALUATE A FAIR ROE?

A25. No. Current capital market conditions reflect the legacy of the Great Recession, and are not representative of what investors expect in the future. Investors have had to contend with a level of economic uncertainty and capital market volatility that has been unprecedented in recent history. 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. In response to heightened uncertainties in recent years, investors have repeatedly sought a safe haven in U.S. government bonds. As a result of this "flight to safety," Treasury bond yields have been pushed significantly lower in the face of political, economic, and capital market risks. In addition, the Federal Reserve has implemented measures designed to push interest rates to historically low levels in an effort to stimulate the economy and bolster employment.

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[6] On June 10, 2014, S&P placed its corporate credit ratings for PPL and its utility subsidiaries, including KU and LGE, on CreditWatch with positive implications, noting the potential for an upgrade of up to two notches following the anticipated divestiture of PPL's unregulated power generation subsidiary.

Q26. HOW DO CURRENT YIELDS ON PUBLIC UTILITY BONDS COMPARE WITH WHAT INVESTORS HAVE EXPERIENCED IN THE PAST?

A26. The yields on utility bonds remain near their lowest levels in modern history. Figure 1, below, compares the September 2014 average yield on long-term, triple-B rated utility bonds with those prevailing since 1968:

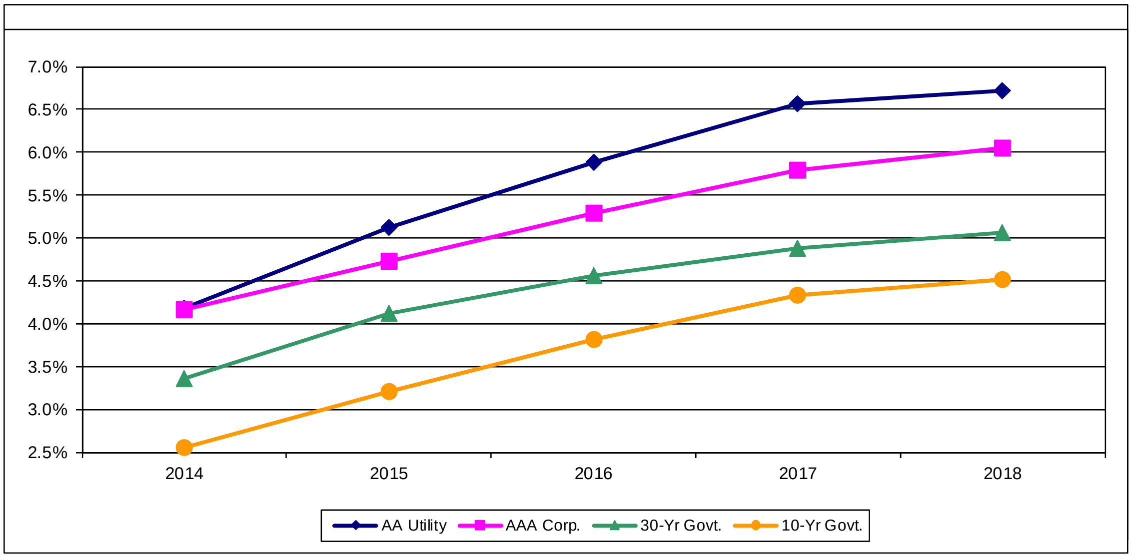
FIGURE 1
BBB UTILITY BOND YIELDS – CURRENT VS. HISTORICAL

As illustrated above, prevailing capital market conditions, as reflected in the yields on triple-B utility bonds, are an anomaly when compared with historical experience.

Q27. ARE THESE VERY LOW INTEREST RATES EXPECTED TO CONTINUE?

A27. No. Investors do not anticipate that these low interest rates will continue into the future. It is widely anticipated that as the economy stabilizes and resumes a more robust pattern of growth, long-term capital costs will increase significantly from present levels. Figure 2 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 the Value Line Investment Survey ("Value Line"), IHS Global Insight, Blue Chip Financial Forecasts ("Blue Chip"), and the Energy Information Administration ("EIA"):

FIGURE 2
INTEREST RATE TRENDS



<u>Source:</u>
Value Line Investment Survey, Forecast for the U.S. Economy (Aug. 22, 2014)
IHS Global Insight, U.S. Economic Outlook at 79 (May 2014)
Energy Information Administration, Annual Energy Outlook 2014 (May 7, 2014)
Blue Chip Financial Forecasts, Vol. 33, No. 6 (Jun. 1, 2014)

These forecasting services are highly regarded and widely referenced, with FERC incorporating forecasts from IHS Global Insight and the EIA in its preferred DCF model for natural gas and oil pipelines, as well as for electric transmission utilities. As evidenced above, there is a clear consensus in the investment community that the cost of long-term capital will be significantly higher over 2015-2019 than it is currently.

Q28. DO RECENT ACTIONS OF THE FEDERAL RESERVE SUPPORT THE CONTENTION THAT CURRENT LOW INTEREST RATES WILL CONTINUE INDEFINITELY?

A28. No. While the Federal Reserve continues to express support for maintaining a highly accommodative monetary policy and an exceptionally low target range for the federal funds rate, it has also acted to steadily pare back its monthly bond-buying program. Citing improvement in the outlook for the labor market and increasing strength in the broader economy, the Federal Reserve elected to discontinue further purchases under its bond-buying program at its October 2014 meeting. Elimination of the Federal Reserve's bond buying program should ultimately exert upward pressure on long-term interest rates, with *The Wall Street Journal* observing that:

> The Fed's decision to begin trimming its $85 billion monthly bond-buying program is widely expected to result in higher medium-term and long-term market interest rates. That means many borrowers, from home buyers to businesses, will be paying higher rates in the near future.[7]

While the Federal Reserve's tapering announcements and subsequent conclusion of its asset purchases have moderated uncertainties over just when, and to what degree, the stimulus program would be altered, investors continue to face ongoing uncertainties over future modification that could ultimately affect how quickly and how much interest rates are affected.

Q29. DOES THE CESSATION OF FURTHER ASSET PURCHASES MARK A RETURN TO "NORMAL?"

A29. No. The Federal Reserve continues to exert considerable influence over capital market conditions through its massive holdings of Treasuries and mortgage-backed securities. Prior to the initiation of the stimulus program in 2009, the Federal Reserve's holdings of U.S. Treasury bonds and notes amounted to approximately $400 - $500 billion. With the implementation of its asset purchase program, balances of Treasury securities and mortgage backed instruments climbed steadily, and their effect on capital market conditions became more pronounced. Far from representing a return to normal, the Federal Reserve's holdings of Treasuries and

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[7] Hilsenrath, Jon, "Fed Dials Back Bond Buying, Keeps a Wary Eye on Growth," *The Wall Street Journal* at A1 (Dec. 19, 2013).

mortgage-backed securities now amount to more than $4 trillion,[8] which is an all-time high.

For now, the Federal Reserve is maintaining its policy of reinvesting principal payments from these securities – about $16 billion a month – and rolling over maturing Treasuries at auction. As the Federal Reserve recently noted:

> The Committee is maintaining its existing policy of reinvesting principal payments from its holdings of agency debt and agency mortgage-backed securities in agency mortgage-backed securities and of rolling over maturing Treasury securities at auction. The Committee's sizable and still-increasing holdings of longer-term securities should maintain downward pressure on longer-term interest rates, support mortgage markets, and help to make broader financial conditions more accommodative, which in turn should promote a stronger economic recovery and help to ensure that inflation, over time, is at the rate most consistent with the Committee's dual mandate.[9]

Of course, the corollary to these observations is that ending this policy of reinvestment could place significant upward pressure on bond yields, especially considering the unprecedented magnitude of the Federal Reserve's holdings of Treasury bonds and mortgage-backed securities. Changes to this policy of reinvestment would further reduce stimulus measures and could place additional upward pressure on bond yields. The International Monetary Fund noted, "A lack of Fed clarity could cause a major spike in borrowing costs that could cause severe damage to the U.S. recovery and send destructive shockwaves around the global economy," adding that, "[a] smooth and gradual upward shift in the yield curve might be difficult to engineer, and there could be periods of higher volatility when longer yields jump sharply—as recent events suggest."[10] Similarly, *The Wall Street*

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[8] Appelbaum, Binyamin, "Federal Reserve's Bond-Buying Fades, but Stimulus Doesn't End There," *The New York Times* (Jun. 19, 2014).

[9] Federal Open Market Committee, *Press Release* (Sep. 17, 2014).

[10] Talley, Ian, "IMF Urges 'Improved' U.S. Fed Policy Transparency as It Mulls Easy Money Exit," *The Wall Street Journal* (July 26, 2013).

Journal noted investors' "hypersensitivity to Fed interest rate decisions," and expectations that higher interest rates "may come a bit sooner and be a touch more aggressive than expected."[11] As a *Financial Analysts Journal* article noted:

> Because no precedent exists for the massive monetary easing that has been practiced over the past five years in the United States and Europe, the uncertainty surrounding the outcome of central bank policy is so vast. . . . Total assets on the balance sheets of most developed nations' central banks have grown massively since 2008, and the timing of when the banks will unwind those positions is uncertain.[12]

These developments highlight continued concerns for investors and support expectations for higher interest rates as the economy and labor markets continue to recover. With the Federal Reserve curtailing the expansion of its enormous portfolio of Treasuries and mortgage bonds, ongoing concerns over political stalemate in Washington, the threat of renewed recession in the Eurozone, and political and economic unrest in Ukraine, the Middle East, and emerging markets, the potential for significant volatility and higher capital costs is clearly evident to investors.

Q30. WHAT DO THESE EVENTS IMPLY WITH RESPECT TO THE ROE FOR KU MORE GENERALLY?

A30. Current capital market conditions continue to reflect the impact of unprecedented policy measures taken in response to recent dislocations in the economy and financial markets and ongoing economic and political risks. As a result, current capital costs are not representative of what is likely to prevail over the near-term future. As FERC recently concluded:

> [W]e also understand that any DCF analysis may be affected by potentially unrepresentative financial inputs to the DCF formula, including those produced by historically anomalous capital market

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[11] Jon Hilsenrath and Victoria McGrane, "Yellen Debut Rattles Markets," Wall Street Journal (Mar. 19, 2014).

[12] Poole, William, "Prospects for and Ramifications of the Great Central Banking Unwind," *Financial Analysts Journal* (November/December 2013).

> conditions. Therefore, while the DCF model remains the Commission's preferred approach to determining allowed rate of return, the Commission may consider the extent to which economic anomalies may have affected the reliability of DCF analyses …[13]

This conclusion is supported by comparisons of current conditions to the historical record and independent forecasts. As demonstrated earlier, recognized economic forecasting services project that long-term capital costs will increase from present levels.

Given investors' expectations for rising interest rates and capital costs, the KPSC should consider near-term forecasts for public utility bond yields in assessing the reasonableness of individual cost of equity estimates and in evaluating a fair ROE for KU from within the range of reasonableness. The use of these near-term forecasts for public utility bond yields is supported below by economic studies that show that equity risk premiums are higher when interest rates are at very low levels.

IV. COMPARABLE RISK PROXY GROUP

Q31. HOW DID YOU IMPLEMENT QUANTITATIVE METHODS TO ESTIMATE THE COST OF COMMON EQUITY FOR KU?

A31. Application of 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 quantitative methods such as the DCF and ECAPM to a proxy group of publicly traded companies that investors regard as risk-comparable.

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[13] Opinion No. 531, 147 FERC ¶ 61,234 at P 41 (2014).

Q32. WHAT SPECIFIC PROXY GROUP OF UTILITIES DID YOU RELY ON FOR YOUR ANALYSIS?

A32. In order to reflect the risks and prospects associated with KU's jurisdictional utility operations, our analyses focused on a reference group of other utilities composed of those companies included in Value Line's electric utility industry groups with:

1. Both electric and gas utility operations;
2. Corporate credit ratings from Standard & Poor's Corporation ("S&P") and Moody's Investors Service ("Moody's") of triple-B or single-A;
3. No ongoing involvement in a major merger or acquisition;[14] and,
4. No cuts in dividend payments during the past six months.

These criteria resulted in a proxy group composed of 20 companies, which we refer to as the "Utility Group."

Q33. HOW DID YOU EVALUATE THE RISKS OF THE UTILITY GROUP RELATIVE TO KU?

A33. Our evaluation of relative risk considered four objective, published benchmarks that are widely relied on in the investment community. 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.*, "+" or "-") are used to show relative standing within a category. Because the rating agencies' evaluation includes virtually all of the factors normally considered important in assessing a firm's relative credit standing, corporate credit ratings provide a broad, objective measure of overall investment risk that is readily available to investors. Widely cited in the investment community and referenced by investors, credit ratings are also

[14] PPL Corporation was eliminated from the proxy group due to its planned spin-off of its unregulated power generation subsidiary. In addition, the following companies were eliminated due to ongoing involvement in a major merger or acquisition: Exelon Corporation, Integrys Energy Group, Inc., Pepco Holdings Inc., TECO Energy, Inc., UIL Holdings Corporation, and Wisconsin Energy Corporation.

frequently used as a primary risk indicator in establishing proxy groups to estimate the cost of common equity.

While credit ratings provide the most widely referenced benchmark for investment risks, other quality rankings published by investment advisory services also provide relative assessments of risks that are considered by investors in forming their expectations for common stocks. Value Line's primary risk indicator is its Safety Rank, which ranges from "1" (Safest) to "5" (Riskiest). This overall risk measure is intended to capture the total risk of a stock, and incorporates elements of stock price stability and financial strength. Given that Value Line is perhaps the most widely available source of investment advisory information, its Safety Rank provides useful guidance regarding the risk perceptions of investors.

The Financial Strength Rating is designed as a guide to overall financial strength and creditworthiness, with the key inputs including financial leverage, business volatility measures, and company size. Value Line's Financial Strength Ratings range from "A++" (strongest) down to "C" (weakest) in nine steps. These objective, published indicators incorporate consideration of a broad spectrum of risks, including financial and business position, relative size, and exposure to firm-specific factors.

Finally, beta measures a utility's stock price volatility relative to the market as a whole, and reflects the tendency of a stock's price to follow changes in the market. 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. Beta is the only relevant measure of investment risk under modern capital market theory, and is widely cited in academics and in the investment industry as a guide to investors' risk perceptions. Moreover, in our experience Value Line 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.[15]

Q34. HOW DO THE OVERALL RISKS OF YOUR PROXY GROUP COMPARE TO KU?

A34. Table 1 compares the Utility Group with KU across the four key indicia of investment risk discussed above. Because the Company has no publicly traded common stock, the Value Line risk measures shown reflect those published for its parent, PPL:

TABLE 1
COMPARISON OF RISK INDICATORS

			Value Line		
Proxy Group	**S&P**	**Moody's**	**Safety Rank**	**Financial Strength**	**Beta**
Utility Group	BBB+	Baa1	2	B++	0.73
KU	BBB	A3	3	B++	0.65

Q35. WHAT DOES THIS COMPARISON INDICATE REGARDING INVESTORS' ASSESSMENT OF THE RELATIVE RISKS ASSOCIATED WITH YOUR UTILITY GROUP?

A35. As shown above, KU's credit ratings are comparable to the averages for the proxy group, with its S&P rating falling one notch below the average for the Utility Group and its Moody's rating being one notch above. Meanwhile, the Safety Rank corresponding to the Company suggests greater risk, while its lower beta suggests somewhat less risk. The average Financial Strength Rank for the Utility Group is identical to that corresponding to KU. Considered together, this comparison of

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[15] Morin, Roger A., "New Regulatory Finance," *Public Utilities Reports* at 71 (2006).

objective measures, which incorporate a broad spectrum of risks, including financial and business position, relative size, 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 Utility Group.

Q36. IS AN EVALUATION OF THE CAPITAL STRUCTURE MAINTAINED BY A UTILITY RELEVANT IN ASSESSING ITS RETURN ON EQUITY?

A36. 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 any remaining cash flow.

Q37. WHAT COMMON EQUITY RATIO IS USED IN KU'S CAPITAL STRUCTURE?

A37. The Company's capital structure is discussed in the testimony of Kent W. Blake. As summarized there, common equity as a percent of the capital sources used to compute the overall rate of return for KU was 53.02%.

Q38. HOW DOES THIS COMPARE TO THE AVERAGE CAPITALIZATION MAINTAINED BY THE UTILITY GROUP?

A38. As shown on page 1 of Exhibit No. 4, common equity ratios for the individual firms in the Utility Group ranged from a low of 31.3% to a high of 58.0% at year-end 2013, and averaged 48.0%. Meanwhile, Value Line's three-to-five year forecast indicates an average common equity ratio of 48.5% for the Utility Group, with the individual equity ratios ranging from 37.0% to 57.5%.

Q39. WHAT CAPITALIZATION RATIOS ARE MAINTAINED BY OTHER UTILITY OPERATING COMPANIES?

A39. Page 2 of Exhibit No. 4 displays capital structure data at year-end 2013 for the group of electric utility operating companies owned by the firms in the Utility Group used to estimate the cost of equity. As shown there, common equity ratios for these utilities ranged from 41.4% to 70.7% and averaged 52.1%.

Q40. WHAT OTHER FACTORS DO INVESTORS CONSIDER IN THEIR ASSESSMENT OF A COMPANY'S CAPITAL STRUCTURE?

A40. Utilities are facing significant capital investment plans, uncertainties over accommodating future environmental mandates, and ongoing regulatory risks. Coupled with the potential for 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.

In addition, 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 the Company's financial risk. Because investors consider the debt impact of such fixed obligations in assessing a utility's financial position, they imply greater risk and reduced financial flexibility. Unless the utility takes action to offset this additional financial risk by maintaining a higher equity ratio, the resulting leverage will weaken its creditworthiness and imply greater risk.

Q41. WHAT DID YOU CONCLUDE REGARDING THE REASONABLENESS OF KU'S REQUESTED CAPITAL STRUCTURE?

A41. Based on our evaluation, we concluded that the 53.02% common equity ratio requested by KU represents a reasonable mix of capital sources from which to calculate the Company's overall rate of return. Although this common equity ratio is somewhat higher than the historical and projected averages maintained by the Utility 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.

V. CAPITAL MARKET ESTIMATES

Q42. WHAT IS THE PURPOSE OF THIS SECTION?

A42. This section presents capital market estimates of the cost of equity. First, we address the concept of the cost of common equity, along with the risk-return tradeoff principle fundamental to capital markets. Next, we describe DCF, ECAPM, and risk premium analyses conducted to estimate the cost of common equity for the proxy group of comparable risk firms. Finally, we examine flotation costs, which are properly considered in evaluating a fair rate of return on equity.

A. Economic Standards

Q43. WHAT ROLE DOES THE RATE OF RETURN ON COMMON EQUITY PLAY IN A UTILITY'S RATES?

A43. The ROE compensates common equity investors for the use of their capital to finance the plant and equipment necessary to provide utility service. 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. To be consistent with sound regulatory economics and the standards set forth by the Supreme Court in the Bluefield[16] and Hope[17] 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. Meeting these objectives allows the utility to fulfill its obligation to provide reliable service while meeting the needs of customers through necessary system expansion.

Q44. WHAT FUNDAMENTAL ECONOMIC PRINCIPLE UNDERLIES THE COST OF EQUITY CONCEPT?

A44. 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.

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[16] *Bluefield Water Works & Improvement Co. v. Pub. Serv. Comm'n*, 262 U.S. 679 (1923).
[17] *Fed. Power Comm'n v. Hope Natural Gas Co.*, 320 U.S. 591 (1944).

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.

Q45. IS THERE EVIDENCE THAT THE RISK-RETURN TRADEOFF PRINCIPLE ACTUALLY OPERATES IN THE CAPITAL MARKETS?

A45. 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. Comparing the observed yields on government securities, which are considered free of default risk, to the yields on bonds of various rating categories demonstrates that the risk-return tradeoff does, in fact, exist.

Q46. DOES THE RISK-RETURN TRADEOFF OBSERVED WITH FIXED INCOME SECURITIES EXTEND TO COMMON STOCKS AND OTHER ASSETS?

A46. It is widely 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.

Q47. IS THIS RISK-RETURN TRADEOFF LIMITED TO DIFFERENCES BETWEEN FIRMS?

A47. 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. As noted earlier, 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.

Q48. DOES THE FACT THAT KU IS A SUBSIDIARY OF PPL IN ANY WAY ALTER THESE FUNDAMENTAL STANDARDS UNDERLYING A FAIR ROE?

A48. No. While KU has no publicly traded common stock and PPL is its only shareholder, this does not change the standards governing the determination of a fair ROE for the Company. Ultimately, the common equity that is required to support the utility operations of KU must be raised in the capital markets, where investors consider the Company's ability to offer a rate of return that is competitive with other risk-comparable alternatives. KU must compete with other investment opportunities and unless there is a reasonable expectation that investors will have the opportunity to earn returns commensurate with the underlying risks, capital will be allocated elsewhere, the Company's financial integrity will be weakened, and investors will demand an even higher rate of return. KU's ability to offer a reasonable return on investment is a necessary ingredient in ensuring that customers continue to enjoy economical rates and reliable service.

Q49. WHAT DOES THE ABOVE DISCUSSION IMPLY WITH RESPECT TO ESTIMATING THE COST OF COMMON EQUITY FOR A UTILITY?

A49. 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. Discounted Cash Flow Analyses

Q50. HOW IS THE DCF MODEL USED TO ESTIMATE THE COST OF COMMON EQUITY?

A50. DCF models attempt to replicate the market valuation process that sets the price investors are willing to pay for a share of a company's stock. The model rests on the assumption that investors evaluate the risks and expected rates of return from all securities in the capital markets. Given these expectations, the price of each stock is adjusted by the market until investors are adequately compensated for the risks they bear. Therefore, we can look to the market to determine what investors believe a share of common stock is worth. By estimating the cash flows investors expect to receive from the stock in the way of future dividends and capital gains, we can calculate their required rate of return. That is, the cost of equity is the discount rate that equates the current price of a share of stock with the present value of all expected cash flows from the stock. The formula for the general form of the DCF model is as follows:

$$P_0 = \frac{D_1}{(1+k_e)^1} + \frac{D_2}{(1+k_e)^2} + \cdots + \frac{D_t}{(1+k_e)^t} + \frac{P_t}{(1+k_e)^t}$$

where: P_0 = Current price per share;
P_t = Expected future price per share in period t;
D_t = Expected dividend per share in period t;
k_e = Cost of common equity.

Q51. WHAT FORM OF THE DCF MODEL IS CUSTOMARILY USED TO ESTIMATE THE COST OF COMMON EQUITY IN RATE CASES?

A51. Rather than developing annual estimates of cash flows into perpetuity, the DCF model can be simplified to a "constant growth" form:[18]

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

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

[18] 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.

other words, investors expect to receive a portion of their total return in the form of current dividends and the remainder through price appreciation.

Q52. WHAT FORM OF THE DCF MODEL DID YOU USE?

A52. We applied the constant growth DCF model to estimate the cost of common equity for the Company, 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.

Q53. HOW IS THE CONSTANT GROWTH FORM OF THE DCF MODEL TYPICALLY USED TO ESTIMATE THE COST OF COMMON EQUITY?

A53. 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.

Q54. HOW DID YOU DETERMINE THE DIVIDEND YIELD FOR THE UTILITY GROUP?

A54. Estimates of dividends to be paid by each of these utilities over the next twelve months, obtained from Value Line, served as D_1. This annual dividend was then divided by the corresponding stock price for each utility to arrive at the expected dividend yield. The expected dividends, stock prices, and resulting dividend yields for the firms in the Utility Group are presented on page 1 of Exhibit No. 5. As shown there, dividend yields for the firms in the Utility Group ranged from 2.6% to 4.5%.

Q55. WHAT IS THE NEXT STEP IN APPLYING THE CONSTANT GROWTH DCF MODEL?

A55. 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.

Q56. WHAT ARE INVESTORS MOST LIKELY TO CONSIDER IN DEVELOPING THEIR LONG-TERM GROWTH EXPECTATIONS?

A56. Given that 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 ratios falling significantly. 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.

A measure that plays a pivotal role in determining investors' long-term growth expectations are future trends in earnings per share ("EPS"), which provide the source for future dividends and ultimately support share prices. 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 than trends in dividends per share ("DPS").

The availability of projected EPS growth rates also is key to investors relying on this measure as compared to future trends in 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 DPS 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.

Q57. DO THE GROWTH RATE PROJECTIONS OF SECURITY ANALYSTS CONSIDER HISTORICAL TRENDS?

A57. 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.

Q58. DID PROFESSOR MYRON J. GORDON, WHO ORIGINATED THE DCF APPROACH, RECOGNIZE THE PIVOTAL ROLE THAT EARNINGS PLAY IN FORMING INVESTORS' EXPECTATIONS?

A58. Yes. Dr. Gordon specifically recognized that "it is the growth that investors expect that should be used" in applying the DCF model and he concluded:

> A number of considerations suggest that investors may, in fact, use earnings growth as a measure of expected future growth."[19]

[19] Gordon, Myron J., "The Cost of Capital to a Public Utility," *MSU Public Utilities Studies* at 89 (1974).

Q59. ARE ANALYSTS' ASSESSMENTS OF GROWTH RATES APPROPRIATE FOR ESTIMATING INVESTORS' REQUIRED RETURN USING THE DCF MODEL?

A59. Yes. 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, as well as the continued success of services such as Thomson Reuters and Value Line, implies that investors use them as a basis for their expectations.

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>.[20]

Q60. HAVE OTHER REGULATORS ALSO RECOGNIZED THAT ANALYSTS' GROWTH RATE ESTIMATES ARE AN IMPORTANT AND MEANINGFUL GUIDE TO INVESTORS' EXPECTATIONS?

A60. Yes. The KPSC has indicated its preference for relying on analysts' projections in establishing investors' expectations:

> 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…[21]

Similarly, FERC has expressed a clear preference for projected EPS growth rates from IBES in applying the DCF model to estimate the cost of equity for both electric and natural gas pipeline utilities, and has expressly rejected reliance on other sources.[22] As FERC concluded:

> Opinion No. 414-A held that the IBES five-year growth forecasts for each company in the proxy group are the best available evidence of the short-term growth rates expected by the investment community. It cited evidence that (1) those forecasts are provided to IBES by professional security analysts, (2) IBES reports the forecast for each firm as a service to investors, and (3) the IBES reports are well known in the investment community and used by investors. The Commission has also rejected the suggestion that the IBES analysts are biased and

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[20] Morin, Roger A., "New Regulatory Finance," *Public Utilities Reports, Inc.* at 298 (2006) (emphasis added).

[21] *Case No. 2009-00548*, Final Order at 30-31.

[22] *See, e.g., Midwest Independent Transmission System Operator, Inc.*, 99 FERC ¶ 63,011 at P 53 (2002); *Golden Spread Elec. Coop. Inc.*, 123 FERC ¶ 61,047 (2008).

> stated that "in fact the analysts have a significant incentive to make their analyses as accurate as possible to meet the needs of their clients since those investors will not utilize brokerage firms whose analysts repeatedly overstate the growth potential of companies."[23]

More recently, the Public Utility Regulatory Authority of Connecticut noted that:

> The Authority used growth in earnings exclusively based on the record of this docket showing that financial literature supports security analysts' EPS growth rate projections as superior for use in a DCF analysis. Response to Interrogatory FI-106. The Authority takes note that long-term, there is not growth in DPS without growth in EPS. Market prices are more highly influenced by security analyst's earnings expectations then expectations in dividends. The Authority agrees with Ms. Ahern that "the use of earnings growth rates in a DCF analysis provides a better matching between investors' market price appreciation expectations and the growth rate component of the DCF."[24]

Q61. WHAT ARE SECURITY ANALYSTS CURRENTLY PROJECTING IN THE WAY OF GROWTH FOR THE FIRMS IN THE UTILITY GROUP?

A61. The earnings growth projections for each of the firms in the Utility Group reported by Value Line, IBES,[25] Zacks Investment Research ("Zacks"), and Reuters are displayed on page 2 of Exhibit No. 5.

Q62. HOW ELSE ARE INVESTORS' EXPECTATIONS OF FUTURE LONG-TERM GROWTH PROSPECTS OFTEN ESTIMATED WHEN APPLYING THE CONSTANT GROWTH DCF MODEL?

A62. 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 never met in practice, this

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[23] *Kern River Gas Transmission Co.*, 126 FERC ¶ 61,034at P 121 (2009) (footnote omitted).

[24] *Decision*, Docket No. 13-02-20 (Sep. 24, 2013).

[25] Formerly I/B/E/S International, Inc., IBES growth rates are now compiled and published by Thomson Reuters.

"sustainable growth" approach may provide a rough guide for evaluating a firm's growth prospects and is frequently proposed in regulatory proceedings.

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. 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. The sustainable, "br+sv" growth rates for each firm in the Utility Group are summarized on page 2 of Exhibit No. 5, with the underlying details being presented on Exhibit No. 6.[26]

Q63. ARE THERE SIGNIFICANT SHORTCOMINGS ASSOCIATED WITH THE "BR+SV" GROWTH RATE?

A63. Yes. First, in order to calculate the sustainable growth rate, it is necessary to develop estimates of investors' expectations for four separate variables; namely, "b", "r", "s", and "v." Given the inherent difficulty in forecasting each parameter and the difficulty of estimating the expectations of investors, the potential for measurement error is significantly increased when using four variables, as opposed to referencing a direct projection for EPS growth. Second, empirical research in the finance literature indicates that sustainable growth rates are not as significantly correlated to measures of value, such as share prices, as are analysts' EPS growth forecasts.[27]

The "sustainable growth" approach was included for completeness, but evidence indicates that analysts' forecasts provide a superior and more direct guide to investors' growth expectations. Accordingly, we give less weight to cost of

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[26] Because Value Line reports end-of-year book values, an adjustment factor was incorporated to compute an average rate of return over the year, which is consistent with the theory underlying this approach.

[27] Morin, Roger A., "New Regulatory Finance," *Public Utilities Reports, Inc.*, at 307 (2006).

equity estimates based on br+sv growth rates in evaluating the results of the DCF model.

Q64. WHAT COST OF COMMON EQUITY ESTIMATES WERE IMPLIED FOR THE UTILITY GROUP USING THE DCF MODEL?

A64. 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 No. 5.

Q65. IN EVALUATING THE RESULTS OF THE CONSTANT GROWTH DCF MODEL, IS IT APPROPRIATE TO ELIMINATE ESTIMATES THAT ARE EXTREME LOW OR HIGH OUTLIERS?

A65. 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.

Q66. HOW DID YOU EVALUATE DCF ESTIMATES AT THE LOW END OF THE RANGE?

A66. We based our evaluation of DCF estimates at the low end of the range on the fundamental risk-return tradeoff, which holds that investors will only take on more risk if they expect to earn a higher rate of return to compensate them for the greater uncertainly. Because common stocks lack the protections associated with an investment in long-term bonds, a utility's common stock imposes far greater risks on investors. As a result, the rate of return that investors require from a utility's common stock is considerably higher than the yield offered by senior, long-term debt. Consistent with this principle, DCF results that are not sufficiently higher than the yield available on less risky utility bonds must be eliminated.

Q67. HAVE SIMILAR TESTS BEEN APPLIED BY REGULATORS?

A67. 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. The practice of eliminating low-end outliers has been affirmed in numerous FERC proceedings,[28] 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."[29]

Q68. WHAT INTEREST RATE BENCHMARK DID YOU CONSIDER IN EVALUATING THE DCF RESULTS FOR THE UTILITY GROUP?

A68. As noted earlier, the average corporate credit ratings for the Utility Group are BBB+ and Baa1 by S&P and Moody's, respectively, which fall in the triple-B rating category. Accordingly, we referenced average yields on triple-B utilities bonds as one benchmark in evaluating low-end DCF results. Monthly yields on triple-B bonds reported by Moody's averaged approximately 4.7% over the six months ended September 2014.[30] Based on our professional experience and the risk-return principle that is fundamental to finance, it is inconceivable that investors are not requiring a substantially higher rate of return for holding common stock.

Q69. WHAT ELSE SHOULD BE CONSIDERED IN EVALUATING DCF ESTIMATES AT THE LOW END OF THE RANGE?

A69. As indicated earlier, while corporate bond yields have declined substantially as the worst of the financial crisis has abated, it is generally expected that long-term interest rates will rise as the economy returns to a more normal pattern of growth.

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[28] *See, e.g., Virginia Electric Power Co.*, 123 FERC ¶ 61,098 at P 64 (2008).
[29] *Southern California Edison Co.,* 131 FERC ¶ 61,020 at P 55 (2010) ("*SoCal Edison*").
[30] Moody's Investors Service, http://credittrends.moodys.com/chartroom.asp?c=3.

As shown in Table 2 below, forecasts of IHS Global Insight and the EIA imply an average triple-B bond yield of approximately 6.75% over the period 2015-2019:

TABLE 2
IMPLIED BBB BOND YIELD

	2015-19
Projected AA Utility Yield	
IHS Global Insight (a)	6.32%
EIA (b)	6.08%
Average	6.20%
Current BBB - AA Yield Spread (c)	0.55%
Implied Triple-B Utility Yield	**6.75%**

(a) IHS Global Insight, U.S. Economic Outlook at 79 (May 2014)
(b) Energy Information Administration, Annual Energy Outlook 2014 (May 7, 2014)
(c) Based on monthly average bond yields from Moody's Investors Service for the six-month period Apr. 2014 - Sep. 2014

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 on the order of 200 basis points through 2019.[31]

Q70. WHAT DOES THIS TEST OF LOGIC IMPLY WITH RESPECT TO THE DCF RESULTS FOR THE UTILITY GROUP?

A70. As highlighted on page 3 of Exhibit No. 5, we eliminated low-end DCF estimates ranging from 3.4% to 7.4%. In light of the risk-return tradeoff principle, 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 upward trend expected for utility bond yields, these values

[31] *Blue Chip Financial Forecasts*, Vol. 33, No. 6 (Jun. 1, 2014).

provide little guidance as to the returns investors require from utility common stocks and should be excluded.

Q71. IS THERE ANY JUSTIFICATION TO ELIMINATE HIGH-END DCF VALUES FOR THE UTILITY GROUP?

A71. No. As shown on page 3 of Exhibit No. 5, the upper end of the cost of equity range produced by the DCF analysis for the firms in the Utility Group is represented by cost of equity estimates of 13.1%. While these cost of equity estimates may exceed expectations for most electric utilities, low-end estimates on the order of 7.6% are assuredly far below investors' required rate of return. 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. In addition, these high-end values fall below the threshold for high-end outliers adopted by FERC, which has determined that DCF cost of equity estimates above 17.7% are "extreme," and that including such results would "skew the results."[32]

Q72. WHAT COST OF COMMON EQUITY ESTIMATES ARE IMPLIED BY YOUR DCF RESULTS FOR THE UTILITY GROUP?

A72. As shown on page 3 of Exhibit No. 5 and summarized in Table 3, below, after eliminating illogical values, application of the constant growth DCF model resulted in the following average cost of common equity estimates:

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[32] See, *e.g.*, *ISO New England*, *Inc.*, 109 FERC ¶ 61,147 at P 205 (2004). FERC has continued to utilize this benchmark in evaluating DCF estimates at the upper end of the range. *See, e.g.*, *Southern California Edison Co.*, 131 FERC ¶ 61,020 at P 57 (2010).

TABLE 3
DCF RESULTS – UTILITY GROUP

	Cost of Equity	
Growth Rate	**Average**	**Midpoint**
Value Line	9.7%	10.1%
IBES	9.7%	10.5%
Zacks	9.6%	10.4%
Reuters	9.6%	10.5%
br + sv	9.0%	9.5%

C. Empirical Capital Asset Pricing Model

Q73. PLEASE DESCRIBE THE ECAPM.

A73. The ECAPM is a variant of the traditional CAPM, which 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. 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. 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 ECAPM 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 ECAPM must be applied using estimates that reflect the expectations of actual investors in the market, not with backward-looking, historical data.

Q74. WHY IS THE ECAPM APPROACH AN APPROPRIATE COMPONENT IN EVALUATING THE COST OF EQUITY FOR KU?

A74. The CAPM approach, which forms the foundation of the ECAPM, generally is considered to be the most widely referenced method for estimating the cost of equity among academicians and professional practitioners, with the pioneering researchers of this method receiving the Nobel Prize in 1990. Because this is the dominant model for estimating the cost of equity outside the regulatory sphere,[33] the ECAPM provides important insight into investors' required rate of return for utility stocks.

Q75. HOW DOES THE ECAPM APPROACH DIFFER FROM TRADITIONAL APPLICATIONS OF THE CAPM?

A75. The ECAPM is designed to correct for an observed bias in the CAPM results. Specifically, empirical tests of the CAPM have shown that low-beta securities earn returns somewhat higher than the CAPM would predict, and high-beta securities earn less than predicted. In other words, the CAPM tends to overstate the actual sensitivity of the cost of capital to beta, with low-beta stocks tending to have higher returns and high-beta stocks tending to have lower risk returns than predicted by the CAPM. This empirical finding is widely reported in the finance literature, as summarized in *New Regulatory Finance*:

> As discussed in the previous section, several finance scholars have developed refined and expanded versions of the standard CAPM by relaxing the constraints imposed on the CAPM, such as dividend yield, size, and skewness effects. These enhanced CAPMs typically produce a risk-return relationship that is flatter than the CAPM prediction in keeping with the actual observed risk-return relationship. The ECAPM makes use of these empirical relationships.[34]

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

[34] Morin, Roger A., "New Regulatory Finance," *Public Utilities Reports* at 189 (2006).

As discussed in *New Regulatory Finance*, based on a review of the empirical evidence, the expected return on a security is related to its risk by the ECAPM, which is represented by the following formula:

$$R_j = R_f + 0.25(R_m - R_f) + 0.75[\beta_j(R_m - R_f)]$$

This ECAPM equation, and the associated weighting factors, recognize the observed relationship between standard CAPM estimates and the cost of capital documented in the financial research, and correct for the understated returns that would otherwise be produced for low beta stocks.

Q76. HOW DID YOU APPLY THE ECAPM TO ESTIMATE THE COST OF COMMON EQUITY?

A76. Application of the ECAPM to the Utility Group based on a forward-looking estimate for investors' required rate of return from common stocks is presented on Exhibit No. 7. 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 408 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 average of the EPS 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 408 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 2.3% results in a current cost of common equity estimate for the market as a whole (R_m) of approximately 13.1%. Subtracting a 3.4% risk-free rate based on the average yield on 30-year Treasury bonds for September 2014 produced a market equity risk premium of 9.7%.

Q77. WHAT WAS THE SOURCE OF THE BETA VALUES YOU USED TO APPLY THE ECAPM?

A77. As indicated earlier, we relied on the beta values reported by Value Line, which in our experience is the most widely referenced source for beta in regulatory proceedings.

Q78. WHAT ELSE SHOULD BE CONSIDERED IN APPLYING THE ECAPM?

A78. 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.[35]

Because financial research indicates that the ECAPM does not fully account for observed differences in rates of return attributable to firm size, a modification is required to account for this size effect.

According to the ECAPM, 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 ECAPM cost of equity estimates to account for the level of a firm's market capitalization in determining the ECAPM cost of equity.[36] These premiums correspond to the size deciles of publicly traded common stocks, and range from a premium of approximately 6.0% for a company in the first decile (market capitalization less than $338.8 million), to a reduction of 33 basis points for firms in the tenth decile (market capitalization between $21.8 billion and $428.7

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[35] *Morningstar*, "Ibbotson SBBI 2013 Valuation Yearbook," at p. 85.
[36] *Id.* at Table C-1.

billion). Accordingly, our ECAPM analyses also incorporated an adjustment to recognize the impact of size distinctions, as measured by the average market capitalization for the Utility Group.

Q79. WHAT COST OF EQUITY IS IMPLIED FOR THE UTILITY GROUP USING THE ECAPM APPROACH?

A79. As shown on page 1 of Exhibit No. 7, a forward-looking application of the ECAPM approach resulted in an average unadjusted ROE estimate of 11.1%. After adjusting for the impact of firm size, the ECAPM approach implied an average cost of equity of 11.9% for the Utility Group.[37]

Q80. DID YOU ALSO APPLY THE ECAPM USING FORECASTED BOND YIELDS?

A80. Yes. As discussed earlier, there is widespread consensus that interest rates will increase materially as the economy continues to strengthen. Accordingly, in addition to the use of current bond yields, we also applied the ECAPM based on the forecasted long-term Treasury bond yields developed based on projections published by Value Line, IHS Global Insight and Blue Chip. As shown on page 2 of Exhibit No. 7, incorporating a forecasted Treasury bond yield for 2015-2019 implied a cost of equity of approximately 11.4% for the Utility Group, or 12.2% after adjusting for the impact of relative size. The midpoints of the unadjusted and size adjusted cost of equity ranges were 11.4% and 12.1%, respectively.

D. Utility Risk Premium

Q81. BRIEFLY DESCRIBE THE RISK PREMIUM METHOD.

A81. The risk premium method extends the risk-return tradeoff observed with bonds to estimate investors' required rate of return on common stocks. The cost of equity is

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[37] The midpoints of the unadjusted and size adjusted ECAPM ranges were 11.1% and 11.9%, respectively.

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 risk premium method 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.

Q82. IS THE RISK PREMIUM APPROACH A WIDELY ACCEPTED METHOD FOR ESTIMATING THE COST OF EQUITY?

A82. Yes. The risk premium approach is based on the fundamental risk-return principle that is central to finance, which holds that investors will require a premium in the form of a higher return in order to assume additional risk. This method is routinely referenced by the investment community and in academia and regulatory proceedings, and provides an important tool in estimating a fair ROE for KU.

Q83. HOW DID YOU IMPLEMENT THE RISK PREMIUM METHOD?

A83. Estimates of equity risk premiums for utilities were based on surveys of previously authorized ROEs. Authorized ROEs presumably reflect regulatory commissions' best estimates of the cost of equity, however determined, at the time they issued their final order. Such ROEs 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.

Q84. IS IT CIRCULAR TO CONSIDER RISK PREMIUMS BASED ON AUTHORIZED RETURNS IN ASSESSING A FAIR ROE FOR KU?

A84. No. In establishing authorized ROEs, 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.

Q85. HOW DID YOU CALCULATE THE EQUITY RISK PREMIUMS BASED ON ALLOWED ROES?

A85. The ROEs authorized for electric utilities by regulatory commissions across the U.S. are compiled by Regulatory Research Associates and published in its *Regulatory Focus* report. In Exhibit No. 8, the average yield on public utility bonds is subtracted from the average allowed ROE for electric utilities to calculate equity risk premiums for each year between 1974 and 2013.[38] As shown on page 3 of Exhibit No. 8, over this period, these equity risk premiums for electric utilities averaged 3.53%, and the yield on public utility bonds averaged 8.69%.

Q86. IS THERE ANY CAPITAL MARKET RELATIONSHIP THAT MUST BE CONSIDERED WHEN IMPLEMENTING THE RISK PREMIUM METHOD?

A86. 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 rates.[39] 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

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[38] Our analysis encompasses the entire period for which published data is available.

[39] *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).

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.

Q87. HAS THIS INVERSE RELATIONSHIP BEEN DOCUMENTED IN THE FINANCIAL RESEARCH?

A87. Yes. There is considerable empirical evidence that when interest rates are relatively high, equity risk premiums narrow, and when interest rates are relatively low, equity risk premiums are greater.[40] This inverse relationship between equity risk premiums and interest rates has been widely reported in the financial literature. For example, *New Regulatory Finance* documented this inverse relationship:

> Published studies by Brigham, Shome, and Vinson (1985), Harris (1986), Harris and Marston (1992, 1993), Carelton, Chambers, and Lakonishok (1983), Morin (2005), and McShane (2005), and others demonstrate that, beginning in 1980, risk premiums varied inversely with the level of interest rates – rising when rates fell and declining when rates rose.[41]

Other regulators have also recognized that the cost of equity does not move in tandem with interest rates.[42]

Q88. WHAT ARE THE IMPLICATIONS OF THIS RELATIONSHIP UNDER CURRENT CAPITAL MARKET CONDITIONS?

A88. As noted earlier, bond yields are at unprecedented lows. Given that equity risk premiums move inversely with interest rates, these uncharacteristically low bond yields also imply a sharp increase in the equity risk premium that investors require

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[40] *Id.*

[41] Morin, Roger A., "New Regulatory Finance," Public Utilities Reports, at 128 (2006).

[42] *See, e.g.*, California Public Utilities Commission, Decision 08-05-035 (May 29, 2008); Entergy Mississippi Formula Rate Plan FRP-5, http://www.entergy-mississippi.com/content/price/tariffs/emi_frp.pdf; *Martha Coakley et al.*, 147 FERC ¶ 61,234 at P 147 (2014).

to accept the higher uncertainties associated with an investment in utility common stocks versus bonds. In other words, higher required equity risk premiums offset the impact of declining interest rates on the ROE.

Q89. WHAT COST OF EQUITY IS IMPLIED BY THE RISK PREMIUM METHOD USING SURVEYS OF ALLOWED ROES?

A89. Based on the regression output between the interest rates and equity risk premiums displayed on page 4 of Exhibit No. 8, the equity risk premium for electric utilities increased approximately 42 basis points for each percentage point drop in the yield on average public utility bonds. As illustrated on page 1 of Exhibit No. 8, with an average yield on public utility bonds for the six-months ending September 2014 of 4.39%, this implied a current equity risk premium of 5.36% for electric utilities. Adding this equity risk premium to the average yield on triple-B utility bonds of 4.73% implies a current cost of equity of 10.09%.

Q90. WHAT RISK PREMIUM COST OF EQUITY ESTIMATE WAS PRODUCED AFTER INCORPORATING FORECASTED BOND YIELDS?

A90. As shown on page 2 of Exhibit No. 8, incorporating a forecasted yield for 2015-2019 and adjusting for changes in interest rates since the study period implied an equity risk premium of 4.50% for electric utilities. Adding this equity risk premium to the implied average yield on triple-B public utility bonds for 2015-2019 of 6.75% resulted in an implied cost of equity of 11.25%.

E. Flotation Costs

Q91. WHAT OTHER CONSIDERATIONS ARE RELEVANT IN SETTING THE RETURN ON EQUITY FOR A UTILITY?

A91. 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.

Q92. IS THERE AN ESTABLISHED MECHANISM FOR A UTILITY TO RECOGNIZE EQUITY ISSUANCE COSTS?

A92. 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.

Q93. THE KPSC HAS NOT ROUTINELY APPROVED A FLOTATION COST ADJUSTMENT FOR KU. WHY DO YOU CONTINUE TO RECOMMEND AN ADJUSTMENT IN THIS CASE?

A93. We are aware that the KPSC has not routinely approved a flotation cost adjustment for KU in past proceedings. Nevertheless, the financial literature and evidence in this case provides a sound theoretical and practical basis to include consideration of flotation costs for KU. 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.[43] 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-looking unless all past flotation costs associated with past issues have been recovered.[44]

Q94. CAN YOU ILLUSTRATE WHY INVESTORS WILL NOT HAVE THE OPPORTUNITY TO EARN THEIR REQUIRED ROE UNLESS A FLOTATION COST ADJUSTMENT IS INCLUDED?

A94. Yes. 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

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[43] Brigham, E.F., Aberwald, D.A., and Gapenski, L.C., "Common Equity Flotation Costs and Rate Making," *Public Utilities Fortnightly,* May, 2, 1985.

[44] Morin, Roger A., "New Regulatory Finance," *Public Utilities Reports, Inc.* (2006) at 335.

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 in Table 4 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 4
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.

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 in Table 5 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 5
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.

Q95. WHAT IS THE MAGNITUDE OF THE ADJUSTMENT TO THE "BARE BONES" COST OF EQUITY TO ACCOUNT FOR ISSUANCE COSTS?

A95. The most common method used to account for flotation costs in regulatory proceedings is to apply an average flotation-cost percentage to a utility's dividend yield. Based on a review of the finance literature, *Regulatory Finance: Utilities' Cost of Capital* concluded:

> The flotation cost allowance requires an estimated adjustment to the return on equity of approximately 5% to 10%, depending on the size and risk of the issue.[45]

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%.[46] Applying a 3.6% expense percentage to a representative

[45] Roger A. Morin, "Regulatory Finance: Utilities' Cost of Capital," *Public Utilities Reports, Inc. at 166* (1994).

[46] *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%. Meanwhile, PPL incurred underwriting discounts equal to approximately 3.0% of the gross proceeds from its 2011 public offering of common stock. PPL Corporation, *Form 10-K Report)* at 296 (2011).

dividend yield of 3.8% implies a minimum flotation cost adjustment on the order of 14 basis points.

VI. OTHER ROE BENCHMARKS

Q96. WHAT IS THE PURPOSE OF THIS SECTION OF YOUR TESTIMONY?

A96. This section presents alternative tests to demonstrate that the end-results of the ROE analyses discussed earlier are reasonable and do not exceed a fair ROE given the facts and circumstances of KU. The first test is based on applications of the traditional CAPM analysis using current and projected interest rates. The second test is based on expected earned returns for electric utilities. Finally, we present a DCF analysis for a select, low risk group of non-utility firms, with which KU must compete for investors' money.

A. Capital Asset Pricing Model

Q97. WHAT COST OF EQUITY ESTIMATES WERE INDICATED BY THE TRADITIONAL CAPM?

A97. Our application of the traditional CAPM was based on the same forward-looking market rate of return, risk-free rates, and beta values discussed earlier in connections with the ECAPM. As shown on page 1 of Exhibit No. 9, applying the forward-looking CAPM approach to the firms in the Utility Group results in an average theoretical cost of equity estimate of 10.4%, or 11.2% after incorporating the size adjustment corresponding to the market capitalization of the individual utilities.

As shown on page 2 of Exhibit No. 9, incorporating a forecasted Treasury bond yield for 2015-2019 implied a cost of equity of approximately 10.8% for the Utility Group, or 11.6 % after adjusting for the impact of relative size.

B. Expected Earnings Approach

Q98. WHAT OTHER ANALYSES DID YOU CONDUCT TO ESTIMATE THE COST OF COMMON EQUITY?

A98. As noted earlier, we 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 approach is consistent with the economic underpinnings for a fair rate of return, as reflected in the comparable earnings test established by the U.S. Supreme Court in *Bluefield* and *Hope*. As FERC recently recognized:

> [T]he . . . expected earnings analysis, given its close relationship to the comparable earnings standard that originated in *Hope*, and the fact that it is used by investors to estimate the ROE that a utility will earn in the future can be useful in validating our ROE recommendation.[47]

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 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. 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.

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[47] Opinion No. 531, 147 FERC ¶ 61,234 at P 147 (2014).

Q99. HOW IS THE EXPECTED EARNINGS APPROACH TYPICALLY IMPLEMENTED?

A99. 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. Our application of the expected earnings approach was focused exclusively on forward-looking projections, not historical data.

Q100. WHAT RATES OF RETURN ON EQUITY ARE INDICATED FOR UTILITIES BASED ON THE EXPECTED EARNINGS APPROACH?

A100. Value Line's projections imply an average rate of return on common equity for the electric utility industry of 10.5% over its forecast horizon.[48] Meanwhile, for the firms in the Utility Group specifically, the year-end returns on common equity projected by Value Line over its forecast horizon are shown on Exhibit No. 10. Consistent with the rationale underlying the development of the br+sv growth rates, these year-end values were converted to average returns using the same adjustment factor discussed earlier and developed on Exhibit No. 6. As shown on Exhibit No. 10, Value Line's projections for the Utility Group suggest an average ROE of approximately 10.8%.

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[48] The Value Line Investment Survey (Aug. 1, Aug. 22, & Sep. 19, 2014). Value Line reports return on year-end equity so the equivalent return on average equity would be higher.

C. Low Risk Non-Utility DCF

Q101. WHAT OTHER PROXY GROUP DID YOU CONSIDER IN EVALUATING A FAIR ROE FOR KU?

A101. Consistent with underlying economic and regulatory standards, we also applied the DCF model to a reference group of low-risk companies in the non-utility sectors of the economy. We refer to this group as the "Non-Utility Group".

Q102. DO UTILITIES HAVE TO COMPETE WITH NON-REGULATED FIRMS FOR CAPITAL?

A102. 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. 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.

Q103. IS IT CONSISTENT WITH THE *BLUEFIELD* AND *HOPE* CASES TO CONSIDER INVESTORS' REQUIRED ROE FOR NON-UTILITY COMPANIES?

A103. Yes. The cost of equity capital in the competitive sector of the economy form 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." It does not restrict consideration to other utilities. Similarly, the *Hope* case states:

> By that standard the return to the equity owner should be commensurate with returns on investments in other enterprises having corresponding risks.[49]

As in the *Bluefield* decision, there is nothing to restrict "other enterprises" solely to the utility industry.

Q104. DOES CONSIDERATION OF THE RESULTS FOR THE NON-UTILITY GROUP MAKE THE ESTIMATION OF THE COST OF EQUITY USING THE DCF MODEL MORE RELIABLE?

A104. 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 by the industry falling into favor or disfavor by analysts. The result of such distortions would be to bias the DCF estimates for utilities. 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.

Q105. WHAT CRITERIA DID YOU APPLY TO DEVELOP THE NON-UTILITY GROUP?

A105. The comparable risk proxy group was composed of those United States 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 0.70 or less; and
5) have investment grade credit ratings from S&P.[50]

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[49] *Federal Power Comm'n v. Hope Natural Gas Co.* 320 U.S. 391, (1944).

[50] Credit rating firms, such as S&P and Moody', use designations consisting of upper- and lower-case letters 'A' and 'B' to identify a bond's credit quality rating. 'AAA', 'AA', 'A', and 'BBB' ratings are considered investment grade. Credit ratings for bonds below these designations ('BB', 'B', 'CCC', etc.) are considered speculative grade, and are commonly referred to as "junk bonds". The term "investment grade" refers to bonds with ratings in the 'BBB' category and above.

Q106. HOW DO THE OVERALL RISKS OF THIS NON-UTILITY GROUP COMPARE WITH THE UTILITY GROUP?

A106. Table 6 compares the Non-Utility Group with the Utility Group and KU across the five key risk measures discussed earlier:

TABLE 6
COMPARISON OF RISK INDICATORS

			Value Line		
Proxy Group	**S&P**	**Moody's**	**Safety Rank**	**Financial Strength**	**Beta**
Non-Utility	A	A2	1	A+	0.65
Utility	BBB+	Baa1	2	B++	0.73
KU	BBB	A3	3	B++	0.65

As shown above, the average credit rating, Safety Rank, and Financial Strength Rating for the Non-Utility Group suggest less risk than for KU and the proxy group of electric utilities. The average beta value for the Non-Utility group is identical to that corresponding to KU, and indicates less investment risk than the Utility Group. When considered together, a comparison of these objective measures, which consider a broad spectrum of risks, including financial and business position, relative size, and exposure to company-specific factors, indicates that investors would likely conclude that the overall investment risks for the Utility Group and KU are greater than those of the firms in the Non-Utility Group.

The sixteen companies that make up the Non-Utility Group are representative of the pinnacle of corporate America. These firms, which include household names such as Colgate-Palmolive, McDonalds, Proctor & Gamble, and Wal-Mart, have long corporate histories, well-established track records, and exceedingly conservative risk profiles. Many of these companies pay dividends on a par with utilities, with the average dividend yield for the group approaching 3%. Moreover, because of their significance and name recognition, these companies receive intense scrutiny by the investment community, which increases confidence that published growth estimates are representative of the consensus expectations reflected in common stock prices.

Q107. DO THE BETA VALUES FOR THE NON-UTILITY GROUP ADDRESS THE CONCERNS EXPRESSED BY THE KPSC IN PRIOR RATE PROCEEDING FOR KU?

A107. Yes. The KPSC concluded in Case No. 2009-00549 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."[51] Our proxy group criteria restricted the Non-Utility Group to include only firms with beta values of 0.70 or less, with the group's average beta of 0.65 being lower than the 0.73 average for the Utility Group and equal to the 0.65 value corresponding to KU.

Q108. WHAT WERE THE RESULTS OF YOUR DCF ANALYSIS FOR THE NON-UTILITY GROUP?

A108. We applied the DCF model to the Non-Utility Group using the same analysts' EPS growth projections described earlier for the Utility Group, with the results being presented in Exhibit No. 11. As summarized in Table 7, below, application of the constant growth DCF model resulted in the following cost of equity estimates:

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[51] *Case No. 2009-00549*, Final Order at 33.

TABLE 7
DCF RESULTS – NON-UTILITY GROUP

	Cost of Equity	
Growth Rate	**Average**	**Midpoint**
Value Line	11.0%	12.0%
IBES	10.4%	10.8%
Zacks	10.7%	10.8%
Reuters	10.3%	10.4%

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.

Q109. HOW CAN YOU RECONCILE THESE DCF RESULTS FOR THE NON-UTILITY GROUP AGAINST THE SIGNIFICANTLY LOWER ESTIMATES PRODUCED FOR YOUR GROUP OF UTILITIES?

A109. First, it is important to be clear that the higher DCF results for the Non-Utility Group cannot be attributed to risk differences. As documented earlier, the risks that investors associate with the group of non-utility firms - as measured by S&P's credit ratings, Value Line's Safety Rank, Financial Strength, and beta – are generally lower than the risks investors associate with the Utility Group and KU. 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 group of utilities and the Non-Utility Group suggests that both should be considered to ensure a balanced end-result. The DCF results for the Non-Utility Group suggest that a 10.64% ROE for KU is a conservative estimate of a fair return.

Q110. PLEASE SUMMARIZE THE RESULTS OF YOUR ALTERNATIVE ROE BENCHMARKS.

A110. The cost of common equity estimates produced by the various tests of reasonableness discussed above are shown on page 2 of Exhibit No. 2, and summarized in Table 8, below:

TABLE 8
SUMMARY OF ALTERNATIVE ROE BENCHMARKS

	Average	Midpoint
CAPM - Historical Bond Yield		
Unadjusted	10.4%	10.4%
Size Adjusted	11.2%	11.2%
CAPM - Projected Bond Yield		
Unadjusted	10.8%	10.8%
Size Adjusted	11.6%	11.5%
Expected Earnings		
Industry	10.5%	
Proxy Group	10.8%	11.4%
Non-Utility DCF		
Value Line	11.0%	12.0%
IBES	10.4%	10.8%
Zacks	10.7%	10.8%
Reuters	10.3%	10.4%

The results of these alternative benchmarks confirm our conclusion that an ROE of 10.64% for KU is reasonable.

Q111. DOES THIS CONCLUDE YOUR PRE-FILED DIRECT TESTIMONY?

A111. 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
William E. Avera

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 12th day of November 2014.

_______________(SEAL)
Notary Public

My Commission Expires:

1/10/15

ADRIEN MCKENZIE
Notary Public
STATE OF TEXAS
My Comm. Exp. Jan. 10, 2015

VERIFICATION

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

The undersigned, **Adrien M. McKenzie**, being duly sworn, deposes and says he is Vice 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.

____
Adrien M. McKenzie

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 14 day of November 2014.

______________________________(SEAL)
Notary Public

My Commission Expires:

TRINIDAD ZAPATA
Notary Public, State of New York
No. 01ZA6259401
Qualified in Kings County
Certificate Filed in New York County
Commission Expires April 9, 2016

____

Exhibit No. 1

Qualifications of William E. Avera and Adrien M. McKenzie

EXHIBIT NO. 1

QUALIFICATIONS OF WILLIAM E. AVERA
AND
ADRIEN M. MCKENZIE

Q. WHAT IS THE PURPOSE OF THIS EXHIBIT?

A. This exhibit describes our background and experience and contains the details of our qualifications.

Q. DR. AVERA, PLEASE DESCRIBE YOUR QUALIFICATIONS AND EXPERIENCE.

A. I received a B.A. degree with a major in economics from Emory University. After serving in the U.S. Navy, I entered the doctoral program in economics at the University of North Carolina at Chapel Hill. Upon receiving my Ph.D., I joined the faculty at the University of North Carolina and taught finance in the Graduate School of Business. I subsequently accepted a position at the University of Texas at Austin where I taught courses in financial management and investment analysis. I then went to work for International Paper Company in New York City as Manager of Financial Education, a position in which I had responsibility for all corporate education programs in finance, accounting, and economics.

In 1977, I joined the staff of the Public Utility Commission of Texas ("PUCT") as Director of the Economic Research Division. During my tenure at the PUCT, I managed a division responsible for financial analysis, cost allocation and rate design, economic and financial research, and data processing systems, and I testified in cases on a variety of financial and economic issues. Since leaving the PUCT, I have been engaged as a consultant. I have participated in a wide range of assignments involving utility-related matters on behalf of utilities, industrial customers, municipalities, and regulatory commissions. I have previously testified before the Federal Energy Regulatory Commission ("FERC"), as well as the Federal Communications Commission, the Surface Transportation Board (and its predecessor, the Interstate Commerce Commission), the Canadian Radio-Television and Telecommunications Commission, and regulatory agencies, courts, and legislative committees in over 40 states.

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.

Q. MR. MCKENZIE, PLEASE DESCRIBE YOUR QUALIFICATIONS AND EXPERIENCE.

A. Since joining FINCAP in 1984, I have participated in consulting assignments involving a broad range of economic and financial issues, including cost of capital, cost of service, rate design, economic damages, and business valuation. I have extensive experience in economic and financial analysis for regulated industries, and in preparing and supporting expert witness testimony before courts, regulatory agencies, and legislative committees throughout the U.S. and Canada. I have personally sponsored direct and rebuttal testimony concerning the rate of return on equity ("ROE") in ten proceedings filed with FERC, the Kansas State Corporation Commission, the Montana Public Service Commission, the Washington Utilities and Transportation Commission, and the Wyoming Public Service Commission. My testimony addressed the establishment of risk-comparable proxy groups, the application of alternative quantitative methods, and the consideration of regulatory standards and policy objectives in establishing a fair ROE for regulated electric and gas utility operations. In addition, I have previously prepared prefiled direct and rebuttal testimony in over 250 regulatory proceedings (including Docket No. EL11-66-001, which established FERC's current policies with respect to ROE for electric utilities), the Canadian Radio-Television and Telecommunications Commission, and regulatory agencies in over 30 states. This testimony was sponsored by Dr. William Avera, who is President of FINCAP, Inc. In connection with these assignments, my responsibilities have included performing analytical methods to estimate investors' required rate of return and critically evaluating the results of alternative approaches, preparing direct testimony, responding to data requests, evaluating the positions of other parties and preparing responsive testimony, representing clients in settlement negotiations and hearings, and assisting in the preparation of legal briefs. Prior to joining FINCAP, I was employed by an oil and gas firm and was responsible for operations and accounting. I earned B.A. and M.B.A. degrees with a major in finance from The University of Texas at Austin, and hold the Chartered Financial Analyst (CFA®) designation.

WILLIAM E. AVERA

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Economic and Financial Counsel

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fincap@texas.net

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 almost 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)

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

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

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

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

Articles

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

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

"The Energy Crisis and the Homeowner: The Grief Process," *Texas Business Review* (Jan.–Feb. 1980); reprinted in *The Energy Picture: Problems and Prospects*, J. E. Pluta, ed., Bureau of Business Research (1980)

"Use of IFPS at the Public Utility Commission of Texas," *Proceedings of the IFPS Users Group Annual Meeting* (1979)

"Production Capacity Allocation: Conversion, CWIP, and One-Armed Economics," *Proceedings of the NARUC Biennial Regulatory Information Conference* (1978)

"Some Thoughts on the Rate of Return to Public Utility Companies," with Bruce H. Fairchild in *Proceedings of the NARUC Biennial Regulatory Information Conference* (1978)

"A New Capital Budgeting Measure: The Integration of Time, Liquidity, and Uncertainty," with David Cordell in *Proceedings of the Southwestern Finance Association* (1977)

"Usefulness of Current Values to Investors and Creditors," in *Inflation Accounting/Indexing and Stock Behavior* (1977)

"Consumer Expectations and the Economy," *Texas Business Review* (Nov. 1976)

"Portfolio Performance Evaluation and Long-run Capital Growth," with Henry A. Latané in *Proceedings of the Eastern Finance Association* (1973)

Book reviews in *Journal of Finance* and *Financial Review*. Abstracts for *CFA Digest*. Articles in *Carolina Financial Times*.

Selected Papers and Presentations

"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)

ADRIEN M. McKENZIE

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Summary of Qualifications

Adrien McKenzie has an MBA in finance from the University of Texas at Austin and holds the Chartered Financial Analyst (CFA) designation. He has over 25 years experience in economic and financial analysis for regulated industries, and in preparing and supporting expert witness testimony before courts, regulatory agencies, and legislative committees throughout the U.S. and Canada. Assignments have included a broad range of economic and financial issues, including cost of capital, cost of service, rate design, economic damages, and business valuation.

Employment

Consultant, FINCAP, Inc. (June 1984 to June 1987) (April 1988 to present)	Economic consulting firm specializing in regulated industries and valuation of closely-held businesses. Assignments have involved electric, gas, telecommunication, and water/sewer utilities, with clients including utilities, consumer groups, municipalities, regulatory agencies, and cogenerators. Areas of participation have included rate of return, revenue requirements, rate design, tariff analysis, avoided cost, forecasting, and negotiations. Develop cost of capital analyses using alternative market models for electric, gas, and telephone utilities. Prepare pre-filed direct and rebuttal testimony, participate in settlement negotiations, respond to interrogatories, evaluate opposition testimony, and assist in the areas of cross-examination and the preparations of legal briefs. Other assignments have involved preparation of technical reports, valuations, estimation of damages, industry studies, and various economic analyses in support of litigation.
Manager, McKenzie Energy Company (Jan. 1981 to May. 1984)	Responsible for operations and accounting for firm engaged in the management of working interests in oil and gas properties.

Education

M.B.A., Finance, University of Texas at Austin (Sep. 1982 to May. 1984)	Program included coursework in corporate finance, accounting, financial modeling, and statistics. Received Dean's Award for Academic Excellence and Good Neighbor Scholarship. Professional Report: *The Impact of Construction Expenditures on Investor-Owned Electric Utilities*
B.B.A., Finance, University of Texas at Austin (Jan. 1981 to May 1982)	Electives included capital market theory, portfolio management, and international economics and finance. Elected to Beta Gamma Sigma business honor society. Dean's List 1981-1982.
Simon Fraser University, Vancouver, Canada and University of Hawaii at Manoa, Honolulu, Hawaii (Jan. 1979 to Dec 1980)	Coursework in accounting, finance, economics, and liberal arts.

Professional Associations

Received Chartered Financial Analyst (CFA) designation in 1990.

Member – CFA Institute.

Bibliography

"A Profile of State Regulatory Commissions," A Special Report by the Electricity Consumers Resource Council (ELCON), Summer 1991.

"The Impact of Regulatory Climate on Utility Capital Costs: An Alternative Test," with Bruce H. Fairchild, *Public Utilities Fortnightly* (May 25, 1989).

Presentations

"ROE at FERC: Issues and Methods," *Expert Briefing on Parallels in ROE Issues between AER, ERA, and FERC,* Jones Day (Sydney, Melbourne, and Perth, Australia) (April 15, 2014)

Cost of Capital Working Group eforum, Edison Electric Institute (April 24, 2012)

"Cost-of-Service Studies and Rate Design," General Management of Electric Utilities (A Training Program for Electric Utility Managers from Developing Countries), Austin, Texas (October 1989 and November 1990 and 1991).

Representative Assignments

Mr. McKenzie has prepared and supported prefiled testimony submitted in over 250 regulatory proceedings. In addition to filings before regulators in 33 states, Mr. McKenzie has considerable expertise in preparing expert analyses and testimony before the Federal Energy Regulatory Commission ("FERC") on the issue of ROE. Many of these proceedings have been influential in addressing key aspects of FERC's policies with respect to ROE determinations. Broad experience in applying and evaluating the results of quantitative methods to estimate a fair ROE, including discounted cash flow approaches, the Capital Asset Pricing Model, risk premium methods, and other quantitative benchmarks. Other representative assignments have included the application of econometric models to analyze the impact of anti-competitive behavior and estimate lost profits; development of explanatory models for nuclear plant capital costs in connection with prudency reviews; and the analysis of avoided cost pricing for cogenerated power.

Exhibit No. 2

Summary of Results

SUMMARY OF RESULTS

	Average	Midpoint
DCF		
Value Line	9.7%	10.1%
IBES	9.7%	10.5%
Zacks	9.6%	10.4%
Reuters	9.6%	10.5%
Internal br + sv	9.0%	9.5%
Empirical CAPM - Historical Bond Yield		
Unadjusted	11.1%	11.1%
Size Adjusted	11.9%	11.9%
Empirical CAPM - Projected Bond Yield		
Unadjusted	11.4%	11.4%
Size Adjusted	12.2%	12.1%
Utility Risk Premium		
Historical Bond Yields	10.1%	
Projected Bond Yields	11.2%	

Cost of Equity Recommendation	
Cost of Equity Range	9.6% -- 11.4%
Recommended Point Estimate	10.50%
Flotation Cost Adjustment	
Dividend Yield	3.8%
Flotation Cost Percentage	3.6%
Adjustment	0.14%
ROE Recommendation	**10.64%**

CHECKS OF REASONABLENESS

	Average	Midpoint
CAPM - Historical Bond Yield		
Unadjusted	10.4%	10.4%
Size Adjusted	11.2%	11.2%
CAPM - Projected Bond Yield		
Unadjusted	10.8%	10.8%
Size Adjusted	11.6%	11.5%
Expected Earnings		
Industry	10.5%	
Proxy Group	10.8%	11.4%
Non-Utility DCF		
Value Line	11.0%	12.0%
IBES	10.4%	10.8%
Zacks	10.7%	10.8%
Reuters	10.3%	10.4%

Exhibit No. 3

Regulatory Mechanisms – Utility Group

UTILITY GROUP

	Company	Mechanism
1	Alliant Energy	FCA;PGA; TCR; ICR; DSM
2	Ameren Corp.	FCA, PGA, ICR, DSM, ECA, BDR
3	Avista Corp.	FCA, PGA
4	Black Hills Corp.	FCA, PGA, ICR; ECA, TCR, WNA, Construction financing rider to recover financing costs in lieu of AFUDC
5	CenterPoint Energy	PGA; ICR; RDM; WNA
6	CMS Energy Corp.	FCA, PGA, RDM
7	Consolidated Edison	FCA, PGA, RDM, WNA, PCR, SCR
8	Dominion Resources	FCA, PGA, ICR, TCR, DSM
9	DTE Energy Co.	FCA, PGA, RDM, ICR, DSM, BDR, SCR
10	Duke Energy Corp.	FCA, ICR, DSM, ECA, SCR
11	Empire District Elec	FCA, PGA, DSM, TCR, PCR, other O&M trackers
12	Entergy Corp.	FCA; PGA; SCR; DSM; Pre-Approval rider for generating facility
13	Northeast Utilities	RDM, PGA, ICR, DSM, PCR, TCR, SCR, other trackers related to residential assistance, solar projects, net-metering facitlities, smart grid, and safety and reliability programs
14	NorthWestern Corp.	FCA, PGA, Investment Pre-Approval, Property tax tracker
15	PG&E Corp.	FCA, RDM
16	Pub Sv Enterprise Group	FCA, PGA, WNA, ICR, DSM
17	SCANA Corp.	FCA, PGA, RDM, ICR, DSM, PCR, SCR
18	Sempra Energy	FCA, RDM
19	Vectren Corp.	FCA, PGA, RDM, WNA, ICR, DSM, TCR
20	Xcel Energy Inc.	FCA, PGA, ECA, ICR, DSM, TCR, Capacity clause to recover capacity payments for purchased power, residential assistance trackers

BDR -- Bad Debt Cost Recovery Rider
DSM -- Demand Side Management / Conservation Adjustment Clause
ECA -- Environmental and/or Emissions Cost Adjustment Clause
FCA -- Fuel and/or Power Cost Adjustment Clause
ICR -- Infrastructure Investment / Renewables Cost Recovery Mechanism
PCR -- Pension Cost Recovery Mechanism
PGA -- Gas Cost Adjustment Clause
RDM -- Revenue Decoupling Mechanism
SCR - Storm Cost Recovery Tracker
TCR -- Transmission Cost Recovery Tracker
WNC -- Weather Normalization Clause or other mitigants

Source : 2013 Form 10-K Reports

Exhibit No. 4

Capital Structure

CAPITAL STRUCTURE

UTILITY GROUP

		At Fiscal Year-End 2013 (a)			Value Line Projected (b)		
	Company	Debt	Preferred	Common Equity	Debt	Other	Common Equity
1	Alliant Energy	48.9%	2.9%	48.1%	46.0%	2.5%	51.5%
2	Ameren Corp.	47.5%	0.0%	52.5%	45.5%	1.0%	53.5%
3	Avista Corp.	49.0%	0.0%	51.0%	53.5%	0.0%	46.5%
4	Black Hills Corp.	51.6%	0.0%	48.4%	53.5%	0.0%	46.5%
5	CenterPoint Energy	52.4%	0.0%	47.6%	59.5%	0.0%	40.5%
6	CMS Energy Corp.	68.7%	0.0%	31.3%	62.5%	0.5%	37.0%
7	Consolidated Edison	47.3%	0.0%	52.7%	49.0%	0.0%	51.0%
8	Dominion Resources	63.7%	0.8%	35.6%	57.5%	0.5%	42.0%
9	DTE Energy Co.	50.2%	0.0%	49.8%	50.5%	0.0%	49.5%
10	Duke Energy Corp.	49.3%	0.0%	50.7%	52.0%	0.0%	48.0%
11	Empire District Elec	49.8%	0.0%	50.2%	50.0%	0.0%	50.0%
12	Entergy Corp.	54.1%	1.4%	44.5%	54.5%	1.0%	44.5%
13	Northeast Utilities	46.4%	0.0%	53.6%	45.5%	1.0%	53.5%
14	NorthWestern Corp.	52.8%	0.0%	47.2%	42.5%	0.0%	57.5%
15	PG&E Corp.	48.2%	0.9%	50.9%	48.5%	0.5%	51.0%
16	Pub Sv Enterprise Grp	42.0%	0.0%	58.0%	44.5%	0.0%	55.5%
17	SCANA Corp.	53.9%	0.0%	46.1%	52.5%	0.0%	47.5%
18	Sempra Energy	51.1%	0.1%	48.8%	52.0%	0.0%	48.0%
19	Vectren Corp.	53.8%	0.0%	46.2%	53.0%	0.0%	47.0%
20	Xcel Energy, Inc.	53.9%	0.0%	46.1%	50.5%	0.0%	49.5%
	Average	**51.7%**	**0.3%**	**48.0%**	**51.2%**	**0.3%**	**48.5%**

(a) Company Form 10-K and Annual Reports.
(b) The Value Line Investment Survey (Aug. 1, Aug. 22, & Sep. 19, 2014).

ELECTRIC OPERATING COS.

	Company	At Fiscal Year-End 2013 (a) Debt	Preferred	Common Equity
1	Ameren Illinois Co.	43.1%	1.4%	55.4%
2	Black Hills Power	44.1%	0.0%	55.9%
3	CenterPoint Energy Houston Electric, LLC	56.4%	0.0%	43.6%
4	Cheyenne Light Fuel & Power	39.5%	0.0%	60.5%
5	Connecticut Light & Power	49.3%	2.1%	48.6%
6	Consolidated Edison of NY	47.6%	0.0%	52.4%
7	Consumers Energy Co.	48.9%	0.4%	50.7%
8	DTE Electric Co.	51.0%	0.0%	49.0%
9	Duke Energy Carolinas	44.0%	0.0%	56.0%
10	Duke Energy Florida	50.5%	0.0%	49.5%
11	Duke Energy Indiana	48.1%	0.0%	51.9%
12	Duke Energy Ohio	29.3%	0.0%	70.7%
13	Duke Energy Progress	48.2%	0.0%	51.8%
14	Entergy Arkansas Inc.	55.8%	2.8%	41.4%
15	Entergy Gulf States Louisiana LLC	51.1%	0.3%	48.6%
16	Entergy Louisiana LLC	50.7%	1.7%	47.7%
17	Entergy Mississippi Inc.	51.3%	2.5%	46.3%
18	Entergy New Orleans Inc.	50.0%	4.4%	45.6%
19	Entergy Texas Inc.	51.1%	0.0%	48.9%
20	Interstate Power & Light	45.3%	5.8%	48.9%
21	Northern States Power Co. (MN)	46.5%	0.0%	53.5%
22	Northern States Power Co. (WI)	43.7%	0.0%	56.3%
23	NSTAR Electric Co.	42.3%	1.0%	56.7%
24	Orange & Rockland	48.3%	0.0%	51.7%
25	Pacific Gas & Electric Co.	47.2%	0.9%	51.9%
26	Progress Energy Inc.	56.5%	0.0%	43.5%
27	Pub Service Electric & Gas Co.	48.6%	0.0%	51.4%
28	Public Service Co. of Colorado	44.6%	0.0%	55.4%
29	Public Service Co. of New Hampshire	48.1%	0.0%	51.9%
30	San Diego Gas & Electric	49.1%	0.0%	50.9%
31	South Carolina Electric & Gas	47.5%	0.0%	52.5%
32	Southern California Gas Co.	35.6%	0.6%	63.8%
33	Southern Indiana Gas & Electric Co.	43.7%	0.0%	56.3%
34	Southwestern Public Service Co.	46.8%	0.0%	53.2%
35	Union Electric Co.	48.5%	1.0%	50.5%
36	Virginia Electric Power	45.0%	0.0%	55.0%
37	Western Massachussetts Electric Co.	52.1%	0.0%	47.9%
38	Wisconsin Power & Light	44.8%	0.0%	55.2%
	Average	**47.2%**	**0.7%**	**52.1%**

(a) Company Form 10-K and FERC Form 1 Annual Reports.

Exhibit No. 5

DCF Model –Utility Group

DIVIDEND YIELD

	Company	(a) Price	(b) Dividends	Yield
1	Alliant Energy	$ 57.55	$ 2.04	3.5%
2	Ameren Corp.	$ 39.02	$ 1.63	4.2%
3	Avista Corp.	$ 32.00	$ 1.30	4.1%
4	Black Hills Corp.	$ 52.46	$ 1.60	3.1%
5	CenterPoint Energy	$ 24.56	$ 1.01	4.1%
6	CMS Energy Corp.	$ 29.90	$ 1.13	3.8%
7	Consolidated Edison	$ 57.09	$ 2.57	4.5%
8	Dominion Resources	$ 69.27	$ 2.48	3.6%
9	DTE Energy Co.	$ 76.76	$ 2.80	3.6%
10	Duke Energy Corp.	$ 73.16	$ 3.20	4.4%
11	Empire District Elec	$ 25.36	$ 1.04	4.1%
12	Entergy Corp.	$ 75.20	$ 3.32	4.4%
13	Northeast Utilities	$ 45.03	$ 1.65	3.7%
14	NorthWestern Corp.	$ 47.76	$ 1.64	3.4%
15	PG&E Corp.	$ 45.95	$ 1.82	4.0%
16	Pub Sv Enterprise Grp	$ 36.59	$ 1.50	4.1%
17	SCANA Corp.	$ 50.76	$ 2.15	4.2%
18	Sempra Energy	$104.23	$ 2.72	2.6%
19	Vectren Corp.	$ 40.51	$ 1.46	3.6%
20	Xcel Energy, Inc.	$ 31.38	$ 1.23	3.9%
	Average			**3.8%**

(a) Average of closing prices for 30 trading days ended Sep. 19, 2014.

(b) The Value Line Investment Survey, Summary & Index (Sep. 19, 2014).

GROWTH RATES

		(a)	(b)	(c)	(d)	(e)
		Earnings Growth				br+sv
	Company	**V Line**	**IBES**	**Zacks**	**Reuters**	**Growth**
1	Alliant Energy	6.0%	4.7%	5.1%	5.1%	5.2%
2	Ameren Corp.	4.5%	8.9%	8.3%	8.9%	4.0%
3	Avista Corp.	5.5%	5.0%	NA	NA	3.1%
4	Black Hills Corp.	9.5%	7.0%	NA	NA	4.1%
5	CenterPoint Energy	3.5%	3.9%	4.5%	3.9%	3.1%
6	CMS Energy Corp.	6.5%	6.8%	6.1%	6.8%	6.3%
7	Consolidated Edison	2.0%	2.7%	2.9%	2.7%	3.1%
8	Dominion Resources	5.5%	6.2%	5.6%	6.2%	6.9%
9	DTE Energy Co.	6.5%	5.9%	6.2%	5.9%	4.3%
10	Duke Energy Corp.	5.0%	4.7%	4.7%	4.8%	2.9%
11	Empire District Elec	4.0%	3.0%	3.0%	3.0%	3.2%
12	Entergy Corp.	1.0%	1.3%	-1.1%	2.5%	4.2%
13	Northeast Utilities	8.0%	6.3%	6.5%	6.1%	4.5%
14	NorthWestern Corp.	3.5%	7.0%	7.0%	7.0%	3.7%
15	PG&E Corp.	5.0%	7.0%	5.6%	7.0%	3.0%
16	Pub Sv Enterprise Grp	2.0%	1.8%	2.1%	4.2%	4.8%
17	SCANA Corp.	5.0%	4.6%	4.4%	4.6%	5.0%
18	Sempra Energy	6.0%	7.5%	7.5%	7.5%	5.7%
19	Vectren Corp.	9.0%	4.5%	4.7%	4.5%	7.8%
20	Xcel Energy, Inc.	5.5%	4.5%	4.2%	5.1%	4.8%

(a) The Value Line Investment Survey (Aug. 1, Aug. 22, & Sep. 19, 2014).
(b) www.finance.yahoo.com (retrieved Oct. 2, 2014).
(c) www.zacks.com (retrieved Oct. 6, 2014).
(d) www.reuters.com/finance/stocks (retrieved Oct. 6, 2014).
(e) See Exhibit No. 6.

DCF COST OF EQUITY ESTIMATES

		(a)	(a)	(a)	(a)	(a)
		Earnings Growth				br+sv
	Company	V Line	IBES	Zacks	Reuters	Growth
1	Alliant Energy	9.5%	8.2%	8.7%	8.7%	8.8%
2	Ameren Corp.	8.7%	13.1%	12.5%	13.1%	8.2%
3	Avista Corp.	9.6%	9.1%	NA	NA	7.2%
4	Black Hills Corp.	12.6%	10.1%	NA	NA	7.2%
5	CenterPoint Energy	7.6%	8.0%	8.6%	8.0%	7.2%
6	CMS Energy Corp.	10.3%	10.6%	9.9%	10.6%	10.1%
7	Consolidated Edison	6.5%	7.2%	7.4%	7.2%	7.6%
8	Dominion Resources	9.1%	9.8%	9.1%	9.8%	10.4%
9	DTE Energy Co.	10.1%	9.5%	9.9%	9.5%	7.9%
10	Duke Energy Corp.	9.4%	9.1%	9.1%	9.1%	7.3%
11	Empire District Elec	8.1%	7.1%	7.1%	7.1%	7.3%
12	Entergy Corp.	5.4%	5.7%	3.4%	6.9%	8.6%
13	Northeast Utilities	11.7%	10.0%	10.2%	9.7%	8.1%
14	NorthWestern Corp.	6.9%	10.4%	10.4%	10.4%	7.1%
15	PG&E Corp.	9.0%	10.9%	9.6%	10.9%	6.9%
16	Pub Sv Enterprise Grp	6.1%	5.9%	6.2%	8.3%	8.9%
17	SCANA Corp.	9.2%	8.8%	8.6%	8.8%	9.2%
18	Sempra Energy	8.6%	10.1%	10.1%	10.1%	8.3%
19	Vectren Corp.	12.6%	8.1%	8.3%	8.1%	11.4%
	Average (b)	**9.7%**	**9.7%**	**9.6%**	**9.6%**	**9.0%**
	Midpoint (c)	**10.1%**	**10.5%**	**10.4%**	**10.5%**	**9.5%**

(a) Sum of dividend yield (Exhibit No. 5, p. 1) and respective growth rate (Exhibit No. 5, p. 2).
(b) Excludes highlighted figures.
(c) Average of low and high values.

Exhibit No. 6

Sustainable Growth Rate –Utility Group

BR+SV GROWTH RATE

		(a)	(a)	(a)			(b)	(c)		(d)	(e)		
		2018					Adjustment			"sv" Factor			
	Company	EPS	DPS	BVPS	b	r	Factor	Adjusted r	br	s	v	sv	br + sv
1	Alliant Energy	$4.00	$2.40	$34.65	40.0%	11.5%	1.0202	11.8%	4.7%	0.0125	0.4225	0.53%	**5.2%**
2	Ameren Corp.	$3.00	$1.80	$32.00	40.0%	9.4%	1.0210	9.6%	3.8%	0.0095	0.2000	0.19%	**4.0%**
3	Avista Corp.	$2.25	$1.50	$25.75	33.3%	8.7%	1.0219	8.9%	3.0%	0.0111	0.1417	0.16%	**3.1%**
4	Black Hills Corp.	$3.25	$1.90	$35.50	41.5%	9.2%	1.0218	9.4%	3.9%	0.0078	0.2900	0.23%	**4.1%**
5	CenterPoint Energy	$1.60	$1.30	$11.25	18.8%	14.2%	1.0117	14.4%	2.7%	0.0062	0.6250	0.39%	**3.1%**
6	CMS Energy Corp.	$2.25	$1.35	$17.25	40.0%	13.0%	1.0338	13.5%	5.4%	0.0215	0.4250	0.92%	**6.3%**
7	Consolidated Edison	$4.25	$2.75	$49.25	35.3%	8.6%	1.0160	8.8%	3.1%	0.0001	0.1792	0.00%	**3.1%**
8	Dominion Resources	$4.00	$2.80	$28.00	30.0%	14.3%	1.0427	14.9%	4.5%	0.0420	0.5692	2.39%	**6.9%**
9	DTE Energy Co.	$5.50	$3.30	$56.75	40.0%	9.7%	1.0296	10.0%	4.0%	0.0140	0.2172	0.30%	**4.3%**
10	Duke Energy Corp.	$5.25	$3.40	$65.00	35.2%	8.1%	1.0115	8.2%	2.9%	0.0014	-	0.00%	**2.9%**
11	Empire District Elec	$1.75	$1.15	$20.25	34.3%	8.6%	1.0237	8.8%	3.0%	0.0197	0.1000	0.20%	**3.2%**
12	Entergy Corp.	$6.50	$3.80	$66.75	41.5%	9.7%	1.0220	10.0%	4.1%	0.0016	0.2147	0.03%	**4.2%**
13	Northeast Utilities	$3.50	$2.00	$36.50	42.9%	9.6%	1.0193	9.8%	4.2%	0.0088	0.3048	0.27%	**4.5%**
14	NorthWestern Corp.	$3.00	$1.90	$31.75	36.7%	9.4%	1.0205	9.6%	3.5%	0.0065	0.2529	0.16%	**3.7%**
15	PG&E Corp.	$3.00	$2.10	$36.50	30.0%	8.2%	1.0242	8.4%	2.5%	0.0226	0.1889	0.43%	**3.0%**
16	Pub Sv Enterprise Grp	$3.00	$1.65	$29.00	45.0%	10.3%	1.0237	10.6%	4.8%	0.0001	0.2267	0.00%	**4.8%**
17	SCANA Corp.	$4.25	$2.35	$43.50	44.7%	9.8%	1.0380	10.1%	4.5%	0.0270	0.1714	0.46%	**5.0%**
18	Sempra Energy	$6.25	$3.40	$55.50	45.6%	11.3%	1.0242	11.5%	5.3%	0.0107	0.4308	0.46%	**5.7%**
19	Vectren Corp.	$3.00	$1.55	$21.50	48.3%	14.0%	1.0177	14.2%	6.9%	0.0180	0.5222	0.94%	**7.8%**
20	Xcel Energy, Inc.	$2.50	$1.45	$24.25	42.0%	10.3%	1.0305	10.6%	4.5%	0.0169	0.1917	0.32%	**4.8%**

DCF MODEL - UTILITY GROUP

BR+SV GROWTH RATE

		(a)	(a)	(f)	(a)	(a)	(f)	(g)	(a)	(a)		(h)	(a)	(a)	(g)
		---- 2013 ----			---- 2018 ----			Chg	---- 2018 Price ----				---- Common Shares ----		
	Company	Eq Ratio	Tot Cap	Com Eq	Eq Ratio	Tot Cap	Com Eq	Equity	High	Low	Avg.	M/B	2013	2018	Growth
1	Alliant Energy	50.8%	$6,461	$3,282	51.5%	$7,800	$4,017	4.1%	$70.00	$50.00	$60.00	1.732	110.94	115.00	0.72%
2	Ameren Corp.	53.7%	$12,190	$6,546	53.5%	$15,100	$8,079	4.3%	$45.00	$35.00	$40.00	1.250	242.63	252.00	0.76%
3	Avista Corp.	48.6%	$2,670	$1,297	46.5%	$3,475	$1,616	4.5%	$35.00	$25.00	$30.00	1.165	60.08	63.00	0.95%
4	Black Hills Corp.	48.4%	$2,705	$1,309	46.5%	$3,500	$1,628	4.5%	$60.00	$40.00	$50.00	1.408	44.50	45.75	0.56%
5	CenterPoint Energy	35.6%	$12,146	$4,324	40.5%	$12,000	$4,860	2.4%	$35.00	$25.00	$30.00	2.667	429.00	434.00	0.23%
6	CMS Energy Corp.	32.2%	$10,730	$3,455	37.0%	$13,100	$4,847	7.0%	$35.00	$25.00	$30.00	1.739	266.10	283.00	1.24%
7	Consolidated Edison	53.9%	$22,735	$12,254	51.0%	$28,200	$14,382	3.3%	$65.00	$55.00	$60.00	1.218	292.87	293.00	0.01%
8	Dominion Resources	37.3%	$31,229	$11,648	42.0%	$42,500	$17,850	8.9%	$75.00	$55.00	$65.00	2.321	581.50	636.00	1.81%
9	DTE Energy Co.	52.3%	$15,135	$7,916	49.5%	$21,500	$10,643	6.1%	$85.00	$60.00	$72.50	1.278	177.09	187.00	1.09%
10	Duke Energy Corp.	52.0%	$79,482	$41,331	48.0%	$96,600	$46,368	2.3%	$75.00	$55.00	$65.00	1.000	706.00	711.00	0.14%
11	Empire District Elec	50.2%	$1,494	$750	50.0%	$1,900	$950	4.8%	$25.00	$20.00	$22.50	1.111	43.04	47.00	1.78%
12	Entergy Corp.	43.6%	$22,109	$9,640	44.5%	$27,000	$12,015	4.5%	$100.00	$70.00	$85.00	1.273	178.37	179.50	0.13%
13	Northeast Utilities	54.8%	$17,544	$9,614	53.5%	$21,800	$11,663	3.9%	$60.00	$45.00	$52.50	1.438	315.27	325.00	0.61%
14	NorthWestern Corp.	46.5%	$2,216	$1,030	57.5%	$2,200	$1,265	4.2%	$50.00	$35.00	$42.50	1.339	38.75	39.70	0.49%
15	PG&E Corp.	52.5%	$27,311	$14,338	51.0%	$35,800	$18,258	5.0%	$55.00	$35.00	$45.00	1.233	456.67	500.00	1.83%
16	Pub Sv Enterprise Grp	59.6%	$19,470	$11,604	55.5%	$26,500	$14,708	4.9%	$40.00	$35.00	$37.50	1.293	505.86	506.00	0.01%
17	SCANA Corp.	46.4%	$10,059	$4,667	47.5%	$14,375	$6,828	7.9%	$60.00	$45.00	$52.50	1.207	141.00	157.50	2.24%
18	Sempra Energy	49.4%	$22,281	$11,007	48.0%	$29,200	$14,016	5.0%	$110.00	$85.00	$97.50	1.757	244.46	252.00	0.61%
19	Vectren Corp.	46.7%	$3,331	$1,556	47.0%	$3,950	$1,857	3.6%	$50.00	$40.00	$45.00	2.093	82.40	86.00	0.86%
20	Xcel Energy, Inc.	46.7%	$20,477	$9,563	49.5%	$26,200	$12,969	6.3%	$35.00	$25.00	$30.00	1.237	497.97	533.00	1.37%

(a) The Value Line Investment Survey (Aug. 1, Aug. 22, & Sep. 19, 2014).
(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 2018 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 2018 BVPS.

Exhibit No. 7

Empirical Capital Asset Pricing Model

EMPIRICAL CAPM - CURRENT BOND YIELD

UTILITY GROUP

		(a)	(b)		(c)		(d)		(e)	(d)				(f)	(g)	
		Market Return (R_m)				Market										Size
		Div	Proj.	Cost of	Risk-Free	Risk	Unadjusted RP		Beta Adjusted RP			Total	Unadjusted	Market	Size	Adjusted
	Company	**Yield**	**Growth**	**Equity**	**Rate**	**Premium**	**Weight**	***RP*[1]**	**Beta**	**Weight**	***RP*[2]**	**RP**	**K_e**	**Cap**	**Adjustment**	**K_e**
1	Alliant Energy	2.3%	10.8%	13.1%	3.4%	9.7%	25%	2.4%	0.80	75%	5.8%	8.2%	11.6%	$ 6,487.5	0.93%	12.6%
2	Ameren Corp.	2.3%	10.8%	13.1%	3.4%	9.7%	25%	2.4%	0.75	75%	5.5%	7.9%	11.3%	$ 9,638.5	0.80%	12.1%
3	Avista Corp.	2.3%	10.8%	13.1%	3.4%	9.7%	25%	2.4%	0.75	75%	5.5%	7.9%	11.3%	$ 1,947.5	1.75%	13.0%
4	Black Hills Corp.	2.3%	10.8%	13.1%	3.4%	9.7%	25%	2.4%	0.85	75%	6.2%	8.6%	12.0%	$ 2,368.2	1.75%	13.8%
5	CenterPoint Energy	2.3%	10.8%	13.1%	3.4%	9.7%	25%	2.4%	0.75	75%	5.5%	7.9%	11.3%	$10,612.8	0.80%	12.1%
6	CMS Energy Corp.	2.3%	10.8%	13.1%	3.4%	9.7%	25%	2.4%	0.75	75%	5.5%	7.9%	11.3%	$ 8,340.8	0.93%	12.2%
7	Consolidated Edison	2.3%	10.8%	13.1%	3.4%	9.7%	25%	2.4%	0.60	75%	4.4%	6.8%	10.2%	$16,872.7	0.80%	11.0%
8	Dominion Resources	2.3%	10.8%	13.1%	3.4%	9.7%	25%	2.4%	0.70	75%	5.1%	7.5%	10.9%	$40,944.0	-0.33%	10.6%
9	DTE Energy Co.	2.3%	10.8%	13.1%	3.4%	9.7%	25%	2.4%	0.75	75%	5.5%	7.9%	11.3%	$13,761.2	0.80%	12.1%
10	Duke Energy Corp.	2.3%	10.8%	13.1%	3.4%	9.7%	25%	2.4%	0.60	75%	4.4%	6.8%	10.2%	$52,332.1	-0.33%	9.9%
11	Empire District Elec	2.3%	10.8%	13.1%	3.4%	9.7%	25%	2.4%	0.65	75%	4.7%	7.2%	10.6%	$ 1,110.2	1.75%	12.3%
12	Entergy Corp.	2.3%	10.8%	13.1%	3.4%	9.7%	25%	2.4%	0.70	75%	5.1%	7.5%	10.9%	$13,800.5	0.80%	11.7%
13	Northeast Utilities	2.3%	10.8%	13.1%	3.4%	9.7%	25%	2.4%	0.75	75%	5.5%	7.9%	11.3%	$14,501.8	0.80%	12.1%
14	NorthWestern Corp.	2.3%	10.8%	13.1%	3.4%	9.7%	25%	2.4%	0.70	75%	5.1%	7.5%	10.9%	$ 1,892.0	1.75%	12.7%
15	PG&E Corp.	2.3%	10.8%	13.1%	3.4%	9.7%	25%	2.4%	0.65	75%	4.7%	7.2%	10.6%	$22,228.8	-0.33%	10.2%
16	Pub Sv Enterprise Grp	2.3%	10.8%	13.1%	3.4%	9.7%	25%	2.4%	0.75	75%	5.5%	7.9%	11.3%	$18,528.9	0.80%	12.1%
17	SCANA Corp.	2.3%	10.8%	13.1%	3.4%	9.7%	25%	2.4%	0.75	75%	5.5%	7.9%	11.3%	$ 7,325.4	0.93%	12.2%
18	Sempra Energy	2.3%	10.8%	13.1%	3.4%	9.7%	25%	2.4%	0.75	75%	5.5%	7.9%	11.3%	$26,070.0	-0.33%	11.0%
19	Vectren Corp.	2.3%	10.8%	13.1%	3.4%	9.7%	25%	2.4%	0.80	75%	5.8%	8.2%	11.6%	$ 3,400.7	1.72%	13.4%
20	Xcel Energy, Inc.	2.3%	10.8%	13.1%	3.4%	9.7%	25%	2.4%	0.65	75%	4.7%	7.2%	10.6%	$16,092.7	0.80%	11.4%
	Average												**11.1%**			**11.9%**
	Midpoint (h)												**11.1%**			**11.9%**

(a) Weighted average dividend yield for the dividend paying firms in the S&P 500 from www.valueline.com (Retreived Sep. 19, 2014).
(b) Weighted average of IBES earnings growth rates for the dividend paying firms in the S&P 500 from http://finance.yahoo.com (retrieved Sep. 22, 2014).
(c) Average yield on 30-year Treasury bonds for the six-months ending Sep. 2014 based on data from the http://www.federalreserve.gov/releases/h15/data.htm.
(d) Morin, Roger A., "New Regulatory Finance," *Public Utilities Reports, Inc.* at 190 (2006).
(e) The Value Line Investment Survey (Aug. 1, Aug. 22, & Sep. 19, 2014).
(f) www.valueline.com (retrieved Sep. 12, 2014).
(g) Morningstar, "2014 Ibbotson SBBI Market Report," at Table 10 (2014).
(h) Average of low and high values.

UTILITY GROUP

		(a)	(b)		(c)		(d)		(e)	(d)				(f)	(g)	
		Market Return (R_m)				Market										Size
		Div	Proj.	Cost of	Risk-Free	Risk	Unadjusted RP		Beta Adjusted RP			Total	Unadjusted	Market	Size	Adjusted
	Company	Yield	Growth	Equity	Rate	Premium	Weight	RP^1	Beta	Weight	RP^2	RP	K_e	Cap	Adjustment	K_e
1	Alliant Energy	2.3%	10.8%	13.1%	4.7%	8.4%	25%	2.1%	0.80	75%	5.0%	7.1%	11.8%	$ 6,487.5	0.93%	12.8%
2	Ameren Corp.	2.3%	10.8%	13.1%	4.7%	8.4%	25%	2.1%	0.75	75%	4.7%	6.8%	11.5%	$ 9,638.5	0.80%	12.3%
3	Avista Corp.	2.3%	10.8%	13.1%	4.7%	8.4%	25%	2.1%	0.75	75%	4.7%	6.8%	11.5%	$ 1,947.5	1.75%	13.3%
4	Black Hills Corp.	2.3%	10.8%	13.1%	4.7%	8.4%	25%	2.1%	0.85	75%	5.4%	7.5%	12.2%	$ 2,368.2	1.75%	13.9%
5	CenterPoint Energy	2.3%	10.8%	13.1%	4.7%	8.4%	25%	2.1%	0.75	75%	4.7%	6.8%	11.5%	$10,612.8	0.80%	12.3%
6	CMS Energy Corp.	2.3%	10.8%	13.1%	4.7%	8.4%	25%	2.1%	0.75	75%	4.7%	6.8%	11.5%	$ 8,340.8	0.93%	12.5%
7	Consolidated Edison	2.3%	10.8%	13.1%	4.7%	8.4%	25%	2.1%	0.60	75%	3.8%	5.9%	10.6%	$16,872.7	0.80%	11.4%
8	Dominion Resources	2.3%	10.8%	13.1%	4.7%	8.4%	25%	2.1%	0.70	75%	4.4%	6.5%	11.2%	$40,944.0	-0.33%	10.9%
9	DTE Energy Co.	2.3%	10.8%	13.1%	4.7%	8.4%	25%	2.1%	0.75	75%	4.7%	6.8%	11.5%	$13,761.2	0.80%	12.3%
10	Duke Energy Corp.	2.3%	10.8%	13.1%	4.7%	8.4%	25%	2.1%	0.60	75%	3.8%	5.9%	10.6%	$52,332.1	-0.33%	10.3%
11	Empire District Elec	2.3%	10.8%	13.1%	4.7%	8.4%	25%	2.1%	0.65	75%	4.1%	6.2%	10.9%	$ 1,110.2	1.75%	12.6%
12	Entergy Corp.	2.3%	10.8%	13.1%	4.7%	8.4%	25%	2.1%	0.70	75%	4.4%	6.5%	11.2%	$13,800.5	0.80%	12.0%
13	Northeast Utilities	2.3%	10.8%	13.1%	4.7%	8.4%	25%	2.1%	0.75	75%	4.7%	6.8%	11.5%	$14,501.8	0.80%	12.3%
14	NorthWestern Corp.	2.3%	10.8%	13.1%	4.7%	8.4%	25%	2.1%	0.70	75%	4.4%	6.5%	11.2%	$ 1,892.0	1.75%	13.0%
15	PG&E Corp.	2.3%	10.8%	13.1%	4.7%	8.4%	25%	2.1%	0.65	75%	4.1%	6.2%	10.9%	$22,228.8	-0.33%	10.6%
16	Pub Sv Enterprise Grp	2.3%	10.8%	13.1%	4.7%	8.4%	25%	2.1%	0.75	75%	4.7%	6.8%	11.5%	$18,528.9	0.80%	12.3%
17	SCANA Corp.	2.3%	10.8%	13.1%	4.7%	8.4%	25%	2.1%	0.75	75%	4.7%	6.8%	11.5%	$ 7,325.4	0.93%	12.5%
18	Sempra Energy	2.3%	10.8%	13.1%	4.7%	8.4%	25%	2.1%	0.75	75%	4.7%	6.8%	11.5%	$26,070.0	-0.33%	11.2%
19	Vectren Corp.	2.3%	10.8%	13.1%	4.7%	8.4%	25%	2.1%	0.80	75%	5.0%	7.1%	11.8%	$ 3,400.7	1.72%	13.6%
20	Xcel Energy, Inc.	2.3%	10.8%	13.1%	4.7%	8.4%	25%	2.1%	0.65	75%	4.1%	6.2%	10.9%	$16,092.7	0.80%	11.7%
	Average												**11.4%**			**12.2%**
	Midpoint (h)												**11.4%**			**12.1%**

(a) Weighted average dividend yield for the dividend paying firms in the S&P 500 from www.valueline.com (Retreived Sep. 19, 2014).

(b) Weighted average of IBES earnings growth rates for the dividend paying firms in the S&P 500 from http://finance.yahoo.com (retrieved Sep. 22, 2014).

(c) Average yield on 30-year Treasury bonds for 2015-2019 based on data from the Value Line Investment Survey, Forecast for the U.S. Economy (Aug. 22, 2014); IHS Global Insight, U.S. Economic Outlook at 79 (May 2014); & Blue Chip Financial Forecasts, Vol. 33, No. 6 (Jun. 1, 2014).

(d) Morin, Roger A., "New Regulatory Finance," *Public Utilities Reports, Inc.* at 190 (2006).

(e) The Value Line Investment Survey (Aug. 1, Aug. 22, & Sep. 19, 2014).

(f) www.valueline.com (retrieved Sep. 12, 2014).

(g) Morningstar, "2014 Ibbotson SBBI Market Report," at Table 10 (2014).

(h) Average of low and high values.

Exhibit No. 8

Risk Premium Method

ELECTRIC UTILITY RISK PREMIUM

CURRENT BOND YIELD

Current Equity Risk Premium

(a)	Avg. Yield over Study Period	8.69%
(b)	Average Utility Bond Yield	4.39%
	Change in Bond Yield	-4.30%
(c)	Risk Premium/Interest Rate Relationship	-0.4246
	Adjustment to Average Risk Premium	1.83%
(a)	Average Risk Premium over Study Period	3.53%
	Adjusted Risk Premium	**5.36%**

Implied Cost of Equity

(b)	BBB Utility Bond Yield	4.73%
	Adjusted Equity Risk Premium	5.36%
	Risk Premium Cost of Equity	**10.09%**

(a) Exhibit No. 8, page 3.
(b) Average bond yield for six-months ending Sep. 2014 based on data from Moody's Investors Service at www.credittrends.com.
(c) Exhibit No. 8, page 4.

2015-2019 BOND YIELD

Current Equity Risk Premium

(a)	Avg. Yield over Study Period	8.69%
(b)	Average Utility Bond Yield 2015-2019	6.41%
	Change in Bond Yield	-2.28%
(c)	Risk Premium/Interest Rate Relationship	-0.4246
	Adjustment to Average Risk Premium	0.97%
(a)	Average Risk Premium over Study Period	3.53%
	Adjusted Risk Premium	**4.50%**

Implied Cost of Equity

(b)	BBB Utility Bond Yield 2015-2019	6.75%
	Adjusted Equity Risk Premium	4.50%
	Risk Premium Cost of Equity	**11.25%**

(a) Exhibit No. 8, page 3.
(b) Based on data from IHS Global Insight, U.S. Economic Outlook at 79 (May 2014); Energy Information Administration, Annual Energy Outlook 2014 (May 7, 2014); & Moody's Investors Service at www.credittrends.com.
(c) Exhibit No. 8, 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	10.29%	5.13%	5.16%
2012	10.17%	4.26%	5.91%
2013	10.02%	4.55%	5.47%
Average	12.21%	8.69%	3.53%

(a) Major Rate Case Decisions, Regulatory Focus, Regulatory Research Associates; *UtilityScope Regulatory Service* , Argus.

(b) Moody's Investors Service.

ELECTRIC UTILITY RISK PREMIUM

REGRESSION RESULTS

SUMMARY OUTPUT

Regression Statistics	
Multiple R	0.9186517
R Square	0.8439209
Adjusted R Square	0.8398135
Standard Error	0.0051378
Observations	40

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	0.005423795	0.005424	205.4662	6.5706E-17
Residual	38	0.001003105	2.64E-05		
Total	39	0.0064269			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
Intercept	0.0721319	0.002698047	26.73484	3.02E-26	0.06666996	0.07759379	0.066669963	0.077593786
X Variable 1	-0.4245597	0.02961887	-14.3341	6.57E-17	-0.48451992	-0.36459938	-0.48451992	-0.36459938

Exhibit No. 9

Capital Asset Pricing Model

CAPM - CURRENT BOND YIELD **Exhibit No. 9**

UTILITY GROUP

		(a)	(b)		(c)		(d)		(e)	(f)	
		Market Return (R_m)									Size
		Div	Proj.	Cost of	Risk-Free	Risk		Unadjusted	Market	Size	Adjusted
	Company	Yield	Growth	Equity	Rate	Premium	Beta	K_e	Cap	Adjustment	K_e
1	Alliant Energy	2.3%	10.8%	13.1%	3.4%	9.7%	0.80	11.2%	$ 6,487.5	0.93%	12.1%
2	Ameren Corp.	2.3%	10.8%	13.1%	3.4%	9.7%	0.75	10.7%	$ 9,638.5	0.80%	11.5%
3	Avista Corp.	2.3%	10.8%	13.1%	3.4%	9.7%	0.75	10.7%	$ 1,947.5	1.75%	12.4%
4	Black Hills Corp.	2.3%	10.8%	13.1%	3.4%	9.7%	0.85	11.6%	$ 2,368.2	1.75%	13.4%
5	CenterPoint Energy	2.3%	10.8%	13.1%	3.4%	9.7%	0.75	10.7%	$ 10,612.8	0.80%	11.5%
6	CMS Energy Corp.	2.3%	10.8%	13.1%	3.4%	9.7%	0.75	10.7%	$ 8,340.8	0.93%	11.6%
7	Consolidated Edison	2.3%	10.8%	13.1%	3.4%	9.7%	0.60	9.2%	$ 16,872.7	0.80%	10.0%
8	Dominion Resources	2.3%	10.8%	13.1%	3.4%	9.7%	0.70	10.2%	$ 40,944.0	-0.33%	9.9%
9	DTE Energy Co.	2.3%	10.8%	13.1%	3.4%	9.7%	0.75	10.7%	$ 13,761.2	0.80%	11.5%
10	Duke Energy Corp.	2.3%	10.8%	13.1%	3.4%	9.7%	0.60	9.2%	$ 52,332.1	-0.33%	8.9%
11	Empire District Elec	2.3%	10.8%	13.1%	3.4%	9.7%	0.65	9.7%	$ 1,110.2	1.75%	11.5%
12	Entergy Corp.	2.3%	10.8%	13.1%	3.4%	9.7%	0.70	10.2%	$ 13,800.5	0.80%	11.0%
13	Northeast Utilities	2.3%	10.8%	13.1%	3.4%	9.7%	0.75	10.7%	$ 14,501.8	0.80%	11.5%
14	NorthWestern Corp.	2.3%	10.8%	13.1%	3.4%	9.7%	0.70	10.2%	$ 1,892.0	1.75%	11.9%
15	PG&E Corp.	2.3%	10.8%	13.1%	3.4%	9.7%	0.65	9.7%	$ 22,228.8	-0.33%	9.4%
16	Pub Sv Enterprise Grp	2.3%	10.8%	13.1%	3.4%	9.7%	0.75	10.7%	$ 18,528.9	0.80%	11.5%
17	SCANA Corp.	2.3%	10.8%	13.1%	3.4%	9.7%	0.75	10.7%	$ 7,325.4	0.93%	11.6%
18	Sempra Energy	2.3%	10.8%	13.1%	3.4%	9.7%	0.75	10.7%	$ 26,070.0	-0.33%	10.3%
19	Vectren Corp.	2.3%	10.8%	13.1%	3.4%	9.7%	0.80	11.2%	$ 3,400.7	1.72%	12.9%
20	Xcel Energy, Inc.	2.3%	10.8%	13.1%	3.4%	9.7%	0.65	9.7%	$ 16,092.7	0.80%	10.5%
	Average							**10.4%**			**11.2%**
	Midpoint (g)							**10.4%**			**11.2%**

(a) Weighted average dividend yield for the dividend paying firms in the S&P 500 from www.valueline.com (Retreived Sep. 19, 2014).
(b) Weighted average of IBES earnings growth rates for the dividend paying firms in the S&P 500 from http://finance.yahoo.com (retrieved Sep. 22, 2014).
(c) Average yield on 30-year Treasury bonds for the six-months ending Sep. 2014 based on data from the
(d) The Value Line Investment Survey (Aug. 1, Aug. 22, & Sep. 19, 2014).
(e) www.valueline.com (retrieved Sep. 12, 2014).
(f) Morningstar, "2014 Ibbotson SBBI Market Report," at Table 10 (2014).
(g) Average of low and high values.

UTILITY GROUP

	Company	(a) Market Return (R_m) Div Yield	(b) Proj. Growth	Cost of Equity	(c) Risk-Free Rate	Risk Premium	(d) Beta	Unadjusted K_e	(e) Market Cap	(f) Size Adjustment	Size Adjusted K_e
1	Alliant Energy	2.3%	10.8%	13.1%	4.7%	8.4%	0.80	11.4%	$ 6,487.5	0.93%	12.4%
2	Ameren Corp.	2.3%	10.8%	13.1%	4.7%	8.4%	0.75	11.0%	$ 9,638.5	0.80%	11.8%
3	Avista Corp.	2.3%	10.8%	13.1%	4.7%	8.4%	0.75	11.0%	$ 1,947.5	1.75%	12.8%
4	Black Hills Corp.	2.3%	10.8%	13.1%	4.7%	8.4%	0.85	11.8%	$ 2,368.2	1.75%	13.6%
5	CenterPoint Energy	2.3%	10.8%	13.1%	4.7%	8.4%	0.75	11.0%	$10,612.8	0.80%	11.8%
6	CMS Energy Corp.	2.3%	10.8%	13.1%	4.7%	8.4%	0.75	11.0%	$ 8,340.8	0.93%	11.9%
7	Consolidated Edison	2.3%	10.8%	13.1%	4.7%	8.4%	0.60	9.7%	$16,872.7	0.80%	10.5%
8	Dominion Resources	2.3%	10.8%	13.1%	4.7%	8.4%	0.70	10.6%	$40,944.0	-0.33%	10.3%
9	DTE Energy Co.	2.3%	10.8%	13.1%	4.7%	8.4%	0.75	11.0%	$13,761.2	0.80%	11.8%
10	Duke Energy Corp.	2.3%	10.8%	13.1%	4.7%	8.4%	0.60	9.7%	$52,332.1	-0.33%	9.4%
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12	Entergy Corp.	2.3%	10.8%	13.1%	4.7%	8.4%	0.70	10.6%	$13,800.5	0.80%	11.4%
13	Northeast Utilities	2.3%	10.8%	13.1%	4.7%	8.4%	0.75	11.0%	$14,501.8	0.80%	11.8%
14	NorthWestern Corp.	2.3%	10.8%	13.1%	4.7%	8.4%	0.70	10.6%	$ 1,892.0	1.75%	12.3%
15	PG&E Corp.	2.3%	10.8%	13.1%	4.7%	8.4%	0.65	10.2%	$22,228.8	-0.33%	9.8%
16	Pub Sv Enterprise Grp	2.3%	10.8%	13.1%	4.7%	8.4%	0.75	11.0%	$18,528.9	0.80%	11.8%
17	SCANA Corp.	2.3%	10.8%	13.1%	4.7%	8.4%	0.75	11.0%	$ 7,325.4	0.93%	11.9%
18	Sempra Energy	2.3%	10.8%	13.1%	4.7%	8.4%	0.75	11.0%	$26,070.0	-0.33%	10.7%
19	Vectren Corp.	2.3%	10.8%	13.1%	4.7%	8.4%	0.80	11.4%	$ 3,400.7	1.72%	13.1%
20	Xcel Energy, Inc.	2.3%	10.8%	13.1%	4.7%	8.4%	0.65	10.2%	$16,092.7	0.80%	11.0%
	Average							**10.8%**			**11.6%**
	Midpoint (g)							**10.8%**			**11.5%**

(a) Weighted average dividend yield for the dividend paying firms in the S&P 500 from www.valueline.com (Retreived Sep. 19, 2014).
(b) Weighted average of IBES earnings growth rates for the dividend paying firms in the S&P 500 from http://finance.yahoo.com (retrieved Sep. 22, 2014).
(c) Average yield on 30-year Treasury bonds for 2015-2019 based on data from the Value Line Investment Survey, Forecast for the U.S. Economy (Aug. 22, 2014); IHS Global Insight, U.S. Economic Outlook at 79 (May 2014); & Blue Chip Financial Forecasts, Vol. 33, No. 6 (Jun. 1, 2014).
(d) The Value Line Investment Survey (Aug. 1, Aug. 22, & Sep. 19, 2014).
(e) www.valueline.com (retrieved Sep. 12, 2014).
(f) Morningstar, "2014 Ibbotson SBBI Market Report," at Table 10 (2014).
(g) Average of low and high values.

Exhibit No. 10

Expected Earnings Approach

EXPECTED EARNINGS APPROACH **Exhibit No. 10**

UTILITY GROUP

	Company	(a) Expected Return on Common Equity	(b) Adjustment Factor	(c) Adjusted Return on Common Equity
1	Alliant Energy	12.0%	1.0202	12.2%
2	Ameren Corp.	9.5%	1.0210	9.7%
3	Avista Corp.	8.5%	1.0219	8.7%
4	Black Hills Corp.	9.0%	1.0218	9.2%
5	CenterPoint Energy	14.5%	1.0117	14.7%
6	CMS Energy Corp.	13.5%	1.0338	14.0%
7	Consolidated Edison	9.0%	1.0160	9.1%
8	Dominion Resources	14.0%	1.0427	14.6%
9	DTE Energy Co.	10.0%	1.0296	10.3%
10	Duke Energy Corp.	8.0%	1.0115	8.1%
11	Empire District Elec	9.0%	1.0237	9.2%
12	Entergy Corp.	10.0%	1.0220	10.2%
13	Northeast Utilities	9.5%	1.0193	9.7%
14	NorthWestern Corp.	9.5%	1.0205	9.7%
15	PG&E Corp.	8.5%	1.0242	8.7%
16	Pub Sv Enterprise Grp	10.5%	1.0237	10.7%
17	SCANA Corp.	10.0%	1.0380	10.4%
18	Sempra Energy	11.5%	1.0242	11.8%
19	Vectren Corp.	14.0%	1.0177	14.2%
20	Xcel Energy, Inc.	10.5%	1.0305	10.8%
	Average (d)			**10.8%**
	Midpoint (e)			**11.4%**

(a) The Value Line Investment Survey (Aug. 1, Aug. 22, & Sep. 19, 2014).

(b) Adjustment to convert year-end return to an average rate of return from Exhibit No. 6.

(c) (a) x (b).

(d) Excludes highlighted figures.

(e) Average of low and high values.

Exhibit No. 11

DCF Model – Non-Utility Group

DIVIDEND YIELD

	Company	(a) Price	(b) Dividends	Yield
1	Church & Dwight	$ 69.07	$ 1.24	1.8%
2	Coca-Cola	$ 41.05	$ 1.50	3.7%
3	Colgate-Palmolive	$ 67.72	$ 1.47	2.2%
4	ConAgra Foods	$ 31.31	$ 1.00	3.2%
5	Gen'l Mills	$ 54.22	$ 1.64	3.0%
6	Hormel Foods	$ 48.69	$ 0.84	1.7%
7	Johnson & Johnson	$ 102.64	$ 2.80	2.7%
8	Kellogg	$ 67.51	$ 1.86	2.8%
9	Kimberly-Clark	$ 111.19	$ 3.36	3.0%
10	McCormick & Co.	$ 71.75	$ 1.54	2.1%
11	McDonald's Corp.	$ 101.63	$ 3.24	3.2%
12	PepsiCo, Inc.	$ 87.62	$ 2.62	3.0%
13	Procter & Gamble	$ 79.94	$ 2.58	3.2%
14	Smucker (J.M.)	$ 103.48	$ 2.38	2.3%
15	Verizon Communic.	$ 49.40	$ 2.12	4.3%
16	Wal-Mart Stores	$ 76.03	$ 1.92	2.5%
	Average			**2.8%**

(a) Average of closing prices for 30 trading days ended Jun. 27, 2014.
(b) The Value Line Investment Survey, Summary & Index (Jun. 27, 2014).

GROWTH RATES

		(a)	(b)	(c)	(d)
		Earnings Growth Rates			
	Company	V Line	IBES	Zacks	Reuters
1	Church & Dwight	9.5%	10.0%	9.9%	10.0%
2	Coca-Cola	6.5%	6.7%	7.2%	6.7%
3	Colgate-Palmolive	10.5%	8.9%	8.9%	8.9%
4	ConAgra Foods	10.0%	6.5%	7.0%	6.5%
5	Gen'l Mills	6.5%	6.9%	7.7%	6.9%
6	Hormel Foods	11.0%	11.0%	8.0%	NA
7	Johnson & Johnson	6.5%	7.0%	6.6%	7.0%
8	Kellogg	6.5%	6.0%	6.7%	6.0%
9	Kimberly-Clark	9.0%	6.9%	7.3%	6.9%
10	McCormick & Co.	7.5%	7.6%	7.5%	7.6%
11	McDonald's Corp.	7.0%	7.6%	8.6%	7.6%
12	PepsiCo, Inc.	8.5%	7.2%	7.9%	7.2%
13	Procter & Gamble	7.5%	8.4%	8.6%	8.7%
14	Smucker (J.M.)	7.5%	7.3%	7.8%	7.3%
15	Verizon Communic.	10.5%	6.1%	8.0%	6.1%
16	Wal-Mart Stores	7.5%	8.1%	8.7%	8.1%

(a) www.valueline.com (retrieved Jul. 9, 2014).
(b) www.finance.yahoo.com (retreived Jul. 9, 2014).
(c) www.zacks.com (Retreived Jul. 9, 2014).
(d) www.reuters.com (retreived Jul. 9, 2014).

DCF MODEL - NON-UTILITY GROUP **Exhibit No. 11**

Page 3 of 3

DCF COST OF EQUITY ESTIMATES

			(a)	(a)	(a)	(a)
			Cost of Equity Estimates			
	Company	**Industry Group**	**V Line**	**IBES**	**Zacks**	**Reuters**
1	Church & Dwight	Household Products	11.3%	11.8%	11.7%	11.8%
2	Coca-Cola	Beverage	10.2%	10.4%	10.9%	10.4%
3	Colgate-Palmolive	Household Products	12.7%	11.1%	11.1%	11.1%
4	ConAgra Foods	Food Processing	13.2%	9.7%	10.2%	9.7%
5	Gen'l Mills	Food Processing	9.5%	9.9%	10.7%	9.9%
6	Hormel Foods	Food Processing	12.7%	12.7%	9.7%	NA
7	Johnson & Johnson	Medical Supply	9.2%	9.8%	9.3%	9.8%
8	Kellogg	Food Processing	9.3%	8.8%	9.4%	8.8%
9	Kimberly-Clark	Household Products	12.0%	9.9%	10.3%	9.9%
10	McCormick & Co.	Food Processing	9.6%	9.8%	9.7%	9.8%
11	McDonald's Corp.	Restaurant	10.2%	10.8%	11.8%	10.8%
12	PepsiCo, Inc.	Beverage	11.5%	10.2%	10.9%	10.2%
13	Procter & Gamble	Household Products	10.7%	11.6%	11.8%	11.9%
14	Smucker (J.M.)	Food Processing	9.8%	9.6%	10.1%	9.6%
15	Verizon Communic.	Telecommunications	14.8%	10.4%	12.3%	10.4%
16	Wal-Mart Stores	Retail Store	10.0%	10.6%	11.2%	10.6%
	Average		**11.0%**	**10.4%**	**10.7%**	**10.3%**
	Midpoint (b)		**12.0%**	**10.8%**	**10.8%**	**10.4%**

(a) Sum of dividend yield (Exhibit No. 11, p. 1) and respective growth rate (Exhibit No. 11, p. 2).

(b) Average of low and high values.

COMMONWEALTH OF KENTUCKY

BEFORE THE

PUBLIC SERVICE COMMISSION

In the Matter of:

APPLICATION OF KENTUCKY	**)**	
UTILITIES COMPANY FOR AN	**)**	**CASE NO. 2014-00371**
ADJUSTMENT OF ITS ELECTRIC	**)**	
RATES	**)**	

DIRECT TESTIMONY OF

JOHN J. SPANOS

ON BEHALF OF

KENTUCKY UTILITIES COMPANY

Filed: November 26, 2014

TABLE OF CONTENTS

I. INTRODUCTION AND PURPOSE

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. John J. Spanos, 207 Senate Avenue, Camp Hill, Pennsylvania, 17011.

Q. On whose behalf are you testifying?

A. I am testifying on behalf of Kentucky Utilities Company ("KU").

Q. PLEASE STATE YOUR EDUCATIONAL BACKGROUND AND DESCRIBE YOUR PROFESSIONAL TRAINING AND EXPERIENCE.

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 of Pennsylvania.

Q. BY WHOM AND IN WHAT CAPACITY HAVE YOU BEEN EMPLOYED?

A. I am employed by Gannett Fleming Valuation and Rate Consultants, LLC (Gannett Fleming) as Senior Vice President, which provides depreciation consulting services to utility companies in the United States and Canada. I am responsible for conducting depreciation, valuation and original cost studies, determining service life and salvage estimates, conducting field reviews, presenting recommended depreciation rates to clients, and supporting such rates before state and federal regulatory agencies. I have been associated with the firm since college graduation in 1986.

Q. DO YOU BELONG TO ANY PROFESSIONAL SOCIETIES?

A. Yes. I am a past President and member of the Society of Depreciation Professionals. I am also a member of 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, February 2008 and January 2013. Recertification involves extensive hours and various tasks in the field of depreciation each year.

Q. CAN YOU OUTLINE YOUR EXPERIENCE IN THE FIELD OF DEPRECIATION?

A. Yes. I have 28 years of depreciation experience which includes giving expert testimony in over 190 cases before 40 regulatory commissions, including this Commission. Please refer to Appendix A for my qualifications. I have also conducted more than 300 additional depreciation assignments which did not require testimony.

Q. HAVE YOU RECEIVED 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 projected depreciation rates for the new Cane Run Unit 7 facility for KU attached hereto as Exhibit JJS-1.

Q. WAS THE DEPRECIATION EXHIBIT FILED BY LG&E PREPARED BY YOU OR UNDER YOUR DIRECTION AND CONTROL?

A. Yes.

II. DEPRECIATION METHODOLOGY

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 RATES FOR CANE RUN UNIT 7 FILED BY KU IN THIS PROCEEDING?

A. Yes. I prepared the depreciation rates for the soon to be completed Cane Run Unit 7 facility submitted by Kentucky Utilities Company with its filing in this proceeding. My exhibit is entitled: "Calculated Annual Depreciation Accruals Related to Electric Plant as of April 30, 2015." This exhibit sets forth the results of my depreciation calculation for KU.

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

A. Yes.

Q. DID YOU CONDUCT THE 2011 DEPRECIATION STUDY FOR KU?

A. Yes. The study was filed in June 2012.

Q. ARE THE METHODS AND PROCEDURES OF THESE DEPRECIATION RATES CONSISTENT WITH PAST PRACTICES?

A. The methods and procedures of this calculation are the same as those utilized in past studies of KU. Depreciation rates by account 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 Exhibit JJS-1. The report sets forth a summary of the depreciation calculations and the detailed depreciation calculations by account.

The summary table on page 2 presents the estimated survivor curve, the net salvage percent, the projected original cost as of April 30, 2015, the book depreciation reserve and the calculated annual depreciation accrual and rate for each account or subaccount for KU based on the percentage of ownership. The pages beginning on page 3 present the depreciation calculations related to projected original cost as of April 30, 2015 for each account.

Q. PLEASE EXPLAIN HOW YOU PERFORMED YOUR DEPRECIATION CALCULATIONS.

A. I used the straight line remaining life method of depreciation, with the average service life procedure, which is the most commonly used depreciation procedure. 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 remaining life of the vintage. The average remaining life is a directly-weighted average derived from the estimated future survivor curve in accordance 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.

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. Additionally, I determined the most appropriate life span date for the facility. 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 IN DETERMINING DEPRECIATION RATES, IN WHICH YOU ESTIMATED THE SERVICE LIFE AND NET SALVAGE CHARACTERISTICS FOR EACH DEPRECIABLE GROUP.

A. The service life and net salvage characteristics consisted of reviewing historical data from records related to both KU's and LG&E's other production plant; obtaining supplementary information from management and operating personnel concerning practices and plans as they relate to plant operations for the Cane Run Unit 7; and interpreting the above data and the estimates used by other electric utilities to form judgments of average service life and net salvage characteristics for this type of facility.

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

A. I reviewed the accounting entries that were part of the 2011 Depreciation Studies for the pertinent asset classes for both KU and LG&E.

Q. WHAT METHOD WAS USED TO ANALYZE SERVICE LIFE DATA IN THE 2011 DEPRECIATION STUDIES?

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 each Company during the period of time covered by the depreciation studies.

Q. PLEASE DESCRIBE HOW YOU USED THE RETIREMENT RATE METHOD TO ANALYZE BOTH KU'S AND LG&E'S SERVICE LIFE DATA.

A. I applied the retirement rate analysis to each different group of property for the data available through December 31, 2011. 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 truncated Iowa curves were used in this calculation 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 30-R2 indicates an average service life of thirty 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 SUCH AS CANE RUN UNIT 7?

A. I used the life span technique to estimate the lives of facilities at Cane Run Unit 7 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 an estimated probable retirement date.

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 KU for all other generation facilities in the same manner recommended in this case.

Q. WHAT IS THE BASIS FOR THE PROBABLE RETIREMENT YEAR THAT YOU HAVE ESTIMATED FOR CANE RUN UNIT 7?

A. The basis for the probable retirement year is the life span for Cane Run Unit 7 that is based on informed judgment which includes objective information, the outlook of Company management and incorporating consideration of the age, use, size, nature of construction, and typical life spans experienced and used by other electric utilities for similar facilities. The life span results in a probable retirement year that is many years in the future. As a result, the retirement of this facility is 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. PLEASE DESCRIBE HOW YOU ESTIMATED NET SALVAGE PERCENTAGES.

A. I estimated the net salvage percentages by reviewing the historical data for the period 2004 through 2011 for both KU and LG&E. I also considered estimates for other electric companies for similar facilities.

Q. DID YOU INCLUDE A NET SALVAGE COMPONENT FOR DISMANTLEMENT IN THE DEPRECIATION CALCULATIONS?

A. No. Although it is important to establish the full service value of the facility at the early stages, including an amount at this time is premature. There is analysis of the facility and site that needs to be performed before an adequate estimate of dismantlement costs assigned for recovery. Once the study is completed, the dismantlement component will be included in future depreciation rates.

Q. PLEASE DESCRIBE THE SECOND PHASE OF THE PROCESS THAT YOU USED IN THE DEPRECIATION CALCULATION 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 USE AN EXAMPLE TO ILLUSTRATE HOW THE ANNUAL DEPRECIATION ACCRUAL RATE FOR A PARTICULAR GROUP OF PROPERTY IS PRESENTED IN YOUR EXHIBIT.

A. I will use Account 344, Generators, as an example because it is projected to be the largest depreciable account at Cane Run Unit 7.

Based on the estimates of other electric companies, including the related assets for KU and LG&E, and discussions with Company personnel, a 50-R1.5 interim survivor curve was selected for Account 344.00, Generators. This estimate took into account anticipated overhauls, inspections and the expected wear and tear of the assets. The life span was determined to be 40 years or April 2055 from the projected initial date in service.

The interim net salvage percent was determined to be negative 10 percent. This reflects the estimated cost to remove, and scrap value of the assets that are replaced during the life of the generator property.

My calculation of the annual depreciation related to the projected original cost as of April 30, 2015, of utility plant is presented on page 6 of Exhibit JJS-1. The calculation is based on the 50-R1.5 survivor curve, 10% negative net salvage, April 2055 retirement date, 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 2.

III. CONCLUSION

Q. WHAT IS YOUR RECOMMENDATION WITH REGARDS TO CANE RUN UNIT 7?

A. The Commission should approve the depreciation rates by account set forth in Exhibit JJS-1 for Cane Run Unit 7 when the facility goes on-line in 2015.

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, Gannett Fleming Valuation and Rate Consultants, LLC, that he has personal knowledge of the matters set forth in the foregoing testimony and exhibits, and the answers contained therein are true and correct to the best of his information, knowledge and belief.

John J. Spanos

JOHN J. SPANOS

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 6th day of November 2014.

_______________ (SEAL)

Notary Public

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

My Commission Expires:

February 20, 2015

APPENDIX A

JOHN SPANOS

DEPRECIATION EXPERIENCE

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. (now doing business as Gannett Fleming Valuation and Rate Consultants, LLC). 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; Central

Maine Power; PEPCO; PacifiCorp; Minnesota Energy Resource Group; Jersey Central Power & Light Company; Cheyenne Light, Fuel and Power Company; Central Vermont Public Service Corporation; Green Mountain Power; Portland General Electric Company; Atlantic City Electric; Nicor Gas Company; Black Hills Power; Black Hills Colorado Gas; Public Service Company of Oklahoma; Peoples Gas Light and Coke Company; North Shore Gas Company; Connecticut Light and Power; Yankee Gas Service; 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; Railroad Commission of Texas – Gas Services Division; the New York Public Service Commission; 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; Maryland Public Service Commission; Washington Utilities and Transportation Commission; The

Tennessee Regulatory Commission; the Regulatory Commission of Alaska; Minnesota Public Utility Commission; Utah Public Service Commission; District of Columbia Public Service Commission; the Mississippi Public Service Commission; Delaware Public Service Commission; Virginia State Corporation Commission; Colorado Public Utility Commission; Oregon Public Utility Commission; South Dakota Public Utilities Commission Wisconsin Public Service Commission; Wyoming Public Service Commission; Maine Public Utility Commission; Iowa Utility Board; Connecticut Public Utilities Regulatory Authority; and the North Carolina Utilities Commission.

LIST OF CASES IN WHICH JOHN J. SPANOS SUBMITTED TESTIMONY

	Year	Jurisdiction	Docket No.	Client/Utility	Subject
01.	1998	PA PUC	R-00984375	City of Bethlehem – Bureau of Water	Original Cost and Depreciation
02.	1998	PA PUC	R-00984567	City of Lancaster	Original Cost and Depreciation
03.	1999	PA PUC	R-00994605	The York Water Company	Depreciation
04.	2000	D.T.&E.	DTE 00-105	Massachusetts-American Water Company	Depreciation
05.	2001	PA PUC	R-00016114	City of Lancaster	Original Cost and Depreciation
06.	2001	PA PUC	R-00017236	The York Water Company	Depreciation
07.	2001	PA PUC	R-00016339	Pennsylvania-American Water Company	Depreciation
08.	2001	OH PUC	01-1228-GA-AIR	Cinergy Corp – Cincinnati Gas & Elect Co.	Depreciation
09.	2001	KY PSC	2001-092	Cinergy Corp – Union Light, Heat & Power Co.	Depreciation
10.	2002	PA PUC	R-00016750	Philadelphia Suburban Water Company	Depreciation
11.	2002	KY PSC	2002-00145	Columbia Gas of Kentucky	Depreciation
12.	2002	NJ BPU	GF02040245	NUI Corporation/Elizabethtown Gas Co.	Depreciation
13.	2002	ID PUC	IPC-E-03-7	Idaho Power Company	Depreciation
14.	2003	PA PUC	R-0027975	The York Water Company	Depreciation
15.	2003	IN URC	R-0027975	Cinergy Corp – PSI Energy, Inc.	Depreciation
16.	2003	PA PUC	R-00038304	Pennsylvania-American Water Co.	Depreciation
17.	2003	MO PSC	WR-2003-0500	Missouri-American Water Co.	Depreciation
18.	2003	FERC	ER-03-1274-000	NSTAR-Boston Edison Company	Depreciation
19.	2003	NJ BPU	BPU 03080683	South Jersey Gas Company	Depreciation
20.	2003	NV PUC	03-10001	Nevada Power Company	Depreciation
21.	2003	LA PSC	U-27676	CenterPoint Energy – Arkla	Depreciation
22.	2003	PA PUC	R-00038805	Pennsylvania Suburban Water Company	Depreciation
23.	2004	AB En/Util Bd	1306821	EPCOR Distribution, Inc.	Depreciation
24.	2004	PA PUC	R-00038168	National Fuel Gas Distribution Corp (PA)	Depreciation
25.	2004	PA PUC	R-00049255	PPL Electric Utilities	Depreciation
26.	2004	PA PUC	R-00049165	The York Water Company	Depreciation
27.	2004	OK Corp Cm	PUC 200400187	CenterPoint Energy – Arkla	Depreciation
28.	2004	OH PUC	04-680-El-AIR	Cinergy Corp. – Cincinnati Gas and Electric Company	Depreciation
29.	2004	RR Com of TX	GUD#	CenterPoint Energy – Entex Gas Services Div.	Depreciation
30.	2004	NY PUC	04-G-1047	National Fuel Gas Distribution Gas (NY)	Depreciation
31.	2004	AR PSC	04-121-U	CenterPoint Energy – Arkla	Depreciation
32.	2005	IL CC	05-	North Shore Gas Company	Depreciation
33.	2005	IL CC	05-	Peoples Gas Light and Coke Company	Depreciation
34.	2005	KY PSC	2005-00042	Union Light Heat & Power	Depreciation
35.	2005	IL CC	05-0308	MidAmerican Energy Company	Depreciation

	Year	Jurisdiction	Docket No.	Client/Utility	Subject
36.	2005	MO PSC	GF-2005	Laclede Gas Company	Depreciation
37.	2005	KS CC	05-WSEE-981-RTS	Westar Energy	Depreciation
38.	2005	RR Com of TX	GUD #	CenterPoint Energy – Entex Gas Services Div.	Depreciation
39.	2005	FERC		Cinergy Corporation	Accounting
40.	2005	OK CC	PUD 200500151	Oklahoma Gas and Electric Co.	Depreciation
41.	2005	MA Dept Tele- com & Ergy	DTE 05-85	NSTAR	Depreciation
42.	2005	NY PUC	05-E-934/05-G-0935	Central Hudson Gas & Electric Co.	Depreciation
43.	2005	AK Reg Com	U-04-102	Chugach Electric Association	Depreciation
44.	2005	CA PUC	A05-12-002	Pacific Gas & Electric	Depreciation
45.	2006	PA PUC	R-00051030	Aqua Pennsylvania, Inc.	Depreciation
46.	2006	PA PUC	R-00051178	T.W. Phillips Gas and Oil Co.	Depreciation
47.	2006	NC Util Cm.		Pub. Service Co. of North Carolina	Depreciation
48.	2006	PA PUC	R-00051167	City of Lancaster	Depreciation
49.	2006	PA PUC		Duquesne Light Company	Depreciation
50.	2006	PA PUC	R-00061322	The York Water Company	Depreciation
51.	2006	PA PUC	R-00051298	PPL GAS Utilities	Depreciation
52.	2006	PUC of TX	32093	CenterPoint Energy – Houston Electric	Depreciation
53.	2006	SC PSC		Duke Energy Kentucky SCANA	Depreciation
54.	2006	AK Reg Com	U-06-6	Municipal Light and Power	Depreciation
55.	2006	DE PSC		Delmarva Power and Light	Depreciation
56.	2006	IN URC	IURC43081	Indiana American Water Company	Depreciation
57.	2006	AK Reg Com	U-06-134	Chugach Electric Association	Depreciation
58.	2006	MO PSC	WR-2007-0216	Missouri American Water Company	Depreciation
59.	2006	FERC	Iso5-82, ETC. AL	TransAlaska Pipeline	Depreciation
60.	2006	PA PUC	R-00061493	National Fuel Gas Distribution Corp. (PA)	Depreciation
61.	2007	NC Util Com.	E-7	Duke Energy Carolinas, LLC	Depreciation
62.	2007	OH PSC	08-709-EL-AIR	Duke Energy Ohio Gas	Depreciation
63.	2007	PA PUC	R-00072155	PPL Electric Utilities Corporation	Depreciation
64.	2007	KY PSC	2007-00143	Kentucky American Water Company	Depreciation
65.	2007	PA PUC	R-00072229	Pennsylvania American Water Company	Depreciation
66.	2007	KY PSC	2007-0008	NiSource – Columbia Gas of Kentucky	Depreciation
67.	2007	NY PSC	07-G-0141	National Fuel Gas Distribution Corp (NY)	Depreciation
68.	2008	AK PSC	U-08-004	Anchorage Water & Wastewater Utility	Depreciation

LIST OF CASES IN WHICH JOHN J. SPANOS SUBMITTED TESTIMONY, cont.

	Year	Jurisdiction	Docket No.	Client/Utility	Subject
69.	2008	TN Reg Auth	08-00039	Tennessee-American Water Company	Depreciation
70.	2008	DE PSC	08-96	Artesian Water Company	Depreciation
71.	2008	PA PUC	R-2008-2023067	The York Water Company	Depreciation
72.	2008	KS CC	08-WSEE1-RTS	Westar Energy	Depreciation
73.	2008	IN URC	43526	Northern Indiana Public Service Co.	Depreciation
74.	2008	IN URC	43501	Duke Energy Indiana	Depreciation
75.	2008	MD PSC	9159	NiSource – Columbia Gas of Maryland	Depreciation
76.	2008	KY PSC	2008-000251	Kentucky Utilities	Depreciation
77.	2008	KY PSC	2008-000252	Louisville Gas & Electric	Depreciation
78.	2008	PA PUC	2008-20322689	Pennsylvania American Water Co.	Depreciation
79.	2008	NY PSC	08-E887/08-00888	Central Hudson	Depreciation
80.	2008	WV TC	VE-080416/VG-080417	Avista Corporation	Depreciation
81.	2008	IL CC	09-	Peoples Gas, Light and Coke Co.	Depreciation
82.	2009	IL CC	09-	North Shore Gas Company	Depreciation
83.	2009	DC PSC	1076	Potomac Electric Power Company	Depreciation
84.	2009	KY PSC	2009-00141	NiSource – Columbia Gas of Kentucky	Depreciation
85.	2009	FERC	ER08-1056-002	Entergy Services	Depreciation
86.	2009	PA PUC	R-2009-2097323	Pennsylvania American Water Co.	Depreciation
87.	2009	NC Util Cm	E-7, Sub 090	Duke Energy Carolinas, LLC	Depreciation
88.	2009	KY PSC	2009-00202	Duke Energy Kentucky	Depreciation
89.	2009	VA St. CC	PUE-2009-00059	Aqua Virginia, Inc.	Depreciation
90.	2009	PA PUC	2009-2132019	Aqua Pennsylvania, Inc.	Depreciation
91.	2009	MS PSC	09-	Entergy Mississippi	Depreciation
92.	2009	AK PSC	09-08-U	Entergy Arkansas	Depreciation
93.	2009	TX PUC	37744	Entergy Texas	Depreciation
94.	2009	TX PUC	37690	El Paso Electric Company	Depreciation
95.	2009	PA PUC	R-2009-2106908	The Borough of Hanover	Depreciation
96.	2009	KS CC	10-KCPE-415-RTS	Kansas City Power & Light	Depreciation
97.	2009	PA PUC	R-2009-	United Water Pennsylvania	Depreciation
98.	2009	OH PUC		Aqua Ohio Water Company	Depreciation
99.	2009	WI PSC	3270-DU-103	Madison Gas & Electric Co.	Depreciation
100.	2009	MO PSC	WR-2010	Missouri American Water Co.	Depreciation
101.	2009	AK Reg Cm	U-09-097	Chugach Electric Association	Depreciation
102.	2010	IN URC		Northern Indiana Public Service Co.	Depreciation
103.	2010	WI PSC	6690-DU-104	Wisconsin Public Service Corp.	Depreciation
104.	2010	PA PUC	R-2010-2161694	PPL Electric Utilities Corp.	Depreciation

	Year	Jurisdiction	Docket No.	Client/Utility	Subject
105.	2010	KY PSC	2010-00036	Kentucky American Water Company	Depreciation
106.	2010	PA PUC	R-2009-2149262	Columbia Gas of Pennsylvania	Depreciation
107.	2010	MO PSC	GR-2010-0171	Laclede Gas Company	Depreciation
108.	2010	SC PSC	2009-489-E	South Carolina Electric & Gas Co.	Depreciation
109.	2010	NJ BD OF PU	ER09080664	Atlantic City Electric	Depreciation
110.	2010	VA St. CC	PUE-2010-00001	Virginia American Water Company	Depreciation
111.	2010	PA PUC	R-2010-2157140	The York Water Company	Depreciation
112.	2010	MO PSC	ER-2010-0356	Greater Missouri Operations Co.	Depreciation
113.	2010	PA PUC	R-2010-2167797	T.W. Phillips Gas and Oil Co.	Depreciation
114.	2010	PSC SC	2009-489-E	SCANA – Electric	Depreciation
115.	2010	PA PUC	R-2010-22010702	Peoples Natural Gas, LLC	Depreciation
116.	2010	AK PSC		Oklahoma Gas and Electric Co.	Depreciation
117.	2010	IN URC		Northern Indiana Public Serv. Co. - NIFL	Depreciation
118.	2010	IN URC		Northern Indiana Public Serv. Co. - Kokomo	Depreciation
119.	2010	PA PUC	R-2010-2166212	Pennsylvania American Water Co - WW	Depreciation
120.	2010	NC Util Cn.		Aqua North Carolina, Inc.	Depreciation
121.	2011	OH PUC	11-4161-WS-AIR	Ohio American Water Company	Depreciation
122.	2011	MS PSC	EC-123-0082-00	Energy Mississippi	Depreciation
123.	2011	CO PUC	11AL-387E	Black Hills Colorado	Depreciation
124.	2011	PA PUC	R-2010-2215623	Columbia Gas of Pennsylvania	Depreciation
125.	2011	IN URC	43114 IGCC 4S	Duke Energy Indiana	Depreciation
126.	2011	FERC	IS11-146-000	Enbridge Pipelines (Southern Lights)	Depreciation
127.	2011	Il CC	11-0217	MidAmerican Energy Corporation	Depreciation
128.	2011	OK CC	201100087	Oklahoma Gas & Electric Co.	Depreciation
129.	2011	PA PUC	2011-2232243	Pennsylvania American Water Company	Depreciation
130.	2011	FERC	2011-2232243	Carolina Gas Transmission	Depreciation
131.	2012	WA UTC	UE-120436/UG-120437	Avista Corporation	Depreciation
133.	2012	MA PUC	DPU 12-25	Columbia Gas of Massachusetts	Depreciation
134.	2012	TX PUC	40094	El Paso Electric Company	Depreciation
135.	2012	ID PUC	IPC-E-12	Idaho Power Company	Depreciation
136.	2012	PA PUC	R-2012-2290597	PPL Electric Utilities	Depreciation
137.	2012	PA PUC	R-2012-2311725	Hanover, Borough of – Bureau of Water	Depreciation
138.	2012	KY PSC	2012-00222	Louisville Gas and Electric Company	Depreciation
139.	2012	KY PSC	2012-00221	Kentucky Utilities Company	Depreciation
140.	2012	PA PUC	R-2012-2285985	Peoples Natural Gas Company	Depreciation
141.	2012	DC PSC	Case 1087	Potomac Electric Power Company	Depreciation
142.	2012	OH PSC	12-1682-EL-AIR	Duke Energy Ohio (Electric)	Depreciation

LIST OF CASES IN WHICH JOHN J. SPANOS SUBMITTED TESTIMONY, cont.

	Year	Jurisdiction	Docket No.	Client/Utility	Subject
143.	2012	OH PSC	12-1685-GA-AIR	Duke Energy Ohio (Gas)	Depreciation
144.	2012	PA PUC	R-2012-	Lancaster, City of – Bureau of Water	Depreciation
145.	2012	PA PUC	R-2012-2310366	Lancaster, City of – Sewer Fund	Depreciation
146.	2012	PA PUC	R-2012-2321748	Columbia Gas of Pennsylvania	Depreciation
147.	2012	FERC		ITC Holdings	Depreciation
148.	2012	MO PSC	ER-2012-0174	Kansas City Power and Light	Depreciation
149.	2012	MO PSC	ER-2012-0174	KCPL Greater Missouri Operations Co.	Depreciation
150.	2012	MO PSC	GO-2012-0363	Laclede Gas Company	Depreciation
151.	2012	MN PUC	G007,001/D-12-533	Integrys – MN Energy Resource Group	Depreciation
152.	2012	TX PUC		Aqua Texas	Depreciation
153.	2012	PA PUC	2012-2336379	York Water Company	Depreciation
154.	2013	NJ BPU	ER12121071	PHI Service Co.– Atlantic City Electric	Depreciation
155.	2013	KY PSC	2013-00167	Columbia Gas of Kentucky	Depreciation
156.	2013	VA St CC	2013-00020	Virginia Electric and Power Co.	Depreciation
157.	2013	IA Util Bd	2013-0004	MidAmerican Energy Corporation	Depreciation
158.	2013	PA PUC	2013-2355276	Pennsylvania American Water Co.	Depreciation
159.	2013	NY PSC	13-E-0030, 13-G-0031, 13-S-0032	Consolidated Edison of New York	Depreciation
160.	2013	PA PUC	2013-2355886	Peoples TWP LLC	Depreciation
161.	2013	TN Reg Auth	12-0504	Tennessee American Water	Depreciation
162.	2013	ME PUC	2013-168	Central Maine Power Company	Depreciation
163.	2013	DC PSC	Case 1103	PHI Service Co. – PEPCO	Depreciation
164.	2013	WY PSC	2003-ER-13	Cheyenne Light, Fuel and Power Co.	Depreciation
165.	2013	FERC	ER13- -0000	Kentucky Utilities	Depreciation
166.	2013	FERC	ER13- -0000	MidAmerican Energy Company	Depreciation
167.	2013	FERC	ER13- -0000	PPL Utilities	Depreciation
168.	2013	PA PUC	R-2013-2372129	Duquesne Light Company	Depreciation
169.	2013	NJ BPU	ER12111052	Jersey Central Power and Light Co.	Depreciation
170.	2013	PA PUC	R-2013-2390244	Bethlehem, City of – Bureau of Water	Depreciation
171.	2013	OK CC	UM 1679	Oklahoma, Public Service Company of	Depreciation
172.	2013	IL CC	13-0500	Nicor Gas Company	Depreciation
173.	2013	WY PSC	20000-427-EA-13	PacifiCorp	Depreciation
174.	2013	UT PSC	13-035-02	PacifiCorp	Depreciation
175.	2013	OR PUC	UM 1647	PacifiCorp	Depreciation
176.	2013	PA PUC	2013-2350509	Dubois, City of	Depreciation
177.	2014	IL CC	14-0224	North Shore Gas Company	Depreciation
178.	2014	FERC	ER14-	Duquesne Light Company	Depreciation

LIST OF CASES IN WHICH JOHN J. SPANOS SUBMITTED TESTIMONY, cont.

	Year	Jurisdiction	Docket No.	Client/Utility	Subject
179.	2014	SD PUC	EL14-026	Black Hills Power Company	Depreciation
180.	2014	PA PUC	2014-2428304	Hanover, Borough of – Municipal Water Works	Depreciation
181.	2014	PA PUC	2014-2406274	Columbia Gas of Pennsylvania	Depreciation
182.	2014	IL CC	14-0225	Peoples Gas Light and Coke Company	Depreciation
183.	2014	MO PSC	ER-2014-0258	Ameren Missouri	Depreciation
184.	2014	KS CC	14-BHCG-502-RTS	Black Hills Service Company	Depreciation
185.	2014	KS CC	14-BHCG-502-RTS	Black Hills Utility Holdings	Depreciation
186.	2014	KS CC	14-BHCG-502-RTS	Black Hills Kansas Gas	Depreciation
187.	2014	PA PUC	2014-2418872	Lancaster, City of – Bureau of Water	Depreciation
188.	2014	WV PSC	14-0701-E-D	First Energy – MonPower/PotomacEdison	Depreciation
189.	2014	VA St CC	PUC-2014-00045	Aqua Virginia	Depreciation
190.	2014	VA St CC	PUE-2013	Virginia American	Depreciation
191.	2014	OK CC	PUD201400229	Oklahoma Gas and Electric	Depreciation
192.	2014	OR PUC	UM1679	Portland General Electric	Depreciation

EXHIBIT JJS-1

CALCULATED ANNUAL DEPRECIATION ACCRUALS
RELATED TO ELECTRIC PLANT AS OF APRIL 30, 2015

KENTUCKY UTILITIES COMPANY
CANE RUN 7

TABLE 1. SUMMARY OF ESTIMATED SURVIVOR CURVES, NET SALVAGE PERCENT, ORIGINAL COST, BOOK DEPRECIATION RESERVE AND CALCULATED ANNUAL DEPRECIATION RATES AS OF APRIL 30, 2015

	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)
	ELECTRIC PLANT									
	OTHER PRODUCTION									
341	STRUCTURES AND IMPROVEMENTS	60-S1.5	*	0	66,577,870.00	0	66,577,870	1,742,876	2.62	38.2
342	FUEL HOLDERS, PRODUCERS AND ACCESSORIES	55-R3	*	(5)	31,069,673.00	0	32,623,157	849,119	2.73	38.4
343	PRIME MOVERS	55-R2.5	*	(5)	102,086,067.00	0	107,190,370	2,844,755	2.79	37.7
344	GENERATORS	50-R1.5	*	(10)	199,733,610.00	0	219,706,971	6,215,190	3.11	35.4
345	ACCESSORY ELECTRIC EQUIPMENT	50-S0.5	*	(5)	35,508,197.00	0	37,283,607	1,055,296	2.97	35.3
346	MISCELLANEOUS POWER PLANT EQUIPMENT	45-R2	*	0	8,877,049.00	0	8,877,049	250,693	2.82	35.4
	TOTAL OTHER PRODUCTION PLANT				443,852,466.00	0	472,259,024	12,957,929	2.92	

* Life Span Procedure was used. Curve Shown is Interim Survivor Curve.

KENTUCKY UTILITIES COMPANY
CANE RUN 7

ACCOUNT 341 STRUCTURES AND IMPROVEMENTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF APRIL 30, 2015

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.. IOWA 60-S1.5						
PROBABLE RETIREMENT YEAR.. 6-2055						
NET SALVAGE PERCENT.. 0						
2015	66,577,870.00			66,577,870	38.20	1,742,876
	66,577,870.00			66,577,870		1,742,876

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 38.2 2.62

KENTUCKY UTILITIES COMPANY
CANE RUN 7

ACCOUNT 342 FUEL HOLDERS, PRODUCERS AND ACCESSORIES

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF APRIL 30, 2015

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.. IOWA 55-R3						
PROBABLE RETIREMENT YEAR.. 6-2055						
NET SALVAGE PERCENT.. -5						
2015	31,069,673.00			32,623,157	38.42	849,119
	31,069,673.00			32,623,157		849,119

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 38.4 2.73

KENTUCKY UTILITIES COMPANY
CANE RUN 7

ACCOUNT 343 PRIME MOVERS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF APRIL 30, 2015

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.. IOWA 55-R2.5						
PROBABLE RETIREMENT YEAR.. 6-2055						
NET SALVAGE PERCENT.. -5						
2015	102,086,067.00			107,190,370	37.68	2,844,755
	102,086,067.00			107,190,370		2,844,755

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 37.7 2.79

KENTUCKY UTILITIES COMPANY
CANE RUN 7

ACCOUNT 344 GENERATORS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF APRIL 30, 2015

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.. IOWA 50-R1.5						
PROBABLE RETIREMENT YEAR.. 6-2055						
NET SALVAGE PERCENT.. -10						
2015	199,733,610.00			219,706,971	35.35	6,215,190
	199,733,610.00			219,706,971		6,215,190

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 35.4 3.11

KENTUCKY UTILITIES COMPANY
CANE RUN 7

ACCOUNT 345 ACCESSORY ELECTRIC EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF APRIL 30, 2015

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.. IOWA 50-S0.5						
PROBABLE RETIREMENT YEAR.. 6-2055						
NET SALVAGE PERCENT.. -5						
2015	35,508,197.00			37,283,607	35.33	1,055,296
	35,508,197.00			37,283,607		1,055,296

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 35.3 2.97

KENTUCKY UTILITIES COMPANY
CANE RUN 7

ACCOUNT 346 MISCELLANEOUS POWER PLANT EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF APRIL 30, 2015

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.. IOWA 45-R2						
PROBABLE RETIREMENT YEAR.. 6-2055						
NET SALVAGE PERCENT.. 0						
2015	8,877,049.00			8,877,049	35.41	250,693
	8,877,049.00			8,877,049		250,693

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 35.4 2.82

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

APPLICATION OF KENTUCKY UTILITIES	**)**	
COMPANY FOR AN ADJUSTMENT OF ITS	**)**	**CASE NO. 2014-00371**
ELECTRIC RATES	**)**	

TESTIMONY OF
EDWIN R. "ED" STATON
VICE PRESIDENT, STATE REGULATION AND RATES
KENTUCKY UTILITIES COMPANY

Filed: November 26, 2014

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

A. My name is Ed R. Staton. I am Vice President of State Regulation and Rates for Louisville Gas and Electric Company ("LG&E") and Kentucky Utilities Company ("KU" or the "Company") (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. A complete statement of my work experience and education is contained in the Appendix attached hereto.

Q. Have you previously testified before this Commission?

A. Yes, I have testified before the Commission on multiple occasions, including two KU applications for Certificates of Public Convenience and Necessity for the construction of transmission facilities,[1] the Commission's administrative proceeding considering the implementation of smart grid and smart meter technologies,[2] and most recently in the Companies' application for Certificates of Public Convenience and Necessity for the construction of generating facilities.[3]

Q. What are the purposes of your testimony?

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[1] *In the Matter of: Application of Kentucky Utilities Company Concerning the Need to Obtain Certificates of Public Convenience and Necessity for the Construction of Temporary Transmission Facilities in Hardin County, Kentucky,* Case No. 2009-00325; *In the Matter of Application of Kentucky Utilities Company for a Certificate of Public Convenience and Necessity for Construction of Transmission Facilities in McCracken County, Kentucky,* Case No. 2010-00164.

[2] *In the Matter of: Consideration of the Implementation of Smart Grid and Smart Meter Technologies,* Case No. 2012-00428.

[3] *In the Matter of: Joint Application of Louisville Gas and Electric Company and Kentucky Utilities Company for Certificates of Public Convenience and Necessity for the Construction of a Combined Cycle Combustion Turbine at the Green River Generating Station and a Solar Photovoltaic Facility at the E.W. Brown Generating Station,* Case No. 2014-00002.

A. The purposes of my testimony are: (1) to support certain exhibits required by the Commission's regulations; (2) to present the bill impacts to the average residential customer; (3) to describe the methods by which KU informed its customers of the proposed rate adjustment; and (4) to describe the various ways KU assists customers with low incomes.

Q. Are you supporting the schedules that are required by the Commission regulations 807 KAR 5:001?

A. Yes, I am sponsoring the following schedules for the corresponding filing requirements in 807 KAR 5:001 Rules of Procedure:

• Name, Address, Facts	Section 14(1)	Tab 1
• Corp. – Incorporation, Good Standing	Section 14(2)	Tab 1
• LLC – Organized, Good Standing	Section 14(3)	Tab 1
• LP – Agreement	Section 14(4)	Tab 1
• Reason for Rate Adjustment	Section 16(1)(b)(1)	Tab 2
• Certificate of Assumed Name	Section 16(1)(b)(2)	Tab 3
• Proposed Tariff	Section 16(1)(b)(3)	Tab 4
• Proposed Tariff Changes	Section 16(1)(b)(4)	Tab 5
• Statement about Customer Notice	Section 16(1)(b)(5)	Tab 6
• Notice of Intent	Section 16(2)	Tab 7
• Testimony	Section 16(7)(a)	Tab 14
• Mix of Gas Supply (Gas)	Section 16(7)(h)(8)	Tab 29
• Customer Notice Information	Section 17(4)	Tab 67

Although I am sponsoring KU's proposed tariff and proposed tariff changes, Robert M. Conroy's testimony will address issues of rate structure and specific rates, as well as changes to the terms and conditions of KU's electric service in detail.

KU Values Its Customers

Q. Please describe the importance and value the Company places on its customers.

A. Customer focus is a key value to KU, and customer satisfaction is important to us. Therefore, the Company is dedicated to providing the best customer experience possible at every point of contact, and as explained in Mr. Staffieri's testimony, the decision to file for rate increases is a serious matter. We understand it will impact all customers and their experience with the Company. KU specifically understands the needs of its low- and fixed-income customers through its numerous engagements and relations with these customers. I will describe in detail later in my testimony a number of initiatives KU has for these customers. Our Company's culture also includes service to the community through donations of personal and shareholder funds and through volunteering in the communities KU serves. When the Company makes the decision to seek additional revenues by a rate increase, our customers may rest assured that the persons making these decisions recognize and respect the impact on customers by such a request.

KU's Proposed Revenue Increase

Q. Please briefly describe the increase in revenues requested by KU.

A. KU is requesting a 9.6 percent, or approximately $153 million, increase in its annual electric revenue. Kent Blake and Paul Thompson describe in their testimonies the primary drivers of the needed revenue increase.

Bill Impact

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 9.57 percent, or approximately $11.01, for a residential customer using an average of 1,200 kWh of electricity. A detailed explanation of the bill increase is contained in Mr. Conroy's testimony.

Q. How does KU's average residential rate compare to the average residential rate of investor-owned utilities across the United States?

A. KU strives to ensure its residential customers receive reasonably priced energy. Based on the Edison Electric Institute's *Typical Bills and Average Rates Report Winter 2014*, which provides data covering the 12-month period ending December 31, 2013, KU's average residential rate is approximately 28 percent lower than the average residential rate of investor-owned utilities across the United States.

Q. If the Commission approves KU's requested electric rate adjustment in this case, how will KU's average residential electric rate compare with the average residential electric rate of investor-owned utilities across the United States?

A. Even with this rate adjustment, KU's projected average retail rate for 2015-2016 is approximately 16 percent lower than the 2013 average retail rate of investor-owned utilities in the U.S.

Customer Notice

Q. Please describes the methods by which KU informed its customers of its proposed rate adjustment.

A. Notice to the public of the proposed rate adjustment is being given as prescribed in the Commission's regulations. On November 5, 2014, KU delivered a notice of the filing of KU's application, including its proposed rates, to the Kentucky Press Association, an agency that acts on behalf of newspapers of general circulation through the Commonwealth of Kentucky in which customers affected reside, for publication in the applicable newspapers once a week for three consecutive weeks beginning on November 19, 2014.

Furthermore, KU is posting the notice to the public along with a complete copy of the application for public inspection at KU's main business office, One Quality Street, Lexington, Kentucky. KU is also posting the notice to the public at every KU business office where customers can transact business with the Company.

KU is also posting a complete copy of its application in this case on its website (www.lge-ku.com), along with a link to the Commission's website where the case documents are available.

Finally, beginning on November 26, 2014, KU began including a notice of the proposed rate adjustment and general statement explaining the application in this case with the bills for all Kentucky retail customers during the course of their regular monthly billing cycle.

Low-Income Customer Assistance

Q. Does KU provide assistance its low-income customers?

A. Yes. KU is keenly aware of its low-income customers' needs through direct contact with such customers and through KU's relationships with a number of organizations engaged in community-assistance programs and efforts, including the Community Action Council for Lexington-Fayette, Bourbon, Harrison, and Nicholas Counties, Inc. ("CAC"). KU meets and communicates with these groups on a regular basis to understand low-income customers' needs, how community organizations are working to meet those needs, and how KU can help.

KU has turned awareness into action, having worked on its own and in conjunction with community groups to provide various forms of assistance to low-income customers over the years. For example, KU matches customer donations to the WinterCare Energy Assistance Fund, which assists low-income customers with their utility bills during winter months. Due to delay of the distribution of the Low-Income Home Energy Assistance Program ("LIHEAP") funds caused by the federal government shutdown in October 2013, KU announced it would match $2.00 for every $1.00 donated by KU's residential customers to the program from October 1, 2013 through March 31, 2014. In the 2013-14 heating season alone, KU's shareholders contributed $96,488 to WinterCare. Since 2009, customer donations and matching funds from the Companies have raised nearly $2 million for WinterCare and LG&E's Winterhelp. For the 2014-2015 heating season, KU's shareholders will once again match $1.00 for every $1.00 donated by KU's residential customers to WinterCare. Moreover, KU's employees participate in Winterblitz, an annual weatherization effort performed in conjunction with CAC. Each November, hundreds of employees join volunteers and community organizations to weatherize the homes of low-income senior citizens and the disabled. KU provides the weatherization materials for Winterblitz, and in 2013, 22 KU employees weatherized 45 homes through their participation and donations.

Also, KU responded proactively during the extreme cold of the 2014 winter season. KU and LG&E jointly relaxed installment plan restrictions that helped customers defer payments from January through April 2014. Customers were issued more than 12,000 installment plans resulting in the deferment of approximately $5 million in payments. During the same timeframe, the Companies also donated more than $200,000 to various organizations that assist low-income customers in need.

In addition, KU committed in its most recent base rate case (Case No. 2012-00221) to make annual shareholder contributions of $407,500 per year beginning in 2013.[4] The $407,500 comprises a $100,000 contribution to the WinterCare program and a $307,500 contribution to the Home Energy Assistance ("HEA") program, both of which CAC administers.[5] KU further agreed in that case to increase its monthly residential meter charge for the HEA program from the current $0.16 per meter to $0.25 per meter.[6] KU's shareholder contribution amounts will continue until the effective date of the new base rates proposed in this proceeding, and will thereafter cease absent a settlement extending the contributions.[7]

Q. Does KU propose to continue the current HEA charge ($0.25 per meter per month)?

A. Yes, although KU maintains discretion to discontinue or reduce the monthly residential HEA charge, KU proposes to continue the charge at $0.25 per meter, the same amount currently charged under its tariff.

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[4] *In the Matter of: Application of Kentucky Utilities Company for an Adjustment of its Electric Rates*, Case No. 2012-00221, Order at 4 (Dec. 20, 2012).
[5] *Id.*
[6] *Id.*
[7] *Id.*

Q. In addition to KU's significant shareholder contributions and the support the HEA charge provides to low-income customers, has KU implemented any policy or tariff measures to assist fixed- and low-income customers?

A. Yes. In its 2012 rate case KU made it easier for all customers to pay their bills on time by extending payment due dates from 12 calendar days to at least 22 calendar days after issuance, and KU reduced late-payment charges from 5 percent to 3 percent for all schedules to which a 5 percent charge was previously applied, including residential customers.[8] Since increasing the time to pay bills, assessment of late-payment charges has reduced by approximately 25 percent across all customer segments. Additionally, customer satisfaction increased almost an entire point from a 7.61 to an 8.44 average score on a 10-point scale when customers were asked about the length of time they had to pay their bills.

But KU has gone even further to assist fixed- and low-income customers. First, KU's FLEX Program allows residential customers with limited incomes to pay their bills 28 days from issuance. This helps prevent fixed- and low-income customers from incurring late payment charges, increases the time in which such customers may seek financial aid, and helps reduce the issuance of disconnection notices to these customers. The popularity of the FLEX Program indicates it is achieving its intended aims: since KU implemented the program in December 2009 through September 30, 2014, a total of 10,073 KU customers have used it.

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

[8] *Id.*

notice is 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 provided significant benefits to low-income customers. From September 2013 through August 2014, KU waived approximately $540,000 in late-payment charges, helping to alleviate the financial burden KU's fixed- and low-income customers face.

In addition, KU offers a demand-side management and energy-efficiency ("DSM/EE") program to assist low-income customers. Specifically, the Companies' Low-Income Weatherization Program ("WeCare") is an education and weatherization program designed to reduce the energy consumption of KU's low-income customers.[9] The program provides energy audits, energy education, and blower door tests, and installs weatherization and energy conservation measures. A qualified low-income customer can receive—at no direct cost to the customer—energy conservation measures with a value of up to $2,100.[10] As a result of WeCare, the Companies have experienced an energy reduction of 25,317 MWh and a demand reduction of 1.5 MW through November 2013.[11] WeCare is now KU and LG&E's second largest DSM/EE program by budget: over $25.5 million total for both Companies for program years 2015-18, an average of over $6.35 million for both Companies for each program year for that period.[12] The Companies project that this significant program will produce total energy savings for KU's low-income customers of 17,204 MWh for program

[9] *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*, Case No. 2014-00003, Application Exhibit MEH-1 at 17 (Jan. 17, 2014).
[10] Kentucky Utilities Company, P.S.C. No. 16, Second Revision of Original Sheet No. 86.4 (KU's Kentucky tariff).
[11] Case No. 2014-00003, Application Exhibit MEH-1 at 45.
[12] Case No. 2014-00003, Rebuttal Testimony of Michael E. Hornung at 13 (June 16, 2014).

years 2015-18, the value of which energy savings participating customers will receive in the form of relatively reduced energy bills.[13] In addition, KU offers specific DSM/EE programming for multi-family households, providing yet another opportunity for many low-income customers to participate in KU's DSM/EE offerings. KU's Residential Conservation / Home Energy Performance Program is available to multi-family properties, offering financial incentives to customers who implement energy-efficiency measures identified during on-site audits.[14] Moreover, KU this year requested approval to enhance the program by implementing a tier structure specifically for multi-family properties.[15] The Commission recently approved KU's DSM/EE programming for 2015-18, and in doing so noted its appreciation for "the Companies' efforts in offering low-income programs for its customers" and that the record in the DSM/EE "proceeding reflects the Companies' efforts to work with [community action agencies] and other interested parties to encourage participation by low-income customers in programs such as the WeCare and Residential Conservation/Home Energy Performance programs, which encourage EE and energy savings and aid in reducing the cost of customers' energy bills."[16]

Cumulatively, these efforts demonstrate that KU is committed to assisting its fixed- and low-income customers. Through the WeCare program, KU works to weatherize the homes of low-income customers to decrease their monthly energy bills. KU's FLEX program extends a low-income customer's bill-due date to 28 days from bill issuance. To the extent further assistance is required, KU has generously

[13] Case No. 2014-00003, Application Exhibit MEH-1 Appendix B at 69.
[14] *Id.* at 39-42.
[15] *Id.*
[16] Case No. 2014-00003, Order at 27 (Nov. 14, 2014).

increased its giving to agencies that provide financial support, and KU waives late payment charges for customers receiving assistance from such agencies. In short, KU provides full-spectrum assistance to its fixed- and low-income customers, from before energy is consumed until after the bill is issued.

Conclusion

Q. Does this conclude your testimony?

A. Yes, it does.

VERIFICATION

COMMONWEALTH OF KENTUCKY)
) SS:
COUNTY OF JEFFERSON)

The undersigned, **Edwin R. Staton**, being duly sworn, deposes and says that he is Vice President, State Regulation and Rates 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.

E. R. S.
Edwin R. Staton

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 19th day of November 2014.

Susan M. Watkins (SEAL)
Notary Public

My Commission Expires:

SUSAN M. WATKINS
Notary Public, State at Large, KY
My Commission Expires Mar. 19, 2017
Notary ID # 485723

APPENDIX A

Edwin R. "Ed" Staton
Vice President, State Regulation and Rates
LG&E and KU Services Company
220 West Main Street
Louisville, Kentucky 40202
Telephone: (502) 627-4314

Work History

Vice President, State Regulation and Rates	2/2013-present
Vice President, Transmission –Kentucky Utilities Company and Louisville Gas and Electric Company	2011-2013
Director Transmission –LG&E and KU Services Company	2007-2011
Director of Distribution Operations – Kentucky Utilities Company	2003-2007
Manager of Distribution Operations – Auburndale Operations Center, Louisville Gas & Electric Company	2000-2003
District Manager – Kentucky Utilities Co. - Elizabethtown, Ky.	1998-2000
Local Service Manager – Kentucky Utilities Co. – Eddyville, Ky.	1992-1998
Line and Service Technician – Kentucky Utilities Co.	1988-1992
Drafter, Eng. Asst., Sr. Engineering Asst. – Transmission	1982-1988

Education

Associate Degree – Business Management, University of Kentucky – Henderson Community College, Henderson, Ky.	1985
Bachelor of Science Degree – Business Administration (minor in Accounting), University of Southern Indiana, Evansville, Indiana	1990
Master of Business Administration – Western Kentucky University	2004

Vocational Training

Kentucky Institute for Economic Development

Public Utilities Regulations Guide

Gas Distribution Operations – Institute of Gas Technology, Des Plains, Ill.

E.ON Academy - International Management Program – IMD (International Institute for Management Development), Lausanne, Switzerland

M.I.T. Sloan School of Management, Executive Program in Corporate Strategy, Boston, Mass.

Community Service

President – Lyon Co. Chamber of Commerce	1996-1997
Co-Chairman – Eddyville Industrial Foundation	1997-1998
Board member – Elizabethtown Chamber of Commerce	2000
Member – Larue Co. Industrial Foundation	1999-2003
Member – Elizabethtown luncheon Rotary Club	1999-2000
Member – Kentucky Industrial Development Council	1996-present
Junior Achievement:	
Classroom instructor	
Coral Ridge Elementary School, Louisville, Ky.	2001-2002
Board member – Junior Achievement of the Bluegrass	2007-present
Junior Achievement:	
Classroom instructor	
Tates Creek Middle School, Lexington, Ky.	2008-present

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In re the Matter of:

APPLICATION OF KENTUCKY	**)**
UTILITIES COMPANY FOR AN	**) CASE NO. 2014-00371**
ADJUSTMENT OF ITS ELECTRIC	**)**
BASE RATES	**)**

TESTIMONY OF
DR. MARTIN BLAKE
PRINCIPAL
THE PRIME GROUP, LLC

Filed: November 26, 2014

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I. INTRODUCTION AND QUALIFICATIONS

Q. Please state your name and business address.

A. My name is Martin J. Blake. My business address is 6001 Claymont Village Drive, Suite 8, Crestwood, Kentucky 40014.

Q. By whom and in what capacity are you employed?

A. I am a Member and Principal of The Prime Group, LLC. The Prime Group provides consulting services in the areas of strategic planning, cost of service, rate design, regulatory support, and training for energy industry clients. A core part of our business is working with utilities to perform cost of service analyses and providing assistance in developing reasonable cost-based rates.

Q. Please describe your professional experience and educational background.

A. I hold a Ph.D. in Agricultural Economics and a Master of Arts degree in Economics from the University of Missouri, Columbia. I served as Commissioner on the New Mexico Public Service Commission from January 1986 through November 1989. I then worked as the Director of Rates, Regulatory and Strategic Planning for Louisville Gas and Electric from December 1989 through June 1996. I have taught at the NARUC Institute at Michigan State University for many years; and I have been an independent consultant with the Prime Group since 1996. A detailed description of my professional experience and educational background is provided in Exhibit MJB-1.

Q. In what cases have you previously testified?

A. I have testified in numerous proceedings before both state and federal regulatory bodies. Exhibit MJB-2 is a summary of the testimony I have presented in other regulatory proceedings.

Q. On whose behalf are your testifying?

A. I am testifying on behalf of Kentucky Utilities Company ("KU" or "Company").

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to: (i) describe and support KU's electric cost of service study; (ii) describe the proposed allocation of the revenue increase to KU's electric rate classes; (iii) describe the electric rate designs, new rates, and percentage increase by rate class; and (iv) support certain filing requirements from 807 KAR 5:001.

Q. What are the fully forecasted test period and base period on which the rate case application and the electric cost of service study that you developed are based?

A. The fully forecasted test period on which the filing is based is the twelve months ended June 30, 2016. Consistent with KRS 278.192, the cost of service study and the adjustments in rates are supported by a fully forecasted test period. Because the effective date of KU's proposed rates is January 1, 2015, the first twelve consecutive calendar months after the 6 month suspension period corresponds to the 12 months beginning July 1, 2015 and ending on June 30, 2016. The base period for the filing is the 12 months ending February 28, 2015. The base period consists of six months of actual historical data for the period March 1, 2014 through August 31, 2014 and six months of estimated data for the period September 1, 2014 through February 28, 2015. KRS 278.192(2)(a) requires that any rate case application utilizing a forecasted test period must include a base period which begins not more than nine months prior to the date of the filing, consisting of not less than six months of actual historical data and not more than six months of estimated data. Because KU's proposed base period, which begins March 1, 2014, includes not less than six months of actual historical data (March 1, 2014 through August 31, 2014), includes no more than six months of estimated data (September 1, 2014 through February 28, 2015), and begins less than nine months prior to the filing date in this proceeding, the proposed base period is in compliance with the requirements for a forecasted test year set forth in KRS 278.192(2)(a).

Q. Please summarize your testimony.

A. The Company's fully allocated, embedded cost of service study for its electric operations were prepared using cost of service methodologies that have been accepted by the Commission in previous rate cases. The purpose of the cost of service study is to fairly allocate the cost of providing safe, reliable service to the various customer classes that KU serves, to determine the contribution that each customer class is making towards KU's overall rate of return and to provide the data necessary to develop rate components that more accurately reflect cost causation. In the cost of service study, rates of return are calculated for each rate class. Because of the magnitude of the increase, KU is proposing to increase each electric rate class by the same percentage. Increasing each rate class by the same percentage comports with gradualism and will minimize rate shock. The Company is proposing unit charges that more accurately reflect cost causation for its electric rates.

Q. Are you supporting certain information required by Commission Regulations 807 KAR 5:001, Section 16(7) and 16(8)?

A. Yes. I am sponsoring the following schedules for the corresponding Filing

Requirements:

• Cost of Service Studies	Section 16(7)(v)	Tab 52
• Revenue Summary	Section 16(8)(m)	Tab 65

Q. How is your testimony organized?

A. My testimony is divided into the following sections: (I) Introduction and Qualifications, (II) Electric Cost of Service Study, and (III) Electric Rate Design and the Allocation of the Increase.

Q. Did you use the same methodology in KU's electric cost of service study that was used in LG&E's electric cost of service study filed concurrently in Case No. 2014-00372?

A. Yes. However, for KU the data needs to be split between the Kentucky, Virginia, Tennessee, and wholesale jurisdictions before developing a cost of service study for KU's Kentucky jurisdiction. Therefore, as I describe further below and in accordance with KU's practice in all of its recent base rate cases, a jurisdictional separation study was prepared as the first step in the cost of service study process.

II. ELECTRIC COST OF SERVICE STUDY

Q. Did The Prime Group prepare a cost of service study for KU's electric operations based on forecasted financial and operating results for the 12 months ended June 30, 2016?

A. Yes. I supervised the preparation of a fully allocated, time-differentiated, embedded cost of service study for KU's electric operations based on a forecasted test year ended June 30, 2016. The cost of service study corresponds to the pro-forma financial exhibits that the Company has provided to meet the requirements of Section 16(8). The objective in performing the electric cost of service study is to allocate KU's revenue requirement as fairly as possible to all of the classes of customers that KU serves, to determine the rate of return on rate base that KU is earning from each customer class, and to provide the data necessary to develop rate components that more accurately reflect cost causation.

Q. What model was used to perform the cost of service study?

A. The cost of service study was performed using a proprietary EXCEL spreadsheet model that was developed by The Prime Group and that has been utilized in previous filings by KU to support requests for adjustments in its rates.

Q. Have you prepared an exhibit showing the results of the jurisdictional separation of KU's costs?

A. Yes. Exhibit MJB-3 shows the results of the study separating KU's costs into Kentucky, Virginia, Tennessee and wholesale components.

Q. What procedure was used in performing the cost of service study?

A. Regardless of whether a historic test year or a forecasted test year is used to develop a cost of service study, the methodology for developing a cost of service study is basically the same. However, because KU operates in multiple jurisdictions, it is necessary to perform a jurisdictional split among the jurisdictions, which is provided in Exhibit MJB-3, prior to developing a cost of service study for the Kentucky jurisdiction. The three traditional steps of an embedded cost of service study – functional assignment, classification, and allocation – were augmented to include a fourth step, assigning costs to costing periods which time differentiates the costs. The cost of service study was therefore prepared using the following procedure: (1) costs were functionally assigned (*functionalized*) to the major functional groups; (2) costs were then *classified* as commodity-related, demand-related, or customer-related; (3) costs were assigned to the costing periods; and then (4) costs were allocated to the various rate classes that KU serves. These steps are depicted in the following diagram (Figure 1).

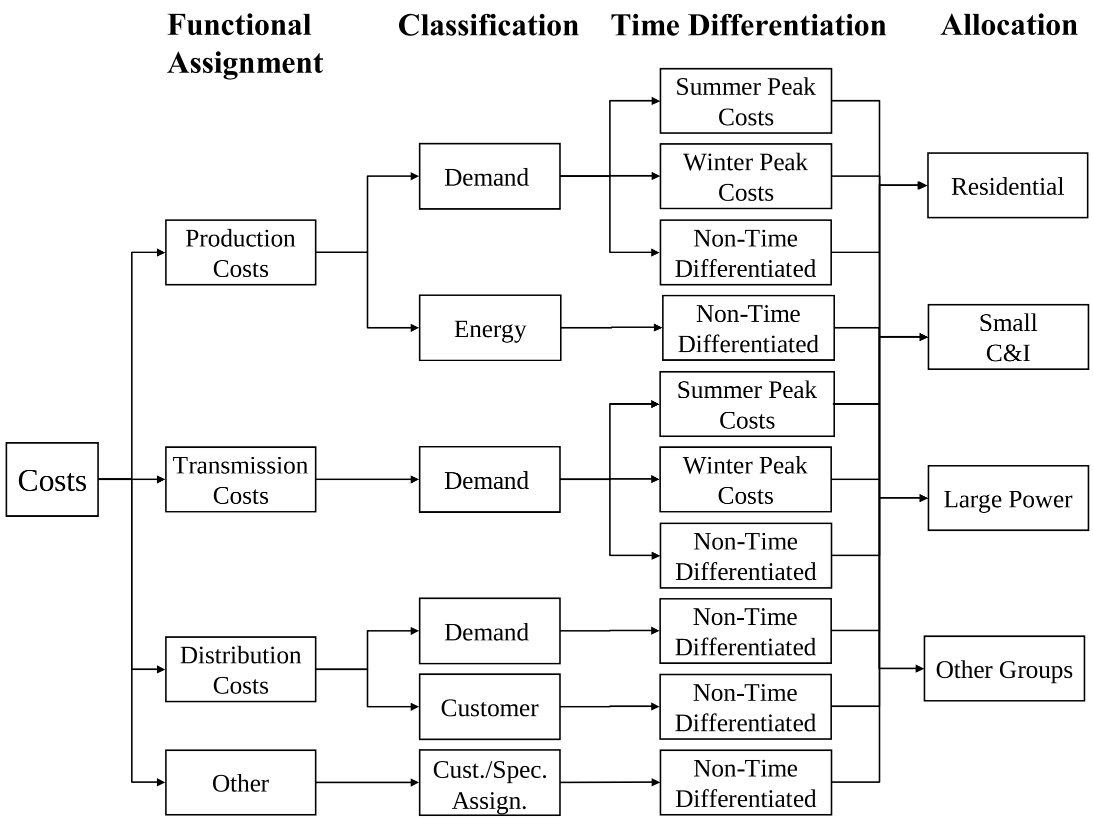

Figure 1

The following functional groups were identified in the cost of service study: (1) Production, (2) Transmission, (3) Distribution Substation (4) Distribution Primary Lines, (5) Distribution Secondary Lines (6) Distribution Line Transformers, (7) Distribution Services, (8) Distribution Meters, (9) Distribution Street and Customer Lighting, (10) Customer Accounts Expense, (11) Customer Service and Information, and (12) Sales Expense.

Q. How were costs time differentiated in the study?

A. A modified Base-Intermediate-Peak ("BIP") methodology was used to assign production and transmission costs to the relevant costing periods.[1] Using this methodology, production and transmission demand-related costs were assigned to three categories of capacity – base, intermediate, and peak. The percentages of production and transmission fixed cost that were assigned to the base period were determined by dividing the minimum system demand by the maximum demand. The percentages of production and transmission fixed cost that were assigned to the intermediate period were calculated by dividing the summer peak demand by the winter 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 pro-rated to the winter and summer peak periods in the same ratio as the number of hours contained in each costing period to the total. Peak costs are assigned to the summer peak period.

Q. In applying the modified BIP methodology, what demands were used?

[1] 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.)

A Demands for the combined KU and LG&E systems were used to determine the costing periods and in determining the percentages of production and transmission fixed cost assigned to the costing periods. Since the two systems are planned and operated jointly, developing costing periods and assigning costs to the costing periods based on the combined loads for KU and LG&E accurately reflects cost causation. Developing the costing periods and allocation factors in the cost of service study based on the combined loads for KU and LG&E does not result in any shifting of booked expenses from one utility to the other. KU's cost of service study relied on KU's accounting costs, and LG&E's cost of service study relied on LG&E's accounting costs. The modified BIP methodology simply affects how costs are assigned to the costing periods within the KU and LG&E cost of service studies.

Q. What percentages were assigned to the costing periods?

A Exhibit MJB-4 shows the application of the modified BIP methodology. Using this methodology 34.10% of KU's production and transmission fixed costs were assigned to the winter peak period, 30.91% to the summer peak period, and 34.99% as base period costs that are non-time-differentiated.

Q. How were costs classified as energy-related, demand-related or customer-related?

A. Classification involves utilizing the appropriate cost driver for each functionally assigned cost which provides a method of arranging costs so that the service characteristics that give rise to the costs can serve as a basis for allocation. For costs classified as *energy-related*, the appropriate cost driver is 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. The costs of production plant and transmission lines are examples of costs typically classified as demand-related 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 set of distribution equipment necessary to provide a customer with access to the electric grid. As will be discussed later in my testimony, a portion of the 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 because these costs do not vary with customers' capacity or energy usage.

Q. What methodologies are commonly used to classify distribution plant between customer-related and demand-related components?

A. Two commonly used methodologies for determining demand/customer splits of distribution plant are the "minimum system" methodology and the "zero-intercept" methodology. In the minimum system approach, "minimum" standard poles, conductor, and line transformers are selected and the minimum system is obtained by pricing all of the applicable distribution facilities at the unit cost of the minimum size plant. The minimum system determined in this manner is then classified as customer-related and allocated on the basis of the average number of customers in each rate class. All costs in excess of the minimum system are classified as demand-related. The theory supporting this approach maintains that in order for a utility to serve even the smallest customer, it would have to install a minimum size system. Therefore, the costs associated with the minimum system are related to the number of customers that are served, instead of the demand imposed by the customers on the system.

In preparing this study, the "zero-intercept" methodology was used to determine the customer components of overhead conductor, underground conductor, and line transformers. Because the zero-intercept methodology is less subjective than the minimum system approach, the zero-intercept methodology is preferred over the minimum system methodology when the necessary data is available. Additionally, KU has utilized the zero-intercept methodology in determining customer-related costs in prior rate case filings before this Commission. With the zero-intercept methodology, we are not forced to choose a minimum size conductor or line transformer to determine the customer-related component of distribution costs. In the zero-intercept methodology, the estimated cost of a zero-size conductor or line transformer is the absolute minimum system for determining customer-related costs.

Q. What is the theory behind the zero-intercept methodology?

A. The theory behind the zero-intercept methodology is that there is a linear relationship between the unit cost of conductor ($/ft) or line transformers ($/kVA of transformer size) and the load flow capability of the plant measured as the cross-sectional area of the conductor or the kVA rating of the transformer. After establishing a linear relation, which is given by the equation:

$$y = a + bx$$

where:

y is the unit cost of the conductor or transformer,

x is the size of the conductor (MCM) or transformer (kVA), and

a, **b** are the coefficients representing the intercept and slope, respectively

it can be determined that, theoretically, the unit cost of a foot of conductor or transformer with zero size (or conductor or transformer with zero load carrying capability) is **a**, the zero-intercept. The zero-intercept is essentially the cost component of conductor or transformers that is invariant to the size and load carrying capability of the plant.

Like most electric utilities, the feet of conductor and the 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 linear regression analysis, instead of a standard least-squares analysis, in the determination of the zero intercept. Without performing a weighted linear regression analysis all types of conductor and transformers would have the same impact on the analyses, even though the quantity of conductor and transformers are not the same for each size and type.

Using a weighted linear regression analysis, the cost and size of each type of conductor or transformer is weighted by the number of feet of installed conductor or the number of transformers. In a weighted linear regression analysis, the following weighted sum of squared differences is minimized,

$$\sum_i w_i (y_i - \hat{y}_i)^2$$

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 study (both electric and natural 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 that are suitable for use as a guide in developing appropriate revenue allocations and rate design. The cost of service studies in both of these proceedings utilized a zero-intercept methodology to calculate the splits between demand-related and customer-related distribution costs. The Commission also found the embedded cost of service study submitted by Union Light Heat and Power in Case No. 2001-00092, which utilized a zero-intercept methodology, to be reasonable. Additionally, the Commission has approved stipulations in prior KU rate proceedings which utilized a zero-intercept approach for calculating the splits between demand-related and customer-related distribution costs.

Q. Have you prepared exhibits showing the results of the zero-intercept analysis?

A. Yes. The zero-intercept analysis for overhead conductor, underground conductor, and line transformers are included in Exhibits MJB-5, MJB-6 and MJB-7, respectively.

Q. Have you prepared an exhibit showing the results of the functional assignment, time-differentiation and classification steps of the electric cost of service study?

A. Yes. Exhibit MJB-8 shows the results of the first three steps of the electric cost of service study; namely functional assignment, classification, and time differentiation. In the cost of service model used in this study, the calculations for functionally assigning, classifying and time differentiating KU's accounting costs are made using what are referred to in the model as "functional vectors". These vectors are multiplied (using *scalar multiplication*) by the dollar amount in the various accounts in order to simultaneously functionally assign, classify and time differentiate KU's accounting costs. These calculations occur in the portion of the cost of service model included in Exhibit MJB-8. In Exhibit MJB-8, KU's accounting costs are functionally assigned, classified and time differentiated using explicitly determined functional vectors and using internally generated functional vectors. The explicitly determined functional vectors, which are primarily used to direct where costs are functionally assigned, classified, and time differentiated, are shown on pages 49 through 52 of Exhibit MJB-8. Internally generated functional vectors are utilized throughout the study to functionally assign, classify and time differentiate 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 Exhibit MJB-8. 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, classify and time differentiate these costs on the same basis. (See Exhibit MJB-8, pages 9 through 12, row 112 for the functional assignment, classification and time differentiation of cash working capital on the basis of OMLPP which is shown on pages 25 through 28, row 330.) The functional vector used to allocate a specific cost is identified in the column of the model labeled “Vector” and refers to a vector identified elsewhere in the analysis by the column labeled “Name”.

Q. Please describe the how the functionally assigned, classified and time differentiated costs were allocated to the various classes of customers that KU serves.

A. Exhibit MJB-9 shows the allocation of the functionally assigned, classified and time differentiated costs to the various classes of customers that KU serves. For a forecasted test year, the average number of customers is used for allocating customer-related costs rather than the year end number of customers that is used for a historic test year. The following allocation factors were used in the electric cost of service study to allocate the functionally assigned, classified and time differentiated costs:

- **E01 –** The energy cost component of purchased power costs was allocated on the basis of the kWh sales to each class of customers during the test year.
- **PPWDA and PPSDA –** The winter demand and summer demand cost components of production and transmission fixed costs were allocated on the basis of each class’s contribution to the coincident peak demand during the winter and summer peak hour of the test year.
- **NCPP –** The demand cost component is allocated on the basis of the maximum class demands for primary and secondary voltage customers.

- **SICD –** The demand cost component is allocated on the basis of the sum of individual customer demands for secondary voltage customers.
- **C02 –** The customer cost component of customer services is allocated on the basis of the average number of customers for the test year.
- **C03 –** Meter costs were specifically assigned by relating the costs associated with various types of meters to the class of customers for whom these meters were installed.
- **Cust04 –** Customer-related costs associated with lighting systems were specifically assigned to the lighting class of customers.
- **Cust05 and Cust06 –** Meter reading, billing costs and customer service expenses were allocated on the basis of a customer weighting factor calculated using the average number of customers for the test year based on discussions with KU's meter reading, billing and customer service departments.
- **Cust07 –** Customer-related costs are allocated on the basis of the average number of customers using line transformers and secondary voltage conductor.

- **Cust08** – Customer-related costs are allocated on the basis of the average number of customers using primary voltage conductor.

Q. In your cost of service model, once costs are functionally assigned, classified and time differentiated, what calculations are used to allocate these costs to the various customer classes that KU serves?

A. Once costs for all of the major accounts are functionally assigned, classified, and time differentiated, 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". A transpose of a matrix is formed by turning all the rows of a given matrix into columns and vice-versa. This process results in the columns of functionally assigned, classified and time differentiated costs becoming rows in the transposed matrix which then can be allocated to the various classes of customers that KU serves. This process is illustrated in Figure 2 below.

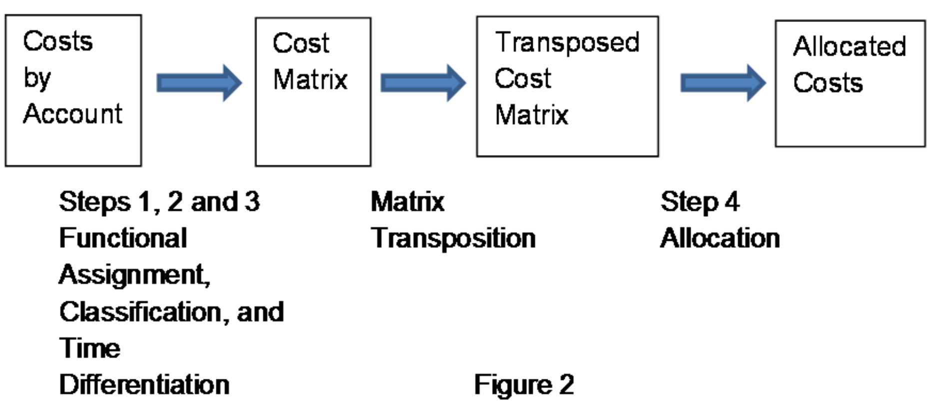

Figure 2

The results of the class allocation step of the cost of service study are included in Exhibit MJB-9. The costs shown in the column labeled "Total System" in Exhibit

MJB-9 were carried forward from the functionally assigned, classified and time differentiated costs shown in Exhibit MJB-8. The column labeled "Ref" in Exhibit MJB-9 provides a reference to the results included in Exhibit MJB-8.

Q. Please summarize the results of the electric cost of service study.

A. Table 1 below 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 the testimony of Mr. Kent W. Blake and Mr. Robert M. Conroy. 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

Rate Class	Actual Adjusted Rates of Return	Proposed Rates of Return
Residential Rate RS	2.77%	4.84%
General Service Single Phase	9.01%	12.14%
All Electric Schools Single Phase	4.43%	7.14%
Power Service Secondary Rate PS	11.29%	15.04%
Power Service Primary Rate PS	8.24%	11.46%
Time of Day Secondary Rate TODS	5.42%	8.69%
Time of Day Primary Rate TODP	3.34%	6.40%
Retail Transmission Service Rate RTS	3.41%	6.52%
Fluctuating Load Service Rate FLS	1.53%	4.61%
Lighting	2.75%	4.13%
Total	4.55%	7.18%

Determination of the actual adjusted and proposed rates of return are detailed in

Exhibit MJB-9, pages 29 and 30 and pages 33 and 34, respectively.

III. ELECTRIC RATE DESIGN AND THE ALLOCATION OF THE INCREASE

A. ALLOCATION OF THE ELECTRIC REVENUE INCREASE

Q. Have you prepared exhibits showing KU's base year and test year billing determinants for the electric business and showing the impact of applying the new rates to base year and test year billing determinants?

A. Yes. The KU's base year electric billing determinants are provided in Schedule M-1.3, and KU's test year electric billing determinants are provided in Schedule M-2.3. Schedule M-2.3 shows the result of applying the proposed rates to the test year billing determinants by class of customers. A summary of the revenue increases that result from applying KU's proposed rates to the test year billing determinants is provided on page 2 of Schedule M-2.3.

Q. What revenue increase is KU proposing for electric operations?

A. KU is proposing an increase in electric test-year revenues of $153,442,682, which is calculated by applying the proposed rates to test-year billing determinants as shown on page 1 of Schedule M-2.3. It should be pointed out that this amount is slightly less than the revenue requirement increase of $153,443,950 shown in Schedule A.

Q. Please summarize how KU proposes to allocate the electric revenue increase to the classes of service.

A. The increase for all rate classes served by KU was calculated by applying the same 9.57 percent increase to all of the rate classes that KU serves. With an increase of this magnitude, attempting to reduce the differences in rates of return among classes would result in large double digit increases for some classes. Increasing each rate class by the same percentage comports with gradualism and will minimize rate shock. In particular, with the third lowest rate of return as shown in the cost of service summary in Table 1 above, the increase to the residential class would have been particularly large if differences in rates of return among customer classes were reduced in this proceeding.

B. RESIDENTIAL ELECTRIC RATE INCREASE

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 $10.75 to $18.00 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 amount that would recover all of the customer-related distribution costs identified in the cost of service. The cost of service study indicates that the customer-related, non-volumetric fixed distribution cost for the residential class is $21.47 per customer per month. KU is proposing to increase the basic service charge in a direction that will more accurately reflect the actual cost of providing service, but is not proposing to go all of the way to the full amount indicated by the cost of service study. The derivation of the cost based residential basic service cost from data in the electric cost of service study is provided in Exhibit MJB-10.

Q. Does the current monthly basic service charge of $10.75 adequately recover customer-related costs from residential customers?

A. No. The current basic service charge of $10.75 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. These customer-related costs are non-volumetric fixed distribution costs that are not related to a customer's energy or capacity usage. Based on calculations from the cost of service study shown in Exhibit MJB-10, customer-related costs are $21.47 per customer per month; therefore, the current service charge of $10.75 under-recovers customer-related fixed distribution costs by $10.72 per customer per month. When this under-recovery of $10.72 per customer per month is multiplied by the 5,164,249 customer months for KU's residential rate class during the test year, the result is $55,360,749 in non-volumetric customer-related fixed operating expenses and margins that are being "variablized" and recovered through a kWh energy charge rather than being recovered through the basic service charge. When this amount is recovered through the energy charge instead, the result is about 0.89 cents per kWh of fixed operating expenses and margins collected through the energy charge (calculated as $55,360,749 / 6,197,488,349 kWh = $0.0089 per kWh). Thus, compared to rates that reflect straight cost causation, the basic service charge is $10.72 per customer per month too low and the energy charge is 0.89 cents per kWh too high. The recovery of non-volumetric fixed operating expenses and margins through the energy charge results in intra-class subsidies, as I discuss below, and results in customer energy bills being more variable than necessary and does not provide the proper environment for energy efficiency and conservation, as Mr. Conroy discusses in his testimony.

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 the customer-related, non-volumetric fixed costs that should be collected through a fixed monthly charge. The collection of fixed costs through the energy charge typically results in customers with above-average usage subsidizing customers with below-average usage. In order to eliminate this source of intra-class subsidies, KU is pursuing a rate design that moves more in the direction of recovering fixed costs through fixed charges and variable costs through variable charges.

Q. What would be the impact of the proposed increase in the basic service charge on the average customer?

A. Given a specified increase for the class, the average residential customer would see the same increase whether all of the increase is recovered through the basic service charge or through an increase of both the basic service charge and energy charge. Ultimately, the proposed rate for any given class of customers is based on averages and any rate design that was revenue neutral (i.e., generates the same amount of revenue) would have no impact whatsoever on a customer with a usage equal to the class average. 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.

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 both a rural and urban service territories, low usage customers tend to be loads like vacation homes, hunting cabins, fishing cabins, boat docks, 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 revenue that was insufficient to support the investment necessary to serve the types of low usage loads described above. Such a rate design would result in these customers being subsidized by the other customers who have above-average usage. A rate design with a low basic service charge and with a significant portion of the utility’s fixed operating expenses and margins recovered through the energy charge sends an improper economic signal to customers. It sends a signal that it is relatively inexpensive to provide the minimum set of equipment necessary to provide service to customers, and this is definitely not the case.

C. OPTIONAL RESIDENTIAL TIME-OF-DAY RATES

Q. What is the purpose of residential time-of-day rate options?

A. Time-of-day rates more accurately reflect the actual cost of providing service to customers. Production and transmission plant costs are designed to meet the maximum load requirements placed on the systems. Because loads vary significantly throughout the course of a day, the likelihood of maximum loads occurring during certain hours greatly exceeds the likelihood of maximum system loads occurring during other hours of the day. It is therefore reasonable from a cost of service perspective to recover the majority of the Company's fixed production and transmission costs through the application of higher charges that would be applicable during on-peak periods. Time-of-day rates also send a better price signal to customers encouraging them to reduce their loads during hours of the day for which the Company would have to install new production and transmission facilities to meet load increases on the system in the future. Time-of-day rates represent a standard ratemaking tool to encourage the efficient utilization of KU's generation and transmission resources on the part of customers. The introduction of time-of-day rates for residential customers that the Company is proposing in this proceeding will provide customers with the opportunity to reduce their energy bills by moving usage from on-peak to off-peak periods. The derivation of the Residential time-of-day rate options that KU is proposing is shown in Exhibit MJB-

11. As shown on page 1 of Exhibit MJB-11, the on-peak windows of 7 AM to 11 AM in the winter and 1 PM to 5 PM in the summer capture 76.7% of KU and LG&E's combined peaks for the period January 2000 through August 2014. The on-peak windows were constructed to capture the majority of the combined peaks while not being overly large, which would make them less useful to customers as well as reducing the on-peak/off-peak price differential. The summer peak period, which is the peak that typically drives KU's and LG&E's capacity planning process, captures 73 of the 74 summer peaks for the period January 2000 through August 2014.

Q. Describe the time-of-use rate options that the Company is proposing for residential customers.

A. There are two time-of-day rate options that the Company is offering to residential customers, an all-energy rate option with a time differentiated energy charge and a demand rate option with a time differentiated demand charge. Customers can opt to take service under either one of these options or to remain on the standard residential service rate, but the decision to take either of the options is voluntary. The time-of-day periods for the winter months of October through April are:

All-Energy Rate Option

	Off-Peak	On-Peak
Weekdays	11 AM - 7 AM	7 AM – 11 AM
Weekends	All Hours	

Demand Rate Option

	Off Peak	On-Peak
Weekdays	11 AM - 7 AM	7 AM – 11 AM
Weekends	All Hours	

The time-of-day periods for the summer months of May through September are:

All-Energy Rate Option

	Off-Peak	On-Peak
Weekdays	5 PM – 1 PM	1 PM - 5 PM
Weekends	All Hours	

Demand Rate Option

	Off Peak	On-Peak
Weekdays	5 PM – 1 PM	1 PM – 5 PM
Weekends	All Hours	

The months included in the winter and summer periods are consistent with the months included in the winter and summer periods in the commercial and industrial time-of-day rates that KU offers. The time-of-day rates that apply to the on-peak and off-peak periods are:

All-Energy Rate Option

Basic Service Charge: $18.00 per month

Plus an Energy Charge:
Off Peak Hours: $0.051 per kWh
On Peak Hours: $0.25874 per kWh

Demand Rate Option

Basic Service Charge: $18.00 per month

Plus an Energy Charge: $ 0.04008 per kWh

Plus a Demand Charge:
Off Peak Hours: $ 3.25 per kW
On Peak Hours: $11.56 per kW

The on-peak demand charge will apply to the customer's maximum integrated hourly demand during the on-peak period for each month.

Q. Explain the derivation of KU's residential time of day rates.

A. Derivation of the on-peak and off-peak periods and calculation of the on-peak and off-peak time-of-day rates are provided in Exhibit MJB-11. KU's proposed Residential Time-of-Day rates were developed to be revenue neutral compared to the existing Residential Service electric rate. Using data from the Company's forecasted integrated hourly demands, which included a sample of the residential demand usage for each hour of the forecast period, the kWhs of energy and kW demand for each time period was determined.

For the TOD Residential Energy rate, the hourly demands from the forecast that fell into the On-Peak period (7am – 11am in the months of October – April and 1pm – 5pm in the months of May – September) were summed together to determine the On-Peak Energy consumed and the remaining hourly kWh usage was summed to determine the Off-Peak Energy consumed. The Off Peak Energy rate includes the total unitized energy-related and distribution demand-related costs based on the Cost of Service Study Residential Unit Charge calculation shown in Exhibit MJB-10. The On-Peak Energy rate was set to collect the remaining revenue requirement needed to match the total revenue collected from the current Residential customer class less the revenue from the Customer Charge and Off Peak Energy rate. Thus, the On-Peak Energy charge includes all unitized costs included in the Off-Peak Energy charge plus production and transmission-demand related costs expressed as a charge per kWh.

For the TOD Residential Demand rate, the highest hourly demand for each month in the forecast which fell into the On-Peak window was summed together to determine the On-Peak demand kW. To determine the Off-Peak demand kW, the highest hourly demand in each month regardless of the hour in which is occurred was summed together. The Energy charge was set to collect Energy-related costs based on the Cost of Service Study Residential Unit Charge calculation shown in Exhibit MJB-10 and the Off-Peak Demand rate was set to collect only distribution-demand related costs also shown in MJB-10. The On-Peak Demand rate was set to collect the remaining revenue requirement needed to match the total revenue collected from the current Residential customer class less the revenue from the Customer Charge, Energy Charge, and Off-Peak Demand Charge.

D. STANDBY CHARGES

Q. What are the proposed Supplemental/Standby Service charges?

A. The proposed demand charges per contract demand (kW or kVA) for customers taking service at secondary voltages is $12.84 per kW per month, for customers taking service at primary voltages is $11.63 per kW and for customers taking service at transmission voltage is $10.58 per kW per month 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:

Table 2		
		Charge
Standby Charge at Transmission Voltage	**$**	**10.58**
Plus: additional primary standby costs	$	1.05
Charge for Primary Standby Service	**$**	**11.63**
Plus: additional secondary standby costs	$	1.21
Charge for Primary Standby Service	**$**	**12.84**

Production and Transmission Costs represent annual fixed cost revenue requirements. The unit charge is calculated by multiplying the KU coincident peak demand by twelve months and dividing this product into the production and transmission fixed cost determined based on the rate of return proposed 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 Exhibit MJB-12.

E. REDUNDANT CAPACITY CHARGES

Q. What are the proposed Redundant Capacity charges?

A. The proposed demand charge for Redundant Capacity for primary voltage customers is $1.11 per kW or kVA per month of billing demand and the proposed demand charge for secondary voltage customers is $1.12 per kW per month of billing demand.

Q. How was the demand charge for the proposed Redundant Capacity rider determined?

A. The demand charge was determined by computing the distribution demand-related revenue requirements from the electric cost of service study for primary and secondary voltage service under KU's 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 Exhibit MJB-13.

F. OTHER CHARGES

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 move them more in the direction of straight cost based rates that more accurately reflect the unit costs from the cost of service study. A cost based rate is one that calculates and bills rate components using the same cost drivers used to allocate each classification of costs in the cost of service study. For example, the Company is proposing to increase the basic service charge for Residential Service

Rate RS from $10.75 to $18.00 per month to more accurately reflect the actual cost of providing service. As demonstrated in Exhibit MJB-10 this charge is calculated by dividing customer-related, non-volumetric fixed costs for the residential class by the number of customer-months for the residential class during the test year which results in a flat monthly charge per customer served.

IV. CONCLUSION

Q. Does this conclude your testimony?

A. Yes, it does.

VERIFICATION

COMMONWEALTH OF KENTUCKY)
) SS:
COUNTY OF JEFFERSON)

The undersigned, **Dr. Martin J. Blake**, being duly sworn, deposes and states that he is a Principal of The Prime Group, LLC, that he has personal knowledge of the matters set forth in the foregoing testimony and exhibits, and the answers contained therein are true and correct to the best of his information, knowledge and belief.

Martin J Blake
Dr. Martin J. Blake

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 14th day of November 2014.

Judy Schooler (SEAL)
Notary Public

My Commission Expires:

July 11, 2018

Exhibit MJB-1

Professional Experience and Educational Background

Professional Qualifications & Experience of Dr. Martin J. Blake

Q: PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND.

A: I received my Ph.D. in Agricultural Economics in 1976 from the University of Missouri, Columbia. My doctoral work centered on the areas of marketing and econometrics. I also hold a Master of Arts in Economics from the University of Missouri, Columbia, which I received in 1972. In addition, I received a Bachelor of Arts degree in Economics from Illinois Benedictine College in 1970.

Q: IN WHAT AREAS DOES YOUR PRACTICE CONCENTRATE?

A: As a member of The Prime Group, I have provided utility clients with assistance regarding rate design for both wholesale and retail rates; the development of rates to achieve strategic objectives; the unbundling of rates and the development of menus of rate alternatives for use by customers; performance-based rate and incentive rate development; state and federal regulatory filing development, testimony and support; cost of service development and support; and strategic planning. I have also been involved in the development of the Midwest ISO and represent Southern Illinois Power Cooperative and Hoosier Energy on the Midwest ISO Transmission Owners Committee, the Transmission Owners Tariff Working Group, the Finance Subcommittee and the Demand Response Working Group. I served a three year term as Chairman of the Transmission Owners Tariff Working Group. I have made presentations to train utility personnel in cost of service, rate making, utility finance, and utility marketing. I have provided marketing and marketing support services for utility clients and have assisted them in assessing their marketing capabilities and processes.

Q: PLEASE BRIEFLY SUMMARIZE YOUR AREAS OF PROFESSIONAL EXPERIENCE PRIOR TO JOINING THE PRIME GROUP.

A: I have professional experience as an economist and professor of economics, as a utility regulator, as a utility manager and executive and as a consultant.

Q: PLEASE DESCRIBE YOUR PROFESSIONAL EXPERIENCE AS AN ECONOMIST.

A: From January 1977 to December 1986, I was employed first as an Assistant Professor, then as an Associate Professor, and finally as a Professor of Agricultural Economics at New Mexico State University in Las Cruces, New Mexico ("NMSU"). I was the head of the undergraduate program and taught agricultural economics and econometrics. While at NMSU, I also worked as a consultant for various clients, providing price forecasting, load forecasting, and marketing services. From 1992 through 1994, I taught mathematical economics and econometrics as an Adjunct Professor in the Economics Department at the University of Louisville. Prior to my joining the faculty at NMSU, I served in the U. S. Army as an instructor of economics, statistics, and accounting at the U. S. Army Institute of Administration at Fort Benjamin Harrison, Indianapolis, Indiana.

I also have a variety of experience with the application of economics to utility public policy issues. In addition to my experience as a utility regulator and executive, which I describe below, I taught retail and wholesale pricing for electric utilities at the NARUC Annual Regulatory Studies Program at Michigan State University for thirteen years. From May 1983 to August 1983, while on a sabbatical leave from NMSU, I served as a Policy Analyst for the Assistant Secretary for Land and Water at the U. S. Department of Interior.

Q: PLEASE DESCRIBE YOUR PROFESSIONAL EXPERIENCE AS A UTILITY REGULATOR.

A: From January 1987 to November 1990, I served as a Commissioner and as the Chairman of the New Mexico Public Service Commission. As a Commissioner, my duties included making policy and adjudicatory decisions regarding rates, terms of service, financing, certificates of public convenience and necessity, and complaints for electric, natural gas, water, and sewer utilities. As Chairman, I supervised a staff of 32 professionals and 16 support staff. During my tenure on the New Mexico Commission, I also served as Chairman of the Western Conference of Public Service Commissioners Electric Committee and as Chairman of the Committee on Regional Electric Power Cooperation, a group composed of state public service commissioners and representatives from the state energy offices of the 13 western states.

As a Commissioner, I interpreted legislation, reviewed prior Commission cases to determine the precedents that they provided, drafted rules and regulations, wrote orders, and served as an arbitrator in alternative dispute resolution proceedings. I performed adjudicatory and regulatory functions for the four years that I served on the Commission.

Q: PLEASE DESCRIBE YOUR PROFESSIONAL EXPERIENCE AS A UTILITY MANAGER.

A: From December, 1990 to June 1996, I was employed by Louisville Gas and Electric Company ("LG&E"). Initially, I served as LG&E's Director of Regulatory Planning. In this position, I was responsible for coordinating all of LG&E's state and federal regulatory efforts, and prepared and presented testimony to regulators.

My areas of responsibility were expanded in April 1994 to include marketing and strategic planning. As the Director, Marketing, Planning and Regulatory Affairs, I was responsible for coordinating LG&E's retail gas and electric marketing, strategic planning, and state and federal regulatory efforts. I continued to be employed in that capacity at LG&E until June 1996, when I joined the Prime Group as one of its Principals.

Q: PLEASE DESCRIBE THE INDUSTRY GROUPS IN WHICH YOU HAVE PARTICIPATED.

A: I have served on several regional transmission coordination groups such as the Interregional Transmission Coordination Forum, and the General Agreement on Parallel Paths, as well as the following committees of the Edison Electric Institute ("EEI") -- Economics and Public Policy Executive Advisory Committee, Strategic Planning Executive Advisory Committee, Transmission Task Force, and Power Supply Policy Technical Task Force.

Q: HAVE YOU TAUGHT ANY COURSES OR SEMINARS IN THE UTILITY AREA?

A: Yes. I have taught the following courses at the NARUC Annual Regulatory Studies Program at Michigan State University: 1) retail ratemaking, 2) wholesale pricing, 3) rate of return regulation, 4) competitive market fundamentals, 5) electric industry overview, 6) the economics of power production and delivery, 7) electric system technologies, and 8) the institutions and organizations of the new electric utility industry. Each year, I also teach and conduct numerous workshops and programs and deliver invited presentations to utility managers and regulators on a variety of subjects.

Exhibit MJB-2

Prior Testimony

Prior Testimony of Dr. Martin J. Blake

Federal Energy Regulatory Commission

ER92-533	LG&E's open transmission access and authority to charge market-based rates for its generation.
ER94-1380	The first comparability tariff approved by the FERC.
ER97-4345	A market power analysis that was filed in support of OGE Energy Resources, Inc.'s request for the authority to charge market based rates.
ER98-511	A market power analysis that was filed in support of Oklahoma Gas and Electric Co.'s request for the authority to charge market based rates.
ER99-51	An affidavit in support of Commonwealth Edison Co.'s request for authority to charge cost based rates to its affiliates.
ER01-1938	Testimony in support of Southern Indiana Gas and Electric Company's request for a revision in transmission and ancillary service rates including cost of capital testimony
ER02-708	Testimony in support of Central Illinois Power Company's request for a revision in transmission and ancillary service rates including cost of capital testimony
NJ03-2	Testimony in support of Southern Illinois Power Company's request for a revision in ancillary service rates
EL03-53	Testimony regarding the calculation of avoided cost for a qualifying facility interconnecting with a cooperative
EL02-111	Testimony regarding the process for developing a combined transmission service rate that would apply to the combined Midwest ISO and PJM footprint
ER06-18	Filed Affidavit describing the compromise that was supported by the majority of stakeholders regarding cost allocation for reliability projects and explained the wide range of opinions on various issues that were ultimately resolved by the compromise.

ER11-2786 Filed Affidavit and Answering Testimony on behalf of Southern Illinois Power Cooperative analyzing the Wholesale Distribution Service Tariff filed by Ameren Services Company and identified problems with the calculation of the WDS rate.

ER11-2779 Filed Affidavit and Answering Testimony on behalf of Norris Electric Cooperative analyzing the Wholesale Distribution Service Tariff filed by Ameren Services Company and identified problems with the calculation of the WDS rate.

Arkansas Public Service Commission

96-360-U Direct and rebuttal testimony for Oklahoma Gas and Electric regarding recovery of stranded costs by Entergy Arkansas, Inc.

California Public Utility Commission

90-12-018 (phase 5) Direct and rebuttal testimony for Southern California Edison Company concerning the reasonableness of contracting by Southern California Edison with Integrated Energy Group ("IEG") to provide marketing services to Southern California Edison and the reasonableness of the resulting marketing services performed by IEG.

Illinois Commerce Commission

98-0013 and 98-0035 Testimony regarding non-discrimination with regard to affiliate transactions for electric utilities. I sponsored ComEd's proposed affiliate transactions rules and suggested some basic principles that the Illinois Commerce Commission should follow in developing rules and regulations for ensuring non-discrimination and non-cross subsidization in transactions with affiliated and unaffiliated alternative retail electric suppliers ("ARES").

98-0036 Testimony in a rulemaking to develop rules and regulations for assessing and assuring the reliability of the transmission and distribution systems as a part of electric utility restructuring in Illinois.

98-0147 and 98-0148 Testimony concerning standards of conduct and rules for functional separation. I sponsored ComEd's proposed standards of conduct and functional separation rules.

07-0572	Testimony in a reconciliation proceeding concerning the prudence and recovery of the costs of gas injections and withdrawals from the Hillsboro storage field.

Kentucky Public Service Commission

90-158	An LG&E rate case.
92-494	An LG&E biennial fuel adjustment clause review.
93-150	An application for approval of a DSM cost recovery mechanism and a set of initial programs.
94-332	An application for an environmental cost recovery mechanism.
92-494-B	Testimony regarding the confidentiality of coal bid data.
95-455	A biannual review of the environmental cost recovery mechanism.
91-423	Participation in the conference with Commission staff and intervenors to review LG&E's first integrated resource plan.
Other	Several fuel adjustment clause proceedings on behalf of LG&E.
98-489	Testimony on behalf of Blazer Energy Corp. in an application for an adjustment in their natural gas rates.
99-046	Direct and rebuttal testimony regarding Return on equity in support of Delta Natural Gas Company's request for an adjustment in rates
04-00067	Direct testimony regarding Return on Equity in support of Delta Natural Gas Company's request for an adjustment in rates
07- 00089	Direct testimony regarding Return on Equity in support of Delta Natural Gas Company's request for an adjustment in rates
10-00116	Direct testimony regarding Return on Equity in support of Delta Natural Gas Company's request for an adjustment in rates

Maryland Public Service Commission

9234	Provide Direct and Rebuttal Testimony supporting the rate design for Southern Maryland Electric Cooperative

Nevada Public Utility Commission

01-10001	Direct testimony on behalf of Shareholders Association to support Nevada Power Company's request for return on equity

New Mexico Public Utility Commission

2797	Direct and rebuttal testimony in a general rate case for Plains Electric Generation and Transmission Cooperative, Inc.
10-00379-UT	Sponsor the fully allocated class cost of service study for Kit Carson Electric Cooperative and explain the rate design for the proposed rates as reflected in the Rate Application
12-00375-UT	Filed an Affidavit in support of a Protest filed by Kit Carson Electric Cooperative opposing a Tri-State G&T rate increase.

Oklahoma Corporation Commission

PUD 960000116	Testimony in an Oklahoma Gas and Electric Company rate case, including rebuttal of intervenor and staff proposals to disallow certain marketing, advertising, economic development and research and development expenses.
PUD 200300226	Testimony in an Oklahoma Gas and Electric Company case regarding the prudence of natural gas transportation and storage contracts

Indiana Utility Regulatory Commission

41884	Direct and rebuttal testimony to support a request by eleven gas local distribution companies for switching from a quarterly gas cost adjustment mechanism to a monthly gas cost adjustment mechanism
42027	Direct testimony in support of a transfer of functional control of transmission assets from electric utilities in Indiana to the Midwest System Operator, Inc.
43861	Provide Direct and Rebuttal Testimony supporting the rate design for Jackson Rural Electric Membership Cooperative
44040	Provide Direct and Responsive Testimony regarding the Commission's investigation into the request for Waiver of the requirement for Jackson REMC and Harrison County REMC to provide end-use customers the

opportunity to participate in demand response programs offered by the Midwest ISO.

Colorado Public Utility Commission

C08-0059 Provide an independent review, assessment and recommendation concerning Public Service Company of Colorado's Application and request for the Commission to approve the Company's 2007 Colorado Resource Plan ("2007 CRP") and to review supporting testimony in this proceeding as it relates to the retirement of Cameo Units 1 and 2 and Arapahoe Units 3 and 4.

02S-594E Direct and surrebuttal testimony regarding pro forma adjustments to the revenue requirement in Aquila Networks-WPC rate case.

03S-539E Testimony regarding the use of zero intercept methodology to allocate distribution costs and determine an appropriate customer charge in an Aquila Networks-WPC rate case.

07A-447E Testimony regarding Public Service Company of Colorado's Integrated Resource Plan.

11AL-382E Testimony regarding Black Hills ECA mechanism.

11AL-387E Testimony regarding the revenue requirement requested by Black Hills for an increase in rates.

12AL-1052E Testimony regarding rate design in Black Hills Phase II rate case.

Virginia State Corporation Commission

PUE-2008-00076 Direct and Rebuttal testimony regarding rate design for Northern Neck Electric Cooperative

PUE-2009-00065 Direct and Rebuttal testimony regarding rate design for Craig-Botetourt Electric Cooperative

Iowa District Court for Hamilton County

No. LACV025993 Testimony that net metering was not appropriate for making payments to a wind generator. When a utility sells electric energy to a customer, it is charging a retail rate that recovers the cost of distribution, transmission and generation service. When a customer sells electric energy to a utility, it is selling only generation service. The customer cannot sell distribution and transmission service to a utility, as the customer does not own these assets. Net metering is a subsidy to the wind generator that is paid by other customers of the utility and paying the customer for generation service on the basis of a retail rate that includes recovery of distribution and transmission costs is not appropriate.

U.S. District Court, District of New Mexico

CIV-08-00026	Prepare Report analyzing whether the decision by Arkansas River Power Authority to repower an existing 25 MW natural gas-fired generation plant as a coal-fired generating plant with 44 MW of gross capacity in Lamar Colorado was prudent.

Exhibit MJB-3

Kentucky Jurisdictional Separation Study

KENTUCKY UTILITIES COMPANY
ELECTRIC COST OF SERVICE STUDY
JURISDICTIONAL SEPARATION

RATE BASE: THIRTEEN MONTH AVERAGE
ALLOCATION METHOD: AVG 12 CP (COMBINED CO SYS)

12 MONTHS ENDING JUNE 30, 2016

		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		8,868,523,964	7,862,178,029	460,302,601	546,043,334	209,440	545,833,894	172,084,603	373,749,291
2	LESS RESERVE FOR DEPRECIATION		2,985,197,561	2,633,674,749	176,617,026	174,905,786	166,657	174,739,130	55,280,732	119,458,397
3	NET PLANT IN SERVICE		5,883,326,402	5,228,503,280	283,685,575	371,137,548	42,784	371,094,764	116,803,871	254,290,893
4	CONST WORK IN PROGRESS		248,354,919	218,053,378	13,056,216	17,245,325	1,132	17,244,193	5,358,458	11,885,735
5	NET PLANT		6,131,681,321	5,446,556,658	296,741,791	388,382,873	43,916	388,338,957	122,162,328	266,176,629
	ADD:									
6	MATERIALS & SUPPLIES		45,480,732	40,223,725	2,436,113	2,820,893	906	2,819,988	886,227	1,933,760
7	FUEL INVENTORY		97,765,470	85,822,785	3,941,230	8,001,455	475	8,000,980	2,560,254	5,440,725
8	PREPAYMENTS		8,145,080	7,731,379	-	413,701	172	413,529	131,065	282,464
9	WORKING CASH		131,788,560	122,344,908	-	9,443,652	1,771	9,441,882	3,015,923	6,425,959
10	EMISSION ALLOWANCES		199,126	174,249	8,753	16,124	1	16,123	5,002	11,121
11	TOTAL ADDITIONS		283,378,968	256,297,047	6,386,096	20,695,825	3,324	20,692,501	6,598,472	14,094,029
	DEDUCT:									
12	RESERVE FOR DEF TAXES		884,835,714	789,021,702	43,141,556	52,672,457	19,460	52,652,997	16,586,477	36,066,520
13	RESERVE FOR ITC		92,993,888	80,778,668	4,150,438	8,064,782	311	8,064,471	2,502,043	5,562,428
14	CUSTOMER ADVANCES		2,472,128	2,445,372	26,756	-	-	-	-	-
15	CUSTOMER DEPOSITS-VIRGINIA		26,702,517	-	899,457	-	-	-	-	-
16	DEFERRED FUEL-VIRGINIA		-	-	-	-	-	-	-	-
17	OPEB UNFUNDED-VIRGINIA		29,367,667	-	1,444,097	0	-	0	-	-
18	WORKMANS COMPENSATION-FERC		2,178,554	-	-	108,567	-	108,567	34,767	73,800
19	VESTED VACATION-FERC		6,441,615	-	-	321,013	-	321,013	102,799	218,214
20	MEDICAL AND DENTAL RESERVE-FERC		1,355,653	-	-	67,558	-	67,558	21,634	45,924
21	TOTAL DEDUCTIONS		1,046,347,736	872,245,742	49,662,304	61,234,376	19,770	61,214,606	19,247,720	41,966,886
22	NET ORIGINAL COST RATE BASE		5,368,712,554	4,830,607,963	253,465,583	347,844,322	27,470	347,816,852	109,513,080	238,303,772
	DEVELOPMENT OF RETURN									
23	OPERATING REVENUES		1,838,424,883	1,642,376,592	77,526,753	118,521,538	502	118,521,035	38,497,545	80,023,490
	OPERATING EXPENSES									
24	OPERATION & MAINT EXPENSE		1,181,890,501	1,047,172,869	52,794,990	81,922,642	14,531	81,908,111	26,160,359	55,747,752
25	DEPRECIATION & AMORT EXP		239,971,068	213,000,412	12,060,943	14,909,713	5,623	14,904,090	4,701,987	10,202,103
26	REGULATORY CREDITS		-	-	-	-	-	-	-	-
27	TAXES OTHER THAN INC TAX		40,737,389	36,661,033	1,830,218	2,246,138	445	2,245,692	709,639	1,536,053
28	INCOME TAXES		107,414,252	99,602,110	2,665,244	5,324,974	(8,021)	5,332,995	1,988,842	3,344,154
29	(GAIN) / LOSS DISPOSITION ALLOWANCES		-	-	-	-	-	-	-	-
30	(GAIN) / LOSS DISPOSITION PROPERTY-VA		-	-	-	-	-	-	-	-
31	CHARITABLE CONTRIBUTIONS-VA		1,331,648	-	32,741	-	-	-	-	-
32	INTEREST ON CUSTOMER DEPOSITS-VA		31,771	-	1,071	-	-	-	-	-
33	ACCRETION EXPENSE		-	-	-	-	-	-	-	-
34	TOTAL OPERATING EXPENSES		1,571,376,629	1,396,436,424	69,385,207	104,403,466	12,577	104,390,889	33,560,827	70,830,062
35	RETURN		267,048,254	245,940,168	8,141,546	14,118,072	(12,075)	14,130,146	4,936,718	9,193,429
36	RATE OF RETURN		4.97%	5.09%	3.21%	4.06%	-43.96%	4.06%	4.51%	3.86%

RATE BASE: THIRTEEN MONTH AVERAGE
ALLOCATION METHOD: AVG 12 CP (COMBINED CO SYS)

12 MONTHS ENDING JUNE 30, 2016

	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	39,411	2,307	2,737	1	2,736	863	1,874
2 302-FRANCHISE	KURETPLT	55,919	55,919	-	-	-	-	-	-
3 303-SOFTWARE	PTDGPLT	94,925,631	84,153,983	4,926,952	5,844,697	2,242	5,842,455	1,841,946	4,000,509
4 TOTAL INTANGIBLE PLANT		95,026,006	84,249,313	4,929,259	5,847,434	2,243	5,845,191	1,842,809	4,002,383
PRODUCTION PLANT									
STEAM PRODUCTION PLANT									
5 310-LAND	DEMPROD	22,962,183	20,093,520	1,009,358	1,859,305	77	1,859,227	576,835	1,282,393
6 311-STRUCTURES AND IMPROVEMENTS	DEMPROD	327,322,673	286,430,292	14,388,256	26,504,124	1,102	26,503,022	8,222,696	18,280,326
7 312-BOILER PLANT EQUIPMENT	DEMPROD	3,801,121,355	3,326,247,740	167,087,440	307,786,175	12,799	307,773,376	95,488,241	212,285,135
8 314-TURBOGENERATOR UNITS	DEMPROD	341,176,024	298,552,946	14,997,213	27,625,864	1,149	27,624,716	8,570,707	19,054,008
9 315-ACCESSORY ELECTRIC EQUIP	DEMPROD	212,670,807	186,101,870	9,348,457	17,220,480	716	17,219,764	5,342,519	11,877,245
10 316-MISC POWER PLANT EQUIP	DEMPROD	40,265,712	35,235,321	1,769,976	3,260,414	136	3,260,278	1,011,518	2,248,761
11 317-ARO COST STEAM EQUIP	DEMPROD	189,370,852	165,712,775	8,324,252	15,333,825	638	15,333,187	4,757,199	10,575,989
12 FERC-AFUDC PRE	DEMFERC	17,053,963	-	6,000,712	11,053,251	-	11,053,251	3,429,327	7,623,924
13 FERC-AFUDC POST	DEMFERCP	22,028,831	-	-	22,028,831	-	22,028,831	6,834,556	15,194,275
14 TOTAL STEAM PROD PLANT		4,973,972,397	4,318,374,465	222,925,664	432,672,269	16,616	432,655,653	134,233,597	298,422,056
HYDRAULIC PRODUCTION PLANT									
15 330-LAND RIGHTS	DEMPROD	879,311	769,459	38,652	71,200	3	71,197	22,089	49,108
16 331-STRUCTURES AND IMPROVEMENTS	DEMPROD	1,626,321	1,423,145	71,489	131,687	5	131,682	40,855	90,827
17 332-RESERVOIRS, DAMS, AND WATER	DEMPROD	21,817,857	19,092,155	959,056	1,766,646	73	1,766,572	548,088	1,218,484
18 333-WATER WHEEL, TURBINES, GEN	DEMPROD	13,811,982	12,086,453	607,139	1,118,390	47	1,118,344	346,972	771,372
19 334-ACCESSORY ELECTRIC EQUIP	DEMPROD	1,324,616	1,159,132	58,227	107,257	4	107,253	33,276	73,977
20 335-MISC POWER PLANT EQUIP	DEMPROD	286,794	250,965	12,607	23,222	1	23,221	7,205	16,017
21 336-ROADS, RAILROADS, AND BRIDGES	DEMPROD	176,360	154,327	7,752	14,280	1	14,280	4,430	9,849
22 337-ARO COST HYDRO PROD EQUIP	DEMPROD	388,628	340,076	17,083	31,468	1	31,467	9,763	21,704
23 FERC-AFUDC PRE	DEMFERC	820	-	289	531	-	531	165	367
24 FERC-AFUDC POST	DEMFERCP	105,337	-	-	105,337	-	105,337	32,681	72,655
25 TOTAL HYDRAULIC PROD PLANT		40,418,026	35,275,713	1,772,294	3,370,020	136	3,369,884	1,045,523	2,324,360
OTHER PRODUCTION PLANT									
26 340-LAND & LAND RIGHTS	DEMPROD	298,979	261,627	13,142	24,209	1	24,208	7,511	16,697
27 341-STRUCTURES AND IMPROVEMENTS	DEMPROD	36,047,857	31,544,402	1,584,570	2,918,884	121	2,918,763	905,561	2,013,202
28 342-FUEL HOLDERS, PRODUCERS, ACC	DEMPROD	31,162,626	27,269,483	1,369,828	2,523,315	105	2,523,210	782,839	1,740,371
29 343-PRIME MOVERS	DEMPROD	823,323,410	720,465,719	36,191,162	66,666,528	2,772	66,663,756	20,682,766	45,980,990
30 344-GENERATORS	DEMPROD	59,041,243	51,665,228	2,595,300	4,780,715	199	4,780,516	1,483,179	3,297,337
31 345-ACCESSORY ELECTRIC EQUIP	DEMPROD	47,115,222	41,229,123	2,071,063	3,815,036	159	3,814,877	1,183,585	2,631,292
32 346-MISC POWER PLANT EQUIP	DEMPROD	5,492,796	4,806,581	241,449	444,765	18	444,747	137,985	306,762
33 347-ARO COST OTHER PROD EQUIP	DEMPROD	-	-	-	-	-	-	-	-
34 FERC-AFUDC PRE	DEMFERC	1,987	-	699	1,288	-	1,288	400	888
35 FERC-AFUDC POST	DEMFERCP	5,024,889	-	-	5,024,889	-	5,024,889	1,558,997	3,465,892
36 TOTAL OTHER PROD PLANT		1,007,509,008	877,242,165	44,067,215	86,199,628	3,375	86,196,253	26,742,822	59,453,431
37 TOTAL PRODUCTION PLANT		6,021,899,432	5,230,892,343	268,765,173	522,241,917	20,127	522,221,789	162,021,942	360,199,847

KENTUCKY UTILITIES COMPANY
ELECTRIC COST OF SERVICE STUDY
JURISDICTIONAL SEPARATION

RATE BASE: THIRTEEN MONTH AVERAGE
ALLOCATION METHOD: AVG 12 CP (COMBINED CO SYS)

12 MONTHS ENDING JUNE 30, 2016

	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	DEMTRANNF	29,756,906	28,333,519	1,423,278	109	109	-	-	-
2 352-STRUCTURES AND IMPROVEMENTS	DEMTRANNF	37,179,724	35,401,276	1,778,313	136	136	-	-	-
3 353-STATION EQUIPMENT	DEMTRANNF	260,992,385	248,508,118	12,483,311	956	956	-	-	-
4 354-TOWERS AND FIXTURES	DEMTRANNF	68,285,072	65,018,735	3,266,087	250	250	-	-	-
5 355-POLES AND FIXTURES	DEMTRANNF	229,752,570	218,762,623	10,989,105	842	842	-	-	-
6 356-OH CONDUCTORS AND DEVICES	DEMTRANNF	154,514,172	147,123,166	7,390,440	566	566	-	-	-
7 357-UNDERGROUND CONDUIT	DEMTRANNF	447,363	425,964	21,397	2	2	-	-	-
8 358-UG CONDUCTORS AND DEVICES	DEMTRANNF	1,157,970	1,102,580	55,386	4	4	-	-	-
9 359-ARO COST KY TRANS	DEMTRANNF	413,451	393,674	19,775	2	2	-	-	-
10 FERC-AFUDC PRE	DEMFERC	3,143,921	-	1,106,239	2,037,682	-	2,037,682	632,201	1,405,481
11 FERC-AFUDC POST	DEMFERCP	1,431,125	-	-	1,431,125	-	1,431,125	444,014	987,111
12 TOTAL KENTUCKY SYSTEM PROPERTY		787,074,659	745,069,655	38,533,331	3,471,673	2,867	3,468,806	1,076,215	2,392,592
VIRGINIA PROPERTY									
13 350-LAND & LAND RIGHTS	DEMVA	1,883,961	-	1,883,961	-	-	-	-	-
14 352-STRUCTURES AND IMPROVEMENTS	DEMVA	1,618,029	-	1,618,029	-	-	-	-	-
15 353-STATION EQUIPMENT	DEMVA	21,150,308	-	21,150,308	-	-	-	-	-
16 354-TOWERS AND FIXTURES	DEMVA	2,411,758	-	2,411,758	-	-	-	-	-
17 355-POLES AND FIXTURES	DEMVA	9,480,773	-	9,480,773	-	-	-	-	-
18 356-OH CONDUCTORS AND DEVICES	DEMVA	14,205,219	-	14,205,219	-	-	-	-	-
19 FERC-AFUDC PRE	DEMVA	324	-	324	-	-	-	-	-
20 FERC-AFUDC POST	DEMVA	4,332	-	4,332	-	-	-	-	-
21 TOTAL VIRGINIA PROPERTY		50,754,704	-	50,754,704	-	-	-	-	-
VIRGINIA PROPERTY-500 KV LINE									
22 350-LAND & LAND RIGHTS	DEMTRANNVF	280,371	280,370	-	1	1	-	-	-
23 354-TOWERS AND FIXTURES	DEMTRANNVF	4,769,323	4,769,305	-	18	18	-	-	-
24 355-POLES AND FIXTURES	DEMTRANNVF	51,358	51,358	-	0	0	-	-	-
25 356-OH CONDUCTORS AND DEVICES	DEMTRANNVF	3,129,378	3,129,366	-	12	12	-	-	-
26 FERC-AFUDC PRE	DEMFERC	-	-	-	-	-	-	-	-
27 FERC-AFUDC POST	DEMFERCP	-	-	-	-	-	-	-	-
28 TOTAL VIRGINIA PROPERTY-500 KV LINE		8,230,429	8,230,398	-	32	32	-	-	-
29 TOTAL TRANSMISSION PLANT		846,059,793	753,300,052	89,288,036	3,471,705	2,899	3,468,806	1,076,215	2,392,592

KENTUCKY UTILITIES COMPANY
ELECTRIC COST OF SERVICE STUDY
JURISDICTIONAL SEPARATION

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12 MONTHS ENDING JUNE 30, 2016

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ELECTRIC PLANT IN SERVICE CON'T									
DISTRIBUTION PLANT									
KENTUCKY DISTRIBUTION PLANT									
1 360-LAND & LAND RIGHTS	DEM360K	7,728,170	7,719,013	-	9,157	-	9,157	9,157	-
2 361-STRUCTURES AND IMPROVEMENTS	DEM361K	10,216,987	9,909,039	-	307,948	-	307,948	307,948	-
3 362-STATION EQUIPMENT	DEM362K	173,525,692	170,027,418	-	3,498,274	-	3,498,274	3,498,274	-
4 364-POLES, TOWERS, AND FIXTURES	DEM364K	329,576,141	329,576,141	-	-	-	-	-	-
5 365-OH CONDUCTORS AND DEVICES	DEM365K	336,362,320	336,362,320	-	-	-	-	-	-
6 366-UNDERGROUND CONDUIT	DEM366K	1,788,405	1,788,405	-	-	-	-	-	-
7 367-UG CONDUCTORS AND DEVICES	DEM367K	180,059,462	180,059,462	-	-	-	-	-	-
368-LINE TRANSFORMERS									
8 POWER POOL	DPRODKY	5,932,406	5,429,977	-	502,429	-	502,429	155,881	346,548
9 ALL OTHER	DEM368K	290,915,324	290,915,324	-	-	-	-	-	-
10 TOTAL 368-LINE TRANSFORMERS		296,847,730	296,345,301	-	502,429	-	502,429	155,881	346,548
11 369-SERVICES	CUST369K	89,746,639	89,746,639	-	-	-	-	-	-
12 370-METERS	CUST370K	73,410,395	73,127,621	-	282,774	-	282,774	66,911	215,863
13 371-INSTALL ON CUSTOMER PREMISES	CUST371K	17,289,842	17,289,842	-	-	-	-	-	-
14 373-STREET LIGHTING	CUST373K	100,291,893	100,291,893	-	-	-	-	-	-
15 374-ARO COST KY ELEC DISTRIB	DEM374K	913,218	913,218	-	-	-	-	-	-
16 TOTAL KENTUCKY DISTRIB PLANT		1,617,756,893	1,613,156,311	-	4,600,582	-	4,600,582	4,038,171	562,411
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	7,845,255	-	7,845,255	-	-	-	-	-
20 364-POLES, TOWERS, AND FIXTURES	DEM364V	26,127,299	-	26,127,299	-	-	-	-	-
21 365-OH CONDUCTORS AND DEVICES	DEM365V	22,622,780	-	22,622,780	-	-	-	-	-
22 367-UG CONDUCTORS AND DEVICES	DEM367V	4,107,123	-	4,107,123	-	-	-	-	-
368-LINE TRANSFORMERS									
23 POWER POOL	DPRODVA	128,028	-	128,028	-	-	-	-	-
24 ALL OTHER	DEM368V	13,795,797	-	13,795,797	-	-	-	-	-
25 TOTAL 368-LINE TRANSFORMERS		13,923,824	-	13,923,824	-	-	-	-	-
26 369-SERVICES	CUST369V	5,218,706	-	5,218,706	-	-	-	-	-
27 370-METERS	CUST370V	3,759,366	-	3,759,366	-	-	-	-	-
28 371-INSTALL ON CUSTOMER PREMISES	CUST371V	855,169	-	855,169	-	-	-	-	-
29 373-STREET LIGHTING	CUST373V	2,650,328	-	2,650,328	-	-	-	-	-
30 TOTAL VIRGINIA DISTRIB PLANT		87,751,274	-	87,751,274	-	-	-	-	-
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	69,594	-	-	69,594	69,594	-	-	-
34 364-POLES, TOWERS, AND FIXTURES	DEM364T	47,927	-	-	47,927	47,927	-	-	-
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	4,199	-	-	4,199	4,199	-	-	-
39 371-INSTALL ON CUSTOMER PREMISES	CUST371T	-	-	-	-	-	-	-	-
40 TOTAL TENNESSEE DISTRIB PLANT		179,518	-	-	179,518	179,518	-	-	-
41 TOTAL DISTRIBUTION PLANT		1,705,687,685	1,613,156,311	87,751,274	4,780,099	179,518	4,600,582	4,038,171	562,411

KENTUCKY UTILITIES COMPANY
ELECTRIC COST OF SERVICE STUDY
JURISDICTIONAL SEPARATION

RATE BASE: THIRTEEN MONTH AVERAGE
ALLOCATION METHOD: AVG 12 CP (COMBINED CO SYS)

12 MONTHS ENDING JUNE 30, 2016

	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	2,814,999	2,536,226	138,422	140,351	67	140,283	44,923	95,360
2 390-STRUCTURES AND IMPROVEMENTS	LABOR	57,524,546	51,827,822	2,828,656	2,868,067	1,376	2,866,691	918,009	1,948,683
3 391-OFFICE EQUIPMENT	LABOR	53,880,876	48,544,990	2,649,486	2,686,401	1,289	2,685,112	859,861	1,825,251
4 392-TRANSPORTATION EQUIPMENT	LABOR	17,880,994	16,110,218	879,263	891,513	428	891,086	285,355	605,731
5 393-STORES EQUIPMENT	LABOR	877,380	790,492	43,143	43,745	21	43,724	14,002	29,722
6 394-TOOLS, SHOP, AND GARAGE EQUIP	LABOR	11,844,391	10,671,427	582,425	590,539	283	590,256	189,019	401,237
7 395-LABORATORY EQUIPMENT	LABOR	-	-	-	-	-	-	-	-
8 396-POWER OPERATED EQUIPMENT	LABOR	2,253,006	2,029,888	110,787	112,331	54	112,277	35,955	76,322
397-COMMUNICATION EQUIPMENT									
9 DEMAND SIDE MANAGEMENT	LABPTDKY	4,931,299	4,931,299	-	-	-	-	-	-
10 ALL OTHER	LABOR	47,519,469	42,813,560	2,336,676	2,369,233	1,136	2,368,096	758,342	1,609,754
11 TOTAL 397-COMMUNICATION EQUIPMENT		52,450,768	47,744,859	2,336,676	2,369,233	1,136	2,368,096	758,342	1,609,754
12 398-MISC EQUIPMENT	LABOR	-	-	-	-	-	-	-	-
13 TOTAL GENERAL PLANT		199,526,961	180,255,923	9,568,859	9,702,179	4,654	9,697,525	3,105,466	6,592,059
PLANT HELD FOR FUTURE USE									
14 PRODUCTION	DEMPROD	-	-	-	-	-	-	-	-
15 TRANSMISSION	DEMTRANNF	-	-	-	-	-	-	-	-
16 DISTRIBUTION	DEM360K	324,088	324,088	-	-	-	-	-	-
17 GENERAL	LABOR	-	-	-	-	-	-	-	-
18 TOTAL PLANT HELD FOR FUTURE USE		324,088	324,088	-	-	-	-	-	-
19 TOTAL ELECTRIC PLANT		8,868,523,964	7,862,178,029	460,302,601	546,043,334	209,440	545,833,894	172,084,603	373,749,291

KENTUCKY UTILITIES COMPANY
ELECTRIC COST OF SERVICE STUDY
JURISDICTIONAL SEPARATION

RATE BASE: THIRTEEN MONTH AVERAGE
ALLOCATION METHOD: AVG 12 CP (COMBINED CO SYS)

12 MONTHS ENDING JUNE 30, 2016

		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									
	ACCUMULATED PROVISION FOR DEP									
	PRODUCTION PLANT									
	STEAM PRODUCTION PLANT									
1	SYSTEM	STMSYS	1,548,926,961	1,355,419,710	68,086,813	125,420,438	5,215	125,415,222	38,910,705	86,504,518
2	FERC-AFUDC PRE	DEMFERC	16,849,648	-	5,928,821	10,920,828	-	10,920,828	3,388,242	7,532,586
3	FERC-AFUDC POST	DEMFERCP	5,129,653	-	-	5,129,653	-	5,129,653	1,591,501	3,538,152
4	TOTAL STEAM PROD PLT		1,570,906,263	1,355,419,710	74,015,634	141,470,919	5,215	141,465,703	43,890,448	97,575,256
	HYDRAULIC PRODUCTION PLANT									
5	SYSTEM	HYDSYS	10,719,986	9,380,739	471,223	868,024	36	867,988	269,298	598,690
6	FERC-AFUDC PRE	DEMFERC	3,323	-	1,169	2,154	-	2,154	668	1,486
7	FERC-AFUDC POST	DEMFERCP	9,813	-	-	9,813	-	9,813	3,045	6,768
8	TOTAL HYDRO PROD PLT		10,733,122	9,380,739	472,392	879,990	36	879,954	273,010	606,944
	OTHER PRODUCTION PLANT									
9	SYSTEM	OTHSYS	250,563,803	219,260,899	11,014,135	20,288,769	844	20,287,926	6,294,431	13,993,494
10	FERC-AFUDC PRE	DEMFERC	1,515	-	533	982	-	982	305	677
11	FERC-AFUDC POST	DEMFERCP	1,174,955	-	-	1,174,955	-	1,174,955	364,536	810,419
12	TOTAL OTHER PROD PLT		251,740,273	219,260,899	11,014,668	21,464,706	844	21,463,862	6,659,271	14,804,591
13	TOTAL PRODUCTION PLANT		1,833,379,657	1,584,061,348	85,502,694	163,815,615	6,095	163,809,520	50,822,729	112,986,791
	TRANSMISSION PLANT									
14	KENTUCKY SYSTEM PROPERTY	KYTRPLTXF	317,053,874	301,461,787	15,590,927	1,160	1,160	-	-	-
15	VIRGINIA PROPERTY	TRPLTVA	30,287,284	4,226,088	26,061,179	16	16	-	-	-
16	FERC-AFUDC PRE	DEMFERC	2,795,967	-	983,806	1,812,161	-	1,812,161	562,232	1,249,929
17	FERC-AFUDC POST	DEMFERCP	261,983	-	-	261,983	-	261,983	81,282	180,701
18	TOTAL TRANSMISSION PLANT		350,399,108	305,687,875	42,635,913	2,075,320	1,176	2,074,144	643,514	1,430,630
19	DISTRIBUTION PLANT-VA & TN	DIRACDEP	42,078,160	-	41,921,885	156,275	156,275	-	-	-
20	DISTRIBUTION PLANT-KY & FERC	DISTPLTKF	626,518,921	624,737,225	-	1,781,696	-	1,781,696	1,563,888	217,808
21	TOTAL DISTRIBUTION PLANT		668,597,081	624,737,225	41,921,885	1,937,971	156,275	1,781,696	1,563,888	217,808
22	GENERAL PLANT	GENPLT	84,809,260	76,618,074	4,067,259	4,123,927	1,978	4,121,949	1,319,984	2,801,965
23	INTANGIBLE PLANT-FRANCHISES	PLT302TOT	52,578	52,578	-	-	-	-	-	-
24	INTANGIBLE PLANT-SOFTWARE	PLT303TOT	47,959,877	42,517,649	2,489,275	2,952,953	1,133	2,951,821	930,618	2,021,203
25	TOTAL DEPRECIATION RESERVE		2,985,197,561	2,633,674,749	176,617,026	174,905,786	166,657	174,739,130	55,280,732	119,458,397
26	NET ELECTRIC PLANT IN SERVICE		5,883,326,402	5,228,503,280	283,685,575	371,137,548	42,784	371,094,764	116,803,871	254,290,893

KENTUCKY UTILITIES COMPANY
ELECTRIC COST OF SERVICE STUDY
JURISDICTIONAL SEPARATION

RATE BASE: THIRTEEN MONTH AVERAGE
ALLOCATION METHOD: AVG 12 CP (COMBINED CO SYS)

12 MONTHS ENDING JUNE 30, 2016

	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)
ADDITIONS TO NET PLANT									
CONSTRUCTION WORK IN PROGRESS									
PRODUCTION PLANT									
1 SYSTEM	PRODSYS	202,624,801	177,310,910	8,906,861	16,407,030	682	16,406,348	5,090,152	11,316,196
2 FERC-AFUDC PRE	DEMFERC	-	-	-	-	-	-	-	-
3 FERC-AFUDC POST	DEMFERCP	-	-	-	-	-	-	-	-
4 TOTAL PRODUCTION PLANT		202,624,801	177,310,910	8,906,861	16,407,030	682	16,406,348	5,090,152	11,316,196
TRANSMISSION PLANT									
5 SYSTEM	KYTRPLTXF	13,137,379	12,491,309	646,022	48	48	-	-	-
6 TRANS VIRGINIA-KY SYSTEM	KYTRPLTXF	-	-	-	-	-	-	-	-
7 TRANS VIRGINIA	VATRPLT	-	-	-	-	-	-	-	-
8 FERC-AFUDC PRE	DEMFERC	-	-	-	-	-	-	-	-
9 FERC-AFUDC POST	DEMFERCP	-	-	-	-	-	-	-	-
10 TOTAL TRANSMISSION PLT		13,137,379	12,491,309	646,022	48	48	-	-	-
11 DISTRIBUTION - VA & TN	DIRCWIP	2,676,604	-	2,676,604	-	-	-	-	-
12 DISTRIBUTION - KY & FERC	PLANTKY	12,677,442	12,677,442	-	-	-	-	-	-
13 TOTAL DISTRIBUTION PLT		15,354,047	12,677,442	2,676,604	-	-	-	-	-
14 GENERAL	GENPLT	17,238,692	15,573,716	826,728	838,247	402	837,845	268,305	569,539
15 TOTAL CWIP		248,354,919	218,053,378	13,056,216	17,245,325	1,132	17,244,193	5,358,458	11,885,735
WORKING CAPITAL									
MATERIALS & SUPPLIES									
16 FUEL STOCK	ENERGY	97,765,470	85,822,785	3,941,230	8,001,455	475	8,000,980	2,560,254	5,440,725
PLANT MATERIAL & SUPPLIES									
17 PRODUCTION	PRODPLT	24,818,928	21,558,836	1,107,701	2,152,391	83	2,152,308	667,765	1,484,544
18 TRANSMISSION	TRANPLTXF	4,459,880	3,987,258	472,606	15	15	-	-	-
19 DISTRIBUTION	DISTPLT	5,680,713	5,372,541	292,252	15,920	598	15,322	13,449	1,873
20 GENERAL	GENPLT	-	-	-	-	-	-	-	-
21 STORES UNDISTRIBUTED	M_S	10,521,211	9,305,090	563,554	652,567	210	652,357	205,014	447,343
22 TOTAL PLT MAT & SUPPLIES		45,480,732	40,223,725	2,436,113	2,820,893	906	2,819,988	886,227	1,933,760
23 TOTAL MATERIALS & SUPPLIES		143,246,202	126,046,511	6,377,343	10,822,348	1,381	10,820,967	3,446,482	7,374,486
PREPAYMENTS									
24 PREPAYMENTS OTHER THAN TAXES	EXP9245TOT	6,882,841	6,469,140	-	413,701	172	413,529	131,065	282,464
25 PUBLIC SERVICE COMM TAX	REVKY	1,262,239	1,262,239	-	-	-	-	-	-
26 TOTAL PREPAYMENTS		8,145,080	7,731,379	-	413,701	172	413,529	131,065	282,464
27 WORKING CASH - CALC BY JURIS		131,788,560	122,344,908	-	9,443,652	1,771	9,441,882	3,015,923	6,425,959
28 TOTAL WORKING CAPITAL		283,179,842	256,122,797	6,377,343	20,679,702	3,323	20,676,378	6,593,470	14,082,909
29 EMISSION ALLOWANCES	DEMPROD	199,126	174,249	8,753	16,124	1	16,123	5,002	11,121
30 TOTAL ADDITIONS TO NET PLANT		531,733,887	474,350,424	19,442,313	37,941,151	4,457	37,936,694	11,956,930	25,979,764

KENTUCKY UTILITIES COMPANY
ELECTRIC COST OF SERVICE STUDY
JURISDICTIONAL SEPARATION

RATE BASE: THIRTEEN MONTH AVERAGE
ALLOCATION METHOD: AVG 12 CP (COMBINED CO SYS)

12 MONTHS ENDING JUNE 30, 2016

	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)
DEDUCTIONS FROM NET PLANT									
ACCUMULATED DEFERRED INC TAX									
PRODUCTION PLANT									
1 SYSTEM	PRODSYS	634,662,075	555,373,822	27,898,099	51,390,154	2,137	51,388,017	15,943,391	35,444,626
2 FERC-AFUDC PRE	DEMFERC	-	-	-	-	-	-	-	-
3 FERC-AFUDC POST	DEMFERCP	-	-	-	-	-	-	-	-
4 TOTAL PRODUCTION PLANT		634,662,075	555,373,822	27,898,099	51,390,154	2,137	51,388,017	15,943,391	35,444,626
TRANSMISSION PLANT									
5 KENTUCKY SYSTEM PROPERTY	KYTRPLTXF	71,922,187	68,385,195	3,536,729	263	263	-	-	-
6 VIRGINIA PROPERTY-500 KV LINE	DEMTRANNVF	-	-	-	-	-	-	-	-
7 VIRGINIA PROPERTY-OTHER	VATRPLT	4,191,870	-	4,191,870	-	-	-	-	-
8 FERC-AFUDC PRE	DEMFERC	-	-	-	-	-	-	-	-
9 FERC-AFUDC POST	DEMFERCP	-	-	-	-	-	-	-	-
10 TOTAL TRANSMISSION PLANT		76,114,057	68,385,195	7,728,599	263	263	-	-	-
11 DISTRIBUTION - VA	DIRACDFTX	6,687,884	-	6,687,884	-	-	-	-	-
12 DISTRIBUTION PLT KY,FERC & TN	DPLTXVA	150,127,898	149,684,354	-	443,544	16,657	426,887	374,701	52,186
13 TOTAL DISTRIBUTION PLANT		156,815,782	149,684,354	6,687,884	443,544	16,657	426,887	374,701	52,186
14 GENERAL	GENPLT	17,243,800	15,578,331	826,973	838,495	402	838,093	268,385	569,708
15 TOTAL DEFERRED INCOME TAX		884,835,714	789,021,702	43,141,556	52,672,457	19,460	52,652,997	16,586,477	36,066,520
ACCUM DEFER INVEST TAX CREDITS									
16 PRODUCTION	PRODPLT	92,993,888	80,778,668	4,150,438	8,064,782	311	8,064,471	2,502,043	5,562,428
17 TRANSMISSION	TRANPLTXF	-	-	-	-	-	-	-	-
18 TRANSMISSION - VA	TRPLTVA	-	-	-	-	-	-	-	-
18 DISTRIBUTION - VA	DIRACITC	-	-	-	-	-	-	-	-
20 DISTRIBUTION PLT KY,FERC & TN	DPLTXVA	-	-	-	-	-	-	-	-
21 GENERAL	GENPLT	-	-	-	-	-	-	-	-
22 TOTAL DEFERRED INVEST CREDIT		92,993,888	80,778,668	4,150,438	8,064,782	311	8,064,471	2,502,043	5,562,428
23 CUSTOMER ADVANCES	CUSTADV	2,472,128	2,445,372	26,756	-	-	-	-	-
24 CUSTOMER DEPOSITS-VIRGINIA	CUSTDEP	26,702,517	-	899,457	-	-	-	-	-
25 DEFERRED FUEL-VIRGINIA	DFUELVA	-	-	-	-	-	-	-	-
26 OPEB UNFUNDED-VIRGINIA	LABOR	29,367,667	-	1,444,097	0	-	0	-	-
27 WORKMANS COMPENSATION-FERC	LABOR	2,178,554	-	-	108,567	-	108,567	34,767	73,800
28 VESTED VACATION-FERC	LABOR	6,441,615	-	-	321,013	-	321,013	102,799	218,214
29 MEDICAL AND DENTAL RESERVE-FERC	LABOR	1,355,653	-	-	67,558	-	67,558	21,634	45,924
30 TOTAL DEDUCTIONS FROM NET PLT		1,046,347,736	872,245,742	49,662,304	61,234,376	19,770	61,214,606	19,247,720	41,966,886
31 RATE BASE		5,368,712,554	4,830,607,963	253,465,583	347,844,322	27,470	347,816,852	109,513,080	238,303,772

KENTUCKY UTILITIES COMPANY
ELECTRIC COST OF SERVICE STUDY
JURISDICTIONAL SEPARATION

RATE BASE: THIRTEEN MONTH AVERAGE
ALLOCATION METHOD: AVG 12 CP (COMBINED CO SYS)

12 MONTHS ENDING JUNE 30, 2016

	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)
OPERATING REVENUES									
SALES OF ELECTRICITY									
1 440-RESIDENTIAL		636,681,927	598,599,985	38,081,941	-	-	-	-	-
2 442-COMMERCIAL		404,163,983	385,820,490	18,343,493	-	-	-	-	-
3 442-INDUSTRIAL		482,180,321	470,749,538	11,430,783	-	-	-	-	-
4 444-PUBLIC ST & HWY LIGHTING		9,256,010	8,843,378	412,632	-	-	-	-	-
5 445-OTHER PUBLIC AUTHORITIES		134,905,779	128,071,668	6,834,111	-	-	-	-	-
6 447-SALES FOR RESALE-MUNICIPALS		115,977,824	-	-	115,977,824	-	115,977,824	37,685,971	78,291,853
7 447-SALES FOR RESALE-CITY OF PARIS	ENERGY	2,935,446	2,576,862	118,337	240,247	14	240,233	76,873	163,360
8 447-SALES FOR RESALE-OFF SYSTEM:									
9 DEMAND	DEMPROD	-	-	-	-	-	-	-	-
10 ENERGY	ENERGY	25,243,043	22,159,442	1,017,626	2,065,975	123	2,065,853	661,058	1,404,795
11 TOTAL 447-OFF SYSTEM		25,243,043	22,159,442	1,017,626	2,065,975	123	2,065,853	661,058	1,404,795
12 449-PROVISION FOR RATE REFUND		-	-	-	-	-	-	-	-
13 TOTAL ELECTRIC SALES REVENUES		1,811,344,332	1,616,821,364	76,238,923	118,284,046	137	118,283,909	38,423,901	79,860,008
OTHER OPERATING REVENUES									
14 450-LATE PAYMENT CHARGES	DIR450REV	3,956,662	3,786,198	170,356	108	-	108	108	-
15 451-RECONNECT CHARGES	DIR451REC	2,159,044	2,027,537	131,507	-	-	-	-	-
16 451-OTHER SERVICE CHARGES	DIR451OTH	55,747	55,410	337	-	-	-	-	-
17 454-RENT FROM ELEC PROPERTY	DIR454REV	3,679,709	3,491,578	187,827	304	304	-	-	-
18 456-TRANSMISSION SERVICE	DEMTRANNF	13,968,167	13,300,016	668,100	51	51	-	-	-
19 456-ANCILLARY SERVICES	DEMTRAN	2,927,269	2,561,566	128,675	237,028	10	237,018	73,536	163,482
20 456-TAX REMITTANCE COMPENSATION	REVKY	7,206	7,206	-	-	-	-	-	-
21 456-RETURN CHECK CHARGES	DIR456CHK	142,262	142,291	(29)	-	-	-	-	-
22 456-OTHER MISC REVENUES	DIR456OTH	12,814	12,814	-	-	-	-	-	-
23 456-EXCESS FACILITIES CHARGES	DIR456FAC	31,832	30,775	1,057	-	-	-	-	-
24 456-FORFEITED REFUNDABLE ADVANCES	REVKY	139,838	139,838	-	-	-	-	-	-
25 TOTAL OTHER REVENUES		27,080,551	25,555,228	1,287,830	237,492	365	237,127	73,644	163,482
26 TOTAL OPERATING REVENUES		1,838,424,883	1,642,376,592	77,526,753	118,521,538	502	118,521,035	38,497,545	80,023,490

KENTUCKY UTILITIES COMPANY
ELECTRIC COST OF SERVICE STUDY
JURISDICTIONAL SEPARATION

RATE BASE: THIRTEEN MONTH AVERAGE
ALLOCATION METHOD: AVG 12 CP (COMBINED CO SYS)

12 MONTHS ENDING JUNE 30, 2016

	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	12,495,311	10,848,358	560,020	1,086,933	42	1,086,891	337,213	749,678
2 501-FUEL	ENERGY	478,674,513	420,201,323	19,296,858	39,176,331	2,326	39,174,005	12,535,391	26,638,614
3 501-I/S SALES & PARIS VAR EXP.	REVFERC	-	-	-	-	-	-	-	-
4 502 & 504-STEAM EXPENSES	STMPLT	29,662,265	25,752,609	1,329,416	2,580,239	99	2,580,140	800,502	1,779,639
5 505-ELECTRIC EXPENSES	STMPLT	7,011,908	6,087,699	314,263	609,947	23	609,923	189,232	420,692
6 506-MISC STEAM POWER EXP	STMPLT	38,926,552	33,795,810	1,744,627	3,386,114	130	3,385,984	1,050,519	2,335,466
7 507 & 509 - RENTS & ALLOWANCE	STMPLT	94,392	81,951	4,231	8,211	0	8,211	2,547	5,663
8 TOTAL STEAM OPERATIONS		566,864,941	496,767,750	23,249,415	46,847,775	2,621	46,845,154	14,915,404	31,929,751
9 510-SUPERV & ENGINEERING	STMPLT	9,056,351	7,862,672	405,891	787,787	30	787,757	244,406	543,351
10 511-STRUCTURES	STMPLT	6,441,658	5,592,611	288,705	560,342	22	560,321	173,842	386,478
11 512-BOILER PLANT	ENERGY	50,727,578	44,530,876	2,044,986	4,151,715	247	4,151,469	1,328,439	2,823,030
12 513-ELECTRIC PLANT	ENERGY	10,233,861	8,983,729	412,559	837,574	50	837,524	268,001	569,522
13 514-MISC STEAM PLANT	STMPLT	3,367,768	2,923,877	150,938	292,953	11	292,942	90,887	202,055
14 TOTAL STEAM MAINTENANCE		79,827,216	69,893,765	3,303,080	6,630,371	359	6,630,012	2,105,575	4,524,437
15 TOTAL STEAM GENERATION		646,692,157	566,661,515	26,552,495	53,478,147	2,980	53,475,166	17,020,979	36,454,188
PRODUCTION EXPENSE-HYDRO									
16 535-SUPERV & ENGINEERING	HYDPLT	-	-	-	-	-	-	-	-
17 536-WATER FOR POWER	HYDPLT	-	-	-	-	-	-	-	-
18 537-HYDRAULIC EXPENSES	HYDPLT	-	-	-	-	-	-	-	-
19 538-ELECTRIC EXPENSES	HYDPLT	-	-	-	-	-	-	-	-
20 539-MISC HYDR POWER GENER	HYDPLT	9,378	8,185	411	782	0	782	243	539
21 540-RENTS	HYDPLT	-	-	-	-	-	-	-	-
22 TOTAL HYDRO OPERATIONS		9,378	8,185	411	782	0	782	243	539
23 541-SUPERV & ENGINEERING	HYDPLT	214,045	186,812	9,386	17,847	1	17,846	5,537	12,309
23 542-STRUCTURES	HYDPLT	148,648	129,736	6,518	12,394	0	12,394	3,845	8,548
25 543-RESERV, DAMS & WATERWAY	HYDPLT	-	-	-	-	-	-	-	-
26 544-ELECTRIC PLANT	ENERGY	31,008	27,220	1,250	2,538	0	2,538	812	1,726
27 545-MISC HYDRAULIC PLANT	HYDPLT	10,554	9,211	463	880	0	880	273	607
28 TOTAL HYDRO MAINTENANCE		404,255	352,980	17,617	33,659	1	33,657	10,467	23,190
29 TOTAL HYDRO GENERATION		413,633	361,164	18,028	34,441	1	34,439	10,710	23,730
PRODUCTION EXPENSE-OTHER									
30 546-SUPERV & ENGINEERING	OTHPLT	375,068	326,573	16,405	32,090	1	32,088	9,956	22,133
31 547-FUEL	ENERGY	159,434,754	139,958,767	6,427,311	13,048,676	775	13,047,901	4,175,232	8,872,670
32 548-GENERATION EXPENSES	OTHPLT	362,023	315,215	15,834	30,974	1	30,972	9,609	21,363
33 549-550 MISC & RENTS	OTHPLT	4,372,727	3,807,351	191,258	374,118	15	374,103	116,067	258,036
34 TOTAL OTHER OPERATIONS		164,544,571	144,407,905	6,650,808	13,485,858	792	13,485,066	4,310,864	9,174,202
35 551-SUPERV & ENGINEERING	OTHPLT	191,100	166,391	8,358	16,350	1	16,349	5,072	11,277
36 552-STRUCTURES	OTHPLT	394,345	343,358	17,248	33,739	1	33,738	10,467	23,270
37 553-GENERATING & ELECT PLT	OTHPLT	4,809,780	4,187,895	210,374	411,511	16	411,495	127,668	283,827
38 554-MISC OTH POWER GEN PLT	OTHPLT	7,964,534	6,934,752	348,359	681,423	27	681,396	211,407	469,990
39 TOTAL OTHER MAINTENANCE		13,359,759	11,632,396	584,340	1,143,023	45	1,142,979	354,615	788,364
40 TOTAL OTHER GENERATION		177,904,330	156,040,301	7,235,147	14,628,881	837	14,628,044	4,665,479	9,962,565
555-PURCHASED POWER									
41 CAPACITY COMPONENT	DEMPROD	8,058,767	7,051,986	354,243	652,538	27	652,511	202,445	450,066
42 ENERGY COMPONENT	ENERGY	69,900,405	61,361,618	2,817,903	5,720,884	340	5,720,544	1,830,532	3,890,013
43 TOTAL ACCT 555		77,959,172	68,413,605	3,172,145	6,373,422	367	6,373,056	2,032,977	4,340,079
44 556-SYSTEM CONTROL & DISP	DEMPROD	1,661,410	1,453,850	73,031	134,528	6	134,523	41,736	92,786
45 557-OTHER EXPENSES	PRODPLT	359,725	312,473	16,055	31,197	1	31,196	9,679	21,517
46 TOTAL PRODUCTION EXPENSES		904,990,427	793,242,909	37,066,902	74,680,616	4,192	74,676,424	23,781,559	50,894,865

KENTUCKY UTILITIES COMPANY
ELECTRIC COST OF SERVICE STUDY
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12 MONTHS ENDING JUNE 30, 2016

	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 & MAINT EXP CON'T									
TRANSMISSION EXPENSES									
1 560-SUPERV & ENGINEERING	LABTROP	1,748,004	1,562,765	185,233	6	6	-	-	-
2 561-LOAD DISPATCHING	TRANPLTXF	3,825,565	3,420,163	405,389	13	13	-	-	-
3 562-STATION EXPENSES	TRANPLTXF	865,153	773,471	91,679	3	3	-	-	-
4 563-OVERHEAD LINE EXPENSES	TRANPLTXF	930,394	831,798	98,592	3	3	-	-	-
5 564-UNDERGROUND LINE EXP	TRANPLTXF	-	-	-	-	-	-	-	-
6 565-TRANSM OF ELECT BY OTH	TRANPLTXF	4,301,649	3,845,795	455,839	15	15	-	-	-
7 566-MISC TRANSMISSION EXP	TRANPLTXF	10,873,800	9,721,483	1,152,279	37	37	-	-	-
8 567-RENTS	TRANPLTXF	-	-	-	-	-	-	-	-
9 575-MISO DAY 1 &2 EXP	TRANPLTXF	141,420	(342,725)	(1)	484,145	(0)	484,145	150,209	333,937
10 TOTAL TRANSM OPERATIONS		22,685,985	19,812,751	2,389,011	484,223	78	484,145	150,209	333,937
11 568-SUPERV & ENGINEERING	TRANPLTXF	-	-	-	-	-	-	-	-
12 569-MAINT OF STRUCTURES	TRANPLTXF	-	-	-	-	-	-	-	-
13 570-MAINT OF STATION EQUIP	TRANPLTXF	2,695,281	2,409,657	285,615	9	9	-	-	-
14 571-MAINT OF OH LINES	TRANPLTXF	4,350,709	3,897,752	452,943	15	15	-	-	-
15 572-MAINT OF UG LINES	TRANPLTXF	-	-	-	-	-	-	-	-
16 573-MAINT OF MISC TRAN PLT	TRANPLTXF	122,162	109,216	12,945	0	0	-	-	-
17 TOTAL TRANSM MAINTENANCE		7,168,152	6,416,625	751,503	24	24	-	-	-
18 TOTAL TRANSMISSION EXPENSES		29,854,137	26,229,376	3,140,514	484,247	102	484,145	150,209	333,937
DISTRIBUTION EXPENSES									
19 580-SUPERV & ENGINEERING	DISTPLT	1,493,193	1,412,189	76,819	4,185	157	4,027	3,535	492
20 581-DIST SYSTEM CONTROL	PLT3602TOT	1,109,544	1,040,879	47,074	21,591	429	21,163	21,163	-
21 582-STATION EXPENSES	PLT3602TOT	1,896,513	1,779,146	80,461	36,906	732	36,173	36,173	-
22 583-OVERHEAD LINES	PLT3645TOT	4,586,758	4,273,322	312,829	608	608	-	-	-
23 584-UNDERGROUND LINES	PLT3667TOT	542	530	12	-	-	-	-	-
24 585-STREET LIGHTING	PLT373TOT	-	-	-	-	-	-	-	-
25 586-METERS	PLT370TOT	8,153,391	7,725,897	397,175	30,319	444	29,875	7,069	22,806
26 587-CUSTOMER INSTALLATIONS	PLT371TOT	(112,008)	(106,729)	(5,279)	-	-	-	-	-
27 588-MISCELLANEOUS EXP	DISTPLT	4,880,264	4,615,516	251,071	13,677	514	13,163	11,554	1,609
28 589-RENTS	DISTPLT	-	-	-	-	-	-	-	-
29 TOTAL DISTR OPERATIONS		22,008,197	20,740,750	1,160,163	107,285	2,883	104,402	79,494	24,907
30 590-SUPERV & ENGINEERING	DISTPLT	34,129	32,278	1,756	96	4	92	81	11
31 591-MAINT OF STRUCTURES	PLT3602TOT	-	-	-	-	-	-	-	-
32 592-MAINT OF STATION EQUIP	PLT3602TOT	1,173,683	1,101,049	49,795	22,840	453	22,386	22,386	-
33 593-MAINT OF OH LINES	PLT3645TOT	32,495,769	29,550,316	2,942,085	3,368	3,368	-	-	-
34 594-MAINT OF UG LINES	PLT3667TOT	748,731	732,194	16,537	-	-	-	-	-
35 595-MAINT OF LINE TRANSF	PLT368TOT	103,920	99,095	4,656	169	1	168	52	116
36 596-MAINT OF ST LIGHTING	PLT373TOT	155	151	4	-	-	-	-	-
37 597-MAINT OF METERS	PLT370TOT	-	-	-	-	-	-	-	-
38 598-MISCELLANEOUS	DISTPLT	45,748	43,266	2,354	128	5	123	108	15
39 TOTAL DISTR MAINTENANCE		34,602,135	31,558,349	3,017,186	26,600	3,830	22,770	22,628	142
40 TOTAL DISTRIBUTION EXPENSES		56,610,332	52,299,098	4,177,349	133,885	6,713	127,171	102,122	25,050

KENTUCKY UTILITIES COMPANY
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12 MONTHS ENDING JUNE 30, 2016

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OPERATION & MAINT EXP CON'T									
CUSTOMER ACCOUNTING EXPENSES									
1 901-SUPERVISION	LABCA	2,979,467	2,823,189	152,883	3,395	28	3,367	1,804	1,563
2 902-METER READING	CUST902	5,398,133	5,114,992	276,990	6,151	50	6,101	3,269	2,832
3 903-CUSTOMER RECORDS	CUST903	18,408,138	17,442,601	944,561	20,976	171	20,805	11,148	9,657
4 904-UNCOLLECTIBLE ACCOUNTS	CUST904	6,798,000	6,441,434	348,820	7,746	63	7,683	4,117	3,566
5 905-MISCELLANEOUS	EXP9024CA	133,156	126,172	6,833	152	1	150	81	70
6 TOTAL CUSTOMER ACCOUNTS		33,716,894	31,948,387	1,730,086	38,420	313	38,107	20,419	17,688
CUSTOMER SERVICES									
7 907-SUPERVISION	LABCS	328,580	328,102	478	0	0	-	-	-
8 908-CUSTOMER ASSISTANCE	CUST908	19,076,550	19,076,550	-	-	-	-	-	-
9 909-INFORMATION & INSTRUCT	CUST909	366,574	347,196	19,376	3	3	-	-	-
10 910-MISCELLANEOUS	EXP9089CS	740,424	739,686	738	0	0	-	-	-
11 TOTAL CUSTOMER SERVICE		20,512,128	20,491,534	20,591	3	3	-	-	-
SALES EXPENSE									
12 911-SUPERVISION	LABSA	-	-	-	-	-	-	-	-
13 912-DEMONSTRATING & SELLING	CUST912	-	-	-	-	-	-	-	-
14 913-ADVERTISING	CUST913	180,000	170,485	9,514	1	1	-	-	-
15 916-MISCELLANEOUS	EXP9123SA	-	-	-	-	-	-	-	-
16 TOTAL SALES EXPENSE		180,000	170,485	9,514	1	1	-	-	-
ADMINISTRATIVE & GENERAL									
PLANT COMPONENT									
17 924-PROPERTY INSURANCE	PLANT	5,865,990	5,200,353	304,462	361,175	139	361,036	113,824	247,212
18 TOTAL NET PLT COMPONENT		5,865,990	5,200,353	304,462	361,175	139	361,036	113,824	247,212
LABOR COMPONENT									
19 920-ADMIN & GENERAL EXP	LABOR	38,011,395	34,247,082	1,869,136	1,895,178	909	1,894,269	606,607	1,287,662
20 921-OFFICE SUPPLIES & EXP	LABOR	9,201,662	8,290,411	452,474	458,778	220	458,558	146,845	311,712
21 922-ADMIN EXP TRANSF-CRED	LABOR	(5,295,379)	(4,770,971)	(260,390)	(264,018)	(127)	(263,891)	(84,507)	(179,385)
22 923-OUTSIDE SERVICES	LABOR	22,572,351	20,336,984	1,109,951	1,125,416	540	1,124,876	360,222	764,654
23 925-INJURIES & DAMAGES	LABOR	3,687,717	3,322,518	181,336	183,863	88	183,775	58,851	124,924
24 926-PENSIONS & BENEFITS	LABOR	51,092,477	46,032,729	2,512,372	2,547,376	1,222	2,546,154	815,362	1,730,792
25 929-DUPLICATE CHARGES-CR	REVNJVA	-	-	-	-	-	-	-	-
26 930-MISC GENERAL EXPENSE	LABORXF	4,219,983	4,006,788	213,091	104	104	-	-	-
27 931-RENTS	LABOR	2,133,914	1,922,590	104,931	106,393	51	106,342	34,054	72,288
28 935-MAINTENANCE	LABOR	2,251,618	2,028,638	110,719	112,261	54	112,208	35,933	76,275
29 TOTAL LABOR COMPONENT		127,875,738	115,416,768	6,293,620	6,165,350	3,061	6,162,289	1,973,368	4,188,922
928-REGULATORY COMMISSION									
30 STATE JURISDICTION	DIRECT	1,042,686	1,042,686	-	-	-	-	-	-
31 FEDERAL JURISDICTION	REVFERC	-	-	-	-	-	-	-	-
32 VIRGINIA JURISDICTION	REVVA	-	-	-	-	-	-	-	-
33 928 ALLOCATED	ENERGY	720,174	632,200	29,032	58,941	4	58,938	18,860	40,078
34 TOTAL ACCOUNT 928		1,762,860	1,674,886	29,032	58,941	4	58,938	18,860	40,078
35 927-FRANCHISE NJ VA	REVNJVA	-	-	-	-	-	-	-	-
36 930-ASSOC DUES & ADVERTISING	ENERGY1	521,995	499,073	22,919	3	3	-	-	-
37 TOTAL ADMINISTRATIVE & GEN		136,026,583	122,791,081	6,650,033	6,585,469	3,206	6,582,263	2,106,051	4,476,212
38 TOTAL OPERATION & MAINTENANCE		1,181,890,501	1,047,172,869	52,794,990	81,922,642	14,531	81,908,111	26,160,359	55,747,752

KENTUCKY UTILITIES COMPANY
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	DEPRECIATION & AMORT EXPENSE									
	DEPRECIATION EXPENSE									
	PRODUCTION PLANT									
	STEAM PRODUCTION PLANT									
1	SYSTEM	STMSYS	117,786,247	103,071,226	5,177,578	9,537,443	397	9,537,046	2,958,917	6,578,130
2	FERC-AFUDC PRE	DEMFERC	352,912	-	124,178	228,734	-	228,734	70,966	157,768
3	FERC-AFUDC POST	DEMFERCP	565,414	-	-	565,414	-	565,414	175,423	389,991
4	TOTAL STEAM PROD PLT		118,704,573	103,071,226	5,301,756	10,331,591	397	10,331,195	3,205,305	7,125,889
	HYDRAULIC PRODUCTION PLANT									
5	SYSTEM	HYDSYS	1,139,467	997,114	50,088	92,265	4	92,262	28,625	63,637
6	FERC-AFUDC PRE	DEMFERC	22	-	8	14	-	14	4	10
7	FERC-AFUDC POST	DEMFERCP	2,759	-	-	2,759	-	2,759	856	1,903
8	TOTAL HYDRO PROD PLT		1,142,248	997,114	50,096	95,039	4	95,035	29,485	65,550
	OTHER PRODUCTION PLANT									
9	SYSTEM	OTHSYS	34,790,323	30,443,972	1,529,292	2,817,058	117	2,816,941	873,970	1,942,971
10	FERC-AFUDC PRE	DEMFERC	78	-	27	51	-	51	16	35
11	FERC-AFUDC POST	DEMFERCP	77,772	-	-	77,772	-	77,772	24,129	53,643
12	TOTAL OTHER PROD PLT		34,868,173	30,443,972	1,529,320	2,894,881	117	2,894,764	898,115	1,996,649
13	TOTAL PRODUCTION PLANT		154,714,995	134,512,312	6,881,171	13,321,511	518	13,320,993	4,132,905	9,188,088
	TRANSMISSION PLANT									
14	KENTUCKY SYSTEM PROPERTY	KYTRPLTXF	14,319,797	13,615,578	704,167	52	52	-	-	-
15	VIRGINIA PROPERTY	TRPLTVA	1,058,284	147,666	910,618	1	1	-	-	-
17	FERC-AFUDC PRE	DEMFERC	55,968	-	19,693	36,275	-	36,275	11,254	25,020
18	FERC-AFUDC POST	DEMFERCP	25,545	-	-	25,545	-	25,545	7,925	17,620
19	TOTAL TRANSMISSION PLANT		15,459,594	13,763,244	1,634,478	61,873	53	61,820	19,180	42,640
	DISTRIBUTION PLANT									
20	DISTRIBUTION-KENTUCKY	KYDIST	41,941,569	41,822,295	-	119,274	-	119,274	104,693	14,581
21	DISTRIBUTION-VIRGINIA	VADIST	2,270,499	-	2,270,499	-	-	-	-	-
22	DISTRIBUTION-TENNESSEE	TNDIST	4,452	-	-	4,452	4,452	-	-	-
23	TOTAL DISTRIBUTION PLANT		44,216,519	41,822,295	2,270,499	123,726	4,452	119,274	104,693	14,581
24	GENERAL PLANT	GENPLT	13,266,600	11,985,263	636,236	645,100	309	644,791	206,483	438,308
25	INTANGIBLE PLANT-SOFTWARE	PLT303TOT	12,302,859	10,906,796	638,559	757,503	291	757,213	238,726	518,487
26	INTANGIBLE PLANT-FRANCHISES	PLT302TOT	10,502	10,502	-	-	-	-	-	-
27	TOTAL DEPREC & AMORT EXP		239,971,068	213,000,412	12,060,943	14,909,713	5,623	14,904,090	4,701,987	10,202,103

KENTUCKY UTILITIES COMPANY
ELECTRIC COST OF SERVICE STUDY
JURISDICTIONAL SEPARATION

RATE BASE: THIRTEEN MONTH AVERAGE
ALLOCATION METHOD: AVG 12 CP (COMBINED CO SYS)

12 MONTHS ENDING JUNE 30, 2016

	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)
ARO REGULATORY CREDITS AND ACCRETION									
REGULATORY CREDITS									
PRODUCTION PLANT									
1 STEAM PRODUCTION PLANT	STMSYS	-	-	-	-	-	-	-	-
2 HYDRAULIC PRODUCTION PLANT	HYDSYS	-	-	-	-	-	-	-	-
3 OTHER PRODUCTION PLANT	OTHSYS	-	-	-	-	-	-	-	-
4 TOTAL PRODUCTION PLANT		-	-	-	-	-	-	-	-
TRANSMISSION PLANT									
5 KENTUCKY SYSTEM PROPERTY	KYTRPLTXF	-	-	-	-	-	-	-	-
6 VIRGINIA PROPERTY	TRPLTVA	-	-	-	-	-	-	-	-
7 TOTAL TRANSMISSION PLANT		-	-	-	-	-	-	-	-
DISTRIBUTION PLANT									
8 KENTUCKY DISTRIBUTION PROPERTY	KYDIST	-	-	-	-	-	-	-	-
9 VIRGINIA DISTRIBUTION PROPERTY	VADIST	-	-	-	-	-	-	-	-
10 TOTAL DISTRIBUTION PLANT		-	-	-	-	-	-	-	-
11 TOTAL REGULATORY CREDITS		-	-	-	-	-	-	-	-
ACCRETION									
PRODUCTION PLANT									
12 STEAM PRODUCTION PLANT	STMSYS	-	-	-	-	-	-	-	-
13 HYDRAULIC PRODUCTION PLANT	HYDSYS	-	-	-	-	-	-	-	-
14 OTHER PRODUCTION PLANT	OTHSYS	-	-	-	-	-	-	-	-
15 TOTAL PRODUCTION PLANT		-	-	-	-	-	-	-	-
TRANSMISSION PLANT									
16 KENTUCKY SYSTEM PROPERTY	KYTRPLTXF	-	-	-	-	-	-	-	-
17 VIRGINIA PROPERTY	TRPLTVA	-	-	-	-	-	-	-	-
18 TOTAL TRANSMISSION PLANT		-	-	-	-	-	-	-	-
DISTRIBUTION PLANT									
19 KENTUCKY SYSTEM PROPERTY	KYDIST	-	-	-	-	-	-	-	-
20 VIRGINIA PROPERTY	DPLTXVA	-	-	-	-	-	-	-	-
21 TOTAL DISTRIBUTION PLANT		-	-	-	-	-	-	-	-
22 TOTAL ACCRETION EXPENSE		-	-	-	-	-	-	-	-

KENTUCKY UTILITIES COMPANY
ELECTRIC COST OF SERVICE STUDY
JURISDICTIONAL SEPARATION

RATE BASE: THIRTEEN MONTH AVERAGE
ALLOCATION METHOD: AVG 12 CP (COMBINED CO SYS)

12 MONTHS ENDING JUNE 30, 2016

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OTHER TAXES & OTHER EXPENSES									
TAXES OTHER THAN INCOME TAX									
1 PROPERTY TAXES	NETPLANT	27,508,734	24,446,970	1,326,432	1,735,332	200	1,735,132	546,141	1,188,991
2 PSC ASSESSMENT-KY REVENUE	REVKY	2,983,476	2,983,476	-	-	-	-	-	-
3 VA GROSS RECEIPTS TAX	REVVA	-	-	-	-	-	-	-	-
4 FICA & UNEMPLOYMENT	LABOR	10,245,179	9,230,587	503,787	510,806	245	510,561	163,498	347,062
5 OTHER	LABOR	-	-	-	-	-	-	-	-
6 MISCELLANEOUS	PLANT	-	-	-	-	-	-	-	-
7 TOTAL OTHER TAXES		40,737,389	36,661,033	1,830,218	2,246,138	445	2,245,692	709,639	1,536,053
8 GAIN DISPOSITION OF ALLOWANCES	DEMPROD	-	-	-	-	-	-	-	-
9 GAIN/LOSS PROP DISPOSITION (NET)	PLANT	-	-	-	-	-	-	-	-
10 CHARITABLE CONTRIBUTIONS-VA ONLY	LABOR	1,331,648	-	32,741	-	-	-	-	-
INVESTMENT TAX CREDIT ADJ									
11 PRODUCTION	PRODPLT	-	-	-	-	-	-	-	-
12 TRANSMISSION	TRANPLTXF	-	-	-	-	-	-	-	-
13 TRANSMISSION VA	TRPLTVA	-	-	-	-	-	-	-	-
14 DISTRIBUTION - DIRECT	DIRITCADJ	-	-	-	-	-	-	-	-
15 DISTRIBUTION PLT KY,FERC & TN	DPLTXVA	-	-	-	-	-	-	-	-
16 GENERAL	GENPLT	-	-	-	-	-	-	-	-
17 TOTAL INVEST TAX CREDIT ADJ		-	-	-	-	-	-	-	-
18 TOTAL EXP OTHER THAN INC TAX		1,462,598,958	1,296,834,314	66,686,151	99,078,492	20,599	99,057,894	31,571,986	67,485,908

KENTUCKY UTILITIES COMPANY
ELECTRIC COST OF SERVICE STUDY
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12 MONTHS ENDING JUNE 30, 2016

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INCOME TAXES									
1 OPERATING INC BEFORE INC TAXES		375,825,925	345,542,278	10,840,602	19,443,045	(20,096)	19,463,142	6,925,559	12,537,582
DEVELOPMENT OF FED INC TAX									
ADDITIONS TO INCOME									
2									
3									
4 TOTAL ADDITIONS		-	-	-	-	-	-	-	-
DEDUCTIONS FROM INCOME									
INTEREST EXPENSE									
5 LONG TERM DEBT OTHER	RATEBASE	93,938,710	83,539,754	4,383,393	6,015,564	475	6,015,088	1,893,902	4,121,187
6 INT ON CUSTOMER DEPOSITS	CUSTDEPI	-	-	1,071	-	-	-	-	-
7 AFUDC-INTEREST POST FERC	AFUDC	-	-	-	-	-	-	-	-
8 TOTAL DEDUCTIONS		93,938,710	83,539,754	4,384,463	6,015,564	475	6,015,088	1,893,902	4,121,187
PLUS: ABOVE THE LINE DIFF:									
9 SEC. 199 DEDUCTION-STATE	STMSYS	(933,282)	(816,687)	(41,025)	(75,570)	(3)	(75,567)	(23,445)	(52,122)
10 DEPREC-EQUITY AFUDC PRE	DEMFERC	268,990	-	94,649	174,342	-	174,342	54,090	120,251
11 DEPREC-EQUITY AFUDC POST	DEMFERCP	631,010	-	-	631,010	-	631,010	195,774	435,236
12 OTHER	RATEBASE	-	-	(30,700)	-	-	-	-	-
13 TOTAL PERMANENT DIFFERENCES		(33,282)	(816,687)	22,924	729,781	(3)	729,784	226,419	503,365
14 STATE TAXABLE INCOME		281,853,933	261,185,837	6,479,062	14,157,263	(20,574)	14,177,837	5,258,077	8,919,760
15 APPORTIONED STATE TAXABLE INCOME		281,853,933	261,185,837	11,086,524	14,157,263	(20,574)	14,177,837	5,258,077	8,919,760
16 STATE TAX		16,911,236	15,671,150	665,191	849,436	(1,234)	850,670	315,485	535,186
17 STATE TAX ADJUSTMENTS	RATEBASE	108,008	96,051	5,040	6,917	1	6,916	2,178	4,738
18 KENTUCKY TAX CREDITS	DPRODKY	(1,620,000)	(1,482,799)	-	(137,201)	-	(137,201)	(42,567)	(94,634)
19 203(E) EXCESS	PLANTKF	(300,000)	(280,518)	-	(19,482)	(7)	(19,475)	(6,140)	(13,335)
20 STATE TAX TOTAL		15,099,244	14,003,884	670,231	699,670	(1,240)	700,910	268,956	431,955
21 SEC. 199 DEDUCTION-FEDERAL INCREMENT	STMSYS	(3,211,967)	(2,810,696)	(141,190)	(260,081)	(11)	(260,070)	(80,688)	(179,382)
22 STATE TAX ADJUSTS FOR FEDERAL	RATEBASE	-	-	30,700	-	-	-	-	-
23 FEDERAL TAXABLE INCOME (LINE 14-20+21+22)		263,542,722	244,371,256	5,698,341	13,197,512	(19,344)	13,216,857	4,908,433	8,308,423
24 FEDERAL TAXES @ 35%		92,239,953	85,529,940	1,994,419	4,619,129	(6,771)	4,625,900	1,717,952	2,907,948
25 EXCESS DEFERRED TAXES	RATEBASE	-	-	-	-	-	-	-	-
26 203(E) EXCESS	PLANT	(555,000)	(492,022)	(28,806)	(34,172)	(13)	(34,159)	(10,769)	(23,390)
27 INVESTMENT TAX CREDIT ADJ		-	-	-	-	-	-	-	-
28 FEDERAL TAX ADJUSTMENTS	RATEBASE	630,055	560,308	29,400	40,347	3	40,344	12,703	27,641
29 FEDERAL TAX TOTAL		92,315,008	85,598,226	1,995,013	4,625,304	(6,781)	4,632,085	1,719,886	2,912,199
30 RETURN		268,411,673	245,940,168	8,175,357	14,118,072	(12,075)	14,130,146	4,936,718	9,193,429
31 RATE OF RETURN		4.9996%	5.0913%	3.2254%	4.0587%	-43.9568%	4.0625%	4.5079%	3.8579%
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

KENTUCKY UTILITIES COMPANY
ELECTRIC COST OF SERVICE STUDY
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12 MONTHS ENDING JUNE 30, 2016

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	LABOR ALLOCATOR									
	LABOR EXPENSE									
	PRODUCTION LABOR									
	ENERGY RELATED									
1	FERC 501	ENERGY	3,051,886	2,679,078	123,031	249,777	15	249,762	79,922	169,840
2	FERC 510	ENERGY	7,031,676	6,172,711	283,469	575,496	34	575,462	184,144	391,318
3	FERC 512	ENERGY	11,539,664	10,130,019	465,200	944,445	56	944,389	302,197	642,191
4	FERC 513	ENERGY	1,624,030	1,425,644	65,470	132,916	8	132,908	42,530	90,379
5	FERC 547	ENERGY	-	-	-	-	-	-	-	-
6	TOTAL ENERGY LABOR		23,247,256	20,407,453	937,169	1,902,634	113	1,902,521	608,792	1,293,728
	DEMAND RELATED									
7	FERC 500	PRODPLT	10,607,300	9,213,977	473,418	919,905	35	919,870	285,394	634,476
8	FERC 502	PRODPLT	12,436,191	10,802,634	555,043	1,078,514	42	1,078,472	334,601	743,871
9	FERC 505	PRODPLT	6,251,145	5,430,025	278,997	542,123	21	542,102	168,190	373,912
10	FERC 506	PRODPLT	2,072,377	1,800,160	92,493	179,724	7	179,717	55,758	123,959
11	FERC 509	PRODPLT	-	-	-	-	-	-	-	-
12	FERC 511	PRODPLT	896,814	779,013	40,026	77,775	3	77,772	24,129	53,643
13	FERC 514	PRODPLT	569,588	494,770	25,421	49,397	2	49,395	15,325	34,070
14	FERC 535	PRODPLT	-	-	-	-	-	-	-	-
15	FERC 538	PRODPLT	-	-	-	-	-	-	-	-
16	FERC 539	PRODPLT	-	-	-	-	-	-	-	-
17	FERC 541	PRODPLT	192,988	167,638	8,613	16,737	1	16,736	5,192	11,544
18	FERC 542	PRODPLT	57,156	49,648	2,551	4,957	0	4,957	1,538	3,419
19	FERC 544	PRODPLT	-	-	-	-	-	-	-	-
20	FERC 545	PRODPLT	-	-	-	-	-	-	-	-
21	FERC 546	PRODPLT	367,891	319,567	16,419	31,905	1	31,904	9,898	22,005
22	FERC 548	PRODPLT	353,884	307,400	15,794	30,690	1	30,689	9,521	21,168
23	FERC 549	PRODPLT	1,874,093	1,627,921	83,643	162,528	6	162,522	50,423	112,099
24	FERC 550	PRODPLT	-	-	-	-	-	-	-	-
25	FERC 551	PRODPLT	132,443	115,046	5,911	11,486	0	11,486	3,563	7,922
26	FERC 552	PRODPLT	7,188	6,244	321	623	0	623	193	430
27	FERC 553	PRODPLT	1,301,969	1,130,949	58,109	112,912	4	112,907	35,030	77,877
28	FERC 554	PRODPLT	1,898,867	1,649,441	84,749	164,677	6	164,671	51,090	113,581
29	FERC 555	PRODPLT	-	-	-	-	-	-	-	-
30	FERC 556	PRODPLT	1,620,515	1,407,652	72,326	140,537	5	140,532	43,601	96,931
31	FERC 557	PRODPLT	-	-	-	-	-	-	-	-
32	TOTAL DEMAND		40,640,409	35,302,085	1,813,834	3,524,490	136	3,524,354	1,093,449	2,430,906
33	TOTAL PRODUCTION		63,887,665	55,709,538	2,751,003	5,427,124	249	5,426,875	1,702,241	3,724,634

KENTUCKY UTILITIES COMPANY
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12 MONTHS ENDING JUNE 30, 2016

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	TRANSMISSION LABOR									
1	FERC 560	TRANPLTXF	1,599,420	1,429,926	169,488	6	6	-	-	-
2	FERC 561	TRANPLTXF	3,471,306	3,103,445	367,849	12	12	-	-	-
3	FERC 562	TRANPLTXF	392,831	351,202	41,628	1	1	-	-	-
4	FERC 563	TRANPLTXF	-	-	-	-	-	-	-	-
5	FERC 565	TRANPLTXF	-	-	-	-	-	-	-	-
6	FERC 566	TRANPLTXF	273,083	244,144	28,938	1	1	-	-	-
7	FERC 567	TRANPLTXF	-	-	-	-	-	-	-	-
8	FERC 569	TRANPLTXF	-	-	-	-	-	-	-	-
9	FERC 570	TRANPLTXF	1,169,647	1,045,697	123,946	4	4	-	-	-
10	FERC 571	TRANPLTXF	223,471	199,789	23,681	1	1	-	-	-
11	FERC 572	TRANPLTXF	-	-	-	-	-	-	-	-
12	FERC 573	TRANPLTXF	-	-	-	-	-	-	-	-
13	TOTAL TRANSMISSION LABOR	TRANPLTXF	7,129,758	6,374,204	755,529	25	25	-	-	-
	DISTRIBUTION LABOR									
1	FERC 580	DISTPLT	1,080,574	1,021,954	55,592	3,028	114	2,915	2,558	356
2	FERC 581	DISTPLT	1,109,544	1,049,353	57,082	3,109	117	2,993	2,627	366
3	FERC 582	DISTPLT	1,010,017	955,225	51,962	2,831	106	2,724	2,391	333
4	FERC 583	DISTPLT	1,847,485	1,747,261	95,046	5,177	194	4,983	4,374	609
5	FERC 584	DISTPLT	-	-	-	-	-	-	-	-
6	FERC 585	DISTPLT	-	-	-	-	-	-	-	-
7	FERC 586	DISTPLT	4,871,872	4,607,579	250,640	13,653	513	13,140	11,534	1,606
8	FERC 587	DISTPLT	-	-	-	-	-	-	-	-
9	FERC 588	DISTPLT	3,122,335	2,952,952	160,632	8,750	329	8,422	7,392	1,030
10	FERC 589	DISTPLT	-	-	-	-	-	-	-	-
11	FERC 590	DISTPLT	-	-	-	-	-	-	-	-
13	FERC 592	DISTPLT	647,379	612,260	33,305	1,814	68	1,746	1,533	213
14	FERC 593	DISTPLT	6,961,394	6,583,747	358,138	19,509	733	18,776	16,481	2,295
15	FERC 594	DISTPLT	395,952	374,472	20,370	1,110	42	1,068	937	131
16	FERC 595	DISTPLT	-	-	-	-	-	-	-	-
17	FERC 596	DISTPLT	-	-	-	-	-	-	-	-
18	FERC 597	DISTPLT	-	-	-	-	-	-	-	-
19	FERC 598	DISTPLT	-	-	-	-	-	-	-	-
20	TOTAL DISTRIBUTION LABOR	DISTPLT	21,046,552	19,904,803	1,082,767	58,982	2,215	56,767	49,827	6,940
21	TOT PROD, TRNS & DISTR LABOR		92,063,975	81,988,546	4,589,299	5,486,130	2,488	5,483,642	1,752,068	3,731,573

KENTUCKY UTILITIES COMPANY
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	CUSTOMER ACCOUNTING									
1	FERC 901	EXP9025CA	2,819,965	2,672,053	144,698	3,213	26	3,187	1,708	1,479
2	FERC 902	EXP9025CA	565,701	536,029	29,027	645	5	639	343	297
3	FERC 903	EXP9025CA	12,789,441	12,118,614	656,254	14,574	119	14,455	7,745	6,709
4	FERC 904	EXP9025CA	-	-	-	-	-	-	-	-
5	FERC 905	EXP9025CA	133,152	126,168	6,832	152	1	150	81	70
6	TOTAL CUSTOMER ACCOUNTING LABOR		16,308,259	15,452,864	836,812	18,583	152	18,432	9,876	8,555
	CUSTOMER SERVICE & SALES EXP									
7	FERC 907	EXP9080CS	302,195	301,755	440	0	0	-	-	-
8	FERC 908	EXP9080CS	1,733,082	1,730,560	2,522	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 LABOI		2,035,277	2,032,315	2,961	0	0	-	-	-
15	TOTAL PROD, TRAN, DIST, CUSTOMER LABOR		110,407,511	99,473,725	5,429,072	5,504,714	2,640	5,502,073	1,761,945	3,740,129
	ADMIN & GENERAL LABOR									
16	FERC 920	PTDCUSTLABOF	38,011,395	34,247,082	1,869,136	1,895,178	909	1,894,269	606,607	1,287,662
17	FERC 921	PTDCUSTLABOF	-	-	-	-	-	-	-	-
18	FERC 922	PTDCUSTLABOF	(4,053,252)	(3,651,854)	(199,311)	(202,088)	(97)	(201,991)	(64,684)	(137,307)
19	FERC 923	PTDCUSTLABOF	-	-	-	-	-	-	-	-
20	FERC 924	PTDCUSTLABOF	-	-	-	-	-	-	-	-
21	FERC 925	PTDCUSTLABOF	651,920	587,360	32,057	32,504	16	32,488	10,404	22,084
22	FERC 926	PTDCUSTLABOF	51,092,477	46,032,729	2,512,372	2,547,376	1,222	2,546,154	815,362	1,730,792
23	FERC 927	PTDCUSTLABOF	-	-	-	-	-	-	-	-
24	FERC 929	PTDCUSTLABOF	-	-	-	-	-	-	-	-
25	FERC 930	PTDCUSTLABOF	-	-	-	-	-	-	-	-
26	FERC 931	PTDCUSTLABOF	-	-	-	-	-	-	-	-
27	FERC 935	PTDCUSTLABOF	825,134	743,420	40,574	41,140	20	41,120	13,168	27,952
28	TOTAL ADMIN & GENERAL LABOR		86,527,674	77,958,736	4,254,828	4,314,109	2,069	4,312,040	1,380,857	2,931,183
29	TOTAL LABOR EXPENSES		196,935,185	177,432,461	9,683,900	9,818,823	4,710	9,814,113	3,142,802	6,671,312

KENTUCKY UTILITIES COMPANY
ELECTRIC COST OF SERVICE STUDY
JURISDICTIONAL SEPARATION

RATE BASE: THIRTEEN MONTH AVERAGE
ALLOCATION METHOD: AVG 12 CP (COMBINED CO SYS)

12 MONTHS ENDING JUNE 30, 2016

	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	3,860,942	3,378,595	169,717	312,630	13	312,617	96,991	215,626
2 DEMAND (12 CP GEN LEV)-FERC	DEMFERC	482,334	-	169,717	312,617	-	312,617	96,991	215,626
3 DEMAND (12 CP GEN)-PROD VA	DPRODVA	169,717	-	169,717	-	-	-	-	-
4 DEMAND (12 CP GEN)-PROD KY	DPRODKY	3,691,212	3,378,595	-	312,617	-	312,617	96,991	215,626
5 DEM (12 CP GEN LV)-FERC POST	DEMFERCP	312,617	-	-	312,617	-	312,617	96,991	215,626
6 DEM (12 CP GEN LV)-NON VA	DEMPRODNV	3,691,225	3,378,595	-	312,630	13	312,617	96,991	215,626
TRANSMISSION ALLOCATORS									
7 DEMAND (12 CP GEN LEV)-TRAN	DEMTRAN	3,860,942	3,378,595	169,717	312,630	13	312,617	96,991	215,626
8 DEMAND (12 CP GEN LEV)-VA	DEMVA	169,717	-	169,717	-	-	-	-	-
9 DEM (12 CP GEN LEV)-NON FERC	DEMTRANNF	3,548,325	3,378,595	169,717	13	13	-	-	-
10 DEM (12 CP GN LEV)-TRAN FERC	DEMFERCT	482,334	-	169,717	312,617	-	312,617	96,991	215,626
11 DEM (12 CP GEN LEV)-NON VA&FERC	DEMTRANNVF	3,378,608	3,378,595	-	13	13	-	-	-
DISTRIBUTION ALLOCATORS									
12 DIRECT ASSIGN 360 KY	DEM360K	7,728,170	7,719,013	-	9,157	-	9,157	9,157	-
13 DIRECT ASSIGN 361 KY	DEM361K	10,216,987	9,909,039	-	307,948	-	307,948	307,948	-
14 DIRECT ASSIGN 362 KY	DEM362K	173,525,692	170,027,418	-	3,498,274	-	3,498,274	3,498,274	-
15 DIRECT ASSIGN 364 KY	DEM364K	329,576,141	329,576,141	-	-	-	-	-	-
16 DIRECT ASSIGN 365 KY	DEM365K	336,362,320	336,362,320	-	-	-	-	-	-
17 DIRECT ASSIGN 366 KY	DEM366K	1,788,405	1,788,405	-	-	-	-	-	-
18 DIRECT ASSIGN 367 KY	DEM367K	180,059,462	180,059,462	-	-	-	-	-	-
19 DIRECT ASSIGN 368 KY	DEM368K	296,847,730	296,847,730	-	-	-	-	-	-
20 DIRECT ASSIGN 374 KY	DEM374K	913,218	913,218	-	-	-	-	-	-
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	7,845,255	-	7,845,255	-	-	-	-	-
24 DIRECT ASSIGN 360-362-FERC VA	DIR3602V	-	-	-	-	-	-	-	-
25 DIRECT ASSIGN 364-VA	DEM364V	26,127,299	-	26,127,299	-	-	-	-	-
26 DIRECT ASSIGN 365-VA	DEM365V	22,622,780	-	22,622,780	-	-	-	-	-
27 DIRECT ASSIGN 367-VA	DEM367V	4,107,123	-	4,107,123	-	-	-	-	-
28 DIRECT ASSIGN 368-VA	DEM368V	13,923,824	-	13,923,824	-	-	-	-	-
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	69,594	-	-	69,594	69,594	-	-	-
32 DIRECT ASSIGN 364-TN	DEM364T	47,927	-	-	47,927	47,927	-	-	-
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	4,199	-	-	4,199	4,199	-	-	-
37 DIRECT ASSIGN 371-TN	CUST371T	-	-	-	-	-	-	-	-
38 DIR ASSIGN ACC.DEPRC.DIST.VA&TN	DIRACDEP	42,078,160	-	41,921,885	156,275	156,275	-	-	-
39 DIR ASSIGN CWIP DIST VA & TN	DIRCWIP	2,676,604	-	2,676,604	-	-	-	-	-
40 DIR ASSIGN ACC.DFDTX.DIST.VA&TN	DIRACDFTX	6,954,261	-	6,954,261	-	-	-	-	-
41 DIR ASSIGN ACC.ITC.DIST.VA & TN	DIRACITC	-	-	-	-	-	-	-	-
42 DIR ASSIGN RENT REVENUE	DIR454REV	4,326,909	4,105,689	220,862	358	358	-	-	-
43 DIR ASSIGN EXCESS FACILITIES REV.	DIR456FAC	31,114	30,080	1,034	-	-	-	-	-
44 DIR ASSIGN OTHER MISC REV.	DIR456OTH	19,570	19,570	-	-	-	-	-	-
45 DIR ASSIGN RECONNECT REV	DIR451REC	2,139,667	2,009,340	130,327	-	-	-	-	-
46 DIR ASSIGN OTHER SERVICE REV	DIR451OTH	56,681	56,338	343	-	-	-	-	-
47 DIR ASSIGN RETURN CHECK REV	DIR456CHK	147,840	147,870	(30)	-	-	-	-	-
48 DIR ASSIGN 203(E) EXCESS	DIR203E	23,841	-	23,841	-	-	-	-	-
49 DIR ASSIGN ITC ADJ	DIRITCADJ	-	-	-	-	-	-	-	-
50 DIR ASSIGN DEFERRED FUEL-VIRGINIA	DFUELVA	(19,176)	-	(19,176)	-	-	-	-	-

KENTUCKY UTILITIES COMPANY
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ENERGY									
-									
1 ENERGY (MWH AT GEN LEVEL)	ENERGY	23,044,166	20,229,172	928,982	1,886,012	112	1,885,900	603,474	1,282,426
2 ENERGY (MWH RETAIL @ GEN LEVEL)	ENERGY1	21,158,266	20,229,172	928,982	112	112	-	-	-
3									
4									
CUSTOMER									
-									
1 DIRECT ASSIGN 369-SERV KY	CUST369K	89,746,639	89,746,639	-	-	-	-	-	-
2 DIRECT ASSIGN 370 METERS KY	CUST370K	73,410,395	73,127,621	-	282,774	-	282,774	66,911	215,863
3 DIRECT ASSIGN 371 CUST INST KY	CUST371K	17,289,842	17,289,842	-	-	-	-	-	-
4 DIRECT ASSIGN 373 ST LIGHT KY	CUST373K	100,291,893	100,291,893	-	-	-	-	-	-
5 CUSTOMER ADVANCES	CUSTADV	2,717,982	2,688,565	29,417	-	-	-	-	-
6 CUSTOMER DEPOSITS	CUSTDEP	26,250,522	25,366,290	884,232	-	-	-	-	-
7 DIR ASSIGN 902-METER READING	CUST902	752,960	713,466	38,636	858	7	851	456	395
8 DIR ASSIGN 903-CUSTOMER REC	CUST903	752,960	713,466	38,636	858	7	851	456	395
9 DIR ASSIGN 904-UNCOLL ACCTS	CUST904	752,960	713,466	38,636	858	7	851	456	395
10 DIR ASSIGN ACCT 369-SERV VA	CUST369V	5,218,706	-	5,218,706	-	-	-	-	-
11 DIR ASSIGN ACCT 370 METERS VA	CUST370V	3,759,366	-	3,759,366	-	-	-	-	-
12 DIR ASSIGN ACCT 371 CUST INST VA	CUST371V	855,169	-	855,169	-	-	-	-	-
13 DIR ASGN ACCT 373 ST LIGHT VA	CUST373V	2,650,328	-	2,650,328	-	-	-	-	-
14 DIR ASSIGN 908-CUST ASSIST	CUST908	513,014	513,014	-	-	-	-	-	-
15 DIR ASSIGN 909-INFO & INSTRCT	CUST909	541,643	513,010	28,629	4	4	-	-	-
16 DIR ASSIGN 912-DEM & SELLING	CUST912	541,643	513,010	28,629	4	4	-	-	-
17 DIR ASSIGN 913-ADVERTISING	CUST913	541,643	513,010	28,629	4	4	-	-	-
18 CUSTOMER ANNUALIZATION	CUSTANN	-	-	-	-	-	-	-	-
19 CUSTOMER DEPOSITS INTEREST	CUSTDEPI	31,771	30,700	1,071	-	-	-	-	-
20 DIR ASSIGN LATE PAYMENT REVENUE	DIR450REV	3,905,100	3,736,858	168,136	107	-	107	107	-
21									
22									
23									
24									
25									

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INTERNALLY DEVELOPED									
-									
1 PROD-TRANSM-DISTR-GENL PLT	PTDGPLT	8,773,497,958	7,777,928,717	455,373,342	540,195,900	207,197	539,988,702	170,241,794	369,746,908
2 PROD-TRANSM-DISTR-GENL PLT KY	KURETPLT	7,777,928,717	7,777,928,717	-	-	-	-	-	-
3 ALLOCATED O&M LABOR EXPENSE	LABOR	196,935,185	177,432,461	9,683,900	9,818,823	4,710	9,814,113	3,142,802	6,671,312
4 TOTAL STEAM PROD PLANT-SYSTEM	STMSYS	4,934,889,604	4,318,374,465	216,924,952	399,590,187	16,616	399,573,571	123,969,715	275,603,857
5 ALLOCATED NON A&G LABOR EXPENSE	PTDCUSTLABOF	110,407,511	99,473,725	5,429,072	5,504,714	2,640	5,502,073	1,761,945	3,740,129
6 TOT HYDRAULIC PROD PLANT-SYS	HYDSYS	40,311,870	35,275,713	1,772,005	3,264,152	136	3,264,016	1,012,677	2,251,338
7 TOTAL OTHER PROD PLANT-SYS	OTHSYS	1,002,482,132	877,242,165	44,066,515	81,173,452	3,375	81,170,076	25,183,425	55,986,651
8 TRANSM KENTUCKY SYSTEM PROP	KYTRPLT	787,074,659	745,069,655	38,533,331	3,471,673	2,867	3,468,806	1,076,215	2,392,592
9 TRANSM VIRGINIA PROPERTY	VATRPLT	50,754,704	-	50,754,704	-	-	-	-	-
10 TRANSM VIRGINIA PROP TOTAL	VATRPLTT	58,985,134	8,230,398	50,754,704	32	32	-	-	-
11 TOTAL DISTRIBUTION PLANT	DISTPLT	1,705,687,685	1,613,156,311	87,751,274	4,780,099	179,518	4,600,582	4,038,171	562,411
12 TOTAL DIST PLANT KY & FERC	DISTPLTKF	1,617,756,893	1,613,156,311	-	4,600,582	-	4,600,582	4,038,171	562,411
13 TOTAL GENERAL PLANT	GENPLT	199,526,961	180,255,923	9,568,859	9,702,179	4,654	9,697,525	3,105,466	6,592,059
14 ACCT 302-FRANCHISE	PLT302TOT	55,919	55,919	-	-	-	-	-	-
15 ACCT 303-SOFTWARE	PLT303TOT	94,925,631	84,153,983	4,926,952	5,844,697	2,242	5,842,455	1,841,946	4,000,509
16 TOTAL PRODUCTION PLANT SYSTEM	PRODSYS	5,977,683,606	5,230,892,343	262,763,473	484,027,791	20,127	484,007,663	150,165,817	333,841,846
17 TOTAL PRODUCTION PLANT	PRODPLT	6,021,899,432	5,230,892,343	268,765,173	522,241,917	20,127	522,221,789	162,021,942	360,199,847
18 TOTAL TRANSMISSION PLANT	TRANPLT	846,059,793	753,300,052	89,288,036	3,471,705	2,899	3,468,806	1,076,215	2,392,592
19 TOTAL TRANSMISSION PLANT EXCL FERC	TRANPLTXF	842,590,987	753,300,052	89,288,036	2,899	2,899	-	-	-
20 MAT & SUPPLIES DISTRIBUTED	M_S	34,959,521	30,918,635	1,872,559	2,168,327	696	2,167,630	681,213	1,486,417
21 ACCT 924 & 925 INSURANCE	EXP9245TOT	9,553,707	8,522,871	485,798	545,037	227	544,811	172,674	372,136
22 REVENUE SALE OF ELECT-KY	REVKY	1,616,821,364	1,616,821,364	-	-	-	-	-	-
23 CWIP PROD FERC-POST ALLOC	CWIPPP	16,406,348	-	-	16,406,348	-	16,406,348	5,090,152	11,316,196
24 CWIP TRAN FERC-POST ALLOC	CWIPTP	-	-	-	-	-	-	-	-
25 ACC DEF INC TX PROD FERC-POST	ADITPP	-	-	-	-	-	-	-	-
26 ACC DEF INC TX TRAN FERC-POST	ADITTP	-	-	-	-	-	-	-	-
27 TRANSMISSION PLANT EXCL VA	TRANPLTX	787,074,659	745,069,655	38,533,331	3,471,673	2,867	3,468,806	1,076,215	2,392,592
28 TRANSM PLANT VA	TRPLTVA	58,985,134	8,230,398	50,754,704	32	32	-	-	-
29 TOT ACCT 364 & 365-OVHD LINE	PLT3645TOT	714,783,230	665,938,460	48,750,079	94,690	94,690	-	-	-
30 TOTAL ELECTRIC PLANT	PLANT	8,868,523,964	7,862,178,029	460,302,601	546,043,334	209,440	545,833,894	172,084,603	373,749,291
31 TOTAL ELECTRIC PLANT KY	PLANTKY	7,862,178,029	7,862,178,029	-	-	-	-	-	-
32 TOTAL ELECTRIC PLANT KY & FERC	PLANTKF	8,408,221,363	7,862,178,029	-	546,043,334	209,440	545,833,894	172,084,603	373,749,291
33 TOTAL ELECTRIC PLANT VA	PLANTVA	460,302,601	-	460,302,601	-	-	-	-	-
34 TOTAL STEAM PROD PLANT	STMPLT	4,973,972,397	4,318,374,465	222,925,664	432,672,269	16,616	432,655,653	134,233,597	298,422,056
35 TOTAL HYDRAULIC PROD PLANT	HYDPLT	40,418,026	35,275,713	1,772,294	3,370,020	136	3,369,884	1,045,523	2,324,360
36 TOTAL OTHER PROD PLANT	OTHPLT	1,007,509,008	877,242,165	44,067,215	86,199,628	3,375	86,196,253	26,742,822	59,453,431
37 TOT ACCT 360-362 SUBSTATIONS	PLT3602TOT	200,034,784	187,655,470	8,486,679	3,892,634	77,255	3,815,379	3,815,379	-
38 TOT ACCT 366 & 367-UG LINES	PLT3667TOT	185,954,989	181,847,866	4,107,123	-	-	-	-	-
39 TOT ACCT 373-STREET LIGHTING	PLT373TOT	102,942,221	100,291,893	2,650,328	-	-	-	-	-
40 TOTAL ACCT 370-METERS	PLT370TOT	77,173,960	73,127,621	3,759,366	286,973	4,199	282,774	66,911	215,863
41 TOT ACCT 371-CUSTOMER INSTALL	PLT371TOT	18,145,011	17,289,842	855,169	-	-	-	-	-
42 TOT ACCT 368-LINE TRANSFORMER	PLT368TOT	310,774,673	296,345,301	13,923,824	505,547	3,118	502,429	155,881	346,548
43 TOT ACCT 902-904 CUST ACCTS	EXP9024CA	30,604,271	28,999,026	1,570,371	34,874	285	34,589	18,534	16,055
44 TOT ACCT 908-909 CUST SERV	EXP9089CS	19,443,124	19,423,746	19,376	3	3	-	-	-
45 TOTAL TRANS & DISTRIB PLANT	TRDSPLT	2,551,747,478	2,366,456,363	177,039,310	8,251,804	182,416	8,069,388	5,114,386	2,955,002

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INTERNALLY DEVELOPED-CON'T									
-									
1 TOT ACCT 912-913 SALES EXP	EXP9123SA	180,000	170,485	9,514	1	1	-	-	-
2 REVENUE SALE OF ELECT-FERC	REVFERC	118,283,909	-	-	118,283,909	-	118,283,909	38,423,901	79,860,008
3 REVENUE SALE OF ELECT-VA	REVVA	76,238,923	-	76,238,923	-	-	-	-	-
4 REVENUE SALE OF ELECT	REVENUE	1,811,344,332	1,616,821,364	76,238,923	118,284,046	137	118,283,909	38,423,901	79,860,008
5 REV SALE OF ELECT-VA NON JUR	REVNJVA	1	-	1	-	-	-	-	-
6 REV SALE OF ELECT-EXCL FERC	REVENUEX	1,693,060,424	1,616,821,364	76,238,923	137	137	-	-	-
7 KENTUCKY DISTRIBUTION PLANT	KYDIST	1,617,756,893	1,613,156,311	-	4,600,582	-	4,600,582	4,038,171	562,411
8 VIRGINIA DISTRIBUTION PLANT	VADIST	87,751,274	-	87,751,274	-	-	-	-	-
9 TENNESSEE DISTRIBUTION PLT	TNDIST	179,518	-	-	179,518	179,518	-	-	-
10 NET ELECTRIC PLANT IN SERVICE	NETPLANT	5,883,326,402	5,228,503,280	283,685,575	371,137,548	42,784	371,094,764	116,803,871	254,290,893
11 RATE BASE	RATEBASE	5,431,917,868	4,830,607,963	253,465,583	347,844,322	27,470	347,816,852	109,513,080	238,303,772
12 TOTAL CWIP FERC-AFUDC POST	AFUDC	-	-	-	-	-	-	-	-
13 TOTAL 203(E) EXCESS	TAX203E	(855,000)	(772,540)	(28,806)	(53,654)	(20)	(53,634)	(16,909)	(36,725)
14 STEAM OPERATING EXP 501-507	EXP5017STM	554,369,630	485,919,392	22,689,395	45,760,842	2,579	45,758,263	14,578,190	31,180,073
15 STEAM MAINTENANCE EXP 511-514	EXP5114STM	70,770,865	62,031,092	2,897,188	5,842,584	329	5,842,255	1,861,170	3,981,086
16 HYDRO OPERATING EXP 536-540	EXP5360HYD	9,378	8,185	411	782	0	782	243	539
17 HYDRO MAINTENANCE EXP 542-545	EXP5425HYD	190,210	166,167	8,231	15,812	1	15,811	4,930	10,881
18 OTHER PROD OPER EXP 547-549	EXP5479OTH	159,796,776	140,273,981	6,443,145	13,079,650	776	13,078,874	4,184,841	8,894,033
19 OTHER PROD MAINT EXP 552-554	EXP5524OTH	13,168,659	11,466,005	575,981	1,126,673	44	1,126,629	349,542	777,087
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	16,970,996	15,172,548	1,798,390	58	58	-	-	-
27 TRANSM MAINT EXP 569-573	EXP5693TX	7,168,152	6,416,625	751,503	24	24	-	-	-
28 TOT TRANSM OPERATIONS LABOR	LABTROP	7,129,758	6,374,204	755,529	25	25	-	-	-
29 TOT TRANSM MAINTENANCE LABOR	LABTRMN	-	-	-	-	-	-	-	-
30 DISTR OPER EXP 582-589	EXP5829DIS	19,405,460	18,287,681	1,036,270	81,509	2,297	79,211	54,796	24,415
31 DISTR MAINT EXP 591-598	EXP5918DIS	34,568,006	31,526,071	3,015,430	26,504	3,827	22,678	22,547	131
32 TOT DISTR OPERATIONS LABOR	LABDISOP	21,046,552	19,904,803	1,082,767	58,982	2,215	56,767	49,827	6,940
33 TOT DISTR MAINTENANCE LABOR	LABDISMN	-	-	-	-	-	-	-	-
34 CUST ACCT EXP 902, 903 & 905	EXP9025CA	23,939,427	22,683,764	1,228,384	27,279	223	27,056	14,498	12,559
35 TOTAL CUST ACCOUNTS LABOR	LABCA	2,819,965	2,672,053	144,698	3,213	26	3,187	1,708	1,479
36 CUST SERVICES & SALES EXP	EXP9080CS	20,363,548	20,333,916	29,627	4	4	-	-	-
37 TOTAL CUST SERVICES LABOR	LABCS	302,195	301,755	440	0	0	-	-	-
38 SALES EXPENSE 912-916	EXP9126SA	180,000	170,485	9,514	1	1	-	-	-
39 TOTAL SALES EXP LABOR	LABSA	2,035,277	2,032,315	2,961	0	0	-	-	-
40 TOT ADMINISTRATIVE & GEN EXP	A_GEXP	136,026,583	122,791,081	6,650,033	6,585,469	3,206	6,582,263	2,106,051	4,476,212

KENTUCKY UTILITIES COMPANY
ELECTRIC COST OF SERVICE STUDY
JURISDICTIONAL SEPARATION

RATE BASE: THIRTEEN MONTH AVERAGE
ALLOCATION METHOD: AVG 12 CP (COMBINED CO SYS)

12 MONTHS ENDING JUNE 30, 2016

	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	521,995	499,073	22,919	3	3	-	-	-
2 TOTAL CUSTOMER SERVICES EXP	CUSTSER	20,512,128	20,491,534	20,591	3	3	-	-	-
3 DISTRIBUTION PLANT EXCL VA	DPLTXVA	1,617,936,410	1,613,156,311	-	4,780,099	179,518	4,600,582	4,038,171	562,411
4 ACCT 926 DIR ASSIGN COMP.KY RET	LABPTDKY	81,988,546	81,988,546	-	-	-	-	-	-
5 ACCT 926 DIR ASSIGN COMP.VAJ	LABPTDVAJ	4,589,299	-	4,589,299	-	-	-	-	-
6 ACCT 926 DIR ASSIGN COMP.VANJ	LABPTDVNJ	-	-	-	-	-	-	-	-
7 ACCT 926 DIR ASSIGN COMP.FERC	LABPTDFER	5,483,642	-	-	5,483,642	-	5,483,642	1,752,068	3,731,573
8 203(E) EXCESS DEF TAXES EXCL VA	STATE203E	(300,000)	(280,518)	-	(19,482)	(7)	(19,475)	(6,140)	(13,335)
9 ALLOC O&M LABOR EXPENSE EXCL FERC	LABORXF	187,121,072	177,432,461	9,683,900	4,710	4,710	-	-	-
10 TRANSM KENTUCKY SYS PROP XFERC	KYTRPLTXF	783,605,853	745,069,655	38,533,331	2,867	2,867	-	-	-
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REVENUES FROM ELECTRIC SALES									
-									
1 440-RESIDENTIAL		636,681,927	598,599,985	38,081,941	-	-	-	-	-
2 442-COMMERCIAL		404,163,983	385,820,490	18,343,493	-	-	-	-	-
3 442-LARGE COMMERCIAL		-	-	-	-	-	-	-	-
4 442-INDUSTRIAL		482,180,321	470,749,538	11,430,783	-	-	-	-	-
5 442-MINE POWER		-	-	-	-	-	-	-	-
6 444-PUBLIC ST & HWY LIGHTING		9,256,010	8,843,378	412,632	-	-	-	-	-
7 445-OTHER PUBLIC AUTHORITIES		134,905,779	128,071,668	6,834,111	-	-	-	-	-
8 445-MUNICIPAL PUMPING		-	-	-	-	-	-	-	-
9 447-SALES FOR RESALE-MUNICIPAL WHOLESAL		115,977,824	-	-	115,977,824	-	115,977,824	37,685,971	78,291,853
10 ANNUALIZATION		-	-	-	-	-	-	-	-
11 449-PROVISION FOR RATE REFUND		-	-	-	-	-	-	-	-
12									
13									

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	0.87507	0.04396	0.08097	0.00000	0.08097	0.02512	0.05585
2 DEMAND (12 CP GEN LEV)-FERC	DEMFERC	1.00000	-	0.35187	0.64813	-	0.64813	0.20109	0.44705
3 DEMAND (12 CP GEN)-PROD VA	DPRODVA	1.00000	-	1.00000	-	-	-	-	-
4 DEMAND (12 CP GEN)-PROD KY	DPRODKY	1.00000	0.91531	-	0.08469	-	0.08469	0.02628	0.05842
5 DEM (12 CP GEN LV)-FERC POST	DEMFERCP	1.00000	-	-	1.00000	-	1.00000	0.31026	0.68974
6 DEM (12 CP GEN LV)-NON VA	DEMPRODNV	1.00000	0.91530	-	0.08470	0.00000	0.08469	0.02628	0.05842
TRANSMISSION ALLOCATORS									
7 DEMAND (12 CP GEN LEV)-TRAN	DEMTRAN	1.00000	0.87507	0.04396	0.08097	0.00000	0.08097	0.02512	0.05585
8 DEMAND (12 CP GEN LEV)-VA	DEMVA	1.00000	-	1.00000	-	-	-	-	-
9 DEM (12 CP GEN LEV)-NON FERC	DEMTRANNF	1.00000	0.95217	0.04783	0.00000	0.00000	-	-	-
10 DEM (12 CP GN LEV)-TRAN FERC	DEMFERCT	1.00000	-	0.35187	0.64813	-	0.64813	0.20109	0.44705
11 DEM (12 CP GEN LEV)-NON VA&FERC	DEMTRANNVF	1.00000	1.00000	-	0.00000	0.00000	-	-	-
DISTRIBUTION ALLOCATORS									
12 DIRECT ASSIGN 360 KY	DEM360K	1.00000	0.99882	-	0.00118	-	0.00118	0.00118	-
13 DIRECT ASSIGN 361 KY	DEM361K	1.00000	0.96986	-	0.03014	-	0.03014	0.03014	-
14 DIRECT ASSIGN 362 KY	DEM362K	1.00000	0.97984	-	0.02016	-	0.02016	0.02016	-
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	-	0.99629	0.00371	0.00371	-	-	-
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	0.94887	0.05104	0.00008	0.00008	-	-	-
43 DIR ASSIGN EXCESS FACILITIES REV.	DIR456FAC	1.00000	0.96678	0.03322	-	-	-	-	-
44 DIR ASSIGN OTHER MISC REV.	DIR456OTH	1.00000	1.00000	-	-	-	-	-	-
45 DIR ASSIGN RECONNECT REV.	DIR451REC	1.00000	0.93909	0.06091	-	-	-	-	-
46 DIR ASSIGN OTHER SERVICE REV.	DIR451OTH	1.00000	0.99395	0.00605	-	-	-	-	-
47 DIR ASSIGN RETURN CHECK REV.	DIR456CHK	1.00000	1.00020	(0.00020)	-	-	-	-	-
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	0.87784	0.04031	0.08184	0.00000	0.08184	0.02619	0.05565
2 ENERGY (MWH RETAIL @ GEN LEVEL)	ENERGY1	1.00000	0.95609	0.04391	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	0.99615	-	0.00385	-	0.00385	0.00091	0.00294
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	0.98918	0.01082	-	-	-	-	-
6 CUSTOMER DEPOSITS	CUSTDEP	1.00000	0.96632	0.03368	-	-	-	-	-
7 DIR ASSIGN 902-METER READING	CUST902	1.00000	0.94755	0.05131	0.00114	0.00001	0.00113	0.00061	0.00052
8 DIR ASSIGN 903-CUSTOMER REC	CUST903	1.00000	0.94755	0.05131	0.00114	0.00001	0.00113	0.00061	0.00052
9 DIR ASSIGN 904-UNCOLL ACCTS	CUST904	1.00000	0.94755	0.05131	0.00114	0.00001	0.00113	0.00061	0.00052
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	0.94714	0.05286	0.00001	0.00001	-	-	-
16 DIR ASSIGN 912-DEM & SELLING	CUST912	1.00000	0.94714	0.05286	0.00001	0.00001	-	-	-
17 DIR ASSIGN 913-ADVERTISING	CUST913	1.00000	0.94714	0.05286	0.00001	0.00001	-	-	-
18 CUSTOMER ANNUALIZATION	CUSTANN	-	-	-	-	-	-	-	-
19 CUSTOMER DEPOSITS INTEREST	CUSTDEPI	1.00000	0.96630	0.03370	-	-	-	-	-
20 LATE PAYMENT REVENUES	DIR450REV	1.00000	0.95692	0.04306	0.00003	-	0.00003	0.00003	-
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INTERNALLY DEVELOPED									
-									
1 PROD-TRANSM-DISTR-GENL PLT	PTDGPLT	1.00000	0.88653	0.05190	0.06157	0.00002	0.06155	0.01940	0.04214
2 PROD-TRANSM-DISTR-GENL PLT KY	KURETPLT	1.00000	1.00000	-	-	-	-	-	-
3 ALLOCATED O&M LABOR EXPENSE	LABOR	1.00000	0.90097	0.04917	0.04986	0.00002	0.04983	0.01596	0.03388
4 ALLOCATED O&M LABOR EXPENSE	PTDCUSTLABOF	1.00000	0.90097	0.04917	0.04986	0.00002	0.04983	0.01596	0.03388
5 TOTAL STEAM PROD PLANT-SYSTEM	STMSYS	1.00000	0.87507	0.04396	0.08097	0.00000	0.08097	0.02512	0.05585
6 TOT HYDRAULIC PROD PLANT-SYS	HYDSYS	1.00000	0.87507	0.04396	0.08097	0.00000	0.08097	0.02512	0.05585
7 TOTAL OTHER PROD PLANT-SYS	OTHSYS	1.00000	0.87507	0.04396	0.08097	0.00000	0.08097	0.02512	0.05585
8 TRANSM KENTUCKY SYSTEM PROP	KYTRPLT	1.00000	0.94663	0.04896	0.00441	0.00000	0.00441	0.00137	0.00304
9 TRANSM VIRGINIA PROPERTY	VATRPLT	1.00000	-	1.00000	-	-	-	-	-
10 TRANSM VIRGINIA PROP TOTAL	VATRPLTT	1.00000	0.13953	0.86047	0.00000	0.00000	-	-	-
11 TOTAL DISTRIBUTION PLANT	DISTPLT	1.00000	0.94575	0.05145	0.00280	0.00011	0.00270	0.00237	0.00033
12 TOTAL DIST PLANT KY & FERC	DISTPLTKF	1.00000	0.99716	-	0.00284	-	0.00284	0.00250	0.00035
13 TOTAL GENERAL PLANT	GENPLT	1.00000	0.90342	0.04796	0.04863	0.00002	0.04860	0.01556	0.03304
14 ACCT 302-FRANCHISE	PLT302TOT	1.00000	1.00000	-	-	-	-	-	-
15 ACCT 303-SOFTWARE	PLT303TOT	1.00000	0.88653	0.05190	0.06157	0.00002	0.06155	0.01940	0.04214
16 TOTAL PRODUCTION PLANT SYSTEM	PRODSYS	1.00000	0.87507	0.04396	0.08097	0.00000	0.08097	0.02512	0.05585
17 TOTAL PRODUCTION PLANT	PRODPLT	1.00000	0.86864	0.04463	0.08672	0.00000	0.08672	0.02691	0.05981
18 TOTAL TRANSMISSION PLANT	TRANPLT	1.00000	0.89036	0.10553	0.00410	0.00000	0.00410	0.00127	0.00283
19 TOTAL TRANSMISSION PLANT EXCL FERC	TRANPLTXF	1.00000	0.89403	0.10597	0.00000	0.00000	-	-	-
20 MAT & SUPPLIES DISTRIBUTED	M_S	1.00000	0.88441	0.05356	0.06202	0.00002	0.06200	0.01949	0.04252
21 ACCT 924 & 925 INSURANCE	EXP9245TOT	1.00000	0.89210	0.05085	0.05705	0.00002	0.05703	0.01807	0.03895
22 REVENUE SALE OF ELECT-KY	REVKY	1.00000	1.00000	-	-	-	-	-	-
23 CWIP PROD FERC-POST ALLOC	CWIPPP	1.00000	-	-	1.00000	-	1.00000	0.31026	0.68974
24 CWIP TRAN FERC-POST ALLOC	CWIPTP	-	-	-	-	-	-	-	-
25 ACC DEF INC TX PROD FERC-POST	ADITPP	-	-	-	-	-	-	-	-
26 ACC DEF INC TX TRAN FERC-POST	ADITTP	-	-	-	-	-	-	-	-
27 TRANSMISSION PLANT EXCL VA	TRANPLTX	1.00000	0.94663	0.04896	0.00441	0.00000	0.00441	0.00137	0.00304
28 TRANSM PLANT VA & 500 KV	TRPLTVA	1.00000	0.13953	0.86047	0.00000	0.00000	-	-	-
29 TOT ACCT 364 & 365-OVHD LINE	PLT3645TOT	1.00000	0.93166	0.06820	0.00013	0.00013	-	-	-
30 TOTAL ELECTRIC PLANT	PLANT	1.00000	0.88653	0.05190	0.06157	0.00002	0.06155	0.01940	0.04214
31 TOTAL ELECTRIC PLANT KY	PLANTKY	1.00000	1.00000	-	-	-	-	-	-
32 TOTAL ELECTRIC PLANT KY & FERC	PLANTKF	1.00000	0.93506	-	0.06494	0.00002	0.06492	0.02047	0.04445
33 TOTAL ELECTRIC PLANT VA	PLANTVA	1.00000	-	1.00000	-	-	-	-	-
34 TOTAL STEAM PROD PLANT	STMPLT	1.00000	0.86819	0.04482	0.08699	0.00000	0.08698	0.02699	0.06000
35 TOTAL HYDRAULIC PROD PLANT	HYDPLT	1.00000	0.87277	0.04385	0.08338	0.00000	0.08338	0.02587	0.05751
36 TOTAL OTHER PROD PLANT	OTHPLT	1.00000	0.87070	0.04374	0.08556	0.00000	0.08555	0.02654	0.05901
37 TOT ACCT 360-362 SUBSTATIONS	PLT3602TOT	1.00000	0.93811	0.04243	0.01946	0.00039	0.01907	0.01907	-
38 TOT ACCT 366 & 367-UG LINES	PLT3667TOT	1.00000	0.97791	0.02209	-	-	-	-	-
39 TOT ACCT 373-STREET LIGHTING	PLT373TOT	1.00000	0.97425	0.02575	-	-	-	-	-
40 TOTAL ACCT 370-METERS	PLT370TOT	1.00000	0.94757	0.04871	0.00372	0.00005	0.00366	0.00087	0.00280
41 TOT ACCT 371-CUSTOMER INSTALL	PLT371TOT	1.00000	0.95287	0.04713	-	-	-	-	-
42 TOT ACCT 368-LINE TRANSFORMER	PLT368TOT	1.00000	0.95357	0.04480	0.00163	0.00001	0.00162	0.00050	0.00112
43 TOT ACCT 902-904 CUST ACCTS	EXP9024CA	1.00000	0.94755	0.05131	0.00114	0.00001	0.00113	0.00061	0.00052
44 TOT ACCT 908-909 CUST SERV	EXP9089CS	1.00000	0.99900	0.00100	0.00000	0.00000	-	-	-
45 TOTAL TRANS & DISTRIB PLANT	TRDSPLT	1.00000	0.92739	0.06938	0.00323	0.00007	0.00316	0.00200	0.00116

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INTERNALLY DEVELOPED-CON'T									
-									
1 TOT ACCT 912-913 SALES EXP	EXP9123SA	1.00000	0.94714	0.05286	0.00001	0.00001	-	-	-
2 REVENUE SALE OF ELECT-FERC	REVFERC	1.00000	-	-	1.00000	-	1.00000	0.32484	0.67516
3 REVENUE SALE OF ELECT-VA	REVVA	1.00000	-	1.00000	-	-	-	-	-
4 REVENUE SALE OF ELECT	REVENUE	1.00000	0.89261	0.04209	0.06530	0.00000	0.06530	0.02121	0.04409
5 REV SALE OF ELECT-VA NON JUR	REVNJVA	1.00000	-	1.00000	-	-	-	-	-
6 REV SALE OF ELECT-EXCL FERC	REVENUEX	1.00000	0.95497	0.04503	0.00000	0.00000	-	-	-
7 KENTUCKY DISTRIBUTION PLANT	KYDIST	1.00000	0.99716	-	0.00284	-	0.00284	0.00250	0.00035
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	0.88870	0.04822	0.06308	0.00001	0.06308	0.01985	0.04322
11 RATE BASE	RATEBASE	1.00000	0.88930	0.04666	0.06404	0.00001	0.06403	0.02016	0.04387
12 TOTAL CWIP FERC-AFUDC POST	AFUDC	-	-	-	-	-	-	-	-
13 TOTAL 201(E) EXCESS	TAX203E	1.00000	0.90356	0.03369	0.06275	0.00002	0.06273	0.01978	0.04295
14 STEAM OPERATING EXP 501-507	EXP5017STM	1.00000	0.87653	0.04093	0.08255	0.00000	0.08254	0.02630	0.05624
15 STEAM MAINTENANCE EXP 511-514	EXP5114STM	1.00000	0.87651	0.04094	0.08256	0.00000	0.08255	0.02630	0.05625
16 HYDRO OPERATING EXP 536-540	EXP5360HYD	1.00000	0.87277	0.04385	0.08338	0.00000	0.08338	0.02587	0.05751
17 HYDRO MAINTENANCE EXP 542-545	EXP5425HYD	1.00000	0.87360	0.04327	0.08313	0.00000	0.08313	0.02592	0.05721
18 OTHER PROD OPER EXP 547-549	EXP5479OTH	1.00000	0.87783	0.04032	0.08185	0.00000	0.08185	0.02619	0.05566
19 OTHER PROD MAINT EXP 552-554	EXP5524OTH	1.00000	0.87070	0.04374	0.08556	0.00000	0.08555	0.02654	0.05901
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	0.89403	0.10597	0.00000	0.00000	-	-	-
27 TRANSM MAINT EXP 569-573	EXP5693TX	1.00000	0.89516	0.10484	0.00000	0.00000	-	-	-
28 TOT TRANSM OPERATIONS LABOR	LABTROP	1.00000	0.89403	0.10597	0.00000	0.00000	-	-	-
29 TOT TRANSM MAINTENANCE LABOR	LABTRMN	-	-	-	-	-	-	-	-
30 DISTR OPER EXP 582-589	EXP5829DIS	1.00000	0.94240	0.05340	0.00420	0.00012	0.00408	0.00282	0.00126
31 DISTR MAINT EXP 591-598	EXP5918DIS	1.00000	0.91200	0.08723	0.00077	0.00011	0.00066	0.00065	0.00000
32 TOT DISTR OPERATIONS LABOR	LABDISOP	1.00000	0.94575	0.05145	0.00280	0.00011	0.00270	0.00237	0.00033
33 TOT DISTR MAINTENANCE LABOR	LABDISMN	-	-	-	-	-	-	-	-
34 CUST ACCT EXP 902, 903 & 905	EXP9025CA	1.00000	0.94755	0.05131	0.00114	0.00001	0.00113	0.00061	0.00052
35 TOTAL CUST ACCOUNTS LABOR	LABCA	1.00000	0.94755	0.05131	0.00114	0.00001	0.00113	0.00061	0.00052
36 CUST SERVICES EXP 908-910	EXP9080CS	1.00000	0.99854	0.00145	0.00000	0.00000	-	-	-
37 TOTAL CUST SERVICES LABOR	LABCS	1.00000	0.99854	0.00145	0.00000	0.00000	-	-	-
38 SALES EXPENSE 912-916	EXP9126SA	1.00000	0.94714	0.05286	0.00001	0.00001	-	-	-
39 TOTAL SALES EXP LABOR	LABSA	1.00000	0.99854	0.00145	0.00000	0.00000	-	-	-
40 TOT ADMINISTRATIVE & GEN EXP	A_GEXP	1.00000	0.90270	0.04889	0.04841	0.00002	0.04839	0.01548	0.03291

KENTUCKY UTILITIES COMPANY
ELECTRIC COST OF SERVICE STUDY
JURISDICTIONAL SEPARATION

RATE BASE: THIRTEEN MONTH AVERAGE
ALLOCATION METHOD: AVG 12 CP (COMBINED CO SYS)

12 MONTHS ENDING JUNE 30, 2016

	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	0.95609	0.04391	0.00001	0.00001	-	-	-
2 TOTAL CUSTOMER SERVICES EXP	CUSTSER	1.00000	0.99900	0.00100	0.00000	0.00000	-	-	-
3 DISTRIBUTION PLANT EXCL VA	DPLTXVA	1.00000	0.99705	-	0.00295	0.00011	0.00284	0.00250	0.00035
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	0.31951	0.68049
8 203(E) EXCESS DEF TAXES EXCL VA	STATE203E	1.00000	0.93506	-	0.06494	0.00002	0.06492	0.02047	0.04445
9 ALLOC O&M LABOR EXPENSE EXCL FERC	LABORXF	1.00000	0.94822	0.05175	0.00003	0.00003	-	-	-
10 TRANSM KENTUCKY SYS PROP XFERC	KYTRPLTXF	1.00000	0.95082	0.04917	0.00000	0.00000	-	-	-
11									
12									
13									

Exhibit MJB-4

Base-Intermediate-Peak (BIP) Differentiation

LOUISVILLE GAS AND ELECTRIC COMPANY AND KENTUCKY UTILITIES
Assignment of Production and Transmission Demand-Related Costs
Based on Forecasted 12 Months Ended June 30, 2016

Minimum System Demand	2,429
Winter System Peak Demand	6,069
Summer System Peak Demand	6,942

Assignment of Production and Transmission
Demand-Related Costs to the Costing Periods

Non-Time-Differentiated Capacity Costs

1. Minimum System Demand	2,429	
2. Maximum System Demand	6,942	
3. Non-Time-Differentiated Capacity Factor (Line 1/Line 2)	0.3499	
4. Non-Time-Differentiated Cost (Line 3)		34.99%

Winter Peak Period Costs

5. Maximum Winter System Demand	6,069	
6. Intermediate Peak Period Capacity Factor (Line 5/Line2 - Line 3)	0.5243	
7. Winter Peak Period Hours	2,432	
8. Summer Peak Period Hours	1,308	
9. Total Summer and Winter Peak Period Hours (Line 7 + Line 8)	3,740	
10. Winter Peak Period Costs (Line 8/Line 9 x Line 6)		34.10%

Summer Peak Period Costs

11. Peak Capacity Factor (1.0000 - Line 3 - Line 6)	0.1258	
12. Summer Peak Period Costs (Line 11 + Line 7/Line 9 x Line 6)		30.91%

Exhibit MJB-5

Zero Intercept – Overhead Conductor

Kentucky Utilities Company

Zero Intercept Analysis
Account 365 -- Overhead Conductor

August 31, 2014

Weighted Linear Regression Statistics

	Estimate	Standard Error
Size Coefficient ($ per MCM)	0.0041499	0.0007672
Zero Intercept ($ per Unit)	1.0416929	0.2298079
R-Square	0.8202656	

Plant Classification

Total Number of Units		98,057,849
Zero Intercept		1.0416929
Zero Intercept Cost	$	102,146,168
Total Cost of Sample	$	178,439,181
Percentage of Total		0.572442485
Percentage Classified as Customer-Related		57.24%
Percentage Classified as Demand-Related		42.76%

Kentucky Utilities Company

Zero Intercept Analysis
Account 365 -- Overhead Conductor

August 31, 2014

Description	Size	Cost	Quantity	Avg Cost
1 CONDUCTOR	83.69	1,284,769.59	162,794.00	7.891996
1/0 CONDUCTOR	105.6	2,874,293.80	428,867.00	6.7020633
123,270 ACAR WIRE	123.27	15,699,716.04	9,028,739.00	1.7388603
195,700 ACAR WIRE	195.7	2,273,799.53	1,847,997.00	1.230413
2/0 COPPER CONDUCTOR	133.1	759,602.80	618,000.00	1.2291307
20 M.A.W. MESSENGER WIRE	20	2,745,544.35	1,313,619.00	2.0900614
336,400 19 STR. ALL ALUMINUM	336.4	8,530,974.45	5,637,131.00	1.5133539
350 MCM COPPER CONDUCTOR	350	1,343,426.45	74,915.00	17.932676
392,500 24/13 ACAR WIRE	392.5	1,021,961.83	873,608.00	1.1698174
4 COPPER CONDUCTOR	41.74	14,657,091.16	11,460,265.00	1.2789487
4A COPPER CONDUCTOR	41.74	592,346.58	40,681.00	14.560767
6 COPPER CONDUCTOR	26.25	7,790,531.95	14,812,888.00	0.5259293
6A COPPER CONDUCTOR	26.25	839,458.78	112,335.00	7.472816
750 MCM COPPER CONDUCTOR	750	876,670.60	27,263.00	32.156058
795 MCM ALUMINUM CONDUCTOR	795	47,869,522.72	10,744,462.00	4.455274
8 COPPER CONDUCTOR	16.51	619,537.19	308,125.00	2.0106684
840,200 24/13 ACAR WIRE	840.2	573,415.22	211,847.00	2.7067422
#2 CONDUCTOR	66.36	10,947,654.25	9,400,976.00	1.1645232
1/0 CABLE	105.6	39,626,917.27	22,190,701.00	1.7857443
101 MCM ACSR CONDUCTOR	101	1,181.18	250.00	4.72472
1272 MCM ACSR CONDUCTOR	1272	77,148.92	29,563.00	2.6096445
200 MCM CABLE	200	3,238.76	500.00	6.47752
3/0 CONDUCTOR	167.8	5,712,778.73	2,030,933.00	2.8128839
300 MCM COPPER CONDUCTOR	300	3,564.60	260.00	13.71
4/0 CONDUCTOR	211.6	11,007,519.63	6,552,125.00	1.6799923
520 MCM CONDUCTOR	520	688.25	112.00	6.1450893
600 MCM CONDUCTOR	600	101,105.38	14,560.00	6.9440508
636 MCM ALUMINUM CONDUCTOR	636	21,911.09	3,040.00	7.2075954
7/C CONDUCTOR	20.92	18,059.98	4,050.00	4.4592543
80 MCM ACSR CONDUCTOR	80	11,173.82	5,500.00	2.0316036
954 MCM ACSR CONDUCTOR	954	553,575.80	121,743.00	4.5470853

Kentucky Utilities Company

Zero Intercept Analysis
Account 365 -- Overhead Conductor

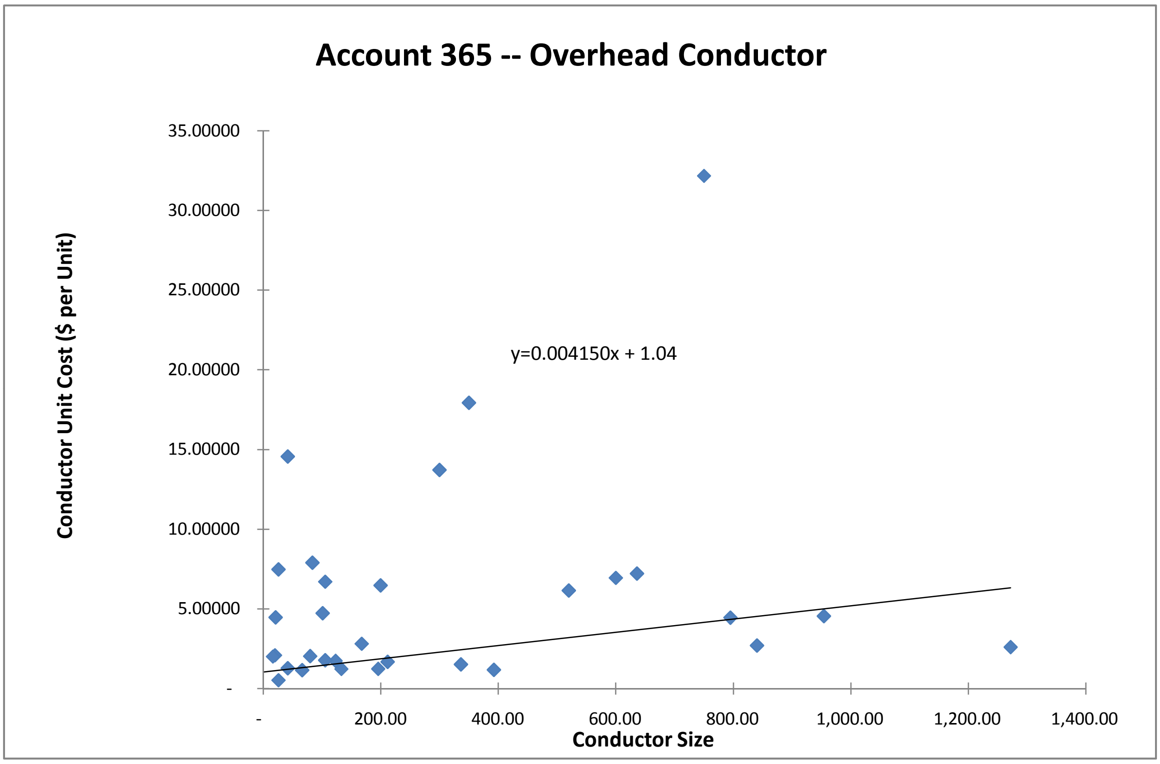
August 31, 2014

n	y	x	est y	y*n^.5	n^.5	xn^.5
162,794	7.89200	83.69	1.389	3184.24189	403.48	33767.02
428,867	6.70206	105.60	1.480	4389.043075	654.88	69155.26
9,028,739	1.73886	123.27	1.553	5224.90319	3,004.79	370400
1,847,997	1.23041	195.70	1.854	1672.636391	1,359.41	266036.6
618,000	1.22913	133.10	1.594	966.2562574	786.13	104633.9
1,313,619	2.09006	20.00	1.125	2395.486638	1,146.13	22922.64
5,637,131	1.51335	336.40	2.438	3593.102261	2,374.26	798702.5
74,915	17.93268	350.00	2.494	4908.281955	273.71	95797.12
873,608	1.16982	392.50	2.671	1093.393214	934.67	366858
11,460,265	1.27895	41.74	1.215	4329.626758	3,385.30	141302.5
40,681	14.56077	41.74	1.215	2936.838571	201.70	8418.762
14,812,888	0.52593	26.25	1.151	2024.171209	3,848.75	101029.7
112,335	7.47282	26.25	1.151	2504.619924	335.16	8798.059
27,263	32.15606	750.00	4.154	5309.451042	165.12	123836.3
10,744,462	4.45527	795.00	4.341	14603.82971	3,277.87	2605910
308,125	2.01067	16.51	1.110	1116.102069	555.09	9164.537
211,847	2.70674	840.20	4.528	1245.827913	460.27	386717.5
9,400,976	1.16452	66.36	1.317	3570.545741	3,066.10	203466.5
22,190,701	1.78574	105.60	1.480	8412.10679	4,710.70	497450
250	4.72472	101.00	1.461	74.70438253	15.81	1596.95
29,563	2.60964	1,272.00	6.320	448.699514	171.94	218706.3
500	6.47752	200.00	1.872	144.8417505	22.36	4472.136
2,030,933	2.81288	167.80	1.738	4008.663529	1,425.11	239133.1
260	13.71000	300.00	2.287	221.0671075	16.12	4837.355
6,552,125	1.67999	211.60	1.920	4300.29631	2,559.71	541635
112	6.14509	520.00	3.200	65.03351214	10.58	5503.163
14,560	6.94405	600.00	3.532	837.9026777	120.66	72398.9
3,040	7.20760	636.00	3.681	397.3993852	55.14	35066.62
4,050	4.45925	20.92	1.129	283.7852072	63.64	1331.341
5,500	2.03160	80.00	1.374	150.6677581	74.16	5932.959
121,743	4.54709	954.00	5.001	1586.55487	348.92	332866.7

Kentucky Utilities Company

Zero Intercept Analysis
Account 365 -- Overhead Conductor

August 31, 2014



Kentucky Utilities Company
Pri/Sec Splits for Overhead Conductor
As of August 31, 2014

		Customer	Demand
Overhead		57.24%	42.76%
Primary	75.00%	0.4293	0.3207
Secondary	25.00%	0.1431	0.1069

Exhibit MJB-6

Zero Intercept – Underground Conductor

Kentucky Utilities Company

Zero Intercept Analysis
Account 367 -- Underground Conductor

August 31, 2014

Weighted Linear Regression Statistics

	Estimate	Standard Error
Size Coefficient ($ per MCM)	0.0069717	0.0013479
Zero Intercept ($ per Unit)	3.3551919	0.4378996
R-Square	0.9155632	

Plant Classification

Total Number of Units	26,711,988
Zero Intercept	3.3551919
Zero Intercept Cost	$89,623,845
Total Cost of Sample	128,057,867
Percentage of Total	0.699869885
Percentage Classified as Customer-Related	69.99%
Percentage Classified as Demand-Related	30.01%

Kentucky Utilities Company

Zero Intercept Analysis
Account 367 -- Underground Conductor

August 31, 2014

Description	Size	Cost	Quantity	Avg Cost
#12 CABLE	13.12	701,059.49	97,261	7.20802264
1 CONDUCTOR	83.69	1,514,957.43	153,578	9.864416974
1/0 CONDUCTOR	105.6	2,234,527.12	190,474	11.73140229
1000 MCM CONDUCTOR	1000	20,821,953.96	2,106,325	9.885442161
2/0 COPPER CONDUCTOR	133.1	1,582,404.51	557,414	2.838831658
200 MCM 1/C 500/600V CABLE	200	28,562.39	1,550	18.42734839
250 MCM COPPER CONDUCTOR	250	235,557.28	175,014	1.345933925
350 MCM COPPER CONDUCTOR	350	10,704,400.11	963,488	11.11005027
4 COPPER CONDUCTOR	41.74	803,373.41	649,418	1.237066743
6 COPPER CONDUCTOR	26.25	996,347.58	339,049	2.938653646
750 MCM COPPER CONDUCTOR	750	2,383,315.92	265,617	8.972753702
795 MCM ALUMINUM CONDUCTOR	795	502,850.86	53,029	9.482563503
8 COPPER CONDUCTOR	16.51	40,615.72	27,641	1.469401252
#2 CONDUCTOR	66.36	16,758,267.63	3,577,493	4.684360705
1/0 CABLE	105.6	46,418,107.42	12,288,964	3.777218927
123,270 ACAR WIRE	123.27	7,397.12	496	14.91354839
195,700 ACAR WIRE	195.7	10,289.60	7,611	1.351937984
3/0 CONDUCTOR	167.8	327,842.85	31,894	10.27913871
336,400 19 STR. ALL ALUMINUM	336.4	95,736.62	2,289	41.82464832
4/0 CONDUCTOR	211.6	21,561,255.00	5168864	4.171372085
600 MCM CONDUCTOR	600	21,636.43	1634	13.24138923
6A COPPER CONDUCTOR	26.25	307,231.56	52777	5.821315346
840,200 24/13 ACAR WIRE	840.2	177.03	108	1.639166667

Kentucky Utilities Company

Zero Intercept Analysis
Account 367 -- Underground Conductor

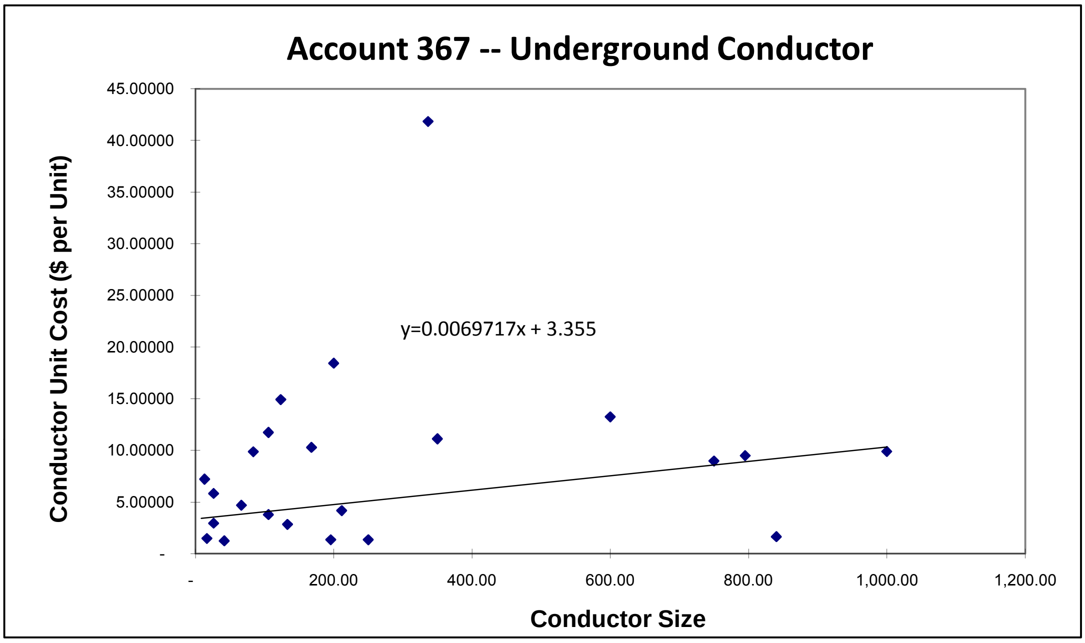
August 31, 2014

n	y	x	est y	y*n^.5	n^.5	xn^.5
97,261	7.20802	13.12	3.447	2247.9441	311.87	4091.6945
153,578	9.86442	83.69	3.939	3865.769236	391.89	32797.29843
190,474	11.73140	105.60	4.091	5119.974275	436.43	46087.35341
2,106,325	9.88544	1,000.00	10.327	14346.92377	1,451.32	1451318.366
557,414	2.83883	133.10	4.283	2119.476355	746.60	99372.6775
1,550	18.42735	200.00	4.750	725.4854315	39.37	7874.007874
175,014	1.34593	250.00	5.098	563.0670782	418.35	104586.6865
963,488	11.11005	350.00	5.795	10905.33921	981.57	343550.986
649,418	1.23707	41.74	3.646	996.9084851	805.86	33636.79479
339,049	2.93865	26.25	3.538	1711.116726	582.28	15284.8275
265,617	8.97275	750.00	8.584	4624.381769	515.38	386535.3315
53,029	9.48256	795.00	8.898	2183.647227	230.28	183072.8099
27,641	1.46940	16.51	3.470	244.2965203	166.26	2744.883703
3,577,493	4.68436	66.36	3.818	8860.12248	1,891.43	125515.0414
12,288,964	3.77722	105.60	4.091	13241.27463	3,505.56	370187.3331
496	14.91355	123.27	4.215	332.1404929	22.27	2745.353252
7,611	1.35194	195.70	4.720	117.9444831	87.24	17073.07258
31,894	10.27914	167.80	4.525	1835.740213	178.59	29967.21967
2,289	41.82465	336.40	5.700	2001.037347	47.84	16094.55167
5,168,864	4.17137	211.60	4.830	9483.671084	2,273.51	481075.4736
1,634	13.24139	600.00	7.538	535.2535765	40.42	24253.65952
52,777	5.82132	26.25	3.538	1337.345055	229.73	6030.476893
108	1.63917	840.20	9.213	17.03471969	10.39	8731.614531

Kentucky Utilities Company

Zero Intercept Analysis
Account 367 -- Underground Conductor

August 31, 2014



Kentucky Utilities Company
Pri/Sec Splits for Underground Conductor
As of August 31, 2014

		Customer	Demand
Underground		69.99%	30.01%
Primary	75.00%	0.5249	0.2251
Secondary	25.00%	0.1750	0.0750

Exhibit MJB-7

Zero Intercept – Transformers

KENTUCKY UTILITIES COMPANY

Zero Intercept Analysis
Account 368 - Line Transformers

August 31, 2014

Weighted Linear Regression Statistics

	Estimate	Standard Error
Size Coefficient ($ per kVA)	10.7167809	0.4435087
Zero Intercept ($ per Unit)	416.49	53.9477002
R-Square	0.9475024	

Plant Classification

Total Number of Units		251,790
Zero Intercept	$	416.49
Zero Intercept Cost	$	104,869,124
Total Cost of Sample	$	220,398,969
Percentage of Total		0.475814947
Percentage Classified as Customer-Related		47.58%
Percentage Classified as Demand-Related		52.42%

KENTUCKY UTILITIES COMPANY

Zero Intercept Analysis
Account 368 - Line Transformers

August 31, 2014

Description	Size	Cost	Quantity	Avg Cost
TRANSFORMERS - OH 1P - .6 KVA	0.6	6350.91	5	1270.18
TRANSFORMERS - OH 1P - 1 KVA	1	7595.25	16	474.70
TRANSFORMERS - OH 1P - 1.5 KVA	1.5	3882.71	56	69.33
TRANSFORMERS - OH 1P - 10 KVA	10	9667665.43	28304	341.57
TRANSFORMERS - OH 1P - 100 KVA	100	5772267.36	4239	1361.70
TRANSFORMERS - OH 1P - 1250 KVA	1250	148540.75	14	10610.05
TRANSFORMERS - OH 1P - 15 KVA	15	26466888.56	53160	497.87
TRANSFORMERS - OH 1P - 150 KVA	150	9231.17	6	1538.53
TRANSFORMERS - OH 1P - 167 KVA	167	4006048.52	2243	1786.02
TRANSFORMERS - OH 1P - 25 KVA	25	37789610.73	60965	619.86
TRANSFORMERS - OH 1P - 250 KVA	250	1003782.95	308	3259.04
TRANSFORMERS - OH 1P - 3 KVA	3	88649.51	805	110.12
TRANSFORMERS - OH 1P - 333 KVA	333	470066.43	131	3588.29
TRANSFORMERS - OH 1P - 37.5 KVA	37.5	22636426.68	30454	743.30
TRANSFORMERS - OH 1P - 5 KVA	5	841010.49	5585	150.58
TRANSFORMERS - OH 1P - 50 KVA	50	22274810.83	18888	1179.31
TRANSFORMERS - OH 1P - 500 KVA	500	1117989.41	242	4619.79
TRANSFORMERS - OH 1P - 667 KVA	667	92692.95	17	5452.53
TRANSFORMERS - OH 1P - 7.5 KVA	7.5	5242.88	18	291.27
TRANSFORMERS - OH 1P - 75 KVA	75	7591450.84	6648	1141.91
TRANSFORMERS - OH 1P - 833 KVA	833	269780.64	27	9991.88
TRANSFORMERS - PM 1P - 10 KVA	10	138383.93	182	760.35
TRANSFORMERS - PM 1P - 100 KVA	100	2456794.87	1357	1810.46
TRANSFORMERS - PM 1P - 15 KVA	15	2440177.42	2819	865.62
TRANSFORMERS - PM 1P - 150 KVA	150	72670.89	16	4541.93
TRANSFORMERS - PM 1P - 167 KVA	167	2025235.34	921	2198.95
TRANSFORMERS - PM 1P - 225 KVA	225	486.66	4	121.67
TRANSFORMERS - PM 1P - 25 KVA	25	9123245.22	9404	970.15
TRANSFORMERS - PM 1P - 250 KVA	250	1638685.69	448	3657.78
TRANSFORMERS - PM 1P - 333 KVA	333	3901.90	2	1950.95
TRANSFORMERS - PM 1P - 37.5 KVA	37.5	9333287.18	8873	1051.88
TRANSFORMERS - PM 1P - 50 KVA	50	7870696.96	7020	1121.18
TRANSFORMERS - PM 1P - 500 KVA	500	6978.58	1	6978.58
TRANSFORMERS - PM 1P - 75 KVA	75	4147323.94	2938	1411.61
TRANSFORMERS - PM 3P - 1000 KVA	1000	4184505.78	354	11820.64
TRANSFORMERS - PM 3P - 112 KVA	112	85072.96	31	2744.29
TRANSFORMERS - PM 3P - 112.5 KVA	112.5	809578.10	227	3566.42
TRANSFORMERS - PM 3P - 1250 KVA	1250	14355.37	2	7177.69
TRANSFORMERS - PM 3P - 150 KVA	150	3189390.51	798	3996.73
TRANSFORMERS - PM 3P - 1500 KVA	1500	4272333.58	258	16559.43
TRANSFORMERS - PM 3P - 2000 KVA	2000	2599166.05	113	23001.47
TRANSFORMERS - PM 3P - 225 KVA	225	2459547.83	549	4480.05
TRANSFORMERS - PM 3P - 2500 KVA	2500	3154157.01	159	19837.47
TRANSFORMERS - PM 3P - 300 KVA	300	5099742.68	956	5334.46
TRANSFORMERS - PM 3P - 3000 KVA	3000	573153.95	15	38210.26
TRANSFORMERS - PM 3P - 333 KVA	333	117861.40	33	3571.56
TRANSFORMERS - PM 3P - 45 KVA	45	377611.64	118	3200.10
TRANSFORMERS - PM 3P - 500 KVA	500	6860935.61	948	7237.27
TRANSFORMERS - PM 3P - 75 KVA	75	2142509.63	619	3461.24
TRANSFORMERS - PM 3P - 750 KVA	750	4914779.70	491	10009.73
TRANSFORMERS - PM 3P - 833 KVA	833	16413.78	3	5471.26

KENTUCKY UTILITIES COMPANY

Zero Intercept Analysis
Account 368 - Line Transformers

August 31, 2014

n	y	x	est y	y*n^.5	n^.5	xn^.5
5	1,270	0.60	261	2840.213296	2.24	1.341640786
16	475	1.00	427	1898.8125	4.00	4
56	69	1.50	635	518.8489483	7.48	11.22497216
28,304	342	10.00	4,176	57464.24493	168.24	1682.379268
4,239	1,362	100.00	41,660	88657.3468	65.11	6510.760324
14	10,610	1,250.00	520,629	39699.18532	3.74	4677.071733
53,160	498	15.00	6,258	114791.6775	230.56	3458.467869
6	1,539	150.00	62,485	3768.609371	2.45	367.4234614
2,243	1,786	167.00	69,565	84586.59992	47.36	7909.173598
60,965	620	25.00	10,423	153049.5754	246.91	6172.772878
308	3,259	250.00	104,134	57195.84181	17.55	4387.482194
805	110	3.00	1,260	3124.484678	28.37	85.11756575
131	3,588	333.00	138,703	41069.89468	11.45	3811.359206
30,454	743	37.50	15,629	129713.6559	174.51	6544.152925
5,585	151	5.00	2,093	11253.55724	74.73	373.6642878
18,888	1,179	50.00	20,835	162076.8686	137.43	6871.681017
242	4,620	500.00	208,258	71867.08119	15.56	7778.174593
17	5,453	667.00	277,812	22481.34256	4.12	2750.111452
18	291	7.50	3,134	1235.758667	4.24	31.81980515
6,648	1,142	75.00	31,248	93106.34508	81.54	6115.145133
27	9,992	833.00	346,951	51919.30838	5.20	4328.394968
182	760	10.00	4,176	10257.69935	13.49	134.9073756
1,357	1,810	100.00	41,660	66692.80334	36.84	3683.748091
2,819	866	15.00	6,258	45959.34876	53.09	796.4138371
16	4,542	150.00	62,485	18167.7225	4.00	600
921	2,199	167.00	69,565	66733.77336	30.35	5068.112962
4	122	225.00	93,722	243.33	2.00	450
9,404	970	25.00	10,423	94079.07485	96.97	2424.355584
448	3,658	250.00	104,134	77420.62166	21.17	5291.502622
2	1,951	333.00	138,703	2759.05995	1.41	470.9331163
8,873	1,052	37.50	15,629	99083.05493	94.20	3532.372609
7,020	1,121	50.00	20,835	93938.71937	83.79	4189.272013
1	6,979	500.00	208,258	6978.58	1.00	500
2,938	1,412	75.00	31,248	76514.20372	54.20	4065.24907
354	11,821	1,000.00	416,505	222403.9729	18.81	18814.88772
31	2,744	112.00	46,658	15279.55468	5.57	623.5896086
227	3,566	112.50	46,866	53733.58575	15.07	1694.983407
2	7,178	1,250.00	520,629	10150.77947	1.41	1767.766953
798	3,997	150.00	62,485	112903.2002	28.25	4237.334068
258	16,559	1,500.00	624,752	265983.8707	16.06	24093.56761
113	23,001	2,000.00	833,000	244508.9744	10.63	21260.29163
549	4,480	225.00	93,722	104970.9434	23.43	5271.918531
159	19,837	2,500.00	1,041,247	250140.9218	12.61	31523.80053
956	5,334	300.00	124,959	164937.4657	30.92	9275.7749
15	38,210	3,000.00	1,249,494	147987.7135	3.87	11618.95004
33	3,572	333.00	138,703	20517.03624	5.74	1912.939361
118	3,200	45.00	18,753	34761.96912	10.86	488.8251221
948	7,237	500.00	208,258	222832.8294	30.79	15394.80432
619	3,461	75.00	31,248	86114.73275	24.88	1865.978296
491	10,010	750.00	312,382	221800.9029	22.16	16618.88985
3	5,471	833.00	346,951	9476.500301	1.73	1442.798323

KENTUCKY UTILITIES COMPANY

Zero Intercept Analysis
Account 368 - Line Transformers

August 31, 2014

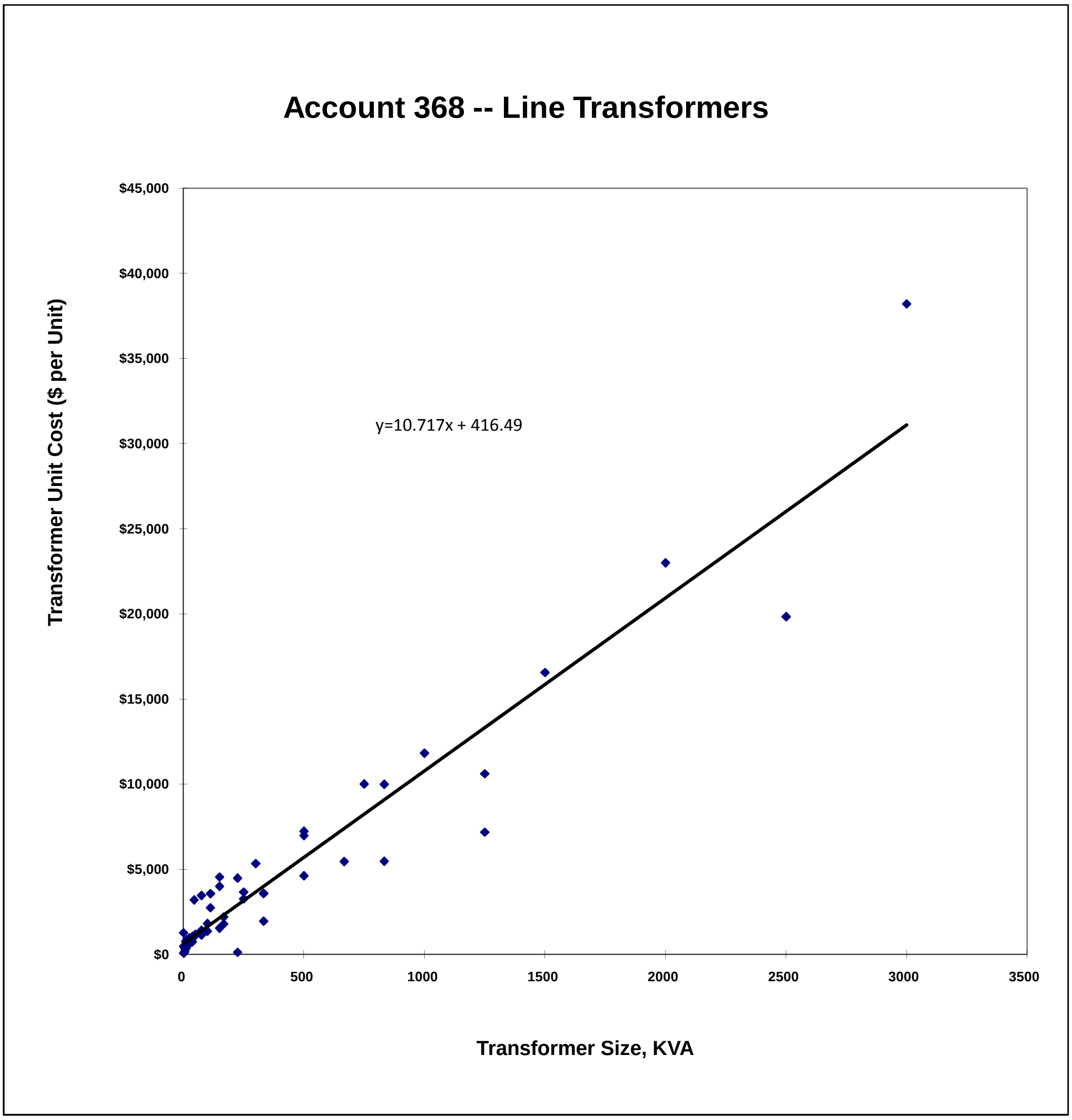


Exhibit MJB-8

Electric Cost of Service Study - Functional Assignment, Classification and Time Differentiation

KENTUCKY UTILITIES COMPANY
Cost of Service Study
Functional Assignment and Classification
12 Months Ended June 30, 2016

				Production Demand			Production Energy		
Description	**Name**	**Functional Vector**	**Total System**	**Base**	**Inter.**	**Peak**	**Base**	**Inter.**	**Peak**
Plant in Service									
Intangible Plant									
301.00 ORGANIZATION	P301	PT&D	$ 39,411	8,681	8,459	7,670	-	-	-
302.00 FRANCHISE AND CONSENTS	P301	PT&D	55,919	12,317	12,002	10,882	-	-	-
303.00 SOFTWARE	P302	PT&D	84,153,983	18,536,232	18,062,892	16,376,801	-	-	-
Total Intangible Plant	PINT		$ 84,249,313	$ 18,557,229	$ 18,083,354	$ 16,395,352	$ -	$ -	$ -
Steam Production Plant									
Total Steam Production Plant	PSTPR	F017	$ 3,105,160,878	1,086,493,197	1,058,748,599	959,919,082	-	-	-
Hydraulic Production Plant									
Total Hydraulic Production Plant	PHDPR	F017	$ 34,935,637	12,223,950	11,911,800	10,799,886	-	-	-
Other Production Plant									
Total Other Production Plant	POTPR	F017	$ 877,242,165	306,946,301	299,108,146	271,187,719	-	-	-
Total Production Plant	PPRTL		$ 4,017,338,680	$ 1,405,663,448	$ 1,369,768,545	$ 1,241,906,687	$ -	$ -	$ -
Transmission									
KENTUCKY SYSTEM PROPERTY	P350	F011	$ 744,675,981	-	-	-	-	-	-
VIRGINIA PROPERTY - 500 KV LINE	P352	F011	8,230,398	-	-	-	-	-	-
Total Transmission Plant	PTRAN		$ 752,906,378	$ -	$ -	$ -	$ -	$ -	$ -
Distribution									
TOTAL ACCTS 360-362	P362	F001	$ 187,655,470	-	-	-	-	-	-
364 & 365-OVERHEAD LINES	P365	F003	665,938,460	-	-	-	-	-	-
366 & 367-UNDERGROUND LINES	P367	F004	181,847,866	-	-	-	-	-	-
368-TRANSFORMERS - POWER POOL	P368	F005	5,429,977	-	-	-	-	-	-
368-TRANSFORMERS - ALL OTHER	P368a	F005	290,915,324	-	-	-	-	-	-
369-SERVICES	P369	F006	89,746,639	-	-	-	-	-	-
370-METERS	P370	F007	73,127,621	-	-	-	-	-	-
371-CUSTOMER INSTALLATION	P371	F008	17,289,842	-	-	-	-	-	-
373-STREET LIGHTING	P373	F008	99,477,208	-	-	-	-	-	-
Total Distribution Plant	PDIST		$ 1,611,428,408	$ -	$ -	$ -	$ -	$ -	$ -
Total Prod, Trans, and Dist Plant	PT&D		$ 6,381,673,467	$ 1,405,663,448	$ 1,369,768,545	$ 1,241,906,687	$ -	$ -	$ -

KENTUCKY UTILITIES COMPANY
Cost of Service Study
Functional Assignment and Classification
12 Months Ended June 30, 2016

	A / B	C	D	O	P	Q	S	T	U	V	W
1											
2			**Functional**	**Transmission Demand**			**Distribution Poles**	**Distribution Substation**	**Distribution Primary Lines**		
3	**Description**	**Name**	**Vector**	**Base**	**Winter**	**Summer**	**Specific**	**General**	**Specific**	**Demand**	**Customer**
4											
5	**Plant in Service**										
6											
7	**Intangible Plant**										
8	301.00 ORGANIZATION	P301	PT&D	1,627	1,585	1,437	-	1,159	-	1,572	2,355
9	302.00 FRANCHISE AND CONSENTS	P301	PT&D	2,308	2,249	2,039	-	1,644	-	2,230	3,341
10	303.00 SOFTWARE	P302	PT&D	3,473,953	3,385,243	3,069,245	-	2,474,579	-	3,355,991	5,028,713
11											
12	Total Intangible Plant	PINT		$ 3,477,889	$ 3,389,078	$ 3,072,722	$ -	$ 2,477,382	$ -	$ 3,359,793	$ 5,034,410
13											
14	**Steam Production Plant**										
15											
16	Total Steam Production Plant	PSTPR	F017	-	-	-	-	-	-	-	-
17											
18	**Hydraulic Production Plant**										
19											
20	Total Hydraulic Production Plant	PHDPR	F017	-	-	-	-	-	-	-	-
21											
22	**Other Production Plant**										
23											
24	Total Other Production Plant	POTPR	F017	-	-	-	-	-	-	-	-
25											
26	**Total Production Plant**	PPRTL		$ -	$ -	$ -	$ -		$ -	$ -	
27											
28	**Transmission**										
29	KENTUCKY SYSTEM PROPERTY	P350	F011	260,561,503	253,907,827	230,206,650	-	-	-	-	-
30	VIRGINIA PROPERTY - 500 KV LINE	P352	F011	2,879,809	2,806,271	2,544,318	-	-	-	-	-
31											
32	Total Transmission Plant	PTRAN		$ 263,441,313	$ 256,714,098	$ 232,750,968	$ -	$ -	$ -	$ -	$ -
33											
34	**Distribution**										
35	TOTAL ACCTS 360-362	P362	F001	-	-	-	-	187,655,470	-	-	-
36	364 & 365-OVERHEAD LINES	P365	F003	-	-	-	-	-	-	213,566,464	285,887,381
37	366 & 367-UNDERGROUND LINES	P367	F004	-	-	-	-	-	-	40,929,408	95,456,491
38	368-TRANSFORMERS - POWER POOL	P368	F005	-	-	-	-	-	-	-	-
39	368-TRANSFORMERS - ALL OTHER	P368a	F005	-	-	-	-	-	-	-	-
40	369-SERVICES	P369	F006	-	-	-	-	-	-	-	-
41	370-METERS	P370	F007	-	-	-	-	-	-	-	-
42	371-CUSTOMER INSTALLATION	P371	F008	-	-	-	-	-	-	-	-
43	373-STREET LIGHTING	P373	F008	-	-	-	-	-	-	-	-
44											
45	Total Distribution Plant	PDIST		$ -	$ -	$ -	$ -	$ 187,655,470	$ -	$ 254,495,873	$ 381,343,872
46											
47	**Total Prod, Trans, and Dist Plant**	PT&D		$ 263,441,313	$ 256,714,098	$ 232,750,968	$ -	$ 187,655,470	$ -	$ 254,495,873	$ 381,343,872
48											
49											
50											
51											
52											

KENTUCKY UTILITIES COMPANY
Cost of Service Study
Functional Assignment and Classification
12 Months Ended June 30, 2016

B	C	D	X	Y	Z	AA	AB	AC	AD
			Distribution Sec. Lines		**Distribution Line Trans.**		**Distribution Services**	**Distribution Meters**	**Distribution St. & Cust. Lighting**
Description	**Name**	**Functional Vector**	**Demand**	**Customer**	**Demand**	**Customer**	**Customer**		
Plant in Service									
Intangible Plant									
301.00 ORGANIZATION	P301	PT&D	524	785	959	871	554	452	721
302.00 FRANCHISE AND CONSENTS	P301	PT&D	743	1,114	1,361	1,236	786	641	1,023
303.00 SOFTWARE	P302	PT&D	1,118,664	1,676,238	2,048,496	1,859,356	1,183,473	964,321	1,539,786
Total Intangible Plant	PINT		$ 1,119,931	$ 1,678,137	$ 2,050,817	$ 1,861,462	$ 1,184,813	$ 965,413	$ 1,541,530
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	71,188,821	95,295,794	-	-	-	-	-
366 & 367-UNDERGROUND LINES	P367	F004	13,643,136	31,818,830	-	-	-	-	-
368-TRANSFORMERS - POWER POOL	P368	F005	-	-	2,846,394	2,583,583	-	-	-
368-TRANSFORMERS - ALL OTHER	P368a	F005	-	-	152,497,813	138,417,511	-	-	-
369-SERVICES	P369	F006	-	-	-	-	89,746,639	-	-
370-METERS	P370	F007	-	-	-	-	-	73,127,621	-
371-CUSTOMER INSTALLATION	P371	F008	-	-	-	-	-	-	17,289,842
373-STREET LIGHTING	P373	F008	-	-	-	-	-	-	99,477,208
Total Distribution Plant	PDIST		$ 84,831,958	$ 127,114,624	$ 155,344,207	$ 141,001,094	$ 89,746,639	$ 73,127,621	$ 116,767,050
Total Prod, Trans, and Dist Plant	PT&D		$ 84,831,958	$ 127,114,624	$ 155,344,207	$ 141,001,094	$ 89,746,639	$ 73,127,621	$ 116,767,050

	A	B	C	D	E	A	AF	A	AH	A	AJ
1											
2				Functional			Customer Accounts Expense		Customer Service & Info.		Sales Expense
3	Description		Name	Vector							
4											
5	**Plant in Service**										
6											
7	**Intangible Plant**										
8	301.00	ORGANIZATION	P301	PT&D			-		-		-
9	302.00	FRANCHISE AND CONSENTS	P301	PT&D			-		-		-
10	303.00	SOFTWARE	P302	PT&D			-		-		-
11											
12		Total Intangible Plant	PINT				$ -		$ -		$ -
13											
14	**Steam Production Plant**										
15											
16		Total Steam Production Plant	PSTPR	F017			-		-		-
17											
18	**Hydraulic Production Plant**										
19											
20		Total Hydraulic Production Plant	PHDPR	F017			-		-		-
21											
22	**Other Production Plant**										
23											
24		Total Other Production Plant	POTPR	F017			-		-		-
25											
26		**Total Production Plant**	PPRTL				$ -		$ -		$ -
27											
28	**Transmission**										
29		KENTUCKY SYSTEM PROPERTY	P350	F011			-		-		-
30		VIRGINIA PROPERTY - 500 KV LINE	P352	F011			-		-		-
31											
32		Total Transmission Plant	PTRAN				$ -		$ -		$ -
33											
34	**Distribution**										
35		TOTAL ACCTS 360-362	P362	F001			-		-		-
36		364 & 365-OVERHEAD LINES	P365	F003			-		-		-
37		366 & 367-UNDERGROUND LINES	P367	F004			-		-		-
38		368-TRANSFORMERS - POWER POOL	P368	F005			-		-		-
39		368-TRANSFORMERS - ALL OTHER	P368a	F005			-		-		-
40		369-SERVICES	P369	F006			-		-		-
41		370-METERS	P370	F007			-		-		-
42		371-CUSTOMER INSTALLATION	P371	F008			-		-		-
43		373-STREET LIGHTING	P373	F008			-		-		-
44											
45		Total Distribution Plant	PDIST				$ -		$ -		$ -
46											
47		**Total Prod, Trans, and Dist Plant**	PT&D				$ -		$ -		$ -
48											
49											
50											
51											
52											

KENTUCKY UTILITIES COMPANY
Cost of Service Study
Functional Assignment and Classification
12 Months Ended June 30, 2016

	A	B	C	D	E	F	G	H	I	J	K	L	M
1													
2				Functional		Total		Production Demand			Production Energy		
3	Description		Name	Vector		System		Base	Inter.	Peak	Base	Inter.	Peak
4													
53	**Plant in Service (Continued)**												
54													
55	**General Plant**												
56													
57		Total General Plant	PGP	PT&D	$	175,293,867		38,611,217	37,625,245	34,113,094	-	-	-
58													
59		TOTAL COMMON PLANT	PCOM	PT&D	$	-		-	-	-	-	-	-
60	106.00	COMPLETED CONSTR NOT CLASSIFIED	P106	PT&D	$	-		-	-	-	-	-	-
61	105.00	PLANT HELD FOR FUTURE USE	P105	PDIST	$	324,088		-	-	-	-	-	-
62													
63		OTHER		PDIST		-		-	-	-	-	-	-
64													
65		Total Plant in Service	TPIS		$	6,641,540,734	$	1,462,831,894	$ 1,425,477,143	$ 1,292,415,133	$ -	$ -	$ -
66													
67													
68	**Construction Work in Progress (CWIP)**												
69													
70		CWIP Production	CWIP1	F017	$	51,131,695		17,890,937	17,434,076	15,806,682	-	-	-
71		CWIP Transmission	CWIP2	F011		12,491,309		-	-	-	-	-	-
72		CWIP Distribution Plant	CWIP3	PDIST		12,677,442		-	-	-	-	-	-
73		CWIP General Plant	CWIP4	PT&D		15,573,716		3,430,355	3,342,757	3,030,726	-	-	-
74		RWIP	CWIP5	F004		-		-	-	-	-	-	-
75													
76	**Total Construction Work in Progress**		TCWIP		$	91,874,163	$	21,321,292	$ 20,776,833	$ 18,837,408	$ -	$ -	$ -
77													
78	**Total Utility Plant**				$	6,733,414,896	$	1,484,153,187	$ 1,446,253,977	$ 1,311,252,541	$ -	$ -	$ -
79													
80													
81													
82													
83													
84													
85													
86													
87													
88													

KENTUCKY UTILITIES COMPANY
Cost of Service Study
Functional Assignment and Classification
12 Months Ended June 30, 2016

	A / B	C	D	O	P	Q	S	T	U	V	W
1											
2			Functional	Transmission Demand			Distribution Poles	Distribution Substation	Distribution Primary Lines		
3	**Description**	**Name**	**Vector**	**Base**	**Winter**	**Summer**	**Specific**	**General**	**Specific**	**Demand**	**Customer**
4											
53	**Plant in Service (Continued)**										
54											
55	**General Plant**										
56											
57	Total General Plant	PGP	PT&D	7,236,291	7,051,506	6,393,279	-	5,154,581	-	6,990,575	10,474,877
58											
59	TOTAL COMMON PLANT	PCOM	PT&D	-	-	-	-	-	-	-	-
60	106.00 COMPLETED CONSTR NOT CLASSIFIED	P106	PT&D	-	-	-	-	-	-	-	-
61	105.00 PLANT HELD FOR FUTURE USE	P105	PDIST	-	-	-	-	37,741	-	51,184	76,695
62											
63	OTHER		PDIST	-	-	-	-	-	-	-	-
64											
65	Total Plant in Service	TPIS		$ 274,155,492	$ 267,154,681	$ 242,216,969	$ -	$ 195,325,175	$ -	$ 264,897,424	$ 396,929,854
66											
67											
68	**Construction Work in Progress (CWIP)**										
69											
70	CWIP Production	CWIP1	F017	-	-	-	-	-	-	-	-
71	CWIP Transmission	CWIP2	F011	4,370,699	4,259,089	3,861,522	-	-	-	-	-
72	CWIP Distribution Plant	CWIP3	PDIST	-	-	-	-	1,476,325	-	2,002,172	3,000,112
73	CWIP General Plant	CWIP4	PT&D	642,897	626,480	568,001	-	457,951	-	621,067	930,624
74	RWIP	CWIP5	F004	-	-	-	-	-	-	-	-
75											
76	**Total Construction Work in Progress**	TCWIP		$ 5,013,596	$ 4,885,569	$ 4,429,523	$ -	$ 1,934,276	$ -	$ 2,623,239	$ 3,930,736
77											
78	**Total Utility Plant**			$ 279,169,088	$ 272,040,250	$ 246,646,491	$ -	$ 197,259,450	$ -	$ 267,520,663	$ 400,860,590
79											
80											
81											
82											
83											
84											
85											
86											
87											
88											

KENTUCKY UTILITIES COMPANY
Cost of Service Study
Functional Assignment and Classification
12 Months Ended June 30, 2016

	A / B	C	D	X	Y	Z	AA	AB	AC	AD
1										
2			Functional	Distribution Sec. Lines		Distribution Line Trans.		Distribution Services	Distribution Meters	Distribution St. & Cust. Lighting
3	Description	Name	Vector	Demand	Customer	Demand	Customer	Customer		
4										
53	**Plant in Service (Continued)**									
54										
55	**General Plant**									
56										
57	Total General Plant	PGP	PT&D	2,330,192	3,491,626	4,267,045	3,873,064	2,465,190	2,008,693	3,207,395
58										
59	TOTAL COMMON PLANT	PCOM	PT&D	-	-	-	-	-	-	-
60	106.00 COMPLETED CONSTR NOT CLASSIFIED	P106	PT&D	-	-	-	-	-	-	-
61	105.00 PLANT HELD FOR FUTURE USE	P105	PDIST	17,061	25,565	31,243	28,358	18,050	14,707	23,484
62										
63	OTHER		PDIST	-	-	-	-	-	-	-
64										
65	Total Plant in Service	TPIS		$ 88,299,141	$ 132,309,951	$ 161,693,311	$ 146,763,978	$ 93,414,691	$ 76,116,435	$ 121,539,460
66										
67										
68	**Construction Work in Progress (CWIP)**									
69										
70	CWIP Production	CWIP1	F017	-	-	-	-	-	-	-
71	CWIP Transmission	CWIP2	F011	-	-	-	-	-	-	-
72	CWIP Distribution Plant	CWIP3	PDIST	667,391	1,000,037	1,222,125	1,109,285	706,055	575,310	918,631
73	CWIP General Plant	CWIP4	PT&D	207,022	310,208	379,099	344,096	219,016	178,459	284,956
74	RWIP	CWIP5	F004	-	-	-	-	-	-	-
75										
76	**Total Construction Work in Progress**	TCWIP		$ 874,413	$ 1,310,245	$ 1,601,224	$ 1,453,381	$ 925,071	$ 753,769	$ 1,203,587
77										
78	**Total Utility Plant**			$ 89,173,554	$ 133,620,197	$ 163,294,535	$ 148,217,360	$ 94,339,763	$ 76,870,204	$ 122,743,047
79										
80										
81										
82										
83										
84										
85										
86										
87										
88										

KENTUCKY UTILITIES COMPANY
Cost of Service Study
Functional Assignment and Classification
12 Months Ended June 30, 2016

	A	B	C	D	E	A	AF	A	AH	A	AJ
1											
2				**Functional**			**Customer Accounts Expense**		**Customer Service & Info.**		**Sales Expense**
3	**Description**		**Name**	**Vector**							
4											
53	**Plant in Service (Continued)**										
54											
55	**General Plant**										
56											
57		Total General Plant	PGP	PT&D			-		-		-
58											
59		TOTAL COMMON PLANT	PCOM	PT&D			-		-		-
60	106.00	COMPLETED CONSTR NOT CLASSIFIED	P106	PT&D			-		-		-
61	105.00	PLANT HELD FOR FUTURE USE	P105	PDIST			-		-		-
62											
63		OTHER		PDIST			-		-		-
64											
65		Total Plant in Service	TPIS				$ -		$ -		$ -
66											
67											
68	**Construction Work in Progress (CWIP)**										
69											
70		CWIP Production	CWIP1	F017			-		-		-
71		CWIP Transmission	CWIP2	F011			-		-		-
72		CWIP Distribution Plant	CWIP3	PDIST			-		-		-
73		CWIP General Plant	CWIP4	PT&D			-		-		-
74		RWIP	CWIP5	F004			-		-		-
75											
76	**Total Construction Work in Progress**		TCWIP				$ -		$ -		$ -
77											
78	**Total Utility Plant**						$ -		$ -		$ -
79											
80											
81											
82											
83											
84											
85											
86											
87											
88											

KENTUCKY UTILITIES COMPANY
Cost of Service Study
Functional Assignment and Classification
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	A / B	C	D	F	H	I	J	K	L	M
1										
2			Functional	Total	Production Demand			Production Energy		
3	**Description**	**Name**	**Vector**	**System**	**Base**	**Inter.**	**Peak**	**Base**	**Inter.**	**Peak**
4										
89	**Rate Base**									
90										
91	**Utility Plant**									
92	Plant in Service			$ 6,641,540,734	$ 1,462,831,894	$ 1,425,477,143	$ 1,292,415,133	$ -	$ -	$ -
93	Construction Work in Progress (CWIP)			91,874,163	21,321,292.11	20,776,833.41	18,837,407.56	-	-	-
94										
95	**Total Utility Plant**	TUP		$ 6,733,414,896	$ 1,484,153,187	$ 1,446,253,977	$ 1,311,252,541	$ -	$ -	$ -
96										
97	**Less: Acummulated Provision for Depreciation**									
98	Steam Production	ADEPREPA	F017	$ 1,287,054,629	450,339,339	438,839,512	397,875,778	-	-	-
99	Hydraulic Production	RWIP	F017	9,356,555	3,273,851	3,190,250	2,892,454	-	-	-
100	Other Production		F017	219,260,899	76,719,205	74,760,110	67,781,583	-	-	-
101	Transmission - Kentucky System Property	ADEPRTP	PTRAN	301,423,662	-	-	-	-	-	-
102	Transmission - Virginia Property	ADEPRD1	PTRAN	4,226,088	-	-	-	-	-	-
103	Distribution	ADEPRD11	PDIST	623,851,597	-	-	-	-	-	-
104	General Plant	ADEPRD12	PT&D	76,118,822	16,766,362	16,338,217	14,813,117	-	-	-
105	Intangible Plant	ADEPRGP	PT&D	42,570,227	9,376,759	9,137,315	8,284,387	-	-	-
106										
107	Total Accumulated Depreciation	TADEPR		$ 2,563,862,479	$ 556,475,516	$ 542,265,404	$ 491,647,318	$ -	$ -	$ -
108										
109	**Net Utility Plant**	NTPLANT		$ 4,169,552,417	$ 927,677,671	$ 903,988,572	$ 819,605,222	$ -	$ -	$ -
110										
111	**Working Capital**									
112	Cash Working Capital - Operation and Maintenance Expenses	CWC	OMLPP	$ 119,087,393	5,152,144	4,866,973	4,960,923	81,873,888	-	-
113	Materials and Supplies	M&S	TPIS	126,046,511	27,762,362	27,053,424	24,528,106	-	-	-
114	Prepayments	PREPAY	TPIS	6,469,140	1,424,860	1,388,475	1,258,867	-	-	-
115										
116	Total Working Capital	TWC		$ 251,603,043	$ 34,339,365	$ 33,308,872	$ 30,747,896	$ 81,873,888	$ -	$ -
117										
118	Emission Allowance	EMALL	PROFIX	375	129	121	125	-	-	-
119										
120	**Deferred Debits**									
121	Service Pension Cost	PENSCOST	TLB	$ -	-	-	-	-	-	-
122	Accumulated Deferred Income Tax									
123	Total Production Plant	ADITPP	F017	435,628,372	152,426,003	148,533,666	134,668,703	-	-	-
124	Total Transmission Plant	ADITTP	F011	68,385,195	-	-	-	-	-	-
125	Total Distribution Plant	ADITDP	PDIST	149,071,355	-	-	-	-	-	-
126	Total General Plant	ADITGP	PT&D	15,578,331	3,431,371	3,343,748	3,031,624	-	-	-
127										
128	**Total Accumulated Deferred Income Tax**	ADITT		668,663,253	155,857,375	151,877,414	137,700,327	-	-	-
129										
130	Accumulated Deferred Investment Tax Credits									
131	Production	ADITCP	F017	$ 80,778,668	28,264,389	27,542,632	24,971,648	-	-	-
132	Transmission	ADITCT	F011	-	-	-	-	-	-	-
133	Transmission VA	ADITCTVA	F011	-	-	-	-	-	-	-
134	Distribution VA	ADITCDVA	PDIST	-	-	-	-	-	-	-
135	Distribution Plant KY,FERC & TN	ADITCDKY	PDIST	-	-	-	-	-	-	-
136	General	ADITCG	PT&D	-	-	-	-	-	-	-
137										
138	**Total Accum. Deferred Investment Tax Credits**	ADITCTL		80,778,668	28,264,389	27,542,632	24,971,648	-	-	-
139										
140	Total Deferred Debits			$ 749,441,921	$ 184,121,763	$ 179,420,046	$ 162,671,975	$ -	$ -	$ -
141	Less: Customer Advances	CSTDEP	F027	$ 2,445,372	-	-	-	-	-	-
142	Less: Asset Retirement Obligations		F017		-	-	-	-	-	-
143										
144	**Net Rate Base**	RB		$ 3,669,268,542	$ 777,895,402	$ 757,877,520	$ 687,681,269	$ 81,873,888	$ -	$ -

KENTUCKY UTILITIES COMPANY
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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
89	**Rate Base**										
90											
91	**Utility Plant**										
92	Plant in Service			$ 274,155,492	$ 267,154,681	$ 242,216,969	$ -	$ 195,325,175	$ -	$ 264,897,424	$ 396,929,854
93	Construction Work in Progress (CWIP)			5,013,595.74	4,885,568.99	4,429,522.65	-	1,934,275.51	-	2,623,238.92	3,930,736.00
94											
95	**Total Utility Plant**	TUP		$ 279,169,088	$ 272,040,250	$ 246,646,491	$ -	$ 197,259,450	$ -	$ 267,520,663	$ 400,860,590
96											
97	**Less: Acummulated Provision for Depreciation**										
98	Steam Production	ADEPREPA	F017	-	-	-	-	-	-	-	-
99	Hydraulic Production	RWIP	F017	-	-	-	-	-	-	-	-
100	Other Production		F017	-	-	-	-	-	-	-	-
101	Transmission - Kentucky System Property	ADEPRTP	PTRAN	105,467,887	102,774,668	93,181,106	-	-	-	-	-
102	Transmission - Virginia Property	ADEPRD1	PTRAN	1,478,705	1,440,945	1,306,439	-	-	-	-	-
103	Distribution	ADEPRD11	PDIST	-	-	-	-	72,649,312	-	98,526,038	147,634,225
104	General Plant	ADEPRD12	PT&D	3,142,255	3,062,014	2,776,189	-	2,238,302	-	3,035,556	4,548,563
105	Intangible Plant	ADEPRGP	PT&D	1,757,338	1,712,463	1,552,612	-	1,251,793	-	1,697,666	2,543,830
106											
107	Total Accumulated Depreciation	TADEPR		$ 111,846,185	$ 108,990,090	$ 98,816,345	$ -	$ 76,139,407	$ -	$ 103,259,259	$ 154,726,618
108											
109	**Net Utility Plant**	NTPLANT		$ 167,322,903	$ 163,050,160	$ 147,830,146	$ -	$ 121,120,043	$ -	$ 164,261,404	$ 246,133,971
110											
111	**Working Capital**										
112	Cash Working Capital - Operation and Maintenance Expenses	CWC	OMLPP	1,626,199	1,584,673	1,436,751	-	1,029,896	-	2,124,442	2,967,841
113	Materials and Supplies	M&S	TPIS	5,203,061	5,070,196	4,596,916	-	3,706,980	-	5,027,357	7,533,135
114	Prepayments	PREPAY	TPIS	267,039	260,220	235,930	-	190,255	-	258,021	386,626
115											
116	Total Working Capital	TWC		$ 7,096,300	$ 6,915,089	$ 6,269,596	$ -	$ 4,927,130	$ -	$ 7,409,821	$ 10,887,603
117											
118	Emission Allowance	EMALL	PROFIX	-	-	-	-	-	-	-	-
119											
120	**Deferred Debits**										
121	Service Pension Cost	PENSCOST	TLB	-	-	-	-	-	-	-	-
122	Accumulated Deferred Income Tax										
123	Total Production Plant	ADITPP	F017	-	-	-	-	-	-	-	-
124	Total Transmission Plant	ADITTP	F011	23,927,923	23,316,901	21,140,371	-	-	-	-	-
125	Total Distribution Plant	ADITDP	PDIST	-	-	-	-	17,359,788	-	23,543,115	35,277,675
126	Total General Plant	ADITGP	PT&D	643,088	626,666	568,169	-	458,087	-	621,251	930,900
127											
128	**Total Accumulated Deferred Income Tax**	ADITT		24,571,010	23,943,567	21,708,541	-	17,817,874	-	24,164,366	36,208,575
129											
130	Accumulated Deferred Investment Tax Credits										
131	Production	ADITCP	F017	-	-	-	-	-	-	-	-
132	Transmission	ADITCT	F011	-	-	-	-	-	-	-	-
133	Transmission VA	ADITCTVA	F011	-	-	-	-	-	-	-	-
134	Distribution VA	ADITCDVA	PDIST	-	-	-	-	-	-	-	-
135	Distribution Plant KY,FERC & TN	ADITCDKY	PDIST	-	-	-	-	-	-	-	-
136	General	ADITCG	PT&D	-	-	-	-	-	-	-	-
137											
138	**Total Accum. Deferred Investment Tax Credits**	ADITCTL		-	-	-	-	-	-	-	-
139											
140	Total Deferred Debits			$ 24,571,010	$ 23,943,567	$ 21,708,541	$ -	$ 17,817,874	$ -	$ 24,164,366	$ 36,208,575
141	Less: Customer Advances	CSTDEP	F027	-	-	-	-	-	-	734,073	1,099,956
142	Less: Asset Retirement Obligations		F017	-	-	-	-	-	-	-	-
143											
144	**Net Rate Base**	RB		$ 149,848,193	$ 146,021,682	$ 132,391,201	$ -	$ 108,229,299	$ -	$ 146,772,785	$ 219,713,043

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	A	B	C	D	E	X	Y	Z	AA	AB	AC	AD
1												
2				Functional		Distribution Sec. Lines		Distribution Line Trans.		Distribution Services	Distribution Meters	Distribution St. & Cust. Lighting
3	Description		Name	Vector		Demand	Customer	Demand	Customer	Customer		
4												
89	**Rate Base**											
90												
91	**Utility Plant**											
92	Plant in Service					$ 88,299,141	$ 132,309,951	$ 161,693,311	$ 146,763,978	$ 93,414,691	$ 76,116,435	$ 121,539,460
93	Construction Work in Progress (CWIP)					874,412.97	1,310,245.33	1,601,224.28	1,453,381.36	925,071.49	753,769.48	1,203,586.79
94												
95	**Total Utility Plant**		TUP			$ 89,173,554	$ 133,620,197	$ 163,294,535	$ 148,217,360	$ 94,339,763	$ 76,870,204	$ 122,743,047
96												
97	**Less: Acummulated Provision for Depreciation**											
98	Steam Production		ADEPREPA	F017		-	-	-	-	-	-	-
99	Hydraulic Production		RWIP	F017		-	-	-	-	-	-	-
100	Other Production			F017		-	-	-	-	-	-	-
101	Transmission - Kentucky System Property		ADEPRTP	PTRAN		-	-	-	-	-	-	-
102	Transmission - Virginia Property		ADEPRD1	PTRAN		-	-	-	-	-	-	-
103	Distribution		ADEPRD11	PDIST		32,842,013	49,211,408	60,140,265	54,587,444	34,744,692	28,310,773	45,205,428
104	General Plant		ADEPRD12	PT&D		1,011,852	1,516,188	1,852,902	1,681,822	1,070,473	872,246	1,392,765
105	Intangible Plant		ADEPRGP	PT&D		565,889	847,943	1,036,255	940,576	598,673	487,812	778,918
106												
107	Total Accumulated Depreciation		TADEPR			$ 34,419,753	$ 51,575,539	$ 63,029,422	$ 57,209,842	$ 36,413,838	$ 29,670,831	$ 47,377,111
108												
109	**Net Utility Plant**		NTPLANT			$ 54,753,801	$ 82,044,657	$ 100,265,113	$ 91,007,518	$ 57,925,925	$ 47,199,373	$ 75,365,936
110												
111	**Working Capital**											
112	Cash Working Capital - Operation and Maintenance Expenses		CWC	OMLPP		708,147	989,280	396,536	359,924	225,069	1,295,703	278,550
113	Materials and Supplies		M&S	TPIS		1,675,786	2,511,045	3,068,697	2,785,361	1,772,871	1,444,576	2,306,637
114	Prepayments		PREPAY	TPIS		86,007	128,875	157,496	142,954	90,990	74,141	118,385
115												
116	Total Working Capital		TWC			$ 2,469,940	$ 3,629,201	$ 3,622,730	$ 3,288,239	$ 2,088,930	$ 2,814,420	$ 2,703,572
117												
118	Emission Allowance		EMALL	PROFIX		-	-	-	-	-	-	-
119												
120	**Deferred Debits**											
121	Service Pension Cost		PENSCOST	TLB		-	-	-	-	-	-	-
122	Accumulated Deferred Income Tax											
123	Total Production Plant		ADITPP	F017		-	-	-	-	-	-	-
124	Total Transmission Plant		ADITTP	F011		-	-	-	-	-	-	-
125	Total Distribution Plant		ADITDP	PDIST		7,847,705	11,759,225	14,370,711	13,043,846	8,302,356	6,764,951	10,801,983
126	Total General Plant		ADITGP	PT&D		207,084	310,300	379,211	344,198	219,081	178,512	285,041
127												
128	**Total Accumulated Deferred Income Tax**		ADITT			8,054,789	12,069,525	14,749,922	13,388,044	8,521,437	6,943,463	11,087,024
129												
130	Accumulated Deferred Investment Tax Credits											
131	Production		ADITCP	F017		-	-	-	-	-	-	-
132	Transmission		ADITCT	F011		-	-	-	-	-	-	-
133	Transmission VA		ADITCTVA	F011		-	-	-	-	-	-	-
134	Distribution VA		ADITCDVA	PDIST		-	-	-	-	-	-	-
135	Distribution Plant KY,FERC & TN		ADITCDKY	PDIST		-	-	-	-	-	-	-
136	General		ADITCG	PT&D		-	-	-	-	-	-	-
137												
138	**Total Accum. Deferred Investment Tax Credits**		ADITCTL			-	-	-	-	-	-	-
139												
140	Total Deferred Debits					$ 8,054,789	$ 12,069,525	$ 14,749,922	$ 13,388,044	$ 8,521,437	$ 6,943,463	$ 11,087,024
141	Less: Customer Advances		CSTDEP	F027		244,691	366,652	-	-	-	-	-
142	Less: Asset Retirement Obligations			F017		-	-	-	-	-	-	-
143												
144	**Net Rate Base**		RB			$ 48,924,262	$ 73,237,681	$ 89,137,921	$ 80,907,712	$ 51,493,417	$ 43,070,330	$ 66,982,484

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	Description	Name	Functional Vector	Customer Accounts Expense	Customer Service & Info.	Sales Expense
89	**Rate Base**					
90						
91	**Utility Plant**					
92	Plant in Service			$ -	$ -	$ -
93	Construction Work in Progress (CWIP)			-	-	-
94						
95	**Total Utility Plant**	TUP		$ -	$ -	$ -
96						
97	**Less: Acummulated Provision for Depreciation**					
98	Steam Production	ADEPREPA	F017	-	-	-
99	Hydraulic Production	RWIP	F017	-	-	-
100	Other Production		F017	-	-	-
101	Transmission - Kentucky System Property	ADEPRTP	PTRAN	-	-	-
102	Transmission - Virginia Property	ADEPRD1	PTRAN	-	-	-
103	Distribution	ADEPRD11	PDIST	-	-	-
104	General Plant	ADEPRD12	PT&D	-	-	-
105	Intangible Plant	ADEPRGP	PT&D	-	-	-
106						
107	Total Accumulated Depreciation	TADEPR		$ -	$ -	$ -
108						
109	**Net Utility Plant**	NTPLANT		$ -	$ -	$ -
110						
111	**Working Capital**					
112	Cash Working Capital - Operation and Maintenance Expenses	CWC	OMLPP	6,611,581	598,872	-
113	Materials and Supplies	M&S	TPIS	-	-	-
114	Prepayments	PREPAY	TPIS	-	-	-
115						
116	Total Working Capital	TWC		$ 6,611,581	$ 598,872	$ -
117						
118	Emission Allowance	EMALL	PROFIX	-	-	-
119						
120	**Deferred Debits**					
121	Service Pension Cost	PENSCOST	TLB	-	-	-
122	Accumulated Deferred Income Tax					
123	Total Production Plant	ADITPP	F017	-	-	-
124	Total Transmission Plant	ADITTP	F011	-	-	-
125	Total Distribution Plant	ADITDP	PDIST	-	-	-
126	Total General Plant	ADITGP	PT&D	-	-	-
127						
128	**Total Accumulated Deferred Income Tax**	ADITT		-	-	-
129						
130	Accumulated Deferred Investment Tax Credits					
131	Production	ADITCP	F017	-	-	-
132	Transmission	ADITCT	F011	-	-	-
133	Transmission VA	ADITCTVA	F011	-	-	-
134	Distribution VA	ADITCDVA	PDIST	-	-	-
135	Distribution Plant KY,FERC & TN	ADITCDKY	PDIST	-	-	-
136	General	ADITCG	PT&D	-	-	-
137						
138	**Total Accum. Deferred Investment Tax Credits**	ADITCTL		-	-	-
139						
140	Total Deferred Debits			$ -	$ -	$ -
141	Less: Customer Advances	CSTDEP	F027	-	-	-
142	Less: Asset Retirement Obligations		F017	-	-	-
143						
144	**Net Rate Base**	RB		$ 6,611,581	$ 598,872	$ -

KENTUCKY UTILITIES COMPANY
Cost of Service Study
Functional Assignment and Classification
12 Months Ended June 30, 2016

	Description	Name	Functional Vector	Total System	Production Demand Base	Production Demand Inter.	Production Demand Peak	Production Energy Base	Production Energy Inter.	Production Energy Peak
145										
146										
147	**Operation and Maintenance Expenses**									
148										
149	**Steam Power Generation Operation Expenses**									
150	500 OPERATION SUPERVISION & ENGINEERING	OM500	LBSUB1	$ 10,848,358	3,244,840	3,058,838	3,141,448	1,403,232	-	-
151	501 FUEL	OM501	Energy	373,903,375	-	-	-	373,903,375	-	-
152	502 STEAM EXPENSES	OM502		20,958,561	3,711,207	3,498,472	3,592,955	10,155,927	-	-
153	505 ELECTRIC EXPENSES	OM505		6,087,699	1,865,466	1,758,533	1,806,026	657,673	-	-
154	506 MISC. STEAM POWER EXPENSES	OM506	PROFIX	16,741,620	5,751,525	5,421,834	5,568,261	-	-	-
155	507 RENTS	OM507	PROFIX	55,923	19,212	18,111	18,600	-	-	-
156										
157	Total Steam Power Operation Expenses			$ 428,595,536	$ 14,592,249	$ 13,755,789	$ 14,127,290	$ 386,120,208	$ -	$ -
158										
159	**Steam Power Generation Maintenance Expenses**									
160	510 MAINTENANCE SUPERVISION & ENGINEERING	OM510	LBSUB2	$ 7,862,672	164,018	154,616	158,792	7,385,245	-	-
161	511 MAINTENANCE OF STRUCTURES	OM511	PROFIX	5,592,611	1,921,322	1,811,187	1,860,102	-	-	-
162	512 MAINTENANCE OF BOILER PLANT	OM512	Energy	41,163,033	-	-	-	41,163,033	-	-
163	513 MAINTENANCE OF ELECTRIC PLANT	OM513	Energy	8,983,729	-	-	-	8,983,729	-	-
164	514 MAINTENANCE OF MISC STEAM PLANT	OM514	Energy	2,923,877	-	-	-	2,923,877	-	-
165										
166	Total Steam Power Generation Maintenance Expense			$ 66,525,922	$ 2,085,340	$ 1,965,804	$ 2,018,894	$ 60,455,884	$ -	$ -
167										
168	Total Steam Power Generation Expense			$ 495,121,458	$ 16,677,589	$ 15,721,592	$ 16,146,184	$ 446,576,092	$ -	$ -
169										
170	**Hydraulic Power Generation Operation Expenses**									
171	535 OPERATION SUPERVISION & ENGINEERING	OM535	LBSUB3	$ -	-	-	-	-	-	-
172	536 WATER FOR POWER	OM536	PROFIX	-	-	-	-	-	-	-
173	537 HYDRAULIC EXPENSES	OM537	PROFIX	-	-	-	-	-	-	-
174	538 ELECTRIC EXPENSES	OM538		-	-	-	-	-	-	-
175	539 MISC. HYDRAULIC POWER EXPENSES	OM539	PROFIX	8,185	2,812	2,651	2,722	-	-	-
176	540 RENTS		PROFIX	-	-	-	-	-	-	-
177										
178	Total Hydraulic Power Operation Expenses			$ 8,185	$ 2,812	$ 2,651	$ 2,722	$ -	$ -	$ -
179										
180	**Hydraulic Power Generation Maintenance Expenses**									
181	541 MAINTENANCE SUPERVISION & ENGINEERING	OM541	LBSUB4	$ 186,812	64,179	60,500	62,134	-	-	-
182	542 MAINTENANCE OF STRUCTURES	OM542	PROFIX	129,736	44,570	42,015	43,150	-	-	-
183	543 MAINT. OF RESERVES, DAMS, AND WATERWAYS	OM543	PROFIX	-	-	-	-	-	-	-
184	544 MAINTENANCE OF ELECTRIC PLANT	OM544	Energy	27,220	-	-	-	27,220	-	-
185	545 MAINTENANCE OF MISC HYDRAULIC PLANT	OM545	Energy	9,211	-	-	-	9,211	-	-
186										
187	Total Hydraulic Power Generation Maint. Expense			$ 352,980	$ 108,749	$ 102,515	$ 105,284	$ 36,431	$ -	$ -
188										
189	Total Hydraulic Power Generation Expense			$ 361,164	$ 111,561	$ 105,166	$ 108,006	$ 36,431	$ -	$ -
190										
191	**Other Power Generation Operation Expense**									
192	546 OPERATION SUPERVISION & ENGINEERING	OM546	LBSUB5	$ 326,573	112,193	105,762	108,618	-	-	-
193	547 FUEL	OM547	Energy	139,958,767	-	-	-	139,958,767	-	-
194	548 GENERATION EXPENSE	OM548	PROFIX	315,215	108,291	102,083	104,840	-	-	-
195	549 MISC OTHER POWER GENERATION	OM549	PROFIX	3,807,351	1,308,002	1,233,024	1,266,324	-	-	-
196	550 RENTS	OM550	PROFIX	-	-	-	-	-	-	-
197										
198	Total Other Power Generation Expenses			$ 144,407,905	$ 1,528,486	$ 1,440,870	$ 1,479,783	$ 139,958,767	$ -	$ -
199										

KENTUCKY UTILITIES COMPANY
Cost of Service Study
Functional Assignment and Classification
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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
145											
146											
147	**Operation and Maintenance Expenses**										
148											
149	**Steam Power Generation Operation Expenses**										
150	500 OPERATION SUPERVISION & ENGINEERING	OM500	LBSUB1	-	-	-	-	-	-	-	-
151	501 FUEL	OM501	Energy	-	-	-	-	-	-	-	-
152	502 STEAM EXPENSES	OM502		-	-	-	-	-	-	-	-
153	505 ELECTRIC EXPENSES	OM505		-	-	-	-	-	-	-	-
154	506 MISC. STEAM POWER EXPENSES	OM506	PROFIX	-	-	-	-	-	-	-	-
155	507 RENTS	OM507	PROFIX	-	-	-	-	-	-	-	-
156											
157	Total Steam Power Operation Expenses			$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
158											
159	**Steam Power Generation Maintenance Expenses**										
160	510 MAINTENANCE SUPERVISION & ENGINEERING	OM510	LBSUB2	-	-	-	-	-	-	-	-
161	511 MAINTENANCE OF STRUCTURES	OM511	PROFIX	-	-	-	-	-	-	-	-
162	512 MAINTENANCE OF BOILER PLANT	OM512	Energy	-	-	-	-	-	-	-	-
163	513 MAINTENANCE OF ELECTRIC PLANT	OM513	Energy	-	-	-	-	-	-	-	-
164	514 MAINTENANCE OF MISC STEAM PLANT	OM514	Energy	-	-	-	-	-	-	-	-
165											
166	Total Steam Power Generation Maintenance Expense			$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
167											
168	Total Steam Power Generation Expense			$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
169											
170	**Hydraulic Power Generation Operation Expenses**										
171	535 OPERATION SUPERVISION & ENGINEERING	OM535	LBSUB3	-	-	-	-	-	-	-	-
172	536 WATER FOR POWER	OM536	PROFIX	-	-	-	-	-	-	-	-
173	537 HYDRAULIC EXPENSES	OM537	PROFIX	-	-	-	-	-	-	-	-
174	538 ELECTRIC EXPENSES	OM538		-	-	-	-	-	-	-	-
175	539 MISC. HYDRAULIC POWER EXPENSES	OM539	PROFIX	-	-	-	-	-	-	-	-
176	540 RENTS		PROFIX	-	-	-	-	-	-	-	-
177											
178	Total Hydraulic Power Operation Expenses			$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
179											
180	**Hydraulic Power Generation Maintenance Expenses**										
181	541 MAINTENANCE SUPERVISION & ENGINEERING	OM541	LBSUB4	-	-	-	-	-	-	-	-
182	542 MAINTENANCE OF STRUCTURES	OM542	PROFIX	-	-	-	-	-	-	-	-
183	543 MAINT. OF RESERVES, DAMS, AND WATERWAYS	OM543	PROFIX	-	-	-	-	-	-	-	-
184	544 MAINTENANCE OF ELECTRIC PLANT	OM544	Energy	-	-	-	-	-	-	-	-
185	545 MAINTENANCE OF MISC HYDRAULIC PLANT	OM545	Energy	-	-	-	-	-	-	-	-
186											
187	Total Hydraulic Power Generation Maint. Expense			$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
188											
189	Total Hydraulic Power Generation Expense			$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
190											
191	**Other Power Generation Operation Expense**										
192	546 OPERATION SUPERVISION & ENGINEERING	OM546	LBSUB5	-	-	-	-	-	-	-	-
193	547 FUEL	OM547	Energy	-	-	-	-	-	-	-	-
194	548 GENERATION EXPENSE	OM548	PROFIX	-	-	-	-	-	-	-	-
195	549 MISC OTHER POWER GENERATION	OM549	PROFIX	-	-	-	-	-	-	-	-
196	550 RENTS	OM550	PROFIX	-	-	-	-	-	-	-	-
197											
198	Total Other Power Generation Expenses			$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
199											

KENTUCKY UTILITIES COMPANY
Cost of Service Study
Functional Assignment and Classification
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	A	B	C	D	E	X	Y	Z	AA	AB	AC	AD
1												
2				Functional		Distribution Sec. Lines		Distribution Line Trans.		Distribution Services	Distribution Meters	Distribution St. & Cust. Lighting
3	Description		Name	Vector		Demand	Customer	Demand	Customer	Customer		
4												
145												
146												
147	**Operation and Maintenance Expenses**											
148												
149	**Steam Power Generation Operation Expenses**											
150	500	OPERATION SUPERVISION & ENGINEERING	OM500	LBSUB1		-	-	-	-	-	-	-
151	501	FUEL	OM501	Energy		-	-	-	-	-	-	-
152	502	STEAM EXPENSES	OM502			-	-	-	-	-	-	-
153	505	ELECTRIC EXPENSES	OM505			-	-	-	-	-	-	-
154	506	MISC. STEAM POWER EXPENSES	OM506	PROFIX		-	-	-	-	-	-	-
155	507	RENTS	OM507	PROFIX		-	-	-	-	-	-	-
156												
157		Total Steam Power Operation Expenses				$ -	$ -	$ -	$ -	$ -	$ -	$ -
158												
159	**Steam Power Generation Maintenance Expenses**											
160	510	MAINTENANCE SUPERVISION & ENGINEERING	OM510	LBSUB2		-	-	-	-	-	-	-
161	511	MAINTENANCE OF STRUCTURES	OM511	PROFIX		-	-	-	-	-	-	-
162	512	MAINTENANCE OF BOILER PLANT	OM512	Energy		-	-	-	-	-	-	-
163	513	MAINTENANCE OF ELECTRIC PLANT	OM513	Energy		-	-	-	-	-	-	-
164	514	MAINTENANCE OF MISC STEAM PLANT	OM514	Energy		-	-	-	-	-	-	-
165												
166		Total Steam Power Generation Maintenance Expense				$ -	$ -	$ -	$ -	$ -	$ -	$ -
167												
168		Total Steam Power Generation Expense				$ -	$ -	$ -	$ -	$ -	$ -	$ -
169												
170	**Hydraulic Power Generation Operation Expenses**											
171	535	OPERATION SUPERVISION & ENGINEERING	OM535	LBSUB3		-	-	-	-	-	-	-
172	536	WATER FOR POWER	OM536	PROFIX		-	-	-	-	-	-	-
173	537	HYDRAULIC EXPENSES	OM537	PROFIX		-	-	-	-	-	-	-
174	538	ELECTRIC EXPENSES	OM538			-	-	-	-	-	-	-
175	539	MISC. HYDRAULIC POWER EXPENSES	OM539	PROFIX		-	-	-	-	-	-	-
176	540	RENTS		PROFIX		-	-	-	-	-	-	-
177												
178		Total Hydraulic Power Operation Expenses				$ -	$ -	$ -	$ -	$ -	$ -	$ -
179												
180	**Hydraulic Power Generation Maintenance Expenses**											
181	541	MAINTENANCE SUPERVISION & ENGINEERING	OM541	LBSUB4		-	-	-	-	-	-	-
182	542	MAINTENANCE OF STRUCTURES	OM542	PROFIX		-	-	-	-	-	-	-
183	543	MAINT. OF RESERVES, DAMS, AND WATERWAYS	OM543	PROFIX		-	-	-	-	-	-	-
184	544	MAINTENANCE OF ELECTRIC PLANT	OM544	Energy		-	-	-	-	-	-	-
185	545	MAINTENANCE OF MISC HYDRAULIC PLANT	OM545	Energy		-	-	-	-	-	-	-
186												
187		Total Hydraulic Power Generation Maint. Expense				$ -	$ -	$ -	$ -	$ -	$ -	$ -
188												
189		Total Hydraulic Power Generation Expense				$ -	$ -	$ -	$ -	$ -	$ -	$ -
190												
191	**Other Power Generation Operation Expense**											
192	546	OPERATION SUPERVISION & ENGINEERING	OM546	LBSUB5		-	-	-	-	-	-	-
193	547	FUEL	OM547	Energy		-	-	-	-	-	-	-
194	548	GENERATION EXPENSE	OM548	PROFIX		-	-	-	-	-	-	-
195	549	MISC OTHER POWER GENERATION	OM549	PROFIX		-	-	-	-	-	-	-
196	550	RENTS	OM550	PROFIX		-	-	-	-	-	-	-
197												
198		Total Other Power Generation Expenses				$ -	$ -	$ -	$ -	$ -	$ -	$ -
199												

	A	B	C	D	E	AF	AH	AJ
1								
2				Functional		Customer Accounts Expense	Customer Service & Info.	Sales Expense
3	Description		Name	Vector				
4								
145								
146								
147	**Operation and Maintenance Expenses**							
148								
149	**Steam Power Generation Operation Expenses**							
150	500	OPERATION SUPERVISION & ENGINEERING	OM500	LBSUB1		-	-	-
151	501	FUEL	OM501	Energy		-	-	-
152	502	STEAM EXPENSES	OM502			-	-	-
153	505	ELECTRIC EXPENSES	OM505			-	-	-
154	506	MISC. STEAM POWER EXPENSES	OM506	PROFIX		-	-	-
155	507	RENTS	OM507	PROFIX		-	-	-
156								
157		Total Steam Power Operation Expenses				$ -	$ -	$ -
158								
159	**Steam Power Generation Maintenance Expenses**							
160	510	MAINTENANCE SUPERVISION & ENGINEERING	OM510	LBSUB2		-	-	-
161	511	MAINTENANCE OF STRUCTURES	OM511	PROFIX		-	-	-
162	512	MAINTENANCE OF BOILER PLANT	OM512	Energy		-	-	-
163	513	MAINTENANCE OF ELECTRIC PLANT	OM513	Energy		-	-	-
164	514	MAINTENANCE OF MISC STEAM PLANT	OM514	Energy		-	-	-
165								
166		Total Steam Power Generation Maintenance Expense				$ -	$ -	$ -
167								
168		Total Steam Power Generation Expense				$ -	$ -	$ -
169								
170	**Hydraulic Power Generation Operation Expenses**							
171	535	OPERATION SUPERVISION & ENGINEERING	OM535	LBSUB3		-	-	-
172	536	WATER FOR POWER	OM536	PROFIX		-	-	-
173	537	HYDRAULIC EXPENSES	OM537	PROFIX		-	-	-
174	538	ELECTRIC EXPENSES	OM538			-	-	-
175	539	MISC. HYDRAULIC POWER EXPENSES	OM539	PROFIX		-	-	-
176	540	RENTS		PROFIX		-	-	-
177								
178		Total Hydraulic Power Operation Expenses				$ -	$ -	$ -
179								
180	**Hydraulic Power Generation Maintenance Expenses**							
181	541	MAINTENANCE SUPERVISION & ENGINEERING	OM541	LBSUB4		-	-	-
182	542	MAINTENANCE OF STRUCTURES	OM542	PROFIX		-	-	-
183	543	MAINT. OF RESERVES, DAMS, AND WATERWAYS	OM543	PROFIX		-	-	-
184	544	MAINTENANCE OF ELECTRIC PLANT	OM544	Energy		-	-	-
185	545	MAINTENANCE OF MISC HYDRAULIC PLANT	OM545	Energy		-	-	-
186								
187		Total Hydraulic Power Generation Maint. Expense				$ -	$ -	$ -
188								
189		Total Hydraulic Power Generation Expense				$ -	$ -	$ -
190								
191	**Other Power Generation Operation Expense**							
192	546	OPERATION SUPERVISION & ENGINEERING	OM546	LBSUB5		-	-	-
193	547	FUEL	OM547	Energy		-	-	-
194	548	GENERATION EXPENSE	OM548	PROFIX		-	-	-
195	549	MISC OTHER POWER GENERATION	OM549	PROFIX		-	-	-
196	550	RENTS	OM550	PROFIX		-	-	-
197								
198		Total Other Power Generation Expenses				$ -	$ -	$ -
199								

KENTUCKY UTILITIES COMPANY
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	A/B	C	D	F	H	I	J	K	L	M
1										
2			Functional	Total	Production Demand			Production Energy		
3	**Description**	**Name**	**Vector**	**System**	**Base**	**Inter.**	**Peak**	**Base**	**Inter.**	**Peak**
4										
200	**Other Power Generation Maintenance Expense**									
201	551 MAINTENANCE SUPERVISION & ENGINEERING	OM551	PROFIX	$ 166,391	57,163	53,886	55,342	-	-	-
202	552 MAINTENANCE OF STRUCTURES	OM552	PROFIX	343,358	117,959	111,198	114,201	-	-	-
203	553 MAINTENANCE OF GENERATING & ELEC PLANT	OM553	PROFIX	4,187,895	1,438,736	1,356,265	1,392,893	-	-	-
204	554 MAINTENANCE OF MISC OTHER POWER GEN PLT	OM554	PROFIX	6,934,752	2,382,410	2,245,845	2,306,498	-	-	-
205										
206	Total Other Power Generation Maintenance Expense			$ 11,632,396	$ 3,996,269	$ 3,767,194	$ 3,868,934	$ -	$ -	$ -
207										
208	Total Other Power Generation Expense			$ 156,040,301	$ 5,524,754	$ 5,208,063	$ 5,348,717	$ 139,958,767	$ -	$ -
209										
210	Total Station Expense			$ 651,522,923	$ 22,313,905	$ 21,034,822	$ 21,602,907	$ 586,571,290	$ -	$ -
211				$ (70,179,929)						
212	**Other Power Supply Expenses**									
213	555 PURCHASED POWER	OM555	OMPP	$ 68,413,605	2,467,484	2,404,475	2,180,028	61,361,618	-	-
214	555 PURCHASED POWER OPTIONS	OMO555	OMPP	-	-	-	-	-	-	-
215	555 BROKERAGE FEES	OMB555	OMPP	-	-	-	-	-	-	-
216	555 MISO TRANSMISSION EXPENSES	OMM555	OMPP	-	-	-	-	-	-	-
217	556 SYSTEM CONTROL AND LOAD DISPATCH	OM556	PROFIX	1,453,850	499,465	470,835	483,550	-	-	-
218	557 OTHER EXPENSES	OM557	PROFIX	312,473	107,349	101,196	103,929	-	-	-
219										
220	Total Other Power Supply Expenses	TPP		$ 70,179,928	$ 3,074,298	$ 2,976,505	$ 2,767,507	$ 61,361,618	$ -	$ -
221										
222	Total Electric Power Generation Expenses			$ 721,702,852	$ 25,388,203	$ 24,011,327	$ 24,370,414	$ 647,932,908	$ -	$ -
223										
224	**Transmission Expenses**									
225	560 OPERATION SUPERVISION AND ENG	OM560	LBTRAN	$ 1,562,765	-	-	-	-	-	-
226	561 LOAD DISPATCHING	OM561	LBTRAN	3,420,163	-	-	-	-	-	-
227	562 STATION EXPENSES	OM562	LBTRAN	773,471	-	-	-	-	-	-
228	563 OVERHEAD LINE EXPENSES	OM563	LBTRAN	831,798	-	-	-	-	-	-
229	565 TRANSMISSION OF ELECTRICITY BY OTHERS	OM565	LBTRAN	3,845,795	-	-	-	-	-	-
230	566 MISC. TRANSMISSION EXPENSES	OM566	PTRAN	9,721,483	-	-	-	-	-	-
231	567 RENTS	OM567	PTRAN	-	-	-	-	-	-	-
232	568 MAINTENACE SUPERVISION AND ENG	OM568	LBTRAN	-	-	-	-	-	-	-
233	569 STRUCTURES	OM569	LBTRAN	-	-	-	-	-	-	-
234	570 MAINT OF STATION EQUIPMENT	OM570	LBTRAN	2,409,657	-	-	-	-	-	-
235	571 MAINT OF OVERHEAD LINES	OM571	LBTRAN	3,897,752	-	-	-	-	-	-
236	572 UNDERGROUND LINES	OM572	LBTRAN	-	-	-	-	-	-	-
237	573 MISC PLANT	OM573	PTRAN	109,216	-	-	-	-	-	-
238	575 MISO DAY 1&2 EXPENSE	OM575	PTRAN	(342,725)	-	-	-	-	-	-
239										
240	Total Transmission Expenses			$ 26,229,376	$ -	$ -	$ -	$ -	$ -	$ -
241										
242	**Distribution Operation Expense**									
243	580 OPERATION SUPERVISION AND ENGI	OM580	LBDO	$ 1,412,189	-	-	-	-	-	-
244	581 LOAD DISPATCHING	OM581	P362	1,040,879	-	-	-	-	-	-
245	582 STATION EXPENSES	OM582	P362	1,779,146	-	-	-	-	-	-
246	583 OVERHEAD LINE EXPENSES	OM583	P365	4,273,322	-	-	-	-	-	-
247	584 UNDERGROUND LINE EXPENSES	OM584	P367	530	-	-	-	-	-	-
248	585 STREET LIGHTING EXPENSE	OM585	P373	-	-	-	-	-	-	-
249	586 METER EXPENSES	OM586	P370	7,725,897	-	-	-	-	-	-
250	586 METER EXPENSES - LOAD MANAGEMENT	OM586x	F012	-	-	-	-	-	-	-
251	587 CUSTOMER INSTALLATIONS EXPENSE	OM587	P371	(106,729)	-	-	-	-	-	-
252	588 MISCELLANEOUS DISTRIBUTION EXP	OM588	PDIST	4,615,516	-	-	-	-	-	-
253	588 MISC DISTR EXP -- MAPPIN	OM588x	PDIST	-	-	-	-	-	-	-
254	589 RENTS	OM589	PDIST	-	-	-	-	-	-	-
255										
256	Total Distribution Operation Expense	OMDO		$ 20,740,750	$ -	$ -	$ -	$ -	$ -	$ -

KENTUCKY UTILITIES COMPANY
Cost of Service Study
Functional Assignment and Classification
12 Months Ended June 30, 2016

	A / B	C	D	O	P	Q	S	T	U	V	W
1											
2			Functional	Transmission Demand			Distribution Poles	Distribution Substation	Distribution Primary Lines		
3	Description	Name	Vector	Base	Winter	Summer	Specific	General	Specific	Demand	Customer
4											
200	**Other Power Generation Maintenance Expense**										
201	551 MAINTENANCE SUPERVISION & ENGINEERING	OM551	PROFIX	-	-	-	-	-	-	-	-
202	552 MAINTENANCE OF STRUCTURES	OM552	PROFIX	-	-	-	-	-	-	-	-
203	553 MAINTENANCE OF GENERATING & ELEC PLANT	OM553	PROFIX	-	-	-	-	-	-	-	-
204	554 MAINTENANCE OF MISC OTHER POWER GEN PLT	OM554	PROFIX	-	-	-	-	-	-	-	-
205											
206	Total Other Power Generation Maintenance Expense			$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
207											
208	Total Other Power Generation Expense			$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
209											
210	Total Station Expense			$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
211											
212	**Other Power Supply Expenses**										
213	555 PURCHASED POWER	OM555	OMPP	-	-	-	-	-	-	-	-
214	555 PURCHASED POWER OPTIONS	OMO555	OMPP	-	-	-	-	-	-	-	-
215	555 BROKERAGE FEES	OMB555	OMPP	-	-	-	-	-	-	-	-
216	555 MISO TRANSMISSION EXPENSES	OMM555	OMPP	-	-	-	-	-	-	-	-
217	556 SYSTEM CONTROL AND LOAD DISPATCH	OM556	PROFIX	-	-	-	-	-	-	-	-
218	557 OTHER EXPENSES	OM557	PROFIX	-	-	-	-	-	-	-	-
219											
220	Total Other Power Supply Expenses	TPP		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
221											
222	Total Electric Power Generation Expenses			$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
223											
224	**Transmission Expenses**										
225	560 OPERATION SUPERVISION AND ENG	OM560	LBTRAN	546,810	532,847	483,108	-	-	-	-	-
226	561 LOAD DISPATCHING	OM561	LBTRAN	1,196,712	1,166,153	1,057,298	-	-	-	-	-
227	562 STATION EXPENSES	OM562	LBTRAN	270,637	263,726	239,108	-	-	-	-	-
228	563 OVERHEAD LINE EXPENSES	OM563	LBTRAN	291,046	283,613	257,139	-	-	-	-	-
229	565 TRANSMISSION OF ELECTRICITY BY OTHERS	OM565	LBTRAN	1,345,641	1,311,278	1,188,876	-	-	-	-	-
230	566 MISC. TRANSMISSION EXPENSES	OM566	PTRAN	3,401,539	3,314,677	3,005,267	-	-	-	-	-
231	567 RENTS	OM567	PTRAN	-	-	-	-	-	-	-	-
232	568 MAINTENACE SUPERVISION AND ENG	OM568	LBTRAN	-	-	-	-	-	-	-	-
233	569 STRUCTURES	OM569	LBTRAN	-	-	-	-	-	-	-	-
234	570 MAINT OF STATION EQUIPMENT	OM570	LBTRAN	843,137	821,607	744,913	-	-	-	-	-
235	571 MAINT OF OVERHEAD LINES	OM571	LBTRAN	1,363,820	1,328,994	1,204,938	-	-	-	-	-
236	572 UNDERGROUND LINES	OM572	LBTRAN	-	-	-	-	-	-	-	-
237	573 MISC PLANT	OM573	PTRAN	38,215	37,239	33,763	-	-	-	-	-
238	575 MISO DAY 1&2 EXPENSE	OM575	PTRAN	(119,919)	(116,857)	(105,949)	-	-	-	-	-
239											
240	Total Transmission Expenses			$ 9,177,637	$ 8,943,277	$ 8,108,462	$ -	$ -	$ -	$ -	$ -
241											
242	**Distribution Operation Expense**										
243	580 OPERATION SUPERVISION AND ENGI	OM580	LBDO	-	-	-	-	293,172	-	128,170	180,876
244	581 LOAD DISPATCHING	OM581	P362	-	-	-	-	1,040,879	-	-	-
245	582 STATION EXPENSES	OM582	P362	-	-	-	-	1,779,146	-	-	-
246	583 OVERHEAD LINE EXPENSES	OM583	P365	-	-	-	-	-	-	1,370,454	1,834,537
247	584 UNDERGROUND LINE EXPENSES	OM584	P367	-	-	-	-	-	-	119	278
248	585 STREET LIGHTING EXPENSE	OM585	P373	-	-	-	-	-	-	-	-
249	586 METER EXPENSES	OM586	P370	-	-	-	-	-	-	-	-
250	586 METER EXPENSES - LOAD MANAGEMENT	OM586x	F012	-	-	-	-	-	-	-	-
251	587 CUSTOMER INSTALLATIONS EXPENSE	OM587	P371	-	-	-	-	-	-	-	-
252	588 MISCELLANEOUS DISTRIBUTION EXP	OM588	PDIST	-	-	-	-	537,490	-	728,937	1,092,260
253	588 MISC DISTR EXP -- MAPPIN	OM588x	PDIST	-	-	-	-	-	-	-	-
254	589 RENTS	OM589	PDIST	-	-	-	-	-	-	-	-
255											
256	Total Distribution Operation Expense	OMDO		$ -	$ -	$ -	$ -	$ 3,650,686	$ -	$ 2,227,681	$ 3,107,952

KENTUCKY UTILITIES COMPANY
Cost of Service Study
Functional Assignment and Classification
12 Months Ended June 30, 2016

	A	B	C	D	E	X	Y	Z	AA	AB	AC	AD
1												
2				**Functional**		**Distribution Sec. Lines**		**Distribution Line Trans.**		**Distribution Services**	**Distribution Meters**	**Distribution St. & Cust. Lighting**
3	**Description**		**Name**	**Vector**		**Demand**	**Customer**	**Demand**	**Customer**	**Customer**		
4												
200	**Other Power Generation Maintenance Expense**											
201		551 MAINTENANCE SUPERVISION & ENGINEERING	OM551	PROFIX		-	-	-	-	-	-	-
202		552 MAINTENANCE OF STRUCTURES	OM552	PROFIX		-	-	-	-	-	-	-
203		553 MAINTENANCE OF GENERATING & ELEC PLANT	OM553	PROFIX		-	-	-	-	-	-	-
204		554 MAINTENANCE OF MISC OTHER POWER GEN PLT	OM554	PROFIX		-	-	-	-	-	-	-
205												
206		Total Other Power Generation Maintenance Expense				$ -	$ -	$ -	$ -	$ -	$ -	$ -
207												
208		Total Other Power Generation Expense				$ -	$ -	$ -	$ -	$ -	$ -	$ -
209												
210		Total Station Expense				$ -	$ -	$ -	$ -	$ -	$ -	$ -
211												
212	**Other Power Supply Expenses**											
213		555 PURCHASED POWER	OM555	OMPP		-	-	-	-	-	-	-
214		555 PURCHASED POWER OPTIONS	OMO555	OMPP		-	-	-	-	-	-	-
215		555 BROKERAGE FEES	OMB555	OMPP		-	-	-	-	-	-	-
216		555 MISO TRANSMISSION EXPENSES	OMM555	OMPP		-	-	-	-	-	-	-
217		556 SYSTEM CONTROL AND LOAD DISPATCH	OM556	PROFIX		-	-	-	-	-	-	-
218		557 OTHER EXPENSES	OM557	PROFIX		-	-	-	-	-	-	-
219												
220		Total Other Power Supply Expenses	TPP			$ -	$ -	$ -	$ -	$ -	$ -	$ -
221												
222		Total Electric Power Generation Expenses				$ -	$ -	$ -	$ -	$ -	$ -	$ -
223												
224	**Transmission Expenses**											
225		560 OPERATION SUPERVISION AND ENG	OM560	LBTRAN		-	-	-	-	-	-	-
226		561 LOAD DISPATCHING	OM561	LBTRAN		-	-	-	-	-	-	-
227		562 STATION EXPENSES	OM562	LBTRAN		-	-	-	-	-	-	-
228		563 OVERHEAD LINE EXPENSES	OM563	LBTRAN		-	-	-	-	-	-	-
229		565 TRANSMISSION OF ELECTRICITY BY OTHERS	OM565	LBTRAN		-	-	-	-	-	-	-
230		566 MISC. TRANSMISSION EXPENSES	OM566	PTRAN		-	-	-	-	-	-	-
231		567 RENTS	OM567	PTRAN		-	-	-	-	-	-	-
232		568 MAINTENACE SUPERVISION AND ENG	OM568	LBTRAN		-	-	-	-	-	-	-
233		569 STRUCTURES	OM569	LBTRAN		-	-	-	-	-	-	-
234		570 MAINT OF STATION EQUIPMENT	OM570	LBTRAN		-	-	-	-	-	-	-
235		571 MAINT OF OVERHEAD LINES	OM571	LBTRAN		-	-	-	-	-	-	-
236		572 UNDERGROUND LINES	OM572	LBTRAN		-	-	-	-	-	-	-
237		573 MISC PLANT	OM573	PTRAN		-	-	-	-	-	-	-
238		575 MISO DAY 1&2 EXPENSE	OM575	PTRAN		-	-	-	-	-	-	-
239												
240	Total Transmission Expenses					$ -	$ -	$ -	$ -	$ -	$ -	$ -
241												
242	**Distribution Operation Expense**											
243		580 OPERATION SUPERVISION AND ENGI	OM580	LBDO		42,723	60,292	35,537	32,256	20,531	591,920	26,712
244		581 LOAD DISPATCHING	OM581	P362		-	-	-	-	-	-	-
245		582 STATION EXPENSES	OM582	P362		-	-	-	-	-	-	-
246		583 OVERHEAD LINE EXPENSES	OM583	P365		456,818	611,512	-	-	-	-	-
247		584 UNDERGROUND LINE EXPENSES	OM584	P367		40	93	-	-	-	-	-
248		585 STREET LIGHTING EXPENSE	OM585	P373		-	-	-	-	-	-	-
249		586 METER EXPENSES	OM586	P370		-	-	-	-	-	7,725,897	-
250		586 METER EXPENSES - LOAD MANAGEMENT	OM586x	F012		-	-	-	-	-	-	-
251		587 CUSTOMER INSTALLATIONS EXPENSE	OM587	P371		-	-	-	-	-	-	(106,729)
252		588 MISCELLANEOUS DISTRIBUTION EXP	OM588	PDIST		242,979	364,087	444,943	403,861	257,056	209,455	334,449
253		588 MISC DISTR EXP -- MAPPIN	OM588x	PDIST		-	-	-	-	-	-	-
254		589 RENTS	OM589	PDIST		-	-	-	-	-	-	-
255												
256	Total Distribution Operation Expense		OMDO			$ 742,560	$ 1,035,984	$ 480,480	$ 436,117	$ 277,586	$ 8,527,272	$ 254,432

	A	B	C	D	E	AF	AH	AJ
1								
2				Functional		Customer Accounts Expense	Customer Service & Info.	Sales Expense
3	Description		Name	Vector				
4								
200	**Other Power Generation Maintenance Expense**							
201	551	MAINTENANCE SUPERVISION & ENGINEERING	OM551	PROFIX		-	-	-
202	552	MAINTENANCE OF STRUCTURES	OM552	PROFIX		-	-	-
203	553	MAINTENANCE OF GENERATING & ELEC PLANT	OM553	PROFIX		-	-	-
204	554	MAINTENANCE OF MISC OTHER POWER GEN PLT	OM554	PROFIX		-	-	-
205								
206		Total Other Power Generation Maintenance Expense				$ -	$ -	$ -
207								
208		Total Other Power Generation Expense				$ -	$ -	$ -
209								
210		Total Station Expense				$ -	$ -	$ -
211								
212	**Other Power Supply Expenses**							
213	555	PURCHASED POWER	OM555	OMPP		-	-	-
214	555	PURCHASED POWER OPTIONS	OMO555	OMPP		-	-	-
215	555	BROKERAGE FEES	OMB555	OMPP		-	-	-
216	555	MISO TRANSMISSION EXPENSES	OMM555	OMPP		-	-	-
217	556	SYSTEM CONTROL AND LOAD DISPATCH	OM556	PROFIX		-	-	-
218	557	OTHER EXPENSES	OM557	PROFIX		-	-	-
219								
220		Total Other Power Supply Expenses	TPP			$ -	$ -	$ -
221								
222		Total Electric Power Generation Expenses				$ -	$ -	$ -
223								
224	**Transmission Expenses**							
225	560	OPERATION SUPERVISION AND ENG	OM560	LBTRAN		-	-	-
226	561	LOAD DISPATCHING	OM561	LBTRAN		-	-	-
227	562	STATION EXPENSES	OM562	LBTRAN		-	-	-
228	563	OVERHEAD LINE EXPENSES	OM563	LBTRAN		-	-	-
229	565	TRANSMISSION OF ELECTRICITY BY OTHERS	OM565	LBTRAN		-	-	-
230	566	MISC. TRANSMISSION EXPENSES	OM566	PTRAN		-	-	-
231	567	RENTS	OM567	PTRAN		-	-	-
232	568	MAINTENACE SUPERVISION AND ENG	OM568	LBTRAN		-	-	-
233	569	STRUCTURES	OM569	LBTRAN		-	-	-
234	570	MAINT OF STATION EQUIPMENT	OM570	LBTRAN		-	-	-
235	571	MAINT OF OVERHEAD LINES	OM571	LBTRAN		-	-	-
236	572	UNDERGROUND LINES	OM572	LBTRAN		-	-	-
237	573	MISC PLANT	OM573	PTRAN		-	-	-
238	575	MISO DAY 1&2 EXPENSE	OM575	PTRAN		-	-	-
239								
240	Total Transmission Expenses					$ -	$ -	$ -
241								
242	**Distribution Operation Expense**							
243	580	OPERATION SUPERVISION AND ENGI	OM580	LBDO		-	-	-
244	581	LOAD DISPATCHING	OM581	P362		-	-	-
245	582	STATION EXPENSES	OM582	P362		-	-	-
246	583	OVERHEAD LINE EXPENSES	OM583	P365		-	-	-
247	584	UNDERGROUND LINE EXPENSES	OM584	P367		-	-	-
248	585	STREET LIGHTING EXPENSE	OM585	P373		-	-	-
249	586	METER EXPENSES	OM586	P370		-	-	-
250	586	METER EXPENSES - LOAD MANAGEMENT	OM586x	F012		-	-	-
251	587	CUSTOMER INSTALLATIONS EXPENSE	OM587	P371		-	-	-
252	588	MISCELLANEOUS DISTRIBUTION EXP	OM588	PDIST		-	-	-
253	588	MISC DISTR EXP -- MAPPIN	OM588x	PDIST		-	-	-
254	589	RENTS	OM589	PDIST		-	-	-
255								
256	Total Distribution Operation Expense		OMDO			$ -	$ -	$ -

	Description	Name	Functional Vector	Total System	Production Demand Base	Production Demand Inter.	Production Demand Peak	Production Energy Base	Production Energy Inter.	Production Energy Peak
257										
258	**Operation and Maintenance Expenses (Continued)**									
259										
260	**Distribution Maintenance Expense**									
261	590 MAINTENANCE SUPERVISION AND EN	OM590	LBDM	$ 32,278	-	-	-	-	-	-
262	591 STRUCTURES	OM591	P362	-	-	-	-	-	-	-
263	592 MAINTENANCE OF STATION EQUIPME	OM592	P362	1,101,049	-	-	-	-	-	-
264	593 MAINTENANCE OF OVERHEAD LINES	OM593	P365	29,550,316	-	-	-	-	-	-
265	594 MAINTENANCE OF UNDERGROUND LIN	OM594	P367	732,194	-	-	-	-	-	-
266	595 MAINTENANCE OF LINE TRANSFORME	OM595	P368	99,095	-	-	-	-	-	-
267	596 MAINTENANCE OF ST LIGHTS & SIG SYSTEMS	OM596	P373	151	-	-	-	-	-	-
268	597 MAINTENANCE OF METERS	OM597	P370	-	-	-	-	-	-	-
269	598 MISCELLANEOUS DISTRIBUTION EXPENSES	OM598	PDIST	43,266	-	-	-	-	-	-
270										
271	Total Distribution Maintenance Expense	OMDM		$ 31,558,349	$ -	$ -	$ -	$ -	$ -	$ -
272										
273	Total Distribution Operation and Maintenance Expenses			52,299,098	-	-	-	-	-	-
274										
275	Transmission and Distribution Expenses			78,528,474	-	-	-	-	-	-
276										
277	Production, Transmission and Distribution Expenses	OMSUB		$ 800,231,326	$ 25,388,203	$ 24,011,327	$ 24,370,414	$ 647,932,908	$ -	$ -
278										
279	**Customer Accounts Expense**									
280	901 SUPERVISION/CUSTOMER ACCTS	OM901	F025	$ 2,823,189	-	-	-	-	-	-
281	902 METER READING EXPENSES	OM902	F025	5,114,992	-	-	-	-	-	-
282	903 RECORDS AND COLLECTION	OM903	F025	17,442,601	-	-	-	-	-	-
283	904 UNCOLLECTIBLE ACCOUNTS	OM904	F025	6,441,434	-	-	-	-	-	-
284	905 MISC CUST ACCOUNTS	OM903	F025	126,172	-	-	-	-	-	-
285										
286	Total Customer Accounts Expense	OMCA		$ 31,948,387	$ -	$ -	$ -	$ -	$ -	$ -
287										
288	**Customer Service Expense**									
289	907 SUPERVISION	OM907	F026	$ 328,102	-	-	-	-	-	-
290	908 CUSTOMER ASSISTANCE EXPENSES	OM908	F026	596,349	-	-	-	-	-	-
291	908 CUSTOMER ASSISTANCE EXP-INCENTIVES	OM908x	F026	-	-	-	-	-	-	-
292	909 INFORMATIONAL AND INSTRUCTIONA	OM909	F026	347,196	-	-	-	-	-	-
293	909 INFORM AND INSTRUC -LOAD MGMT	OM909x	F026	-	-	-	-	-	-	-
294	910 MISCELLANEOUS CUSTOMER SERVICE	OM910	F026	739,686	-	-	-	-	-	-
295	911 DEMONSTRATION AND SELLING EXP	OM911	F026	-	-	-	-	-	-	-
296	912 DEMONSTRATION AND SELLING EXP	OM912	F026	-	-	-	-	-	-	-
297	913 ADVERTISING EXPENSES	OM913	F026	170,485	-	-	-	-	-	-
298	915 MDSE-JOBBING-CONTRACT	OM915	F026	-	-	-	-	-	-	-
299	916 MISC SALES EXPENSE	OM916	F026	-	-	-	-	-	-	-
300										
301	Total Customer Service Expense	OMCS		$ 2,181,817	$ -	$ -	$ -	$ -	$ -	$ -
302										
303	Sub-Total Prod, Trans, Dist, Cust Acct and Cust Service	OMSUB2		834,361,530	25,388,203	24,011,327	24,370,414	647,932,908	-	-
304										
305										
306										
307										
308										

KENTUCKY UTILITIES COMPANY
Cost of Service Study
Functional Assignment and Classification
12 Months Ended June 30, 2016

	A B	C	D	O	P	Q	S	T	U	V	W
1											
2			Functional	Transmission Demand			Distribution Poles	Distribution Substation	Distribution Primary Lines		
3	Description	Name	Vector	Base	Winter	Summer	Specific	General	Specific	Demand	Customer
4											
257											
258	**Operation and Maintenance Expenses (Continued)**										
259											
260	**Distribution Maintenance Expense**										
261	590 MAINTENANCE SUPERVISION AND EN	OM590	LBDM	-	-	-	-	2,610	-	9,362	12,889
262	591 STRUCTURES	OM591	P362	-	-	-	-	-	-	-	-
263	592 MAINTENANCE OF STATION EQUIPME	OM592	P362	-	-	-	-	1,101,049	-	-	-
264	593 MAINTENANCE OF OVERHEAD LINES	OM593	P365	-	-	-	-	-	-	9,476,786	12,685,951
265	594 MAINTENANCE OF UNDERGROUND LIN	OM594	P367	-	-	-	-	-	-	164,799	384,347
266	595 MAINTENANCE OF LINE TRANSFORME	OM595	P368	-	-	-	-	-	-	-	-
267	596 MAINTENANCE OF ST LIGHTS & SIG SYSTEMS	OM596	P373	-	-	-	-	-	-	-	-
268	597 MAINTENANCE OF METERS	OM597	P370	-	-	-	-	-	-	-	-
269	598 MISCELLANEOUS DISTRIBUTION EXPENSES	OM598	PDIST	-	-	-	-	5,038	-	6,833	10,239
270											
271	Total Distribution Maintenance Expense	OMDM		$ -	$ -	$ -	$ -	$ 1,108,698	$ -	$ 9,657,780	$ 13,093,425
272											
273	Total Distribution Operation and Maintenance Expenses			-	-	-	-	4,759,384	-	11,885,461	16,201,377
274											
275	Transmission and Distribution Expenses			9,177,637	8,943,277	8,108,462	-	4,759,384	-	11,885,461	16,201,377
276											
277	Production, Transmission and Distribution Expenses	OMSUB		$ 9,177,637	$ 8,943,277	$ 8,108,462	$ -	$ 4,759,384	$ -	$ 11,885,461	$ 16,201,377
278											
279	**Customer Accounts Expense**										
280	901 SUPERVISION/CUSTOMER ACCTS	OM901	F025	-	-	-	-	-	-	-	-
281	902 METER READING EXPENSES	OM902	F025	-	-	-	-	-	-	-	-
282	903 RECORDS AND COLLECTION	OM903	F025	-	-	-	-	-	-	-	-
283	904 UNCOLLECTIBLE ACCOUNTS	OM904	F025	-	-	-	-	-	-	-	-
284	905 MISC CUST ACCOUNTS	OM903	F025	-	-	-	-	-	-	-	-
285											
286	Total Customer Accounts Expense	OMCA		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
287											
288	**Customer Service Expense**										
289	907 SUPERVISION	OM907	F026	-	-	-	-	-	-	-	-
290	908 CUSTOMER ASSISTANCE EXPENSES	OM908	F026	-	-	-	-	-	-	-	-
291	908 CUSTOMER ASSISTANCE EXP-INCENTIVES	OM908x	F026	-	-	-	-	-	-	-	-
292	909 INFORMATIONAL AND INSTRUCTIONA	OM909	F026	-	-	-	-	-	-	-	-
293	909 INFORM AND INSTRUC -LOAD MGMT	OM909x	F026	-	-	-	-	-	-	-	-
294	910 MISCELLANEOUS CUSTOMER SERVICE	OM910	F026	-	-	-	-	-	-	-	-
295	911 DEMONSTRATION AND SELLING EXP	OM911	F026	-	-	-	-	-	-	-	-
296	912 DEMONSTRATION AND SELLING EXP	OM912	F026	-	-	-	-	-	-	-	-
297	913 ADVERTISING EXPENSES	OM913	F026	-	-	-	-	-	-	-	-
298	915 MDSE-JOBBING-CONTRACT	OM915	F026	-	-	-	-	-	-	-	-
299	916 MISC SALES EXPENSE	OM916	F026	-	-	-	-	-	-	-	-
300											
301	Total Customer Service Expense	OMCS		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
302											
303	Sub-Total Prod, Trans, Dist, Cust Acct and Cust Service	OMSUB2		9,177,637	8,943,277	8,108,462	-	4,759,384	-	11,885,461	16,201,377
304											
305											
306											
307											
308											

KENTUCKY UTILITIES COMPANY
Cost of Service Study
Functional Assignment and Classification
12 Months Ended June 30, 2016

	A / B	C	D	E	X	Y	Z	AA	AB	AC	AD
1											
2			Functional		Distribution Sec. Lines		Distribution Line Trans.		Distribution Services	Distribution Meters	Distribution St. & Cust. Lighting
3	Description	Name	Vector		Demand	Customer	Demand	Customer	Customer		
4											
257											
258	**Operation and Maintenance Expenses (Continued)**										
259											
260	**Distribution Maintenance Expense**										
261	590 MAINTENANCE SUPERVISION AND EN	OM590	LBDM		3,121	4,296	-	-	-	-	-
262	591 STRUCTURES	OM591	P362		-	-	-	-	-	-	-
263	592 MAINTENANCE OF STATION EQUIPME	OM592	P362		-	-	-	-	-	-	-
264	593 MAINTENANCE OF OVERHEAD LINES	OM593	P365		3,158,929	4,228,650	-	-	-	-	-
265	594 MAINTENANCE OF UNDERGROUND LIN	OM594	P367		54,933	128,116	-	-	-	-	-
266	595 MAINTENANCE OF LINE TRANSFORME	OM595	P368		-	-	51,946	47,149	-	-	-
267	596 MAINTENANCE OF ST LIGHTS & SIG SYSTEMS	OM596	P373		-	-	-	-	-	-	151
268	597 MAINTENANCE OF METERS	OM597	P370		-	-	-	-	-	-	-
269	598 MISCELLANEOUS DISTRIBUTION EXPENSES	OM598	PDIST		2,278	3,413	4,171	3,786	2,410	1,963	3,135
270											
271	Total Distribution Maintenance Expense	OMDM			$ 3,219,260	$ 4,364,475	$ 56,117	$ 50,935	$ 2,410	$ 1,963	$ 3,286
272											
273	Total Distribution Operation and Maintenance Expenses				3,961,820	5,400,459	536,596	487,052	279,996	8,529,236	257,718
274											
275	Transmission and Distribution Expenses				3,961,820	5,400,459	536,596	487,052	279,996	8,529,236	257,718
276											
277	Production, Transmission and Distribution Expenses	OMSUB			$ 3,961,820	$ 5,400,459	$ 536,596	$ 487,052	$ 279,996	$ 8,529,236	$ 257,718
278											
279	**Customer Accounts Expense**										
280	901 SUPERVISION/CUSTOMER ACCTS	OM901	F025		-	-	-	-	-	-	-
281	902 METER READING EXPENSES	OM902	F025		-	-	-	-	-	-	-
282	903 RECORDS AND COLLECTION	OM903	F025		-	-	-	-	-	-	-
283	904 UNCOLLECTIBLE ACCOUNTS	OM904	F025		-	-	-	-	-	-	-
284	905 MISC CUST ACCOUNTS	OM903	F025		-	-	-	-	-	-	-
285											
286	Total Customer Accounts Expense	OMCA			$ -	$ -	$ -	$ -	$ -	$ -	$ -
287											
288	**Customer Service Expense**										
289	907 SUPERVISION	OM907	F026		-	-	-	-	-	-	-
290	908 CUSTOMER ASSISTANCE EXPENSES	OM908	F026		-	-	-	-	-	-	-
291	908 CUSTOMER ASSISTANCE EXP-INCENTIVES	OM908x	F026		-	-	-	-	-	-	-
292	909 INFORMATIONAL AND INSTRUCTIONA	OM909	F026		-	-	-	-	-	-	-
293	909 INFORM AND INSTRUC -LOAD MGMT	OM909x	F026		-	-	-	-	-	-	-
294	910 MISCELLANEOUS CUSTOMER SERVICE	OM910	F026		-	-	-	-	-	-	-
295	911 DEMONSTRATION AND SELLING EXP	OM911	F026		-	-	-	-	-	-	-
296	912 DEMONSTRATION AND SELLING EXP	OM912	F026		-	-	-	-	-	-	-
297	913 ADVERTISING EXPENSES	OM913	F026		-	-	-	-	-	-	-
298	915 MDSE-JOBBING-CONTRACT	OM915	F026		-	-	-	-	-	-	-
299	916 MISC SALES EXPENSE	OM916	F026		-	-	-	-	-	-	-
300											
301	Total Customer Service Expense	OMCS			$ -	$ -	$ -	$ -	$ -	$ -	$ -
302											
303	Sub-Total Prod, Trans, Dist, Cust Acct and Cust Service	OMSUB2			3,961,820	5,400,459	536,596	487,052	279,996	8,529,236	257,718
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KENTUCKY UTILITIES COMPANY
Cost of Service Study
Functional Assignment and Classification
12 Months Ended June 30, 2016

	A	B	C	D	AF	AH	AJ
1							
2				Functional	Customer Accounts Expense	Customer Service & Info.	Sales Expense
3	**Description**		**Name**	**Vector**			
4							
257							
258	**Operation and Maintenance Expenses (Continued)**						
259							
260	**Distribution Maintenance Expense**						
261	590	MAINTENANCE SUPERVISION AND EN	OM590	LBDM	-	-	-
262	591	STRUCTURES	OM591	P362	-	-	-
263	592	MAINTENANCE OF STATION EQUIPME	OM592	P362	-	-	-
264	593	MAINTENANCE OF OVERHEAD LINES	OM593	P365	-	-	-
265	594	MAINTENANCE OF UNDERGROUND LIN	OM594	P367	-	-	-
266	595	MAINTENANCE OF LINE TRANSFORME	OM595	P368	-	-	-
267	596	MAINTENANCE OF ST LIGHTS & SIG SYSTEMS	OM596	P373	-	-	-
268	597	MAINTENANCE OF METERS	OM597	P370	-	-	-
269	598	MISCELLANEOUS DISTRIBUTION EXPENSES	OM598	PDIST	-	-	-
270							
271	Total Distribution Maintenance Expense		OMDM		$ -	$ -	$ -
272							
273	Total Distribution Operation and Maintenance Expenses				-	-	-
274							
275	Transmission and Distribution Expenses				-	-	-
276							
277	Production, Transmission and Distribution Expenses		OMSUB		$ -	$ -	$ -
278							
279	**Customer Accounts Expense**						
280	901	SUPERVISION/CUSTOMER ACCTS	OM901	F025	2,823,189	-	-
281	902	METER READING EXPENSES	OM902	F025	5,114,992	-	-
282	903	RECORDS AND COLLECTION	OM903	F025	17,442,601	-	-
283	904	UNCOLLECTIBLE ACCOUNTS	OM904	F025	6,441,434	-	-
284	905	MISC CUST ACCOUNTS	OM903	F025	126,172	-	-
285							
286	Total Customer Accounts Expense		OMCA		$ 31,948,387	$ -	$ -
287							
288	**Customer Service Expense**						
289	907	SUPERVISION	OM907	F026	-	328,102	-
290	908	CUSTOMER ASSISTANCE EXPENSES	OM908	F026	-	596,349	-
291	908	CUSTOMER ASSISTANCE EXP-INCENTIVES	OM908x	F026	-	-	-
292	909	INFORMATIONAL AND INSTRUCTIONA	OM909	F026	-	347,196	-
293	909	INFORM AND INSTRUC -LOAD MGMT	OM909x	F026	-	-	-
294	910	MISCELLANEOUS CUSTOMER SERVICE	OM910	F026	-	739,686	-
295	911	DEMONSTRATION AND SELLING EXP	OM911	F026	-	-	-
296	912	DEMONSTRATION AND SELLING EXP	OM912	F026	-	-	-
297	913	ADVERTISING EXPENSES	OM913	F026	-	170,485	-
298	915	MDSE-JOBBING-CONTRACT	OM915	F026	-	-	-
299	916	MISC SALES EXPENSE	OM916	F026	-	-	-
300							
301	Total Customer Service Expense		OMCS		$ -	$ 2,181,817	$ -
302							
303	Sub-Total Prod, Trans, Dist, Cust Acct and Cust Service		OMSUB2		31,948,387	2,181,817	-
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KENTUCKY UTILITIES COMPANY
Cost of Service Study
Functional Assignment and Classification
12 Months Ended June 30, 2016

Row	Description	Name	Functional Vector	Total System	Production Demand Base	Production Demand Inter.	Production Demand Peak	Production Energy Base	Production Energy Inter.	Production Energy Peak
309	**Operation and Maintenance Expenses (Continued)**									
310										
311	**Administrative and General Expense**									
312	920 ADMIN. & GEN. SALARIES-	OM920	LBSUB7	$ 34,247,082	4,020,274	3,789,823	3,892,175	7,477,557	-	-
313	921 OFFICE SUPPLIES AND EXPENSES	OM921	LBSUB7	8,290,411	973,214	917,427	942,204	1,810,140	-	-
314	922 ADMINISTRATIVE EXPENSES TRANSFERRED	OM922	LBSUB7	(4,770,971)	(560,066)	(527,961)	(542,220)	(1,041,701)	-	-
315	923 OUTSIDE SERVICES EMPLOYED	OM923	LBSUB7	20,336,984	2,387,364	2,250,515	2,311,295	4,440,407	-	-
316	924 PROPERTY INSURANCE	OM924	TUP	5,200,353	1,146,242	1,116,971	1,012,707	-	-	-
317	925 INJURIES AND DAMAGES - INSURAN	OM925	LBSUB7	3,322,518	390,031	367,674	377,604	725,443	-	-
318	926 EMPLOYEE BENEFITS	OM926	LBSUB7	46,032,729	5,403,795	5,094,037	5,231,611	10,050,853	-	-
319	928 REGULATORY COMMISSION FEES	OM928	TUP	1,674,886	369,172	359,745	326,164	-	-	-
320	929 DUPLICATE CHARGES	OM929	LBSUB7	-	-	-	-	-	-	-
321	930 MISCELLANEOUS GENERAL EXPENSES	OM930	LBSUB7	4,505,861	528,944	498,624	512,090	983,816	-	-
322	931 RENTS AND LEASES	OM931	PGP	1,922,590	423,481	412,667	374,146	-	-	-
323	932 MAINTENANCE OF GENERAL PLANT	OM932	PGP	-	-	-	-	-	-	-
324	935 MAINTENANCE OF GENERAL PLANT	OM935	PGP	2,028,638	446,839	435,429	394,783	-	-	-
325										
326	Total Administrative and General Expense	OMAG		$ 122,791,081	$ 15,529,290	$ 14,714,950	$ 14,832,559	$ 24,446,516	$ -	$ -
327										
328	Total Operation and Maintenance Expenses	TOM		$ 957,152,611	$ 40,917,494	$ 38,726,277	$ 39,202,972	$ 672,379,424	$ -	$ -
329										
330	Operation and Maintenance Expenses Less Purchase Power	OMLPP		$ 888,739,006	$ 38,450,009	$ 36,321,802	$ 37,022,944	$ 611,017,806	$ -	$ -

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Row	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
309	**Operation and Maintenance Expenses (Continued)**										
310											
311	**Administrative and General Expense**										
312	920 ADMIN. & GEN. SALARIES-	OM920	LBSUB7	767,864	748,255	678,409	-	798,037	-	1,082,288	1,621,731
313	921 OFFICE SUPPLIES AND EXPENSES	OM921	LBSUB7	185,882	181,135	164,227	-	193,186	-	261,996	392,583
314	922 ADMINISTRATIVE EXPENSES TRANSFERRED	OM922	LBSUB7	(106,971)	(104,240)	(94,509)	-	(111,175)	-	(150,774)	(225,924)
315	923 OUTSIDE SERVICES EMPLOYED	OM923	LBSUB7	455,981	444,337	402,860	-	473,900	-	642,696	963,034
316	924 PROPERTY INSURANCE	OM924	TUP	215,608	210,102	190,490	-	152,347	-	206,612	309,593
317	925 INJURIES AND DAMAGES - INSURAN	OM925	LBSUB7	74,495	72,593	65,817	-	77,422	-	104,999	157,334
318	926 EMPLOYEE BENEFITS	OM926	LBSUB7	1,032,113	1,005,757	911,874	-	1,072,671	-	1,454,742	2,179,827
319	928 REGULATORY COMMISSION FEES	OM928	TUP	69,441	67,668	61,351	-	49,067	-	66,544	99,711
320	929 DUPLICATE CHARGES	OM929	LBSUB7	-	-	-	-	-	-	-	-
321	930 MISCELLANEOUS GENERAL EXPENSES	OM930	LBSUB7	101,027	98,447	89,258	-	104,997	-	142,396	213,370
322	931 RENTS AND LEASES	OM931	PGP	79,366	77,340	70,120	-	56,534	-	76,671	114,886
323	932 MAINTENANCE OF GENERAL PLANT	OM932	PGP	-	-	-	-	-	-	-	-
324	935 MAINTENANCE OF GENERAL PLANT	OM935	PGP	83,744	81,606	73,988	-	59,653	-	80,900	121,223
325											
326	Total Administrative and General Expense	OMAG		$ 2,958,550	$ 2,883,001	$ 2,613,885	$ -	$ 2,926,640	$ -	$ 3,969,071	$ 5,947,369
327											
328	Total Operation and Maintenance Expenses	TOM		$ 12,136,187	$ 11,826,278	$ 10,722,347	$ -	$ 7,686,024	$ -	$ 15,854,532	$ 22,148,746
329											
330	Operation and Maintenance Expenses Less Purchase Power	OMLPP		$ 12,136,187	$ 11,826,278	$ 10,722,347	$ -	$ 7,686,024	$ -	$ 15,854,532	$ 22,148,746

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	A / B	C	D	E	X	Y	Z	AA	AB	AC	AD
1											
2			Functional		Distribution Sec. Lines		Distribution Line Trans.		Distribution Services	Distribution Meters	Distribution St. & Cust. Lighting
3	Description	Name	Vector		Demand	Customer	Demand	Customer	Customer		
4											
309	**Operation and Maintenance Expenses (Continued)**										
310											
311	**Administrative and General Expense**										
312	920 ADMIN. & GEN. SALARIES-	OM920	LBSUB7		360,763	540,577	660,628	599,632	381,663	310,988	496,572
313	921 OFFICE SUPPLIES AND EXPENSES	OM921	LBSUB7		87,332	130,861	159,923	145,157	92,392	75,283	120,208
314	922 ADMINISTRATIVE EXPENSES TRANSFERRED	OM922	LBSUB7		(50,258)	(75,308)	(92,032)	(83,535)	(53,170)	(43,324)	(69,178)
315	923 OUTSIDE SERVICES EMPLOYED	OM923	LBSUB7		214,232	321,011	392,302	356,080	226,643	184,674	294,880
316	924 PROPERTY INSURANCE	OM924	TUP		68,871	103,198	126,116	114,471	72,861	59,368	94,797
317	925 INJURIES AND DAMAGES - INSURAN	OM925	LBSUB7		35,000	52,445	64,092	58,174	37,027	30,171	48,175
318	926 EMPLOYEE BENEFITS	OM926	LBSUB7		484,914	726,609	887,974	805,986	513,007	418,010	667,460
319	928 REGULATORY COMMISSION FEES	OM928	TUP		22,181	33,237	40,618	36,868	23,466	19,121	30,531
320	929 DUPLICATE CHARGES	OM929	LBSUB7		-	-	-	-	-	-	-
321	930 MISCELLANEOUS GENERAL EXPENSES	OM930	LBSUB7		47,465	71,123	86,918	78,893	50,215	40,916	65,334
322	931 RENTS AND LEASES	OM931	PGP		25,557	38,295	46,800	42,479	27,038	22,031	35,178
323	932 MAINTENANCE OF GENERAL PLANT	OM932	PGP		-	-	-	-	-	-	-
324	935 MAINTENANCE OF GENERAL PLANT	OM935	PGP		26,967	40,408	49,382	44,822	28,529	23,246	37,118
325											
326	Total Administrative and General Expense	OMAG			$ 1,323,024	$ 1,982,456	$ 2,422,720	$ 2,199,027	$ 1,399,672	$ 1,140,485	$ 1,821,077
327											
328	Total Operation and Maintenance Expenses	TOM			$ 5,284,844	$ 7,382,915	$ 2,959,316	$ 2,686,079	$ 1,679,668	$ 9,669,720	$ 2,078,795
329											
330	Operation and Maintenance Expenses Less Purchase Power	OMLPP			$ 5,284,844	$ 7,382,915	$ 2,959,316	$ 2,686,079	$ 1,679,668	$ 9,669,720	$ 2,078,795
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	A / B	C	D	AF	AH	AJ
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2			Functional	Customer Accounts Expense	Customer Service & Info.	Sales Expense
3	Description	Name	Vector			
4						
309	Operation and Maintenance Expenses (Continued)					
310						
311	Administrative and General Expense					
312	920 ADMIN. & GEN. SALARIES-	OM920	LBSUB7	5,320,154	699,691	-
313	921 OFFICE SUPPLIES AND EXPENSES	OM921	LBSUB7	1,287,884	169,379	-
314	922 ADMINISTRATIVE EXPENSES TRANSFERRED	OM922	LBSUB7	(741,152)	(97,474)	-
315	923 OUTSIDE SERVICES EMPLOYED	OM923	LBSUB7	3,159,273	415,498	-
316	924 PROPERTY INSURANCE	OM924	TUP	-	-	-
317	925 INJURIES AND DAMAGES - INSURAN	OM925	LBSUB7	516,141	67,881	-
318	926 EMPLOYEE BENEFITS	OM926	LBSUB7	7,151,009	940,480	-
319	928 REGULATORY COMMISSION FEES	OM928	TUP	-	-	-
320	929 DUPLICATE CHARGES	OM929	LBSUB7	-	-	-
321	930 MISCELLANEOUS GENERAL EXPENSES	OM930	LBSUB7	699,968	92,058	-
322	931 RENTS AND LEASES	OM931	PGP	-	-	-
323	932 MAINTENANCE OF GENERAL PLANT	OM932	PGP	-	-	-
324	935 MAINTENANCE OF GENERAL PLANT	OM935	PGP	-	-	-
325						
326	Total Administrative and General Expense	OMAG		$ 17,393,276	$ 2,287,513	$ -
327						
328	Total Operation and Maintenance Expenses	TOM		$ 49,341,663	$ 4,469,330	$ -
329						
330	Operation and Maintenance Expenses Less Purchase Power	OMLPP		$ 49,341,663	$ 4,469,330	$ -
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	A / B	C	D	E / F	G / H	I	J	K	L	M
1										
2			Functional	Total	Production Demand			Production Energy		
3	Description	Name	Vector	System	Base	Inter.	Peak	Base	Inter.	Peak
4										
356	**Labor Expenses**									
357										
358	**Steam Power Generation Operation Expenses**									
359	500 OPERATION SUPERVISION & ENGINEERING	LB500	F019	$ 9,213,977	2,755,982	2,598,003	2,668,167	1,191,825	-	-
360	501 FUEL	LB501	Energy	2,679,078	-	-	-	2,679,078	-	-
361	502 STEAM EXPENSES	LB502	PROFIX	10,802,634	3,711,207	3,498,472	3,592,955	-	-	-
362	505 ELECTRIC EXPENSES	LB505	PROFIX	5,430,025	1,865,466	1,758,533	1,806,026	-	-	-
363	506 MISC. STEAM POWER EXPENSES	LB506	PROFIX	1,800,160	618,439	582,988	598,733	-	-	-
364	507 RENTS	LB507	PROFIX	-	-	-	-	-	-	-
365										
366	Total Steam Power Operation Expenses	LBSUB1		$ 29,925,875	$ 8,951,093	$ 8,437,997	$ 8,665,881	$ 3,870,904	$ -	$ -
367										
368	**Steam Power Generation Maintenance Expenses**									
369	510 MAINTENANCE SUPERVISION & ENGINEERING	LB510	F020	$ 6,172,711	128,765	121,384	124,662	5,797,900	-	-
370	511 MAINTENANCE OF STRUCTURES	LB511	PROFIX	779,013	267,627	252,286	259,100	-	-	-
371	512 MAINTENANCE OF BOILER PLANT	LB512	Energy	10,130,019	-	-	-	10,130,019	-	-
372	513 MAINTENANCE OF ELECTRIC PLANT	LB513	Energy	1,425,644	-	-	-	1,425,644	-	-
373	514 MAINTENANCE OF MISC STEAM PLANT	LB514	Energy	494,770	-	-	-	494,770	-	-
374										
375	Total Steam Power Generation Maintenance Expense	LBSUB2		$ 19,002,158	$ 396,392	$ 373,670	$ 383,762	$ 17,848,333	$ -	$ -
376										
377	Total Steam Power Generation Expense			$ 48,928,032	$ 9,347,486	$ 8,811,667	$ 9,049,643	$ 21,719,237	$ -	$ -
378										
379	**Hydraulic Power Generation Operation Expenses**									
380	535 OPERATION SUPERVISION & ENGINEERING	LB535	F021	$ -	-	-	-	-	-	-
381	536 WATER FOR POWER	LB536	PROFIX	-	-	-	-	-	-	-
382	537 HYDRAULIC EXPENSES	LB537	PROFIX	-	-	-	-	-	-	-
383	538 ELECTRIC EXPENSES	LB538	PROFIX	-	-	-	-	-	-	-
384	539 MISC. HYDRAULIC POWER EXPENSES	LB539	PROFIX	-	-	-	-	-	-	-
385	540 RENTS	LB540	PROFIX	-	-	-	-	-	-	-
386										
387	Total Hydraulic Power Operation Expenses	LBSUB3		$ -	$ -	$ -	$ -	$ -	$ -	$ -
388										
389	**Hydraulic Power Generation Maintenance Expenses**									
390	541 MAINTENANCE SUPERVISION & ENGINEERING	LB541	F022	$ 167,638	57,591	54,290	55,756	-	-	-
391	542 MAINTENANCE OF STRUCTURES	LB542	PROFIX	49,648	17,056	16,079	16,513	-	-	-
392	543 MAINT. OF RESERVES, DAMS, AND WATERWAYS	LB543	PROFIX	-	-	-	-	-	-	-
393	544 MAINTENANCE OF ELECTRIC PLANT	LB544	Energy	-	-	-	-	-	-	-
394	545 MAINTENANCE OF MISC HYDRAULIC PLANT	LB545	Energy	-	-	-	-	-	-	-
395										
396	Total Hydraulic Power Generation Maint. Expense	LBSUB4		$ 217,286	$ 74,648	$ 70,369	$ 72,269	$ -	$ -	$ -
397										
398	Total Hydraulic Power Generation Expense			$ 217,286	$ 74,648	$ 70,369	$ 72,269	$ -	$ -	$ -
399										
400	**Other Power Generation Operation Expense**									
401	546 OPERATION SUPERVISION & ENGINEERING	LB546	PROFIX	$ 319,567	109,786	103,493	106,288	-	-	-
402	547 FUEL	LB547	Energy	-	-	-	-	-	-	-
403	548 GENERATION EXPENSE	LB548	PROFIX	307,400	105,606	99,552	102,241	-	-	-
404	549 MISC OTHER POWER GENERATION	LB549	PROFIX	1,627,921	559,267	527,208	541,446	-	-	-
405	550 RENTS	LB550	PROFIX	-	-	-	-	-	-	-
406										
407	Total Other Power Generation Expenses	LBSUB5		$ 2,254,888	$ 774,659	$ 730,253	$ 749,975	$ -	$ -	$ -
408										

	A/B	C	D	O	P	Q	S	T	U	V	W
1											
2			Functional	Transmission Demand			Distribution Poles	Distribution Substation	Distribution Primary Lines		
3	Description	Name	Vector	Base	Winter	Summer	Specific	General	Specific	Demand	Customer
4											
356	**Labor Expenses**										
357											
358	**Steam Power Generation Operation Expenses**										
359	500 OPERATION SUPERVISION & ENGINEERING	LB500	F019	-	-	-	-	-	-	-	-
360	501 FUEL	LB501	Energy	-	-	-	-	-	-	-	-
361	502 STEAM EXPENSES	LB502	PROFIX	-	-	-	-	-	-	-	-
362	505 ELECTRIC EXPENSES	LB505	PROFIX	-	-	-	-	-	-	-	-
363	506 MISC. STEAM POWER EXPENSES	LB506	PROFIX	-	-	-	-	-	-	-	-
364	507 RENTS	LB507	PROFIX	-	-	-	-	-	-	-	-
365											
366	Total Steam Power Operation Expenses	LBSUB1		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
367											
368	**Steam Power Generation Maintenance Expenses**										
369	510 MAINTENANCE SUPERVISION & ENGINEERING	LB510	F020	-	-	-	-	-	-	-	-
370	511 MAINTENANCE OF STRUCTURES	LB511	PROFIX	-	-	-	-	-	-	-	-
371	512 MAINTENANCE OF BOILER PLANT	LB512	Energy	-	-	-	-	-	-	-	-
372	513 MAINTENANCE OF ELECTRIC PLANT	LB513	Energy	-	-	-	-	-	-	-	-
373	514 MAINTENANCE OF MISC STEAM PLANT	LB514	Energy	-	-	-	-	-	-	-	-
374											
375	Total Steam Power Generation Maintenance Expense	LBSUB2		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
376											
377	Total Steam Power Generation Expense			$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
378											
379	**Hydraulic Power Generation Operation Expenses**										
380	535 OPERATION SUPERVISION & ENGINEERING	LB535	F021	-	-	-	-	-	-	-	-
381	536 WATER FOR POWER	LB536	PROFIX	-	-	-	-	-	-	-	-
382	537 HYDRAULIC EXPENSES	LB537	PROFIX	-	-	-	-	-	-	-	-
383	538 ELECTRIC EXPENSES	LB538	PROFIX	-	-	-	-	-	-	-	-
384	539 MISC. HYDRAULIC POWER EXPENSES	LB539	PROFIX	-	-	-	-	-	-	-	-
385	540 RENTS	LB540	PROFIX	-	-	-	-	-	-	-	-
386											
387	Total Hydraulic Power Operation Expenses	LBSUB3		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
388											
389	**Hydraulic Power Generation Maintenance Expenses**										
390	541 MAINTENANCE SUPERVISION & ENGINEERING	LB541	F022	-	-	-	-	-	-	-	-
391	542 MAINTENANCE OF STRUCTURES	LB542	PROFIX	-	-	-	-	-	-	-	-
392	543 MAINT. OF RESERVES, DAMS, AND WATERWAYS	LB543	PROFIX	-	-	-	-	-	-	-	-
393	544 MAINTENANCE OF ELECTRIC PLANT	LB544	Energy	-	-	-	-	-	-	-	-
394	545 MAINTENANCE OF MISC HYDRAULIC PLANT	LB545	Energy	-	-	-	-	-	-	-	-
395											
396	Total Hydraulic Power Generation Maint. Expense	LBSUB4		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
397											
398	Total Hydraulic Power Generation Expense			$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
399											
400	**Other Power Generation Operation Expense**										
401	546 OPERATION SUPERVISION & ENGINEERING	LB546	PROFIX	-	-	-	-	-	-	-	-
402	547 FUEL	LB547	Energy	-	-	-	-	-	-	-	-
403	548 GENERATION EXPENSE	LB548	PROFIX	-	-	-	-	-	-	-	-
404	549 MISC OTHER POWER GENERATION	LB549	PROFIX	-	-	-	-	-	-	-	-
405	550 RENTS	LB550	PROFIX	-	-	-	-	-	-	-	-
406											
407	Total Other Power Generation Expenses	LBSUB5		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
408											

KENTUCKY UTILITIES COMPANY
Cost of Service Study
Functional Assignment and Classification
12 Months Ended June 30, 2016

	A	B	C	D	E	X	Y	Z	AA	AB	AC	AD
1												
2				Functional		Distribution Sec. Lines		Distribution Line Trans.		Distribution Services	Distribution Meters	Distribution St. & Cust. Lighting
3	Description		Name	Vector		Demand	Customer	Demand	Customer	Customer		
4												
356	**Labor Expenses**											
357												
358	**Steam Power Generation Operation Expenses**											
359		500 OPERATION SUPERVISION & ENGINEERING	LB500	F019		-	-	-	-	-	-	-
360		501 FUEL	LB501	Energy		-	-	-	-	-	-	-
361		502 STEAM EXPENSES	LB502	PROFIX		-	-	-	-	-	-	-
362		505 ELECTRIC EXPENSES	LB505	PROFIX		-	-	-	-	-	-	-
363		506 MISC. STEAM POWER EXPENSES	LB506	PROFIX		-	-	-	-	-	-	-
364		507 RENTS	LB507	PROFIX		-	-	-	-	-	-	-
365												
366		Total Steam Power Operation Expenses	LBSUB1			$ -	$ -	$ -	$ -	$ -	$ -	$ -
367												
368	**Steam Power Generation Maintenance Expenses**											
369		510 MAINTENANCE SUPERVISION & ENGINEERING	LB510	F020		-	-	-	-	-	-	-
370		511 MAINTENANCE OF STRUCTURES	LB511	PROFIX		-	-	-	-	-	-	-
371		512 MAINTENANCE OF BOILER PLANT	LB512	Energy		-	-	-	-	-	-	-
372		513 MAINTENANCE OF ELECTRIC PLANT	LB513	Energy		-	-	-	-	-	-	-
373		514 MAINTENANCE OF MISC STEAM PLANT	LB514	Energy		-	-	-	-	-	-	-
374												
375		Total Steam Power Generation Maintenance Expense	LBSUB2			$ -	$ -	$ -	$ -	$ -	$ -	$ -
376												
377		Total Steam Power Generation Expense				$ -	$ -	$ -	$ -	$ -	$ -	$ -
378												
379	**Hydraulic Power Generation Operation Expenses**											
380		535 OPERATION SUPERVISION & ENGINEERING	LB535	F021		-	-	-	-	-	-	-
381		536 WATER FOR POWER	LB536	PROFIX		-	-	-	-	-	-	-
382		537 HYDRAULIC EXPENSES	LB537	PROFIX		-	-	-	-	-	-	-
383		538 ELECTRIC EXPENSES	LB538	PROFIX		-	-	-	-	-	-	-
384		539 MISC. HYDRAULIC POWER EXPENSES	LB539	PROFIX		-	-	-	-	-	-	-
385		540 RENTS	LB540	PROFIX		-	-	-	-	-	-	-
386												
387		Total Hydraulic Power Operation Expenses	LBSUB3			$ -	$ -	$ -	$ -	$ -	$ -	$ -
388												
389	**Hydraulic Power Generation Maintenance Expenses**											
390		541 MAINTENANCE SUPERVISION & ENGINEERING	LB541	F022		-	-	-	-	-	-	-
391		542 MAINTENANCE OF STRUCTURES	LB542	PROFIX		-	-	-	-	-	-	-
392		543 MAINT. OF RESERVES, DAMS, AND WATERWAYS	LB543	PROFIX		-	-	-	-	-	-	-
393		544 MAINTENANCE OF ELECTRIC PLANT	LB544	Energy		-	-	-	-	-	-	-
394		545 MAINTENANCE OF MISC HYDRAULIC PLANT	LB545	Energy		-	-	-	-	-	-	-
395												
396		Total Hydraulic Power Generation Maint. Expense	LBSUB4			$ -	$ -	$ -	$ -	$ -	$ -	$ -
397												
398		Total Hydraulic Power Generation Expense				$ -	$ -	$ -	$ -	$ -	$ -	$ -
399												
400	**Other Power Generation Operation Expense**											
401		546 OPERATION SUPERVISION & ENGINEERING	LB546	PROFIX		-	-	-	-	-	-	-
402		547 FUEL	LB547	Energy		-	-	-	-	-	-	-
403		548 GENERATION EXPENSE	LB548	PROFIX		-	-	-	-	-	-	-
404		549 MISC OTHER POWER GENERATION	LB549	PROFIX		-	-	-	-	-	-	-
405		550 RENTS	LB550	PROFIX		-	-	-	-	-	-	-
406												
407		Total Other Power Generation Expenses	LBSUB5			$ -	$ -	$ -	$ -	$ -	$ -	$ -
408												

KENTUCKY UTILITIES COMPANY
Cost of Service Study
Functional Assignment and Classification
12 Months Ended June 30, 2016

	A	B	C	D	E	A	AF	A	AH	A	AJ
1											
2				Functional			Customer Accounts Expense		Customer Service & Info.		Sales Expense
3	Description		Name	Vector							
4											
356	**Labor Expenses**										
357											
358	**Steam Power Generation Operation Expenses**										
359		500 OPERATION SUPERVISION & ENGINEERING	LB500	F019			-		-		-
360		501 FUEL	LB501	Energy			-		-		-
361		502 STEAM EXPENSES	LB502	PROFIX			-		-		-
362		505 ELECTRIC EXPENSES	LB505	PROFIX			-		-		-
363		506 MISC. STEAM POWER EXPENSES	LB506	PROFIX			-		-		-
364		507 RENTS	LB507	PROFIX			-		-		-
365											
366		Total Steam Power Operation Expenses	LBSUB1				$ -		$ -		$ -
367											
368	**Steam Power Generation Maintenance Expenses**										
369		510 MAINTENANCE SUPERVISION & ENGINEERING	LB510	F020			-		-		-
370		511 MAINTENANCE OF STRUCTURES	LB511	PROFIX			-		-		-
371		512 MAINTENANCE OF BOILER PLANT	LB512	Energy			-		-		-
372		513 MAINTENANCE OF ELECTRIC PLANT	LB513	Energy			-		-		-
373		514 MAINTENANCE OF MISC STEAM PLANT	LB514	Energy			-		-		-
374											
375		Total Steam Power Generation Maintenance Expense	LBSUB2				$ -		$ -		$ -
376											
377		Total Steam Power Generation Expense					$ -		$ -		$ -
378											
379	**Hydraulic Power Generation Operation Expenses**										
380		535 OPERATION SUPERVISION & ENGINEERING	LB535	F021			-		-		-
381		536 WATER FOR POWER	LB536	PROFIX			-		-		-
382		537 HYDRAULIC EXPENSES	LB537	PROFIX			-		-		-
383		538 ELECTRIC EXPENSES	LB538	PROFIX			-		-		-
384		539 MISC. HYDRAULIC POWER EXPENSES	LB539	PROFIX			-		-		-
385		540 RENTS	LB540	PROFIX			-		-		-
386											
387		Total Hydraulic Power Operation Expenses	LBSUB3				$ -		$ -		$ -
388											
389	**Hydraulic Power Generation Maintenance Expenses**										
390		541 MAINTENANCE SUPERVISION & ENGINEERING	LB541	F022			-		-		-
391		542 MAINTENANCE OF STRUCTURES	LB542	PROFIX			-		-		-
392		543 MAINT. OF RESERVES, DAMS, AND WATERWAYS	LB543	PROFIX			-		-		-
393		544 MAINTENANCE OF ELECTRIC PLANT	LB544	Energy			-		-		-
394		545 MAINTENANCE OF MISC HYDRAULIC PLANT	LB545	Energy			-		-		-
395											
396		Total Hydraulic Power Generation Maint. Expense	LBSUB4				$ -		$ -		$ -
397											
398		Total Hydraulic Power Generation Expense					$ -		$ -		$ -
399											
400	**Other Power Generation Operation Expense**										
401		546 OPERATION SUPERVISION & ENGINEERING	LB546	PROFIX			-		-		-
402		547 FUEL	LB547	Energy			-		-		-
403		548 GENERATION EXPENSE	LB548	PROFIX			-		-		-
404		549 MISC OTHER POWER GENERATION	LB549	PROFIX			-		-		-
405		550 RENTS	LB550	PROFIX			-		-		-
406											
407		Total Other Power Generation Expenses	LBSUB5				$ -		$ -		$ -
408											

KENTUCKY UTILITIES COMPANY
Cost of Service Study
Functional Assignment and Classification
12 Months Ended June 30, 2016

				Production Demand			Production Energy		
Description	**Name**	**Functional Vector**	**Total System**	**Base**	**Inter.**	**Peak**	**Base**	**Inter.**	**Peak**
Other Power Generation Maintenance Expense									
551 MAINTENANCE SUPERVISION & ENGINEERING	LB551	PROFIX	$ 115,046	39,524	37,258	38,264	-	-	-
552 MAINTENANCE OF STRUCTURES	LB552	PROFIX	6,244	2,145	2,022	2,077	-	-	-
553 MAINTENANCE OF GENERATING & ELEC PLANT	LB553	PROFIX	1,130,949	388,533	366,262	376,153	-	-	-
554 MAINTENANCE OF MISC OTHER POWER GEN PLT	LB554	PROFIX	1,649,441	566,660	534,177	548,604	-	-	-
Total Other Power Generation Maintenance Expense	LBSUB6		$ 2,901,680	$ 996,862	$ 939,719	$ 965,098	$ -	$ -	$ -
Total Other Power Generation Expense			$ 5,156,567	$ 1,771,521	$ 1,669,973	$ 1,715,074	$ -	$ -	$ -
Total Production Expense	LPREX		$ 54,301,886	$ 11,193,654	$ 10,552,009	$ 10,836,986	$ 21,719,237	$ -	$ -
Purchased Power									
555 PURCHASED POWER	LB555	OMPP	$ -	-	-	-	-	-	-
556 SYSTEM CONTROL AND LOAD DISPATCH	LB556	PROFIX	$ 1,407,652	483,594	455,873	468,185	-	-	-
557 OTHER EXPENSES	LB557	PROFIX	$ -	-	-	-	-	-	-
Total Purchased Power Labor	LBPP		$ 1,407,652	$ 483,594	$ 455,873	$ 468,185	$ -	$ -	$ -
Transmission Labor Expenses									
560 OPERATION SUPERVISION AND ENG	LB560	PTRAN	$ 1,429,926	-	-	-	-	-	-
561 LOAD DISPATCHING	LB561	PTRAN	3,103,445	-	-	-	-	-	-
562 STATION EXPENSES	LB562	PTRAN	351,202	-	-	-	-	-	-
563 OVERHEAD LINE EXPENSES	LB563	PTRAN	-	-	-	-	-	-	-
566 MISC. TRANSMISSION EXPENSES	LB566	PTRAN	244,144	-	-	-	-	-	-
568 MAINTENACE SUPERVISION AND ENG	LB568	PTRAN	-	-	-	-	-	-	-
570 MAINT OF STATION EQUIPMENT	LB570	PTRAN	1,045,697	-	-	-	-	-	-
571 MAINT OF OVERHEAD LINES	LB571	PTRAN	199,789	-	-	-	-	-	-
572 UNDERGROUND LINES	LB572	PTRAN	-	-	-	-	-	-	-
573 MISC PLANT	LB573	PTRAN	-	-	-	-	-	-	-
Total Transmission Labor Expenses	LBTRAN		$ 6,374,204	$ -	$ -	$ -	$ -	$ -	$ -
Distribution Operation Labor Expense									
580 OPERATION SUPERVISION AND ENGI	LB580	F023	$ 1,021,954	-	-	-	-	-	-
581 LOAD DISPATCHING	LB581	P362	1,049,353	-	-	-	-	-	-
582 STATION EXPENSES	LB582	P362	955,225	-	-	-	-	-	-
583 OVERHEAD LINE EXPENSES	LB583	P365	1,747,261	-	-	-	-	-	-
584 UNDERGROUND LINE EXPENSES	LB584	P367	-	-	-	-	-	-	-
585 STREET LIGHTING EXPENSE	LB585	P371	-	-	-	-	-	-	-
586 METER EXPENSES	LB586	P370	4,607,579	-	-	-	-	-	-
586 METER EXPENSES - LOAD MANAGEMENT	LB586x	F012	-	-	-	-	-	-	-
587 CUSTOMER INSTALLATIONS EXPENSE	LB587	P371	-	-	-	-	-	-	-
588 MISCELLANEOUS DISTRIBUTION EXP	LB588	PDIST	2,952,952	-	-	-	-	-	-
589 RENTS	LB589	PDIST	-	-	-	-	-	-	-
Total Distribution Operation Labor Expense	LBDO		$ 12,334,325	$ -	$ -	$ -	$ -	$ -	$ -

KENTUCKY UTILITIES COMPANY
Cost of Service Study
Functional Assignment and Classification
12 Months Ended June 30, 2016

	A / B	C	D	O	P	Q	S	T	U	V	W
1											
2			Functional	Transmission Demand			Distribution Poles	Distribution Substation	Distribution Primary Lines		
3	Description	Name	Vector	Base	Winter	Summer	Specific	General	Specific	Demand	Customer
4											
409	**Other Power Generation Maintenance Expense**										
410	551 MAINTENANCE SUPERVISION & ENGINEERING	LB551	PROFIX	-	-	-	-	-	-	-	-
411	552 MAINTENANCE OF STRUCTURES	LB552	PROFIX	-	-	-	-	-	-	-	-
412	553 MAINTENANCE OF GENERATING & ELEC PLANT	LB553	PROFIX	-	-	-	-	-	-	-	-
413	554 MAINTENANCE OF MISC OTHER POWER GEN PLT	LB554	PROFIX	-	-	-	-	-	-	-	-
414											
415	Total Other Power Generation Maintenance Expense	LBSUB6		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
416											
417	Total Other Power Generation Expense			$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
418											
419	Total Production Expense	LPREX		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
420											
421	**Purchased Power**										
422	555 PURCHASED POWER	LB555	OMPP	-	-	-	-	-	-	-	-
423	556 SYSTEM CONTROL AND LOAD DISPATCH	LB556	PROFIX	-	-	-	-	-	-	-	-
424	557 OTHER EXPENSES	LB557	PROFIX	-	-	-	-	-	-	-	-
425											
426	Total Purchased Power Labor	LBPP		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
427											
428	**Transmission Labor Expenses**										
429	560 OPERATION SUPERVISION AND ENG	LB560	PTRAN	500,330	487,554	442,043	-	-	-	-	-
430	561 LOAD DISPATCHING	LB561	PTRAN	1,085,893	1,058,164	959,389	-	-	-	-	-
431	562 STATION EXPENSES	LB562	PTRAN	122,885	119,747	108,569	-	-	-	-	-
432	563 OVERHEAD LINE EXPENSES	LB563	PTRAN	-	-	-	-	-	-	-	-
433	566 MISC. TRANSMISSION EXPENSES	LB566	PTRAN	85,426	83,244	75,474	-	-	-	-	-
434	568 MAINTENACE SUPERVISION AND ENG	LB568	PTRAN	-	-	-	-	-	-	-	-
435	570 MAINT OF STATION EQUIPMENT	LB570	PTRAN	365,889	356,545	323,263	-	-	-	-	-
436	571 MAINT OF OVERHEAD LINES	LB571	PTRAN	69,906	68,121	61,762	-	-	-	-	-
437	572 UNDERGROUND LINES	LB572	PTRAN	-	-	-	-	-	-	-	-
438	573 MISC PLANT	LB573	PTRAN	-	-	-	-	-	-	-	-
439											
440	Total Transmission Labor Expenses	LBTRAN		$ 2,230,329	$ 2,173,375	$ 1,970,500	$ -	$ -	$ -	$ -	$ -
441											
442	**Distribution Operation Labor Expense**										
443	580 OPERATION SUPERVISION AND ENGI	LB580	F023	-	-	-	-	212,159	-	92,753	130,894
444	581 LOAD DISPATCHING	LB581	P362	-	-	-	-	1,049,353	-	-	-
445	582 STATION EXPENSES	LB582	P362	-	-	-	-	955,225	-	-	-
446	583 OVERHEAD LINE EXPENSES	LB583	P365	-	-	-	-	-	-	560,347	750,099
447	584 UNDERGROUND LINE EXPENSES	LB584	P367	-	-	-	-	-	-	-	-
448	585 STREET LIGHTING EXPENSE	LB585	P371	-	-	-	-	-	-	-	-
449	586 METER EXPENSES	LB586	P370	-	-	-	-	-	-	-	-
450	586 METER EXPENSES - LOAD MANAGEMENT	LB586x	F012	-	-	-	-	-	-	-	-
451	587 CUSTOMER INSTALLATIONS EXPENSE	LB587	P371	-	-	-	-	-	-	-	-
452	588 MISCELLANEOUS DISTRIBUTION EXP	LB588	PDIST	-	-	-	-	343,880	-	466,365	698,815
453	589 RENTS	LB589	PDIST	-	-	-	-	-	-	-	-
454											
455	Total Distribution Operation Labor Expense	LBDO		$ -	$ -	$ -	$ -	$ 2,560,616	$ -	$ 1,119,465	$ 1,579,808
456											
457											
458											
459											
460											
461											
462											
463											
464											
465											

KENTUCKY UTILITIES COMPANY
Cost of Service Study
Functional Assignment and Classification
12 Months Ended June 30, 2016

	A / B	C	D	X	Y	Z	AA	AB	AC	AD
1										
2			Functional	Distribution Sec. Lines		Distribution Line Trans.		Distribution Services	Distribution Meters	Distribution St. & Cust. Lighting
3	Description	Name	Vector	Demand	Customer	Demand	Customer	Customer		
4										
409	**Other Power Generation Maintenance Expense**									
410	551 MAINTENANCE SUPERVISION & ENGINEERING	LB551	PROFIX	-	-	-	-	-	-	-
411	552 MAINTENANCE OF STRUCTURES	LB552	PROFIX	-	-	-	-	-	-	-
412	553 MAINTENANCE OF GENERATING & ELEC PLANT	LB553	PROFIX	-	-	-	-	-	-	-
413	554 MAINTENANCE OF MISC OTHER POWER GEN PLT	LB554	PROFIX	-	-	-	-	-	-	-
414										
415	Total Other Power Generation Maintenance Expense	LBSUB6		$ -	$ -	$ -	$ -	$ -	$ -	$ -
416										
417	Total Other Power Generation Expense			$ -	$ -	$ -	$ -	$ -	$ -	$ -
418										
419	Total Production Expense	LPREX		$ -	$ -	$ -	$ -	$ -	$ -	$ -
420										
421	**Purchased Power**									
422	555 PURCHASED POWER	LB555	OMPP	-	-	-	-	-	-	-
423	556 SYSTEM CONTROL AND LOAD DISPATCH	LB556	PROFIX	-	-	-	-	-	-	-
424	557 OTHER EXPENSES	LB557	PROFIX	-	-	-	-	-	-	-
425										
426	Total Purchased Power Labor	LBPP		$ -	$ -	$ -	$ -	$ -	$ -	$ -
427										
428	**Transmission Labor Expenses**									
429	560 OPERATION SUPERVISION AND ENG	LB560	PTRAN	-	-	-	-	-	-	-
430	561 LOAD DISPATCHING	LB561	PTRAN	-	-	-	-	-	-	-
431	562 STATION EXPENSES	LB562	PTRAN	-	-	-	-	-	-	-
432	563 OVERHEAD LINE EXPENSES	LB563	PTRAN	-	-	-	-	-	-	-
433	566 MISC. TRANSMISSION EXPENSES	LB566	PTRAN	-	-	-	-	-	-	-
434	568 MAINTENACE SUPERVISION AND ENG	LB568	PTRAN	-	-	-	-	-	-	-
435	570 MAINT OF STATION EQUIPMENT	LB570	PTRAN	-	-	-	-	-	-	-
436	571 MAINT OF OVERHEAD LINES	LB571	PTRAN	-	-	-	-	-	-	-
437	572 UNDERGROUND LINES	LB572	PTRAN	-	-	-	-	-	-	-
438	573 MISC PLANT	LB573	PTRAN	-	-	-	-	-	-	-
439										
440	Total Transmission Labor Expenses	LBTRAN		$ -	$ -	$ -	$ -	$ -	$ -	$ -
441										
442	**Distribution Operation Labor Expense**									
443	580 OPERATION SUPERVISION AND ENGI	LB580	F023	30,918	43,631	25,717	23,342	14,857	428,353	19,331
444	581 LOAD DISPATCHING	LB581	P362	-	-	-	-	-	-	-
445	582 STATION EXPENSES	LB582	P362	-	-	-	-	-	-	-
446	583 OVERHEAD LINE EXPENSES	LB583	P365	186,782	250,033	-	-	-	-	-
447	584 UNDERGROUND LINE EXPENSES	LB584	P367	-	-	-	-	-	-	-
448	585 STREET LIGHTING EXPENSE	LB585	P371	-	-	-	-	-	-	-
449	586 METER EXPENSES	LB586	P370	-	-	-	-	-	4,607,579	-
450	586 METER EXPENSES - LOAD MANAGEMENT	LB586x	F012	-	-	-	-	-	-	-
451	587 CUSTOMER INSTALLATIONS EXPENSE	LB587	P371	-	-	-	-	-	-	-
452	588 MISCELLANEOUS DISTRIBUTION EXP	LB588	PDIST	155,455	232,938	284,669	258,385	164,461	134,007	213,976
453	589 RENTS	LB589	PDIST	-	-	-	-	-	-	-
454										
455	Total Distribution Operation Labor Expense	LBDO		$ 373,155	$ 526,603	$ 310,386	$ 281,728	$ 179,319	$ 5,169,939	$ 233,307
456										
457										
458										
459										
460										
461										
462										
463										
464										
465										

	A	B	C	D	E	A	AF	A	AH	A	AJ
1											
2				**Functional**			**Customer Accounts Expense**		**Customer Service & Info.**		**Sales Expense**
3	**Description**		**Name**	**Vector**							
4											
409	**Other Power Generation Maintenance Expense**										
410		551 MAINTENANCE SUPERVISION & ENGINEERING	LB551	PROFIX			-		-		-
411		552 MAINTENANCE OF STRUCTURES	LB552	PROFIX			-		-		-
412		553 MAINTENANCE OF GENERATING & ELEC PLANT	LB553	PROFIX			-		-		-
413		554 MAINTENANCE OF MISC OTHER POWER GEN PLT	LB554	PROFIX			-		-		-
414											
415		Total Other Power Generation Maintenance Expense	LBSUB6				$ -		$ -		$ -
416											
417		Total Other Power Generation Expense					$ -		$ -		$ -
418											
419		Total Production Expense	LPREX				$ -		$ -		$ -
420											
421	**Purchased Power**										
422		555 PURCHASED POWER	LB555	OMPP			-		-		-
423		556 SYSTEM CONTROL AND LOAD DISPATCH	LB556	PROFIX			-		-		-
424		557 OTHER EXPENSES	LB557	PROFIX			-		-		-
425											
426		Total Purchased Power Labor	LBPP				$ -		$ -		$ -
427											
428	**Transmission Labor Expenses**										
429		560 OPERATION SUPERVISION AND ENG	LB560	PTRAN			-		-		-
430		561 LOAD DISPATCHING	LB561	PTRAN			-		-		-
431		562 STATION EXPENSES	LB562	PTRAN			-		-		-
432		563 OVERHEAD LINE EXPENSES	LB563	PTRAN			-		-		-
433		566 MISC. TRANSMISSION EXPENSES	LB566	PTRAN			-		-		-
434		568 MAINTENACE SUPERVISION AND ENG	LB568	PTRAN			-		-		-
435		570 MAINT OF STATION EQUIPMENT	LB570	PTRAN			-		-		-
436		571 MAINT OF OVERHEAD LINES	LB571	PTRAN			-		-		-
437		572 UNDERGROUND LINES	LB572	PTRAN			-		-		-
438		573 MISC PLANT	LB573	PTRAN			-		-		-
439											
440	Total Transmission Labor Expenses		LBTRAN				$ -		$ -		$ -
441											
442	**Distribution Operation Labor Expense**										
443		580 OPERATION SUPERVISION AND ENGI	LB580	F023			-		-		-
444		581 LOAD DISPATCHING	LB581	P362			-		-		-
445		582 STATION EXPENSES	LB582	P362			-		-		-
446		583 OVERHEAD LINE EXPENSES	LB583	P365			-		-		-
447		584 UNDERGROUND LINE EXPENSES	LB584	P367			-		-		-
448		585 STREET LIGHTING EXPENSE	LB585	P371			-		-		-
449		586 METER EXPENSES	LB586	P370			-		-		-
450		586 METER EXPENSES - LOAD MANAGEMENT	LB586x	F012			-		-		-
451		587 CUSTOMER INSTALLATIONS EXPENSE	LB587	P371			-		-		-
452		588 MISCELLANEOUS DISTRIBUTION EXP	LB588	PDIST			-		-		-
453		589 RENTS	LB589	PDIST			-		-		-
454											
455	Total Distribution Operation Labor Expense		LBDO				$ -		$ -		$ -
456											
457											
458											
459											
460											
461											
462											
463											
464											
465											

KENTUCKY UTILITIES COMPANY
Cost of Service Study
Functional Assignment and Classification
12 Months Ended June 30, 2016

Row	Description	Name	Functional Vector	Total System	Production Demand Base	Production Demand Inter.	Production Demand Peak	Production Energy Base	Production Energy Inter.	Production Energy Peak
466	**Labor Expenses (Continued)**									
467										
468	**Distribution Maintenance Labor Expense**									
469	590 MAINTENANCE SUPERVISION AND EN	LB590	F024	$ -	-	-	-	-	-	-
470	591 MAINTENANCE OF STRUCTURES	LB591	P362	-	-	-	-	-	-	-
471	592 MAINTENANCE OF STATION EQUIPME	LB592	P362	612,260	-	-	-	-	-	-
472	593 MAINTENANCE OF OVERHEAD LINES	LB593	P365	6,583,747	-	-	-	-	-	-
473	594 MAINTENANCE OF UNDERGROUND LIN	LB594	P367	374,472	-	-	-	-	-	-
474	595 MAINTENANCE OF LINE TRANSFORME	LB595	P368	-	-	-	-	-	-	-
475	596 MAINTENANCE OF ST LIGHTS & SIG SYSTEMS	LB596	P373	-	-	-	-	-	-	-
476	597 MAINTENANCE OF METERS	LB597	P370	-	-	-	-	-	-	-
477	598 MAINTENANCE OF MISC DISTR PLANT	LB598	PDIST	-	-	-	-	-	-	-
478										
479	Total Distribution Maintenance Labor Expense	LBDM		$ 7,570,479	$ -	$ -	$ -	$ -	$ -	$ -
480										
481	Total Distribution Operation and Maintenance Labor Expenses		PDIST	19,904,803	-	-	-	-	-	-
482										
483	Transmission and Distribution Labor Expenses			26,279,008	-	-	-	-	-	-
484										
485	Production, Transmission and Distribution Labor Expenses	LBSUB		$ 81,988,546	$ 11,677,248	$ 11,007,882	$ 11,305,171	$ 21,719,237	$ -	$ -
486										
487	**Customer Accounts Expense**									
488	901 SUPERVISION/CUSTOMER ACCTS	LB901	F025	$ 2,672,053	-	-	-	-	-	-
489	902 METER READING EXPENSES	LB902	F025	536,029	-	-	-	-	-	-
490	903 RECORDS AND COLLECTION	LB903	F025	12,118,614	-	-	-	-	-	-
491	904 UNCOLLECTIBLE ACCOUNTS	LB904	F025	-	-	-	-	-	-	-
492	905 MISC CUST ACCOUNTS	LB903	F025	126,168	-	-	-	-	-	-
493										
494	Total Customer Accounts Labor Expense	LBCA		$ 15,452,864	$ -	$ -	$ -	$ -	$ -	$ -
495										
496	**Customer Service Expense**									
497	907 SUPERVISION	LB907	F026	$ 301,755	-	-	-	-	-	-
498	908 CUSTOMER ASSISTANCE EXPENSES	LB908	F026	1,730,560	-	-	-	-	-	-
499	908 CUSTOMER ASSISTANCE EXP-LOAD MGMT	LB908x	F026	-	-	-	-	-	-	-
500	909 INFORMATIONAL AND INSTRUCTIONA	LB909	F026	-	-	-	-	-	-	-
501	909 INFORM AND INSTRUC -LOAD MGMT	LB909x	F026	-	-	-	-	-	-	-
502	910 MISCELLANEOUS CUSTOMER SERVICE	LB910	F026	-	-	-	-	-	-	-
503	911 DEMONSTRATION AND SELLING EXP	LB911	F026	-	-	-	-	-	-	-
504	912 DEMONSTRATION AND SELLING EXP	LB912	F026	-	-	-	-	-	-	-
505	913 WATER HEATER - HEAT PUMP PROGRAM	LB913	F026	-	-	-	-	-	-	-
506	915 MDSE-JOBBING-CONTRACT	LB915	F026	-	-	-	-	-	-	-
507	916 MISC SALES EXPENSE	LB916	F026		-	-	-	-	-	-
508										
509	Total Customer Service Labor Expense	LBCS		$ 2,032,315	$ -	$ -	$ -	$ -	$ -	$ -
510										
511	Sub-Total Labor Exp	LBSUB7		99,473,725	11,677,248	11,007,882	11,305,171	21,719,237	-	-
512										
513										
514										
515										
516										

KENTUCKY UTILITIES COMPANY
Cost of Service Study
Functional Assignment and Classification
12 Months Ended June 30, 2016

Row	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
466	**Labor Expenses (Continued)**										
467											
468	**Distribution Maintenance Labor Expense**										
469	590 MAINTENANCE SUPERVISION AND EN	LB590	F024	-	-	-	-	-	-	-	-
470	591 MAINTENANCE OF STRUCTURES	LB591	P362	-	-	-	-	-	-	-	-
471	592 MAINTENANCE OF STATION EQUIPME	LB592	P362	-	-	-	-	612,260	-	-	-
472	593 MAINTENANCE OF OVERHEAD LINES	LB593	P365	-	-	-	-	-	-	2,111,408	2,826,403
473	594 MAINTENANCE OF UNDERGROUND LIN	LB594	P367	-	-	-	-	-	-	84,284	196,570
474	595 MAINTENANCE OF LINE TRANSFORME	LB595	P368	-	-	-	-	-	-	-	-
475	596 MAINTENANCE OF ST LIGHTS & SIG SYSTEMS	LB596	P373	-	-	-	-	-	-	-	-
476	597 MAINTENANCE OF METERS	LB597	P370	-	-	-	-	-	-	-	-
477	598 MAINTENANCE OF MISC DISTR PLANT	LB598	PDIST	-	-	-	-	-	-	-	-
478											
479	Total Distribution Maintenance Labor Expense	LBDM		$ -	$ -	$ -	$ -	$ 612,260	$ -	$ 2,195,692	$ 3,022,972
480											
481	Total Distribution Operation and Maintenance Labor Expenses		PDIST	-	-	-	-	2,317,972	-	3,143,602	4,710,464
482											
483	Transmission and Distribution Labor Expenses			2,230,329	2,173,375	1,970,500	-	2,317,972	-	3,143,602	4,710,464
484											
485	Production, Transmission and Distribution Labor Expenses	LBSUB		$ 2,230,329	$ 2,173,375	$ 1,970,500	$ -	$ 2,317,972	$ -	$ 3,143,602	$ 4,710,464
486											
487	**Customer Accounts Expense**										
488	901 SUPERVISION/CUSTOMER ACCTS	LB901	F025	-	-	-	-	-	-	-	-
489	902 METER READING EXPENSES	LB902	F025	-	-	-	-	-	-	-	-
490	903 RECORDS AND COLLECTION	LB903	F025	-	-	-	-	-	-	-	-
491	904 UNCOLLECTIBLE ACCOUNTS	LB904	F025	-	-	-	-	-	-	-	-
492	905 MISC CUST ACCOUNTS	LB903	F025	-	-	-	-	-	-	-	-
493											
494	Total Customer Accounts Labor Expense	LBCA		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
495											
496	**Customer Service Expense**										
497	907 SUPERVISION	LB907	F026	-	-	-	-	-	-	-	-
498	908 CUSTOMER ASSISTANCE EXPENSES	LB908	F026	-	-	-	-	-	-	-	-
499	908 CUSTOMER ASSISTANCE EXP-LOAD MGMT	LB908x	F026	-	-	-	-	-	-	-	-
500	909 INFORMATIONAL AND INSTRUCTIONA	LB909	F026	-	-	-	-	-	-	-	-
501	909 INFORM AND INSTRUC -LOAD MGMT	LB909x	F026	-	-	-	-	-	-	-	-
502	910 MISCELLANEOUS CUSTOMER SERVICE	LB910	F026	-	-	-	-	-	-	-	-
503	911 DEMONSTRATION AND SELLING EXP	LB911	F026	-	-	-	-	-	-	-	-
504	912 DEMONSTRATION AND SELLING EXP	LB912	F026	-	-	-	-	-	-	-	-
505	913 WATER HEATER - HEAT PUMP PROGRAM	LB913	F026	-	-	-	-	-	-	-	-
506	915 MDSE-JOBBING-CONTRACT	LB915	F026	-	-	-	-	-	-	-	-
507	916 MISC SALES EXPENSE	LB916	F026	-	-	-	-	-	-	-	-
508											
509	Total Customer Service Labor Expense	LBCS		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
510											
511	Sub-Total Labor Exp	LBSUB7		2,230,329	2,173,375	1,970,500	-	2,317,972	-	3,143,602	4,710,464
512											
513											
514											
515											
516											

KENTUCKY UTILITIES COMPANY
Cost of Service Study
Functional Assignment and Classification
12 Months Ended June 30, 2016

	A/B	C	D	X	Y	Z	AA	AB	AC	AD
1										
2			Functional	Distribution Sec. Lines		Distribution Line Trans.		Distribution Services	Distribution Meters	Distribution St. & Cust. Lighting
3	Description	Name	Vector	Demand	Customer	Demand	Customer	Customer		
4										
466	**Labor Expenses (Continued)**									
467										
468	**Distribution Maintenance Labor Expense**									
469	590 MAINTENANCE SUPERVISION AND EN	LB590	F024	-	-	-	-	-	-	-
470	591 MAINTENANCE OF STRUCTURES	LB591	P362	-	-	-	-	-	-	-
471	592 MAINTENANCE OF STATION EQUIPME	LB592	P362	-	-	-	-	-	-	-
472	593 MAINTENANCE OF OVERHEAD LINES	LB593	P365	703,803	942,134	-	-	-	-	-
473	594 MAINTENANCE OF UNDERGROUND LIN	LB594	P367	28,095	65,523	-	-	-	-	-
474	595 MAINTENANCE OF LINE TRANSFORME	LB595	P368	-	-	-	-	-	-	-
475	596 MAINTENANCE OF ST LIGHTS & SIG SYSTEMS	LB596	P373	-	-	-	-	-	-	-
476	597 MAINTENANCE OF METERS	LB597	P370	-	-	-	-	-	-	-
477	598 MAINTENANCE OF MISC DISTR PLANT	LB598	PDIST	-	-	-	-	-	-	-
478										
479	Total Distribution Maintenance Labor Expense	LBDM		$ 731,897	$ 1,007,657	$ -	$ -	$ -	$ -	$ -
480										
481	Total Distribution Operation and Maintenance Labor Expenses		PDIST	1,047,867	1,570,155	1,918,854	1,741,684	1,108,575	903,292	1,442,338
482										
483	Transmission and Distribution Labor Expenses			1,047,867	1,570,155	1,918,854	1,741,684	1,108,575	903,292	1,442,338
484										
485	Production, Transmission and Distribution Labor Expenses	LBSUB		$ 1,047,867	$ 1,570,155	$ 1,918,854	$ 1,741,684	$ 1,108,575	$ 903,292	$ 1,442,338
486										
487	**Customer Accounts Expense**									
488	901 SUPERVISION/CUSTOMER ACCTS	LB901	F025	-	-	-	-	-	-	-
489	902 METER READING EXPENSES	LB902	F025	-	-	-	-	-	-	-
490	903 RECORDS AND COLLECTION	LB903	F025	-	-	-	-	-	-	-
491	904 UNCOLLECTIBLE ACCOUNTS	LB904	F025	-	-	-	-	-	-	-
492	905 MISC CUST ACCOUNTS	LB903	F025	-	-	-	-	-	-	-
493										
494	Total Customer Accounts Labor Expense	LBCA		$ -	$ -	$ -	$ -	$ -	$ -	$ -
495										
496	**Customer Service Expense**									
497	907 SUPERVISION	LB907	F026	-	-	-	-	-	-	-
498	908 CUSTOMER ASSISTANCE EXPENSES	LB908	F026	-	-	-	-	-	-	-
499	908 CUSTOMER ASSISTANCE EXP-LOAD MGMT	LB908x	F026	-	-	-	-	-	-	-
500	909 INFORMATIONAL AND INSTRUCTIONA	LB909	F026	-	-	-	-	-	-	-
501	909 INFORM AND INSTRUC -LOAD MGMT	LB909x	F026	-	-	-	-	-	-	-
502	910 MISCELLANEOUS CUSTOMER SERVICE	LB910	F026	-	-	-	-	-	-	-
503	911 DEMONSTRATION AND SELLING EXP	LB911	F026	-	-	-	-	-	-	-
504	912 DEMONSTRATION AND SELLING EXP	LB912	F026	-	-	-	-	-	-	-
505	913 WATER HEATER - HEAT PUMP PROGRAM	LB913	F026	-	-	-	-	-	-	-
506	915 MDSE-JOBBING-CONTRACT	LB915	F026	-	-	-	-	-	-	-
507	916 MISC SALES EXPENSE	LB916	F026	-	-	-	-	-	-	-
508										
509	Total Customer Service Labor Expense	LBCS		$ -	$ -	$ -	$ -	$ -	$ -	$ -
510										
511	Sub-Total Labor Exp	LBSUB7		1,047,867	1,570,155	1,918,854	1,741,684	1,108,575	903,292	1,442,338
512										
513										
514										
515										
516										

	A	B	C	D	AF	AH	AJ
1							
2				Functional	Customer Accounts Expense	Customer Service & Info.	Sales Expense
3	Description		Name	Vector			
4							
466	**Labor Expenses (Continued)**						
467							
468	**Distribution Maintenance Labor Expense**						
469	590	MAINTENANCE SUPERVISION AND EN	LB590	F024	-	-	-
470	591	MAINTENANCE OF STRUCTURES	LB591	P362	-	-	-
471	592	MAINTENANCE OF STATION EQUIPME	LB592	P362	-	-	-
472	593	MAINTENANCE OF OVERHEAD LINES	LB593	P365	-	-	-
473	594	MAINTENANCE OF UNDERGROUND LIN	LB594	P367	-	-	-
474	595	MAINTENANCE OF LINE TRANSFORME	LB595	P368	-	-	-
475	596	MAINTENANCE OF ST LIGHTS & SIG SYSTEMS	LB596	P373	-	-	-
476	597	MAINTENANCE OF METERS	LB597	P370	-	-	-
477	598	MAINTENANCE OF MISC DISTR PLANT	LB598	PDIST	-	-	-
478							
479	Total Distribution Maintenance Labor Expense		LBDM		$ -	$ -	$ -
480							
481	Total Distribution Operation and Maintenance Labor Expenses			PDIST	-	-	-
482							
483	Transmission and Distribution Labor Expenses				-	-	-
484							
485	Production, Transmission and Distribution Labor Expenses		LBSUB		$ -	$ -	$ -
486							
487	**Customer Accounts Expense**						
488	901	SUPERVISION/CUSTOMER ACCTS	LB901	F025	2,672,053	-	-
489	902	METER READING EXPENSES	LB902	F025	536,029	-	-
490	903	RECORDS AND COLLECTION	LB903	F025	12,118,614	-	-
491	904	UNCOLLECTIBLE ACCOUNTS	LB904	F025	-	-	-
492	905	MISC CUST ACCOUNTS	LB903	F025	126,168	-	-
493							
494	Total Customer Accounts Labor Expense		LBCA		$ 15,452,864	$ -	$ -
495							
496	**Customer Service Expense**						
497	907	SUPERVISION	LB907	F026	-	301,755	-
498	908	CUSTOMER ASSISTANCE EXPENSES	LB908	F026	-	1,730,560	-
499	908	CUSTOMER ASSISTANCE EXP-LOAD MGMT	LB908x	F026	-	-	-
500	909	INFORMATIONAL AND INSTRUCTIONA	LB909	F026	-	-	-
501	909	INFORM AND INSTRUC -LOAD MGMT	LB909x	F026	-	-	-
502	910	MISCELLANEOUS CUSTOMER SERVICE	LB910	F026	-	-	-
503	911	DEMONSTRATION AND SELLING EXP	LB911	F026	-	-	-
504	912	DEMONSTRATION AND SELLING EXP	LB912	F026	-	-	-
505	913	WATER HEATER - HEAT PUMP PROGRAM	LB913	F026	-	-	-
506	915	MDSE-JOBBING-CONTRACT	LB915	F026	-	-	-
507	916	MISC SALES EXPENSE	LB916	F026	-	-	-
508							
509	Total Customer Service Labor Expense		LBCS		$ -	$ 2,032,315	$ -
510							
511	Sub-Total Labor Exp		LBSUB7		15,452,864	2,032,315	-
512							
513							
514							
515							
516							

KENTUCKY UTILITIES COMPANY
Cost of Service Study
Functional Assignment and Classification
12 Months Ended June 30, 2016

	A	B	C	D	E	F	G	H	I	J	K	L	M
1													
2				Functional		Total		Production Demand			Production Energy		
3	Description		Name	Vector		System		Base	Inter.	Peak	Base	Inter.	Peak
4													
517	**Labor Expenses (Continued)**												
518													
519	**Administrative and General Expense**												
520	920	ADMIN. & GEN. SALARIES-	LB920	LBSUB7	$	34,247,082		4,020,274	3,789,823	3,892,175	7,477,557	-	-
521	921	OFFICE SUPPLIES AND EXPENSES	LB921	LBSUB7		-		-	-	-	-	-	-
522	922	ADMIN. EXPENSES TRANSFERRED - CREDIT	LB922	LBSUB7		(3,651,854)		(428,692)	(404,119)	(415,033)	(797,351)	-	-
523	923	OUTSIDE SERVICES EMPLOYED	LB923	LBSUB7		-		-	-	-	-	-	-
524	924	PROPERTY INSURANCE	LB924	TUP		-		-	-	-	-	-	-
525	925	INJURIES AND DAMAGES - INSURAN	LB925	LBSUB7		587,360		68,950	64,998	66,753	128,245	-	-
526	926	EMPLOYEE BENEFITS	LB926	LBSUB7		46,032,729		5,403,795	5,094,037	5,231,611	10,050,853	-	-
527	928	REGULATORY COMMISSION FEES	LB928	TUP		-		-	-	-	-	-	-
528	929	DUPLICATE CHARGES-CR	LB929	LBSUB7		-		-	-	-	-	-	-
529	930	MISCELLANEOUS GENERAL EXPENSES	LB930	LBSUB7		-		-	-	-	-	-	-
530	931	RENTS AND LEASES	LB931	PGP		-		-	-	-	-	-	-
531	932	MAINTENANCE OF GENERAL PLANT	LB932	PGP		-		-	-	-	-	-	-
532	935	MAINTENANCE OF GENERAL PLANT	LB935	PGP		743,420		163,750	159,568	144,673	-	-	-
533													
534	Total Administrative and General Expense		LBAG		$	77,958,736	$	9,228,077	$ 8,704,308	$ 8,920,180	$ 16,859,304	$ -	$ -
535													
536	Total Operation and Maintenance Expenses		TLB		$	177,432,461	$	20,905,325	$ 19,712,190	$ 20,225,351	$ 38,578,541	$ -	$ -
537													
538	Operation and Maintenance Expenses Less Purchase Power		LBLPP		$	177,432,461	$	20,905,325	$ 19,712,190	$ 20,225,351	$ 38,578,541	$ -	$ -
539													
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KENTUCKY UTILITIES COMPANY
Cost of Service Study
Functional Assignment and Classification
12 Months Ended June 30, 2016

	A / B	C	D	O	P	Q	S	T	U	V	W
1											
2			**Functional**	**Transmission Demand**			**Distribution Poles**	**Distribution Substation**	**Distribution Primary Lines**		
3	**Description**	**Name**	**Vector**	**Base**	**Winter**	**Summer**	**Specific**	**General**	**Specific**	**Demand**	**Customer**
4											
517	**Labor Expenses (Continued)**										
518											
519	**Administrative and General Expense**										
520	920 ADMIN. & GEN. SALARIES-	LB920	LBSUB7	767,864	748,255	678,409	-	798,037	-	1,082,288	1,621,731
521	921 OFFICE SUPPLIES AND EXPENSES	LB921	LBSUB7	-	-	-	-	-	-	-	-
522	922 ADMIN. EXPENSES TRANSFERRED - CREDIT	LB922	LBSUB7	(81,879)	(79,788)	(72,340)	-	(85,097)	-	(115,407)	(172,929)
523	923 OUTSIDE SERVICES EMPLOYED	LB923	LBSUB7	-	-	-	-	-	-	-	-
524	924 PROPERTY INSURANCE	LB924	TUP	-	-	-	-	-	-	-	-
525	925 INJURIES AND DAMAGES - INSURAN	LB925	LBSUB7	13,169	12,833	11,635	-	13,687	-	18,562	27,814
526	926 EMPLOYEE BENEFITS	LB926	LBSUB7	1,032,113	1,005,757	911,874	-	1,072,671	-	1,454,742	2,179,827
527	928 REGULATORY COMMISSION FEES	LB928	TUP	-	-	-	-	-	-	-	-
528	929 DUPLICATE CHARGES-CR	LB929	LBSUB7	-	-	-	-	-	-	-	-
529	930 MISCELLANEOUS GENERAL EXPENSES	LB930	LBSUB7	-	-	-	-	-	-	-	-
530	931 RENTS AND LEASES	LB931	PGP	-	-	-	-	-	-	-	-
531	932 MAINTENANCE OF GENERAL PLANT	LB932	PGP	-	-	-	-	-	-	-	-
532	935 MAINTENANCE OF GENERAL PLANT	LB935	PGP	30,689	29,905	27,114	-	21,861	-	29,647	44,424
533											
534	Total Administrative and General Expense	LBAG		$ 1,761,956	$ 1,716,963	$ 1,556,692	$ -	$ 1,821,159	$ -	$ 2,469,832	$ 3,700,866
535											
536	Total Operation and Maintenance Expenses	TLB		$ 3,992,284	$ 3,890,338	$ 3,527,192	$ -	$ 4,139,130	$ -	$ 5,613,434	$ 8,411,330
537											
538	Operation and Maintenance Expenses Less Purchase Power	LBLPP		$ 3,992,284	$ 3,890,338	$ 3,527,192	$ -	$ 4,139,130	$ -	$ 5,613,434	$ 8,411,330
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KENTUCKY UTILITIES COMPANY
Cost of Service Study
Functional Assignment and Classification
12 Months Ended June 30, 2016

	A/B	C	D	X	Y	Z	AA	AB	AC	AD
1										
2			Functional	Distribution Sec. Lines		Distribution Line Trans.		Distribution Services	Distribution Meters	Distribution St. & Cust. Lighting
3	Description	Name	Vector	Demand	Customer	Demand	Customer	Customer		
4										
517	**Labor Expenses (Continued)**									
518										
519	**Administrative and General Expense**									
520	920 ADMIN. & GEN. SALARIES-	LB920	LBSUB7	360,763	540,577	660,628	599,632	381,663	310,988	496,572
521	921 OFFICE SUPPLIES AND EXPENSES	LB921	LBSUB7	-	-	-	-	-	-	-
522	922 ADMIN. EXPENSES TRANSFERRED - CREDIT	LB922	LBSUB7	(38,469)	(57,643)	(70,444)	(63,940)	(40,698)	(33,161)	(52,951)
523	923 OUTSIDE SERVICES EMPLOYED	LB923	LBSUB7	-	-	-	-	-	-	-
524	924 PROPERTY INSURANCE	LB924	TUP	-	-	-	-	-	-	-
525	925 INJURIES AND DAMAGES - INSURAN	LB925	LBSUB7	6,187	9,271	11,330	10,284	6,546	5,334	8,517
526	926 EMPLOYEE BENEFITS	LB926	LBSUB7	484,914	726,609	887,974	805,986	513,007	418,010	667,460
527	928 REGULATORY COMMISSION FEES	LB928	TUP	-	-	-	-	-	-	-
528	929 DUPLICATE CHARGES-CR	LB929	LBSUB7	-	-	-	-	-	-	-
529	930 MISCELLANEOUS GENERAL EXPENSES	LB930	LBSUB7	-	-	-	-	-	-	-
530	931 RENTS AND LEASES	LB931	PGP	-	-	-	-	-	-	-
531	932 MAINTENANCE OF GENERAL PLANT	LB932	PGP	-	-	-	-	-	-	-
532	935 MAINTENANCE OF GENERAL PLANT	LB935	PGP	9,882	14,808	18,097	16,426	10,455	8,519	13,603
533										
534	Total Administrative and General Expense	LBAG		$ 823,277	$ 1,233,622	$ 1,507,585	$ 1,368,387	$ 870,973	$ 709,689	$ 1,133,201
535										
536	Total Operation and Maintenance Expenses	TLB		$ 1,871,145	$ 2,803,777	$ 3,426,439	$ 3,110,071	$ 1,979,548	$ 1,612,981	$ 2,575,539
537										
538	Operation and Maintenance Expenses Less Purchase Power	LBLPP		$ 1,871,145	$ 2,803,777	$ 3,426,439	$ 3,110,071	$ 1,979,548	$ 1,612,981	$ 2,575,539
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2			Functional	Customer Accounts Expense	Customer Service & Info.	Sales Expense
3	**Description**	**Name**	**Vector**			
4						
517	**Labor Expenses (Continued)**					
518						
519	**Administrative and General Expense**					
520	920 ADMIN. & GEN. SALARIES-	LB920	LBSUB7	5,320,154	699,691	-
521	921 OFFICE SUPPLIES AND EXPENSES	LB921	LBSUB7	-	-	-
522	922 ADMIN. EXPENSES TRANSFERRED - CREDIT	LB922	LBSUB7	(567,302)	(74,610)	-
523	923 OUTSIDE SERVICES EMPLOYED	LB923	LBSUB7	-	-	-
524	924 PROPERTY INSURANCE	LB924	TUP	-	-	-
525	925 INJURIES AND DAMAGES - INSURAN	LB925	LBSUB7	91,244	12,000	-
526	926 EMPLOYEE BENEFITS	LB926	LBSUB7	7,151,009	940,480	-
527	928 REGULATORY COMMISSION FEES	LB928	TUP	-	-	-
528	929 DUPLICATE CHARGES-CR	LB929	LBSUB7	-	-	-
529	930 MISCELLANEOUS GENERAL EXPENSES	LB930	LBSUB7	-	-	-
530	931 RENTS AND LEASES	LB931	PGP	-	-	-
531	932 MAINTENANCE OF GENERAL PLANT	LB932	PGP	-	-	-
532	935 MAINTENANCE OF GENERAL PLANT	LB935	PGP	-	-	-
533						
534	Total Administrative and General Expense	LBAG		$ 11,995,105	$ 1,577,561	$ -
535						
536	Total Operation and Maintenance Expenses	TLB		$ 27,447,969	$ 3,609,876	$ -
537						
538	Operation and Maintenance Expenses Less Purchase Power	LBLPP		$ 27,447,969	$ 3,609,876	$ -
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KENTUCKY UTILITIES COMPANY
Cost of Service Study
Functional Assignment and Classification
12 Months Ended June 30, 2016

	A / B	C	D	F	H	I	J	K	L	M
1										
2			**Functional**	**Total**	**Production Demand**			**Production Energy**		
3	**Description**	**Name**	**Vector**	**System**	**Base**	**Inter.**	**Peak**	**Base**	**Inter.**	**Peak**
4										
564	**Other Expenses**									
565										
566	**Depreciation Expenses**									
567	Steam Production	DEPRTP	PPRTL	$ 79,831,194	27,932,868	27,219,577	24,678,749	-	-	-
568	Hydraulic Production	DEPRDP1	PPRTL	997,114	348,889	339,980	308,244	-	-	-
569	Other Production	DEPRDP2	PPRTL	30,443,972	10,652,320	10,380,304	9,411,348	-	-	-
570	Transmission - Kentucky System Property	DEPRDP3	PTRAN	13,615,578	-	-	-	-	-	-
571	Transmission - Virginia Property	DEPRDP4	PTRAN	147,666	-	-	-	-	-	-
572	Distribution	DEPRDP5	PDIST	41,822,295	-	-	-	-	-	-
573	General Plant	DEPRDP6	PGP	11,985,263	2,639,942	2,572,528	2,332,394	-	-	-
574	Intangible Plant	DEPRAADJ	PINT	10,917,298	2,404,706	2,343,299	2,124,563	-	-	-
575										
576	Total Depreciation Expense	TDEPR		$ 189,760,380	43,978,725	42,855,688	38,855,299	-	-	-
577										
578	**Regulatory Credits and Accretion Expenses**									
579	Production Plant	ACRTPP	PPRTL	$ -	-	-	-	-	-	-
580	Transmission Plant	ACRTTP	PTRAN	-	-	-	-	-	-	-
581	Distribution Plant		PDIST	-	-	-	-	-	-	-
582										
583	Total Regulatory Credits and Accretion Expenses	TACRT		$ -	$ -	$ -	$ -	$ -	$ -	$ -
584										
585	Property Taxes	PTAX	TUP	$ 22,812,447	5,028,231	4,899,831	4,442,453	-	-	-
586										
587	Other Taxes	OTAX	TUP	$ 12,214,063	2,692,176	2,623,429	2,378,544	-	-	-
588										
589	Gain Disposition of Allowances	GAIN	F013	$ -	-	-	-	-	-	-
590										
591	Interest	INTLTD	TUP	$ 83,539,684	18,413,493	17,943,288	16,268,361	-	-	-
592										
593	Other Expenses	OT	TUP	$ -	-	-	-	-	-	-
594										
595	**Total Other Expenses**	TOE		$ 308,326,574	$ 70,112,626	$ 68,322,236	$ 61,944,656	$ -	$ -	$ -
596										
597	**Total Cost of Service (O&M + Other Expenses)**			$ 1,265,479,185	$ 111,030,119	$ 107,048,512	$ 101,147,628	$ 672,379,424	$ -	$ -
598										
599										
600	**Non-Operating Items**									
601	Non-Operating Margins - Interest			-						
602	AFUDC			-						
603	Income (Loss) from Equity Investments			-						
604	Non-Operating Margins - Other			-						
605	Generation and Transmission Capital Credits			-						
606	Other Capital Credits and Patronage Dividends			-						
607	Extraordinary Items			-						
608										
609	Long Term Debt Service Requirements			-						
610										

KENTUCKY UTILITIES COMPANY
Cost of Service Study
Functional Assignment and Classification
12 Months Ended June 30, 2016

	A	B	C	D	O	P	Q	S	T	U	V	W
1												
2				Functional	Transmission Demand			Distribution Poles	Distribution Substation	Distribution Primary Lines		
3	Description		Name	Vector	Base	Winter	Summer	Specific	General	Specific	Demand	Customer
4												
564	**Other Expenses**											
565												
566	**Depreciation Expenses**											
567	Steam Production		DEPRTP	PPRTL	-	-	-	-	-	-	-	-
568	Hydraulic Production		DEPRDP1	PPRTL	-	-	-	-	-	-	-	-
569	Other Production		DEPRDP2	PPRTL	-	-	-	-	-	-	-	-
570	Transmission - Kentucky System Property		DEPRDP3	PTRAN	4,764,079	4,642,424	4,209,074	-	-	-	-	-
571	Transmission - Virginia Property		DEPRDP4	PTRAN	51,668	50,349	45,649	-	-	-	-	-
572	Distribution		DEPRDP5	PDIST	-	-	-	-	4,870,326	-	6,605,073	9,897,229
573	General Plant		DEPRDP6	PGP	494,763	482,128	437,124	-	352,431	-	477,962	716,193
574	Intangible Plant		DEPRAADJ	PINT	450,676	439,168	398,173	-	321,027	-	435,373	652,375
575												
576	Total Depreciation Expense		TDEPR		5,761,186	5,614,069	5,090,020	-	5,543,785	-	7,518,408	11,265,797
577												
578	**Regulatory Credits and Accretion Expenses**											
579	Production Plant		ACRTPP	PPRTL	-	-	-	-	-	-	-	-
580	Transmission Plant		ACRTTP	PTRAN	-	-	-	-	-	-	-	-
581	Distribution Plant			PDIST	-	-	-	-	-	-	-	-
582												
583	Total Regulatory Credits and Accretion Expenses		TACRT		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
584												
585	Property Taxes		PTAX	TUP	945,810	921,658	835,625	-	668,304	-	906,346	1,358,094
586												
587	Other Taxes		OTAX	TUP	506,398	493,467	447,404	-	357,818	-	485,269	727,140
588												
589	Gain Disposition of Allowances		GAIN	F013	-	-	-	-	-	-	-	-
590												
591	Interest		INTLTD	TUP	3,463,576	3,375,131	3,060,077	-	2,447,345	-	3,319,058	4,973,370
592												
593	Other Expenses		OT	TUP	-	-	-	-	-	-	-	-
594												
595	**Total Other Expenses**		TOE		$ 10,676,971	$ 10,404,324	$ 9,433,126	$ -	$ 9,017,253	$ -	$ 12,229,079	$ 18,324,401
596												
597	**Total Cost of Service (O&M + Other Expenses)**				$ 22,813,157	$ 22,230,602	$ 20,155,474	$ -	$ 16,703,277	$ -	$ 28,083,611	$ 40,473,147
598												
599												
600	**Non-Operating Items**											
601	Non-Operating Margins - Interest											
602	AFUDC											
603	Income (Loss) from Equity Investments											
604	Non-Operating Margins - Other											
605	Generation and Transmission Capital Credits											
606	Other Capital Credits and Patronage Dividends											
607	Extraordinary Items											
608												
609	Long Term Debt Service Requirements											
610												

KENTUCKY UTILITIES COMPANY
Cost of Service Study
Functional Assignment and Classification
12 Months Ended June 30, 2016

	A / B	C	D	X	Y	Z	AA	AB	AC	AD
1										
2			Functional	Distribution Sec. Lines		Distribution Line Trans.		Distribution Services	Distribution Meters	Distribution St. & Cust. Lighting
3	Description	Name	Vector	Demand	Customer	Demand	Customer	Customer		
4										
564	**Other Expenses**									
565										
566	**Depreciation Expenses**									
567	Steam Production	DEPRTP	PPRTL	-	-	-	-	-	-	-
568	Hydraulic Production	DEPRDP1	PPRTL	-	-	-	-	-	-	-
569	Other Production	DEPRDP2	PPRTL	-	-	-	-	-	-	-
570	Transmission - Kentucky System Property	DEPRDP3	PTRAN	-	-	-	-	-	-	-
571	Transmission - Virginia Property	DEPRDP4	PTRAN	-	-	-	-	-	-	-
572	Distribution	DEPRDP5	PDIST	2,201,691	3,299,076	4,031,734	3,659,480	2,329,244	1,897,922	3,030,520
573	General Plant	DEPRDP6	PGP	159,321	238,731	291,748	264,811	168,551	137,339	219,297
574	Intangible Plant	DEPRAADJ	PINT	145,124	217,458	265,751	241,214	153,532	125,101	199,756
575										
576	Total Depreciation Expense	TDEPR		2,506,136	3,755,266	4,589,234	4,165,505	2,651,327	2,160,362	3,449,574
577										
578	**Regulatory Credits and Accretion Expenses**									
579	Production Plant	ACRTPP	PPRTL	-	-	-	-	-	-	-
580	Transmission Plant	ACRTTP	PTRAN	-	-	-	-	-	-	-
581	Distribution Plant		PDIST	-	-	-	-	-	-	-
582										
583	Total Regulatory Credits and Accretion Expenses	TACRT		$ -	$ -	$ -	$ -	$ -	$ -	$ -
584										
585	Property Taxes	PTAX	TUP	302,115	452,698	553,233	502,152	319,618	260,432	415,847
586										
587	Other Taxes	OTAX	TUP	161,756	242,380	296,208	268,859	171,127	139,439	222,649
588										
589	Gain Disposition of Allowances	GAIN	F013	-	-	-	-	-	-	-
590										
591	Interest	INTLTD	TUP	1,106,353	1,657,790	2,025,952	1,838,893	1,170,448	953,708	1,522,840
592										
593	Other Expenses	OT	TUP	-	-	-	-	-	-	-
594										
595	**Total Other Expenses**	TOE		$ 4,076,360	$ 6,108,134	$ 7,464,627	$ 6,775,409	$ 4,312,521	$ 3,513,941	$ 5,610,910
596										
597	**Total Cost of Service (O&M + Other Expenses)**			$ 9,361,204	$ 13,491,049	$ 10,423,943	$ 9,461,488	$ 5,992,189	$ 13,183,662	$ 7,689,706
598										
599										
600	**Non-Operating Items**									
601	Non-Operating Margins - Interest									
602	AFUDC									
603	Income (Loss) from Equity Investments									
604	Non-Operating Margins - Other									
605	Generation and Transmission Capital Credits									
606	Other Capital Credits and Patronage Dividends									
607	Extraordinary Items									
608										
609	Long Term Debt Service Requirements									
610										

	A	B	C	D	AF	AH	AJ
1							
2				Functional	Customer Accounts Expense	Customer Service & Info.	Sales Expense
3	**Description**		**Name**	**Vector**			
4							
564	**Other Expenses**						
565							
566	**Depreciation Expenses**						
567	Steam Production		DEPRTP	PPRTL	-	-	-
568	Hydraulic Production		DEPRDP1	PPRTL	-	-	-
569	Other Production		DEPRDP2	PPRTL	-	-	-
570	Transmission - Kentucky System Property		DEPRDP3	PTRAN	-	-	-
571	Transmission - Virginia Property		DEPRDP4	PTRAN	-	-	-
572	Distribution		DEPRDP5	PDIST	-	-	-
573	General Plant		DEPRDP6	PGP	-	-	-
574	Intangible Plant		DEPRAADJ	PINT	-	-	-
575							
576	Total Depreciation Expense		TDEPR		-	-	-
577							
578	**Regulatory Credits and Accretion Expenses**						
579	Production Plant		ACRTPP	PPRTL	-	-	-
580	Transmission Plant		ACRTTP	PTRAN	-	-	-
581	Distribution Plant			PDIST	-	-	-
582							
583	Total Regulatory Credits and Accretion Expenses		TACRT		$ -	$ -	$ -
584							
585	Property Taxes		PTAX	TUP	-	-	-
586							
587	Other Taxes		OTAX	TUP	-	-	-
588							
589	Gain Disposition of Allowances		GAIN	F013	-	-	-
590							
591	Interest		INTLTD	TUP	-	-	-
592							
593	Other Expenses		OT	TUP	-	-	-
594							
595	**Total Other Expenses**		TOE		$ -	$ -	$ -
596							
597	**Total Cost of Service (O&M + Other Expenses)**				$ 49,341,663	$ 4,469,330	$ -
598							
599							
600	**Non-Operating Items**						
601	Non-Operating Margins - Interest						
602	AFUDC						
603	Income (Loss) from Equity Investments						
604	Non-Operating Margins - Other						
605	Generation and Transmission Capital Credits						
606	Other Capital Credits and Patronage Dividends						
607	Extraordinary Items						
608							
609	Long Term Debt Service Requirements						
610							

KENTUCKY UTILITIES COMPANY
Cost of Service Study
Functional Assignment and Classification
12 Months Ended June 30, 2016

	A	B	C	D	E	F	G	H	I	J	K	L	M
1													
2				**Functional**		**Total**		**Production Demand**			**Production Energy**		
3	**Description**		**Name**	**Vector**		**System**		**Base**	**Inter.**	**Peak**	**Base**	**Inter.**	**Peak**
4													
611	**Functional Vectors**												
612													
613	Station Equipment		F001			1.000000		0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
614	Poles, Towers and Fixtures		F002			1.000000		0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
615	Overhead Conductors and Devices		F003			1.000000		0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
616	Underground Conductors and Devices		F004			1.000000		0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
617	Line Transformers		F005			1.000000		0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
618	Services		F006			1.000000		0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
619	Meters		F007			1.000000		0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
620	Street Lighting		F008			1.000000		0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
621	Meter Reading		F009			1.000000		0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
622	Billing		F010			1.000000		0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
623	Transmission		F011			1.000000		0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
624	Load Management		F012			1.000000		0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
625	Production Plant		F017			1.000000		0.349899	0.340964	0.309137	0.000000	0.000000	0.000000
626	Provar		PROVAR			1.000000		0.000000	0.000000	0.000000	1.000000	0.000000	0.000000
627	Fuel		F018			1.000000		0.000000	0.000000	0.000000	1.000000	0.000000	0.000000
628	Steam Generation Operation Labor		F019			20,711,898		6,195,111.51	5,839,994	5,997,714	2,679,078	-	-
629	PROFIX		PROFIX			1.000000		0.343546	0.323854	0.332600	0.000000	0.000000	0.000000
630	Steam Generation Maintenance Labor		F020			12,829,446		267,627	252,286	259,100	12,050,433	-	-
631	Hydraulic Generation Operation Labor		F021			-		-	-	-	-	-	-
632	Hydraulic Generation Maintenance Labor		F022			49,648		17,056	16,079	16,513	-	-	-
633	Distribution Operation Labor		F023			11,312,370		-	-	-	-	-	-
634	Distribution Maintenance Labor		F024			7,570,479		-	-	-	-	-	-
635	Customer Accounts Expense		F025			1.000000		0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
636	Customer Service Expense		F026			1.000000		0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
637	Customer Advances		F027			847,786,327		-	-	-	-	-	-
638													
639	Purchase Power Demand			F017		7,051,986		2,467,484	2,404,475	2,180,028	-	-	-
640	Purchase Power Energy			F018		61,361,618		-	-	-	61,361,618	-	-
641	**Purchased Power Expenses**		OMPP	F017		68,413,605		2,467,484	2,404,475	2,180,028	61,361,618	-	-
642													
643	Gain Disposition of Allowances		F013			1.00000		-	-	-	1.000000	-	-
644	Intallations on Customer Premises - Accum Depr		F014			1.00000		-	-	-	-	-	-
645	Generators -Energy		F015			1.000000		0.000000	0.000000	0.000000	0.000000	0.000000	1.000000
646			Energy			1.000000		0.000000	0.000000	0.000000	1.000000	0.000000	0.000000
647	**Internally Generated Functional Vectors**												
648	Total Prod, Trans, and Dist Plant			PT&D		1.000000		0.220266	0.214641	0.194605	-	-	-
649	Total Distribution Plant			PDIST		1.000000		-	-	-	-	-	-
650	Total Transmission Plant			PTRAN		1.000000		-	-	-	-	-	-
651	Operation and Maintenance Expenses Less Purchase Power			OMLPP		1.000000		0.043264	0.040869	0.041658	0.687511	-	-
652	Total Plant in Service			TPIS		1.000000		0.220255	0.214630	0.194596	-	-	-
653	Total Operation and Maintenance Expenses (Labor)			TLB		1.000000		0.117821	0.111097	0.113989	0.217427	-	-
654	Sub-Total Prod, Trans, Dist, Cust Acct and Cust Service			OMSUB2		1.000000		0.030428	0.028778	0.029208	0.776561	-	-
655	Total Steam Power Operation Expenses (Labor)			LBSUB1		1.000000		0.299109	0.281963	0.289578	0.129350	-	-
656	Total Steam Power Generation Maintenance Expense (Labor)			LBSUB2		1.000000		0.020860	0.019665	0.020196	0.939279	-	-
657	Total Hydraulic Power Operation Expenses (Labor)			LBSUB3		1.000000		#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!
658	Total Hydraulic Power Generation Maint. Expense (Labor)			LBSUB4		1.000000		0.343546	0.323854	0.332600	-	-	-
659	Total Other Power Generation Expenses (Labor)			LBSUB5		1.000000		0.343546	0.323854	0.332600	-	-	-
660	Total Transmission Labor Expenses			LBTRAN		1.000000		-	-	-	-	-	-
661	Total Distribution Operation Labor Expense			LBDO		1.000000		-	-	-	-	-	-
662	Total Distribution Maintenance Labor Expense			LBDM		1.000000		-	-	-	-	-	-
663	Sub-Total Labor Exp			LBSUB7		1.000000		0.117390	0.110661	0.113650	0.218341	-	-
664	Total General Plant			PGP		1.000000		0.220266	0.214641	0.194605	-	-	-
665	Total Production Plant			PPRTL		1.000000		0.349899	0.340964	0.309137	-	-	-
666	Total Intangible Plant			PINT		1.000000		0.220266	0.214641	0.194605	-	-	-
667													

				Transmission Demand			Distribution Poles	Distribution Substation	Distribution Primary Lines		
	Description	Name	Functional Vector	Base	Winter	Summer	Specific	General	Specific	Demand	Customer
611	**Functional Vectors**										
612											
613	Station Equipment	F001		0.000000	0.000000	0.000000	0.000000	1.000000	0.000000	0.000000	0.000000
614	Poles, Towers and Fixtures	F002		0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.320700	0.429300
615	Overhead Conductors and Devices	F003		0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.320700	0.429300
616	Underground Conductors and Devices	F004		0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.225075	0.524925
617	Line Transformers	F005		0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
618	Services	F006		0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
619	Meters	F007		0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
620	Street Lighting	F008		0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
621	Meter Reading	F009		0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
622	Billing	F010		0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
623	Transmission	F011		0.349899	0.340964	0.309137	0.000000	0.000000	0.000000	0.000000	0.000000
624	Load Management	F012		0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
625	Production Plant	F017		0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
626	Provar	PROVAR		0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
627	Fuel	F018		0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
628	Steam Generation Operation Labor	F019		-	-	-	-	-	-	-	-
629	PROFIX	PROFIX		0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
630	Steam Generation Maintenance Labor	F020		-	-	-	-	-	-	-	-
631	Hydraulic Generation Operation Labor	F021		-	-	-	-	-	-	-	-
632	Hydraulic Generation Maintenance Labor	F022		-	-	-	-	-	-	-	-
633	Distribution Operation Labor	F023		-	-	-	-	2,348,457	-	1,026,712	1,448,914
634	Distribution Maintenance Labor	F024		-	-	-	-	612,260	-	2,195,692	3,022,972
635	Customer Accounts Expense	F025		0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
636	Customer Service Expense	F026		0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
637	Customer Advances	F027		-	-	-	-	-	-	254,495,873	381,343,872
638											
639	Purchase Power Demand		F017	-	-	-	-	-	-	-	-
640	Purchase Power Energy		F018	-	-	-	-	-	-	-	-
641	**Purchased Power Expenses**	OMPP	F017	-	-	-	-	-	-	-	-
642											
643	Gain Disposition of Allowances	F013		-	-	-	-	-	-	-	-
644	Intallations on Customer Premises - Accum Depr	F014		-	-	-	-	-	-	-	-
645	Generators -Energy	F015		0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
646		Energy		0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
647	**Internally Generated Functional Vectors**										
648	Total Prod, Trans, and Dist Plant		PT&D	0.041281	0.040227	0.036472	-	0.029405	-	0.039879	0.059756
649	Total Distribution Plant		PDIST	-	-	-	-	0.116453	-	0.157932	0.236650
650	Total Transmission Plant		PTRAN	0.349899	0.340964	0.309137	-	-	-	-	-
651	Operation and Maintenance Expenses Less Purchase Power		OMLPP	0.013656	0.013307	0.012065	-	0.008648	-	0.017839	0.024922
652	Total Plant in Service		TPIS	0.041279	0.040225	0.036470	-	0.029410	-	0.039885	0.059765
653	Total Operation and Maintenance Expenses (Labor)		TLB	0.022500	0.021926	0.019879	-	0.023328	-	0.031637	0.047406
654	Sub-Total Prod, Trans, Dist, Cust Acct and Cust Service		OMSUB2	0.011000	0.010719	0.009718	-	0.005704	-	0.014245	0.019418
655	Total Steam Power Operation Expenses (Labor)		LBSUB1	-	-	-	-	-	-	-	-
656	Total Steam Power Generation Maintenance Expense (Labor)		LBSUB2	-	-	-	-	-	-	-	-
657	Total Hydraulic Power Operation Expenses (Labor)		LBSUB3	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!
658	Total Hydraulic Power Generation Maint. Expense (Labor)		LBSUB4	-	-	-	-	-	-	-	-
659	Total Other Power Generation Expenses (Labor)		LBSUB5	-	-	-	-	-	-	-	-
660	Total Transmission Labor Expenses		LBTRAN	0.3498992	0.3409642	0.3091367	-	-	-	-	-
661	Total Distribution Operation Labor Expense		LBDO	-	-	-	-	0.207601	-	0.090760	0.128082
662	Total Distribution Maintenance Labor Expense		LBDM	-	-	-	-	0.080875	-	0.290033	0.399311
663	Sub-Total Labor Exp		LBSUB7	0.022421	0.021849	0.019809	-	0.023302	-	0.031602	0.047354
664	Total General Plant		PGP	0.041281	0.040227	0.036472	-	0.029405	-	0.039879	0.059756
665	Total Production Plant		PPRTL	-	-	-	-	-	-	-	-
666	Total Intangible Plant		PINT	0.041281	0.040227	0.036472	-	0.029405	-	0.039879	0.059756
667											

KENTUCKY UTILITIES COMPANY
Cost of Service Study
Functional Assignment and Classification
12 Months Ended June 30, 2016

	A / B	C	D	X	Y	Z	AA	AB	AC	AD
1										
2			Functional	Distribution Sec. Lines		Distribution Line Trans.		Distribution Services	Distribution Meters	Distribution St. & Cust. Lighting
3	Description	Name	Vector	Demand	Customer	Demand	Customer	Customer		
4										
611	**Functional Vectors**									
612										
613	Station Equipment	F001		0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
614	Poles, Towers and Fixtures	F002		0.106900	0.143100	0.000000	0.000000	0.000000	0.000000	0.000000
615	Overhead Conductors and Devices	F003		0.106900	0.143100	0.000000	0.000000	0.000000	0.000000	0.000000
616	Underground Conductors and Devices	F004		0.075025	0.174975	0.000000	0.000000	0.000000	0.000000	0.000000
617	Line Transformers	F005		0.000000	0.000000	0.524200	0.475800	0.000000	0.000000	0.000000
618	Services	F006		0.000000	0.000000	0.000000	0.000000	1.000000	0.000000	0.000000
619	Meters	F007		0.000000	0.000000	0.000000	0.000000	0.000000	1.000000	0.000000
620	Street Lighting	F008		0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	1.000000
621	Meter Reading	F009		0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
622	Billing	F010		0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
623	Transmission	F011		0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
624	Load Management	F012		0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
625	Production Plant	F017		0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
626	Provar	PROVAR		0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
627	Fuel	F018		0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
628	Steam Generation Operation Labor	F019		-	-	-	-	-	-	-
629	PROFIX	PROFIX		0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
630	Steam Generation Maintenance Labor	F020		-	-	-	-	-	-	-
631	Hydraulic Generation Operation Labor	F021		-	-	-	-	-	-	-
632	Hydraulic Generation Maintenance Labor	F022		-	-	-	-	-	-	-
633	Distribution Operation Labor	F023		342,237	482,971	284,669	258,385	164,461	4,741,586	213,976
634	Distribution Maintenance Labor	F024		731,897	1,007,657	-	-	-	-	-
635	Customer Accounts Expense	F025		0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
636	Customer Service Expense	F026		0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
637	Customer Advances	F027		84,831,958	127,114,624	-	-	-	-	-
638										
639	Purchase Power Demand		F017	-	-	-	-	-	-	-
640	Purchase Power Energy		F018	-	-	-	-	-	-	-
641	**Purchased Power Expenses**	OMPP	F017	-	-	-	-	-	-	-
642										
643	Gain Disposition of Allowances	F013		-	-	-	-	-	-	-
644	Intallations on Customer Premises - Accum Depr	F014		-	-	-	-	-	-	-
645	Generators -Energy	F015		0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
646		Energy		0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
647	**Internally Generated Functional Vectors**									
648	Total Prod, Trans, and Dist Plant		PT&D	0.013293	0.019919	0.024342	0.022095	0.014063	0.011459	0.018297
649	Total Distribution Plant		PDIST	0.052644	0.078883	0.096402	0.087501	0.055694	0.045381	0.072462
650	Total Transmission Plant		PTRAN	-	-	-	-	-	-	-
651	Operation and Maintenance Expenses Less Purchase Power		OMLPP	0.005946	0.008307	0.003330	0.003022	0.001890	0.010880	0.002339
652	Total Plant in Service		TPIS	0.013295	0.019922	0.024346	0.022098	0.014065	0.011461	0.018300
653	Total Operation and Maintenance Expenses (Labor)		TLB	0.010546	0.015802	0.019311	0.017528	0.011157	0.009091	0.014516
654	Sub-Total Prod, Trans, Dist, Cust Acct and Cust Service		OMSUB2	0.004748	0.006473	0.000643	0.000584	0.000336	0.010222	0.000309
655	Total Steam Power Operation Expenses (Labor)		LBSUB1	-	-	-	-	-	-	-
656	Total Steam Power Generation Maintenance Expense (Labor)		LBSUB2	-	-	-	-	-	-	-
657	Total Hydraulic Power Operation Expenses (Labor)		LBSUB3	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!
658	Total Hydraulic Power Generation Maint. Expense (Labor)		LBSUB4	-	-	-	-	-	-	-
659	Total Other Power Generation Expenses (Labor)		LBSUB5	-	-	-	-	-	-	-
660	Total Transmission Labor Expenses		LBTRAN	-	-	-	-	-	-	-
661	Total Distribution Operation Labor Expense		LBDO	0.030253	0.042694	0.025164	0.022841	0.014538	0.419151	0.018915
662	Total Distribution Maintenance Labor Expense		LBDM	0.096678	0.133104	-	-	-	-	-
663	Sub-Total Labor Exp		LBSUB7	0.010534	0.015785	0.019290	0.017509	0.011144	0.009081	0.014500
664	Total General Plant		PGP	0.013293	0.019919	0.024342	0.022095	0.014063	0.011459	0.018297
665	Total Production Plant		PPRTL	-	-	-	-	-	-	-
666	Total Intangible Plant		PINT	0.013293	0.019919	0.024342	0.022095	0.014063	0.011459	0.018297
667										

	A / B	C	D	AF	AH	AJ
1						
2			Functional	Customer Accounts Expense	Customer Service & Info.	Sales Expense
3	Description	Name	Vector			
4						
611	**Functional Vectors**					
612						
613	Station Equipment	F001		0.000000	0.000000	0.000000
614	Poles, Towers and Fixtures	F002		0.000000	0.000000	0.000000
615	Overhead Conductors and Devices	F003		0.000000	0.000000	0.000000
616	Underground Conductors and Devices	F004		0.000000	0.000000	0.000000
617	Line Transformers	F005		0.000000	0.000000	0.000000
618	Services	F006		0.000000	0.000000	0.000000
619	Meters	F007		0.000000	0.000000	0.000000
620	Street Lighting	F008		0.000000	0.000000	0.000000
621	Meter Reading	F009		0.000000	1.000000	0.000000
622	Billing	F010		0.000000	1.000000	0.000000
623	Transmission	F011		0.000000	0.000000	0.000000
624	Load Management	F012		0.000000	0.000000	1.000000
625	Production Plant	F017		0.000000	0.000000	0.000000
626	Provar	PROVAR		0.000000	0.000000	0.000000
627	Fuel	F018		0.000000	0.000000	0.000000
628	Steam Generation Operation Labor	F019		-	-	-
629	PROFIX	PROFIX		0.000000	0.000000	0.000000
630	Steam Generation Maintenance Labor	F020		-	-	-
631	Hydraulic Generation Operation Labor	F021		-	-	-
632	Hydraulic Generation Maintenance Labor	F022		-	-	-
633	Distribution Operation Labor	F023		-	-	-
634	Distribution Maintenance Labor	F024		-	-	-
635	Customer Accounts Expense	F025		1.000000	0.000000	0.000000
636	Customer Service Expense	F026		0.000000	1.000000	0.000000
637	Customer Advances	F027		-	-	-
638						
639	Purchase Power Demand		F017	-	-	-
640	Purchase Power Energy		F018	-	-	-
641	**Purchased Power Expenses**	OMPP	F017	-	-	-
642						
643	Gain Disposition of Allowances	F013		-	-	-
644	Intallations on Customer Premises - Accum Depr	F014		1.00000	-	-
645	Generators -Energy	F015		0.000000	0.000000	0.000000
646		Energy		0.000000	0.000000	0.000000
647	**Internally Generated Functional Vectors**					
648	Total Prod, Trans, and Dist Plant		PT&D	-	-	-
649	Total Distribution Plant		PDIST	-	-	-
650	Total Transmission Plant		PTRAN	-	-	-
651	Operation and Maintenance Expenses Less Purchase Power		OMLPP	0.055519	0.005029	-
652	Total Plant in Service		TPIS	-	-	-
653	Total Operation and Maintenance Expenses (Labor)		TLB	0.154695	0.020345	-
654	Sub-Total Prod, Trans, Dist, Cust Acct and Cust Service		OMSUB2	0.038291	0.002615	-
655	Total Steam Power Operation Expenses (Labor)		LBSUB1	-	-	-
656	Total Steam Power Generation Maintenance Expense (Labor)		LBSUB2	-	-	-
657	Total Hydraulic Power Operation Expenses (Labor)		LBSUB3	#DIV/0!	#DIV/0!	#DIV/0!
658	Total Hydraulic Power Generation Maint. Expense (Labor)		LBSUB4	-	-	-
659	Total Other Power Generation Expenses (Labor)		LBSUB5	-	-	-
660	Total Transmission Labor Expenses		LBTRAN	-	-	-
661	Total Distribution Operation Labor Expense		LBDO	-	-	-
662	Total Distribution Maintenance Labor Expense		LBDM	-	-	-
663	Sub-Total Labor Exp		LBSUB7	0.155346	0.020431	-
664	Total General Plant		PGP	-	-	-
665	Total Production Plant		PPRTL	-	-	-
666	Total Intangible Plant		PINT	-	-	-
667						

Exhibit MJB-9

Electric Cost of Service Study - Allocation to Customer Classes

KENTUCKY UTILITIES COMPANY
Cost of Service Study
Class Allocation
12 Months Ended June 30, 2016

	A	B	C	D	E	F	G	H	J	L	M
1				1	2	3	4	5	7	9	10
2					**Allocation**	**Total**	**Residential**	**General Service**	**All Electric Schools**	**Power Service**	**Power Service**
3	**Description**		**Ref**	**Name**	**Vector**	**System**	**Rate RS**	**GS**	**AES**	**PS-Secondary**	**PS-Primary**
4											
5	**Plant in Service**										
6											
7	**Power Production Plant**										
8	Production Demand - Base		TPIS	PLPPDB	PPBDA	$ 1,462,831,894	$ 484,029,433	$ 148,821,023	$ 11,849,356	$ 164,746,196	$ 18,128,686
9	Production Demand - Inter.		TPIS	PLPPDI	PPWDA	1,425,477,143	751,934,791	104,205,397	11,811,472	115,144,693	16,200,676
10	Production Demand - Peak		TPIS	PLPPDP	PPSDA	1,292,415,133	527,351,024	156,141,036	11,550,497	144,344,333	18,891,667
11	Production Energy - Base		TPIS	PLPPEB	E01	-	-	-	-	-	-
12	Production Energy - Inter.		TPIS	PLPPEI	E01	-	-	-	-	-	-
13	Production Energy - Peak		TPIS	PLPPEP	E01	-	-	-	-	-	-
14	Total Power Production Plant			PLPPT		$ 4,180,724,171	$ 1,763,315,249	$ 409,167,455	$ 35,211,324	$ 424,235,222	$ 53,221,029
15							42.2%	9.8%	0.8%	10.1%	1.3%
16	**Transmission Plant**										
17	Transmission Demand - Base		TPIS	PLTRB	PPBDA	$ 274,155,492	$ 90,713,997	$ 27,891,175	$ 2,220,738	$ 30,875,779	$ 3,397,574
18	Transmission Demand - Inter.		TPIS	PLTRI	PPWDA	267,154,681	140,923,269	19,529,573	2,213,638	21,579,752	3,036,237
19	Transmission Demand - Peak		TPIS	PLTRP	PPSDA	242,216,969	98,833,079	29,263,050	2,164,727	27,052,180	3,540,567
20	Total Transmission Plant			PLTRT		$ 783,527,142	$ 330,470,345	$ 76,683,798	$ 6,599,103	$ 79,507,711	$ 9,974,377
21											
22	**Distribution Poles**										
23	Specific		TPIS	PLDPS	NCP	$ -	$ -	$ -	$ -	$ -	$ -
24											
25	**Distribution Substation**										
26	General		TPIS	PLDSG	NCP	$ 195,325,175	$ 93,139,450	$ 24,599,933	$ 2,594,076	$ 20,873,191	$ 2,688,715
27											
28	**Distribution Primary & Secondary Lines**										
29	Primary Specific		TPIS	PLDPLS	NCP	$ -	$ -	$ -	$ -	$ -	$ -
30	Primary Demand		TPIS	PLDPLD	NCP	264,897,424	126,314,493	33,362,104	3,518,051	28,307,946	3,646,399
31	Primary Customer		TPIS	PLDPLC	Cust08	396,929,854	317,807,405	60,632,821	468,196	3,438,358	146,219
32	Secondary Demand		TPIS	PLDSLD	SICD	88,299,141	69,761,314	16,688,720	1,194,060	-	-
33	Secondary Customer		TPIS	PLDSLC	Cust07	132,309,951	107,046,302	20,422,807	157,701	-	-
34	Total Distribution Primary & Secondary Lines			PLDLT		$ 882,436,371	$ 620,929,515	$ 131,106,452	$ 5,338,008	$ 31,746,304	$ 3,792,618
35											
36	**Distribution Line Transformers**										
37	Demand		TPIS	PLDLTD	SICDT	$ 161,693,311	$ 106,441,290	$ 25,463,524	$ 1,821,888	$ 16,533,993	$ -
38	Customer		TPIS	PLDLTC	Cust09	146,763,978	117,607,739	22,437,768	173,260	1,272,398	-
39	Total Line Transformers			PLDLTT		$ 308,457,289	$ 224,049,029	$ 47,901,292	$ 1,995,149	$ 17,806,391	$ -
40											
41	**Distribution Services**										
42	Customer		TPIS	PLDSC	C02	$ 93,414,691	$ 51,797,276	$ 39,883,240	$ 173,076	$ 1,433,799	$ -
43											
44	**Distribution Meters**										
45	Customer		TPIS	PLDMC	C03	$ 76,116,435	$ 45,800,086	$ 19,985,396	$ 208,756	$ 4,681,006	$ 1,158,360
46											
47	**Distribution Street & Customer Lighting**										
48	Customer		TPIS	PLDSCL	C04	$ 121,539,460	$ -	$ -	$ -	$ -	$ -
49											
50	**Customer Accounts Expense**										
51	Customer		TPIS	PLCAE	C05	$ -	$ -	$ -	$ -	$ -	$ -
52											
53	**Customer Service & Info.**										
54	Customer		TPIS	PLCSI	C05	$ -	$ -	$ -	$ -	$ -	$ -
55											
56	**Sales Expense**										
57	Customer		TPIS	PLSEC	C06	$ -	$ -	$ -	$ -	$ -	$ -
58											
59	Total			PLT		$ 6,641,540,734	$ 3,129,500,950	$ 749,327,565	$ 52,119,492	$ 580,283,625	$ 70,835,099
60											
61											
62											

KENTUCKY UTILITIES COMPANY
Cost of Service Study
Class Allocation
12 Months Ended June 30, 2016

	A / B	C	D	E	N	O	P	Q	R	S	T
1			1	2	11	12	13	14	15	16	17
2				**Allocation**	**Time of Day**	**Time of Day**	**Service**	**Service**	**Outdoor Lighting**	**Lighting Energy**	**Traffic Energy**
3	**Description**	**Ref**	**Name**	**Vector**	**TOD-Secondary**	**TOD-Primary**	**RTS**	**FLS - Transmission**	**ST & POL**	**LE**	**TE**
4											
5	**Plant in Service**										
6											
7	**Power Production Plant**										
8	Production Demand - Base	TPIS	PLPPDB	PPBDA	$ 125,666,869	$ 327,323,729	$ 119,782,558	$ 41,836,310	$ 20,516,132	$ 34,652	$ 96,951
9	Production Demand - Inter.	TPIS	PLPPDI	PPWDA	74,703,449	215,629,181	86,680,498	37,343,146	11,739,256	19,151	65,433
10	Production Demand - Peak	TPIS	PLPPDP	PPSDA	95,779,376	236,710,486	87,132,293	14,462,609	-	-	51,813
11	Production Energy - Base	TPIS	PLPPEB	E01	-	-	-	-	-	-	-
12	Production Energy - Inter.	TPIS	PLPPEI	E01	-	-	-	-	-	-	-
13	Production Energy - Peak	TPIS	PLPPEP	E01	-	-	-	-	-	-	-
14	Total Power Production Plant		PLPPT		$ 296,149,693	$ 779,663,396	$ 293,595,349	$ 93,642,066	$ 32,255,388	$ 53,803	$ 214,197
15					7.1%						
16	**Transmission Plant**										
17	Transmission Demand - Base	TPIS	PLTRB	PPBDA	$ 23,551,758	$ 61,345,120	$ 22,448,954	$ 7,840,719	$ 3,845,015	$ 6,494	$ 18,170
18	Transmission Demand - Inter.	TPIS	PLTRI	PPWDA	14,000,488	40,411,974	16,245,158	6,998,637	2,200,103	3,589	12,263
19	Transmission Demand - Peak	TPIS	PLTRP	PPSDA	17,950,417	44,362,910	16,329,830	2,710,499	-	-	9,710
20	Total Transmission Plant		PLTRT		$ 55,502,663	$ 146,120,004	$ 55,023,942	$ 17,549,854	$ 6,045,118	$ 10,083	$ 40,144
21											
22	**Distribution Poles**										
23	Specific	TPIS	PLDPS	NCP	$ -	$ -	$ -	$ -	$ -	$ -	$ -
24											
25	**Distribution Substation**										
26	General	TPIS	PLDSG	NCP	$ 13,408,961	$ 36,384,976	$ -	$ -	$ 1,625,612	$ 2,324	$ 7,939
27											
28	**Distribution Primary & Secondary Lines**										
29	Primary Specific	TPIS	PLDPLS	NCP	$ -	$ -	$ -	$ -	$ -	$ -	$ -
30	Primary Demand	TPIS	PLDPLD	NCP	18,185,055	49,344,824	-	-	2,204,633	3,151	10,767
31	Primary Customer	TPIS	PLDPLC	Cust08	344,870	188,312	-	-	13,842,215	164	61,294
32	Secondary Demand	TPIS	PLDSLD	SICD	-	-	-	-	650,937	930	3,179
33	Secondary Customer	TPIS	PLDSLC	Cust07	-	-	-	-	4,662,440	55	20,645
34	Total Distribution Primary & Secondary Lines		PLDLT		$ 18,529,925	$ 49,533,136	$ -	$ -	$ 21,360,226	$ 4,301	$ 95,885
35											
36	**Distribution Line Transformers**										
37	Demand	TPIS	PLDLTD	SICDT	$ 10,433,151	$ -	$ -	$ -	$ 993,195	$ 1,420	$ 4,850
38	Customer	TPIS	PLDLTC	Cust09	127,622	-	-	-	5,122,447	61	22,682
39	Total Line Transformers		PLDLTT		$ 10,560,773	$ -	$ -	$ -	$ 6,115,642	$ 1,480	$ 27,533
40											
41	**Distribution Services**										
42	Customer	TPIS	PLDSC	C02	$ 127,300	$ -	$ -	$ -	$ -	$ -	$ -
43											
44	**Distribution Meters**										
45	Customer	TPIS	PLDMC	C03	$ 612,425	$ 1,969,516	$ 1,559,187	$ 61,991	$ -	$ 213	$ 79,499
46											
47	**Distribution Street & Customer Lighting**										
48	Customer	TPIS	PLDSCL	C04	$ -	$ -	$ -	$ -	$ 121,539,460	$ -	$ -
49											
50	**Customer Accounts Expense**										
51	Customer	TPIS	PLCAE	C05	$ -	$ -	$ -	$ -	$ -	$ -	$ -
52											
53	**Customer Service & Info.**										
54	Customer	TPIS	PLCSI	C05	$ -	$ -	$ -	$ -	$ -	$ -	$ -
55											
56	**Sales Expense**										
57	Customer	TPIS	PLSEC	C06	$ -	$ -	$ -	$ -	$ -	$ -	$ -
58											
59	Total		PLT		$ 394,891,739	$ 1,013,671,028	$ 350,178,478	$ 111,253,911	$ 188,941,446	$ 72,204	$ 465,197
60											
61											
62											

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	A / B	C	D	E	F	G	H	J	L	M
1			1	2	3	4	5	7	9	10
2				**Allocation**	**Total**	**Residential**	**General Service**	**All Electric Schools**	**Power Service**	**Power Service**
3	**Description**	**Ref**	**Name**	**Vector**	**System**	**Rate RS**	**GS**	**AES**	**PS-Secondary**	**PS-Primary**
63	**Net Utility Plant**									
64										
65	**Power Production Plant**									
66	Production Demand - Base	NTPLANT	UPPPDB	PPBDA	$ 927,677,671	$ 306,954,818	$ 94,377,174	$ 7,514,454	$ 104,476,371	$ 11,496,589
67	Production Demand - Inter.	NTPLANT	UPPPDI	PPWDA	903,988,572	476,851,180	66,083,478	7,490,429	73,020,804	10,273,911
68	Production Demand - Peak	NTPLANT	UPPPDP	PPSDA	819,605,222	334,427,880	99,019,274	7,324,928	91,538,211	11,980,445
69	Production Energy - Base	NTPLANT	UPPPEB	E01	-	-	-	-	-	-
70	Production Energy - Inter.	NTPLANT	UPPPEI	E01	-	-	-	-	-	-
71	Production Energy - Peak	NTPLANT	UPPPEP	E01	-	-	-	-	-	-
72	Total Power Production Plant		UPPPT		$ 2,651,271,465	$ 1,118,233,878	$ 259,479,926	$ 22,329,810	$ 269,035,386	$ 33,750,946
73										
74	**Transmission Plant**									
75	Transmission Demand - Base	NTPLANT	UPTRB	PPBDA	$ 167,322,903	$ 55,364,673	$ 17,022,575	$ 1,355,363	$ 18,844,142	$ 2,073,611
76	Transmission Demand - Inter.	NTPLANT	UPTRI	PPWDA	163,050,160	86,008,456	11,919,312	1,351,030	13,170,580	1,853,080
77	Transmission Demand - Peak	NTPLANT	UPTRP	PPSDA	147,830,146	60,319,921	17,859,859	1,321,179	16,510,518	2,160,883
78	Total Transmission Plant		UPTRT		$ 478,203,210	$ 201,693,051	$ 46,801,746	$ 4,027,572	$ 48,525,240	$ 6,087,574
79										
80	**Distribution Poles**									
81	Specific	NTPLANT	UPDPS	NCP	$ -	$ -	$ -	$ -	$ -	$ -
82										
83	**Distribution Substation**									
84	General	NTPLANT	UPDSG	NCP	$ 121,120,043	$ 57,755,250	$ 15,254,280	$ 1,608,572	$ 12,943,348	$ 1,667,257
85										
86	**Distribution Primary & Secondary Lines**									
87	Primary Specific	NTPLANT	UPDPLS	NCP	$ -	$ -	$ -	$ -	$ -	$ -
88	Primary Demand	NTPLANT	UPDPLD	NCP	164,261,404	78,326,907	20,687,653	2,181,524	17,553,598	2,261,112
89	Primary Customer	NTPLANT	UPDPLC	Cust08	246,133,971	197,070,586	37,598,071	290,326	2,132,107	90,669
90	Secondary Demand	NTPLANT	UPDSLD	SICD	54,753,801	43,258,599	10,348,581	740,430	-	-
91	Secondary Customer	NTPLANT	UPDSLC	Cust07	82,044,657	66,378,810	12,664,068	97,790	-	-
92	Total Distribution Primary & Secondary Lines		UPDLT		$ 547,193,834	$ 385,034,902	$ 81,298,374	$ 3,310,069	$ 19,685,705	$ 2,351,781
93										
94	**Distribution Line Transformers**									
95	Demand	NTPLANT	UPDLTD	SICDT	$ 100,265,113	$ 66,003,646	$ 15,789,788	$ 1,129,743	$ 10,252,636	$ -
96	Customer	NTPLANT	UPDLTC	Cust09	91,007,518	72,927,898	13,913,534	107,438	789,007	-
97	Total Line Transformers		UPDLTT		$ 191,272,631	$ 138,931,543	$ 29,703,322	$ 1,237,181	$ 11,041,643	$ -
98										
99	**Distribution Services**									
100	Customer	NTPLANT	UPDSC	C02	$ 57,925,925	$ 32,119,200	$ 24,731,373	$ 107,323	$ 889,091	$ -
101										
102	**Distribution Meters**									
103	Customer	NTPLANT	UPDMC	C03	$ 47,199,373	$ 28,400,376	$ 12,392,832	$ 129,449	$ 2,902,666	$ 718,292
104										
105	**Distribution Street & Customer Lighting**									
106	Customer	NTPLANT	UPDSCL	C04	$ 75,365,936	$ -	$ -	$ -	$ -	$ -
107										
108	**Customer Accounts Expense**									
109	Customer	NTPLANT	UPCAE	C05	$ -	$ -	$ -	$ -	$ -	$ -
110										
111	**Customer Service & Info.**									
112	Customer	NTPLANT	UPCSI	C05	$ -	$ -	$ -	$ -	$ -	$ -
113										
114	**Sales Expense**									
115	Customer	NTPLANT	UPSEC	C06	$ -	$ -	$ -	$ -	$ -	$ -
116										
117	Total		UPT		$ 4,169,552,417	$ 1,962,168,200	$ 469,661,852	$ 32,749,976	$ 365,023,078	$ 44,575,850
118										
119										

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	A / B	C	D	E	N	O	P	Q	R	S	T
1			1	2	11	12	13	14	15	16	17
2				**Allocation**	**Time of Day**	**Time of Day**	**Service**	**Service**	**Outdoor Lighting**	**Lighting Energy**	**Traffic Energy**
3	**Description**	**Ref**	**Name**	**Vector**	**TOD-Secondary**	**TOD-Primary**	**RTS**	**FLS - Transmission**	**ST & POL**	**LE**	**TE**
63	**Net Utility Plant**										
64											
65	**Power Production Plant**										
66	Production Demand - Base	NTPLANT	UPPPDB	PPBDA	$ 79,693,606	$ 207,577,450	$ 75,961,978	$ 26,531,149	$ 13,010,625	$ 21,975	$ 61,483
67	Production Demand - Inter.	NTPLANT	UPPPDI	PPWDA	47,374,358	136,744,609	54,969,791	23,681,739	7,444,632	12,145	41,495
68	Production Demand - Peak	NTPLANT	UPPPDP	PPSDA	60,739,986	150,113,648	55,256,303	9,171,689	-	-	32,858
69	Production Energy - Base	NTPLANT	UPPPEB	E01	-	-	-	-	-	-	-
70	Production Energy - Inter.	NTPLANT	UPPPEI	E01	-	-	-	-	-	-	-
71	Production Energy - Peak	NTPLANT	UPPPEP	E01	-	-	-	-	-	-	-
72	Total Power Production Plant		UPPPT		$ 187,807,949	$ 494,435,708	$ 186,188,072	$ 59,384,577	$ 20,455,257	$ 34,120	$ 135,837
73											
74	**Transmission Plant**										
75	Transmission Demand - Base	NTPLANT	UPTRB	PPBDA	$ 14,374,136	$ 37,440,226	$ 13,701,072	$ 4,785,357	$ 2,346,694	$ 3,964	$ 11,090
76	Transmission Demand - Inter.	NTPLANT	UPTRI	PPWDA	8,544,795	24,664,284	9,914,764	4,271,416	1,342,770	2,191	7,484
77	Transmission Demand - Peak	NTPLANT	UPTRP	PPSDA	10,955,519	27,075,624	9,966,441	1,654,275	-	-	5,927
78	Total Transmission Plant		UPTRT		$ 33,874,450	$ 89,180,133	$ 33,582,277	$ 10,711,048	$ 3,689,464	$ 6,154	$ 24,501
79											
80	**Distribution Poles**										
81	Specific	NTPLANT	UPDPS	NCP	$ -	$ -	$ -	$ -	$ -	$ -	$ -
82											
83	**Distribution Substation**										
84	General	NTPLANT	UPDSG	NCP	$ 8,314,821	$ 22,562,119	$ -	$ -	$ 1,008,033	$ 1,441	$ 4,923
85											
86	**Distribution Primary & Secondary Lines**										
87	Primary Specific	NTPLANT	UPDPLS	NCP	$ -	$ -	$ -	$ -	$ -	$ -	$ -
88	Primary Demand	NTPLANT	UPDPLD	NCP	11,276,451	30,598,448	-	-	1,367,081	1,954	6,676
89	Primary Customer	NTPLANT	UPDPLC	Cust08	213,852	116,771	-	-	8,583,480	102	38,008
90	Secondary Demand	NTPLANT	UPDSLD	SICD	-	-	-	-	403,643	577	1,971
91	Secondary Customer	NTPLANT	UPDSLC	Cust07	-	-	-	-	2,891,153	34	12,802
92	Total Distribution Primary & Secondary Lines		UPDLT		$ 11,490,302	$ 30,715,219	$ -	$ -	$ 13,245,356	$ 2,667	$ 59,458
93											
94	**Distribution Line Transformers**										
95	Demand	NTPLANT	UPDLTD	SICDT	$ 6,469,538	$ -	$ -	$ -	$ 615,875	$ 880	$ 3,008
96	Customer	NTPLANT	UPDLTC	Cust09	79,138	-	-	-	3,176,401	38	14,065
97	Total Line Transformers		UPDLTT		$ 6,548,676	$ -	$ -	$ -	$ 3,792,276	$ 918	$ 17,073
98											
99	**Distribution Services**										
100	Customer	NTPLANT	UPDSC	C02	$ 78,938	$ -	$ -	$ -	$ -	$ -	$ -
101											
102	**Distribution Meters**										
103	Customer	NTPLANT	UPDMC	C03	$ 379,761	$ 1,221,286	$ 966,843	$ 38,440	$ -	$ 132	$ 49,297
104											
105	**Distribution Street & Customer Lighting**										
106	Customer	NTPLANT	UPDSCL	C04	$ -	$ -	$ -	$ -	$ 75,365,936	$ -	$ -
107											
108	**Customer Accounts Expense**										
109	Customer	NTPLANT	UPCAE	C05	$ -	$ -	$ -	$ -	$ -	$ -	$ -
110											
111	**Customer Service & Info.**										
112	Customer	NTPLANT	UPCSI	C05	$ -	$ -	$ -	$ -	$ -	$ -	$ -
113											
114	**Sales Expense**										
115	Customer	NTPLANT	UPSEC	C06	$ -	$ -	$ -	$ -	$ -	$ -	$ -
116											
117	Total		UPT		$ 248,494,898	$ 638,114,465	$ 220,737,192	$ 70,134,065	$ 117,556,321	$ 45,432	$ 291,087
118											
119											

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	A / B	C	D	E	F	G	H	J	L	M
1			1	2	3	4	5	7	9	10
2				**Allocation**	**Total**	**Residential**	**General Service**	**All Electric Schools**	**Power Service**	**Power Service**
3	**Description**	**Ref**	**Name**	**Vector**	**System**	**Rate RS**	**GS**	**AES**	**PS-Secondary**	**PS-Primary**
120	**Net Cost Rate Base**									
121										
122	**Power Production Plant**									
123	Production Demand - Base	RB	RBPPDB	PPBDA	$ 777,895,402	$ 257,394,081	$ 79,139,093	$ 6,301,175	$ 87,607,680	$ 9,640,357
124	Production Demand - Inter.	RB	RBPPDI	PPWDA	757,877,520	399,778,052	55,402,451	6,279,756	61,218,501	8,613,346
125	Production Demand - Peak	RB	RBPPDP	PPSDA	687,681,269	280,598,247	83,081,096	6,145,905	76,804,187	10,052,069
126	Production Energy - Base	RB	RBPPEB	E01	81,873,888	27,090,858	8,329,430	663,202	9,220,753	1,014,652
127	Production Energy - Inter.	RB	RBPPEI	E01	-	-	-	-	-	-
128	Production Energy - Peak	RB	RBPPEP	E01	-	-	-	-	-	-
129	Total Power Production Plant		RBPPT		$ 2,305,328,078	$ 964,861,238	$ 225,952,069	$ 19,390,037	$ 234,851,122	$ 29,320,424
130										
131	**Transmission Plant**									
132	Transmission Demand - Base	RB	RBTRB	PPBDA	$ 149,848,193	$ 49,582,550	$ 15,244,787	$ 1,213,813	$ 16,876,115	$ 1,857,049
133	Transmission Demand - Inter.	RB	RBTRI	PPWDA	146,021,682	77,025,986	10,674,494	1,209,932	11,795,083	1,659,550
134	Transmission Demand - Peak	RB	RBTRP	PPSDA	132,391,201	54,020,286	15,994,628	1,183,199	14,786,209	1,935,207
135	Total Transmission Plant		RBTRT		$ 428,261,076	$ 180,628,823	$ 41,913,909	$ 3,606,944	$ 43,457,407	$ 5,451,806
136										
137	**Distribution Poles**									
138	Specific	RB	RBDPS	NCP	$ -	$ -	$ -	$ -	$ -	$ -
139										
140	**Distribution Substation**									
141	General	RB	RBDSG	NCP	$ 108,229,299	$ 51,608,388	$ 13,630,775	$ 1,437,372	$ 11,565,794	$ 1,489,812
142										
143	**Distribution Primary & Secondary Lines**									
144	Primary Specific	RB	RBDPLS	NCP	$ -	$ -	$ -	$ -	$ -	$ -
145	Primary Demand	RB	RBDPLD	NCP	146,772,785	69,987,581	18,485,076	1,949,261	15,684,698	2,020,375
146	Primary Customer	RB	RBDPLC	Cust08	219,713,043	175,916,302	33,562,156	259,161	1,903,239	80,937
147	Secondary Demand	RB	RBDSLD	SICD	48,924,262	38,652,933	9,246,786	661,598	-	-
148	Secondary Customer	RB	RBDSLC	Cust07	73,237,681	59,253,464	11,304,660	87,293	-	-
149	Total Distribution Primary & Secondary Lines		RBDLT		$ 488,647,771	$ 343,810,281	$ 72,598,678	$ 2,957,312	$ 17,587,936	$ 2,101,312
150										
151	**Distribution Line Transformers**									
152	Demand	RB	RBDLTD	SICDT	$ 89,137,921	$ 58,678,712	$ 14,037,473	$ 1,004,367	$ 9,114,822	$ -
153	Customer	RB	RBDLTC	Cust09	80,907,712	64,834,527	12,369,442	95,515	701,445	-
154	Total Line Transformers		RBDLTT		$ 170,045,633	$ 123,513,239	$ 26,406,915	$ 1,099,881	$ 9,816,267	$ -
155										
156	**Distribution Services**									
157	Customer	RB	RBDSC	C02	$ 51,493,417	$ 28,552,455	$ 21,985,025	$ 95,405	$ 790,360	$ -
158										
159	**Distribution Meters**									
160	Customer	RB	RBDMC	C03	$ 43,070,330	$ 25,915,886	$ 11,308,696	$ 118,124	$ 2,648,738	$ 655,455
161										
162	**Distribution Street & Customer Lighting**									
163	Customer	RB	RBDSCL	C04	$ 66,982,484	$ -	$ -	$ -	$ -	$ -
164										
165	**Customer Accounts Expense**									
166	Customer	RB	RBCAE	C05	$ 6,611,581	$ 4,293,261	$ 1,638,178	$ 63,249	$ 232,244	$ 9,876
167										
168	**Customer Service & Info.**									
169	Customer	RB	RBCSI	C05	$ 598,872	$ 388,880	$ 148,385	$ 5,729	$ 21,036	$ 895
170										
171	**Sales Expense**									
172	Customer	RB	RBSEC	C06	$ -	$ -	$ -	$ -	$ -	$ -
173										
174	Total		RBT		$ 3,669,268,542	$ 1,723,572,451	$ 415,582,631	$ 28,774,055	$ 320,970,904	$ 39,029,579
175										
176										

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	A / B	C	D	E	N	O	P	Q	R	S	T
1			1	2	11	12	13	14	15	16	17
2				**Allocation**	**Time of Day**	**Time of Day**	**Service**	**Service**	**Outdoor Lighting**	**Lighting Energy**	**Traffic Energy**
3	**Description**	**Ref**	**Name**	**Vector**	**TOD-Secondary**	**TOD-Primary**	**RTS**	**FLS - Transmission**	**ST & POL**	**LE**	**TE**
120	**Net Cost Rate Base**										
121											
122	**Power Production Plant**										
123	Production Demand - Base	RB	RBPPDB	PPBDA	$ 66,826,325	$ 174,062,122	$ 63,697,204	$ 22,247,446	$ 10,909,938	$ 18,427	$ 51,556
124	Production Demand - Inter.	RB	RBPPDI	PPWDA	39,717,273	114,642,672	46,085,061	19,854,076	6,241,362	10,182	34,789
125	Production Demand - Peak	RB	RBPPDP	PPSDA	50,963,255	125,951,301	46,362,228	7,695,411	-	-	27,569
126	Production Energy - Base	RB	RBPPEB	E01	7,033,505	18,320,127	6,704,163	2,341,555	1,148,277	1,940	5,426
127	Production Energy - Inter.	RB	RBPPEI	E01	-	-	-	-	-	-	-
128	Production Energy - Peak	RB	RBPPEP	E01	-	-	-	-	-	-	-
129	Total Power Production Plant		RBPPT		$ 164,540,358	$ 432,976,222	$ 162,848,656	$ 52,138,487	$ 18,299,576	$ 30,548	$ 119,340
130											
131	**Transmission Plant**										
132	Transmission Demand - Base	RB	RBTRB	PPBDA	$ 12,872,944	$ 33,530,079	$ 12,270,173	$ 4,285,588	$ 2,101,612	$ 3,550	$ 9,931
133	Transmission Demand - Inter.	RB	RBTRI	PPWDA	7,652,401	22,088,418	8,879,295	3,825,322	1,202,535	1,962	6,703
134	Transmission Demand - Peak	RB	RBTRP	PPSDA	9,811,357	24,247,925	8,925,576	1,481,507	-	-	5,308
135	Total Transmission Plant		RBTRT		$ 30,336,703	$ 79,866,423	$ 30,075,043	$ 9,592,418	$ 3,304,147	$ 5,511	$ 21,942
136											
137	**Distribution Poles**										
138	Specific	RB	RBDPS	NCP	$ -	$ -	$ -	$ -	$ -	$ -	$ -
139											
140	**Distribution Substation**										
141	General	RB	RBDSG	NCP	$ 7,429,879	$ 20,160,844	$ -	$ -	$ 900,748	$ 1,288	$ 4,399
142											
143	**Distribution Primary & Secondary Lines**										
144	Primary Specific	RB	RBDPLS	NCP	$ -	$ -	$ -	$ -	$ -	$ -	$ -
145	Primary Demand	RB	RBDPLD	NCP	10,075,867	27,340,686	-	-	1,221,530	1,746	5,966
146	Primary Customer	RB	RBDPLC	Cust08	190,896	104,237	-	-	7,662,097	91	33,928
147	Secondary Demand	RB	RBDSLD	SICD	-	-	-	-	360,668	516	1,761
148	Secondary Customer	RB	RBDSLC	Cust07	-	-	-	-	2,580,806	31	11,428
149	Total Distribution Primary & Secondary Lines		RBDLT		$ 10,266,763	$ 27,444,923	$ -	$ -	$ 11,825,101	$ 2,383	$ 53,083
150											
151	**Distribution Line Transformers**										
152	Demand	RB	RBDLTD	SICDT	$ 5,751,564	$ -	$ -	$ -	$ 547,527	$ 783	$ 2,674
153	Customer	RB	RBDLTC	Cust09	70,355	-	-	-	2,823,891	33	12,504
154	Total Line Transformers		RBDLTT		$ 5,821,919	$ -	$ -	$ -	$ 3,371,417	$ 816	$ 15,178
155											
156	**Distribution Services**										
157	Customer	RB	RBDSC	C02	$ 70,172	$ -	$ -	$ -	$ -	$ -	$ -
158											
159	**Distribution Meters**										
160	Customer	RB	RBDMC	C03	$ 346,539	$ 1,114,447	$ 882,263	$ 35,077	$ -	$ 120	$ 44,984
161											
162	**Distribution Street & Customer Lighting**										
163	Customer	RB	RBDSCL	C04	$ -	$ -	$ -	$ -	$ 66,982,484	$ -	$ -
164											
165	**Customer Accounts Expense**										
166	Customer	RB	RBCAE	C05	$ 116,471	$ 63,598	$ 6,385	$ 499	$ 186,992	$ -	$ 828
167											
168	**Customer Service & Info.**										
169	Customer	RB	RBCSI	C05	$ 10,550	$ 5,761	$ 578	$ 45	$ 16,938	$ -	$ 75
170											
171	**Sales Expense**										
172	Customer	RB	RBSEC	C06	$ -	$ -	$ -	$ -	$ -	$ -	$ -
173											
174	Total		RBT		$ 218,939,354	$ 561,632,217	$ 193,812,925	$ 61,766,526	$ 104,887,403	$ 40,667	$ 259,829
175											
176											

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	A	B	C	D	E	F	G	H	J	L	M
1				1	2	3	4	5	7	9	10
2					**Allocation**	**Total**	**Residential**	**General Service**	**All Electric Schools**	**Power Service**	**Power Service**
3	**Description**		**Ref**	**Name**	**Vector**	**System**	**Rate RS**	**GS**	**AES**	**PS-Secondary**	**PS-Primary**
177	**Operation and Maintenance Expenses**										
178											
179	**Power Production Plant**										
180	Production Demand - Base		TOM	OMPPDB	PPBDA	$ 40,917,494	$ 13,538,993	$ 4,162,736	$ 331,443	$ 4,608,186	$ 507,085
181	Production Demand - Inter.		TOM	OMPPDI	PPWDA	38,726,277	20,427,991	2,830,973	320,885	3,128,163	440,128
182	Production Demand - Peak		TOM	OMPPDP	PPSDA	39,202,972	15,996,197	4,736,243	350,362	4,378,413	573,043
183	Production Energy - Base		TOM	OMPPEB	E01	672,379,424	222,480,404	68,404,438	5,446,465	75,724,321	8,332,710
184	Production Energy - Inter.		TOM	OMPPEI	E01	-	-	-	-	-	-
185	Production Energy - Peak		TOM	OMPPEP	E01	-	-	-	-	-	-
186	Total Power Production Plant			OMPPT		$ 791,226,166	$ 272,443,585	$ 80,134,391	$ 6,449,156	$ 87,839,083	$ 9,852,966
187							34.4%	10.1%	0.8%	11.1%	1.2%
188	**Transmission Plant**										
189	Transmission Demand - Base		TOM	OMTRB	PPBDA	$ 12,136,187	$ 4,015,685	$ 1,234,673	$ 98,307	$ 1,366,794	$ 150,402
190	Transmission Demand - Inter.		TOM	OMTRI	PPWDA	11,826,278	6,238,325	864,526	97,992	955,282	134,407
191	Transmission Demand - Peak		TOM	OMTRP	PPSDA	10,722,347	4,375,096	1,295,403	95,827	1,197,533	156,732
192	Total Transmission Plant			OMTRT		$ 34,684,812	$ 14,629,106	$ 3,394,602	$ 292,126	$ 3,519,610	$ 441,541
193											
194	**Distribution Poles**										
195	Specific		TOM	OMDPS	NCP	$ -	$ -	$ -	$ -	$ -	$ -
196											
197	**Distribution Substation**										
198	General		TOM	OMDSG	NCP	$ 7,686,024	$ 3,665,027	$ 968,005	$ 102,077	$ 821,358	$ 105,801
199											
200	**Distribution Primary & Secondary Lines**										
201	Primary Specific		TOM	OMDPLS	NCP	$ -	$ -	$ -	$ -	$ -	$ -
202	Primary Demand		TOM	OMDPLD	NCP	15,854,532	7,560,123	1,996,775	210,561	1,694,276	218,243
203	Primary Customer		TOM	OMDPLC	Cust08	22,148,746	17,733,701	3,383,321	26,125	191,861	8,159
204	Secondary Demand		TOM	OMDSLD	SICD	5,284,844	4,175,325	998,846	71,466	-	-
205	Secondary Customer		TOM	OMDSLC	Cust07	7,382,915	5,973,200	1,139,596	8,800	-	-
206	Total Distribution Primary & Secondary Lines			OMDLT		$ 50,671,037	$ 35,442,350	$ 7,518,538	$ 316,953	$ 1,886,136	$ 226,402
207											
208	**Distribution Line Transformers**										
209	Demand		TOM	OMDLTD	SICDT	$ 2,959,316	$ 1,948,092	$ 466,034	$ 33,344	$ 302,606	$ -
210	Customer		TOM	OMDLTC	Cust09	2,686,079	2,152,461	410,657	3,171	23,287	-
211	Total Line Transformers			OMDLTT		$ 5,645,395	$ 4,100,552	$ 876,691	$ 36,515	$ 325,893	$ -
212											
213	**Distribution Services**										
214	Customer		TOM	OMDSC	C02	$ 1,679,668	$ 931,355	$ 717,131	$ 3,112	$ 25,781	$ -
215											
216	**Distribution Meters**										
217	Customer		TOM	OMDMC	C03	$ 9,669,720	$ 5,818,376	$ 2,538,915	$ 26,520	$ 594,668	$ 147,156
218											
219	**Distribution Street & Customer Lighting**										
220	Customer		TOM	OMDSCL	C04	$ 2,078,795	$ -	$ -	$ -	$ -	$ -
221											
222	**Customer Accounts Expense**										
223	Customer		TOM	OMCAE	C05	$ 49,341,663	$ 32,040,242	$ 12,225,582	$ 472,019	$ 1,733,217	$ 73,706
224											
225	**Customer Service & Info.**										
226	Customer		TOM	OMCSI	C05	$ 4,469,330	$ 2,902,181	$ 1,107,384	$ 42,755	$ 156,993	$ 6,676
227											
228	**Sales Expense**										
229	Customer		TOM	OMSEC	C06	$ -	$ -	$ -	$ -	$ -	$ -
230											
231	Total			OMT		$ 957,152,611	$ 371,972,774	$ 109,481,239	$ 7,741,233	$ 96,902,740	$ 10,854,248
232											
233											

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	A B	C	D	E	N	O	P	Q	R	S	T
1			1	2	11	12	13	14	15	16	17
2				Allocation	Time of Day	Time of Day	Service	Service	Outdoor Lighting	Lighting Energy	Traffic Energy
3	**Description**	**Ref**	**Name**	**Vector**	**TOD-Secondary**	**TOD-Primary**	**RTS**	**FLS - Transmission**	**ST & POL**	**LE**	**TE**
177	**Operation and Maintenance Expenses**										
178											
179	**Power Production Plant**										
180	Production Demand - Base	TOM	OMPPDB	PPBDA	$ 3,515,081	$ 9,155,711	$ 3,350,489	$ 1,170,221	$ 573,865	$ 969	$ 2,712
181	Production Demand - Inter.	TOM	OMPPDI	PPWDA	2,029,486	5,858,049	2,354,870	1,014,510	318,923	520	1,778
182	Production Demand - Peak	TOM	OMPPDP	PPSDA	2,905,286	7,180,166	2,642,994	438,696	-	-	1,572
183	Production Energy - Base	TOM	OMPPEB	E01	57,761,810	150,451,834	55,057,131	19,229,738	9,430,083	15,928	44,563
184	Production Energy - Inter.	TOM	OMPPEI	E01	-	-	-	-	-	-	-
185	Production Energy - Peak	TOM	OMPPEP	E01	-	-	-	-	-	-	-
186	Total Power Production Plant		OMPPT		$ 66,211,664	$ 172,645,760	$ 63,405,483	$ 21,853,165	$ 10,322,871	$ 17,418	$ 50,624
187					8.4%	21.8%	8.0%	2.8%			
188	**Transmission Plant**										
189	Transmission Demand - Base	TOM	OMTRB	PPBDA	$ 1,042,578	$ 2,715,597	$ 993,760	$ 347,089	$ 170,209	$ 287	$ 804
190	Transmission Demand - Inter.	TOM	OMTRI	PPWDA	619,767	1,788,938	719,133	309,812	97,393	159	543
191	Transmission Demand - Peak	TOM	OMTRP	PPSDA	794,621	1,963,836	722,881	119,987	-	-	430
192	Total Transmission Plant		OMTRT		$ 2,456,966	$ 6,468,372	$ 2,435,774	$ 776,889	$ 267,602	$ 446	$ 1,777
193											
194	**Distribution Poles**										
195	Specific	TOM	OMDPS	NCP	$ -	$ -	$ -	$ -	$ -	$ -	$ -
196											
197	**Distribution Substation**										
198	General	TOM	OMDSG	NCP	$ 527,641	$ 1,431,745	$ -	$ -	$ 63,968	$ 91	$ 312
199											
200	**Distribution Primary & Secondary Lines**										
201	Primary Specific	TOM	OMDPLS	NCP	$ -	$ -	$ -	$ -	$ -	$ -	$ -
202	Primary Demand	TOM	OMDPLD	NCP	1,088,404	2,953,366	-	-	131,951	189	644
203	Primary Customer	TOM	OMDPLC	Cust08	19,244	10,508	-	-	772,398	9	3,420
204	Secondary Demand	TOM	OMDSLD	SICD	-	-	-	-	38,960	56	190
205	Secondary Customer	TOM	OMDSLC	Cust07	-	-	-	-	260,165	3	1,152
206	Total Distribution Primary & Secondary Lines		OMDLT		$ 1,107,648	$ 2,963,874	$ -	$ -	$ 1,203,473	$ 257	$ 5,407
207											
208	**Distribution Line Transformers**										
209	Demand	TOM	OMDLTD	SICDT	$ 190,948	$ -	$ -	$ -	$ 18,177	$ 26	$ 89
210	Customer	TOM	OMDLTC	Cust09	2,336	-	-	-	93,751	1	415
211	Total Line Transformers		OMDLTT		$ 193,284	$ -	$ -	$ -	$ 111,929	$ 27	$ 504
212											
213	**Distribution Services**										
214	Customer	TOM	OMDSC	C02	$ 2,289	$ -	$ -	$ -	$ -	$ -	$ -
215											
216	**Distribution Meters**										
217	Customer	TOM	OMDMC	C03	$ 77,802	$ 250,204	$ 198,077	$ 7,875	$ -	$ 27	$ 10,099
218											
219	**Distribution Street & Customer Lighting**										
220	Customer	TOM	OMDSCL	C04	$ -	$ -	$ -	$ -	$ 2,078,795	$ -	$ -
221											
222	**Customer Accounts Expense**										
223	Customer	TOM	OMCAE	C05	$ 869,214	$ 474,624	$ 47,649	$ 3,723	$ 1,395,508	$ -	$ 6,179
224											
225	**Customer Service & Info.**										
226	Customer	TOM	OMCSI	C05	$ 78,733	$ 42,991	$ 4,316	$ 337	$ 126,404	$ -	$ 560
227											
228	**Sales Expense**										
229	Customer	TOM	OMSEC	C06	$ -	$ -	$ -	$ -	$ -	$ -	$ -
230											
231	Total		OMT		$ 71,525,240	$ 184,277,571	$ 66,091,298	$ 22,641,989	$ 15,570,550	$ 18,266	$ 75,463
232											
233											

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	A / B	C	D	E	F	G	H	J	L	M
1			1	2	3	4	5	7	9	10
2				**Allocation**	**Total**	**Residential**	**General Service**	**All Electric Schools**	**Power Service**	**Power Service**
3	**Description**	**Ref**	**Name**	**Vector**	**System**	**Rate RS**	**GS**	**AES**	**PS-Secondary**	**PS-Primary**
234	**Labor Expenses**									
235										
236	**Power Production Plant**									
237	Production Demand - Base	TLB	LBPPDB	PPBDA	$ 20,905,325	$ 6,917,263	$ 2,126,801	$ 169,339	$ 2,354,387	$ 259,077
238	Production Demand - Inter.	TLB	LBPPDI	PPWDA	19,712,190	10,398,119	1,441,003	163,335	1,592,277	224,031
239	Production Demand - Peak	TLB	LBPPDP	PPSDA	20,225,351	8,252,658	2,443,493	180,757	2,258,883	295,641
240	Production Energy - Base	TLB	LBPPEB	E01	38,578,541	12,765,068	3,924,783	312,497	4,344,770	478,099
241	Production Energy - Inter.	TLB	LBPPEI	E01	-	-	-	-	-	-
242	Production Energy - Peak	TLB	LBPPEP	E01	-	-	-	-	-	-
243	Total Power Production Plant		LBPPT		$ 99,421,407	$ 38,333,108	$ 9,936,080	$ 825,928	$ 10,550,317	$ 1,256,847
244										
245	**Transmission Plant**									
246	Transmission Demand - Base	TLB	LBTRB	PPBDA	$ 3,992,284	$ 1,320,988	$ 406,155	$ 32,339	$ 449,617	$ 49,476
247	Transmission Demand - Inter.	TLB	LBTRI	PPWDA	3,890,338	2,052,141	284,392	32,235	314,247	44,214
248	Transmission Demand - Peak	TLB	LBTRP	PPSDA	3,527,192	1,439,219	426,132	31,523	393,937	51,558
249	Total Transmission Plant		LBTRT		$ 11,409,814	$ 4,812,348	$ 1,116,678	$ 96,097	$ 1,157,801	$ 145,248
250										
251	**Distribution Poles**									
252	Specific	TLB	LBDPS	NCP	$ -	$ -	$ -	$ -	$ -	$ -
253										
254	**Distribution Substation**									
255	General	TLB	LBDSG	NCP	$ 4,139,130	$ 1,973,716	$ 521,297	$ 54,971	$ 442,323	$ 56,976
256										
257	**Distribution Primary & Secondary Lines**									
258	Primary Specific	TLB	LBDPLS	NCP	$ -	$ -	$ -	$ -	$ -	$ -
259	Primary Demand	TLB	LBDPLD	NCP	5,613,434	2,676,727	706,975	74,551	599,873	77,271
260	Primary Customer	TLB	LBDPLC	Cust08	8,411,330	6,734,648	1,284,868	9,922	72,862	3,099
261	Secondary Demand	TLB	LBDSLD	SICD	1,871,145	1,478,310	353,650	25,303	-	-
262	Secondary Customer	TLB	LBDSLC	Cust07	2,803,777	2,268,415	432,779	3,342	-	-
263	Total Distribution Primary & Secondary Lines		LBDLT		$ 18,699,685	$ 13,158,101	$ 2,778,273	$ 113,118	$ 672,735	$ 80,369
264										
265	**Distribution Line Transformers**									
266	Demand	TLB	LBDLTD	SICDT	$ 3,426,439	$ 2,255,594	$ 539,597	$ 38,608	$ 350,371	$ -
267	Customer	TLB	LBDLTC	Cust09	3,110,071	2,492,222	475,478	3,672	26,963	-
268	Total Line Transformers		LBDLTT		$ 6,536,510	$ 4,747,817	$ 1,015,075	$ 42,279	$ 377,335	$ -
269										
270	**Distribution Services**									
271	Customer	TLB	LBDSC	C02	$ 1,979,548	$ 1,097,635	$ 845,165	$ 3,668	$ 30,384	$ -
272										
273	**Distribution Meters**									
274	Customer	TLB	LBDMC	C03	$ 1,612,981	$ 970,548	$ 423,510	$ 4,424	$ 99,195	$ 24,547
275										
276	**Distribution Street & Customer Lighting**									
277	Customer	TLB	LBDSCL	C04	$ 2,575,539	$ -	$ -	$ -	$ -	$ -
278										
279	**Customer Accounts Expense**									
280	Customer	TLB	LBCAE	C05	$ 27,447,969	$ 17,823,468	$ 6,800,893	$ 262,576	$ 964,161	$ 41,002
281										
282	**Customer Service & Info.**									
283	Customer	TLB	LBCSI	C05	$ 3,609,876	$ 2,344,090	$ 894,434	$ 34,533	$ 126,804	$ 5,392
284										
285	**Sales Expense**									
286	Customer	TLB	LBSEC	C06	$ -	$ -	$ -	$ -	$ -	$ -
287										
288	Total		LBT		$ 177,432,461	$ 85,260,831	$ 24,331,405	$ 1,437,594	$ 14,421,053	$ 1,610,382
289										
290										

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1				1	2	11	12	13	14	15	16	17
2					**Allocation**	**Time of Day**	**Time of Day**	**Service**	**Service**	**Outdoor Lighting**	**Lighting Energy**	**Traffic Energy**
3	**Description**		**Ref**	**Name**	**Vector**	**TOD-Secondary**	**TOD-Primary**	**RTS**	**FLS - Transmission**	**ST & POL**	**LE**	**TE**
234	**Labor Expenses**											
235												
236	**Power Production Plant**											
237	Production Demand - Base		TLB	LBPPDB	PPBDA	$ 1,795,905	$ 4,677,782	$ 1,711,812	$ 597,883	$ 293,196	$ 495	$ 1,386
238	Production Demand - Inter.		TLB	LBPPDI	PPWDA	1,033,036	2,981,825	1,198,660	516,399	162,336	265	905
239	Production Demand - Peak		TLB	LBPPDP	PPSDA	1,498,877	3,704,346	1,363,557	226,329	-	-	811
240	Production Energy - Base		TLB	LBPPEB	E01	3,314,150	8,632,347	3,158,966	1,103,328	541,062	914	2,557
241	Production Energy - Inter.		TLB	LBPPEI	E01	-	-	-	-	-	-	-
242	Production Energy - Peak		TLB	LBPPEP	E01	-	-	-	-	-	-	-
243	Total Power Production Plant			LBPPT		$ 7,641,968	$ 19,996,300	$ 7,432,995	$ 2,443,939	$ 996,594	$ 1,674	$ 5,658
244												
245	**Transmission Plant**											
246	Transmission Demand - Base		TLB	LBTRB	PPBDA	$ 342,963	$ 893,315	$ 326,904	$ 114,177	$ 55,992	$ 95	$ 265
247	Transmission Demand - Inter.		TLB	LBTRI	PPWDA	203,877	588,484	236,564	101,915	32,038	52	179
248	Transmission Demand - Peak		TLB	LBTRP	PPSDA	261,396	646,018	237,797	39,471	-	-	141
249	Total Transmission Plant			LBTRT		$ 808,236	$ 2,127,817	$ 801,265	$ 255,563	$ 88,030	$ 147	$ 585
250												
251	**Distribution Poles**											
252	Specific		TLB	LBDPS	NCP	$ -	$ -	$ -	$ -	$ -	$ -	$ -
253												
254	**Distribution Substation**											
255	General		TLB	LBDSG	NCP	$ 284,149	$ 771,033	$ -	$ -	$ 34,448	$ 49	$ 168
256												
257	**Distribution Primary & Secondary Lines**											
258	Primary Specific		TLB	LBDPLS	NCP	$ -	$ -	$ -	$ -	$ -	$ -	$ -
259	Primary Demand		TLB	LBDPLD	NCP	385,359	1,045,665	-	-	46,718	67	228
260	Primary Customer		TLB	LBDPLC	Cust08	7,308	3,991	-	-	293,330	3	1,299
261	Secondary Demand		TLB	LBDSLD	SICD	-	-	-	-	13,794	20	67
262	Secondary Customer		TLB	LBDSLC	Cust07	-	-	-	-	98,802	1	437
263	Total Distribution Primary & Secondary Lines			LBDLT		$ 392,667	$ 1,049,655	$ -	$ -	$ 452,644	$ 91	$ 2,032
264												
265	**Distribution Line Transformers**											
266	Demand		TLB	LBDLTD	SICDT	$ 221,089	$ -	$ -	$ -	$ 21,047	$ 30	$ 103
267	Customer		TLB	LBDLTC	Cust09	2,704	-	-	-	108,550	1	481
268	Total Line Transformers			LBDLTT		$ 223,793	$ -	$ -	$ -	$ 129,596	$ 31	$ 583
269												
270	**Distribution Services**											
271	Customer		TLB	LBDSC	C02	$ 2,698	$ -	$ -	$ -	$ -	$ -	$ -
272												
273	**Distribution Meters**											
274	Customer		TLB	LBDMC	C03	$ 12,978	$ 41,736	$ 33,041	$ 1,314	$ -	$ 5	$ 1,685
275												
276	**Distribution Street & Customer Lighting**											
277	Customer		TLB	LBDSCL	C04	$ -	$ -	$ -	$ -	$ 2,575,539	$ -	$ -
278												
279	**Customer Accounts Expense**											
280	Customer		TLB	LBCAE	C05	$ 483,530	$ 264,026	$ 26,506	$ 2,071	$ 776,298	$ -	$ 3,438
281												
282	**Customer Service & Info.**											
283	Customer		TLB	LBCSI	C05	$ 63,592	$ 34,724	$ 3,486	$ 272	$ 102,096	$ -	$ 452
284												
285	**Sales Expense**											
286	Customer		TLB	LBSEC	C06	$ -	$ -	$ -	$ -	$ -	$ -	$ -
287												
288	Total			LBT		$ 9,913,611	$ 24,285,291	$ 8,297,293	$ 2,703,159	$ 5,155,247	$ 1,997	$ 14,600
289												
290												

KENTUCKY UTILITIES COMPANY
Cost of Service Study
Class Allocation
12 Months Ended June 30, 2016

	A	B	C	D	E	F	G	H	J	L	M
1				1	2	3	4	5	7	9	10
2					**Allocation**	**Total**	**Residential**	**General Service**	**All Electric Schools**	**Power Service**	**Power Service**
3	**Description**		**Ref**	**Name**	**Vector**	**System**	**Rate RS**	**GS**	**AES**	**PS-Secondary**	**PS-Primary**
291	**Depreciation Expenses**										
292											
293	**Power Production Plant**										
294	Production Demand - Base		TDEPR	DEPPDB	PPBDA	$ 43,978,725	$ 14,551,910	$ 4,474,170	$ 356,240	$ 4,952,946	$ 545,023
295	Production Demand - Inter.		TDEPR	DEPPDI	PPWDA	42,855,688	22,606,243	3,132,842	355,101	3,461,722	487,059
296	Production Demand - Peak		TDEPR	DEPPDP	PPSDA	38,855,299	15,854,334	4,694,240	347,255	4,339,583	567,961
297	Production Energy - Base		TDEPR	DEPPEB	E01	-	-	-	-	-	-
298	Production Energy - Inter.		TDEPR	DEPPEI	E01	-	-	-	-	-	-
299	Production Energy - Peak		TDEPR	DEPPEP	E01	-	-	-	-	-	-
300	Total Power Production Plant			DEPPT		$ 125,689,713	$ 53,012,487	$ 12,301,252	$ 1,058,597	$ 12,754,250	$ 1,600,042
301											
302	**Transmission Plant**										
303	Transmission Demand - Base		TDEPR	DETRB	PPBDA	$ 5,761,186	$ 1,906,291	$ 586,114	$ 46,667	$ 648,833	$ 71,398
304	Transmission Demand - Inter.		TDEPR	DETRI	PPWDA	5,614,069	2,961,404	410,400	46,518	453,483	63,804
305	Transmission Demand - Peak		TDEPR	DETRP	PPSDA	5,090,020	2,076,908	614,943	45,490	568,483	74,403
306	Total Transmission Plant			DETRT		$ 16,465,275	$ 6,944,603	$ 1,611,456	$ 138,676	$ 1,670,799	$ 209,605
307											
308	**Distribution Poles**										
309	Specific		TDEPR	DEDPS	NCP	$ -	$ -	$ -	$ -	$ -	$ -
310											
311	**Distribution Substation**										
312	General		TDEPR	DEDSG	NCP	$ 5,543,785	$ 2,643,515	$ 698,204	$ 73,626	$ 592,430	$ 76,312
313											
314	**Distribution Primary & Secondary Lines**										
315	Primary Specific		TDEPR	DEDPLS	NCP	$ -	$ -	$ -	$ -	$ -	$ -
316	Primary Demand		TDEPR	DEDPLD	NCP	7,518,408	3,585,100	946,894	99,851	803,446	103,493
317	Primary Customer		TDEPR	DEDPLC	Cust08	11,265,797	9,020,117	1,720,901	13,288	97,589	4,150
318	Secondary Demand		TDEPR	DEDSLD	SICD	2,506,136	1,979,989	473,665	33,890	-	-
319	Secondary Customer		TDEPR	DEDSLC	Cust07	3,755,266	3,038,224	579,647	4,476	-	-
320	Total Distribution Primary & Secondary Lines			DEDLT		$ 25,045,606	$ 17,623,430	$ 3,721,107	$ 151,505	$ 901,034	$ 107,643
321											
322	**Distribution Line Transformers**										
323	Demand		TDEPR	DEDLTD	SICDT	$ 4,589,234	$ 3,021,052	$ 722,714	$ 51,709	$ 469,273	$ -
324	Customer		TDEPR	DEDLTC	Cust09	4,165,505	3,337,982	636,836	4,918	36,114	-
325	Total Line Transformers			DEDLTT		$ 8,754,739	$ 6,359,035	$ 1,359,551	$ 56,627	$ 505,387	$ -
326											
327	**Distribution Services**										
328	Customer		TDEPR	DEDSC	C02	$ 2,651,327	$ 1,470,128	$ 1,131,980	$ 4,912	$ 40,695	$ -
329											
330	**Distribution Meters**										
331	Customer		TDEPR	DEDMC	C03	$ 2,160,362	$ 1,299,913	$ 567,232	$ 5,925	$ 132,858	$ 32,877
332											
333	**Distribution Street & Customer Lighting**										
334	Customer		TDEPR	DEDSCL	C04	$ 3,449,574	$ -	$ -	$ -	$ -	$ -
335											
336	**Customer Accounts Expense**										
337	Customer		TDEPR	DECAE	C05	$ -	$ -	$ -	$ -	$ -	$ -
338											
339	**Customer Service & Info.**										
340	Customer		TDEPR	DECSI	C05	$ -	$ -	$ -	$ -	$ -	$ -
341											
342	**Sales Expense**										
343	Customer		TDEPR	DESEC	C06	$ -	$ -	$ -	$ -	$ -	$ -
344											
345	Total			DET		$ 189,760,380	$ 89,353,112	$ 21,390,781	$ 1,489,868	$ 16,597,453	$ 2,026,479
346											
347											

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	A	B	C	D	E	N	O	P	Q	R	S	T
1				1	2	11	12	13	14	15	16	17
2					**Allocation**	**Time of Day**	**Time of Day**	**Service**	**Service**	**Outdoor Lighting**	**Lighting Energy**	**Traffic Energy**
3	**Description**		**Ref**	**Name**	**Vector**	**TOD-Secondary**	**TOD-Primary**	**RTS**	**FLS - Transmission**	**ST & POL**	**LE**	**TE**
291	**Depreciation Expenses**											
292												
293	**Power Production Plant**											
294	Production Demand - Base		TDEPR	DEPPDB	PPBDA	$ 3,778,061	$ 9,840,694	$ 3,601,155	$ 1,257,771	$ 616,799	$ 1,042	$ 2,915
295	Production Demand - Inter.		TDEPR	DEPPDI	PPWDA	2,245,892	6,482,697	2,605,971	1,122,688	352,930	576	1,967
296	Production Demand - Peak		TDEPR	DEPPDP	PPSDA	2,879,521	7,116,488	2,619,554	434,805	-	-	1,558
297	Production Energy - Base		TDEPR	DEPPEB	E01	-	-	-	-	-	-	-
298	Production Energy - Inter.		TDEPR	DEPPEI	E01	-	-	-	-	-	-	-
299	Production Energy - Peak		TDEPR	DEPPEP	E01	-	-	-	-	-	-	-
300	Total Power Production Plant			DEPPT		$ 8,903,474	$ 23,439,879	$ 8,826,680	$ 2,815,264	$ 969,729	$ 1,618	$ 6,440
301												
302	**Transmission Plant**											
303	Transmission Demand - Base		TDEPR	DETRB	PPBDA	$ 494,924	$ 1,289,125	$ 471,749	$ 164,767	$ 80,800	$ 136	$ 382
304	Transmission Demand - Inter.		TDEPR	DETRI	PPWDA	294,210	849,229	341,381	147,071	46,234	75	258
305	Transmission Demand - Peak		TDEPR	DETRP	PPSDA	377,215	932,256	343,160	56,959	-	-	204
306	Total Transmission Plant			DETRT		$ 1,166,350	$ 3,070,610	$ 1,156,290	$ 368,798	$ 127,034	$ 212	$ 844
307												
308	**Distribution Poles**											
309	Specific		TDEPR	DEDPS	NCP	$ -	$ -	$ -	$ -	$ -	$ -	$ -
310												
311	**Distribution Substation**											
312	General		TDEPR	DEDSG	NCP	$ 380,578	$ 1,032,691	$ -	$ -	$ 46,139	$ 66	$ 225
313												
314	**Distribution Primary & Secondary Lines**											
315	Primary Specific		TDEPR	DEDPLS	NCP	$ -	$ -	$ -	$ -	$ -	$ -	$ -
316	Primary Demand		TDEPR	DEDPLD	NCP	516,134	1,400,521	-	-	62,573	89	306
317	Primary Customer		TDEPR	DEDPLC	Cust08	9,788	5,345	-	-	392,874	5	1,740
318	Secondary Demand		TDEPR	DEDSLD	SICD	-	-	-	-	18,475	26	90
319	Secondary Customer		TDEPR	DEDSLC	Cust07	-	-	-	-	132,331	2	586
320	Total Distribution Primary & Secondary Lines			DEDLT		$ 525,923	$ 1,405,866	$ -	$ -	$ 606,253	$ 122	$ 2,721
321												
322	**Distribution Line Transformers**											
323	Demand		TDEPR	DEDLTD	SICDT	$ 296,117	$ -	$ -	$ -	$ 28,189	$ 40	$ 138
324	Customer		TDEPR	DEDLTC	Cust09	3,622	-	-	-	145,387	2	644
325	Total Line Transformers			DEDLTT		$ 299,739	$ -	$ -	$ -	$ 173,576	$ 42	$ 781
326												
327	**Distribution Services**											
328	Customer		TDEPR	DEDSC	C02	$ 3,613	$ -	$ -	$ -	$ -	$ -	$ -
329												
330	**Distribution Meters**											
331	Customer		TDEPR	DEDMC	C03	$ 17,382	$ 55,899	$ 44,253	$ 1,759	$ -	$ 6	$ 2,256
332												
333	**Distribution Street & Customer Lighting**											
334	Customer		TDEPR	DEDSCL	C04	$ -	$ -	$ -	$ -	$ 3,449,574	$ -	$ -
335												
336	**Customer Accounts Expense**											
337	Customer		TDEPR	DECAE	C05	$ -	$ -	$ -	$ -	$ -	$ -	$ -
338												
339	**Customer Service & Info.**											
340	Customer		TDEPR	DECSI	C05	$ -	$ -	$ -	$ -	$ -	$ -	$ -
341												
342	**Sales Expense**											
343	Customer		TDEPR	DESEC	C06	$ -	$ -	$ -	$ -	$ -	$ -	$ -
344												
345	Total			DET		$ 11,297,059	$ 29,004,945	$ 10,027,223	$ 3,185,822	$ 5,372,305	$ 2,066	$ 13,268
346												
347												

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	A / B	C	D	E	F	G	H	J	L	M
1			1	2	3	4	5	7	9	10
2				**Allocation**	**Total**	**Residential**	**General Service**	**All Electric Schools**	**Power Service**	**Power Service**
3	**Description**	**Ref**	**Name**	**Vector**	**System**	**Rate RS**	**GS**	**AES**	**PS-Secondary**	**PS-Primary**
348	**Accretion Expenses**									
349										
350	**Power Production Plant**									
351	Production Demand - Base	TACRT	ACPPDB	PPBDA	$ -	$ -	$ -	$ -	$ -	$ -
352	Production Demand - Inter.	TACRT	ACPPDI	PPWDA	-	-	-	-	-	-
353	Production Demand - Peak	TACRT	ACPPDP	PPSDA	-	-	-	-	-	-
354	Production Energy - Base	TACRT	ACPPEB	E01	-	-	-	-	-	-
355	Production Energy - Inter.	TACRT	ACPPEI	E01	-	-	-	-	-	-
356	Production Energy - Peak	TACRT	ACPPEP	E01	-	-	-	-	-	-
357	Total Power Production Plant		ACPPT		$ -	$ -	$ -	$ -	$ -	$ -
358										
359	**Transmission Plant**									
360	Transmission Demand - Base	TACRT	ACTRB	PPBDA	$ -	$ -	$ -	$ -	$ -	$ -
361	Transmission Demand - Inter.	TACRT	ACTRI	PPWDA	-	-	-	-	-	-
362	Transmission Demand - Peak	TACRT	ACTRP	PPSDA	-	-	-	-	-	-
363	Total Transmission Plant		ACTRT		$ -	$ -	$ -	$ -	$ -	$ -
364										
365	**Distribution Poles**									
366	Specific	TACRT	ACDPS	NCP	$ -	$ -	$ -	$ -	$ -	$ -
367										
368	**Distribution Substation**									
369	General	TACRT	ACDSG	NCP	$ -	$ -	$ -	$ -	$ -	$ -
370										
371	**Distribution Primary & Secondary Lines**									
372	Primary Specific	TACRT	ACDPLS	NCP	$ -	$ -	$ -	$ -	$ -	$ -
373	Primary Demand	TACRT	ACDPLD	NCP	-	-	-	-	-	-
374	Primary Customer	TACRT	ACDPLC	Cust08	-	-	-	-	-	-
375	Secondary Demand	TACRT	ACDSLD	SICD	-	-	-	-	-	-
376	Secondary Customer	TACRT	ACDSLC	Cust07	-	-	-	-	-	-
377	Total Distribution Primary & Secondary Lines		ACDLT		$ -	$ -	$ -	$ -	$ -	$ -
378										
379	**Distribution Line Transformers**									
380	Demand	TACRT	ACDLTD	SICDT	$ -	$ -	$ -	$ -	$ -	$ -
381	Customer	TACRT	ACDLTC	Cust09	-	-	-	-	-	-
382	Total Line Transformers		ACDLTT		$ -	$ -	$ -	$ -	$ -	$ -
383										
384	**Distribution Services**									
385	Customer	TACRT	ACDSC	C02	$ -	$ -	$ -	$ -	$ -	$ -
386										
387	**Distribution Meters**									
388	Customer	TACRT	ACDMC	C03	$ -	$ -	$ -	$ -	$ -	$ -
389										
390	**Distribution Street & Customer Lighting**									
391	Customer	TACRT	ACDSCL	C04	$ -	$ -	$ -	$ -	$ -	$ -
392										
393	**Customer Accounts Expense**									
394	Customer	TACRT	ACCAE	C05	$ -	$ -	$ -	$ -	$ -	$ -
395										
396	**Customer Service & Info.**									
397	Customer	TACRT	ACCSI	C05	$ -	$ -	$ -	$ -	$ -	$ -
398										
399	**Sales Expense**									
400	Customer	TACRT	DESEC	C06	$ -	$ -	$ -	$ -	$ -	$ -
401										
402	Total		ACT		$ -	$ -	$ -	$ -	$ -	$ -
403										
404										

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Class Allocation
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	A	B	C	D	E	N	O	P	Q	R	S	T
1				1	2	11	12	13	14	15	16	17
2					**Allocation**	**Time of Day**	**Time of Day**	**Service**	**Service**	**Outdoor Lighting**	**Lighting Energy**	**Traffic Energy**
3	**Description**		**Ref**	**Name**	**Vector**	**TOD-Secondary**	**TOD-Primary**	**RTS**	**FLS - Transmission**	**ST & POL**	**LE**	**TE**
348	**Accretion Expenses**											
349												
350	**Power Production Plant**											
351	Production Demand - Base		TACRT	ACPPDB	PPBDA	$ -	$ -	$ -	$ -	$ -	$ -	$ -
352	Production Demand - Inter.		TACRT	ACPPDI	PPWDA	-	-	-	-	-	-	-
353	Production Demand - Peak		TACRT	ACPPDP	PPSDA	-	-	-	-	-	-	-
354	Production Energy - Base		TACRT	ACPPEB	E01	-	-	-	-	-	-	-
355	Production Energy - Inter.		TACRT	ACPPEI	E01	-	-	-	-	-	-	-
356	Production Energy - Peak		TACRT	ACPPEP	E01	-	-	-	-	-	-	-
357	Total Power Production Plant			ACPPT		$ -	$ -	$ -	$ -	$ -	$ -	$ -
358												
359	**Transmission Plant**											
360	Transmission Demand - Base		TACRT	ACTRB	PPBDA	$ -	$ -	$ -	$ -	$ -	$ -	$ -
361	Transmission Demand - Inter.		TACRT	ACTRI	PPWDA	-	-	-	-	-	-	-
362	Transmission Demand - Peak		TACRT	ACTRP	PPSDA	-	-	-	-	-	-	-
363	Total Transmission Plant			ACTRT		$ -	$ -	$ -	$ -	$ -	$ -	$ -
364												
365	**Distribution Poles**											
366	Specific		TACRT	ACDPS	NCP	$ -	$ -	$ -	$ -	$ -	$ -	$ -
367												
368	**Distribution Substation**											
369	General		TACRT	ACDSG	NCP	$ -	$ -	$ -	$ -	$ -	$ -	$ -
370												
371	**Distribution Primary & Secondary Lines**											
372	Primary Specific		TACRT	ACDPLS	NCP	$ -	$ -	$ -	$ -	$ -	$ -	$ -
373	Primary Demand		TACRT	ACDPLD	NCP	-	-	-	-	-	-	-
374	Primary Customer		TACRT	ACDPLC	Cust08	-	-	-	-	-	-	-
375	Secondary Demand		TACRT	ACDSLD	SICD	-	-	-	-	-	-	-
376	Secondary Customer		TACRT	ACDSLC	Cust07	-	-	-	-	-	-	-
377	Total Distribution Primary & Secondary Lines			ACDLT		$ -	$ -	$ -	$ -	$ -	$ -	$ -
378												
379	**Distribution Line Transformers**											
380	Demand		TACRT	ACDLTD	SICDT	$ -	$ -	$ -	$ -	$ -	$ -	$ -
381	Customer		TACRT	ACDLTC	Cust09	-	-	-	-	-	-	-
382	Total Line Transformers			ACDLTT		$ -	$ -	$ -	$ -	$ -	$ -	$ -
383												
384	**Distribution Services**											
385	Customer		TACRT	ACDSC	C02	$ -	$ -	$ -	$ -	$ -	$ -	$ -
386												
387	**Distribution Meters**											
388	Customer		TACRT	ACDMC	C03	$ -	$ -	$ -	$ -	$ -	$ -	$ -
389												
390	**Distribution Street & Customer Lighting**											
391	Customer		TACRT	ACDSCL	C04	$ -	$ -	$ -	$ -	$ -	$ -	$ -
392												
393	**Customer Accounts Expense**											
394	Customer		TACRT	ACCAE	C05	$ -	$ -	$ -	$ -	$ -	$ -	$ -
395												
396	**Customer Service & Info.**											
397	Customer		TACRT	ACCSI	C05	$ -	$ -	$ -	$ -	$ -	$ -	$ -
398												
399	**Sales Expense**											
400	Customer		TACRT	DESEC	C06	$ -	$ -	$ -	$ -	$ -	$ -	$ -
401												
402	Total			ACT		$ -	$ -	$ -	$ -	$ -	$ -	$ -
403												
404												

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Class Allocation
12 Months Ended June 30, 2016

	A B	C	D	E	F	G	H	J	L	M
1			1	2	3	4	5	7	9	10
2				**Allocation**	**Total**	**Residential**	**General Service**	**All Electric Schools**	**Power Service**	**Power Service**
3	**Description**	**Ref**	**Name**	**Vector**	**System**	**Rate RS**	**GS**	**AES**	**PS-Secondary**	**PS-Primary**
405	**Property Taxes**									
406										
407	**Power Production Plant**									
408	Production Demand - Base	PTAX	PTPPDB	PPBDA	$ 5,028,231	$ 1,663,767	$ 511,546	$ 40,730	$ 566,286	$ 62,314
409	Production Demand - Inter.	PTAX	PTPPDI	PPWDA	4,899,831	2,584,646	358,188	40,600	395,790	55,687
410	Production Demand - Peak	PTAX	PTPPDP	PPSDA	4,442,453	1,812,678	536,708	39,703	496,159	64,937
411	Production Energy - Base	PTAX	PTPPEB	E01	-	-	-	-	-	-
412	Production Energy - Inter.	PTAX	PTPPEI	E01	-	-	-	-	-	-
413	Production Energy - Peak	PTAX	PTPPEP	E01	-	-	-	-	-	-
414	Total Power Production Plant		PTPPT		$ 14,370,515	$ 6,061,091	$ 1,406,442	$ 121,033	$ 1,458,235	$ 182,938
415										
416	**Transmission Plant**									
417	Transmission Demand - Base	PTAX	PTTRB	PPBDA	$ 945,810	$ 312,954	$ 96,222	$ 7,661	$ 106,518	$ 11,721
418	Transmission Demand - Inter.	PTAX	PTTRI	PPWDA	921,658	486,172	67,375	7,637	74,448	10,475
419	Transmission Demand - Peak	PTAX	PTTRP	PPSDA	835,625	340,965	100,955	7,468	93,327	12,215
420	Total Transmission Plant		PTTRT		$ 2,703,093	$ 1,140,091	$ 264,552	$ 22,766	$ 274,294	$ 34,411
421										
422	**Distribution Poles**									
423	Specific	PTAX	PTDPS	NCP	$ -	$ -	$ -	$ -	$ -	$ -
424										
425	**Distribution Substation**									
426	General	PTAX	PTDSG	NCP	$ 668,304	$ 318,676	$ 84,169	$ 8,876	$ 71,418	$ 9,199
427										
428	**Distribution Primary & Secondary Lines**									
429	Primary Specific	PTAX	PTDPLS	NCP	$ -	$ -	$ -	$ -	$ -	$ -
430	Primary Demand	PTAX	PTDPLD	NCP	906,346	432,185	114,148	12,037	96,856	12,476
431	Primary Customer	PTAX	PTDPLC	Cust08	1,358,094	1,087,377	207,455	1,602	11,764	500
432	Secondary Demand	PTAX	PTDSLD	SICD	302,115	238,688	57,100	4,085	-	-
433	Secondary Customer	PTAX	PTDSLC	Cust07	452,698	366,259	69,877	540	-	-
434	Total Distribution Primary & Secondary Lines		PTDLT		$ 3,019,253	$ 2,124,508	$ 448,580	$ 18,264	$ 108,620	$ 12,976
435										
436	**Distribution Line Transformers**									
437	Demand	PTAX	PTDLTD	SICDT	$ 553,233	$ 364,189	$ 87,123	$ 6,234	$ 56,571	$ -
438	Customer	PTAX	PTDLTC	Cust09	502,152	402,394	76,771	593	4,354	-
439	Total Line Transformers		PTDLTT		$ 1,055,386	$ 766,583	$ 163,894	$ 6,826	$ 60,925	$ -
440										
441	**Distribution Services**									
442	Customer	PTAX	PTDSC	C02	$ 319,618	$ 177,224	$ 136,460	$ 592	$ 4,906	$ -
443										
444	**Distribution Meters**									
445	Customer	PTAX	PTDMC	C03	$ 260,432	$ 156,705	$ 68,380	$ 714	$ 16,016	$ 3,963
446										
447	**Distribution Street & Customer Lighting**									
448	Customer	PTAX	PTDSCL	C04	$ 415,847	$ -	$ -	$ -	$ -	$ -
449										
450	**Customer Accounts Expense**									
451	Customer	PTAX	PTCAE	C05	$ -	$ -	$ -	$ -	$ -	$ -
452										
453	**Customer Service & Info.**									
454	Customer	PTAX	PTCSI	C05	$ -	$ -	$ -	$ -	$ -	$ -
455										
456	**Sales Expense**									
457	Customer	PTAX	PTSEC	C06	$ -	$ -	$ -	$ -	$ -	$ -
458										
459	Total		PTT		$ 22,812,447	$ 10,744,878	$ 2,572,477	$ 179,072	$ 1,994,413	$ 243,488
460										
461										

KENTUCKY UTILITIES COMPANY
Cost of Service Study
Class Allocation
12 Months Ended June 30, 2016

	A B	C	D	E	N	O	P	Q	R	S	T
1			1	2	11	12	13	14	15	16	17
2				**Allocation**	**Time of Day**	**Time of Day**	**Service**	**Service**	**Outdoor Lighting**	**Lighting Energy**	**Traffic Energy**
3	**Description**	**Ref**	**Name**	**Vector**	**TOD-Secondary**	**TOD-Primary**	**RTS**	**FLS - Transmission**	**ST & POL**	**LE**	**TE**
405	**Property Taxes**										
406											
407	**Power Production Plant**										
408	Production Demand - Base	PTAX	PTPPDB	PPBDA	$ 431,958	$ 1,125,119	$ 411,732	$ 143,805	$ 70,521	$ 119	$ 333
409	Production Demand - Inter.	PTAX	PTPPDI	PPWDA	256,780	741,188	297,949	128,361	40,352	66	225
410	Production Demand - Peak	PTAX	PTPPDP	PPSDA	329,225	813,651	299,502	49,713	-	-	178
411	Production Energy - Base	PTAX	PTPPEB	E01	-	-	-	-	-	-	-
412	Production Energy - Inter.	PTAX	PTPPEI	E01	-	-	-	-	-	-	-
413	Production Energy - Peak	PTAX	PTPPEP	E01	-	-	-	-	-	-	-
414	Total Power Production Plant		PTPPT		$ 1,017,963	$ 2,679,958	$ 1,009,183	$ 321,878	$ 110,872	$ 185	$ 736
415											
416	**Transmission Plant**										
417	Transmission Demand - Base	PTAX	PTTRB	PPBDA	$ 81,251	$ 211,635	$ 77,447	$ 27,050	$ 13,265	$ 22	$ 63
418	Transmission Demand - Inter.	PTAX	PTTRI	PPWDA	48,300	139,417	56,044	24,145	7,590	12	42
419	Transmission Demand - Peak	PTAX	PTTRP	PPSDA	61,927	153,048	56,336	9,351	-	-	34
420	Total Transmission Plant		PTTRT		$ 191,479	$ 504,100	$ 189,827	$ 60,545	$ 20,855	$ 35	$ 138
421											
422	**Distribution Poles**										
423	Specific	PTAX	PTDPS	NCP	$ -	$ -	$ -	$ -	$ -	$ -	$ -
424											
425	**Distribution Substation**										
426	General	PTAX	PTDSG	NCP	$ 45,879	$ 124,491	$ -	$ -	$ 5,562	$ 8	$ 27
427											
428	**Distribution Primary & Secondary Lines**										
429	Primary Specific	PTAX	PTDPLS	NCP	$ -	$ -	$ -	$ -	$ -	$ -	$ -
430	Primary Demand	PTAX	PTDPLD	NCP	62,220	168,833	-	-	7,543	11	37
431	Primary Customer	PTAX	PTDPLC	Cust08	1,180	644	-	-	47,361	1	210
432	Secondary Demand	PTAX	PTDSLD	SICD	-	-	-	-	2,227	3	11
433	Secondary Customer	PTAX	PTDSLC	Cust07	-	-	-	-	15,953	0	71
434	Total Distribution Primary & Secondary Lines		PTDLT		$ 63,400	$ 169,477	$ -	$ -	$ 73,084	$ 15	$ 328
435											
436	**Distribution Line Transformers**										
437	Demand	PTAX	PTDLTD	SICDT	$ 35,697	$ -	$ -	$ -	$ 3,398	$ 5	$ 17
438	Customer	PTAX	PTDLTC	Cust09	437	-	-	-	17,526	0	78
439	Total Line Transformers		PTDLTT		$ 36,134	$ -	$ -	$ -	$ 20,925	$ 5	$ 94
440											
441	**Distribution Services**										
442	Customer	PTAX	PTDSC	C02	$ 436	$ -	$ -	$ -	$ -	$ -	$ -
443											
444	**Distribution Meters**										
445	Customer	PTAX	PTDMC	C03	$ 2,095	$ 6,739	$ 5,335	$ 212	$ -	$ 1	$ 272
446											
447	**Distribution Street & Customer Lighting**										
448	Customer	PTAX	PTDSCL	C04	$ -	$ -	$ -	$ -	$ 415,847	$ -	$ -
449											
450	**Customer Accounts Expense**										
451	Customer	PTAX	PTCAE	C05	$ -	$ -	$ -	$ -	$ -	$ -	$ -
452											
453	**Customer Service & Info.**										
454	Customer	PTAX	PTCSI	C05	$ -	$ -	$ -	$ -	$ -	$ -	$ -
455											
456	**Sales Expense**										
457	Customer	PTAX	PTSEC	C06	$ -	$ -	$ -	$ -	$ -	$ -	$ -
458											
459	Total		PTT		$ 1,357,385	$ 3,484,765	$ 1,204,345	$ 382,636	$ 647,145	$ 248	$ 1,596
460											
461											

KENTUCKY UTILITIES COMPANY
Cost of Service Study
Class Allocation
12 Months Ended June 30, 2016

	A B	C	D	E	F	G	H	J	L	M
1			1	2	3	4	5	7	9	10
2				**Allocation**	**Total**	**Residential**	**General Service**	**All Electric Schools**	**Power Service**	**Power Service**
3	**Description**	**Ref**	**Name**	**Vector**	**System**	**Rate RS**	**GS**	**AES**	**PS-Secondary**	**PS-Primary**
462	**Other Taxes**									
463										
464	**Power Production Plant**									
465	Production Demand - Base	OTAX	OTPPDB	PPBDA	$ 2,692,176	$ 890,801	$ 273,888	$ 21,807	$ 303,197	$ 33,364
466	Production Demand - Inter.	OTAX	OTPPDI	PPWDA	2,623,429	1,383,851	191,778	21,738	211,911	29,816
467	Production Demand - Peak	OTAX	OTPPDP	PPSDA	2,378,544	970,530	287,360	21,257	265,649	34,768
468	Production Energy - Base	OTAX	OTPPEB	E01	-	-	-	-	-	-
469	Production Energy - Inter.	OTAX	OTPPEI	E01	-	-	-	-	-	-
470	Production Energy - Peak	OTAX	OTPPEP	E01	-	-	-	-	-	-
471	Total Power Production Plant		OTPPT		$ 7,694,149	$ 3,245,182	$ 753,026	$ 64,802	$ 780,757	$ 97,947
472										
473	**Transmission Plant**									
474	Transmission Demand - Base	OTAX	OTTRB	PPBDA	$ 506,398	$ 167,560	$ 51,518	$ 4,102	$ 57,031	$ 6,276
475	Transmission Demand - Inter.	OTAX	OTTRI	PPWDA	493,467	260,302	36,073	4,089	39,860	5,608
476	Transmission Demand - Peak	OTAX	OTTRP	PPSDA	447,404	182,557	54,052	3,999	49,969	6,540
477	Total Transmission Plant		OTTRT		$ 1,447,269	$ 610,418	$ 141,644	$ 12,189	$ 146,860	$ 18,424
478										
479	**Distribution Poles**									
480	Specific	OTAX	OTDPS	NCP	$ -	$ -	$ -	$ -	$ -	$ -
481										
482	**Distribution Substation**									
483	General	OTAX	OTDSG	NCP	$ 357,818	$ 170,623	$ 45,065	$ 4,752	$ 38,238	$ 4,925
484										
485	**Distribution Primary & Secondary Lines**									
486	Primary Specific	OTAX	OTDPLS	NCP	$ -	$ -	$ -	$ -	$ -	$ -
487	Primary Demand	OTAX	OTDPLD	NCP	485,269	231,397	61,116	6,445	51,858	6,680
488	Primary Customer	OTAX	OTDPLC	Cust08	727,140	582,195	111,074	858	6,299	268
489	Secondary Demand	OTAX	OTDSLD	SICD	161,756	127,797	30,572	2,187	-	-
490	Secondary Customer	OTAX	OTDSLC	Cust07	242,380	196,099	37,413	289	-	-
491	Total Distribution Primary & Secondary Lines		OTDLT		$ 1,616,545	$ 1,137,488	$ 240,175	$ 9,779	$ 58,156	$ 6,948
492										
493	**Distribution Line Transformers**									
494	Demand	OTAX	OTDLTD	SICDT	$ 296,208	$ 194,991	$ 46,647	$ 3,338	$ 30,289	$ -
495	Customer	OTAX	OTDLTC	Cust09	268,859	215,447	41,104	317	2,331	-
496	Total Line Transformers		OTDLTT		$ 565,066	$ 410,438	$ 87,751	$ 3,655	$ 32,620	$ -
497										
498	**Distribution Services**									
499	Customer	OTAX	OTDSC	C02	$ 171,127	$ 94,888	$ 73,063	$ 317	$ 2,627	$ -
500										
501	**Distribution Meters**									
502	Customer	OTAX	OTDMC	C03	$ 139,439	$ 83,902	$ 36,611	$ 382	$ 8,575	$ 2,122
503										
504	**Distribution Street & Customer Lighting**									
505	Customer	OTAX	OTDSCL	C04	$ 222,649	$ -	$ -	$ -	$ -	$ -
506										
507	**Customer Accounts Expense**									
508	Customer	OTAX	OTCAE	C05	$ -	$ -	$ -	$ -	$ -	$ -
509										
510	**Customer Service & Info.**									
511	Customer	OTAX	OTCSI	C05	$ -	$ -	$ -	$ -	$ -	$ -
512										
513	**Sales Expense**									
514	Customer	OTAX	OTSEC	C06	$ -	$ -	$ -	$ -	$ -	$ -
515										
516	Total		OTT		$ 12,214,063	$ 5,752,939	$ 1,377,336	$ 95,877	$ 1,067,833	$ 130,366
517										
518										
519										

KENTUCKY UTILITIES COMPANY
Cost of Service Study
Class Allocation
12 Months Ended June 30, 2016

	A / B	C	D	E	N	O	P	Q	R	S	T
1			1	2	11	12	13	14	15	16	17
2				**Allocation**	**Time of Day**	**Time of Day**	**Service**	**Service**	**Outdoor Lighting**	**Lighting Energy**	**Traffic Energy**
3	**Description**	**Ref**	**Name**	**Vector**	**TOD-Secondary**	**TOD-Primary**	**RTS**	**FLS - Transmission**	**ST & POL**	**LE**	**TE**
462	**Other Taxes**										
463											
464	**Power Production Plant**										
465	Production Demand - Base	OTAX	OTPPDB	PPBDA	$ 231,276	$ 602,402	$ 220,446	$ 76,995	$ 37,758	$ 64	$ 178
466	Production Demand - Inter.	OTAX	OTPPDI	PPWDA	137,483	396,841	159,526	68,726	21,605	35	120
467	Production Demand - Peak	OTAX	OTPPDP	PPSDA	176,271	435,639	160,357	26,617	-	-	95
468	Production Energy - Base	OTAX	OTPPEB	E01	-	-	-	-	-	-	-
469	Production Energy - Inter.	OTAX	OTPPEI	E01	-	-	-	-	-	-	-
470	Production Energy - Peak	OTAX	OTPPEP	E01	-	-	-	-	-	-	-
471	Total Power Production Plant		OTPPT		$ 545,030	$ 1,434,882	$ 540,329	$ 172,338	$ 59,362	$ 99	$ 394
472											
473	**Transmission Plant**										
474	Transmission Demand - Base	OTAX	OTTRB	PPBDA	$ 43,503	$ 113,312	$ 41,466	$ 14,483	$ 7,102	$ 12	$ 34
475	Transmission Demand - Inter.	OTAX	OTTRI	PPWDA	25,861	74,646	30,007	12,927	4,064	7	23
476	Transmission Demand - Peak	OTAX	OTTRP	PPSDA	33,157	81,944	30,163	5,007	-	-	18
477	Total Transmission Plant		OTTRT		$ 102,520	$ 269,901	$ 101,636	$ 32,417	$ 11,166	$ 19	$ 74
478											
479	**Distribution Poles**										
480	Specific	OTAX	OTDPS	NCP	$ -	$ -	$ -	$ -	$ -	$ -	$ -
481											
482	**Distribution Substation**										
483	General	OTAX	OTDSG	NCP	$ 24,564	$ 66,654	$ -	$ -	$ 2,978	$ 4	$ 15
484											
485	**Distribution Primary & Secondary Lines**										
486	Primary Specific	OTAX	OTDPLS	NCP	$ -	$ -	$ -	$ -	$ -	$ -	$ -
487	Primary Demand	OTAX	OTDPLD	NCP	33,313	90,395	-	-	4,039	6	20
488	Primary Customer	OTAX	OTDPLC	Cust08	632	345	-	-	25,358	0	112
489	Secondary Demand	OTAX	OTDSLD	SICD	-	-	-	-	1,192	2	6
490	Secondary Customer	OTAX	OTDSLC	Cust07	-	-	-	-	8,541	0	38
491	Total Distribution Primary & Secondary Lines		OTDLT		$ 33,945	$ 90,740	$ -	$ -	$ 39,130	$ 8	$ 176
492											
493	**Distribution Line Transformers**										
494	Demand	OTAX	OTDLTD	SICDT	$ 19,113	$ -	$ -	$ -	$ 1,819	$ 3	$ 9
495	Customer	OTAX	OTDLTC	Cust09	234	-	-	-	9,384	0	42
496	Total Line Transformers		OTDLTT		$ 19,346	$ -	$ -	$ -	$ 11,203	$ 3	$ 50
497											
498	**Distribution Services**										
499	Customer	OTAX	OTDSC	C02	$ 233	$ -	$ -	$ -	$ -	$ -	$ -
500											
501	**Distribution Meters**										
502	Customer	OTAX	OTDMC	C03	$ 1,122	$ 3,608	$ 2,856	$ 114	$ -	$ 0	$ 146
503											
504	**Distribution Street & Customer Lighting**										
505	Customer	OTAX	OTDSCL	C04	$ -	$ -	$ -	$ -	$ 222,649	$ -	$ -
506											
507	**Customer Accounts Expense**										
508	Customer	OTAX	OTCAE	C05	$ -	$ -	$ -	$ -	$ -	$ -	$ -
509											
510	**Customer Service & Info.**										
511	Customer	OTAX	OTCSI	C05	$ -	$ -	$ -	$ -	$ -	$ -	$ -
512											
513	**Sales Expense**										
514	Customer	OTAX	OTSEC	C06	$ -	$ -	$ -	$ -	$ -	$ -	$ -
515											
516	Total		OTT		$ 726,761	$ 1,865,786	$ 644,821	$ 204,868	$ 346,489	$ 133	$ 855
517											
518											
519											

KENTUCKY UTILITIES COMPANY
Cost of Service Study
Class Allocation
12 Months Ended June 30, 2016

	A	B	C	D	E	F	G	H	J	L	M
1				1	2	3	4	5	7	9	10
2					Allocation	Total	Residential	General Service	All Electric Schools	Power Service	Power Service
3	**Description**		Ref	Name	Vector	System	Rate RS	GS	AES	PS-Secondary	PS-Primary
520	**Gain Disposition of Allowances**										
521											
522	**Power Production Plant**										
523	Production Demand - Base		GAIN	OTPPDB	PPBDA	$ -	$ -	$ -	$ -	$ -	$ -
524	Production Demand - Inter.		GAIN	OTPPDI	PPWDA	-	-	-	-	-	-
525	Production Demand - Peak		GAIN	OTPPDP	PPSDA	-	-	-	-	-	-
526	Production Energy - Base		GAIN	OTPPEB	E01	-	-	-	-	-	-
527	Production Energy - Inter.		GAIN	OTPPEI	E01	-	-	-	-	-	-
528	Production Energy - Peak		GAIN	OTPPEP	E01	-	-	-	-	-	-
529	Total Power Production Plant			OTPPT		$ -	$ -	$ -	$ -	$ -	$ -
530											
531	**Transmission Plant**										
532	Transmission Demand - Base		GAIN	OTTRB	PPBDA	$ -	$ -	$ -	$ -	$ -	$ -
533	Transmission Demand - Inter.		GAIN	OTTRI	PPWDA	-	-	-	-	-	-
534	Transmission Demand - Peak		GAIN	OTTRP	PPSDA	-	-	-	-	-	-
535	Total Transmission Plant			OTTRT		$ -	$ -	$ -	$ -	$ -	$ -
536											
537	**Distribution Poles**										
538	Specific		GAIN	OTDPS	NCP	$ -	$ -	$ -	$ -	$ -	$ -
539											
540	**Distribution Substation**										
541	General		GAIN	OTDSG	NCP	$ -	$ -	$ -	$ -	$ -	$ -
542											
543	**Distribution Primary & Secondary Lines**										
544	Primary Specific		GAIN	OTDPLS	NCP	$ -	$ -	$ -	$ -	$ -	$ -
545	Primary Demand		GAIN	OTDPLD	NCP	-	-	-	-	-	-
546	Primary Customer		GAIN	OTDPLC	Cust08	-	-	-	-	-	-
547	Secondary Demand		GAIN	OTDSLD	SICD	-	-	-	-	-	-
548	Secondary Customer		GAIN	OTDSLC	Cust07	-	-	-	-	-	-
549	Total Distribution Primary & Secondary Lines			OTDLT		$ -	$ -	$ -	$ -	$ -	$ -
550											
551	**Distribution Line Transformers**										
552	Demand		GAIN	OTDLTD	SICDT	$ -	$ -	$ -	$ -	$ -	$ -
553	Customer		GAIN	OTDLTC	Cust09	-	-	-	-	-	-
554	Total Line Transformers			OTDLTT		$ -	$ -	$ -	$ -	$ -	$ -
555											
556	**Distribution Services**										
557	Customer		GAIN	OTDSC	C02	$ -	$ -	$ -	$ -	$ -	$ -
558											
559	**Distribution Meters**										
560	Customer		GAIN	OTDMC	C03	$ -	$ -	$ -	$ -	$ -	$ -
561											
562	**Distribution Street & Customer Lighting**										
563	Customer		GAIN	OTDSCL	C04	$ -	$ -	$ -	$ -	$ -	$ -
564											
565	**Customer Accounts Expense**										
566	Customer		GAIN	OTCAE	C05	$ -	$ -	$ -	$ -	$ -	$ -
567											
568	**Customer Service & Info.**										
569	Customer		GAIN	OTCSI	C05	$ -	$ -	$ -	$ -	$ -	$ -
570											
571	**Sales Expense**										
572	Customer		GAIN	OTSEC	C06	$ -	$ -	$ -	$ -	$ -	$ -
573											
574	Total			OTT		$ -	$ -	$ -	$ -	$ -	$ -
575											
576											
577											
578											
579											
580											
581											

KENTUCKY UTILITIES COMPANY
Cost of Service Study
Class Allocation
12 Months Ended June 30, 2016

	A	B	C	D	E	N	O	P	Q	R	S	T
1				1	2	11	12	13	14	15	16	17
2					**Allocation**	**Time of Day**	**Time of Day**	**Service**	**Service**	**Outdoor Lighting**	**Lighting Energy**	**Traffic Energy**
3	**Description**		**Ref**	**Name**	**Vector**	**TOD-Secondary**	**TOD-Primary**	**RTS**	**FLS - Transmission**	**ST & POL**	**LE**	**TE**
520	**Gain Disposition of Allowances**											
521												
522	**Power Production Plant**											
523	Production Demand - Base		GAIN	OTPPDB	PPBDA	$ -	$ -	$ -	$ -	$ -	$ -	$ -
524	Production Demand - Inter.		GAIN	OTPPDI	PPWDA	-	-	-	-	-	-	-
525	Production Demand - Peak		GAIN	OTPPDP	PPSDA	-	-	-	-	-	-	-
526	Production Energy - Base		GAIN	OTPPEB	E01	-	-	-	-	-	-	-
527	Production Energy - Inter.		GAIN	OTPPEI	E01	-	-	-	-	-	-	-
528	Production Energy - Peak		GAIN	OTPPEP	E01	-	-	-	-	-	-	-
529	Total Power Production Plant			OTPPT		$ -	$ -	$ -	$ -	$ -	$ -	$ -
530												
531	**Transmission Plant**											
532	Transmission Demand - Base		GAIN	OTTRB	PPBDA	$ -	$ -	$ -	$ -	$ -	$ -	$ -
533	Transmission Demand - Inter.		GAIN	OTTRI	PPWDA	-	-	-	-	-	-	-
534	Transmission Demand - Peak		GAIN	OTTRP	PPSDA	-	-	-	-	-	-	-
535	Total Transmission Plant			OTTRT		$ -	$ -	$ -	$ -	$ -	$ -	$ -
536												
537	**Distribution Poles**											
538	Specific		GAIN	OTDPS	NCP	$ -	$ -	$ -	$ -	$ -	$ -	$ -
539												
540	**Distribution Substation**											
541	General		GAIN	OTDSG	NCP	$ -	$ -	$ -	$ -	$ -	$ -	$ -
542												
543	**Distribution Primary & Secondary Lines**											
544	Primary Specific		GAIN	OTDPLS	NCP	$ -	$ -	$ -	$ -	$ -	$ -	$ -
545	Primary Demand		GAIN	OTDPLD	NCP	-	-	-	-	-	-	-
546	Primary Customer		GAIN	OTDPLC	Cust08	-	-	-	-	-	-	-
547	Secondary Demand		GAIN	OTDSLD	SICD	-	-	-	-	-	-	-
548	Secondary Customer		GAIN	OTDSLC	Cust07	-	-	-	-	-	-	-
549	Total Distribution Primary & Secondary Lines			OTDLT		$ -	$ -	$ -	$ -	$ -	$ -	$ -
550												
551	**Distribution Line Transformers**											
552	Demand		GAIN	OTDLTD	SICDT	$ -	$ -	$ -	$ -	$ -	$ -	$ -
553	Customer		GAIN	OTDLTC	Cust09	-	-	-	-	-	-	-
554	Total Line Transformers			OTDLTT		$ -	$ -	$ -	$ -	$ -	$ -	$ -
555												
556	**Distribution Services**											
557	Customer		GAIN	OTDSC	C02	$ -	$ -	$ -	$ -	$ -	$ -	$ -
558												
559	**Distribution Meters**											
560	Customer		GAIN	OTDMC	C03	$ -	$ -	$ -	$ -	$ -	$ -	$ -
561												
562	**Distribution Street & Customer Lighting**											
563	Customer		GAIN	OTDSCL	C04	$ -	$ -	$ -	$ -	$ -	$ -	$ -
564												
565	**Customer Accounts Expense**											
566	Customer		GAIN	OTCAE	C05	$ -	$ -	$ -	$ -	$ -	$ -	$ -
567												
568	**Customer Service & Info.**											
569	Customer		GAIN	OTCSI	C05	$ -	$ -	$ -	$ -	$ -	$ -	$ -
570												
571	**Sales Expense**											
572	Customer		GAIN	OTSEC	C06	$ -	$ -	$ -	$ -	$ -	$ -	$ -
573												
574	Total			OTT		$ -	$ -	$ -	$ -	$ -	$ -	$ -
575												
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KENTUCKY UTILITIES COMPANY
Cost of Service Study
Class Allocation
12 Months Ended June 30, 2016

A/B	C	D	E	F	G	H	J	L	M
		1	2	3	4	5	7	9	10
Description	**Ref**	**Name**	**Allocation Vector**	**Total System**	**Residential Rate RS**	**General Service GS**	**All Electric Schools AES**	**Power Service PS-Secondary**	**Power Service PS-Primary**
Interest									
Power Production Plant									
Production Demand - Base	INTLTD	INTPPDB	PPBDA	$ 18,413,493	$ 6,092,752	$ 1,873,294	$ 149,155	$ 2,073,754	$ 228,196
Production Demand - Inter.	INTLTD	INTPPDI	PPWDA	17,943,288	9,465,029	1,311,692	148,678	1,449,391	203,927
Production Demand - Peak	INTLTD	INTPPDP	PPSDA	16,268,361	6,638,066	1,965,436	145,393	1,816,944	237,800
Production Energy - Base	INTLTD	INTPPEB	E01	-	-	-	-	-	-
Production Energy - Inter.	INTLTD	INTPPEI	E01	-	-	-	-	-	-
Production Energy - Peak	INTLTD	INTPPEP	E01	-	-	-	-	-	-
Total Power Production Plant		INTPPT		$ 52,625,141	$ 22,195,847	$ 5,150,422	$ 443,225	$ 5,340,089	$ 669,923
Transmission Plant									
Transmission Demand - Base	INTLTD	INTTRB	PPBDA	$ 3,463,576	$ 1,146,046	$ 352,367	$ 28,056	$ 390,073	$ 42,924
Transmission Demand - Inter.	INTLTD	INTTRI	PPWDA	3,375,131	1,780,371	246,729	27,966	272,630	38,359
Transmission Demand - Peak	INTLTD	INTTRP	PPSDA	3,060,077	1,248,620	369,698	27,348	341,767	44,730
Total Transmission Plant		INTTRT		$ 9,898,785	$ 4,175,037	$ 968,794	$ 83,371	$ 1,004,470	$ 126,013
Distribution Poles									
Specific	INTLTD	INTDPS	NCP	$ -	$ -	$ -	$ -	$ -	$ -
Distribution Substation									
General	INTLTD	INTDSG	NCP	$ 2,447,345	$ 1,167,000	$ 308,227	$ 32,503	$ 261,533	$ 33,689
Distribution Primary & Secondary Lines									
Primary Specific	INTLTD	INTDPLS	NCP	$ -	$ -	$ -	$ -	$ -	$ -
Primary Demand	INTLTD	INTDPLD	NCP	3,319,058	1,582,669	418,014	44,080	354,687	45,688
Primary Customer	INTLTD	INTDPLC	Cust08	4,973,370	3,981,998	759,705	5,866	43,081	1,832
Secondary Demand	INTLTD	INTDSLD	SICD	1,106,353	874,081	209,103	14,961	-	-
Secondary Customer	INTLTD	INTDSLC	Cust07	1,657,790	1,341,247	255,890	1,976	-	-
Total Distribution Primary & Secondary Lines		INTDLT		$ 11,056,571	$ 7,779,996	$ 1,642,711	$ 66,883	$ 397,768	$ 47,520
Distribution Line Transformers									
Demand	INTLTD	INTDLTD	SICDT	$ 2,025,952	$ 1,333,666	$ 319,048	$ 22,828	$ 207,164	$ -
Customer	INTLTD	INTDLTC	Cust09	1,838,893	1,473,577	281,136	2,171	15,943	-
Total Line Transformers		INTDLTT		$ 3,864,845	$ 2,807,244	$ 600,184	$ 24,998	$ 223,107	$ -
Distribution Services									
Customer	INTLTD	INTDSC	C02	$ 1,170,448	$ 648,999	$ 499,721	$ 2,169	$ 17,965	$ -
Distribution Meters									
Customer	INTLTD	INTDMC	C03	$ 953,708	$ 573,857	$ 250,409	$ 2,616	$ 58,651	$ 14,514
Distribution Street & Customer Lighting									
Customer	INTLTD	INTDSCL	C04	$ 1,522,840	$ -	$ -	$ -	$ -	$ -
Customer Accounts Expense									
Customer	INTLTD	INTCAE	C05	$ -	$ -	$ -	$ -	$ -	$ -
Customer Service & Info.									
Customer	INTLTD	INTCSI	C05	$ -	$ -	$ -	$ -	$ -	$ -
Sales Expense									
Customer	INTLTD	INTSEC	C06	$ -	$ -	$ -	$ -	$ -	$ -
Total		INTT		$ 83,539,684	$ 39,347,978	$ 9,420,468	$ 655,764	$ 7,303,583	$ 891,658

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	A / B	C	D	E	N	O	P	Q	R	S	T
1			1	2	11	12	13	14	15	16	17
2				**Allocation**	**Time of Day**	**Time of Day**	**Service**	**Service**	**Outdoor Lighting**	**Lighting Energy**	**Traffic Energy**
3	**Description**	**Ref**	**Name**	**Vector**	**TOD-Secondary**	**TOD-Primary**	**RTS**	**FLS - Transmission**	**ST & POL**	**LE**	**TE**
582	**Interest**										
583											
584	**Power Production Plant**										
585	Production Demand - Base	INTLTD	INTPPDB	PPBDA	$ 1,581,840	$ 4,120,209	$ 1,507,771	$ 526,617	$ 258,248	$ 436	$ 1,220
586	Production Demand - Inter.	INTLTD	INTPPDI	PPWDA	940,335	2,714,247	1,091,096	470,059	147,769	241	824
587	Production Demand - Peak	INTLTD	INTPPDP	PPSDA	1,205,629	2,979,609	1,096,783	182,049	-	-	652
588	Production Energy - Base	INTLTD	INTPPEB	E01	-	-	-	-	-	-	-
589	Production Energy - Inter.	INTLTD	INTPPEI	E01	-	-	-	-	-	-	-
590	Production Energy - Peak	INTLTD	INTPPEP	E01	-	-	-	-	-	-	-
591	Total Power Production Plant		INTPPT		$ 3,727,804	$ 9,814,064	$ 3,695,651	$ 1,178,726	$ 406,017	$ 677	$ 2,696
592											
593	**Transmission Plant**										
594	Transmission Demand - Base	INTLTD	INTTRB	PPBDA	$ 297,544	$ 775,011	$ 283,612	$ 99,057	$ 48,576	$ 82	$ 230
595	Transmission Demand - Inter.	INTLTD	INTTRI	PPWDA	176,877	510,550	205,235	88,418	27,795	45	155
596	Transmission Demand - Peak	INTLTD	INTTRP	PPSDA	226,779	560,464	206,305	34,243	-	-	123
597	Total Transmission Plant		INTTRT		$ 701,200	$ 1,846,025	$ 695,152	$ 221,718	$ 76,372	$ 127	$ 507
598											
599	**Distribution Poles**										
600	Specific	INTLTD	INTDPS	NCP	$ -	$ -	$ -	$ -	$ -	$ -	$ -
601											
602	**Distribution Substation**										
603	General	INTLTD	INTDSG	NCP	$ 168,009	$ 455,889	$ -	$ -	$ 20,368	$ 29	$ 99
604											
605	**Distribution Primary & Secondary Lines**										
606	Primary Specific	INTLTD	INTDPLS	NCP	$ -	$ -	$ -	$ -	$ -	$ -	$ -
607	Primary Demand	INTLTD	INTDPLD	NCP	227,851	618,271	-	-	27,623	39	135
608	Primary Customer	INTLTD	INTDPLC	Cust08	4,321	2,359	-	-	173,437	2	768
609	Secondary Demand	INTLTD	INTDSLD	SICD	-	-	-	-	8,156	12	40
610	Secondary Customer	INTLTD	INTDSLC	Cust07	-	-	-	-	58,418	1	259
611	Total Distribution Primary & Secondary Lines		INTDLT		$ 232,172	$ 620,630	$ -	$ -	$ 267,635	$ 54	$ 1,201
612											
613	**Distribution Line Transformers**										
614	Demand	INTLTD	INTDLTD	SICDT	$ 130,723	$ -	$ -	$ -	$ 12,444	$ 18	$ 61
615	Customer	INTLTD	INTDLTC	Cust09	1,599	-	-	-	64,182	1	284
616	Total Line Transformers		INTDLTT		$ 132,322	$ -	$ -	$ -	$ 76,627	$ 19	$ 345
617											
618	**Distribution Services**										
619	Customer	INTLTD	INTDSC	C02	$ 1,595	$ -	$ -	$ -	$ -	$ -	$ -
620											
621	**Distribution Meters**										
622	Customer	INTLTD	INTDMC	C03	$ 7,673	$ 24,677	$ 19,536	$ 777	$ -	$ 3	$ 996
623											
624	**Distribution Street & Customer Lighting**										
625	Customer	INTLTD	INTDSCL	C04	$ -	$ -	$ -	$ -	$ 1,522,840	$ -	$ -
626											
627	**Customer Accounts Expense**										
628	Customer	INTLTD	INTCAE	C05	$ -	$ -	$ -	$ -	$ -	$ -	$ -
629											
630	**Customer Service & Info.**										
631	Customer	INTLTD	INTCSI	C05	$ -	$ -	$ -	$ -	$ -	$ -	$ -
632											
633	**Sales Expense**										
634	Customer	INTLTD	INTSEC	C06	$ -	$ -	$ -	$ -	$ -	$ -	$ -
635											
636	Total		INTT		$ 4,970,775	$ 12,761,286	$ 4,410,338	$ 1,401,221	$ 2,369,859	$ 909	$ 5,845
637											
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	A B	C	D	E	F	G	H	J	L	M
1			1	2	3	4	5	7	9	10
2				**Allocation**	**Total**	**Residential**	**General Service**	**All Electric Schools**	**Power Service**	**Power Service**
3	**Description**	**Ref**	**Name**	**Vector**	**System**	**Rate RS**	**GS**	**AES**	**PS-Secondary**	**PS-Primary**
648	**Cost of Service Summary -- Unadjusted**									
649										
650	**Operating Revenues**									
651	Sales		REVUC	R01	$ 1,365,866,924	$ 515,927,090	$ 189,855,309	$ 11,008,968	$ 171,520,080	$ 17,766,215
655	Off-System Sales			OSSALL	24,736,304	9,539,699	2,459,015	205,173	2,619,701	311,588
657	LATE PAYMENT CHARGES			LPAY	3,786,198	3,053,813	523,341	741	95,061	5,335
658	RECONNECT CHARGES			MISCSERV	2,027,537	1,839,243	65,403	809	4,049	77,204
659	OTHER SERVICE CHARGES			MISCSERV	55,410	50,264	1,787	22	111	2,110
660	RENT FROM ELEC PROPERTY			UPT	3,491,578	1,643,117	393,294	27,425	305,670	37,328
661	TRANSMISSION SERVICE			PLTRT	13,300,016	5,609,583	1,301,673	112,017	1,349,607	169,311
662	ANCILLARY SERVICES			PLTRT	2,561,566	1,080,399	250,700	21,574	259,933	32,609
663	TAX REMITTANCE COMPENSATION			R01	7,206	2,722	1,002	58	905	94
664	RETURN CHECK CHARGES			MISCSERV	142,291	129,077	4,590	57	284	5,418
665	OTHER MISC REVENUES			MISCSERV	12,814	11,624	413	5	26	488
666	EXCESS FACILITIES CHARGES			MISCSERV	30,775	27,917	993	12	61	1,172
667	FORFEITED REFUNDABLE ADVANCES			R01	139,838	52,821	19,437	1,127	17,560	1,819
668	Unbilled Revenue		UNBREV	R01	-	-	-	-	-	-
669										
670	Total Operating Revenues		TOR		$ 1,416,158,457	$ 538,967,369	$ 194,876,957	$ 11,377,988	$ 176,173,047	$ 18,410,690
671										
672	**Operating Expenses**									
673	Operation and Maintenance Expenses				$ 957,152,611	$ 371,972,774	$ 109,481,239	$ 7,741,233	$ 96,902,740	$ 10,854,248
674	Depreciation and Amortization Expenses				189,760,380	89,353,112	21,390,781	1,489,868	16,597,453	2,026,479
675	Regulatory Credits and Accretion Expenses				-	-	-	-	-	-
676	Property Taxes			NPT	22,812,447	10,744,878	2,572,477	179,072	1,994,413	243,488
677	Other Taxes				12,214,063	5,752,939	1,377,336	95,877	1,067,833	130,366
678	Gain Disposition of Allowances				-	-	-	-	-	-
679	State and Federal Income Taxes			TAXINC	58,839,387	$ 6,327,901	$ 19,328,242	$ 435,041	$ 19,982,756	$ 1,605,356
680	Specific Assignment of Curtailable Service Rider Avoided Cost				(11,877,948)	-	-	-	-	-
681	Allocation of Curtailable Service Rider Credits			INTCRE	11,877,948	$ 5,590,836	$ 1,137,787	$ 102,098	$ 1,134,039	$ 153,363
682										
683	Total Operating Expenses		TOE		$ 1,240,778,888	$ 489,742,440	$ 155,287,862	$ 10,043,188	$ 137,679,234	$ 15,013,301
684										
685	Net Operating Income (Unadjusted)		TOM		$ 175,379,569	$ 49,224,929	$ 39,589,095	$ 1,334,800	$ 38,493,813	$ 3,397,389
686										
687	Net Cost Rate Base				$ 3,669,268,542	$ 1,723,572,451	$ 415,582,631	$ 28,774,055	$ 320,970,904	$ 39,029,579
688										
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	A / B	C	D	E	N	O	P	Q	R	S	T
1			1	2	11	12	13	14	15	16	17
2				**Allocation**	**Time of Day**	**Time of Day**	**Service**	**Service**	**Outdoor Lighting**	**Lighting Energy**	**Traffic Energy**
3	**Description**	**Ref**	**Name**	**Vector**	**TOD-Secondary**	**TOD-Primary**	**RTS**	**FLS - Transmission**	**ST & POL**	**LE**	**TE**
648	**Cost of Service Summary -- Unadjusted**										
649											
650	**Operating Revenues**										
651	Sales		REVUC	R01	$ 99,544,974	$ 235,200,859	$ 84,408,729	$ 15,354,394	$ 25,141,640	$ 10,497	$ 128,169
655	Off-System Sales			OSSALL	1,900,378	4,979,398	1,851,709	614,966	252,838	425	1,415
657	LATE PAYMENT CHARGES			LPAY	38,175	49,887	19,845	-	-	-	-
658	RECONNECT CHARGES			MISCSERV	3,190	120	-	153	37,366	-	-
659	OTHER SERVICE CHARGES			MISCSERV	87	3	-	4	1,021	-	-
660	RENT FROM ELEC PROPERTY			UPT	208,089	534,356	184,845	58,730	98,442	38	244
661	TRANSMISSION SERVICE			PLTRT	942,132	2,480,320	934,006	297,901	102,613	171	681
662	ANCILLARY SERVICES			PLTRT	181,453	477,707	179,888	57,375	19,763	33	131
663	TAX REMITTANCE COMPENSATION			R01	525	1,241	445	81	133	0	1
664	RETURN CHECK CHARGES			MISCSERV	224	8	-	11	2,622	-	-
665	OTHER MISC REVENUES			MISCSERV	20	1	-	1	236	-	-
666	EXCESS FACILITIES CHARGES			MISCSERV	48	2	-	2	567	-	-
667	FORFEITED REFUNDABLE ADVANCES			R01	10,191	24,080	8,642	1,572	2,574	1	13
668	Unbilled Revenue		UNBREV	R01	-	-	-	-	-	-	-
669											
670	Total Operating Revenues		TOR		$ 102,829,489	$ 243,747,982	$ 87,588,110	$ 16,385,191	$ 25,659,815	$ 11,165	$ 130,654
671											
672	**Operating Expenses**										
673	Operation and Maintenance Expenses				$ 71,525,240	$ 184,277,571	$ 66,091,298	$ 22,641,989	$ 15,570,550	$ 18,266	$ 75,463
674	Depreciation and Amortization Expenses				11,297,059	29,004,945	10,027,223	3,185,822	5,372,305	2,066	13,268
675	Regulatory Credits and Accretion Expenses				-	-	-	-	-	-	-
676	Property Taxes			NPT	1,357,385	3,484,765	1,204,345	382,636	647,145	248	1,596
677	Other Taxes				726,761	1,865,786	644,821	204,868	346,489	133	855
678	Gain Disposition of Allowances				-	-	-	-	-	-	-
679	State and Federal Income Taxes			TAXINC	$ 4,766,845	$ 4,310,752	$ 1,836,908	$ (271,716)	$ 508,487	$ (4,116)	$ 12,931
680	Specific Assignment of Curtailable Service Rider Avoided Cost				-	(662,440)	(253,585)	(10,961,923)	-	-	-
681	Allocation of Curtailable Service Rider Credits			INTCRE	$ 745,058	$ 1,976,851	$ 759,610	$ 226,406	$ 51,304	$ 84	$ 512
682											
683	Total Operating Expenses		TOE		$ 90,418,348	$ 224,258,228	$ 80,310,621	$ 15,408,080	$ 22,496,280	$ 16,680	$ 104,625
684											
685	Net Operating Income (Unadjusted)		TOM		$ 12,411,140	$ 19,489,754	$ 7,277,489	$ 977,110	$ 3,163,535	$ (5,516)	$ 26,029
686											
687	Net Cost Rate Base				$ 218,939,354	$ 561,632,217	$ 193,812,925	$ 61,766,526	$ 104,887,403	$ 40,667	$ 259,829
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	A	B	C	D	E	F	G	H	J	L	M
1				1	2	3	4	5	7	9	10
2					Allocation	Total	Residential	General Service	All Electric Schools	Power Service	Power Service
3	**Description**		**Ref**	**Name**	**Vector**	**System**	**Rate RS**	**GS**	**AES**	**PS-Secondary**	**PS-Primary**
700											
701	**Taxable Income Unadjusted**										
702											
703	Total Operating Revenue					$ 1,416,158,457	$ 538,967,369	$ 194,876,957	$ 11,377,988	$ 176,173,047	$ 18,410,690
704											
705	Operating Expenses					$ 1,181,939,501	$ 483,414,539	$ 135,959,620	$ 9,608,147	$ 117,696,478	$ 13,407,945
706											
707	Interest Expense			INTEXP		$ 83,539,684	$ 39,347,978	$ 9,420,468	$ 655,764	$ 7,303,583	$ 891,658
708											
709	Taxable Income			TAXINC		$ 150,679,272	$ 16,204,852	$ 49,496,870	$ 1,114,077	$ 51,172,986	$ 4,111,087

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	A	B	C	D	E	N	O	P	Q	R	S	T
1				1	2	11	12	13	14	15	16	17
2					**Allocation**	**Time of Day**	**Time of Day**	**Service**	**Service**	**Outdoor Lighting**	**Lighting Energy**	**Traffic Energy**
3	**Description**		**Ref**	**Name**	**Vector**	**TOD-Secondary**	**TOD-Primary**	**RTS**	**FLS - Transmission**	**ST & POL**	**LE**	**TE**
700												
701	**Taxable Income Unadjusted**											
702												
703	Total Operating Revenue					$ 102,829,489	$ 243,747,982	$ 87,588,110	$ 16,385,191	$ 25,659,815	$ 11,165	$ 130,654
704												
705	Operating Expenses					$ 85,651,503	$ 219,947,477	$ 78,473,713	$ 15,679,797	$ 21,987,793	$ 20,796	$ 91,694
706												
707	Interest Expense			INTEXP		$ 4,970,775	$ 12,761,286	$ 4,410,338	$ 1,401,221	$ 2,369,859	$ 909	$ 5,845
708												
709	Taxable Income			TAXINC		$ 12,207,210	$ 11,039,220	$ 4,704,059	$ (695,826)	$ 1,302,163	$ (10,540)	$ 33,115

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	A	B	C	D	E	F	G	H	J	L	M
1				1	2	3	4	5	7	9	10
2					**Allocation**	**Total**	**Residential**	**General Service**	**All Electric Schools**	**Power Service**	**Power Service**
3	**Description**		**Ref**	**Name**	**Vector**	**System**	**Rate RS**	**GS**	**AES**	**PS-Secondary**	**PS-Primary**
787											
788	**Cost of Service Summary -- Pro-Forma**										
789											
790	**Operating Revenues**										
791											
792	Total Operating Revenue -- Actual					$ 1,416,158,457	$ 538,967,369	$ 194,876,957	$ 11,377,988	$ 176,173,047	$ 18,410,690
793											
794	Pro-Forma Adjustments:										
795		Adj to reflect Additional Redundant Capacity Revenue				287,062				$ 4,023	$ 9,750
796		Adj to reflect Revenue due to Metering changes				(462,863)					
797		Adj to reflect Lost Lighting Revenue				(270,352)					
798		Adj to reflect new Standby Service Customer				115,104					
799		Adj to eliminate Off System ECR revenues			OSSALL	(2,425,076)	$ (935,245)	$ (241,075)	$ (20,115)	$ (256,828)	$ (30,547)
806											
807	Total Pro-Forma Operating Revenue					$ 1,413,402,331	$ 538,032,125	$ 194,635,882	$ 11,357,873	$ 175,920,242	$ 18,389,893
808											

KENTUCKY UTILITIES COMPANY
Cost of Service Study
Class Allocation
12 Months Ended June 30, 2016

	A / B	C	D	E	N	O	P	Q	R	S	T
1			1	2	11	12	13	14	15	16	17
2				**Allocation**	**Time of Day**	**Time of Day**	**Service**	**Service**	**Outdoor Lighting**	**Lighting Energy**	**Traffic Energy**
3	**Description**	**Ref**	**Name**	**Vector**	**TOD-Secondary**	**TOD-Primary**	**RTS**	**FLS - Transmission**	**ST & POL**	**LE**	**TE**
787											
788	**Cost of Service Summary -- Pro-Forma**										
789											
790	**Operating Revenues**										
791											
792	Total Operating Revenue -- Actual				$ 102,829,489	$ 243,747,982	$ 87,588,110	$ 16,385,191	$ 25,659,815	$ 11,165	$ 130,654
793											
794	Pro-Forma Adjustments:										
795	Adj to reflect Additional Redundant Capacity Revenue				$ 95,207	$ 178,082					
796	Adj to reflect Revenue due to Metering changes					$ (141,053)	$ (321,810)				
797	Adj to reflect Lost Lighting Revenue								$ (288,163)	$ 17,811	
798	Adj to reflect new Standby Service Customer					$ 115,104					
799	Adj to eliminate Off System ECR revenues			OSSALL	$ (186,308)	$ (488,166)	$ (181,536)	$ (60,290)	$ (24,787)	$ (42)	$ (139)
806											
807	Total Pro-Forma Operating Revenue				$ 102,738,388	$ 243,411,949	$ 87,084,764	$ 16,324,901	$ 25,346,864	$ 28,934	$ 130,516
808											

KENTUCKY UTILITIES COMPANY
Cost of Service Study
Class Allocation
12 Months Ended June 30, 2016

	A / B	C	D	E	F	G	H	J	L	M
1			1	2	3	4	5	7	9	10
2				**Allocation**	**Total**	**Residential**	**General Service**	**All Electric Schools**	**Power Service**	**Power Service**
3	**Description**	**Ref**	**Name**	**Vector**	**System**	**Rate RS**	**GS**	**AES**	**PS-Secondary**	**PS-Primary**
809										
810	**Operating Expenses**									
811										
812	Operation and Maintenance Expenses				$ 957,152,611	$ 371,972,774	$ 109,481,239	$ 7,741,233	$ 96,902,740	$ 10,854,248
813	Depreciation and Amortization Expenses				189,760,380	89,353,112	21,390,781	1,489,868	16,597,453	2,026,479
814	Regulatory Credits and Accretion Expenses				-	-	-	-	-	-
815	Property Taxes			NPT	22,812,447	10,744,878	2,572,477	179,072	1,994,413	243,488
816	Other Taxes				12,214,063	5,752,939	1,377,336	95,877	1,067,833	130,366
817	Gain Disposition of Allowances				-	-	-	-	-	-
818	State and Federal Income Taxes			TAXINC	58,839,387	$ 6,327,901	$ 19,328,242	$ 435,041	$ 19,982,756	$ 1,605,356
819	Specific Assignment of Curtailable Service Rider Credit				(11,877,948)	-	-	-	-	-
820	Allocation of Curtailable Service Rider Credits			INTCRE	$ 11,877,948	$ 5,590,836	$ 1,137,787	$ 102,098	$ 1,134,039	$ 153,363
821										
822	Adjustments to Operating Expenses:									
823	Adj for Cane Run 7 Depreciation			DEPPT	243,729	102,798	23,854	2,053	24,732	3,103
824	Adj for Lighting Sale Depreciation Reduction			C04	(33,354)	-	-	-	-	-
825	Adj for Lighting Sale Tax Reduction			C04	(4,819)	-	-	-	-	-
826	Adj for Lighting Sale Maintenance Reduction			C04	(5,599)	-	-	-	-	-
833	Eliminate advertising expenses			REVUC	(669,558)	(252,911)	(93,068)	(5,397)	(84,080)	(8,709)
840	Federal & State Income Tax Interest Adjustment			TAXINC	6,048,846	650,525	1,986,995	44,723	2,054,281	165,035
843	Total Expense Adjustments				$ 5,579,245	$ 500,412	$ 1,917,780	$ 41,379	$ 1,994,932	$ 159,428
844										
845										
846										
847	Total Operating Expenses		TOE		$ 1,246,358,133	$ 490,242,852	$ 157,205,642	$ 10,084,567	$ 139,674,166	$ 15,172,729
848										
849	Net Operating Income (Adjusted)				$ 167,044,198	$ 47,789,272	$ 37,430,240	$ 1,273,306	$ 36,246,076	$ 3,217,164
850										
851	**Net Cost Rate Base**				$ 3,669,268,542	$ 1,723,572,451	$ 415,582,631	$ 28,774,055	$ 320,970,904	$ 39,029,579
852	**ECR Plan Eliminations**			PLPPT	$ -	$ -	$ -	$ -	$ -	$ -
853	**Adjustment to Reflect Depreciation Reserve**			DET	$ -	$ -	$ -	$ -	$ -	$ -
854	**Cash Working Capital**			OMLF	$ -	$ -	$ -	$ -	$ -	$ -
855	**Adjusted Net Cost Rate Base**				$ 3,669,268,542	$ 1,723,572,451	$ 415,582,631	$ 28,774,055	$ 320,970,904	$ 39,029,579
856										
857	**Rate of Return**				**4.55%**	**2.77%**	**9.01%**	**4.43%**	**11.29%**	**8.24%**
858										

KENTUCKY UTILITIES COMPANY
Cost of Service Study
Class Allocation
12 Months Ended June 30, 2016

	A	B	C	D	E	N	O	P	Q	R	S	T
1				1	2	11	12	13	14	15	16	17
2					**Allocation**	**Time of Day**	**Time of Day**	**Service**	**Service**	**Outdoor Lighting**	**Lighting Energy**	**Traffic Energy**
3	**Description**		**Ref**	**Name**	**Vector**	**TOD-Secondary**	**TOD-Primary**	**RTS**	**FLS - Transmission**	**ST & POL**	**LE**	**TE**
809												
810	**Operating Expenses**											
811												
812	Operation and Maintenance Expenses					$ 71,525,240	$ 184,277,571	$ 66,091,298	$ 22,641,989	$ 15,570,550	$ 18,266	$ 75,463
813	Depreciation and Amortization Expenses					11,297,059	29,004,945	10,027,223	3,185,822	5,372,305	2,066	13,268
814	Regulatory Credits and Accretion Expenses					-	-	-	-	-	-	-
815	Property Taxes				NPT	1,357,385	3,484,765	1,204,345	382,636	647,145	248	1,596
816	Other Taxes					726,761	1,865,786	644,821	204,868	346,489	133	855
817	Gain Disposition of Allowances					-	-	-	-	-	-	-
818	State and Federal Income Taxes				TAXINC	$ 4,766,845	$ 4,310,752	$ 1,836,908	$ (271,716)	$ 508,487	$ (4,116)	$ 12,931
819	Specific Assignment of Curtailable Service Rider Credit					-	(662,440)	(253,585)	(10,961,923)	-	-	-
820	Allocation of Curtailable Service Rider Credits				INTCRE	$ 745,058	$ 1,976,851	$ 759,610	$ 226,406	$ 51,304	$ 84	$ 512
821												
822	Adjustments to Operating Expenses:											
823	Adj for Cane Run 7 Depreciation				DEPPT	17,265	45,453	17,116	5,459	1,880	3	12
824	Adj for Lighting Sale Depreciation Reduction				C04	-	-	-	-	(33,354)	-	-
825	Adj for Lighting Sale Tax Reduction				C04	-	-	-	-	(4,819)	-	-
826	Adj for Lighting Sale Maintenance Reduction				C04	-	-	-	-	(5,599)	-	-
833	Eliminate advertising expenses				REVUC	(48,798)	(115,297)	(41,378)	(7,527)	(12,325)	(5)	(63)
840	Federal & State Income Tax Interest Adjustment				TAXINC	490,044	443,157	188,839	(27,933)	52,274	(423)	1,329
843	Total Expense Adjustments					$ 458,512	$ 373,313	$ 164,577	$ (30,001)	$ (1,942)	$ (425)	$ 1,279
844												
845												
846												
847	Total Operating Expenses			TOE		$ 90,876,860	$ 224,631,541	$ 80,475,198	$ 15,378,080	$ 22,494,338	$ 16,255	$ 105,904
848												
849	Net Operating Income (Adjusted)					$ 11,861,528	$ 18,780,408	$ 6,609,566	$ 946,822	$ 2,852,526	$ 12,679	$ 24,611
850												
851	**Net Cost Rate Base**					$ 218,939,354	$ 561,632,217	$ 193,812,925	$ 61,766,526	$ 104,887,403	$ 40,667	$ 259,829
852	**ECR Plan Eliminations**				PLPPT	$ -	$ -	$ -	$ -	$ -	$ -	$ -
853	**Adjustment to Reflect Depreciation Reserve**				DET	$ -	$ -	$ -	$ -	$ -	$ -	$ -
854	**Cash Working Capital**				OMLF	$ -	$ -	$ -	$ -	$ -	$ -	$ -
855	**Adjusted Net Cost Rate Base**					$ 218,939,354	$ 561,632,217	$ 193,812,925	$ 61,766,526	$ 104,887,403	$ 40,667	$ 259,829
856												
857	**Rate of Return**					5.42%	3.34%	3.41%	1.53%	2.72%	31.18%	9.47%
858												

KENTUCKY UTILITIES COMPANY
Cost of Service Study
Class Allocation
12 Months Ended June 30, 2016

	A	B	C	D	E	F	G	H	J	L	M
1				1	2	3	4	5	7	9	10
2					**Allocation**	**Total**	**Residential**	**General Service**	**All Electric Schools**	**Power Service**	**Power Service**
3	**Description**		**Ref**	**Name**	**Vector**	**System**	**Rate RS**	**GS**	**AES**	**PS-Secondary**	**PS-Primary**
893											
894	**Taxable Income Pro-Forma**										
895											
896	Total Operating Revenue					$ 1,413,402,331	$ 538,032,125	$ 194,635,882	$ 11,357,873	$ 175,920,242	$ 18,389,893
897											
898	Operating Expenses					$ 1,187,518,746	$ 483,914,951	$ 137,877,400	$ 9,649,527	$ 119,691,410	$ 13,567,374
899											
900	Interest Expense			INTEXP		$ 83,539,684	$ 39,347,978	$ 9,420,468	$ 655,764	$ 7,303,583	$ 891,658
901											
902	Interest Syncronization Adjustment				INTEXP	$ -	$ -	$ -	$ -	$ -	$ -
903											
904	Taxable Income			TXINCPF		$ 142,343,902	$ 14,769,196	$ 47,338,015	$ 1,052,583	$ 48,925,249	$ 3,930,861
905											

KENTUCKY UTILITIES COMPANY
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Class Allocation
12 Months Ended June 30, 2016

	A / B	C	D	E	N	O	P	Q	R	S	T
1			1	2	11	12	13	14	15	16	17
2				**Allocation**	**Time of Day**	**Time of Day**	**Service**	**Service**	**Outdoor Lighting**	**Lighting Energy**	**Traffic Energy**
3	**Description**	**Ref**	**Name**	**Vector**	**TOD-Secondary**	**TOD-Primary**	**RTS**	**FLS - Transmission**	**ST & POL**	**LE**	**TE**
893											
894	**Taxable Income Pro-Forma**										
895											
896	Total Operating Revenue				$ 102,738,388	$ 243,411,949	$ 87,084,764	$ 16,324,901	$ 25,346,864	$ 28,934	$ 130,516
897											
898	Operating Expenses				$ 86,110,015	$ 220,320,789	$ 78,638,290	$ 15,649,796	$ 21,985,851	$ 20,371	$ 92,973
899											
900	Interest Expense		INTEXP		$ 4,970,775	$ 12,761,286	$ 4,410,338	$ 1,401,221	$ 2,369,859	$ 909	$ 5,845
901											
902	Interest Syncronization Adjustment			INTEXP	$ -	$ -	$ -	$ -	$ -	$ -	$ -
903											
904	Taxable Income		TXINCPF		$ 11,657,598	$ 10,329,874	$ 4,036,135	$ (726,115)	$ 991,155	$ 7,654	$ 31,697
905											

KENTUCKY UTILITIES COMPANY
Cost of Service Study
Class Allocation
12 Months Ended June 30, 2016

	A	B	C	D	E	F	G	H	J	L	M
1				1	2	3	4	5	7	9	10
2					**Allocation**	**Total**	**Residential**	**General Service**	**All Electric Schools**	**Power Service**	**Power Service**
3	**Description**		**Ref**	**Name**	**Vector**	**System**	**Rate RS**	**GS**	**AES**	**PS-Secondary**	**PS-Primary**
1044	**Cost of Service Summary -- Adjusted for Proposed Increase**										
1061											
1062	**Operating Revenue**										
1063											
1064	Total Operating Revenue					$ 1,413,402,331	$ 538,032,125	$ 194,635,882	$ 11,357,873	$ 175,920,242	$ 18,389,893
1065											
1066	Proposed Increase					$ 153,442,682	$ 56,839,411	$ 20,741,924	$ 1,238,148	$ 19,034,075	$ 1,989,750
1067	Increase in Miscellaneous Charges				MISCSERV	$ -	$ -	$ -	$ -	$ -	$ -
1068							$ -	$ -	$ -	$ -	$ -
1069											
1070	Total Pro-Forma Operating Revenue					$ 1,566,845,014	$ 594,871,536	$ 215,377,806	$ 12,596,021	$ 194,954,317	$ 20,379,643
1071											
1072											
1073	**Operating Expenses**										
1074											
1075	Total Operating Expenses					$ 1,240,778,888	$ 489,742,440	$ 155,287,862	$ 10,043,188	$ 137,679,234	$ 15,013,301
1076											
1077	Pro-Forma Adjustments					$ 5,579,245	$ 500,412	$ 1,917,780	$ 41,379	$ 1,994,932	$ 159,428
1078	Increase in Uncollectible Expense				Cust01	$ 491,021	$ 307,074	$ 58,585	$ 452	$ 3,322	$ 141
1079	Increase in PSC Fees				R01	$ 299,523	$ 113,138	$ 41,634	$ 2,414	$ 37,613	$ 3,896
1080											
1081	Incremental Income Taxes				0.36663943	$ 56,258,138	$ 20,839,569	$ 7,604,807	$ 453,954	$ 6,978,642	$ 729,521
1082											
1083	Total Pro-Forma Operating Expenses					$ 1,303,406,815	$ 511,502,634	$ 164,910,668	$ 10,541,388	$ 146,693,744	$ 15,906,287
1084											
1085	Net Operating Income					$ 263,438,199	$ 83,368,901	$ 50,467,138	$ 2,054,634	$ 48,260,573	$ 4,473,355
1086											
1087	**Net Cost Rate Base**					$ 3,669,268,542	$ 1,723,572,451	$ 415,582,631	$ 28,774,055	$ 320,970,904	$ 39,029,579
1088											
1089	**Rate of Return**					**7.18%**	**4.84%**	**12.14%**	**7.14%**	**15.04%**	**11.46%**
1090											
1091											
1092											

KENTUCKY UTILITIES COMPANY
Cost of Service Study
Class Allocation
12 Months Ended June 30, 2016

	A / B	C	D	E	N	O	P	Q	R	S	T
1			1	2	11	12	13	14	15	16	17
2				**Allocation**	**Time of Day**	**Time of Day**	**Service**	**Service**	**Outdoor Lighting**	**Lighting Energy**	**Traffic Energy**
3	**Description**	**Ref**	**Name**	**Vector**	**TOD-Secondary**	**TOD-Primary**	**RTS**	**FLS - Transmission**	**ST & POL**	**LE**	**TE**
1044	**Cost of Service Summary -- Adjusted for Proposed Increase**										
1061											
1062	**Operating Revenue**										
1063											
1064	Total Operating Revenue				$ 102,738,388	$ 243,411,949	$ 87,084,764	$ 16,324,901	$ 25,346,864	$ 28,934	$ 130,516
1065											
1066	Proposed Increase				$ 11,341,999	$ 27,203,590	$ 9,554,633	$ 3,010,052	$ 2,473,044	$ 2,840	$ 13,216
1067	Increase in Miscellaneous Charges			MISCSERV	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1068					$ -	$ -	$ -	$ -	$ -	$ -	$ -
1069											
1070	Total Pro-Forma Operating Revenue				$ 114,080,387	$ 270,615,539	$ 96,639,397	$ 19,334,953	$ 27,819,908	$ 31,774	$ 143,732
1071											
1072											
1073	**Operating Expenses**										
1074											
1075	Total Operating Expenses				$ 90,418,348	$ 224,258,228	$ 80,310,621	$ 15,408,080	$ 22,496,280	$ 16,680	$ 104,625
1076											
1077	Pro-Forma Adjustments				$ 458,512	$ 373,313	$ 164,577	$ (30,001)	$ (1,942)	$ (425)	$ 1,279
1078	Increase in Uncollectible Expense			Cust01	$ 333	$ 182	$ 23	$ 1	$ 120,373	$ 1	$ 533
1079	Increase in PSC Fees			R01	$ 21,829	$ 51,578	$ 18,510	$ 3,367	$ 5,513	$ 2	$ 28
1080											
1081	Incremental Income Taxes			0.36663943	$ 4,158,424	$ 9,973,909	$ 3,503,105	$ 1,103,604	$ 906,715	$ 1,041	$ 4,846
1082											
1083	Total Pro-Forma Operating Expenses				$ 95,057,446	$ 234,657,209	$ 83,996,837	$ 16,485,051	$ 23,526,939	$ 17,300	$ 111,311
1084											
1085	Net Operating Income				$ 19,022,940	$ 35,958,330	$ 12,642,561	$ 2,849,902	$ 4,292,969	$ 14,474	$ 32,421
1086											
1087	**Net Cost Rate Base**				$ 218,939,354	$ 561,632,217	$ 193,812,925	$ 61,766,526	$ 104,887,403	$ 40,667	$ 259,829
1088											
1089	**Rate of Return**				**8.69%**	**6.40%**	**6.52%**	**4.61%**	**4.09%**	**35.59%**	**12.48%**
1090											
1091											
1092											

KENTUCKY UTILITIES COMPANY
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Class Allocation
12 Months Ended June 30, 2016

	A / B	C	D	E	F	G	H	J	L	M
1			1	2	3	4	5	7	9	10
2				**Allocation**	**Total**	**Residential**	**General Service**	**All Electric Schools**	**Power Service**	**Power Service**
3	**Description**	**Ref**	**Name**	**Vector**	**System**	**Rate RS**	**GS**	**AES**	**PS-Secondary**	**PS-Primary**
1093										
1094	**Allocation Factors**									
1095										
1096	**Energy Allocation Factors**									
1097	Energy Usage by Class		E01	Energy	1.000000	0.330885	0.101735	0.008100	0.112621	0.012393
1098										
1099	**Customer Allocation Factors**									
1100	Primary Distribution Plant -- Average Number of Custom		C08	Cust08	1.000000	0.80066	0.15275	0.00118	0.00866	0.00037
1101	Customer Services -- Weighted cost of Services		C02		1.000000	0.554487	0.426948	0.001853	0.015349	-
1102	Meter Costs -- Weighted Cost of Meters		C03		1.000000	0.601711	0.262563	0.002743	0.061498	0.015218
1103	Lighting Systems -- Lighting Customers		C04	Cust04	1.000000	-	-	-	-	-
1104	Meter Reading and Billing -- Weighted Cost		C05	Cust05	1.000000	0.64935	0.24777	0.00957	0.03513	0.00149
1105	Marketing/Economic Development		C06	Cust06	1.000000	0.80062	0.15275	0.00118	0.00866	0.00037
1106										
1107	Total billed revenue per Billing Determinants		R01		1,365,866,924	515,927,090	189,855,309	11,008,968	171,520,080	17,766,215
1108	Energy (at the Meter)				18,938,242,137	6,197,488,349	1,905,496,852	151,718,556	2,109,401,951	237,951,668
1109	Energy (Loss Adjusted)(at Source)		Energy		20,053,989,993	6,635,568,587	2,040,190,210	162,443,046	2,258,508,695	248,526,469
1110										
1111	**O&M Customer Allocators**									
1112	Customers (Monthly Bills)				8,257,782	5,164,249	985,260	7,611	55,875	2,370
1113	Average Customers (Bills/12)				688,149	430,354	82,105	634	4,656	198
1114	Average Customers (Lighting = Lights)				688,149	430,354	82,105	634	4,656	198
1115	Weighted Average Customers (Lighting =9 Lights per Cu		Cust05		662,741	430,354	164,210	6,340	23,280	990
1116	Street Lighting		Cust04		99,477,208	-	-	-	-	-
1117	Average Customers		Cust01		688,149	430,354	82,105	634	4,656	198
1118	Average Customers (Lighting = 9 Lights per Cust)		Cust06		537,529	430,354	82,105	634	4,656	198
1119	Average Secondary Customers		Cust07		531,920	430,354	82,105	634	-	-
1120	Average Primary Customers		Cust08		537,496	430,354	82,105	634	4,656	198
1121	Average Transformer Customers		Cust09		537,043	430,354	82,105	634	4,656	-
1122										
1123	**Plant Customer Allocators**									
1124	Customers (Monthly Bills)				8,257,782	5,164,249	985,260	7,611	55,875	2,370
1125	Average Customers (Bills/12)				688,149	430,354	82,105	634	4,656	198
1126	Average Customers (Lighting = Lights)				688,149	430,354	82,105	634	4,656	198
1127	Weighted Average Customers (Lighting =9 Lights per Cust)				662,741	430,354	164,210	6,340	23,280	990
1128	Street Lighting				99,477,208	-	-	-	-	-
1129	Average Customers				688,149	430,354	82,105	634	4,656	198
1130	Average Customers (Lighting = 9 Lights per Cust)				537,529	430,354	82,105	634	4,656	198
1131	Average Secondary Customers				531,920	430,354	82,105	634	-	-
1132	Average Primary Customers				537,496	430,354	82,105	634	4,656	198
1133	Average Transformer Customers				537,043	430,354	82,105	634	4,656	-
1134										
1135	**Demand Allocators**									
1136	Maximum Class Non-Coincident Peak Demands		NCP		4,034,921	1,924,024	508,172	53,587	431,187	55,542
1137	Sum of the Individual Customer Demands (Secondary)		SICDT		5,467,024	3,598,894	860,949	61,600	559,032	-
1138	Sum of the Individual Customer Demands (Secondary)		SICD		4,555,236	3,598,894	860,949	61,600	-	-
1139	Summer Peak Period Demand Allocator		SCP		3,417,312	1,394,384	412,857	30,541	381,665	49,952
1140	Winter Peak Period Demand Allocator		WCP		3,572,783	1,884,632	261,178	29,604	288,596	40,605
1141	Base Demand Allocator		BDEM		2,283,013	755,415	232,262	18,493	257,116	28,293
1142										

KENTUCKY UTILITIES COMPANY
Cost of Service Study
Class Allocation
12 Months Ended June 30, 2016

	A / B	C	D	E	N	O	P	Q	R	S	T
1			1	2	11	12	13	14	15	16	17
2				**Allocation**	**Time of Day**	**Time of Day**	**Service**	**Service**	**Outdoor Lighting**	**Lighting Energy**	**Traffic Energy**
3	**Description**	**Ref**	**Name**	**Vector**	**TOD-Secondary**	**TOD-Primary**	**RTS**	**FLS - Transmission**	**ST & POL**	**LE**	**TE**
1093											
1094	**Allocation Factors**										
1095											
1096	**Energy Allocation Factors**										
1097	Energy Usage by Class		E01	Energy	0.085907	0.223760	0.081884	0.028600	0.014025	0.000024	0.000066
1098											
1099	**Customer Allocation Factors**										
1100	Primary Distribution Plant -- Average Number of Custom		C08	Cust08	0.00087	0.00047	-	-	0.03487	0.00000	0.00015
1101	Customer Services -- Weighted cost of Services		C02		0.001363	-	-	-	-	-	-
1102	Meter Costs -- Weighted Cost of Meters		C03		0.008046	0.025875	0.020484	0.000814	-	0.000003	0.001044
1103	Lighting Systems -- Lighting Customers		C04	Cust04	-	-	-	-	1.00000	-	-
1104	Meter Reading and Billing -- Weighted Cost		C05	Cust05	0.01762	0.00962	0.00097	0.00008	0.02828	-	0.00013
1105	Marketing/Economic Development		C06	Cust06	0.00087	0.00047	0.00006	0.00000	0.03487	-	0.00015
1106											
1107	Total billed revenue per Billing Determinants		R01		99,544,974	235,200,859	84,408,729	15,354,394	25,141,640	10,497	128,169
1108	Energy (at the Meter)				1,609,032,248	4,296,353,118	1,605,630,259	560,796,543	262,687,527	443,699	1,241,367
1109	Energy (Loss Adjusted)(at Source)		Energy		1,722,769,490	4,487,287,188	1,642,101,330	573,534,750	281,256,052	475,063	1,329,115
1110											
1111	**O&M Customer Allocators**										
1112	Customers (Monthly Bills)				5,598	3,054	384	12	2,024,381	24	8,964
1113	Average Customers (Bills/12)				467	255	32	1	168,698	2	747
1114	Average Customers (Lighting = Lights)				467	255	32	1	168,698	2	747
1115	Weighted Average Customers (Lighting =9 Lights per Cu		Cust05		11,675	6,375	640	50	18,744	-	83
1116	Street Lighting		Cust04		-	-	-	-	99,477,208	-	-
1117	Average Customers		Cust01		467	255	32	1	168,698	2	747
1118	Average Customers (Lighting = 9 Lights per Cust)		Cust06		467	255	32	1	18,744	-	83
1119	Average Secondary Customers		Cust07		-	-	-	-	18,744	0	83
1120	Average Primary Customers		Cust08		467	255	-	-	18,744	0	83
1121	Average Transformer Customers		Cust09		467	-	-	-	18,744	0	83
1122											
1123	**Plant Customer Allocators**							-	1.00	-	-
1124	Customers (Monthly Bills)				5,598	3,054	384	12	2,024,381	24	8,964
1125	Average Customers (Bills/12)				467	255	32	1	168,698	2	747
1126	Average Customers (Lighting = Lights)				467	255	32	1	168,698	2	747
1127	Weighted Average Customers (Lighting =9 Lights per Cust)				11,675	6,375	640	50	18,744	-	83
1128	Street Lighting				-	-	-	-	99,477,208	-	-
1129	Average Customers				467	255	32	1	168,698	2	747
1130	Average Customers (Lighting = 9 Lights per Cust)				467	255	32	1	18,744	-	83
1131	Average Secondary Customers				-	-	-	-	18,744	0	83
1132	Average Primary Customers				467	255	-	-	18,744	0	83
1133	Average Transformer Customers				467	-	-	-	18,744	0	83
1134											
1135	**Demand Allocators**										
1136	Maximum Class Non-Coincident Peak Demands		NCP		276,995	751,621	-	-	33,581	48	164
1137	Sum of the Individual Customer Demands (Secondary)		SICDT		352,756	-	-	-	33,581	48	164
1138	Sum of the Individual Customer Demands (Secondary)		SICD		-	-	-	-	33,581	48	164
1139	Summer Peak Period Demand Allocator		SCP		253,253	625,893	230,389	38,241	-	-	137
1140	Winter Peak Period Demand Allocator		WCP		187,235	540,448	217,254	93,596	29,423	48	164
1141	Base Demand Allocator		BDEM		196,126	510,848	186,942	65,293	32,019	54	151
1142											

KENTUCKY UTILITIES COMPANY
Cost of Service Study
Class Allocation
12 Months Ended June 30, 2016

	A	B	C	D	E	F	G	H	J	L	M
1				1	2	3	4	5	7	9	10
2					**Allocation**	**Total**	**Residential**	**General Service**	**All Electric Schools**	**Power Service**	**Power Service**
3	**Description**		**Ref**	**Name**	**Vector**	**System**	**Rate RS**	**GS**	**AES**	**PS-Secondary**	**PS-Primary**
1143	**Unadjusted Production Allocation**										
1144	Production Residual Winter Demand Allocator			PPWDRA		3,572,783	1,884,632	261,178	29,604	288,596	40,605
1145	Production Winter Demand Costs					$ 38,726,277	$ 20,427,991	$ 2,830,973	$ 320,885	$ 3,128,163	$ 440,128
1146	Customer Specific Assignment					$ -		-	0	-	-
1147	Production Winter Demand Residual				PPWDRA	$ 38,726,277	$ 20,427,991	$ 2,830,973	$ 320,885	$ 3,128,163	$ 440,128
1148	Production Winter Demand Total			PPWDT		$ 38,726,277	$ 20,427,991	$ 2,830,973	$ 320,885	$ 3,128,163	$ 440,128
1149	Production Winter Demand Allocator			PPWDA	PPWDT	1.000000	0.52750	0.07310	0.00829	0.08078	0.01137
1150											
1151	Production Residual Summer Demand Allocator			PPSDRA		3,417,312	1,394,384	412,857	30,541	381,665	49,952
1152	Production Summer Demand Costs					$ 39,202,972	$ 15,996,197	$ 4,736,243	$ 350,362	$ 4,378,413	$ 573,043
1153	Customer Specific Assignment					$ -		-	0	-	-
1154	Production Summer Demand Residual				PPSDRA	$ 39,202,972	15,996,197	4,736,243	350,362	4,378,413	573,043
1155	Production Summer Demand Total			PPSDT		$ 39,202,972	$ 15,996,197	$ 4,736,243	$ 350,362	$ 4,378,413	$ 573,043
1156	Production Summer Demand Allocator			PPSDA	PPSDT	1.000000	0.40804	0.12081	0.00894	0.11169	0.01462
1157											
1158	Production Residual Base Demand Allocator			PPBDRA		2,283,013	755,415	232,262	18,493	257,116	28,293
1159	Production Base Demand Costs					$ 40,917,494					
1160	Customer Specific Assignment					$ -	0	-	0	-	-
1161	Production Base Demand Residual				PPBDRA	$ 40,917,494	13,538,993	4,162,736	331,443	4,608,186	507,085
1162	Production Base Demand Total			PPBDT		$ 40,917,494	$ 13,538,993	$ 4,162,736	$ 331,443	$ 4,608,186	$ 507,085
1163	Production Base Demand Allocator			PPBDA	PPBDT	1.000000	0.33089	0.10173	0.00810	0.11262	0.01239
1164											
1165	**Revenue Adjustment Allocators**										
1166	Remove ECR Revenues			ECRREV01		156,528,392	53,429,817	19,521,060	1,324,344	19,262,739	2,066,497
1167	Customer Account Changes Allocator			CustAcct		(60,697)	-	-	-	4,023	9,750
1168	Interruptible Credit Allocator			INTCRE		2,717,892,276	1,279,285,815	260,346,432	23,361,968	259,489,026	35,092,343
1169	Year End Customers			YRE01		-	-	-	-	-	-
1170	Remove DSM Revenues			DSM01		-	-	-	-	-	-
1171	Base Rate Revenue					1,365,866,924	515,927,090	189,855,309	11,008,968	171,520,080	17,766,215
1172	Late Payment Revenue			LPAY		3,786,198	3,053,813	523,341	741	95,061	5,335
1173	Franchise Fees and HEA			FFHEA		-	-	-	-	-	-
1174	FAC Roll-In			FAC01		-	-	-	-	-	-
1175	Revenue and Expense Adjust before IT			ITADJ		(2,286,525)	(785,132)	(171,860)	(16,771)	(193,457)	(15,191)
1176											
1177	ECR Revenue in Base Rates			ECRPLAN		-	-	-	-	-	-
1178											
1179	Operation and Maintenance Less Fuel			OMLF		284,773,186.32	149,492,370.47	41,076,800.66	2,294,767.23	21,178,418.68	2,521,538.33
1180											
1181	**Off-System Sales Allocator**										
1182											
1183	Off-System Sales				RBPPT	$ 24,736,304	$ 10,353,017	$ 2,424,479	$ 208,056	$ 2,519,966	$ 314,610
1184											
1185	Less: Adjustment to Reallocate Expenses										
1186	Costs allocated on Energy to be reallocated on RBPPT				Energy	$ (9,279,145)	$ (3,070,332)	$ (944,013)	$ (75,164)	$ (1,045,030)	$ (114,995)
1187	Costs allocated on Energy reallocated on RBPPT				RBPPT	$ 9,279,145	$ 3,883,650	$ 909,477	$ 78,047	$ 945,296	$ 118,017
1188	Net Adjustment					$ -	$ 813,318	$ (34,536)	$ 2,883	$ (99,734)	$ 3,022
1189											
1190	Off-System Sales Allocator			OSSALL		$ 24,736,304	$ 9,539,699	$ 2,459,015	$ 205,173	$ 2,619,701	$ 311,588
1191											
1192	Misc Service Revenue Allocator			MISCSERV		1.00	0.91	0.03	0.00	0.00	0.04
1193											
1194	**CSR Avoided Cost**										
1195	Interruptible Demands					2,197,390					
1196	Avoided Cost per kW										
1197	Avoided Cost					11,877,948	-	-	-	-	-

KENTUCKY UTILITIES COMPANY
Cost of Service Study
Class Allocation
12 Months Ended June 30, 2016

	A	B	C	D	E	N	O	P	Q	R	S	T
1				1	2	11	12	13	14	15	16	17
2					**Allocation**	**Time of Day**	**Time of Day**	**Service**	**Service**	**Outdoor Lighting**	**Lighting Energy**	**Traffic Energy**
3	**Description**		**Ref**	**Name**	**Vector**	**TOD-Secondary**	**TOD-Primary**	**RTS**	**FLS - Transmission**	**ST & POL**	**LE**	**TE**
1143	**Unadjusted Production Allocation**											
1144	Production Residual Winter Demand Allocator			PPWDRA		187,235	540,448	217,254	93,596	29,423	48	164
1145	Production Winter Demand Costs					$ 2,029,486	$ 5,858,049	$ 2,354,870	$ 1,014,510	$ 318,923	$ 520	$ 1,778
1146	Customer Specific Assignment					-	-	-	-	-		
1147	Production Winter Demand Residual				PPWDRA	$ 2,029,486	$ 5,858,049	$ 2,354,870	$ 1,014,510	$ 318,923	$ 520	$ 1,778
1148	Production Winter Demand Total			PPWDT		$ 2,029,486	$ 5,858,049	$ 2,354,870	$ 1,014,510	$ 318,923	$ 520	$ 1,778
1149	Production Winter Demand Allocator			PPWDA	PPWDT	0.05241	0.15127	0.06081	0.02620	0.00824	0.00001	0.00005
1150												
1151	Production Residual Summer Demand Allocator			PPSDRA		253,253	625,893	230,389	38,241	-	-	137
1152	Production Summer Demand Costs					$ 2,905,286	$ 7,180,166	$ 2,642,994	$ 438,696	$ -	$ -	$ 1,572
1153	Customer Specific Assignment					-	-	-	-	-		
1154	Production Summer Demand Residual				PPSDRA	2,905,286	7,180,166	2,642,994	438,696	-	-	1,572
1155	Production Summer Demand Total			PPSDT		$ 2,905,286	$ 7,180,166	$ 2,642,994	$ 438,696	$ -	$ -	$ 1,572
1156	Production Summer Demand Allocator			PPSDA	PPSDT	0.07411	0.18315	0.06742	0.01119	-	-	0.00004
1157												
1158	Production Residual Base Demand Allocator			PPBDRA		196,126	510,848	186,942	65,293	32,019	54	151
1159	Production Base Demand Costs											
1160	Customer Specific Assignment					-	-	-	-	-	0	0
1161	Production Base Demand Residual				PPBDRA	3,515,081	9,155,711	3,350,489	1,170,221	573,865	969	2,712
1162	Production Base Demand Total			PPBDT		$ 3,515,081	$ 9,155,711	$ 3,350,489	$ 1,170,221	$ 573,865	$ 969	$ 2,712
1163	Production Base Demand Allocator			PPBDA	PPBDT	0.08591	0.22376	0.08188	0.02860	0.01402	0.00002	0.00007
1164												
1165	**Revenue Adjustment Allocators**											
1166	Remove ECR Revenues			ECRREV01		12,673,875	31,296,091	11,570,825	3,781,476	1,597,240	518	3,910
1167	Customer Account Changes Allocator			CustAcct		95,207	152,133	(321,810)	-	-	-	-
1168	Interruptible Credit Allocator			INTCRE		170,482,825	452,339,667	173,812,791	51,805,755	11,739,256	19,151	117,246
1169	Year End Customers			YRE01		-	-	-	-	-	-	-
1170	Remove DSM Revenues			DSM01		-	-	-	-	-	-	-
1171	Base Rate Revenue					99,544,974	235,200,859	84,408,729	15,354,394	25,141,640	10,497	128,169
1172	Late Payment Revenue			LPAY		38,175	49,887	19,845	-	-	-	-
1173	Franchise Fees and HEA			FFHEA		-	-	-	-	-	-	-
1174	FAC Roll-In			FAC01		-	-	-	-	-	-	-
1175	Revenue and Expense Adjust before IT			ITADJ		(59,568)	(266,189)	(479,085)	(58,222)	(258,735)	17,771	(88)
1176												
1177	ECR Revenue in Base Rates			ECRPLAN		-	-	-	-	-	-	-
1178												
1179	Operation and Maintenance Less Fuel			OMLF		13,763,430.56	33,825,736.64	11,034,167.56	3,412,250.99	6,140,467.19	2,338.01	30,899.98
1180												
1181	**Off-System Sales Allocator**											
1182												
1183	Off-System Sales				RBPPT	$ 1,765,528	$ 4,645,860	$ 1,747,376	$ 559,449	$ 196,356	$ 328	$ 1,281
1184												
1185	Less: Adjustment to Reallocate Expenses											
1186	Costs allocated on Energy to be reallocated on RBPPT				Energy	$ (797,140)	$ (2,076,304)	$ (759,814)	$ (265,379)	$ (130,139)	$ (220)	$ (615)
1187	Costs allocated on Energy reallocated on RBPPT				RBPPT	$ 662,289	$ 1,742,767	$ 655,480	$ 209,862	$ 73,657	$ 123	$ 480
1188	Net Adjustment					$ (134,850)	$ (333,538)	$ (104,334)	$ (55,517)	$ (56,482)	$ (97)	$ (135)
1189												
1190	Off-System Sales Allocator			OSSALL		$ 1,900,378	$ 4,979,398	$ 1,851,709	$ 614,966	$ 252,838	$ 425	$ 1,415
1191												
1192	Misc Service Revenue Allocator			MISCSERV		0.00	0.00	-	0.00	0.02	-	-
1193												
1194	**CSR Avoided Cost**											
1195	Interruptible Demands						120,444	46,960	2,029,986			
1196	Avoided Cost per kW						5.50	5.40	5.40			
1197	Avoided Cost					-	662,440	253,585	10,961,923	-	-	-

Exhibit MJB-10

Electric Residential Basic Service Charge Calculation

Kentucky Utilities Company

Unit Cost of Service Based on the Cost of Service Study
For the 12 Months Ended June 30, 2016

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	$ 937,770,380	$ 27,090,858	$ 180,628,823	$ 218,927,615	$ 354,472,634	$ 4,682,142	$ 1,723,572,451
(2) Rate Base Adjustments	-	-	-	-	-	-	$ -
(3) Rate Base as Adjusted	$ 937,770,380	$ 27,090,858	$ 180,628,823	$ 218,927,615	$ 354,472,634	$ 4,682,142	$ 1,723,572,451
(4) Rate of Return	4.84%	4.84%	4.84%	4.84%	4.84%	4.84%	
(5) Return	$ 45,359,791	$ 1,310,380	$ 8,736,985	$ 10,589,491	$ 17,145,780	$ 226,474	$ 83,368,901
(6) Interest Expenses	$ 21,408,655	$ 618,466	$ 4,123,632	$ 4,997,967	$ 8,092,367	$ 106,890	$ 39,347,978
(7) Net Income	$ 23,951,136	$ 691,914	$ 4,613,353	$ 5,591,523	$ 9,053,413	$ 119,584	$ 44,020,923
(8) Income Taxes	$ 14,781,421	$ 427,014	$ 2,847,126	$ 3,450,803	$ 5,587,305	$ 73,801	$ 27,167,471
(9) Operation and Maintenance Expenses	$ 49,963,182	$ 222,480,404	$ 14,629,106	$ 17,348,567	$ 32,609,093	$ 34,942,422	$ 371,972,774
(10) Depreciation Expenses	$ 53,012,487	$ -	$ 6,944,603	$ 11,229,657	$ 18,166,364	$ -	$ 89,353,112
(11) Other Taxes	$ 9,306,272	$ -	$ 1,750,509	$ 2,078,545	$ 3,362,490	$ -	$ 16,497,816
(12) Curtailable Service Credit	$ 5,590,836						$ 5,590,836
(13) Expense Adjustments - Prod. Demand	$ 102,798	$ -	$ -	$ -	$ -	$ -	$ 102,798
(14) Expense Adjustments - Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -
(15) Expense Adjustments - Trans. Demand	$ -	$ -	$ -	$ -	$ -	$ -	$ -
(16) Expense Adjustments - Distribution	$ -	$ -	$ -	$ -	$ -	$ -	$ -
(17) Expense Adjustments - Other	$ 444,967	$ 12,854	$ 85,707	$ 103,880	$ 168,196	$ 2,222	$ 817,827
(18) Expense Adjustments - Total	$ 547,766	$ 12,854	$ 85,707	$ 103,880	$ 168,196	$ 2,222	$ 920,625
(19) Total Cost of Service	$ 178,561,755	$ 224,230,652	$ 34,994,037	$ 44,800,944	$ 77,039,227	$ 35,244,920	$ 594,871,536
(20) Less: Misc Revenue - Tran. Demand		$ -	$ (6,689,982)	$ -	$ -	$ -	$ (6,689,982)
(21) Less: Misc Revenue - Energy	$ -	$ (9,539,699)	$ -	$ -	$ -	$ -	$ (9,539,699)
(22) Less: Misc Revenue - Other	$ (3,705,546)	$ (107,048)	$ (713,745)	$ (865,080)	$ (1,400,678)	$ (18,501)	$ (6,810,598)
(23) Less: Misc Revenue - Total	$ (3,705,546)	$ (9,646,747)	$ (7,403,726)	$ (865,080)	$ (1,400,678)	$ (18,501)	$ (23,040,279)
(24) Net Cost of Service	$ 174,856,209	$ 214,583,905	$ 27,590,311	$ 43,935,864	$ 75,638,549	$ 35,226,419	$ 571,831,256
(25) Billing Units	6,197,488,349	6,197,488,349	6,197,488,349	6,197,488,349	5,164,249	5,164,249	
(26) Unit Costs	0.028214044	0.034624334	0.004451854	0.007089302	$ 14.65	$ 6.82	$ 21.47

Customer Charge	$ 21.47
Energy Charge	0.07438

Exhibit MJB-11

Time-of-day Loads and on-peak/off-peak window selection

Louisville Gas & Electric & Kentucky Utilities Combined System Peak Hours from January 2000 through August 2014 (Proposed On-Peak hours boxed)			
Hour of Peak	Winter	Summer	Total
6	6	0	6
7	**42**	0	42
8	**13**	0	13
9	**3**	0	3
10	**4**	0	4
13	3	**4**	7
14	2	**22**	24
15	11	**42**	53
16	3	**5**	8
17	1	0	1
18	7	1	8
19	5	0	5
20	2	0	2
	102	74	176

Number of Peaks Captured by Proposed On-Peak Window
76.70%

	Bills	Total kWh	Present Rates	Calculated Revenue at Present Rates	Proposed Rates	Calculated Revenue at Proposed Rates
RESIDENTIAL RATE RS & LEV						
RS Basic Service Charges	5,164,164		$ 10.75	$ 55,514,763	$ 18.00	$ 92,954,952
LEV Basic Service Charges	85		$ 10.75	$ 914	$ 18.00	$ 1,530
RS Energy		6,197,389,895	$ 0.07744	$ 479,925,873	$ 0.08057	$ 499,323,704
LEV Energy, Off-Peak Period		62,620	$ 0.05587	$ 3,499	$ 0.05100	$ 3,194
LEV Energy, Intermediate Period		21,870	$ 0.07763	$ 1,698	$ -	$ -
LEV Energy, On-Peak Period		13,964	$ 0.14297	$ 1,996	$ 0.25874	$ 9,272
		Total Calculated at Base Rates		**$ 535,448,743**		**$ 592,292,652**
		Correction Factor		0.999999176		0.999999176
		Total After Application of Correction Factor		**$ 535,449,184**		**$ 592,293,140**
Adjustment to Reflect Removal of Base ECR Revenues				(19,522,088)		(19,522,088)
Total Base Revenues Net of ECR				**$ 515,927,096**		**$ 572,771,052**
ECR Base Revenues				$ 19,522,088		$ 19,522,088
FAC Billing Mechanism Revenues				$ 15,609,887		$ 15,609,887
DSM Billing Mechanism Revenues				$ 9,031,444		$ 9,031,444
ECR Billing Mechanism Revenues				$ 33,907,729		$ 33,907,729
Total Base Revenues Inclusive of ECR				**$ 593,998,244**		**$ 650,842,200**
Proposed Increase						**56,843,956**
	Percentage Increase					9.57%

	Bills	Total kWh	Present Rates	Calculated Revenue at Present Rates	Proposed Rates	Calculated Revenue at Proposed Rates
RESIDENTIAL RATE RTOD-E, Residential Time of Use Energy Pilot Program						
Basic Service Charges	5,164,249		$ 10.75	$ 55,515,677	$ 18.00	$ 92,956,482
Energy, Off-Peak Period		5,315,433,666	$ 0.05587	$ 296,973,279	$ 0.05100	$ 271,087,117
Energy, On-Peak Period		882,054,683	$ 0.14297	$ 126,107,358	$ 0.25874	$ 228,222,829
		Total Calculated at Base Rates		**$ 478,596,314**		**$ 592,266,428**
Adjustment to Reflect Removal of Base ECR Revenues				$ (19,522,088)		$ (19,522,088)
Total Base Revenues Net of ECR				**$ 459,074,226**		**$ 572,744,340**
ECR Base Revenues				$ 19,522,088		$ 19,522,088
FAC Billing Mechanism Revenues				$ 15,609,887		$ 15,609,887
DSM Billing Mechanism Revenues				$ 9,031,444		$ 9,031,444
ECR Billing Mechanism Revenues				$ 33,907,729		$ 33,907,729
Total Base Revenues Inclusive of ECR				**$ 537,145,374**		**$ 650,815,488**
Difference in Revenue from existing Residential Class						**(26,712)**
						-0.004%

	Bills	Metered Demand, kW	Total kWh	Present Rates	Calculated Revenue at Present Rates	Proposed Rates	Calculated Revenue at Proposed Rates
RESIDENTIAL RATE RTOU-D, Residential Time of Use Demand Pilot Program							
Basic Service Charges	5,164,249			$ -	$ -	$ 18.00	$ 92,956,482
Energy			6,197,488,349	$ -	$ -	$ 0.04008	$ 248,395,333
kW, Off-Peak Period		16,963,714		$ -	$ -	$ 3.25	$ 55,132,071
kW, On-Peak Period		16,931,100		$ -	$ -	$ 11.56	$ 195,723,516
Total Calculated at Base Rates					**$ -**		**$ 592,207,402**
Correction Factor					1.000000000		1.000000000
Total After Application of Correction Factor					**$ -**		**$ 592,207,402**
Adjustment to Reflect Removal of Base ECR Revenues					(19,522,088)		(19,522,088)
Total Base Revenues Net of ECR					**$ (19,522,088)**		**$ 572,685,314**
ECR Base Revenues					$ 19,522,088		$ 19,522,088
FAC Billing Mechanism Revenues					$ 15,609,887		$ 15,609,887
DSM Billing Mechanism Revenues					$ 9,031,444		$ 9,031,444
ECR Billing Mechanism Revenues					$ 33,907,729		$ 33,907,729
Total Base Revenues Inclusive of ECR					**$ 58,549,060**		**$ 650,756,462**
Difference in Revenue from existing Residential Class							**(85,738)**
							-0.013%

Exhibit MJB-12

Cost Support for Supplemental /Standby Rates

Kentucky Utilities Company
Cost Support for Supplemental/Standby Rates
Production and Transmission Unit Demand Costs
From the Cost of Service Study filed in Case # 2014-00371
Total System

	Reference	Total Production Cost	Total Transmission Cost	Total
Operation and Maintenance Expenses		$ 118,846,743	$ 34,684,812	$ 153,531,555
Depreciation Expenses		125,689,713	16,465,275	$ 142,154,988
Accretion Expenses		-	-	$ -
Property Taxes		14,370,515	2,703,093	$ 17,073,607
Other Taxes		7,694,149	1,447,269	$ 9,141,418
Gain Disposition of Allowances and other		-	-	$ -
Expense Adjustments		1,543,420	269,592	$ 1,813,012
Sub-Total Expenses		$ 268,144,540	$ 55,570,040	$ 323,714,580
Adjusted Rate Base		2,223,454,191	428,261,076	2,651,715,267
Return	Rate Base x Weighted Cost of Capital %	166,742,353	32,116,362	198,858,715
Income Taxes	Rate Base x Income Tax %	71,979,163	13,863,957	85,843,121
Total Revenue Requirement	Expenses + Return + Income Taxes	$ 506,866,056	$ 101,550,359	$ 608,416,415
100% Load Factor Demand	System CP x 12 months @ 90% PF	57,527,827	57,527,827	57,527,827
Unit Cost	Total Revenue Requirement / Demand	$ 8.81	$ 1.77	$ 10.58

			Weighted Cost of Capital	Income Taxes	Weighted Cost of Capital Grossed Up For Inc Taxes
Short Term Debt	2.31%	1.58%	0.04%		0.04%
Long Term Debt	44.43%	4.21%	1.87%		1.87%
Common Equity	53.26%	10.50%	5.59%	3.24%	8.83%
Total Capitalization	100.00%		7.50%		10.74%

Composite State and Fed Inc Tax Rate 36.664%

Note: This cost support is based on cost of service data submitted in Case No. 2014-00371

Kentucky Utilities Company
Cost Support for Supplemental/Standby Rates
Primary Distribution Unit Demand Costs
From the Cost of Service Study filed in Case # 2014-00371
PSP & TODP

	Reference	Distribution Primary Substation Cost	Distribution Primary Lines Cost	Distribution Primary Transformer Cost	Total
Operation and Maintenance Expenses		$ 1,537,545	$ 3,171,609	$ -	$ 4,709,154
Depreciation Expenses		1,109,003	1,504,015	-	$ 2,613,017
Accretion Expenses		-	-	-	$ -
Property Taxes		133,690	181,309	-	$ 315,000
Other Taxes		71,580	97,075	-	$ 168,655
Gain Disposition of Allowances and other		-	-	-	$ -
Expense Adjustments		7,405	12,863	-	$ 20,268
Sub-Total Expenses		$ 2,859,223	$ 4,966,871	$ -	$ 7,826,094
Adjusted Rate Base		10,565,486	17,946,763	-	28,512,249
Return	Rate Base x Weighted Cost of Capital %	792,332	1,345,872	-	2,138,204
Income Taxes	Rate Base x Income Tax %	342,033	580,985	-	923,018
Total Revenue Requirement	Expenses + Return + Income Taxes	$ 3,993,588	$ 6,893,728	$ -	$ 10,887,316
Billing Demand	Billing Demand @ 90% PF	10,376,240	10,376,240	10,376,240	10,376,240
Unit Cost	Total Revenue Requirement / Demand	$ 0.3849	$ 0.6644	$ -	$ 1.0493

			Weighted Cost of Capital	Income Taxes	Weighted Cost of Capital Grossed Up For Inc Taxes
Short Term Debt	2.31%	1.58%	0.04%		0.04%
Long Term Debt	44.43%	4.21%	1.87%		1.87%
Common Equity	53.26%	10.50%	5.59%	3.24%	8.83%
Total Capitalization	100.00%		7.50%		10.74%

Composite State and Fed Inc Tax Rate 36.664%

Note: This cost support is based on cost of service data submitted in Case No. 2014-00371

Kentucky Utilities Company
Cost Support for Supplemental/Standby Rates
Secondary Distribution Unit Demand Costs
From the Cost of Service Study filed in Case # 2014-00371
PSS & TODS

	Reference	Distribution Secondary Substation Cost	Distribution Secondary Lines Cost	Distribution Secondary Transformer Cost	Total
Operation and Maintenance Expenses		$ 1,348,999	$ 2,782,680	$ 493,554	$ 4,625,232
Depreciation Expenses		973,008	1,319,580	765,391	$ 3,057,978
Accretion Expenses		-	-	-	$ -
Property Taxes		117,296	159,076	92,268	$ 368,640
Other Taxes		62,802	85,171	49,401	$ 197,374
Gain Disposition of Allowances and other		-	-	-	$ -
Expense Adjustments		28,035	48,701	15,750	$ 92,486
Sub-Total Expenses		$ 2,530,140	$ 4,395,207	$ 1,416,363	$ 8,341,710
Adjusted Rate Base		18,995,673	25,760,565	14,866,386	59,622,624
Return	Rate Base x Weighted Cost of Capital %	1,424,533	1,931,849	1,114,867	4,471,249
Income Taxes	Rate Base x Income Tax %	614,941	833,938	481,265	1,930,144
Total Revenue Requirement	Expenses + Return + Income Taxes	$ 4,569,613	$ 7,160,995	$ 3,012,495	$ 14,743,103
Billing Demand	Billing Demand @ 90% PF	12,160,342	12,160,342	12,160,342	12,160,342
Unit Cost	Total Revenue Requirement / Demand	$ 0.3758	$ 0.5889	$ 0.2477	$ 1.2124

			Weighted Cost of Capital	Income Taxes	Weighted Cost of Capital Grossed Up For Inc Taxes
Short Term Debt	2.31%	1.58%	0.04%		0.04%
Long Term Debt	44.43%	4.21%	1.87%		1.87%
Common Equity	53.26%	10.50%	5.59%	3.24%	8.83%
Total Capitalization	100.00%		7.50%		10.74%

Composite State and Fed Inc Tax Rate 36.664%

Note: This cost support is based on cost of service data submitted in Case No. 2014-00371

KU System Peak	(1) * 12
(1)	(2)
4,314,587	51,775,044

90% Power Factor Adjustment	(2) / (3)
(3)	(4)
90%	57,527,827

100% Load Factor Demand
57,527,827

Exhibit MJB-13

Cost Support for Redundant Capacity Rates

Kentucky Utilities
Derivation of Distribution Demand-Related Cost for
Redundant Capacity
Based on the 12 Months Ended June 30, 2016

Secondary Service

Distribution Demand Costs				
PSS	$	4,797,977		
TODS	$	3,029,974		
Total Cost	$	7,827,951		
Billing Demand				
PSS		6,913,703		
TODS		3,854,008		
Total Cost		10,767,711		
Unit Cost			$	0.73
Rate Base				
PSS	$	36,365,314		
TODS	$	23,257,310		
Total Cost	$	59,622,624		
Return	$	4,280,904		
Unit Return			$	0.40
Capacity Charge			$	1.12 / KW

Source: Electric Cost of Service Study (Exhibit MJB - 9)

Kentucky Utilities Company
Derivation of Distribution Demand-Related Cost for
Redundant Capacity
Based on the 12 Months Ended June 30, 2016

<u>Primary Service</u>

Distribution Demand Costs					
PSP	$	505,706			
TODP	$	6,748,704			
Total Cost	$	7,254,410			
Billing Demand					
PSP		673,741			
TODP		9,136,849			
Total Cost		9,810,590			
Unit Cost			$	0.74	
Rate Base					
PSP	$	3,510,187			
TODP	$	47,501,530			
Total Cost	$	51,011,717			
Return	$	3,662,641			
Unit Return			$	0.37	
Capacity Charge			$	1.11	/ KW

Source: Electric Cost of Service Study (Exhibit MJB - 9)

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

APPLICATION OF KENTUCKY UTILITIES	**)**	
COMPANY FOR AN ADJUSTMENT OF ITS	**)**	**CASE NO. 2014-00371**
ELECTRIC RATES	**)**	

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

Filed: November 26, 2014

I. **<u>INTRODUCTION</u>**

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 "Company") and Louisville Gas and Electric Company ("LG&E") and an employee of LG&E and KU Services Company, which provides services to LG&E and KU (collectively "Companies"). My business address is 220 West Main Street, Louisville, Kentucky 40202.

Q. Please describe your educational and professional background.

A. 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 three most recent base rate cases,[1] and most recently in the Companies' 2014 Demand-Side Management and Energy Efficiency ("DSM/EE") 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 present the revenue effects and the bill impacts to the average residential customer; (4) to present KU's recommendation for the allocation of the proposed increases in revenues among the customer classes based on the results

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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; *In the Matter of: Application of Kentucky Utilities Company for an Adjustment of Its Electric Rates*, Case No. 2012-00221.

[2] *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*, Case No. 2014-00003.

of the Company's cost of service study prepared by Dr. Martin J. Blake in this case; (5) to explain the relationship of KU's various cost-recovery mechanisms to its base rates; and (6) to discuss and explain the various tariff changes KU proposes.

II. <u>FILING REQUIREMENTS</u>

Q. Are you supporting certain information required by Commission regulation 807 KAR 5:001 Sections 16(8)?

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

• Narrative description and explanation of all proposed tariff changes	Section 16(8)(l)	Tab 64
• Typical bill comparison under present and proposed rates for all customer classes	Section 16(8)(n)	Tab 66

I am also the responsible witness for several supporting schedules for certain filing requirements sponsored by Mr. Kent W. Blake. Concerning the filing requirement fulfilling the requirements of Section 16(8)(b), I am sponsoring Schedules B-7 (*Jurisdictional Percentages*), B-7.1 (*Jurisdictional Statistics – Rate Base*), and B-7.2 (*Explanation of Changes in Jurisdictional Procedures – Rate Base*), which concern jurisdictional allocations factors used in rate base calculations. Concerning the filing requirement fulfilling the requirements of Section 16(8)(d), I am sponsoring Schedule D-2, *Jurisdictional Adjustments to Operating Revenues and Expenses by Account*, and co-sponsoring with Mr. Blake Schedule D-2.1, *Jurisdictional Pro Forma Adjustments to Operating Revenues and Expenses by Account*.

Q. Please explain KU Schedule B-7, *Jurisdictional Percentages*.

A. Schedule B-7 provides Kentucky-jurisdictional allocation factors by FERC account number. At my direction, Dr. Blake conducted and sponsors the Kentucky jurisdictional separation study for the forecasted test period that generated the factors shown in Schedule B-7. (The jurisdictional separation study is Exhibit MJB-3 to Dr. Blake's testimony.) As Dr. Blake describes in his testimony, he performed KU's Kentucky jurisdictional separation study using the same methodology KU has historically used in its base-rate cases. The Kentucky-jurisdictional allocation factors in Schedule B-7 appear in the "Juris. Percent" column of Schedule B-2.1 to calculate the Kentucky-jurisdictional amounts of KU's plant in service for each FERC account.

Q. Please explain KU Schedule B-7.1, *Jurisdictional Statistics – Rate Base*.

A. Using the same major groupings for rate base shown in Schedule B-1, Schedule B-7.1 shows for the base period (as of February 28, 2015) and the forecasted test period (13-month average): total-company rate base (Column C); adjustments to total-company rate base (Column D); adjusted total-company rate base (Column E); Kentucky-jurisdictional adjusted rate base (Column F, which amounts appear also in Schedule B-1); and the Kentucky-jurisdictional allocation factor for each major grouping, which is calculated for each major grouping by dividing the amount in Column F by the amount in Column E. The adjustment amounts in Column D remove the environmental cost recovery ("ECR") mechanism, Demand-Side Management Cost-Recovery Mechanism ("DSM mechanism"), and asset retirement obligations ("ARO") rate base components. This schedule therefore provides information additional to what is shown in Schedule B-7 because it provides Kentucky-jurisdictional allocation factors for major groupings.

Q. Please explain KU Schedule B-7.2, *Explanation of Changes in Jurisdictional Procedures – Rate Base*.

A. As I noted above, Dr. Blake conducted KU's Kentucky jurisdictional separation study using the same methodology KU has historically used in its base-rate cases, so the schedule indicates no changes in methodology between Case No. 2012-00221 and this application.

Q. Please explain KU Schedule D-2, *Jurisdictional Adjustments to Operating Revenues and Expenses by Account*.

A. Schedule D-2 provides the adjustments for both the base period and the forecasted test period to operating revenues and expenses by FERC account necessary to remove the effects of KU's other recovery mechanisms: Fuel Adjustment Clause ("FAC"), ECR, and DSM mechanism. The schedule then multiplies the sum of the adjustments for each account by the appropriate Kentucky-jurisdictional factor. The amounts shown in the "Jurisdictional Adjustments" column appear in column 4 of Schedule C-2.1 in the column "Jurisdictional Adjustments Sch D-2."

Q. Please explain KU Schedule D-2.1, *Jurisdictional Pro Forma Adjustments to Operating Revenues and Expenses by Account*.

A. Schedule D-2.1 provides the pro forma adjustments to operating revenues and expenses by FERC account KU is proposing in this proceeding for the forecasted test period: ECR for Off-System Sales, Cane Run Depreciation, Granville Light Sales, Customer Account Changes (each of which I describe separately below), Advertising Expenses, and Interest Synchronization. The schedule then multiplies the sum of the adjustments for each account by the appropriate Kentucky-jurisdictional factor. I am providing testimony in support of all of the above-listed adjustments except Cane Run Depreciation and Interest Synchronization; Mr. Blake is supporting those adjustments. The amounts shown in the "Jurisdictional Pro Forma Adjustments to Forecast Period" column appear in column 4 of Schedule D-1 in the column "Jurisdictional Pro Forma Adjustments to Forecasted Period."

III. <u>HOW THE RELATIONSHIP OF BASE RATES TO OTHER RATEMAKING MECHANISMS AFFECTS PRO FORMA ADJUSTMENTS</u>

Q. Are there items other than base rates that affect customers' total bills from the Company?

A. Yes. In addition to 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 FAC, ECR, and DSM mechanism have any effect on the base rate increases KU is requesting?

A. No. As presented in the testimony of Mr. Blake and as I discuss below, the impact of those mechanisms has been removed from the calculation of KU's operating revenues and expenses for both the base period ending February 28, 2015, and the forecasted test period ending June 30, 2016. 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 increases 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.

IV. PRO FORMA ADJUSTMENTS

A. ELECTRIC PRO FORMA ADJUSTMENTS

1. DSM-Mechanism-Related Adjustments

Q. Please explain the adjustment to operating revenues and expenses shown in Schedule D-2 that eliminates revenues recovered through the DSM mechanism and related expenses.

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 electric revenues to be recovered through the DSM mechanism and the corresponding expenses for both the base period and the forecasted test period. The operating revenue and expense components of the adjustment are shown in the column labeled "Adj 1 Remove DSM Mechanism" of Schedule D-2. The supporting details are contained in Schedule WPD-2.

The Commission determined a similar adjustment to be reasonable in Case Nos. 2003-00434 and 2009-00548, two of KU's previous historical-test-year cases. KU proposed such an adjustment in Case Nos. 2008-00251 and 2012-00221, also two of KU's previous historical-test-year cases, which were resolved by settlement agreements approved by the Commission.

Q. Please explain the adjustments shown in Schedule J-1.1/1.2 and Supporting Schedule B-1.1, which remove DSM rate base from the Company's rate base and capitalization, respectively.

A. In accordance with the Commission's final orders in Case Nos. 2011-00134 and 2014-00003, the Company capitalizes the cost of installing load-control switches and related equipment used in two of its flagship DSM programs, the Residential Load

Management / Demand Conservation Program and the Commercial Load Management / Demand Conservation Program.[3] Also in accordance with the Commission's final order in Case No. 2014-00003, the Company will begin capitalizing the cost of advanced meters, related communications equipment, and other related capital items related to its Advanced Metering Systems customer offering when the Company initiates the offering in 2015.[4] Because the Company recovers the cost of those investments, as well as a return on those investments, through the DSM mechanism, column 4 of Supporting Schedule B-1.1 removes DSM rate base from the Company's rate base and column H of page 1 of Schedule J-1.1/1.2 removes DSM rate base and other mechanism-related rate base from the Company's capitalization.

The Company performed these adjustments using a methodology similar to the one proposed in Case No. 2012-00221, which was an historical-test-year case resolved by a settlement approved by the Commission.

2. <u>FAC Adjustment</u>

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 Schedule D-2.

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[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*, Case No. 2011-00134, Order at 14 (Nov. 9, 2011) ("The Companies' request to add a fifth element to the DSMRC to account for the capital expenditure needed to develop the Residential and Commercial Load Management/Demand Conservation Program in the DSM/EE Program Plan is granted."); *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*, Case No. 2014-00003, Order (Nov. 14, 2014).

[4] *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*, Case No. 2014-00003, Order (Nov. 14, 2014).

A. Consistent with past Commission practice in the Company's historical base-rate cases, this adjustment eliminates the mismatch between fuel costs and fuel cost recovery through the Company's FAC. This mismatch exists even in a fully forecasted test period because the Company incurs fuel costs in a given month, which costs affect the FAC amounts the Company bills two months later. The operating revenue and expense components of the adjustment for both the base period and the forecasted test period are shown in the column labeled "Adj 3 Remove FAC Mechanism" of Schedule D-2. The supporting details are contained in Schedule WPD-2.

The Commission determined a similar adjustment to be reasonable in Case Nos. 2003-00434 and 2009-00548, two of KU's previous historical-test-year cases. KU proposed such an adjustment in Case Nos. 2008-00251 and 2012-00221, also two of KU's previous historical-test-year cases, which were resolved by settlement agreements approved by the Commission.

3. <u>ECR-Related Adjustments</u>

Q. Please explain the adjustment to operating expenses and revenues to eliminate ECR revenues and expenses shown in Schedule D-2.

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 forecasted test period that will continue to be included through the ECR mechanism after the implementation of new base rates. The operating revenue and expense components of the adjustment for both the base period and the forecasted test period are shown in the column labeled "Adj 2 Remove ECR Mechanism" of Schedule D-2. The supporting details are contained in Schedule

WPD-2. The ECR surcharge provides for full recovery of approved environmental costs that qualify for the surcharge.

Consistent with 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.[5] 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. KU proposed such an adjustment using this methodology in Case No. 2012-00221, which was an historical-test-year case that was resolved by a settlement agreement approved by the Commission.

Q. Please explain the adjustment to operating revenues shown in Schedule D-2.1 that concerns off-system sales revenues related to the ECR calculation.

A. In determining 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 the forecasted-test-period, these revenues are credited to jurisdictional customers. Moreover, because total ECR expenses are removed through the adjustment in Schedule D-2, 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

[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, 2009*, Case No. 2009-00310, final Order dated December 2, 2009.

adjustment a reduction to revenues associated with ECR-related off-system and intercompany sales revenues. The operating revenue components of this adjustment are shown in the column labeled "Adj 4 ECR for Off-System Sales" of Schedule D-2.1. The supporting details are contained in Schedule WPD-2.1a.

KU performed the adjustment in a manner generally consistent with the methodology used in Case Nos. 2009-00548 and 2012-00221, both of which were historical-test-year cases. The Commission found the adjustment reasonable in Case No. 2009-00548; Case No. 2012-00221 was resolved by a settlement agreement approved by the Commission.

Q. Please explain the adjustments shown in Schedule J-1.1/1.2 and Supporting Schedule B-1.1, which remove ECR rate base from the Company's rate base and capitalization, respectively.

A. Removing the Company's ECR rate base from its capitalization and rate base is necessary because the Company is recovering its investment, as well as a return on its investment, through the ECR mechanism. Column 3 of Supporting Schedule B-1.1 removes ECR rate base from the Company's rate base and Column H of page 1 of Schedule J-1.1/1.2 removes ECR rate base and other mechanism-related rate base from the Company's capitalization.

The Company performed these adjustments using a methodology similar to the one approved by the Commission in Case Nos. 2009-00548 and 2003-00434, and as proposed in Case Nos. 2012-00221 and 2008-00251, which were resolved by a settlement approved by the Commission.

4. Non-Mechanism-Related Adjustments

Q. Please explain the adjustments to operating expenses and revenues in the column labeled "Adj 6 Granville Light Sales" on Schedule D-2.1, which concerns KU's sale of its Granville lighting fixtures and accessories to the Lexington-Fayette Urban County Government ("LFUCG").

A. KU is selling to the LFUCG all of KU's Granville lighting fixtures and accessories currently used to serve the LFUCG. As a result, LFUCG's lighting service related to those fixtures will move from Rate LS (Lighting Service) to Rate LE (Lighting Energy), and revenues to KU will decrease. The unadjusted forecasted test period does not account for the sale and resulting rate switch. The adjustments shown in the column labeled "Adj 6 Granville Light Sales" on Schedule D-2.1 correct the inaccuracy by appropriately decreasing revenues to reflect the sale and resulting rate switch, as well as decreases in maintenance, depreciation, property tax, and federal and state income tax expenses. The data for each revenue adjustment is shown in work-paper Schedule WPD-2.1a and the specific details of the calculations are contained in Exhibit RMC-1.

Q. Please explain the adjustments to electric operating revenues and expenses shown in the column labeled "Adj 7 Customer Account Changes" on Schedule D-2.1.

A. The column labeled "Adj 7 Customer Account Changes" on Schedule D-2.1 shows the revenue impacts, as well as the related state and federal income tax impacts, associated with two customer account changes that should be included in the forecasted test year. I describe the relevant changes below. The data for each revenue adjustment is shown in work-paper Schedule WPD-2.1a.

First, revenues from KU's Rider RC (Redundant Capacity) were inadvertently excluded from forecasted-test-year data. The operating revenue adjustments calculated in the rows labeled "CUST 442.2 Redundant Capacity Rider Revenue," "CUST 442.3 Redundant Capacity Rider Revenue," and "CUST 445 Redundant Capacity Rider Revenue" in Schedule WPD-2.1a increase revenues to reflect the projected revenues from KU's Rider RC customers. Specific details of the calculations are contained in Exhibit RMC-2.

Second, KU recently entered into a contract with a customer to provide back-up service under Rider SS (Supplemental or Standby Service) at times when the customer's own generation is not available to provide their energy needs. This additional revenue was not included in revenues for the unadjusted forecasted test period because the contract for Standby Service was only recently executed. The operating revenue adjustment in the row labeled "CUST 442.3 Contract for Standby Service" in Schedule WPD-2.1a corrects the inaccuracy by appropriately increasing revenues. A detailed calculation of the Rider SS revenue KU anticipates this customer will provide in the forecasted test period is shown in Exhibit RMC-3.

Third, recently KU entered into a contract with a customer ("Customer A") that consolidated Customer A's two current services into a single service. This consolidation will reduce the relative demand, and therefore the revenues, Customer A will provide KU. The unadjusted forecasted test period does not account for the contract change and resulting service consolidation and revenue decrease. The operating revenue adjustment calculated in the row labeled "CUST 442.3 Totalize Meters-Customer A" in Schedule WPD-2.1a corrects the inaccuracy by appropriately decreasing revenues to reflect the contract change and resulting service consolidation and revenue decrease. Specific details of the calculations are contained in Exhibit RMC-4.

Fourth, KU recently entered into a new contract with a customer ("Customer B") that results in billing two current services as a single billing. This change will reduce demand billings, and therefore the revenue. The unadjusted forecasted test period does not account for the contract change and resulting revenue decrease. The operating revenue adjustment in the row labeled "CUST 442.3 Totalize Meters-Customer B" in Schedule WPD-2.1a corrects the inaccuracy by appropriately decreasing revenues to reflect the contract change and resulting service billings and revenue decrease. Specific details of the calculations are contained in Exhibit RMC-5.

Q. Please explain the adjustment to electric operating expenses shown in the column labeled "Adj 8 Advertising Expenses" on Schedule D-2.1.

A. This adjustment eliminates all advertising expenses. Commission regulation 807 KAR 5:016 §2(1) provides that a utility will be allowed to recover, for ratemaking purposes, only those advertising expenses that produce a "material benefit" for its ratepayers. In previous historical-test-year rate cases the Company has proposed, and the Commission has approved, adjustments to remove only the portion of its advertising expenses attributable to primarily institutional or promotional advertisements.[6] In this case, the Company's current budgeting process does not

[6] The Commission determined a similar adjustment to be reasonable in Case Nos. 2003-00434 and 2009-00548, two of KU's previous historical-test-year cases. KU proposed such an adjustment in Case Nos. 2008-00251 and 2012-00221, also two of KU's previous historical-test-year cases, which were resolved by settlement agreements approved by the Commission.

permit a clear distinction between budgeted advertising expenses eligible for base-rate recovery and those that are not. Therefore, the Company is eliminating all advertising expenses from its forecasted test period in this case out of an abundance of caution, but the Company reserves the right to include appropriate advertising expenses in future base-rate cases.

V. COST OF SERVICE STUDY, ALLOCATION OF INCREASE, AND RATE DESIGN

A. COST OF SERVICE STUDY

Q. Did the Company cause to be prepared an electric cost of service study to be used as the guide to its proposed rate design and the allocation of its requested electric revenue increase?

A. Yes. At my direction, Dr. Blake and The Prime Group conducted a fully allocated and time-differentiated embedded electric cost of service study for the Company.

Q. Which cost of service methodology did The Prime Group use to perform the Company's electric cost of service study?

A. The Prime Group used the modified Base-Intermediate-Peak methodology that the Commission has accepted in every KU rate case for over a decade. The details of that study are presented in Dr. Blake's testimony.

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:

TABLE 1 Electric Class Rates of Return		
Customer Class	**Actual Adjusted Rate of Return**	**Proposed Rate of Return**
Residential – Rate RS	2.77%	4.84%
General Service – Rate GS	9.01%	12.14%
All Electric School – Rate AES	4.43%	7.14%
Power Service – Rate PS		
- Secondary	11.29%	15.04%
- Primary	8.24%	11.46%
Time of Day Secondary – Rate TODS	5.42%	8.69%
Time of Day Primary – Rate TODP	3.34%	6.40%
Retail Transmission Service – Rate RTS	3.41%	6.52%
Fluctuating Load Service – Rate FLS	1.53%	4.61%
Lighting	2.75%	4.13%
Total System	4.55%	7.18%

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 all pro forma adjustments. 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. Dr. Blake discusses the actual adjusted and proposed rates of return in his testimony.

B. ALLOCATION OF ELECTRIC REVENUE INCREASE

Q. What revenue increase is KU proposing for electric operations?

A. As shown on Schedule M-2.1, KU is proposing an increase in electric forecasted-test-period revenues of $153,442,682 which is calculated by applying the proposed rates to forecasted-test-period billing determinants. This increase is slightly lower than the revenue requirement increase of $153,443,950 shown in Schedule A because the number of decimal places in the proposed charges cannot be carried out far enough to yield the exact amount shown in the schedule.

Q. How does the Company propose to allocate the electric revenue increase to the classes of service?

A. KU proposes to allocate the electric revenue increase to the classes of service by increasing each class of service's revenue by the same, system-average percentage of approximately 9.6%. Dr. Blake further discusses this approach in his testimony.

C. ELECTRIC RATE DESIGN APPROACH

Q. What is the basic objective of the rate design being proposed?

A. It is the Company's intent to continue bringing both the structure and the charges of the rate design in line with the results of the cost of service study. My testimony addresses changes the Company is proposing to rate structures and the charges supported by the cost of service study.

Q. What changes does the Company propose to its electric rate structures?

A. Though KU proposes to change most charges for service under the various rate schedules, its most significant proposed structural change is to add two new optional time-of-day rates for residential customers. I address below those rate schedules and the others 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. With the changes proposed in this case, the Companies have almost completely harmonized their rate schedules. In the LG&E rate case proceeding in parallel with this case, LG&E is proposing to consolidate its Rates CTODP and ITODP into a single Rate TODP, which is consistent with KU's tariff. With this change, the only substantive difference that will remain between the Companies' rate schedules will be KU's Rate AES (All-Electric School), which rate schedule LG&E does not have.

D. RESIDENTIAL ELECTRIC RATE DESIGN & INCREASE

Q. Does the Company 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. The Company is adding the word "secondary" to the Availability of Service section of the Rate RS rate schedule to clarify that the rate is available only to residential customers served by the Company's secondary distribution system. This is not a substantive change; the Company's Character of Service provisions on Sheet No. 99 currently state that residential service is to be served at secondary voltages.

Q. Does the Company propose to bring the rate components in residential electric rates more in line with the cost of service study?

A. Yes. KU proposes to increase the monthly residential basic service charge from $10.75 to $18.00. As Dr. Blake discusses further in his testimony, the cost of service study indicates that the customer-related cost for the residential class is $21.47 per customer per month. KU is therefore proposing to increase the basic service charge in a direction that will more accurately reflect the actual cost of providing service but will still be less than the full amount of customer-related cost. This cost is derived in Dr. Blake's Exhibit MJB-10.

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. In fact, increasing the basic service charge to align more closely with residential customers' actual customer-specific fixed costs will provide a more accurate energy-pricing signal to customers, which will in turn enable them to make better energy-efficiency behavioral and investment decisions. And as the Commission noted in its final order in the Company's most recent base-rate case, LG&E and KU have demand-side management and energy-efficiency ("DSM-EE") programs that are "the most comprehensive in the Commonwealth."[7] Therefore, when the Company's customers choose to engage in DSM-EE programs based on the more accurate pricing signals the Company's proposed rates will provide, they will find a wide array of programs and incentives available to them.

Also, it is important to note that a significant amount of fixed cost will still be embedded in residential energy rates even if the Commission approves the Company's requested increase in the residential basic service charge. As I noted above, a portion of customer-specific fixed cost will remain in energy rates because the Company is not requesting a basic service charge that would recovery the full amount of customer-specific fixed cost; the Company is requesting a residential basic service charge of $18.00 per month, not the full $21.47 supported by the cost of service study. But more significantly, the non-customer-specific fixed costs the Company recovers from most other rate classes through demand charges will remain embedded in energy charges for the residential class.

[7] *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, Order at 13 (Dec. 20, 2012).

Q. Would recovering a larger proportion of customer-specific fixed 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. Reducing the bill impact of usage spikes has become of particular concern following the polar vortex of early 2014. As the Commission noted in a letter it sent to Kentucky's utilities in late February 2014, unexpected surges in utility usage caused by extreme weather conditions can create additional hardships for customers who already have difficulty paying their utility bills in high-usage seasons and can cause other customers to have difficulties for the first time.[8] Increasing the basic service charge to more closely align with customer-specific fixed costs will reduce the amount of fixed costs embedded in energy rates. This relative reduction of volumetric energy rates will help mitigate bill fluctuations caused by energy-usage spikes, including the impacts of any future extreme weather events.

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 9.57%, or approximately $11.01, for a residential customer using an

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[8] *See* "TEXT OF PSC LETTER TO ELECTRIC AND NATURAL GAS UTILITY CEOs" included in the Commission's February 24, 2014 News Release *PSC Calls On Utilities to Work with Customers Facing Large Gas or Electric Bills* (Feb. 24, 2014) ("Customers on fixed or limited incomes who struggle to pay their bills in a normal winter will be facing even greater hardships. Others may encounter difficulties for the first time.").

average of 1,200 kWh of electricity. Typical bill calculations for various levels of energy consumptions are shown in Schedule N of filing requirement Section 16(8)(n).

E. NEW OPTIONAL RATES FOR RESIDENTIAL CUSTOMERS

Q. Is the Company proposing to offer new optional rates to residential customers?

A. Yes. The Company is adding two new optional rate schedules for residential customers: Residential Time-of-Day Demand Service (Rate RTOD-Demand) and Residential Time-of-Day Energy Service (Rate RTOD-Energy). These optional time-of-day rates replace and broaden the availability of the Company's existing time-of-day rate offering for residential customers, Low-Emission Vehicle Service (Rate LEV).

Q. The Company instituted Rate LEV as a three-year pilot program. Are these new rates part of a pilot program, too?

A. No, because LG&E and KU already have significant combined experience with pilot programs offering time-of-day rates to residential customers. LG&E conducted a three-year variable-critical-peak-pricing ("CPP") pilot program, which it called its Responsive Pricing Pilot. The pilot offered three-tiered time-of-use ("TOU") rates with a variable-CPP component to a geographically targeted sample of residential and small commercial customers. Low- and medium-pricing periods had rates lower than the standard rate and made up approximately 87% of the hours in a year. CPP events could occur during hours of high generation system demand for up to eighty hours per year, implemented at LG&E's discretion. Customers received at least 30 minutes' notice prior to CPP events, which had an energy rate of approximately five times that of the standard flat rate. Responsive-pricing participants received four devices to help them control their energy usage and respond to CPP events: smart meters, programmable communicating thermostats, in-home energy-usage displays, and load-control switches.

The pilot's results showed that customers consistently decreased their energy usage slightly in high-pricing and CPP periods, but they used more energy overall throughout the summer periods compared to non-Responsive Pricing customers. Average demand reductions during CPP events varied from 0.2 kW to over 1.0 kW per participant during high-temperature periods, but those customers' demand rebounded after CPP periods ended, with a maximum average load increase of 0.8 kW. Even with participating customers' increased usage during summer months, they had an average bill decrease of 1.4% for those months.

LG&E's Responsive Pricing Pilot ended in 2010, and LG&E removed the Responsive Pricing pilot rates from its tariff.[9]

In their 2009 base-rate cases LG&E and KU both proposed, and the Commission approved, a three-year pilot TOU rate to residential customers who have low-emission vehicles, Rate LEV.[10] Rate LEV allows customers who own plug-in electric or hybrid vehicles, or who use electric-powered home-fueling stations for their natural-gas vehicles, to charge or fuel their vehicles at an off-peak rate that is less than the standard residential rate. Rate LEV has three TOU rates, the time-periods for which are different in the summer than for the rest of the year. LG&E and KU formulated the rates to be revenue-neutral compared to the standard residential rate. As of October 2014, LG&E had 20 customers on Rate LEV and KU had 9

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[9] *In the Matter of: Request of Louisville Gas and Electric Company to Cancel and Withdraw the Tariffs for Its Responsive Pricing and Smart Metering Pilot Program*, Case No. 2011-00440, Order (March 22, 2012).
[10] *In the Matter of: Application of Kentucky Utilities Company for an Adjustment of Base Rates*, Case No. 2009-00548, Order (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 (July 30, 2010).

customers on the rate. The three years of the Rate LEV pilot period have now expired, though the rate remains in effect until the Commission authorizes the Company to withdraw it, as the Company is requesting in this case.

Because KU and LG&E now have sufficient experience offering pilot time-of-day rates to residential customers, the Company can offer Rates RTOD-Energy and RTOD-Demand with the reasonable anticipation that they will be permanent rate offerings. Although the Company presently intends for the new rate schedules to be permanent, they will be subject to modification or potential termination based on changing customer-demand, cost-benefit, and operational conditions, i.e., they will be permanent subject to the same conditions and considerations that apply to all of the Company's rates.

Q. Why is the Company offering these new optional residential rates?

A. The Companies are offering these new rates chiefly for two reasons: Commission interest and customer interest. In its order permitting LG&E to cancel and withdraw its tariff provisions for its Responsive Pricing and Smart Metering Pilot Program, the Commission directed LG&E to "submit a report describing its efforts to develop a new program every three months until it has submitted a dynamic pricing or smart meter application for the Commission's consideration[.]"[11] LG&E and KU submitted an application for an advanced-metering program in its most recent demand-side management and energy efficiency application, which satisfied the Commission's

[11] *In the Matter of: Request of Louisville Gas and Electric Company to Cancel and Withdraw the Tariffs for Its Responsive Pricing and Smart Metering Pilot Program,* Case No. 2011-00440, Order at 10-11 (March 22, 2012).

requirement.[12] So although the new rates are not intended to fulfill a Commission requirement, they are responsive to the Commission's clear interest in having the Companies implement such rates.

Also, the Companies have seen increases in customer interest in their only time-of-day rate for residential customers, Rate LEV. As noted above, these optional time-of-day rates replace and broaden the availability of time-of-day rates beyond Rate LEV; any residential customer may participate because there is no low-emission-vehicle or other eligibility requirement for these two optional residential rates. And as more customers begin to take service under these new rates, the Company will be able to refine and improve the rates using the customers' usage data and feedback, which may result in further increased customer interest and participation.

Q. Will there be a cap on the number of customers who may take service under the new rates?

A. Yes. The new rates will be available to up to 500 total residential customers across both rate schedules, e.g., if 400 customers take service under Rate RTOD-Energy, only 100 could take service under Rate RTOD-Demand. This restriction is necessary due to billing-labor constraints. The meters the Company will deploy to serve customers under these rates will be digital meters capable of recording demand and energy usage in multiple time-of-day registers. The Company's meter-reading personnel will have to collect the data from the multiple registers each month and transfer the data into the Company's billing system. This process may require

[12] *In the Matter of: Request of Louisville Gas and Electric Company to Cancel and Withdraw the Tariffs for its Responsive Pricing and Smart Metering Pilot Program*, Case No. 2011-00440, Letter from Rick E. Lovekamp to Jeff DeRouen (Apr. 30, 2014).

additional review and analysis, so to avoid the need to hire additional personnel solely to process these new rates, the Company proposes initially to restrict the number of customers who may take service under the two rates to 500 in total. If the Company's customers show a much greater interest than the proposed cap on participation, the Company will evaluate the costs and benefits of the optional rates to enable greater participation.

Q. Will residential customers with detached garages served under Rate GS be able to have their garages served under one of the new rates?

A. Yes, but only if the customer's detached garage uses less than 300 kWh per month and part of that usage is for charging or fueling the customer's low-emission vehicle. This is the same restriction for detached garages that currently applies to the Company's Rate LEV. Although the Companies currently do not have any customers taking service for a detached garage for electric-vehicle charging or natural-gas-vehicle fueling, the Companies did not want to prevent the use of the new optional time-of-day rates for such purposes.

Q. Please describe Rates RTOD-Demand and RTOD-Energy, including any differences from, or similarities to, Rate RS.

A. Both of the new rate schedules use the same basic service charge as Rate RS. This similarity to Rate RS is important because it eliminates what could be a barrier to customers' interest in taking service under one of the new rates.

Another important similarity between the new rate schedules and Rate RS is that there is no minimum contract term; a customer may try one of the new rates for a month and switch to the other new rate or back to Rate RS without penalty or restriction. The only restriction concerning switching is that a customer who takes service under one of the new rates and then chooses to take service under Rate RS cannot return to the same new rate for 12 months after the end of the billing cycle in which the customer asks to switch rates, though customers may switch between the new rates as often as they like, but such change would not take effect until the next billing cycle. This should minimize potential rate-gaming while allowing customers to try the new rate options without making long-term commitments.

In addition to these similarities, the new rate schedules contain the same Adjustment Clauses, Minimum Charge, Due Date of Bill, Late Payment Charge, and Terms and Conditions provisions as Rate RS. Customers are already familiar with taking service under these provisions, so retaining them for the new rate schedules minimizes barriers to entry.

Another important way in which the Company has attempted to minimize barriers to entry for both new optional rate schedules is by making them revenue-neutral. As Dr. Blake testifies, a residential customer with a residential-class-average load shape and a residential-class-average level of energy consumption should have the same bill under Rates RS, RTOD-Demand, and RTOD-Energy. But customers who choose to take service under the new optional rates will have new opportunities to reduce their bills by adjusting their demand or energy usage, and will be able to choose the rate that best suits their lifestyles.

The important differences between the new rate schedules and Rate RS are the rates themselves (excluding the basic service charge, as I noted above). RTOD-Energy uses two time-of-day energy rates with no demand charge. To reflect seasonal changes in the Company's peak-demand hours, the hours during which each time-of-day energy rate will apply will vary between two groupings of months: one is May through September, the other is all other months. These time-of-day rates (off-peak and on-peak) encourage customers to shift their usage away from the Company's typical peak periods. The rate for each time period is based on the cost of service for each time period and is further discussed in the testimony of Dr. Blake.

Rate RTOD-Demand follows the pattern of the Company's time-of-day rates for larger customers by offering a flat and relatively low energy rate and two time-of-day demand rates. To reflect seasonal changes in the Company's peak-demand hours, the hours during which each time-of-day demand rate will apply will vary between two groupings of months: one is May through September, the other is all other months. Notably, RTOD-Demand uses only two time-of-day demand rates, whereas the Company's time-of-day rates for larger customers use three time-of-day periods. Although the Company considered using three time-of-day demand rates for RTOD-Demand, the Company believes using two such rates will increase customer acceptance by making the rate easier to understand and requiring less customer load-shifting to receive benefits from the rate. As Dr. Blake explains in his testimony, the proposed demand charges accurately reflect the cost of service, and the relatively short daily on-peak periods capture the vast majority of the Company's historical system peaks. These demand charges therefore will send accurate pricing signals to participating customers to encourage load reductions at times of peak demand, when such reductions are most needed and provide greatest system benefits. After customers begin taking service under Rate RTOD-Demand, providing actual data for the Company to review, the Company will review and may revise the duration of the on-peak period in future proceedings if the data indicates a need for such changes.

Q. If Rates RTOD-Demand and RTOD-Energy will replace existing Rate LEV, under which rate will current Rate LEV customers take service when the new rates go into effect and Rate LEV terminates?

A. The Company will make all reasonable efforts to contact Rate LEV customers to advise them of their new rate options after the Commission approves the new rates but before they take effect (at which time Rate LEV will terminate). For Rate LEV customers who inform the Company under which rate they would like to take service before the Company's new rates take effect, the Company will transfer such customers to the rate of their choice when new rates take effect. (Of course, a Rate LEV customer may at any time contact the Company prior to new rates taking effect and ask to move back to Rate RS, which change the Company will make effective as of the customer's next billing cycle.) For Rate LEV customers who do not inform the Company under which rate they would like to take service before new rates go into effect, the Company will automatically transfer all such customers to Rate RTOD-Energy when new rate go into effect because Rate RTOD-Energy is the new rate most similar to Rate LEV; however, the Company will continue to make reasonable efforts to obtain those customers' input even after the rate change.

F. LARGE CUSTOMER TIME OF DAY RATES

Q. Please explain the proposed text change to Rate TODP's Availability of Service provision.

A. The Company's current TODP rate schedule limits loads that can be served under the rate at 50,000 kVA, although that may be increased to 75,000 kVA with appropriate authorization from the Company's transmission operator. The Company proposes to remove the maximum load restriction while retaining the requirement to obtain necessary approvals from the Company's transmission operator. This will allow larger loads and existing customers with increasing loads to take service under Rate TODP without having to execute and seek approval from the Commission for a special contract, but will also ensure that all necessary technical reviews occur to confirm that the Company can serve such large loads safely and reliably.

Q. Please explain the proposed text change to the Retail Transmission Service (Rate RTS) Availability of Service provision.

A. Just like the Company's current TODP rate schedule, the Company's current Rate RTS limits eligibility to those at or below 50,000 kVA, although that may be increased to 75,000 kVA with appropriate authorization from the Company's transmission operator. The Company proposes to remove the maximum load restriction while retaining the requirement to obtain necessary approvals from the Company's transmission operator. This will allow larger loads and existing customers with increasing loads to take service under Rate RTS without having to execute and seek approval from the Commission for a special contract, but will also ensure that all necessary technical reviews occur to confirm that the Company can serve such large loads safely and reliably.

G. OTHER STANDARD RATE SCHEDULES

Q. Please explain the changes shown on Sheet No. 35.2 concerning Lighting Service (Rate LS).

A. The deletion of the Granville lighting fixtures from Sheet 35.2 results from moving those fixtures to the Company's Restricted Lighting Service (Rate RLS) rate schedule at Sheet No. 36.2. Also, the Company is removing all Granville lighting accessories from Rate LS as a result of the Granville sale to the LFUCG I described above.

Q. Please explain the changes shown on Sheet No. 36 concerning Restricted Lighting Service (Rate RLS).

A. The first text change to the Availability of Service section corrects the date for which the service is available, namely to lighting fixtures and poles in place as of, or prior to, the date the Company's most recent rates went into effect, January 1, 2013.

The second text change clarifies that the rate and its associated lights, poles, and accessories are available for new service in subdivisions that have already installed a certain kind of lighting taking service under Rate RLS and where continuity of lighting style is desired for new sections of the affected subdivisions.

Q. Other than the changes mentioned previously, is the Company proposing any other significant structural changes to its rates?

A. No. In general, the Company is proposing to modify individual rate components to more accurately reflect the results of the cost of service study.

H. CHANGES TO RIDERS

Q. Please describe the Company's proposed changes to its Curtailable Service Riders.

A. The Company proposes several changes to its Curtailable Service Riders (CSR10 and CSR30) that will increase their usefulness to the Company while remaining attractive to participants. I provide a summary of the changes to the riders; David Sinclair's testimony provides a more in-depth explanation of the changes and the reasons why the Company is proposing them, as well as an explanation for the Company's decision not to change the amounts of the credits offered under the riders.

First, because all customers eligible for CSR10 or CSR30 take service under standard rate schedules that measure and bill demand based on kVA, the Company is clarifying that all load to be curtailed and actual curtailments will be measured in volt-amperes rather than watts. This ensures that actual curtailments remove the customers' full load impact from the system. Therefore, all references to kW have changed to kVA, and all references to MW have changed to MVA.

Second, the Company has simplified both CSR tariff provisions by eliminating all buy-through curtailment hours and removing restrictions around the hours the Company may request physical curtailments (though the number of physical curtailment hours has not changed).

Third, the Company has added a Certification provision to both CSR rate schedules. The provision requires a CSR customer to demonstrate or certify to the Company's satisfaction the customer's ability to curtail usage in the amount for which the customer seeks credit. A CSR customer must make such a certification or demonstration to begin to receive CSR credits, and must annually certify or demonstrate curtailment ability to continue to receive the credits. This ensures that the Company will receive the demand reductions from curtailments upon which both Companies rely for system planning, as Mr. Sinclair discusses in his testimony.

Q. What changes does the Company propose to make to its Net Metering Service Rider, Rider NMS?

A. The Company proposes a few clarifying changes to Rider NMS concerning billing period credits and how such credits apply to time-of-day or time-of-use customers. These changes do not change the substance or intent of Rider NMS; rather, they reflect how the Company has always interpreted its tariff in accordance with Kentucky's net-metering statutes (KRS 278.465 *et seq.*), and they are in accordance with the Commission's recent final order in Case No. 2013-00287.[13] First, the Company proposes to move its "Definitions" section from near the end of the rate schedule to the front, under the "Availability of Service" section, a change that should help a reader better understand the rate schedule. Second, the Company proposes to revise the definition of "billing period credit" to clarify that the credits for electricity a net-metering customer generates are kilowatt-hour-denominated energy credits only, not monetary credits of any kind.[14] Third, the Company proposes revisions to the second paragraph of the "Metering and Billing" section to clarify that, for net-metering customers taking service under time-of-day or time-of-use rates, the Company will apply billing-period credits a customer creates in a particular time-of-day or time-of-use block only to offset future net energy consumption in the same time-of-day or time-of-use block; such credits may not be used across time-of-day or time-of-use blocks.[15] These changes should help reduce confusion for customers seeking to take net-metering service, particularly for those seeking to take net-metering service while also taking service under time-of-day or time-of-use rates.

Q. What changes does the Company propose to make to its Supplemental/Standby Rider, Rider SS?

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[13] *In the Matter of: Jeff M. Short v. Kentucky Utilities Company*, Case No. 2013-00287, Order (Sept. 11, 2014).

[14] *See id.* at 9-10 ("Thus, in addition to not expressly providing for the monetization of electricity credits, the statute explicitly requires that a customer-generator receive only 'credits' to be applied against kilowatt hours consumed. … [T]here is no basis for either monetizing electricity credits that result from net metering or increasing the value of the on-peak credits in an effort to offset significantly more off-peak usage.").

[15] *See id.* at 11 ("[T]he Commission finds that KRS 278.466 is clear and unambiguous in requiring surplus electricity generated through net metering to be accounted for in the specific time-of-use period in which it was generated and that the credits from excess generation may offset only those kilowatt hours consumed in the same time-of-use block on a one for one basis.").

A. In accordance with the Company's cost-of-service study and the supporting calculations contained in Exhibit MJB-12 of Dr. Blake's testimony, the Company is proposing to change its current Rider SS demand rates as shown below:

Contract Demand per month:	Current (per kW/kVA)	Proposed (per kW/kVA)
Secondary	$12.54	$12.84
Primary	$11.99	$11.63
Transmission	$10.84	$10.58

Also, the Company proposes to replace the text in the "Minimum Bill" section to clarify minimum-bill calculation under Rider SS. From its inception, the purpose of Rider SS has been to provide a minimum demand charge for supplemental or standby facilities that enables the Company to recover its costs for facilities that a customer presumably rarely uses. For Rider SS to apply, a customer must be "regularly supplied with electric energy from generating facilities other than those of Company," so any of Company's facilities would be only for "reserve, breakdown, supplemental or standby service." The revised Minimum Bill text better explains how the Company calculates and implements the minimum demand charge under Rider SS, and clarifies that the other charges applicable to a customer under the customer's usual rate schedule, e.g., the basic service charge and energy charges, still apply; Rider SS merely supplements the demand-charge provisions of the customer's applicable rate schedule.

Q. What changes does the Company propose to make to its Temporary and/or Seasonal Electric Service (Rider TS) at Sheet No. 66?

A. The proposed text changes to the Availability of Service section of Rider TS are intended to clarify that the rider is truly for temporary service as determined by the

Company. Therefore, the first change corrects the Availability of Service by clarifying that the rider is available at the Company's, not the customer's, option. The other changes clarify that the service is available on a temporary basis, meaning not to exceed one year when service requires the installation of permanent facilities for construction where such facilities will then be used by a customer or customers who will occupy the premises being built.

Q. What changes does the Company propose to make to its Economic Development Rider (Rider EDR) at Sheet Nos. 71 – 71.2?

A. The text changes to the Terms and Conditions section at Sheet Nos. 71 and 71.1 clarify that the rider applies only to monthly minimum billing loads, not to annual averages of monthly billing loads.

The text added to item (d) of the Economic Development subsection on Sheet No. 71.1 expands the kinds of state economic development programs for which a customer may demonstrate that it is qualified so it can take service under Rider EDR. Currently, only a certification that the customer has been qualified by the Commonwealth of Kentucky for benefits under the Kentucky Business Investment Program is sufficient to take service under Rider EDR. The added text would add qualification for programs under the Kentucky Industrial Revitalization Act, the Kentucky Jobs Retention Act, or other comparable programs approved by the Commonwealth of Kentucky. This should enable greater participation under Rider EDR by including a broader range of customers who are bringing significant economic development to Kentucky.

The final text addition, which is on Sheet No. 71.2, states that the Company will not provide a Rider EDR customer a billing credit under the rider in any billing month in which the customer's metered load is less than the load required to be eligible for the rider. This provides a Rider EDR customer an incentive to ramp up to and maintain its contracted demand, and helps prevent other customers from subsidizing such customers.

I. CHANGES TO ELECTRIC SPECIAL CHARGES AND CUSTOMER DEPOSITS

Q. Does the Company propose to change any of the Special Charges shown on Sheet No. 45 of its electric tariff?

A. No, the Company proposes to keep all Special Charges at their current levels.

Q. Does the Company propose to increase customer deposits for Rates RS and GS?

A. Yes. The Commission's regulations (807 KAR 5:006 Section 8(d)(2)) state that a utility may establish a deposit of an equal amount for each customer class based on the average bill of customers in that class, and that such a deposit cannot exceed two-twelfths of the average bill of customers in the class where bills are rendered monthly. Consistent with these regulations, as shown in Exhibit RMC-6 the Company could support customer deposits as high as $252.00 for Rate RS customers and $482.00 for Rate GS customers. Instead, the Company proposes more modest increases to customer deposits for Rates RS and GS: for Rate RS, the Company proposes to increase the deposit from $135.00 to $160.00; for Rate GS, the Company proposes to increase the deposit from $220.00 to $240.00.

VI. CHANGES TO TERMS AND CONDITIONS

Q. Please explain the new Company as a Federal Contractor provision at Sheet No. 96.

A. The Company has added this provision at the suggestion of a customer that is a federal contractor. As a service provider to federal agencies and other federal contractors, the Company must include the terms of this provision in all contracts with such entities. Including these terms in the Company's tariff assures that all federal agencies and federal contractors taking service from the Company are doing business with an entity that has agreed to the necessary terms.

Q. Please explain the new Changes in Service provision at Sheet No. 97.3.

A. The Company has added this provision to clarify that a customer who asks the Company to relocate or change facilities must pay for such relocations or changes to the extent the requested relocations or changes are supported by additional load. This protects the Company and other customers from bearing costs created by a particular customer if the customer's service does not justify the additional costs.

Q. Please explain the changes to the Residential Rate Specific Terms and Conditions at Sheet Nos. 100 and 100.1.

A. Although the text changes appear to be extensive in this section, they do not change any of the substance of the current section; rather, the Company is making these changes to clarify the terms of the section.

Q. Please explain the changes to the Discontinuance of Service provisions at Sheet Nos. 105 – 105.2.

A. The Company is making these changes to expand the definition of written notices or communications provided to customers concerning discontinuance of service to include non-paper forms of written communication, including electronic mail. This would include using electronic mail to issue “brown bills.” The Company believes these changes are consistent with the revised Commission regulations providing for delivery of written communications “mailed or otherwise delivered” (e.g., 807 KAR 5:006 Section 15(1)(f)).

Q. Please explain the changes to the Line Extension Plan provisions at Sheet Nos. 106.

A. The Company has deleted a provision requiring a customer to grant to the Company at no cost an easement necessary to serve another customer. On close review of the deleted provision, the Company determined the provision could be interpreted to conflict with 807 KAR 5:006 Section 6(3)(b)(2).

Q. Please explain the changes to the Line Extension Plan provisions at Sheet Nos. 106.1.

A. The Company has deleted as unnecessary a provision stating that the Company will not refund deposits to a customer for service lines not serving the customer. The deleted provision is unnecessary because the Company does not have the right to collect a deposit from a customer for lines not used to serve the customer.

VII. CONCLUSION

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 Louisville Gas and Electric Company and Kentucky Utilities Company, 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.

Robert M. Conroy

Robert M. Conroy

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 19th day of November 2014.

Judy Schooler (SEAL)
Notary Public

My Commission Expires:

July 18, 2018

APPENDIX A

Robert M. Conroy
Director, Rates
LG&E and KU Services Company
220 West Main Street
Louisville, Kentucky 40202
Telephone: (502) 627-3324

<u>Education</u>

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

<u>Previous Positions</u>

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

<u>Professional/Trade Memberships</u>

Registered Professional Engineer in Kentucky, 1995

Exhibit RMC-1

Granville Lights sale

KENTUCKY UTILITIES COMPANY
Case No. 2014-00371
Revenue Impact of Sale of Granville Lights to City of Lexington

Lights Billed During August 2014, Rate LS:

Configuration	Quantity	Monthly Rate	Monthly Billed Amount
360	174	$ 55.33	$ 9,627.42
361	25	$ 83.16	$ 2,079.00
362	43	$ 59.78	$ 2,570.54
363	5	$ 61.75	$ 308.75
364	1	$ 63.11	$ 63.11
365	5	$ 80.94	$ 404.70
366	9	$ 78.97	$ 710.73
367	25	$ 61.23	$ 1,530.75
368	1	$ 56.69	$ 56.69
370	13	$ 74.52	$ 968.76
372	1	$ 82.30	$ 82.30
373	20	$ 74.52	$ 1,490.40
374	4	$ 75.88	$ 303.52
375	3	$ 78.97	$ 236.91
376	2	$ 77.26	$ 154.52
377	51	$ 64.19	$ 3,273.69
378	2	$ 75.90	$ 151.80
	384		$ 24,013.59

Total Monthly Billed Amount, Rate LS: $ 24,013.59
Annual Billed Amount, Rate LS: $ 288,163.08

Equivalent Monthly Energy Billings, Rate LE:

Month	Load/Light, kW	Lighting Hours per Month	Lighting kWh, per Month	August Lights	Total kWh	Billings under Current Rate LE
						$ 0.06380
Sep-13	0.181	304	55	384	21,120	$ 1,347.46
Oct-13		326	59		22,656	$ 1,445.45
Nov-13		392	71		27,264	$ 1,739.44
Dec-13		392	71		27,264	$ 1,739.44
Jan-14		453	82		31,488	$ 2,008.93
Feb-14		370	67		25,728	$ 1,641.45
Mar-14		376	68		26,112	$ 1,665.95
Apr-14		309	56		21,504	$ 1,371.96
May-14		287	52		19,968	$ 1,273.96
Jun-14		282	51		19,584	$ 1,249.46
Jul-14		260	47		18,048	$ 1,151.46
Aug-14		265	48		18,432	$ 1,175.96
						$ 17,810.92

Revenue Reduction due to Lighting Sale:	$ (288,163.08)
Revenue Increase due to LE billing:	$ 17,810.92
Net Revenue Adjustment:	$ (270,352.16)

KENTUCKY UTILITIES COMPANY
Case No. 2014-00371
Sale of Granville Lights to City of Lexington
Asset Selection for Retirement

Depreciation Expense Analysis

Date	Quantity	Cost	Avg. Cost	Account	Asset_id	Asset Description
1-Jan-02	279	$ 688,878.18	$ 2,469.10	137300	10767853	POLE
1-Jan-02	228	62,674.20	274.89	137300	10734683	FIXTURE
1-Jan-02	26	7,388.91	284.19	137300	10768788	FIXTURE
1-Jan-02	88	22,807.69	259.18	137300	10767110	FIXTURE
1-Jan-03	42	12,653.05	301.26	137300	10776849	FIXTURE
1-Jan-03	42	3,793.94	90.33	137300	10773215	POLE
1-Jan-04	61	20,563.36	337.10	137300	10768038	FIXTURE
1-Jan-04	61	17,454.65	286.14	137300	10773216	POLE

$ 836,213.97	**Total cost to retire**
4.00%	**Depreciation rate**
$ 33,448.56	**Annual depreciation expense**
12	
$ 2,787.38	**Monthly depreciation expense**

Per the asset listing:
382 poles and 445 fixtures are to be sold.
Other items listed are not retirement units and were allocated over the cost of the poles and fixtures.

Net Book Calculation

Year	Cost	Monthly Depreciation	Accumulated Depreciation as of Aug. 2014	Net Book
Jan-01	$ 781,748.98	$ 2,605.83	$ 396,086.15	$ 385,662.83
Jan-03	16,446.99	54.82	7,675.26	$ 8,771.73
Jan-04	38,018.01	126.73	16,221.02	$ 21,796.99
	$ 836,213.98	$ 2,787.38	$ 419,982.43	$ 416,231.55

	Cost	Accum. Depr.	Net Book
Aug-14	$ 836,213.98	$ 419,982.43	$ 416,231.55
Sep-14	$ 836,213.98	$ 422,769.81	$ 413,444.17
Oct-14	$ 836,213.98	$ 425,557.19	$ 410,656.79
Nov-14	$ 836,213.98	$ 428,344.57	$ 407,869.41
Dec-14	$ 836,213.98	$ 431,131.95	$ 405,082.03
Jan-15	$ 836,213.98	$ 433,919.33	$ 402,294.65
Feb-15	$ 836,213.98	$ 436,706.71	$ 399,507.27
Mar-15	$ 836,213.98	$ 439,494.09	$ 396,719.89
Apr-15	$ 836,213.98	$ 442,281.47	$ 393,932.51
May-15	$ 836,213.98	$ 445,068.85	$ 391,145.13
Jun-15	$ 836,213.98	$ 447,856.23	$ 388,357.75
Jul-15	$ 836,213.98	$ 450,643.61	$ 385,570.37
Aug-15	$ 836,213.98	$ 453,430.99	$ 382,782.99
Sep-15	$ 836,213.98	$ 456,218.37	$ 379,995.61
Oct-15	$ 836,213.98	$ 459,005.75	$ 377,208.23
Nov-15	$ 836,213.98	$ 461,793.13	$ 374,420.85
Dec-15	$ 836,213.98	$ 464,580.51	$ 371,633.47
Jan-16	$ 836,213.98	$ 467,367.89	$ 368,846.09
Feb-16	$ 836,213.98	$ 470,155.27	$ 366,058.71
Mar-16	$ 836,213.98	$ 472,942.65	$ 363,271.33
Apr-16	$ 836,213.98	$ 475,730.03	$ 360,483.95
May-16	$ 836,213.98	$ 478,517.41	$ 357,696.57
Jun-16	$ 836,213.98	$ 481,304.79	$ 354,909.19
Jul-16	$ 836,213.98	$ 484,092.17	$ 352,121.81

KENTUCKY UTILITIES COMPANY
Case No. 2014-00371
Sale of Granville Lights to City of Lexington

Operational Expenses

Routine Maintenance

455 Fixtures (325 single fixture installations and 65 double fixture installations)

Industry average 24,000 hour bulb life (4000hr/year = 6yr)
Probable Failures per year (455/6) = 76

150W HPS Bulb	$8.25	KU's policy is to replace all three items when any one item fails to prevent multiple repair trips to a single light except at probable 6 year bulb life.
Granville Photo Control	$3.04	
Starter	$22.65	
Material Total	$33.94	
Repair Charge - Labor	$41.68	Estimated labor charge based on average contract unit price available to KU
Per Light Repair Total	$75.62	
Total Cost per Year	**$5,747.12**	

KENTUCKY UTILITIES COMPANY
Case No. 2014-00371
Sale of Granville Lights to City of Lexington
Asset Selection for Retirement

Property Tax Analysis

Total Property Tax Expense **$ 5,346.85**

July thru Dec 2015	State Tax	Local Tax	Total Tax
Net Book Value as of 12/31/14	$ 405,082.03	$ 405,082.03	$ 405,082.03
Tax Rates	0.450%	0.918%	1.368%
2015 Tax Liability	1,823	3,719	5,542
Divide by 12 months	12	12	12
Monthly Accrual	152	310	462
		6 Months (Jul - Dec)	**$ 2,770.76**

Jan thru Jun 2016	State Tax	Local Tax	Total Tax
Net Book Value as of 12/31/15	$ 371,633.47	$ 371,633.47	$ 371,633.47
Tax Rates	0.450%	0.936%	1.386%
2015 Tax Liability	1,672	3,480	5,152
Divide by 12 months	12	12	12
Monthly Accrual	139	290	429
		6 Months (Jan - Jun)	**$ 2,576.09**
		Annual Total	**$ 5,346.85**

Note: Street lights are taxed at the other tangible property tax rate. Assumed 2% annual increase for local taxing authorites in budget.

Exhibit RMC-2

Redundant Capacity Adjustment

KENTUCKY UTILITIES COMPANY
Case No. 2014-00371
Adjustment to Reflect Billed Redundant Capacity Not in Revenue Forecast

Rate Schedule		Average Contracted Monthly kW	Redundant Capacity Rate	Average Monthly Redundant Capacity Revenue	FERC Acct 442.2	FERC Acct 442.3	FERC Acct 445
TODS	Customer 1	500	$ 1.49	$ 745	$ -	$ 745	$ -
	Customer 2	430		$ 640	$ -	$ 640	$ -
	Customer 3	420		$ 626	$ -	$ 626	$ -
	Customer 4	705		$ 1,050	$ -	$ 1,050	$ -
	Customer 5	270		$ 402	$ 402	$ -	$ -
	Customer 6	1,500		$ 2,235	$ 2,235	$ -	$ -
	Customer 7	1,500		$ 2,235	$ 2,235	$ -	$ -
		5,325		$ 7,934	$ 4,872	$ 3,062	$ -
TODP	Customer 8	1,888	$ 1.25	$ 2,361	$ -	$ -	$ 2,361
	Customer 9	1,865		$ 2,331	$ -	$ -	$ 2,331
	Customer 10	2,100		$ 2,625	$ 2,625	$ -	$ -
	Customer 11	4,199		$ 5,249	$ 5,249	$ -	$ -
	Customer 12	1,820		$ 2,274	$ -	$ 2,274	$ -
		11,872		$ 14,840	$ 7,874	$ 2,274	$ 4,692
PSP	Customer 9	650	1.25	$ 813	$ 813	$ -	$ -
PSS	Customer 10	225	1.49	$ 335	$ 335	$ -	$ -
			Total Monthly RC revenue	$ 23,922	$ 13,894	$ 5,336	$ 4,692
			Annual Revenue	$ 287,063	$ 166,732	$ 64,033	$ 56,298

Exhibit RMC-3

Standby Revenue

KENTUCKY UTILITIES COMPANY
Case No. 2014-00371
Adjustment to Reflect Standby Revenues Pursuant to New Contract

Contract for Standby Service (Rate SS)
800 kW-Month Contract Capacity

	kW	Rate	Revenue
Jul-15	800	$ 11.99	$ 9,592
Aug-15	800	$ 11.99	$ 9,592
Sep-15	800	$ 11.99	$ 9,592
Oct-15	800	$ 11.99	$ 9,592
Nov-15	800	$ 11.99	$ 9,592
Dec-15	800	$ 11.99	$ 9,592
Jan-16	800	$ 11.99	$ 9,592
Feb-16	800	$ 11.99	$ 9,592
Mar-16	800	$ 11.99	$ 9,592
Apr-16	800	$ 11.99	$ 9,592
May-16	800	$ 11.99	$ 9,592
Jun-16	800	$ 11.99	$ 9,592
Total	9,600		$ 115,104
Total Incremental Revenue:			$ 115,104

Exhibit RMC-4

Customer A Adjustment

KENTUCKY UTILTIES COMPANY
Case No. 2014-00371
Customer A - Effect of Totalized Billings for Twelve Months Ended August 31, 2014

Customer A	Currrent												
Meter 1 As Billed	Base Rate	Sep '13	Oct '13	Nov '13	Dec '13	Jan '14	Feb '14	Mar-14	Apr-14	May-14	Jun-14	Jul-14	Aug-14
kWh		37,856,000	38,584,000	37,688,000	37,464,000	40,432,000	35,952,000	39,704,000	38,640,000	38,808,000	38,528,000	37,296,000	40,208,000
Peak kVA		67,435.6	69,929.8	69,908.7	70,009.0	69,479.0	68,747.9	68,176.5	65,244.7	68,868.9	71,941.4	66,117.5	70,277.3
Intermediate kVa		68,136.4	69,929.8	71,437.9	70,525.2	70,279.4	68,747.9	68,176.5	70,070.3	71,259.6	71,941.4	66,117.5	70,518.5
Base kVA		69,850.6	69,929.8	71,437.9	70,525.2	72,857.6	74,007.5	71,317.3	71,747.6	71,259.6	71,941.4	71,619.9	73,223.9
Billing													
Basic Service Charge	$ 750.00	$ 750.00	$ 750.00	$ 750.00	$ 750.00	$ 750.00	$ 750.00	$ 750.00	$ 750.00	$ 750.00	$ 750.00	$ 750.00	$ 750.00
kWh	$ 0.03634	$ 1,375,687.04	$ 1,402,142.56	$ 1,369,581.92	$ 1,361,441.76	$ 1,469,298.88	$ 1,306,495.68	$ 1,442,843.36	$ 1,404,177.60	$ 1,410,282.72	$ 1,400,107.52	$ 1,355,336.64	$ 1,461,158.72
Peak kVA	$ 3.97	$ 267,719.33	$ 277,621.31	$ 277,537.54	$ 277,935.73	$ 275,831.63	$ 272,929.16	$ 270,660.71	$ 259,021.46	$ 273,409.53	$ 285,607.36	$ 262,486.48	$ 279,000.88
Intermediate kVa	$ 2.87	$ 195,551.47	$ 200,698.53	$ 205,026.77	$ 202,407.32	$ 201,701.88	$ 197,306.47	$ 195,666.56	$ 201,101.76	$ 204,515.05	$ 206,471.82	$ 189,757.23	$ 202,388.10
Base kVA	$ 1.34	$ 93,599.80	$ 93,705.93	$ 95,726.79	$ 94,503.77	$ 97,629.18	$ 99,170.05	$ 95,565.18	$ 96,141.78	$ 95,487.86	$ 96,401.48	$ 95,970.67	$ 98,120.03
		$ 1,933,307.64	$ 1,974,918.33	$ 1,948,623.02	$ 1,937,038.58	$ 2,045,211.57	$ 1,876,651.36	$ 2,005,485.81	$ 1,961,192.60	$ 1,984,445.16	$ 1,989,338.18	$ 1,904,301.02	$ 2,041,417.73
Customer A													
Meter 2 As Billed													
kWh		15,960,000	16,240,000	16,240,000	16,800,000	17,192,000	15,008,000	16,576,000	15,680,000	16,520,000	16,072,000	16,128,000	16,632,000
Peak kVA		28,332	27,959	28,226	30,295	31,439	29,477	30,935	28,507	30,107	29,119	31,917	31,784
Intermediate kVa		28,956	29,377	31,204	31,630	34,965	32,611	30,935	31,442	31,476	29,119	31,917	31,784
Base kVA		32,701	31,228	32,172	32,185	34,965	32,611	30,935	31,442	32,858	31,785	31,917	32,482
Billing													
Basic Service Charge	$ 750.00	$ 750.00	$ 750.00	$ 750.00	$ 750.00	$ 750.00	$ 750.00	$ 750.00	$ 750.00	$ 750.00	$ 750.00	$ 750.00	$ 750.00
kWh	$ 0.03634	$ 579,986.40	$ 590,161.60	$ 590,161.60	$ 610,512.00	$ 624,757.28	$ 545,390.72	$ 602,371.84	$ 569,811.20	$ 600,336.80	$ 584,056.48	$ 586,091.52	$ 604,406.88
Peak kVA	$ 3.97	$ 112,477.64	$ 110,998.82	$ 112,058.41	$ 120,272.74	$ 124,812.04	$ 117,022.50	$ 122,812.35	$ 113,171.60	$ 119,526.38	$ 115,600.45	$ 126,710.09	$ 126,181.69
Intermediate kVa	$ 2.87	$ 83,103.15	$ 84,310.84	$ 89,554.33	$ 90,779.25	$ 100,348.40	$ 93,593.28	$ 88,783.74	$ 90,237.97	$ 90,336.98	$ 83,570.10	$ 91,601.50	$ 91,219.51
Base kVA	$ 1.34	$ 43,819.47	$ 41,844.98	$ 43,110.21	$ 43,128.30	$ 46,852.56	$ 43,698.61	$ 41,453.03	$ 42,132.01	$ 44,030.26	$ 42,592.17	$ 42,768.65	$ 43,526.28
		$ 820,136.66	$ 828,066.24	$ 835,634.55	$ 865,442.29	$ 897,520.28	$ 800,455.11	$ 856,170.96	$ 816,102.78	$ 854,980.42	$ 826,569.20	$ 847,921.76	$ 866,084.36
Totalized													
kWh		53,816,000	54,824,000	53,928,000	54,264,000	57,624,000	50,960,000	56,280,000	54,320,000	55,328,000	54,600,000	53,424,000	56,840,000
Peak kVA		97,457.6	95,308.3	96,920.5	94,760.4	100,124.2	95,422.6	94,925.3	95,480.1	96,744.5	95,929.0	94,141.6	99,079.6
Intermediate kVa		99,790.7	95,981.5	98,476.4	97,484.9	100,124.2	100,305.8	96,233.1	95,480.1	96,744.5	95,929.0	94,141.6	99,079.6
Base kVA		99,790.7	95,981.5	101,648.6	100,174.0	100,124.2	100,735.0	97,775.8	97,030.2	96,744.5	99,846.6	99,037.0	99,079.6
Billing													
Basic Service Charge	$ 750.00	$ 750.00	$ 750.00	$ 750.00	$ 750.00	$ 750.00	$ 750.00	$ 750.00	$ 750.00	$ 750.00	$ 750.00	$ 750.00	$ 750.00
kWh	$ 0.03634	$ 1,955,673.44	$ 1,992,304.16	$ 1,959,743.52	$ 1,971,953.76	$ 2,094,056.16	$ 1,851,886.40	$ 2,045,215.20	$ 1,973,988.80	$ 2,010,619.52	$ 1,984,164.00	$ 1,941,428.16	$ 2,065,565.60
Peak kVA	$ 3.97	$ 386,906.67	$ 378,373.95	$ 384,774.39	$ 376,198.79	$ 397,493.07	$ 378,827.72	$ 376,853.44	$ 379,056.12	$ 384,075.55	$ 380,838.09	$ 373,742.03	$ 393,346.13
Intermediate kVa	$ 2.87	$ 286,399.31	$ 275,466.91	$ 282,627.27	$ 279,781.66	$ 287,356.45	$ 287,877.65	$ 276,188.91	$ 274,027.97	$ 277,656.63	$ 275,316.20	$ 270,186.31	$ 284,358.54
Base kVA	$ 1.34	$ 133,719.54	$ 128,615.21	$ 136,209.12	$ 134,233.16	$ 134,166.43	$ 134,984.87	$ 131,019.57	$ 130,020.47	$ 129,637.59	$ 133,794.50	$ 132,709.55	$ 132,766.70
		$ 2,763,448.96	$ 2,775,510.23	$ 2,764,104.30	$ 2,762,917.37	$ 2,913,822.11	$ 2,654,326.64	$ 2,830,027.12	$ 2,757,843.36	$ 2,802,739.29	$ 2,774,862.79	$ 2,718,816.05	$ 2,876,786.97
Savings over Individual Billing		$ 10,004.66	$ (27,474.34)	$ (20,153.27)	$ (39,563.50)	$ (28,909.74)	$ (22,779.83)	$ (31,629.65)	$ (19,452.02)	$ (36,686.29)	$ (41,044.59)	$ (33,406.73)	$ (30,715.12)

September 2013 to August 2014 change in billing from Totalized Readings: $ (321,810.42)

Exhibit RMC-4

Exhibit RMC-5

Customer B Adjustment

KENTUCKY UTILTIES COMPANY
Case No. 2014-00371
Customer B - Effect of Totalized Billings for Twelve Months Ended August 31, 2014

Customer B	Currrent												
Meter 1 As Billed	Base Rate	Sep '13	Oct '13	Nov '13	Dec '13	Jan '14	Feb '14	Mar-14	Apr-14	May-14	Jun-14	Jul-14	Aug-14
kWh		22,860,000	21,869,400	19,918,680	18,227,040	19,766,280	18,592,800	19,949,160	20,543,520	21,564,600	23,987,760	20,985,480	22,479,000
Peak kVA		48,289.5	41,088.3	41,700.3	39,907.0	39,485.4	40,203.6	39,129.2	40,170.6	43,317.4	47,901.7	46,367.9	49,464.4
Intermediate kVa		48,289.5	45,121.4	41,700.3	39,907.0	39,485.4	40,203.6	39,129.2	40,213.9	43,937.9	48,730.6	48,061.6	49,464.4
Base kVA		48,892.9	45,994.8	42,127.8	39,907.0	39,485.4	40,203.6	39,129.2	41,288.2	44,979.1	48,730.6	48,061.6	49,464.4
Billing													
Basic Service Charge	$ 300.00	$ 300.00	$ 300.00	$ 300.00	$ 300.00	$ 300.00	$ 300.00	$ 300.00	$ 300.00	$ 300.00	$ 300.00	$ 300.00	$ 300.00
kWh	$ 0.03765	$ 860,679.00	$ 823,382.91	$ 749,938.30	$ 686,248.06	$ 744,200.44	$ 700,018.92	$ 751,085.87	$ 773,463.53	$ 811,907.19	$ 903,139.16	$ 790,103.32	$ 846,334.35
Peak kVA	$ 4.26	$ 205,713.27	$ 175,036.16	$ 177,643.28	$ 170,003.82	$ 168,207.80	$ 171,267.34	$ 166,690.39	$ 171,126.76	$ 184,532.12	$ 204,061.24	$ 197,527.25	$ 210,718.34
Intermediate kVa	$ 2.76	$ 133,279.02	$ 124,535.06	$ 115,092.83	$ 110,143.32	$ 108,979.70	$ 110,961.94	$ 107,996.59	$ 110,990.36	$ 121,268.60	$ 134,496.46	$ 132,650.02	$ 136,521.74
Base kVA	$ 1.71	$ 83,606.86	$ 78,651.11	$ 72,038.54	$ 68,240.97	$ 67,520.03	$ 68,748.16	$ 66,910.93	$ 70,602.82	$ 76,914.26	$ 83,329.33	$ 82,185.34	$ 84,584.12
		$ 1,283,578.15	$ 1,201,905.24	$ 1,115,012.95	$ 1,034,936.17	$ 1,089,207.97	$ 1,051,296.36	$ 1,092,983.78	$ 1,126,483.47	$ 1,194,922.17	$ 1,325,326.19	$ 1,202,765.93	$ 1,278,458.55
Customer B													
Meter 2 As Billed													
kWh		15,499,080	14,706,600	13,091,160	12,100,560	13,335,000	12,633,960	13,533,120	14,112,240	15,026,640	17,434,560	15,834,360	16,611,600
Peak kVA		34,668.8	27,532.0	25,679.3	25,138.6	25,445.3	26,354.8	24,781.7	25,563.1	32,018.4	33,745.3	35,104.1	34,868.2
Intermediate kVa		34,949.6	32,967.8	26,880.7	25,138.6	25,797.5	26,354.8	26,272.8	25,759.2	32,018.4	34,805.7	35,607.9	34,868.2
Base kVA		36,585.8	33,463.4	27,668.1	25,468.8	25,797.5	26,354.8	26,272.8	26,399.5	32,018.4	35,126.8	35,607.9	36,347.6
Base Minimum		27,705.2	27,705.2	27,705.2	27,705.2	27,705.2	27,705.2	27,705.2	27,705.2	27,705.2	27,610.6	27,610.6	27,439.4
Billing													
Basic Service Charge	$ 300.00	$ 300.00	$ 300.00	$ 300.00	$ 300.00	$ 300.00	$ 300.00	$ 300.00	$ 300.00	$ 300.00	$ 300.00	$ 300.00	$ 300.00
kWh	$ 0.03765	$ 583,540.36	$ 553,703.49	$ 492,882.17	$ 455,586.08	$ 502,062.75	$ 475,668.59	$ 509,521.97	$ 531,325.84	$ 565,753.00	$ 656,411.18	$ 596,163.65	$ 625,426.74
Peak kVA	$ 4.26	$ 147,689.09	$ 117,286.32	$ 109,393.82	$ 107,090.44	$ 108,396.98	$ 112,271.45	$ 105,570.04	$ 108,898.81	$ 136,398.38	$ 143,754.98	$ 149,543.47	$ 148,538.53
Intermediate kVa	$ 2.76	$ 96,460.90	$ 90,991.13	$ 74,190.73	$ 69,382.54	$ 71,201.10	$ 72,739.25	$ 72,512.93	$ 71,095.39	$ 88,370.78	$ 96,063.73	$ 98,277.80	$ 96,236.23
Base kVA	$ 1.71	$ 62,561.72	$ 57,222.41	$ 47,375.89	$ 47,375.89	$ 47,375.89	$ 47,375.89	$ 47,375.89	$ 47,375.89	$ 54,751.46	$ 60,066.83	$ 60,889.51	$ 62,154.40
		$ 890,552.07	$ 819,503.35	$ 724,142.61	$ 679,734.95	$ 729,336.72	$ 708,355.18	$ 735,280.83	$ 758,995.93	$ 845,573.62	$ 956,596.72	$ 905,174.43	$ 932,655.90
Totalized													
kWh		38,359,080	36,576,000	33,009,840	30,327,600	33,101,280	31,226,760	33,482,280	34,655,760	36,591,240	41,422,320	36,819,840	39,090,600
Peak kVA		82,208.7	68,179.5	65,197.2	64,460.9	63,981.3	65,607.9	63,015.7	64,264.2	73,122.6	81,070.8	80,077.5	82,116.6
Intermediate kVa		82,752.8	77,870.4	65,555.9	64,560.9	64,606.3	65,607.9	64,089.2	66,481.1	73,456.5	82,888.5	81,006.1	84,179.9
Base kVA		83,308.9	77,870.4	69,218.0	64,560.9	64,606.3	65,607.9	64,089.2	67,432.7	73,907.1	82,888.5	82,375.0	84,179.9
Billing													
Basic Service Charge	$ 300.00	$ 300.00	$ 300.00	$ 300.00	$ 300.00	$ 300.00	$ 300.00	$ 300.00	$ 300.00	$ 300.00	$ 300.00	$ 300.00	$ 300.00
kWh	$ 0.03765	$ 1,444,219.36	$ 1,377,086.40	$ 1,242,820.48	$ 1,141,834.14	$ 1,246,263.19	$ 1,175,687.51	$ 1,260,607.84	$ 1,304,789.36	$ 1,377,660.19	$ 1,559,550.35	$ 1,386,266.98	$ 1,471,761.09
Peak kVA	$ 4.26	$ 350,209.06	$ 290,444.67	$ 277,740.07	$ 274,603.43	$ 272,560.34	$ 279,489.61	$ 268,446.88	$ 273,765.49	$ 311,502.28	$ 345,361.57	$ 341,129.94	$ 349,816.59
Intermediate kVa	$ 2.76	$ 228,397.73	$ 214,922.30	$ 180,934.28	$ 178,188.08	$ 178,313.39	$ 181,077.78	$ 176,886.14	$ 183,487.84	$ 202,739.94	$ 228,772.23	$ 223,576.81	$ 232,336.41
Base kVA	$ 1.71	$ 142,458.22	$ 133,158.38	$ 118,362.78	$ 110,399.14	$ 110,476.77	$ 112,189.49	$ 109,592.50	$ 115,309.92	$ 126,381.14	$ 141,739.32	$ 140,861.27	$ 143,947.56
		$ 2,165,584.37	$ 2,015,911.75	$ 1,820,157.61	$ 1,705,324.79	$ 1,807,913.69	$ 1,748,744.39	$ 1,815,833.36	$ 1,877,652.61	$ 2,018,583.55	$ 2,275,723.47	$ 2,092,135.00	$ 2,198,161.65
Savings over Individual Billing		$ (8,545.85)	$ (5,496.84)	$ (18,997.95)	$ (9,346.33)	$ (10,631.00)	$ (10,907.15)	$ (12,431.25)	$ (7,826.79)	$ (21,912.24)	$ (6,199.44)	$ (15,805.36)	$ (12,952.80)

September 2013 to August 2014 change in billing from Totalized Readings: $ (141,053.00)

Exhibit RMC-5

Exhibit RMC-6

Customer Deposit Calculation

Kentucky Utilities Company
Customer Deposit Requirements

Residential Electric -- Rate RS

(1)	Forecasted Test Period Revenue (Schedule M-2.3 page 3)	$ 593,989,579
(2)	Proposed Increase (Schedule M-2.3 page 3)	$ 56,838,067
(3)	Total Revenues [(1) + (2)]	$ 650,827,646
(4)	Customer Months (Schedule M-2.3, page 3)	5,164,164
(5)	Average Bill [(3) / (4)]	126
(6)	Residential Electric Deposit Requirement [(5) * 2 months]	$ 252
(7)	Proposed Deposit Requirement	$\boxed{\$ \quad 160}$

Kentucky Utilities Company
Customer Deposit Requirements

General Service -- Rate GS

(1)	Forecasted Test Period Revenue (Schedule M-2.3 page 6)	$ 216,871,822
(2)	Proposed Increase (Schedule M-2.3 page 6)	$ 20,741,924
(3)	Total Revenues [(1) + (2)]	$ 237,613,746
(4)	Customer Months (Schedule M-2.3, page 6)	985,260
(5)	Average Bill [(3) / (4)]	241
(6)	General Service Deposit Requirement [(5) * 2 months]	$ 482
(7)	Proposed Deposit Requirement	$ 240