COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

APPLICATION OF KENTUCKY UTILITIES COMPANY FOR AN ADJUSTMENT OF ITS ELECTRIC RATES AND FOR CERTIFICATES OF PUBLIC CONVENIENCE AND NECESSITY	)))))	**CASE NO. 2016-00370**

In the Matter of:

APPLICATION OF LOUISVILLE GAS AND ELECTRIC COMPANY FOR AN ADJUSTMENT OF ITS ELECTRIC AND GAS RATES AND FOR CERTIFICATES OF PUBLIC CONVENIENCE AND NECESSITY	))))))	**CASE NO. 2016-00371**

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

Filed: November 23, 2016

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

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

Q. Please describe your educational and professional background.

A. I 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 previously testified before this Commission?

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

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[1] Case No. 2014-00371, *In the Matter of: Application of Kentucky Utilities Company for an Adjustment of its Electric Rates*; Case No. 2014-00372, *In the Matter of: Application of Louisville Gas and Electric Company for an Adjustment of its Electric and Gas Rates;* Case No. 2012-00221, *In the Matter of: Application of Kentucky Utilities Company for an Adjustment of its Electric Rates;* Case No. 2012-00222; *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.*

[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*

Q. Please provide an overview of the Companies.

A. LG&E and KU are part of the PPL Corporation family of companies and have been since the Commission approved PPL's acquisition of LG&E and KU in 2010.[3] LG&E and KU are regulated utilities that serve nearly 1.3 million customers and have consistently ranked among the best companies for customer service in the United States. LG&E serves 322,000 natural gas and 403,000 electric customers in Louisville and 16 surrounding counties. KU serves 546,000 customers in 77 Kentucky counties and five counties in Virginia. Prior to 1997, LG&E and KU were stand-alone utilities and each operated independently. However, in Case No. 97-300,[4] the Commission approved the merger of the two utilities. Since that merger, the generation and transmission systems of LG&E and KU are planned, operated, and managed on an integrated basis which maximizes the economy, efficiency and reliability of the two utilities' systems.

Q. What is the purpose of your testimony?

A. My testimony will explain why the Companies have filed these rate proceedings and why it is important that the proposed rate increases be approved. I will provide an overview of LG&E's and KU's Applications. I will briefly review the causes for the increased capital expenditures and operation and maintenance expenses incurred by

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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.*

[3] 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* (Order of September 30, 2010).

[4] Case No. 97-300, *In the Matter of: Joint Application of Louisville Gas and Electric Company and Kentucky Utilities for Approval of Merger.*

LG&E and KU to provide safe, efficient, and reliable service. 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 customer service and 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. 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. 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 W. Blake, Chief Financial Officer. Mr. Blake will describe why the Companies' financial condition requires the requested increases in rates and the Companies' existing programs to achieve improvements in efficiency and productivity for the Companies' financial and administrative functions. Mr. Blake will summarize the Companies' revenue deficiencies and the associated proposed increases in revenues. 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. He presents the operational reasons behind the Companies' request for a Certificate of Public Convenience and Necessity ("CPCN") for the Distribution Automation ("DA") project. Mr. Thompson will also discuss existing programs to achieve improvements in efficiency and productivity for the Companies' operations. In addition, Mr. Thompson will discuss safety issues and the Companies' Research and Development activities.

- Daniel K. Arbough, Treasurer. Mr. Arbough will describe the forecasting process used for the estimated months of the base period and the forecast period. He will describe all factors used in preparing the Companies' base and forecast periods, including economic models, assumptions, and changes in activity levels. He will provide the details of the Companies' Budgeting and Planning Process and capital structure and he will sponsor various filling requirement schedules.
- Adrien McKenzie, FINCAP, Inc. Mr. McKenzie presents his analysis of a reasonable return on equity ("ROE"), which demonstrates that a range of a reasonable ROE is from 9.63 percent to 10.83 percent. He also provides his recommendation that an ROE of 10.23 percent is a reasonable ROE for both LG&E's electric and gas operations and KU's electric operations. Additionally, Mr. McKenzie provides his opinion as to the appropriateness of the Companies' capital structure.
- David S. Sinclair, Vice President Energy Supply and Analysis. Mr. Sinclair will discuss the Companies' load and generation forecasts, including off-system sales, and describe how these forecasts were developed. He will also provide support for the proposed changes to Curtailable Service Rider Credit in this case and will sponsor various filing requirement schedules.

- John P. Malloy, Vice President, Customer Services. Mr. Malloy will present the Companies' customer service performance metrics and various customer service initiatives. He will also describe the proposal for full deployment of the Companies' Advanced Meter Service ("AMS") and support the Companies' request for a CPCN for the AMS project.
- Lonnie E. Bellar, Vice President, Gas Distribution. Mr. Bellar describes the status of LG&E's gas distribution business and presents the business metrics of those gas operations. He also discusses LG&E's leak mitigation program, gas service riser replacement program, and main replacement program along with a proposed expansion of LG&E's gas line tracker mechanism.
- Robert M. Conroy, Vice President, State Regulation and Rates. Mr. Conroy will explain and support the tariff revisions the Companies are proposing and revenue allocations based on Mr. Seelye's cost of service study and rate design analysis. He will support filing requirement schedules required in cases based on a forecasted test period and address rate design issues. The Companies are proposing other tariff revisions unrelated to a rate change and Mr. Conroy will present and explain those as well. He also provides information concerning the Companies' requests for CPCNs for the AMS and DA deployments. He will also address the issue of assistance to low income customers.
- Steve Seelye, The Prime Group, LLC. Mr. Seelye will discuss and present his cost of service studies and rate designs for LG&E and KU.
- Christopher M. Garrett, Director, Rates. Mr. Garrett will present and describe many of the filing requirement accounting schedules in support of the Companies'

Applications. He presents various adjustments to the financial forecast for the forward-looking test period. He also presents an overview of the depreciation study presented by Mr. Spanos and addresses his recommended depreciation rates.

- John J. Spanos, Gannett Fleming, Inc. Mr. Spanos will present his depreciation study and recommended changes in depreciation rates.

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

A. We understand that any rate increase will impact customers, so we take the decision to file rate cases very seriously. We decided to file these cases only after full consideration of the impact to all our customers, our obligation to serve our customers, and the need to continue to invest in facilities to provide that service in a safe and reliable manner. 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 raised and are raising the additional debt and equity capital necessary to continue to provide safe and reliable service in this increasingly complex and demanding environment. However, it is a certainty that the Companies must continue to invest capital to meet all of their obligations. And the investment of capital results in financing costs. We continue to see a relatively flat sales growth environment which we expect will continue going forward. As a result, it has become imperative to adjust the Companies' rates so that we have an opportunity to earn a reasonable return that will continue to allow LG&E and KU to attract the necessary capital at reasonable rates to invest in facilities to serve our customers.

Q. Please describe the proposed increase in revenues.

A. LG&E is requesting an 8.5 percent, or approximately $93.6 million a year increase in its electric revenue, and a 4.2 percent, or approximately $13.8 million a year, increase in its gas revenue. KU is requesting a 6.4 percent or approximately $103.1 million a year increase in its electric revenues. 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 customers.

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

A. Absolutely. Based in large part on the Companies' focus on efficiency and productivity, if the requested rates are approved, customers will continue to receive a good value in exchange for what they pay for utility service. As explained throughout the Companies' testimony, many of our planned initiatives are designed to maintain and improve reliability, which we know is critical to customers. In fact, just a few months ago, KU was named as the top-ranked mid-sized Midwest electric utility for customer satisfaction. This prestigious honor was awarded by the global market research company J.D. Power as a result of its 2016 Electric Utility Residential Customer Satisfaction Survey. That survey collected responses from interviews conducted in four phases from July, 2015 to May, 2016 with residential customers of 137 electric utilities. Over 100,000 households were surveyed. LG&E's electric operations were also evaluated as a stand-alone electric utility within the same mid-sized Midwest category as KU. While KU was first place, LG&E Electric placed fourth. Moreover, if one averages the ratings received by KU and LG&E Electric, the "combined" rating would take first place in that category. While the J.D. Power Survey does not formally recognize such a combination or averages, we believe the combined rating is a fair reflection of the good value our electric customers receive for their service. We take pride in the fact that our overall electric operations have received such excellent customer satisfaction scores.

Q. Has J.D. Power evaluated LG&E's gas operations?

Yes. In September, 2016, LG&E was named as the top ranking mid-sized gas utility in the Midwest region for customer satisfaction in J.D. Power's 2016 Gas Utility Residential Customer Satisfaction Study. That survey was based on interviews conducted from September, 2015 to July, 2016 with residential customers of 82 gas utilities. Over 62,000 households were surveyed. We are proud of these honors because they show what we strive to achieve every day in the way of safe and reliable service at a good value.

Q. Will you please describe the Companies support for economic development in Kentucky?

A. Our Companies are long-standing supporters of economic development in Kentucky. The Companies were recognized in September, 2016 as being a top utility for support of economic growth by Site Selection magazine. Our Economic Development team was honored for helping bring to fruition $2.7 billion in corporate projects creating over 9,400 jobs.

Q. Please describe the Companies' efforts and programs to achieve improvements in efficiency and productivity?

A. Messrs. Thompson's, Blake's, and Bellar's testimony provide an extensive description of many of the Companies' existing programs and practices to achieve efficiency and productivity. Those programs and practices arise as a result of one of the core principles of our business culture. We continuously strive to operate our business in the most efficient and productive manner as possible without sacrificing the safety of our employees and our customers or the reliability of service to our customers. These principles govern the Companies' business practices in the construction, operation, and maintenance of our systems and services. As presented in greater detail in Mr. Blake's testimony, the annual benchmarking study shows the Companies are an overall Top Quartile performer and a Top Quartile performer in four of the five categories (i.e., generation, transmission, distribution and customer service) and the second utility holding company in second quartile for the administrative and general category. We are proud of this combination of cost efficiency while maintaining outstanding operational performance as detailed in the performance metrics discussed in Mr. Thompson's testimony.

The Companies' budgeting and financial planning process is of particular importance and relevance to a rate case because it is that process that ultimately results in keeping requested rate increases as low as possible. By seeking efficiency and productivity within the budgeting and financial planning process, we are able to build fundamental cost control measures into 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. It also provides a tool for the ongoing control of those costs while maximizing the ability to respond 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. The testimony of Mr. Blake provides an overview of this planning process. The testimony of Mr. Arbough describes the details of this planning process.

Q. Can you speak to some of the recent actions taken by the Companies in the area of corporate sustainability?

A. Yes. The Commission is well aware of the actions we have taken in recent years to construct additional environmental controls at our coal-fired generation plants, retire 800 megawatts of older coal-fired generation and put into service the first combined-cycle gas plant in the state of Kentucky. These actions ensured compliance with expanded environmental regulations allowing us to continue to provide safe, reliable energy for our customers in the most economic manner possible as we have for over one hundred years. The charts in Mr. Thompson's testimony show our history of dramatically reducing emissions while increasing generation volumes and our current position with respect to emission limits at our plants.

In April, 2016, the Companies began producing power at the solar facility the Commission approved and the Companies constructed at the E.W. Brown generating station. That 10 MW facility (which is enough to provide energy for approximately 1,500 homes based on a usage of 1,000 kilowatt hours per month) is performing as expected and is providing the Companies with the experience they seek in operating an intermittent generation facility. Additionally, the Commission recently issued an order approving the Companies' Solar Share Program which allows customers to subscribe to capacity in 500 kW Solar Share Facilities in 250 Watt increments. The regional facility is located in in Shelby County, Kentucky and is for the utilities' residential, business and industrial customers interested in sharing in local solar energy and receiving solar energy credits generated from the facility. The site, along Interstate 64 in the KU service territory near LG&E, is large enough to accommodate a 4 megawatt (DC) solar field. This type of program is ideal for customers who want solar power, but are unable to install it on their own property or would prefer to avoid the costs and maintenance required for a private system. The details of the Solar Share Program are discussed in the direct testimony of Mr. Malloy.

Finally, the Companies are prepared to offer a Business Solar option to business and industrial customers who prefer to have an onsite solar facility. Under such an arrangement and subject to Commission approval, the Companies would build, own and operate a solar facility on the customer's property which would provide the customer with some or all of its power needs.

With the operation of Cane Run 7, the solar facility at Brown, the proposed Solar Share Program, and the Business Solar concept, the Companies have further diversified their generation portfolio to include solar, coal, hydroelectric, and natural gas facilities. This response to industry changes puts the Companies in an excellent position to continue to address future changes in the most prudent manner possible.

Q. Please provide an update describing the Companies' commitment to the communities they serve.

A. Certainly. Our commitment to the communities in which we provide service is another critical component of the culture we have developed over many decades. The LG&E and KU Foundation reflects that commitment. 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 $25 million dollars to support such benevolent endeavors across the Commonwealth. Our community contributions from the Foundation and directly from the Companies have exceeded $6 million each of the past two years. These contributions are made to music festivals, harvest festivals, children's organizations, and family assistance groups. All of these contributions are funded solely by our shareholders. This commitment was recognized in 2016 by the *Business First* newspaper when it presented us with another "Partners in Philanthropy Award" for being an outstanding corporate citizen. This award was based on being one of the area's top socially responsible organizations. This was the fifth year in a row we have been recognized by *Business First* in this regard. *Business First* started the Partners in Philanthropy Awards in 2011 in response to the recession to honor local companies committed to improving our community.

Our employees have also demonstrated an admirable willingness to donate to worthy causes. For example, in early 2016, the LG&E and KU Foundation joined with the Companies' voluntary employee-giving campaign, Power of One, to raise more than $1.7 million in contributions that were allocated to some 26 nonprofit organizations across Kentucky. Since 2005, this employee-driven campaign has raised more than $17.7 million to support organizations such as Fund for the Arts, United Way, and Crusade for Children. More than 67% of employees participate in this effort which is twice the national average for employee participation in charitable giving.

In addition to these donations, for the last twelve 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. In August, 2016, nearly 200 KU and LG&E employee volunteers, along with family and friends, were stationed at locations in Carrolton, Eddyville, Harlan, Lexington, Louisville, and Shelbyville. Their focus was on sprucing up schools throughout our service territory prior to the start of the school year. They organized classrooms, decorated bulletin boards, trimmed hedges, planted flowers, and painted. In August, 2015, our Day of Caring resulted in employees filling more than 16,000 backpacks with necessary school supplies to benefit students in more than 20 cities in Kentucky and Virginia. Of course, our employees also donate countless hours to the communities we serve through board memberships, Company-sponsored programs such as Big Brothers/Big Sisters and a variety of other causes and efforts in which they have an interest.

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

A. Assistance to low-income customers is another integral part of our culture that is just as important as the efficiency and commitment to community principles discussed above. For example, we helped found and have been involved with Project Warm (www.projectwarm.org) 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 Winter Blitz 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. In 2015, more than 2,000 Louisville residents attended workshops at which they learned weatherization techniques. Earlier this year, LG&E contributed $100,000 to Project Warm.

As explained more fully in the testimony of Mr. Conroy, the Companies currently make $1.15 million in shareholder contributions to low-income assistance programs ($680,000 per year for LG&E and $470,000 per year for KU). In addition to those contributions, the Companies continue their history of providing assistance to Community Winterhelp (www.communitywinterhelp.org) and WinterCare Energy Fund. Community Winterhelp is a third-party nonprofit organization that helps Louisville area customers in financial distress pay their heating bills. The WinterCare Energy Fund is also a third-party nonprofit program that helps Kentucky customers in financial distress pay their heating bills. In 2016, the Companies encouraged customers to "pay it forward" by contributing to those programs. The Companies match customer contributions, dollar for dollar, as a way to help customers in need. Over the last seven years, customer donations and matching funds from the Companies have raised more than $2.5 million to help customers who need it most with their utility bills.

As discussed in Mr. Conroy's testimony, the Companies also offer demand 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.[5] WeCare is now the Companies' second largest DSM/EE program by budget. Finally, as more fully described by Mr. Conroy, the Companies have a strong practice of working with low-income customers on bill due dates via the Companies' FLEX program which extends the due date on bills to 28 days. Approximately 25,000 LG&E and KU customers participate in this program. We also work with low-income customers on waivers for late payment charges for those most in need. In summary, through a variety of programs and initiatives, we believe we meet and exceed our obligations to that part of our customer base most in need of assistance.

Q. Do you have a recommendation for the Commission?

A. Yes. The Commission, following its investigation of the Companies' applications, should issue orders authorizing the rates increases requested in our applications and supported by Mr. Blake and other witnesses and grant the Companies the CPCNs requested in our applications and supported by Mr. Conroy and other witnesses.

Q. Does this conclude your testimony?

A. Yes, it does.

[5] https://lge-ku.com/saving-energy-money/wecare-program

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.

VAStaffieri

Victor A. Staffieri

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 15 day of November 2016.

(SEAL)

Notary Public

My Commission Expires:

June 21, 2018

APPENDIX A

Victor A. Staffieri
Chairman, Chief Executive Officer and President
Louisville Gas and Electric Company, Kentucky Utilities Company
220 West Main Street
Louisville, Kentucky 40202
Telephone: (502) 627-3912

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

<u>Education</u>

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

Previous Positions

<u>LG&E Energy LLC, Louisville KY</u>
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

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

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

APPLICATION OF KENTUCKY UTILITIES COMPANY FOR AN ADJUSTMENT OF ITS ELECTRIC RATES AND CERTIFICATES OF PUBLIC CONVENIENCE AND NECESSITY	)))))	**CASE NO. 2016-00370**

In the Matter of:

APPLICATION OF LOUISVILLE GAS AND ELECTRIC COMPANY FOR AN ADJUSTMENT OF ITS ELECTRIC AND GAS RATES AND CERTIFICATES OF PUBLIC CONVENIENCE AND NECESSITY	)))))	**CASE NO. 2016-00371**

KENT W. BLAKE
CHIEF FINANCIAL OFFICER
LOUISVILLE GAS AND ELECTRIC COMPANY
KENTUCKY UTILITIES COMPANY

Filed: November 23, 2016

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

A. My name is Kent W. Blake. I am the Chief Financial Officer of Kentucky Utilities Company ("KU") and Louisville Gas and Electric Company ("LG&E") (collectively, the "Companies"), and an employee of LG&E and KU Services Company, which provides services to LG&E and KU. My business address is 220 West Main Street, Louisville, Kentucky 40202. In my role, I have oversight responsibility for accounting, financial and regulatory reporting, tax, payroll, corporate finance, cash management, risk management, financial planning, forecasting and budgeting, audit services, supply chain, information technology and state regulation and rates.

Q. Please describe your educational and professional background.

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

Q. Have you previously testified before this Commission?

A. Yes, I have testified before the Commission on numerous occasions, most recently for KU in its last base rate case, *Application of Kentucky Utilities Company for an Adjustment of its Electric Rates*, Case No. 2014-00371, and for LG&E in its last base rate case, *Application of Louisville Gas and Electric Company for an Adjustment of its Electric and Gas Rates*, Case No. 2014-00372.

Q. What is the purpose of your testimony?

A. The purposes of my testimony are: (1) to describe why KU and LG&E require the requested increases in base rates; (2) to discuss efforts in the financial and administrative areas of our companies to achieve improvements in efficiency and productivity (Mr. Thompson and Mr. Bellar will address operational efficiency and productivity efforts); (3) to provide an overview of LG&E and KU's business and financial planning processes and how management uses these processes in the management of its businesses; and (4) to sponsor certain schedules required by 807 KAR 5:001 Section 16 filed with this application.

Q. Please describe the ownership of LG&E and KU.

A. Following the merger of KU Energy Corporation into LG&E Energy Corp. in 1998, LG&E and KU have been subject to common ownership by our Kentucky-based parent company currently known as LG&E and KU Energy LLC. Following our acquisition in 2010, PPL Corporation has served as the holding company parent for LG&E and KU Energy LLC, PPL Electric Utilities and other subsidiaries.

With the formation of their respective holding companies in the 1990s, LG&E and KU each used a services company for the purpose of providing services within each holding company structure. Following their merger in 1998, their common parent company, formerly known as LG&E Energy Corp., continued to use the services company to charge and allocate costs between the two regulated utilities and several unregulated businesses. Over time, we have sold the unregulated businesses. Our services company, LG&E and KU Services Company, allocates costs to LG&E and KU based on our Cost Allocation Manual. The integration of the financial and administrative functions of LG&E and KU through LG&E and KU Services Company has allowed each utility to operate more efficiently than on a stand-alone basis.

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

A. LG&E's application requests Commission approval of rates to reflect an increase in the cost-based revenue requirements of $93.6 million for its electric operations and $13.8 million for its gas operations. KU's application requests Commission approval of rates to reflect an increase in the cost-based revenue requirement of $103.1 million. These revenue requirement calculations are based on a twelve-month forecasted test period beginning July 1, 2017, and ending June 30, 2018.

Q. Briefly explain the primary reasons for the increase in the Companies' revenue requirements.

A. The proposed increases in the cost-based rates are driven by investments in and operating costs associated with providing safe, reliable service to customers. They reflect investments and operating costs that have not yet been incorporated into LG&E and KU's current base electric and gas rates. The Companies' previous rate cases were based on the 13-month average capital investment at LG&E and KU for the year ended June 30, 2016. The current rate cases are based on the 13-month average capital investment at LG&E and KU for the year ended June 30, 2018. The use of average capitalization rather than end of period capitalization means that there was some increase in capitalization as of June 30, 2016, that was not yet reflected in base rates from the Companies' last rate case. Likewise, there will be some amount of capitalization as of June 30, 2018, that is not reflected in this rate case filing. However, as such capital investment not fully included in the revenue requirement calculations in this case and prior case are relatively consistent, capital spend between the end of the previous test year and the test year used in this case represents a good proxy of the capital spend driving the increase requested in this case. LG&E and KU have invested and project to invest more than $2.2 billion of capital into their operations over this two-year period, approximately $1.1 billion for each company. The table below provides a breakdown of this capital spend by area for LG&E and KU. Some of the major projects included in these projections are discussed in the testimonies of Mr. Thompson, Mr. Bellar, and Mr. Malloy.

$ Millions	**KU**	**LG&E**	**Total**
Generation	521.0	581.3	1,102.3
Electric Transmission	206.0	41.9	247.9
Electric Distribution	222.8	196.7	419.5
Gas Distribution		192.8	192.8
Customer Services & Metering	92.4	78.4	170.8
Other	52.1	54.4	106.4
Total	**1,094.3**	**1,145.4**	**2,239.7**

The Generation spend includes approximately $724.8 million - $368.9 million for KU and $355.9 million for LG&E - associated with previously approved Environmental Cost Recovery projects which are the subject of another rate mechanism and not a part of the requested relief in this proceeding. Customer Services & Metering includes approximately $8.3 million - $4.2 million for KU and $4.1 million for LG&E – associated with our Demand Side Management programs which are also the subject of another rate mechanism and not a part of the requested relief in this proceeding. Gas Distribution includes $106.3 million associated with projects which are a part of the Gas Line Tracker rate mechanism, both previously approved projects as well as the adjustments to that mechanism proposed in this proceeding, which are also not part of the requested base rate relief in this proceeding. These projects are discussed in the testimony of Mr. Bellar. After removing projects, which are subject to recovery through other rate mechanisms, the following table reflects amounts spent or to be spent through the end of the forecast test period on capital projects:

$ Millions	**KU**	**LG&E**	**Total**
Generation	152.1	225.5	377.5
Electric Transmission	206.0	41.9	247.9
Electric Distribution	222.8	196.7	419.5
Gas Distribution		86.5	86.5
Customer Services & Metering	88.2	74.2	162.4
Other	52.1	54.4	106.4
Total	**721.1**	**679.2**	**1,400.3**

The caption "Other" primarily represents capital spend on information technology. This capital investment includes both spend on hardware infrastructure as well as upgrades to major applications including our customer care system, financial system and geographic information system. In addition to amount shown for Gas Distribution, LG&E's gas operations are also allocated its portion of the Other, as well as the Customer Services & Metering spend. For this two-year period, that would be $41.0 million of the $128.6 million for those two categories.

After factoring in the jurisdictionalization of capital and the 13-month averaging process, as well as changes in accumulated depreciation, deferred taxes (including the effects of bonus depreciation), and other balance sheet components, the Companies' combined jurisdictional base rate capitalization is projected to increase by $414 million, $330 million for LG&E and $84 million for KU since the Companies' last rate case. In addition to the cost of capital associated with this increase in capitalization, such investments also result in increases in depreciation expense and property taxes. The increase in depreciation expense in this case reflects the impact of the new depreciation rate study discussed in the testimonies of Mr. Spanos and Mr.

Garrett. The resulting effect of capital investment in this application is approximately $77 million for LG&E's electric operations, $6 million for LG&E's gas operations and $68 million for KU.

Q. What are some of the other drivers of the requested increases in LG&E and KU's cost-based rates?

A. The capital investments noted above include some specific new programs that reflect the Companies' continued focus on reliability, including electric distribution automation, reliable backup provisions for key electric distribution transformers, power plant maintenance outages, and a targeted program to enhance the reliability of our electric transmission system. Mr. Thompson explains these efforts in more detail in his testimony. In addition, we have experienced increased costs in LG&E's gas operations in the form of personnel, training and materials associated with providing safe and reliable service, and complying with new regulations also focused on safety and reliability. Mr. Bellar discusses these efforts in his testimony The Companies are also proposing to implement an Advanced Metering System ("AMS"), following completion of an upgrade to their customer care system. These investments, discussed in detail in the testimony of Mr. Malloy, provide multiple benefits for the customer including cost efficiency, improved reliability and a greater customer experience. In addition to the impact of capital investment discussed above, these programs are adding $13 million of operation and maintenance expenses to LG&E's electric operations, $6 million to LG&E's gas operations and $13 million to KU's operations. Finally, KU has experienced a reduction in net revenues between cases. This includes a plant shutdown by one of KU's larger customers, as well as other residential and commercial reductions in the more rural parts of KU's service territory, especially those impacted by reductions in coal mining activities.

Q. Can you discuss the Companies' efforts to improve efficiency and productivity?

A. Yes. The Companies long-standing approach is consistent with that used by this Commission in evaluating requests for certificates of public convenience and necessity. We seek the most reasonable and effective least-cost option that will ensure the delivery of safe and reliable service to our customers. Efforts include a multi-layered, rigorous approach to investment projects and contract approvals, including a requirement that all procurement contracts be competitively bid subject to limited exceptions.

History demonstrates our success in balancing quality of service at the lowest reasonable cost to achieve the best results for our customers. Mr. Thompson's testimony elaborates on our outstanding operational performance metrics. From an operating cost perspective, the Companies have performed an annual benchmarking study for the past thirteen years where we compare our costs to other utilities using publicly-available FERC Form 1 information. The results of the most current study are shown in Exhibit KWB-1. For this year's study we added an overall metric to gauge cost performance – operation and maintenance expenses per megawatt hour sold. Upon doing this, we decided to use megawatt hours as the denominator for all cost categories for consistency. This provides the most direct translation to retail rates charged to customers. Periodic reports by agencies such as the Edison Electric Institute and the U.S. Energy Information Administration on retail rates use total retail sales revenue divided by megawatt hours sold to make comparisons of retail rates across the country.

The only variance among categories is that we continue to use megawatt hours of production to measure the efficiency in Generation rather than megawatt hours sold.

The analysis showed that the Companies are a top quartile performer on both an overall basis, as well as separately in Generation, Transmission, Distribution, and Customer Service. The Companies also just missed the top quartile mark for the Administrative and General (A&G) category. The A&G category does not simply include shared service functions but rather all utility costs which are not pushed out to the FERC accounts of the operating areas based on FERC's Uniform System of Accounts. Through discussions with accounting industry groups, the Companies have determined that there may be certain costs that the Companies report within the A&G category that peers have allocated to operating categories and will look to incorporate that into this analysis going forward. Overall, the Companies are very proud of their favorable cost position highlighted in this analysis and continue to balance cost control with providing the safe and reliable service our customers expect.

Q. What are some specific actions the Companies have taken to improve efficiency within the financial and administrative areas?

A. LG&E and KU continually look for more efficient ways to deliver service. For example, the Companies have studied the issue of rising healthcare costs for some time and have implemented a number of wellness and other initiatives to keep medical costs as low as possible while also ensuring a healthy workforce. The Companies believe that a healthy workforce is both more productive and safer. Specifically, the Companies implemented a new "Healthy for Life" premium structure that allows employees and covered spouses a reduction of $125 per month in their premiums if they complete three steps: (1) obtain and submit a biometric screening; (2) complete a "well-being assessment" survey; and (3) represent they are tobacco-free or complete a "Quit for Life" tobacco cessation program. The Companies also have adopted an intermediary service to decrease gaps in care and improve medical outcomes and have implemented better case management and cost effective physical therapy for workers' compensation cases. For this and other wellness initiatives, LG&E and KU were recognized in September 2016 with a "Healthiest 100 Workplace in America" award. The end result is that, despite an environment in which others have seen healthcare costs increase significantly, the Companies medical costs have only increased 0.4% between rate cases. To assess this positive result relative to internal costs incurred by such wellness and administrative programs to achieve lower medical costs, it is worth noting that the Companies' Human Resources department's expenses in this forecast test year are actually $55,000 lower than the level currently embedded in rates from the last rate case.

All financial and administrative areas have continued to implement technology to automate manual processes and identify other opportunities for savings. Recent examples include moving to a paperless payroll system, upgrades to our fixed asset and tax system, implementing a new SEC reporting system and using the software SharePoint across all administrative functions. As an overall indication of efficiencies, the projected full-time employee headcount for the forecast test year in this rate case across all financial and administrative functions is 8 employees fewer than currently embedded in rates based on the Companies' last rate case filings.

We have made excellent progress in automating the Companies' business by empowering an efficient mobile workforce that must process significantly larger amounts of data while, at the same time, address growing cybersecurity threats. These efforts bring higher projected information technology costs. As a result, the Companies re-evaluated their means of providing information technology services. As part of that, the Chief Information Officer ("CIO") for the Companies assumed that same position for all of PPL Corporation's domestic operations. Within the IT organization, there now exists a combined Infrastructure and Operations group and a combined IT Security group. In addition to the CIO, the heads of those two groups are based in the Companies' Louisville office with their time and expenses allocated not only to the Companies but also to PPL in accordance with the Companies' Cost Allocation Manual. These technical IT areas provide for a consistent, best practices approach and shared resources that can be optimized across the organization. While still sharing best practices and employing common tools and approaches, the applications development and business services functions of IT, those most closely tied to the user community and application portfolios at each business, remain separated with one group located in Kentucky dedicated to serving the Companies. Another group with the same functions remains located in Pennsylvania and is dedicated to serving PPL Corporation and its Pennsylvania-based subsidiaries. This initiative has resulted in the projected annual cost of IT services for the forecast test year in this application being lower than it otherwise would have been.

Q. How is the business and financial planning 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 the Companies' current performance and the Companies' mission, vision, and corporate values. Next, we identify the operating requirements necessary to accomplish those objectives. In turn, the business planning process translates the operational requirements into the resource requirements necessary to achieve those objectives. It is a "bottoms up" process with each business unit preparing detailed five-year plans addressing its individual areas of responsibility. Those plans are reviewed by successive levels of management to ensure not only that they are coordinated but also make efficient and productive use of the Companies' resources. The resulting budget and five-year business plan then serve as ongoing measures to track whether the Companies' objectives are being accomplished as planned or if additional action is required due to external factors or other changes. In summary, the Companies plan the work and then work the plan.

Q. How do customers benefit from the Companies' planning efforts?

A. Our planning process and focus on execution have resulted in the favorable operating cost position mentioned earlier and shown in Exhibit KWB-1. In addition, this planning and attention to detail have enabled us to optimize investments and the financing cost of such investments. As detailed in Mr. Arbough's testimony, Exhibit DKA-5 shows that LG&E and KU have two of the three lowest costs of debt financing relative to our peer group. As the Companies' retail rates are cost-based, these lower operating and financing costs directly benefit our customers. As discussed in the direct testimony of Mr. Conroy, the most recent semi-annual electric retail rate survey conducted by the Edison Electric Institute shows that the Companies' rates remain well below national and regional averages.

At the same time, it is important for LG&E and KU to maintain a strong financial position and deliver on shareholder expectations to attract the necessary capital at reasonable rates. As this Commission knows, the electric and gas utility businesses are very capital intensive. The Companies must be able to access debt and equity markets in an efficient manner during this current period of significant capital investment. The Companies have incurred capital expenditures of approximately $5.3 billion over the past five calendar years and expect to incur another $5.3 billion over the next five calendar years. The past five years of capital investment have included a focus on new generation sources and complying with new environmental regulations, particularly those focused on air quality. The next five years will see continued environmental investment to comply with new regulations, with the focus moving to facilities necessary to comply with coal combustion residuals and water quality regulations. We also see increased investment in an aging transmission and distribution infrastructure to meet customers' expectations with respect to continued reliability of service. The Companies have been thoughtful about their past and projected investments. In the areas of AMS and distribution automation, the Companies have waited until the underlying technologies have stabilized and the economic value for customers was clear. With that now being the case, the Companies plan to deploy these projects as quickly as feasible to make these projects even more affordable for customers due to the benefits of bonus depreciation, which is scheduled to sunset in 2019, due to the passage of the Protecting Americans from Tax Hikes Act of 2015. The

Companies' continue to actively take advantage of such available tax strategies to lower costs for its customers. As of December 31, 2015, the Companies' had a combined $11.4 billion of net utility plant. However, they also had a combined $1.9 billion of deferred taxes that has effectively lowered the amount of debt and equity capital required to fund those investments. Of that amount, nearly $860 million came from the utilization of bonus depreciation in the initial year qualifying plant was placed in service. The Companies project this amount will grow to $1.4 billion by 2019 when the bonus depreciation provision sunsets. In summary, the investments included in these base rate case applications demonstrate the Companies' continued commitment to providing safe, reliable service for our customers using the most effective least-cost options available.

Q. Do you have any recent experience to support the accuracy of your forecasting process?

A. Yes. The Companies' planning process, discussed above and described in greater detail in the testimonies of Mr. Arbough and Mr. Sinclair, were used to develop the forecasted test year ended June 30, 2016 in the Companies' last rate cases. The table below shows that actual results for the Companies were consistent with that forecast:

	Actual Jurisdictional Results	Per Rate Case Settlement	Variance
Net Operating Income	$426,497,330	$ 426,630,077	$ (132,747)
Capitalization	$6,166,937,911	$6,145,868,990	$21,068,921
Rate of Return	6.92%	6.94%	(.02)%

Q. Were there any specific lessons learned from the evaluation of actual results relative to financial projections that the Companies incorporated into this application?

A. Yes. There were many inquiries in our last base rate case related to the Companies' labor forecast. A review of actual labor expenses relative to the forecast from the Companies' last rate case demonstrated that actual labor expense was within $395,000 or 0.15% of the forecast labor expense. A key specific point of discussion from the Companies' previous rate case was the question of whether there should be a downward adjustment in the labor forecast for expected vacant positions. A review was conducted using actual results for the past two years. It indicated an average vacancy rate of 83 positions. Upon further review, 20 of those positions were noted as having been vacant since 2014. Those 20 positions were eliminated from the forecast used in these applications. The remaining 63 positions represented $5.6 million of annual labor expense. However, the Companies used contractors, overtime, and premium pay to provide the labor to accomplish the necessary tasks that would have otherwise been performed by employees in these rolling vacant positions. The Companies could not quantify the impact of the increased use of contractors over this two-year period due to the various categories used to track such costs prior to 2016. However, for this same two-year period, the Companies incurred average annual overtime/premium pay expenses that were $6.1 million greater than the amounts budgeted for that period, an amount slightly greater than the $5.6 million impact of labor vacancies. As a result, the Companies concluded they did not need to embed an explicit vacancy rate reserve in the labor forecast.

Q. Have the Companies conducted salary and benefits studies to address the comments in the Commission's order in Case No. 2015-00312?

A. Yes. The studies are contained in Schedule 807 KAR 5:001 Section 16(7)(h)(10)(labor cost changes).

Q. Please summarize the rationale for the request for the increase in the revenue requirement.

A. The additional revenues requested are primarily associated with the recovery of investments being made to improve the reliability and safety of the service that the Companies provide. There are also additional investments being made to continue with the significant strides made in recent years to improve the customer experience. These prudent investments will allow residents to enjoy improved service at rates well below national and regional averages and allow for continued economic development within the service territories.

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

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

- Section 16(7)(b) - Most recent capital construction budget containing at minimum a 3 year forecast of construction expenditures
- Section 16(7)(c) - Complete description, which may be in written testimony form, of all factors used to prepare forecast period. All econometric models, variables, assumptions, escalation factors, contingency provisions, and changes in activity levels shall be quantified, explained, and properly supported
- Section 16(7)(d) - Annual and monthly budget for the 12 months preceding filing date, base period and forecasted period
- Section 16(7)(f) - For each major construction project constituting 5% or more of annual construction budget within 3 year forecast, following information shall be filed:

1. Date project began or estimated starting date;

2. Estimated completion date;

3. Total estimated cost of construction by year exclusive and inclusive of Allowance for Funds Used During Construction ("AFUDC") or Interest During Construction Credit; and

4. Most recent available total costs incurred exclusive and inclusive of AFUDC or Interest During Construction Credit.

- Section 16(7)(g) - For all construction projects constituting less than 5% of annual construction budget within 3 year forecast, file aggregate of information requested in paragraph (f) 3 and 4 of this subsection

- Section 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 information:

1. Operating income statement (exclusive of dividends per share or earnings per share)

2. Balance sheet

3. Statement of cash flows

4. Revenue requirements necessary to support the forecasted rate of return

9. Employee level

10. Labor cost changes

12. Rate base

- Section 16(7)(i) - Most recent FERC or FCC audit reports

- Section 16(7)(k) - Most recent FERC Form 1 (electric), FERC Form 2 (gas), or and PSC Form T (telephone)

- Section 16(7)(l) - Annual report to shareholders or members and statistical supplements covering the most recent 2 years from the application filing date

- Section 16(7)(m) - Current chart of accounts if more detailed than Uniform System of Accounts chart

- Section 16(7)(n) - Latest 12 months of the monthly managerial reports providing financial results of operations in comparison to forecast

- Section 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

- Section 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

- Section 16(7)(q) - Independent auditor's annual opinion report, with any written communication from auditor which indicates the existence of a material weakness in internal controls

- Section 16(7)(r) - Quarterly reports to the stockholders for the most recent 5 quarters

- Section 16(7)(u) - If the utility had any amounts charged or allocated to it by an affiliate or general or home office or paid any monies to an affiliate or general or home office during the base period or during the previous three (3) calendar years, the utility shall file:

    1. Detailed description of method of calculation and amounts allocated or charged to utility by affiliate or general or home office for each allocation or payment;

    2. Method and amounts allocated during base period and method and estimated amounts to be allocated during forecasted test period;

    3. Explain how allocator for both base and forecasted test period was determined; and

    4. All facts relied upon, including other regulatory approval, to demonstrate that each amount charged, allocated or paid during base period is reasonable.

- Section (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

- Section (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

- Section (16)(8)(k) - Comparative financial data and earnings measures for the 10 most recent calendar years, base period, and forecast period

Q. What are the Companies' recommendations for the Commission in these proceedings?

A. Through the proposed changes in electric and gas base rates, in these applications, the Companies recommend the Commission approve the revenue deficiency recovery of:

- $93.6 million for LG&E's electric operations,
- $13.8 million for LG&E's gas operations, and
- $103.1 million for KU's operations.

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 18th day of November 2016.

Tammy J. Elzy (SEAL)
Notary Public

My Commission Expires:

November 9, 2018

APPENDIX A

Kent W. Blake

Chief Financial Officer
Louisville Gas and Electric Company
Kentucky Utilities Company
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.	
Director, Corporate Accounting and Trading Controls	1997-1998
Arthur Andersen LLP	1988-1997
Manager, Audit and Business Advisory Services	
Senior Auditor	
Audit Staff	

Education

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

Professional and Community Affiliations

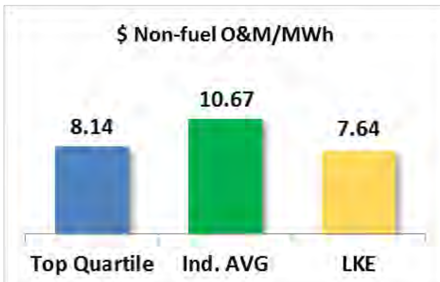
American Institute of Certified Public Accountants
Kentucky State Society of Certified Public Accountants
Edison Electric Institute
Financial Executives Institute
Leadership Louisville, 2007
CASA of the River Region, Immediate Past Chair
Metro United Way, Board Member
University of Louisville College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

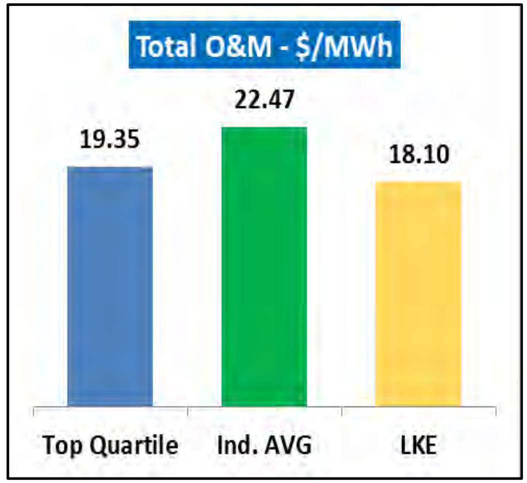
Exhibit KWB-1

Annual Benchmarking Study

FERC Form 1 Benchmarking [2011-2015]: Top Quartile Performance

Generation



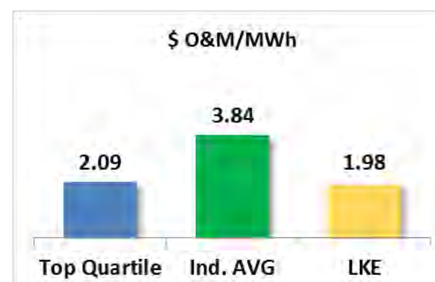


Transmission

A&G

Distribution

Customer Service



COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

APPLICATION OF KENTUCKY UTILITIES COMPANY FOR AN ADJUSTMENT OF ITS ELECTRIC RATES AND FOR CERTIFICATES OF PUBLIC CONVENIENCE AND NECESSITY	)))	**CASE NO. 2016-00370**

In the Matter of:

APPLICATION OF LOUISVILLE GAS AND ELECTRIC COMPANY FOR AN ADJUSTMENT OF ITS ELECTRIC AND GAS RATES AND FOR CERTIFICATES OF PUBLIC CONVENIENCE AND NECESSITY	))))	**CASE NO. 2016-00371**

TESTIMONY OF
PAUL W. THOMPSON
CHIEF OPERATING OFFICER
LOUISVILLE GAS AND ELECTRIC COMPANY
AND
KENTUCKY UTILITIES COMPANY

Filed: November 23, 2016

TABLE OF CONTENTS

BACKGROUND

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 Appendix A 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, customer service, and safety and technical training.

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 position of Chief

Operating Officer combines the responsibilities I had as Senior Vice President of Energy Services with oversight of four additional areas: gas distribution, electric distribution, customer service operations, and safety and technical training.

Q. What is the reporting structure immediately above and below your position?

A. As Chief Operating Officer, I report directly to Victor Staffieri, the Companies' Chief Executive Officer. Seven individuals report directly to me for areas within the operations umbrella: Lonnie Bellar, Vice President of Gas Distribution; John Malloy, Vice President of Customer Services; John Wolfe, Vice President of Electric Distribution; Ralph Bowling, Vice President of Power Production; David Sinclair, Vice President Energy Supply and Analysis; John Voyles, Vice President of Transmission and Generation Services; and Ken Sheridan, Director of Safety and Technical Training.

Q. Have you previously testified before this Commission?

A. Yes, I have testified in the Companies' last five base rate cases.[1] I testified in the proceeding involving the early termination of the lease between Western Kentucky Energy Corporation, an unregulated subsidiary of LG&E and KU Energy, LLC, and

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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. 2003-00433; *In the Matter of: An Adjustment of the Electric Rates, Terms and Conditions of Kentucky Utilities Company*, Case No. 2003-00434; *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; *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.

Big Rivers Electric Corporation[2] and in the Commission's investigation of the Companies' membership in the Midwest Independent Transmission System Operator, Inc.[3] I also testified when the Companies sought and received approval to construct Cane Run 7, a Combined Cycle Gas Turbine (CCGT) Generation Station.[4] I also 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. Please describe how the common ownership of LG&E and KU impacts the Companies' operations.

A. As Mr. Staffieri describes in his testimony, since 1998 LG&E and KU have been subject to common ownership by our Kentucky-based parent company currently known as LG&E and KU Energy LLC. Common ownership has allowed LG&E and KU to streamline and jointly plan many aspects of the operational side of their business, including safety, electric generation, transmission and distribution, and customer service, among others. Joint operations planning and performance has resulted in cost-efficiencies that could not otherwise be achieved by the respective

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

[3] *Investigation Into the Membership of Louisville Gas and Electric Company and Kentucky Utilities Company in the Midwest Independent Transmission System Operator, Inc.*, Case No. 2003-00266.

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

Companies on their own. Indeed, in approving the change in control resulting from the merger of the Companies in 1997, this Commission recognized that "integrated system planning may be the single most important benefit of the merger."[6]

Q. What is the purpose of your testimony?

A. My testimony describes the operational performance 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. As the complexity of the operational side of our business continues to increase, we are implementing programs to meet those challenges. While Mr. Blake and other witnesses explain the specific reasons why the Companies seek a rate increase, my testimony describes the Companies' operational performance since the last base rate case and provides context and detail to the operational reasons supporting the request. My testimony also provides the operational reasons behind the Companies' request for a Certificate of Public Convenience and Necessity ("CPCN") for the Distribution Automation ("DA") program.

Q. Please describe the Companies' recent performance in key operational areas.

A. The Companies have demonstrated operational excellence across multiple areas in the face of increasing complexity, increasing regulatory demands, and increasing customer expectations. The Companies assess their performance not only against internal targets, but also benchmarking data for peer utilities. Benchmarking analysis

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[6] *In the Matter of: Joint Application of Louisville Gas and Electric Company and Kentucky Utilities Company For Approval of Merger*, Order at p. 21 (September 12, 1997).

reveals that the Companies are performing at, and in many cases well above, median performance for the industry in critical areas.

For example, the Companies' safety performance for full time employees in 2016, as measured by the recordable injury incident rate (RIIR), or the rate of injury per 200,000 employee hours worked, is just 1.1 through September. That figure compares favorably to the Companies' target RIIR of 1.4 and places the Companies between first and second quartile performance according to industry benchmarking. The Companies are well within top quartile performance for Days Away/Restricted/Transferred (DART), a metric that gauges the number of lost work days over 200,000 employee hours. The Companies' DART through September 2016 is just .2 days, compared to a target DART of .7. This figure places the Companies within the first quartile of their benchmarked peers according to industry data.

The Companies' generation reliability performance, as measured by Equivalent Forced Outage Rate (EFOR), continues to be strong compared to industry benchmarks. The combined Companies had an EFOR on its steam generation units, including Cane Run 7, of just 4.99% for the 12-month period ending June 30, 2016. This puts the Companies within the industry first quartile performance of 5.00% for EFOR.[7] Additionally, the Companies have consistently completed generation-related capital projects on time and under budget, including the construction of Cane Run Unit 7 and Brown Solar, and major emissions-reduction projects to comply with environmental regulations.

[7] First quartile performance data based on 2013 figures, the latest available NERC data.

Electric transmission and distribution operations are also performing reliably and efficiently. One measure of reliability for both transmission and distribution is System Average Interruption Duration Index (SAIDI), which measures the average number of minutes that a customer is without power per year, typically excluding major outage events. The Companies' transmission SAIDI has historically been in the second or third quartile compared to benchmarked peers, while the combined Companies' distribution SAIDI has historically been in the first or second quartile.

The Companies' customer satisfaction ratings are on a consistent upward trend over the past five years. In 2016 KU and LG&E were honored to be ranked first and fourth, respectively, among comparable mid-sized utilities in the Midwest Region in the J.D. Power and Associates 2016 Electric Utility Residential Customer Satisfaction Study. In addition, LG&E was ranked highest in customer satisfaction among mid-sized utilities in the Midwest Region in the J.D. Power and Associates 2016 Gas Utility Residential Customer Satisfaction Study.

On the gas distribution side, LG&E has significantly improved its average emergency response time from 41.8 minutes in 2013 to approximately 35 minutes for calendar year 2016 through August. These improvements are attributable to a combination of fewer emergency calls and process improvements to allow for faster emergency response.

These performance metrics demonstrate that the Companies have made significant progress to enhance the total customer experience with the Companies' service.

Q. Why is additional investment in the Companies' operations needed?

A. Although the Companies have achieved sustained operational success in many areas, more progress is expected and deserved. Customer expectations for power reliability and quality continue to increase as dependence on the electric grid increases. Industry wide, utilities are increasing investment, particularly in transmission and distribution infrastructure, to keep pace with customer expectations for reliability. Much of this investment is focused on smart grid technologies, which enable utilities to better serve customers through enhanced reliability, decreased reliance on manual intervention, and shorter outage duration when problems arise.

Many of the Companies' planned investments are focused on these same areas. The Companies will update aging transmission and distribution infrastructure to ensure reliability long into the future. The Companies are making significant investments in smart grid technology through the implementation of two major programs – Distribution Automation and Advanced Metering Systems. These programs and the others discussed in my testimony are designed to meet the future expectations of customers and ensure the continued delivery of reliable, safe, and affordable electric service to all customers within the Companies' service area.

SAFETY

Q. Please discuss the Companies' commitment to safety.

A. The safety of the Companies' employees, contractors, and the general public is paramount to the Companies' operations. The Companies' safety mission is "to ensure, without compromise, that safety excellence is a core business expectation, and that management and employees are equally responsible and accountable for a low-risk work environment." Safe work contributes to the Companies' ability to attract and retain a talented workforce and provides the opportunity for the Companies to excel in their operations. Minimizing workplace injuries also contributes to operational efficiencies by reducing injury-related costs, including investigation time, Worker's Compensation, medical and liability insurance costs, employee time off, and lost productivity. The Companies maintain a *Guide to Safety Excellence* which sets forth the Companies' vision and goals for promoting a world-class safety culture, and sets forth specific behaviors and procedures designed to achieve those goals.

Q. Please provide examples of the Companies' safety achievements.

A. Recordable and lost-time injury rates for the Companies' employees and contractors continue to steadily decline from historical rates, reflecting that the Companies' commitment to safety has in fact resulted in a safer work environment. As set forth above, the Companies' RIIR and DART rates for 2016 are at or near the top quartile of benchmarked utilities, indicating that the Companies are on track to continue their strong employee safety performance this year. The Companies' safety culture extends to contractors as well. For the period between January 1, 2015 and September 30, 2016, the recordable injury incident rate for the Companies' contractors was just 1.4 injuries per 200,000 man hours, far below the general industrial average of 3.6 per the Bureau of Labor Statistics.

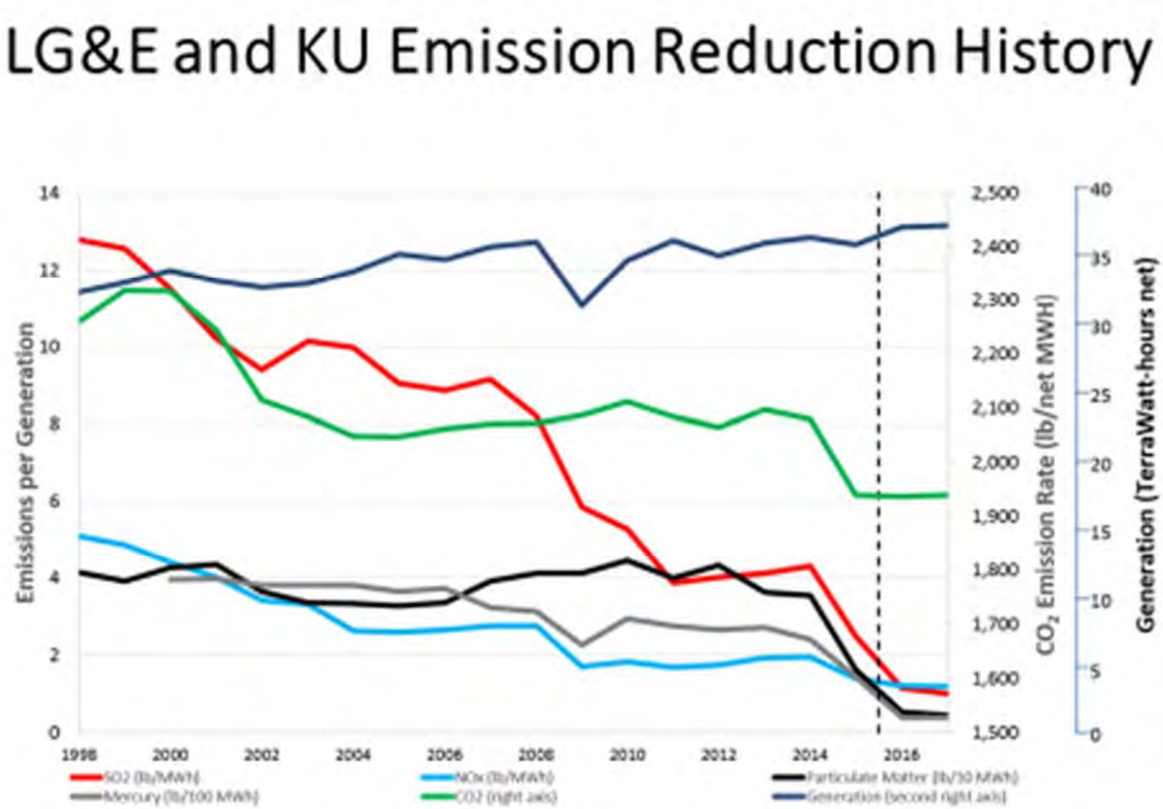
The Companies have earned safety awards and achieved significant safety milestones as a result of their safe work culture and practices. Earlier this year, KU's London employees received the Edison Electric Institute (EEI) Safety Excellence Award for completing 266,966 hours without a lost work day. In February 2016, LG&E employees at the Ohio Falls generating station celebrated a milestone of 10,000 days (nearly 30 years) without a lost-time injury at the facility. LG&E also received the Accident Prevention Award for Excellence in Safety (150 or more employees) from the Kentucky Gas Association for the 17th straight year.

REGULATORY COMPLIANCE

Q. Has the expansion of regulations impacted the Companies' operations?

A. Yes. The proliferation of regulations continues to have a pervasive impact on the Companies' operations. The Companies have made considerable changes to comply with new environmental regulations, audits of reliability standards, and other requirements promulgated by the North American Electric Reliability Corporation ("NERC").

As the Commission is well aware, the Companies have taken steps in recent years to cost effectively comply with environmental regulations through the construction of additional environmental controls at our coal-fired generation plants, retiring 800 megawatts of older coal-fired generation, and placing into service the first CCGT generation plant in the state of Kentucky. The charts below show our history of dramatically reducing emissions while increasing generation volume to meet the energy needs of our customers:



New regulations promulgated by the Environmental Protection Agency, particularly revised Effluent Water Limit Guidelines (ELG), regulations relating to Coal Combustion Residuals (CCRs), and a tightening on NO_x emissions standards, will continue to greatly impact the Companies' operations in numerous ways, including the necessity of operating more equipment, more restrictions on operating flexibility, increases in costs, and higher risk of regulatory non-compliance. Nevertheless, the Companies' historical record for meeting all such requirements has been excellent.

Q. How has compliance with the mandatory NERC Reliability Standards increased the Companies' operational expenses since the last base rate case?

The Companies must comply with approximately 1500 mandatory reliability standards and requirements in total, affecting all facets of their operations. The

NERC Reliability Standards are subject to frequent revisions and the Companies must stay current on the latest changes to ensure that their processes and procedures are compliant with applicable standards. Changes to the standards vary based on the perceived risk to the Bulk Electric System. Based on the current risk environment, NERC has focused more on cyber standards than operational standards, and more cyber standard changes are expected. The Companies' personnel must comply with the NERC Reliability Standards by regularly reviewing business practices, training employees, preparing for new standards, and maintaining evidence and documentation.

Q. Please provide examples of the Companies' achievements in meeting the NERC Reliability Standards.

NERC conducts both spot audits and comprehensive three-year regulatory audits to verify compliance with NERC reliability standards. Achieving successful audit results involves focused effort and devotion of substantial operational resources. Comprehensive audits by NERC cover both operational and cyber reliability. Regulatory compliance, including audit preparation, is an ongoing and intensive effort.

The Companies underwent a comprehensive audit in 2015. The 2015 audit included a visit to the primary and backup Transmission Control Centers, a Transmission substation, and subject matter expert interviews. The results were excellent: no deficiencies were found in an audit of 90 selected NERC Reliability Standards requirements.

ELECTRIC GENERATION

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

A. LG&E owns and operates approximately 2,796 MW of summer net generating capacity with a net book value of approximately $2.5 billion. Several of LG&E's generating assets are jointly owned with KU. A chart showing the entire LG&E and KU generation fleet and the Companies' respective ownership percentages is attached as Exhibit PWT-1.

As the exhibit shows, LG&E's generation fleet includes coal-fired generating stations at Mill Creek in Jefferson County and Trimble County, and a CCGT generating plant, Cane Run 7, also located in Jefferson County. LG&E also owns a number of natural gas-fired simple cycle Combustion Turbines (CTs) used to supplement the system during peak periods, the Brown Solar generating station located in Mercer County, and the Ohio Falls hydroelectric station, which provides base load supply subject to river flow constraints.

In addition to its generation fleet, LG&E purchases power from the Ohio Valley Electric Corporation ("OVEC") through a long-existing Inter-Company Power Agreement. LG&E also has in place a capacity and tolling agreement with Bluegrass Generation Company, LLC ("Bluegrass"), which gives LG&E the right to an additional 165MW of generating capacity through April 2019.

Q. Please describe KU's generation system.

A. KU owns and operates approximately 5,041 MW of summer net generating capacity with a net book value of approximately $4.2 billion. KU's generation assets along with KU's respective ownership percentage in those assets are likewise listed in Exhibit PWT-1. KU's generating system consists primarily of three coal-fired generating stations: Ghent in Carroll County, E.W. Brown in Mercer County and

Trimble County Unit 2. KU also owns a portion of Cane Run 7, the CCGT unit, and a portion of the Brown Solar generating station located in Mercer County. Additionally, KU owns and operates multiple simple-cycle natural-gas-fired CTs, which supplement the system during peak periods, and a hydroelectric generating station at Dix Dam, located next to the Dix System Control Center. Like LG&E, KU also purchases power from OVEC through a long-existing Inter-Company Power Agreement.

Q. Please describe how LG&E and KU operate their generation units.

A. As I indicated above, since 1998 the generation assets of LG&E and KU have been subject to common ownership by our Kentucky-based parent company currently known as LG&E and KU Energy LLC. Since then, generation is jointly dispatched between the two companies to achieve operational efficiencies using the larger scale created by the merger pursuant to a FERC-filed agreement known as the *Power Supply System Agreement*. Under this agreement, the joint planning objectives of LG&E and KU are to maximize the economy, efficiency and reliability of their systems as a whole. The dispatch of generation is determined by the lowest variable operating cost, irrespective of ownership. The dispatch of purchased generation from OVEC and capacity from Bluegrass is the same as the dispatch of generation plant owned by the Companies. The benefits of the jointly dispatched system are then allocated among LG&E and KU according to the After-the-Fact-Billing ("AFB") process, a computer program implemented since the LG&E and KU merger.

Generation Performance

Q. Please describe the reliability of the Companies' generation systems.

A. LG&E and KU compare favorably against the industry for generation reliability, both historically and currently. Weighted average Equivalent Forced Outage Rate ("EFOR") is the industry standard to measure reliability of steam generating units. EFOR measures the percentage of steam generation not available due to forced outages or derates. The Companies' average EFOR for the 12-months ending June 30, 2016 was 4.99%, compared to an average top quartile EFOR of 5.0% for benchmarked utilities according to 2013 NERC data.[8] Historically, the Companies' generation EFOR has been well below (better than) benchmarked median performance.

Q. Please provide a status update on the operation of Cane Run 7.

A. Cane Run 7 has diversified the Companies' generation fleet and fuel mix, and has been a positive driver of the Companies' generation reliability and efficiency success over the past fifteen months. Commercial operation of Cane Run 7, Kentucky's first and only CCGT generating plant, commenced in June 2015. Cane Run 7 is capable of producing 662 MW in the summer and 694 MW in the winter. It was built to replace generating capacity and energy provided from coal-fired plants closed due to environmental regulations. Cane Run 7 was constructed safely, on time, and $35 million under budget.

Cane Run 7 is performing exceptionally well. The plant was recently featured as a Top Generation Plant for September 2016 in *Power* magazine, a business and technology publication for the global generation industry. The feature highlighted Cane Run 7's highly efficient use of a new turbine model that keeps generating costs

[8] 2013 is the most recently-available NERC data for EFOR.

low. Indeed, due to the relatively low price of natural gas, the operation of Cane Run 7 saved ratepayers approximately $38 million in fuel costs for the 12-month period ending June 30, 2016, as compared to the fuel costs for producing the same generating capacity with the rest of the Companies' coal-fired fleet. The article also highlighted that by replacing several coal-fired generating units, Cane Run 7 has substantially reduced emissions. Compared to the three retired coal-fired units at the Cane Run station, Cane Run 7 generates 70 percent fewer particulate emissions, 99 percent less sulfur dioxide (SO_2), 82 percent less nitrogen oxides (NO_x), and 32 percent less carbon dioxide (CO_2).

Cane Run 7 has not only performed efficiently and reduced environmental impact, but it has also performed reliably. From July 1, 2015 through August 31, 2016 Cane Run 7 had an Equivalent Availability Factor (EAF) of 89.0%, an EFOR of 2.99%, and a net heat rate of 6,776 Btu per KWh. Cane Run 7 also had a Net Capacity Factor of 84.5%, which was the highest of any unit in the fleet.

Q. Please provide a status update on the solar project at Brown Generating Station.

A. In April 2016, the Companies began producing power at the solar facility located at the E.W. Brown generating station. The 10 MW facility was placed into commercial operation on June 9, 2016. The facility is performing as designed during the first several months of operation and has met the projected output based on average weather for its location. Although still in its infancy, the site is providing the Companies with valuable experience in the operation of an intermittent generation facility. The project was completed for $9 million under budget. The Companies'

Research and Development (R&D) expectations for the site are described later in my testimony.

Generation Capital Projects

Q. What capital investments are the Companies making to ensure the reliability of their generation operations into the future?

A. Although there are no new generation units planned to be constructed at this time, the Companies are investing capital into their existing generating plant to ensure that generation units perform reliably and will last long into the future. For the period from July 1, 2016 through the end of the forecast test period, June 30, 2018, the Companies will invest roughly $131 million in outage-related maintenance of its generation assets. This figure includes $19 million in combustion inspections for Brown CTs, $9.7 million for a planned combustion inspection of Cane Run 7, $6.5 million for a planned rebuilding of the cooling tower at Mill Creek 2, and roughly $4.2 million each on a rebuild of the cooling tower for Brown 2 and boiler replacement on Trimble County 2. The Companies are also investing approximately $12 million through the end of the forecast test period to convert the boilers on Trimble County Units 1 and 2 to start up using natural gas in addition to fuel oil.

LG&E will also spend $17 million through the forecast test year period on rehabilitation of the Ohio Falls generating station. Ohio Falls is a run-of-the-river hydroelectric generating station located at the McAlpine dam on the Ohio River. The eighth and final hydroelectric generating unit at Ohio Falls is scheduled for completion in 2017, which will increase the generator nameplate rating of the Ohio Falls station to 101 MW. The work being performed at Ohio Falls includes the installation of new runners, new discharge rings, rehabilitation of wicket gates and new stator windings.

By the end of 2016 LG&E will complete a project to extend a gas pipeline from Cane Run to Paddy's Run at a cost of approximately $14 million. Completion of this project will provide interstate gas pipeline service to Paddy's Run and will allow this generation facility to reliably operate in the winter without impacting LG&E's gas distribution system operation.

The Companies are also planning to invest $9 million in a blackstart modernization project at Cane Run, and an additional $6 million for a similar project at Trimble County. The blackstart projects will enhance the current capability for the Companies' CTs to be started without support from the electric grid, and to support the start-up of other units for the purpose of restoring power to the electric grid in the event of a wide-spread blackout. This project will enhance the reliability and availability of the Companies' generation fleet for the benefit of customers.

Q. What capital investments are planned to control costs and promote safety?

A. The Companies continue to seek out opportunities to control future costs associated with expanding and operating dry coal combustion residuals (CCRs) special waste landfills at all stations. LG&E has recently focused its efforts on the beneficial use of CCRs at the Mill Creek generating station to reduce landfill consumption. Currently, much of the synthetic gypsum CCR processed at the existing facilities at Mill Creek cannot be recycled into commercial applications (such as wallboard-grade gypsum) because the resulting chloride and moisture levels are too high. CCRs that cannot be beneficially used for other applications must be landfilled. LG&E is replacing and upgrading its existing gypsum dewatering system at Mill Creek to enable more CCRs to meet desired quality specifications for use in commercial applications like wallboard manufacturing. The replacement facility will be operational by 2018. In the meantime, LG&E will operate portable gypsum dewatering facilities at Mill Creek to meet recent specific commercial beneficial use opportunities.

The Mill Creek gypsum dewatering systems will increase future opportunities to meet the required specification for beneficial use in other potential applications and thereby reduce the amount of CCRs that must be landfilled on-site. LG&E currently has two opportunities for beneficial use of Mill Creek CCRs that will avoid landfilling a total of 2.65 million tons of gypsum over a seven year period starting in late 2016. These opportunities are available because of the processing capabilities of the portable dewatering systems that will ultimately be replaced by the upgraded facility. Thus, the beneficial use program at Mill Creek will, in addition to lessening LG&E's overall environmental impact, greatly reduce landfilling of CCRs, extend the usable life of the current landfill, and save approximately $13 million over a seven year period compared to offsite landfilling.

Demolition of LG&E coal-fired generating units at Paddy's Run is currently in progress. The total cost of that demolition project will be $24 million. The last of the coal-fired units at Paddy's Run was retired in 1984. The level of degradation was such that safety and security issues required the demolition work to proceed.

The Companies are also in the process of demolishing retired coal-fired generation plant at Cane Run and Green River generating stations, at a total cost for both facilities of $55.7 million, $31 million of which will be incurred from the end of the last base rate test period through the forecast test period (July 1, 2016 to June 30, 2018). In addition to providing safer and more secure locations, demolition eliminates the uncertainty of long-term cost associated with maintaining decommissioned facilities. Demolition also allows the space occupied by old generation plant to be potentially available for other uses and gives the Companies' flexibility in planning for such future use. Space at existing generation stations continues to be limited and valuable for potential future uses when compared to possible green-field options and associated permitting.[9]

<u>Other Generation Reliability Projects</u>

Q. In addition to the capital investments described above, what programs are in place to enhance generation reliability?

The Companies are conducting a remote performance monitoring program which is designed for early detection of anomalies that could lead to faults or other emerging issues with generation equipment. The program automatically collects data from equipment operations and reports it to the Companies' outside consultant, which analyzes the data against normal operating parameters to determine anomalies. Early detection and diagnosis of these anomalies enable engineers to optimize generation resources and promote reliability and performance.

A boiler reliability program seeks to maximize the reliability and life of boiler pressure parts through application of industry best practices for inspection, repairs, and replacement. As part of this program, boiler tube failures are tracked and

[9] *In the Matter of: Application of Louisville Gas and Electric Company and Kentucky Utilities Company for a Certificate of Public Convenience and Necessity for the Acquisition of Two Combustion Turbines*, Case No. 2002-00029, Order at 6 (Ky. PSC June 11, 2002).

reviewed to determine further action. Access to this data allows the Companies to take earlier and better-informed maintenance intervention and prevent failures of boiler parts.

The Companies are also implementing state of the art generation data analytics to promote better decision making to optimize generation resources related to reliability and performance. The use of advanced data tools will also lead to greater maintenance efficiencies and support complex operational analysis of generation.

Recently, the Companies engaged with GE to perform real-time monitoring of their gas turbines. The monitoring project allows the Companies to compare the performance of their gas turbines with others in GE's generation fleet. This program will assist the Companies in better detecting, managing, and preventing events that negatively impact reliability.

<u>Generation Cost Savings and Efficiency</u>

Q. Other than the capital projects discussed above, what new programs are the Companies implementing to control costs and maximize efficiency of generation operations?

A. In December 2015, the Companies signed an Exclusivity and Fees Agreement with Tinuum Group (f/k/a Clean Coal Solutions) that allows Tinuum the exclusive right to locate refined coal facilities at Ghent, Mill Creek and Trimble County generating stations. The Companies will generate revenue from this agreement through the receipt of reservation fees, and once the refined coal facilities are operational, through site license fees and coal yard service fees. 100% of the realized revenue generated from this agreement will be passed on to the Companies' customers.[10]

Several other new programs are aimed at leveraging generation data to produce more reliable and cost-effective outcomes. For example, the Companies are initiating a program to automate the collection of data required by NERC to ensure that the correct gross generator rating and reactive power is used for planning purposes, reducing the man-hours devoted to data collection and decreasing reliance on physical verification of readings. Another example involves the use of advanced data to monitor the condition of station battery banks over time to determine when replacement is needed. This program will allow for cost-effective load testing of battery banks and enhance reliability by ensuring that station battery banks perform as expected in emergency situations.

Q. Would you briefly summarize the capital investment the Companies plan to make in their generation operations by the end of the forecasted test period?

A. The following chart summarizes capital expenditures in generation, by company, from July 1, 2016 through June 30, 2018 **(in millions)**:

[10] The Exclusivity and Fees Agreement was approved by this Commission last fall. *In re the Matter of: Application of Louisville Gas & Electric Company and Kentucky Utilities Company Regarding Entrance Into Refined Coal Agreements, for Proposed Accounting and Fuel Adjustment Clause Treatment, and for a Declaratory Ruling*, Case No. 2015-00264, Order (Ky. PSC Nov. 24, 2015).

	LG&E	KU	Total
Outage-related investments	$54	$77	$131
Mill Creek Gypsum Dewatering Facility	$56		$56
Demolition of Retired Coal Plant at Cane Run, Paddy's Run, and Green River	$41	$9	$50
Ohio Falls Rehabilitation	$17		$17
Generation Black Start Projects	$4	$10	$14
All Other	$54	$56	$110
Totals:	**$226**	**$152**	**$378**

ELECTRIC TRANSMISSION

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

A. LG&E serves approximately 405,000 electricity customers over its transmission and distribution network in nine Kentucky counties. LG&E's transmission plant covers approximately 920 circuit miles and has a net book value of approximately $264 million.

Q. Please describe KU's transmission system.

A. KU serves approximately 519,000 electricity customers over a transmission and distribution network in seventy-seven Kentucky counties. KU's transmission plant covers approximately 4,567 circuit miles and has a net book value of approximately $499 million.

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

A. Yes. Like the generation assets, LG&E and KU, as owners of their respective interconnected electric transmission facilities, achieve economic and reliability benefits through joint operation and planning as a single interconnected and centrally controlled system. The transmission systems of LG&E and KU are operated and planned on an integrated basis pursuant to their Transmission Coordination Agreement filed with FERC since the Companies merged in 1998.

<u>Transmission Performance</u>

Q. How do LG&E and KU measure their transmission performance?

A. The Companies track the reliability of their transmission facilities through several different metrics. Transmission System Average Interruption Duration Index ("SAIDI") has been a traditional metric to track transmission reliability. SAIDI measures the average electric service interruption duration in minutes per customer for the specified period and system. Typically, major event days such as a major wind storm are excluded from this metric. The combined Companies have historically been primarily a third quartile performer in transmission SAIDI as compared to industry benchmarking data. On an individual company basis, LG&E's SAIDI performance historically has been better than that of the KU system.

In 2010, the Companies joined the newly-formed North American Transmission Forum (NATF) and began to participate in NATF benchmarking for transmission reliability to further explore ways to improve overall transmission performance. NATF's purpose is to promote transmission reliability excellence through efforts by its members to help one another identify and correct problems through continuous improvement techniques.

Metrics from NATF benchmarking provide further insight into the Companies' transmission performance. For example, one NATF metric is Outages per Hundred Miles (OHMY). OHMY is calculated by dividing the total number of transmission outages of any duration, not normalized for weather, by the total transmission line miles, and then multiplying the result by 100. It provides a measure of the outage incident rate for every 100 miles of transmission line. KU, with five times the number of transmission system miles as LG&E, outperforms LG&E under this metric, with an average of 10.2 outages per hundred miles of lines from 2008 through mid-2016. LG&E's average OHMY for the same period is 12.0 outages. Thus, while the average number of outages per 100 line miles on the LG&E and KU transmission systems is comparable, KU continues to experience a much higher average outage duration than LG&E, as measured by SAIDI.

Q. Why is LG&E's transmission SAIDI lower than KU's SAIDI?

A. In short, the answer lies in differences in service area, geography and system design. LG&E's transmission system serves a more concentrated urban load. Its service territory is more compact, allowing for a design that incorporates more redundancy to provide backup in case of an outage. KU's system is more rural and spread out over a far greater area with diverse geography, including mountainous areas. KU's transmission system thus requires more infrastructure per customer, and typically utilizes a direct connection to transmission lines between circuit breakers to serve customers. An outage that occurs on the transmission line between two circuit breakers interrupts service to all of the customers on that line until service personnel can locate the problem, isolate or repair it and return service to customers. Under the current KU transmission system design, most of that work must be done manually, increasing the time needed to restore power after an outage. Conversely, LG&E's more concentrated transmission system allows for greater redundancy of the system and the ability to remotely diagnose and respond to outages, leading to a shorter average outage duration.

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

A. Yes. Approximately 80 percent of the Companies' transmission line miles were originally installed prior to 1980 and many of the associated assets are still in service and are reaching the end of their useful life. Additionally, FERC and NERC continue to augment mandatory reliability standards with which LG&E and KU must comply. Shifting regional loads and generation resources alter system flows and constraints, which per the mandatory reliability standards and Companies' planning guidelines must be addressed through system upgrades. The Companies continually work to address the challenges posed by these issues and to improve and maintain reliable service to our customers. Cumulatively, the Companies' efforts have resulted in continued good performance, but at a necessarily increasing cost.

Transmission Capital Investment

Q. What investments are the Companies making to meet the challenges you describe above and to ensure the future reliability of their transmission systems?

A. The Companies are currently implementing a Transmission System Improvement Plan ("Transmission Plan") to minimize outage occurrence and duration and improve overall reliability of service to customers. The Transmission Plan document, which includes detailed information about the reasons for the plan and the details of the plan, is attached as Exhibit PWT-2 to my testimony.

In short, the investments included in the Transmission Plan are guided by the enhanced understanding provided by industry benchmarking referenced above, in addition to customer expectation and industry-wide focus on improving transmission reliability. The Transmission Plan contains two primary categories of investment: system integrity and reliability. System integrity involves replacement of aging transmission assets to enhance reliability. Approximately 44% of SAIDI between January 1, 2012 and June 30, 2016 was attributable to equipment failures. Good stewardship of the transmission system requires a consistent effort to identify vulnerable assets, then prioritize and replace them as determined before failures interrupt service to customers.

The reliability component of the Transmission Plan includes, in addition to several maintenance programs, capital investment in line sectionalization, which involves the installation of in-line breakers or switches on transmission lines. This equipment will allow the Companies to perform rapid line sectionalizing when there is an outage, thus reducing the potential for customer service interruption and expediting restoration when sustained outages occur. Transmission lines that experience longer outage times, as measured by SAIDI, will be targeted for new in-line circuit breakers and switching equipment.

In addition to the investments included in the Transmission Plan, the Companies are also making capital investments in transmission system resiliency. Resiliency capital investments include enhancing the inventory of spare equipment access and improving physical security around key locations.

The Companies will spend $177 million in capital between the end of the last base rate case test period and the end of the forecast test period (July 1, 2016 – June 30, 2018), on transmission system integrity, reliability, and resiliency programs. This spending is part of a total of $511 million in transmission capital investments over the five-year period starting in 2017. The breakdown of capital spending on transmission reliability and resiliency improvements from the period from July 1, 2016 through June 30, 2018 **(in millions)** is as follows:

Project/Asset Class	**LG&E**	**KU**	**Total Capital**
Replace Defective Line Equipment (wood poles, cross-arms, insulators)	$8	$84	$92
Replace Overhead Lines	$2	$11	$13
Improve Line Sectionalizing for Reliability	$1	$14	$15
Replace Circuit Breakers	$4	$9	$13
Replace Protection and Control Systems	$4	$8	$12
Replace Misc Substation Equipment	$0	$1	$1
Replace Underground Cable	$2	$7	$9
Replace Control Houses	-	$7	$7
Replace Switches	-	$2	$2
Transmission Plan Total	**$21**	**$143**	**$164**
Resiliency	$7	$6	$13
Total	**$28**	**$149**	**$177**

Q. Why are the Companies increasing capital investments in Transmission system integrity and reliability?

A. Customers increasingly expect affordable, safe and reliable service due to the increasing dependency on an economy and society supported by electrical power. Reliability and power quality are the most important drivers of overall customer satisfaction. Transmission reliability performance must be improved and maintained to meet these increasing customer expectations, continue to serve and attract businesses, and support the growth of the economy within the Companies' service territory.

Much of the Companies' transmission infrastructure is old and at or near the end of its usable life. Despite the success the Companies have achieved in the past through their comprehensive inspection and maintenance programs, equipment failures will occur at a higher rate as transmission equipment ages and experiences wear and tear. The consequences of transmission equipment failure, particularly where no redundancy exists to quickly restore the system, can have a substantial impact on customers. System integrity and reliability investments are necessary to minimize these high-consequence outage risks, improve overall system reliability and, most importantly, provide for the safety of the public and the safety of the Companies' employees and contractors.

Q. **Would you briefly summarize the capital investment the Companies plan to make in their transmission operations by the end of the forecast test period?**

A. The following chart summarizes all capital expenditures in transmission from July 1, 2016 through June 30, 2018 (in millions):

	LG&E	**KU**	**Total**
Transmission Plan and Resiliency Improvements	$28	$149	$177
All Other	$14	$57	$71
Total:	**$42**	**$206**	**$248**

<u>Other Transmission Reliability Programs</u>

Q. **In addition to the capital investments described above, what programs are in place to enhance transmission reliability?**

A. To improve the process for investigating and analyzing transmission outages, the Companies implemented a business intelligence tool, the Transmission Reliability Outage Data System (TRODS), starting in 2014. TRODS provides engineers access to a vast amount of operational data from multiple sources used to efficiently analyze and improve system performance. Utilization of TRODS to improve reliability reduces transmission outages which reduces wear on transmission system equipment.

The Cascade work management program is another program that contributes to transmission reliability. Cascade provides a centralized repository for substation assets, maintenance records and equipment ratings. The system facilitates tracking and reporting of equipment testing, and results from this testing can trigger predictive maintenance activity and enable field technicians to remotely access maintenance history, asset data, and inspection records. Use of the Cascade program substantially increases the likelihood that substation equipment will be replaced before a failure.

The Light Detection and Ranging (LiDAR) program contributes to transmission reliability by allowing the Companies to survey transmission lines, accurately verify existing line ratings, and confirm clearances with decreased involvement of field technicians. The Companies are also using LiDAR survey information as an input in designing new lines and upgrades. On the 345kV and 500kV lines, LiDAR is used to accurately map clearances to vegetation to ensure reliability and ongoing compliance with NERC reliability standards.

Q. Are the Companies changing their approach to vegetation management to enhance transmission reliability?

A. Yes, as part of the Transmission Plan, the Companies are transitioning from their just-in-time tree trimming program to a five-year cycled approach to vegetation management. From January 1, 2012 to June 30, 2016, tree interference caused 19% of all LG&E and KU transmission system SAIDI minutes. These outages were caused by trees falling into the lines. In the same period, the cause for approximately 30% of all outages could not be positively determined and, based on the experience of the Companies' field technicians, a significant portion of these unexplained outages were likely caused by vegetation, in particular by limbs and trees swaying or blowing into and making temporary contact with 69kV lines. Narrow corridors are especially vulnerable to these types of outages.

Instead of frequent line inspections and reacting to hazard trees and encroachments to the Companies' right of way, the Companies will implement a five-year cycled approach to vegetation management and a hazard tree identification and removal program. Hazard trees are those that are dead, dying or diseased, including those trees impacted by the emerald ash borer, an invasive insect species that compromises trees and threatens nearby transmission lines. The proposed comprehensive vegetation improvements will enable the Companies to restore existing rights-of-way through tree trimming, herbicide application, hazard tree patrol and removal, and an emerald ash borer mitigation program. The Companies have already started to transition to the regular cycle for the 345kV and 500kV power lines to ensure cost effective compliance with NERC mandatory standards. The proposed plan begins the conversion for the rest of the transmission system. Starting in mid-2017, the Companies will establish an average five-year line clearance cycle for the balance of the lines operating at less than 345kV, with the first cycle completed by 2022. The project will address vegetation management issues that span nearly 5,500 circuit miles of transmission lines.

After completion of the first five-year cycle, starting in 2022, the program is expected to reduce the costs of vegetation management and right of way maintenance in addition to improving system reliability. Going forward, the Companies will be able to focus on maintaining transmission corridors as opposed to reactively addressing issues identified during inspections.

Q. What other transmission line reliability programs are planned?

A. The Companies are implementing a more proactive approach to line switch maintenance with the goal of improving reliability and minimizing outages due to switch failures and operability problems. Remotely controlled switches will be inspected annually to ensure proper operation including integrity of batteries. Every line switch will be visually inspected on a two-year cycle to ensure there are no visible problems with alignment and condition. Every six years each switch will be operated to ensure proper functioning.

Additionally, the Companies have initiated a program to enable online monitoring of circuit breakers and transformers. The real-time data will provide new operational information on major assets. This will equip the asset management organization with better data on the overall health of the assets and facilitate appropriate corrective actions.

The Companies are participating in a Transmission Modernization Demonstration (TMD) project with the Electric Power Research Institute ("EPRI") to develop new ways to leverage the automatic data retrieval capabilities of Digital Fault Recorders. The analysis will be used to determine and automatically notify engineering with fault location information enabling faster restoration. Additionally, with data analytics, engineers will be able to use event record history to identify trends affecting the Transmission system.

<u>Transmission Regulatory Compliance</u>

Q. Have the Companies faced increased expense associated with FERC and NERC compliance?

A. Yes. The Companies continue to invest in the transmission system to meet requirements related to FERC and NERC compliance, including expenses related to vegetation clearing, ensuring the accuracy of line ratings, and meeting the latest versions of NERC standards for cyber and physical security, amongst others. As I described in detail earlier in my testimony, the Companies have sustained increased operating burdens for complying with FERC and NERC requirements and audits of the Companies' transmission systems.

The Companies are investing capital in response to line-rating and clearance-requirement alerts issued by NERC. The transmission line and structure upgrades resulting from these projects ensure the Companies' transmission lines meet required maximum operating temperature ratings. Many projects designed to meet regulatory requirements are identified in the annual transmission expansion plan, which is based on analysis of forecasted customer demand, generation resources and subsequent power flows on the transmission grid. The plan includes projects that will prevent system or component overload conditions identified through the study and analysis of the power system. These projects are necessary to meet future customer demand and criteria dictated by mandatory NERC planning standards and the Companies' planning criteria.

Q. What measures are the Companies taking to improve physical security?

A. In early 2016, the Companies engaged a third-party consultant to perform a comprehensive physical security assessment of a representative sample of the Companies' transmission facilities. The assessment included a detailed review of physical security features at transmission substations as compared to industry best practices and the NERC Security Guidelines for the Electric Sector – Physical Security. The security assessment concluded that the Companies are well-positioned as compared to other utilities for existing security measures, policies and procedures. The assessment made certain recommendations for further improving physical security, and the Companies are implementing those recommendations as part of their transmission system resiliency investments outlined above.

The Companies are also implementing security enhancements to comply with the recent NERC Critical Infrastructure Protection (CIP) Physical Security Standard 014-2 (CIP-014-2), a standard designed to identify and protect transmission control centers and substations that, if rendered inoperable from a physical attack, could cause grid instability, uncontrolled separation from the grid, or cascading within an interconnection on the grid. These security enhancements will ensure compliance with CIP-014-2 and help to protect against the risks that standard is designed to mitigate.

Transmission Cost Savings and Efficiency Programs

Q. Which efficiency programs and practices have contributed or will contribute to the Companies' operational efficiencies in Transmission?

A. Transmission efficiency programs are increasingly rooted in the premise that technology and automation can improve the quality of information delivery – allowing the Companies to react more quickly to problems and to design a more reliable transmission system to minimize the occurrence of problems in the first place. The maintenance management and inspection programs described above are prime examples of that principle at work.

There are numerous other examples. The Companies have installed new software to automate logging of outages, allowing employees to focus more time on system issues and spend less time logging data. Improvements have been made to simplify data retrieval from the Energy Management System ("EMS") to reduce time spent developing queries and improving information flow. A new accounting and billing application for transmission planned for rollout in 2017 will categorize, summarize, and archive data used to verify system electric flows at interconnection points with other utilities and to ensure accurate billing for third party transmission customers. All of these programs will result in managing cost increases attributable to transmission operations and maintenance going forward.

ELECTRIC DISTRIBUTION

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

A. LG&E's electric distribution business serves approximately 405,000 customers in Jefferson and 16 surrounding counties. LG&E's service area covers approximately 700 square miles. LG&E's electric distribution facilities include 97 substations (32 of which are shared with transmission), 3,899 miles of overhead electric lines, and 2,482 miles of underground electric lines. The net book value of LG&E's distribution plant is approximately $779 million.

Q. Please describe KU's distribution business.

A. KU's distribution business serves approximately 519,000 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), 12,916 miles of overhead electric lines in Kentucky, and approximately 2,369 miles of underground electric lines in Kentucky. The net book value of KU's distribution plant is approximately $1.05 billion.

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

A. Yes. As with the Companies' generation and transmission systems, LG&E and KU, as owners of their respective distribution facilities, achieve economic and reliability benefits through joint operation, planning, maintenance, and investment in their distribution systems.

<u>Distribution Performance</u>

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") and System Average Interruption Frequency Index ("SAIFI"). SAIDI measures the average electric service interruption duration in minutes per customer for the specified period and system. SAIFI measures the average electric service interruption frequency per customer for the specified period and system.

The Companies' distribution reliability performance continues to be strong. In 2015, the Companies achieved a distribution system SAIDI of 76.5 minutes and a SAIFI of 0.841, excluding major events. The Companies' performance was within the second quartile of industry benchmarking for both SAIDI and SAIFI.

Q. Please briefly describe some of the existing projects that have contributed to the reliability of the Companies' distribution system.

A. Since 2010, the Companies have made significant capital investments in systems hardening and reliability improvements. The investments include the Circuits Identified for Improvement ("CIFI") program, which targets replacements for underperforming circuits based on five-year average performance, and the Pole Inspection and Treatment ("PITP") program, which enables the Companies to proactively inspect, treat, and replace poles across LG&E's and KU's service territories.

In recent years, the Companies have also increased capital investment in their Aging Infrastructure Replacement (AIR) program, which targets specific legacy distribution assets based on below average reliability performance, high operational cost to maintain, availability and cost of spare parts, and expected end of life. These projects in combination helped to reduce the Companies' distribution SAIDI by 22% from 2010 to 2015 and SAIFI by 24% over the same period. However, returns on those investments in the form of improved reliability are diminishing as the worst-performing infrastructure has now been replaced.

Q. Are there new or enhanced capital programs proposed to improve resiliency and reliability performance of the Companies' distribution system?

A. Yes. The Companies are seeking a CPCN for a Distribution Automation ("DA") program, which refers broadly to advanced grid intelligence that will enable the Companies to perform remote monitoring and control, circuit segmentation, and "self-healing" of select distribution system circuits. The details of the DA program and the support for the Companies' CPCN request are set forth in later testimony.

The Companies also plan to expand an existing initiative to enhance contingency coverage for critical substation power transformers. The Distribution Substation Transformer Contingency program mitigates potential high consequence, long duration service interruptions that would likely result when a substation transformer fails, by making a back-up source available to support system and customer restoration. This initiative includes transformer additions, circuit upgrades, and distribution system enhancements, as well as two mobile transformers for the eastern and western service territories of KU.

The transformer contingency program provides a three tiered approach for adding capacity in the event of a substation transformer failure: (1) the addition of permanent system capacity for full redundancy through switching; (2) expanded use of mobile transformers; and (3) use of small localized spare distribution power transformers to restore service in the most efficient and cost effective manner. Contingency enhancements will be selected on a value-based approach, balancing load density and customer impact with cost.

Q. Why is expansion of the Distribution Substation Transformer Contingency program needed?

A. Expansion of transformer contingency will increase the resiliency of the distribution system and reduce the duration and impact of high-consequence customer outages. Service to more than half of the distribution substation transformers in the Companies' system cannot be fully restored in the event of a transformer failure during heavy load periods without directly replacing the transformer, which would leave customers without service for extended periods of time. Extended outages can have a significant impact on the affected area, particularly in high-density areas with critical infrastructure including hospitals, schools, law enforcement, and transportation hubs.

Through the use of transformer contingency, the Companies can reduce a potential multi-day outage caused by a transformer failure to mere minutes (for transformers with full contingency) or hours (for contingency through the use of mobile or localized spare transformers). Added substation transformer contingency will also provide improved switching flexibility between substations, which will enable greater access for maintenance, planned and unplanned, of substation transformers and breakers. For transformers with permanent contingency, eliminating the need to install a portable or spare transformer under emergency conditions or scheduled maintenance will result in reduced operating costs.

Distribution Automation

Q. Please describe the Distribution Automation program, for which the Companies seek a CPCN in this case.

A. DA involves the extension of intelligent control over electrical power grid functions to the distribution system level. The intelligent control of distribution equipment can provide real-time information and allow for the remote monitoring, remote control, and automation of distribution line equipment. This program is intended to leverage DA technologies to improve the customer experience through enhanced reliability performance. The DA program will affect approximately 20% of the Companies' circuits, 40% of the distribution circuit miles, and 50% of the Companies' customers.

There are two primary components to the DA program. The first involves the installation of 1,400 electronic SCADA (Supervisory Control and Data Acquisition) capable reclosers, all of which will be connected to the distribution SCADA system. A deployment map showing the planned locations of the 1,400 electronic reclosers throughout the Companies' service territory is attached to my testimony as Exhibit PWT-3. Schematics of SCADA-capable reclosers, installation diagrams, wiring diagrams, a pole-mounted enclosure diagram, and recloser control diagram are attached collectively to my testimony as Exhibit PWT-4.

The second component of the DA program involves the acquisition and deployment of a Distribution SCADA system and a Distribution Management System (DMS), software that enables intelligent control of distribution equipment, including the capability to provide real-time information, remote monitoring, remote control, circuit segmentation, and automation of distribution line equipment. The DA program is described in further detail in a paper entitled "LG&E and KU Electric Distribution Operations Distribution Reliability and Resiliency Improvement Program," attached as Exhibit PWT-5 to my testimony.

Q. What circumstances caused the Companies to consider implementing DA?

A. As stewards of the electric distribution system, the Companies are responsible for providing safe, reliable, high quality electric service to customers. The Companies' existing reliability and resiliency capital programs, in particular CIFI, have contributed to improved customer satisfaction and reliability on a year-over-year basis since 2010. However, the Companies are now seeing diminishing returns on programs like CIFI as the worst-performing circuits have been addressed. While reliability returns on circuit hardening programs like CIFI are diminishing, customer expectations for service reliability, power quality, system resilience, and outage response are increasing.

Investor owned utilities industry-wide are shifting capital investments from generation to power delivery (i.e., transmission and distribution) as a percentage of total investment. These increased investments are being driven by increased customer expectations, growing customer dependence on electricity, increasing penetration of Distribution Energy Resources (DER) on distribution grids, and demonstrated step-improvement in reliability as a result of smart grid investments, including DA. As a result, the industry as a whole has achieved consistent step-improvement in distribution reliability over the past decade. Industry benchmarking data further shows that quartile performance for outage duration, as measured by SAIDI, is compressing throughout the industry. In other words, there is far less difference between a first-quartile performer and a fourth-quartile performer now than there was ten years ago. Reliability improvements throughout the industry are expected to continue as utilities focus new distribution investment on implementation of smart grid technologies. In short, implementation of DA is necessary to keep pace with customer expectations and industry-wide improvements in distribution reliability.

Q. What is the expected cost to the Companies of the DA program?

A. The total capital expenditure for the DA program is expected to be $112 million over a seven-year implementation schedule. The annual capital spending for the DA program is broken out by year in Section 5.1.2 of the Distribution paper attached to my testimony as PWT-5. $23 million of that total capital expenditure is expected to be incurred before the end of the forecast test year on June 30, 2018.

Operations and Maintenance (O&M) expense attributable to DA is expected to be $6 million over the seven-year implementation plan, $1.16 million of which will be incurred before the end of the forecast test period. Estimated annual O&M expenses incurred after full implementation of DA, beginning in 2023, are set forth in Exhibit PWT-6 to my testimony.

Q. What are the expected benefits of Distribution Automation?

A. DA has the capability to improve reliability, automatically monitor the health of the distribution system, and assist with timely outage restoration. The Companies are projecting that DA will improve their distribution SAIDI performance by 12% over the seven-year implementation schedule for DA and improve SAIFI by 19% over the same period (2016 – 2022). In areas where DA is implemented, real-time data from smart reclosers will provide intelligence and remote capabilities to support switching, reducing manual intervention and the time required to isolate outage causes. These capabilities will enhance the safety, reliability and efficiency of the distribution system.

Q. What alternatives to DA were considered?

A. As part of their 2016 business planning process, the Companies modeled the implementation of DA using the Asset Investment Strategy (AIS) decision-support model, and compared the results to the Companies' existing portfolio of distribution reliability and resiliency programs. The results of that process led the Companies to conclude that DA provided the Companies the best option for making the step-improvement in reliability performance required to meet customer expectations and maintain or improve the Companies' position in reliability benchmarking. For example, the results of the model indicated that implementation of DA would result in a larger overall reduction in SAIDI minutes (outage duration) per dollar invested through 2022 than would the CIFI program. Likewise, DA would result in a larger overall reduction in SAIFI (outage frequency) per dollar invested than CIFI through the same period.

Q. Did the Companies consider different variations of DA?

A. Yes. Although the consideration of costs and benefits alone is not the principal reason for this investment – improved reliability is – we modeled the proposed implementation of DA against alternatives using a Capital Evaluation Model (CEM). The results of the CEM process are attached collectively to my testimony as Exhibit PWT-7.

The Companies considered an alternative implementation of DA that would result in the installation of electronic reclosers on all distribution circuits having a contribution to system SAIFI beyond one standard deviation from the mean contribution to SAIFI. However, more than half of the investment would be utilized to complete conductor capacity upgrades to provide full switching capacity. Only 450 electronic reclosers could be installed (versus 1,400 in the proposed alternative) and only about 30 percent of the Companies' customers would be affected (versus 50 percent in the proposed alternative). Contribution to SAIDI and SAIFI reduction would be lower with this alternative compared to the proposed implementation of DA.

In the end, compared to the other considered alternatives, DA in its proposed form provides the most improvement in distribution reliability to benefit the largest number of the Companies' customers in light of the investment proposed.

Q. Does the DA project serve the public convenience and necessity?

A. Yes. Implementation of DA as proposed by the Companies will benefit customers by providing greater distribution reliability and the ability of the distribution system to more quickly recover from outages, often through automatic means. The step-improvement in reliability the Companies expect to be achieved through implementation of DA is necessary to meet customer expectations and keep pace with improved reliability of electric distribution systems nationwide.

Distribution Cost Savings and Efficiency Programs

Q. Have the Companies implemented programs that contribute to operational efficiencies in Distribution?

A. Yes. In addition to the capital projects discussed above, the Companies have implemented a number of other programs to reduce long term cost and enhance reliability of distribution operations. The Companies maintain cost savings and efficiency programs in each of three distinct areas: incident management, system/asset management, and work and resource management. Below are a few examples of efficiency and reliability programs in each of these areas.

Incident Management

The Companies' Incident Command System (ICS) facilitates the Companies' efficient and structured response to power emergencies, including management of communications to key stakeholders. The structure and processes implemented by

ICS ensure that the Companies respond to events on the electric distribution system in a timely, safe, effective, and consistent manner.

Additionally, the Companies are members of a number of mutual assistance organizations, which focus on sharing of resources in the event of a major outage that cannot be restored through reliance on normal internal resources and staffing. Participation in mutual assistance organizations ensures that the Companies receive competent, trained employees and contractors from other experienced utilities in case of a major unplanned outage event. Involvement in mutual assistance organizations also provides the Companies the opportunity to share best practices and technologies with other utilities to prepare for and respond to emergencies.

Mr. Bellar's testimony refers to the Service Suite upgrade for Gas Distribution, which is used by Electric Distribution as well. Service Suite allows the Companies to dispatch detailed work assignments to employees on a mobile platform. Mobile dispatch can improve response times by more readily identifying the location of available crews before work is sent out, and reducing communications cycle times formerly required by radio or phone. The program also includes a damage assessment component, which allows field teams to quickly communicate damage information to dispatch for prioritization.

<u>System/Asset Management and Control</u>

The Companies maintain a program to inspect and proactively replace substation power circuit breakers based on age, persistent operational issues, and service quality, among other factors. This program promotes efficiency and cost savings by avoiding failures and replacements in emergency situations. Planned asset replacements better utilize the Companies' resources and create synergies with other needed work while eliminating customer disruptions occasioned by unplanned outages.

Work and Resource Management

Like Gas Distribution as described in Mr. Bellar's testimony, Electric Distribution uses the Asset and Resource Management (ARM) tool to support high volume and project-related work on distribution systems, including resource integration and tracking, documentation, and cost estimation and reporting. The implementation of ARM also enhances workflow efficiencies, improved business processes, and allows for more accurate cost estimating due to improved construction units.

These projects and many others like them support the Companies' commitment to keeping distribution costs low while providing safe, reliable, and resilient service to customers.

Distribution Capital Investment Summary

Q. Would you briefly summarize the capital investment the Companies plan to make in their distribution operations by the end of the forecasted test period?

A. Yes. The following chart summarizes distribution capital expenditures by company from July 1, 2016 through June 30, 2018 (in millions):

	LG&E	KU	Total
Distribution Automation	$13	$10	$23
Transformer Contingency	$8	$15	$23
New Business	$58	$81	$139
Repair and Replace	$87	$70	$157
All Other	$30	$47	$77
Total:	**$196**	**$223**	**$419**

SMART GRID INVESTMENT SUMMARY

Q. Please summarize the Companies' Smart Grid Investments.

A. A breakdown of the Companies' Smart Grid investments by project is included as Exhibit PWT-8 to my testimony. LG&E plans to spend $80.0 million in Smart Grid investments through the end of the forecast test period, and KU plans to spend $98.1 million on Smart Grid investments during the same time period. As the exhibit shows, the bulk of this investment will be for Advanced Metering Systems, described below and in greater detail in Mr. Malloy's testimony, and Distribution Automation, described in my testimony above. Other Smart Grid investments will be made to update and modernize the Companies' transmission assets, particularly control houses, RTUs, and automated and motor operated switches.

CUSTOMER SERVICE

Q. Does Mr. Malloy, Vice President, Customer Services present direct testimony concerning the Companies' customer service operations, programs, performance, and recognition?

A. Yes. The Companies strive to be customer-focused by providing superior and innovative service to its customers, in addition to providing their customers with safe and reliable energy. The work and programs described in Mr. Malloy's testimony are all aimed at improving the overall customer experience. As Mr. Malloy sets forth in his testimony, the Companies' dedication to the customer is garnering positive results. As of the second quarter of 2016, the Companies exceeded industry median customer service satisfaction ratings by nearly 10%, as measured by the percentage of surveyed customers who rated their overall customer service as a 9 or 10 on a 10 point scale. The Companies' customer satisfaction ratings have been on a consistent upward trend since at least 2011. The Companies have achieved a high level of customer satisfaction while being efficient with the funds spent on customer service programs.

Q. Is there anything else you would like to add to Mr. Malloy's testimony?

A. I would like to briefly address the Companies' planned implementation of the Advanced Metering Systems (AMS) program due to the importance of this program to the future of the Companies' operations. The Companies are requesting a CPCN for the AMS program, and the detailed operational support for that request is included in Mr. Malloy's testimony. Although the initial cost of implementing AMS is substantial, the capabilities provided by this system will reap benefits and cost savings long into the future. Recent data shows that smart meter technology has been installed in over 43% of U.S. homes.[11] Utilities that have installed AMS-type systems have reported decreased outage durations, significant dollar savings from outage management efficiency and customer savings from outage reductions, and improved customer awareness and long-term satisfaction with their utility service.

[11] Institute for Electric Innovation, *Utility-Scale Smart Meter Deployments: Building Block of the Evolving Power Grid*, IEI Report, September 2014.

The Companies expect to realize similar benefits from widespread implementation of AMS.

The AMS program will fundamentally change the way the Companies interact with their customers, empowering customers with information to make better energy utilization decisions and improving overall customer experience. In short, AMS allows for two-way, real-time remote communication between the customer's meter and the Companies' grid operations system. Customers will have access to detailed data about their energy consumption and will be better able to understand and personalize their consumption patterns. AMS will reduce energy theft and eliminate the need for physical meter reading and thus result in substantial long-term operational savings. AMS will provide the Companies with greatly enhanced remote diagnostic capabilities which will allow the Companies' engineers to quickly diagnose and respond to outages on a granular, customer-by-customer basis.

GAS DISTRIBUTION

Q. Does Mr. Bellar, Vice President of Gas Distribution present direct testimony concerning the operations, programs, and new investments of LG&E in its gas business?

A. Yes. As explained by Mr. Bellar, gas operations are performing quite well and have benefitted from investments and productivity initiatives that have been implemented and realized since the last rate case. These include major capital investments in infrastructure, including leak mitigation, gas main replacement, and gas riser replacement, as well as efficiency programs, including gas inspection tracking, gas training tracking, upgrades to the mobile work dispatch system, and enhanced emergency response times. The planned programs in the Business Plan are expected to result in even greater efficiencies in the forecast test period. LG&E's investments in infrastructure and efficiency programs will bear returns in the form of improvements to the already safe, reliable, and affordable gas service provided to LG&E's customers.

WORKFORCE

Q. What has been the net effect on the number of full-time employees caused by the Companies' incremental efforts to provide safe and reliable service to customers and to comply with applicable regulations in the most cost effective manner?

A. Across all operating functions of the Companies, the forecast test year includes a net addition of 26 employees compared to what is currently embedded in rates based on the Companies' last rate case filing. 22 of the 26 new employees will be utilized in the gas distribution business. The need for this increase is discussed in detail in Mr. Bellar's testimony. The remaining net increase of 4 positions reflects the allocation of employees across operating functions with additional resources required primarily for the implementation of reliability and customer service initiatives in the areas of electric distribution, electric transmission and customer service discussed elsewhere in my testimony.

RESEARCH AND DEVELOPMENT

Q. Do the Companies' Research and Development efforts support improvements in Operations?

A. Yes. With the Companies' membership in EPRI and affiliations with other university research initiatives, the R&D programs seek to support both short term efforts to improve operations as well as longer term strategic decision initiatives.

Q. Please describe examples of the Companies' recent research and development activities that are aimed at improvements in operating efficiencies.

A. Many of the Companies' R&D efforts are borne out of their own operational challenges. For example, several of the Companies' turbine oil systems started to fail demulsibility (i.e., the ability for oil to shed water) tests. The Companies sought a solution to this problem that was more cost effective than simply replacing the oil. R&D quickly learned that this problem was not unique to LG&E and KU, and began to test a skid that filters the impurities out of the oil that attract and retain water. The skid has restored oil demulsibility and the Companies are monitoring this project to determine if this is a sustainable solution.

R&D is also working with EPRI to bring a Selective Catalytic Reduction ("SCR") test skid to evaluate the potential for operating the power plant SCRs at lower exit gas temperatures (lower load). If successful, this would lead to operating with the SCR in service at lower load levels and reduce NOx emissions. The ammonia injections systems with the SCRs are currently turned off during lower load operations when the exit gas temperature is below the design minimum operating temperature to avoid fouling of the catalyst. Recent studies have indicated that they can be operated below these current minimum temperatures without problems.

Another R&D project involves evaluating the energy storage of large scale batteries. The Companies are installing a test facility and partnering with EPRI to facilitate testing and evaluating the performance of utility scale energy storage to improve the efficiency of the production and delivery of electricity, particularly associated with intermittent generating resources like solar or wind.

Q. What are the Companies learning from the construction and operation of the Brown Solar generating station?

A. The Brown Solar project has provided the Companies with the opportunity to learn about the construction, installation, operation and maintenance requirements of a solar electric generating plant. During design and construction, the Companies learned that non-utility owned solar facilities are built to a lesser standard and therefore contractors were often experienced in building these types of projects but not for a utility. There were also items that normally are not considered for the Companies' projects but needed to be considered for this type of project. For example, aluminum cables are more expensive than copper but should be evaluated on a safety and security basis. Solar plants are often secluded and are not manned 24/7 therefore are susceptible to theft. Now that the plant is in operation, the Companies are gathering data to develop forecasting models for an intermittent generating resource, cleaning requirements, and overall performance and degradation studies. It is important for planning purposes to be able to forecast generation and understand how the output will change due to variation in light intensity and if the efficiency of the plant will degrade over time.

Q. Do you have a recommendation?

A. Yes. LG&E and KU respectfully request the Commission issue orders granting certificates of public convenience and necessity for the implementation of the Distribution Automation and Advanced Meter Systems projects.

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 Chief Operating 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.

Paul W. Thompson

Paul W. Thompson

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 18th day of November 2016.

Judy Schooler (SEAL)

Notary Public

My Commission Expires:

JUDY SCHOOLER
Notary Public, State at Large, KY
My commission expires July 11, 2018
Notary ID # 512743

APPENDIX A

Paul W. Thompson

Chief Operating Officer
LG&E and KU Services Company, Louisville Gas and Electric Company,
and Kentucky Utilities 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 (2005 - 2016)
Louisville Downtown Development Corporation Board
Fund for the Arts Board
- 2017 Campaign Chair

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)

Trees Louisville
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

Exhibit PWT-1

Summary of Generating Plants

Summary of Generation Plant of LG&E and KU

Generating Facility/Unit	Unit Type	Summer Net Capacity (MW)*	LG&E Ownership %	KU Ownership %
Brown 1,2,3	Coal-fired	681	n/a	100
Brown 5	CT	130	53	47
Brown 6	CT	146	38	62
Brown 7	CT	146	38	62
Brown 8,9,10,11	CT	484	n/a	100
Brown Solar	Solar	8	39	61
Cane Run 7	CCGT	662	22	78
Cane Run 11	CT	14	100	n/a
Dix Dam 1,2,3	Hydroelectric	31.5	n/a	100
Ghent 1,2,3,4	Coal-fired	1,917	n/a	100
Haefling 1,2	CT	24	n/a	100
Mill Creek 1,2,3,4	Coal-fired	1,465	100	n/a
Ohio Falls 1-8	Hydroelectric	60	100	n/a
Paddy's Run 11, 12	CT	35	100	n/a
Paddy's Run 13	CT	147	53	47
Trimble County 1	Coal-fired	370	100[1]	n/a
Trimble County 2	Coal-fired	549	19[2]	81
Trimble County 5,6	CT	318	29	71
Trimble County 7, 8, 9, 10	CT	636	37	63
Zorn 1	CT	14	100	n/a

*Represents the net summer, 2016 capacity of all listed units. The rating for Brown solar reflects the expected output at the time of peak summer demand.

[1] LG&E owns 100% of Trimble County 1 as between LG&E and KU. However, LG&E owns only 75% of the unit's total generating capacity. The remaining 25 percent of Trimble County 1 is owned by Illinois Municipal Electric Agency ("IMEA") and Indiana Municipal Power Association ("IMPA").
[2] LG&E and KU combined own 75 percent of the generating capacity of Trimble County 2. The remaining 25 percent of Trimble County 2 is owned by IMEA and IMPA.

Exhibit PWT-2

Transmission Plan

Transmission System Improvement Plan (2017-2021)

PPL companies

November 2016

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1. Executive Summary

LG&E and KU operates the largest electric transmission system in Kentucky with 952,000 retail customers. In addition, the company serves more than 125,000 electric customers either directly or through interconnects with other smaller distribution companies (cooperatives) and municipal utility systems. The system spans more than 5,000 line miles with voltages from 69kV to 500kV.

Since the LG&E and KU merger in 1998, the transmission systems of both utilities have been jointly planned, operated and maintained in accordance with regulations and generally accepted practices within the industry. However, due to dissimilar geography, the two systems vary significantly in both design and performance. KU transmission is mostly rural, with low customer density, long circuits and more infrastructure required to serve customers. The LG&E system is more compact, with built-in redundancy and circuit ties, serving a mostly urban customer base in and around Louisville. These inherent characteristics in the two system designs drive the difference in reliability performance, with the LG&E transmission system performing in the first quartile, while the KU transmission system is in the fourth quartile among utilities as measured by annual duration of customer outages.

Because LG&E and KU infrastructure was built mostly between the 1950s and 1980s, a significant portion of the system is aging past its assumed useful life and must be replaced in order to ensure system integrity over the long term. Major weather events in 2008 and 2009 revealed an increase in duration of transmission-related customer outages across the system.

In 2010, LG&E and KU joined the newly formed North American Transmission Forum (NATF). NATF benchmarking studies against the industry indicated the LG&E and KU transmission system was experiencing a higher-than-average number of outages compared to other utilities. These findings led the company to formalize its reliability performance monitoring functions to better understand the reliability drivers with the intention of developing improvement plans. This focus uncovered that KU and LG&E have similar number of outages per mile of transmission line, but that outage restoration time at KU is longer than LG&E. The analysis also determined that the sustained outages are primarily caused by tree interference and equipment failure; while momentary outages are driven primarily by weather, but are significantly affected by tree interference and equipment failure.

LG&E and KU leadership recognizes that customer expectations are changing and understands that to keep pace, the company must increase its investment to improve reliability and maintain system integrity, while minimizing the impact on the cost to customers. The company believes that, through targeted investment, it can bring the KU transmission system to the top of the third or even the bottom of the second quartile for reliability (from the current fourth-quartile ranking), while maintaining the first-quartile performance of the LG&E transmission system.

Through a combination of carefully selected capital and O&M reliability programs, the company proposes to invest $108.3 million ($67.8 million in O&M and $40.5 million in capital) over the next five years (2017-2021) to target improving reliability performance by 3–6 SAIDI minutes (excluding major event days). The key reliability programs include enhanced vegetation management, switch maintenance and circuit sectionalizing through installation of in-line breakers and switches.

In order to ensure long-term system integrity and modernize the transmission system to avoid degradation of performance over time due to aging infrastructure, the company proposes to invest approximately $429.5 million over a five-year period (2017–2021). This investment will focus on a more aggressive replacement of critical line and substation assets and upgrades to the protection and control systems.

2. Case for Action/Performance Objectives/Strategy

2.1. Background

2.1.1. LG&E and KU System Characteristics

Kentucky Utilities Company (KU) is a regulated electric utility, based in Lexington, Kentucky, serving customers in 77 Kentucky counties and five counties in Virginia (under the name Old Dominion Power — ODP). Louisville Gas and Electric Company (LG&E) is a regulated electric and natural gas utility, based in Louisville, Kentucky, serving Louisville and 16 surrounding counties. In 1998, the utilities' operations were merged together after LG&E Energy acquired KU Energy. Today, LG&E and KU together operate the largest transmission system in Kentucky. The transmission system serves more than 952,000 retail customers, and more than 125,000 electric customers connected either directly or through interconnects with other smaller distribution companies (cooperatives) and municipal utility systems. While a large number of customers are in the Lexington and Louisville metropolitan areas, a significant portion of the line mileage of the transmission system is used to provide electrical service to the rural customer base spread across the Commonwealth. LG&E and KU service territory is provided in Figure 1.

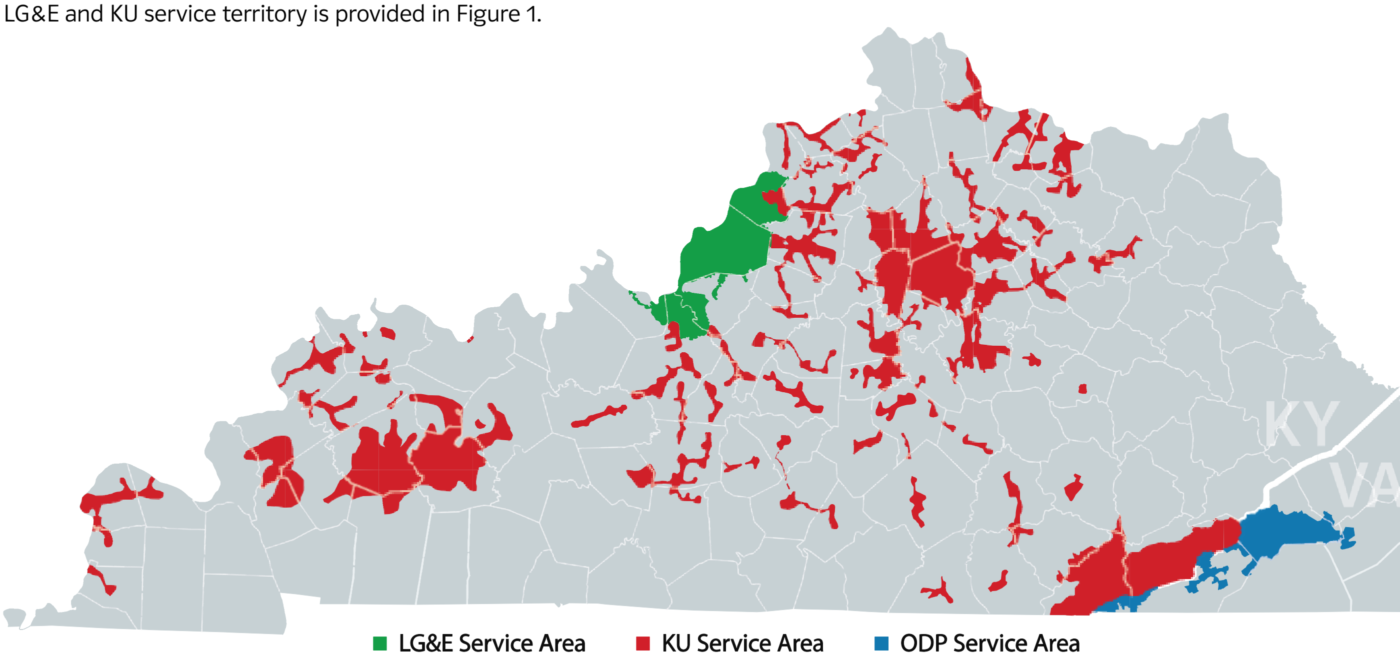

Figure 1: LG&E and KU service territory map.

Table 1 provides a summary of the key LG&E and KU transmission system characteristics and assets by operating voltage.

Table 1: LG&E and KU Transmission System Characteristics

		69kV	138kV	161kV	345kV	500kV	Total
LG&E and KU — Total	Retail Customers*	775,000	176,000	1,000	1	0	952,001
	Circuits/Line Segments	248	134	31	43	2	458
	OH Circuit Miles	2,755	1,344	646	674	57	5,476
	UG Line Miles	6	5	0	0	0	11
	Substations (high end voltage)	57	60	32	18	2	169
	Transformers	0	81	32	22	2	137
	Circuit Breakers	642	417	81	95	3	1,238
	Poles/Structures	29,000	8,700	3,600	2,700	200	44,200
KU System	Retail Customers	505,000	41,000	1,000	1	0	547,001
	Circuits/Line Segments	178	70	29	16	2	295
	OH Circuit Miles	2,468	1,009	530	499	57	4,563
	UG Line Miles	3	1	0	0	0	4
	Substations (high end voltage)	43	40	31	9	2	125
	Transformers	0	54	31	9	2	96
	Circuit Breakers	476	213	80	43	3	815
	Poles/Structures	24,200	6,300	3,200	2,100	200	36,000
LG&E System	Retail Customers	270,000	135,000	0	0	0	405,000
	Circuits/Line Segments	70	64	2	27	0	163
	OH Circuit Miles	287	335	116	175	0	913
	UG Line Miles	3	4	0	0	0	7
	Substations (high end voltage)	14	20	1	9	0	44
	Transformers	0	27	1	13	0	41
	Circuit Breakers	166	204	1	52	0	423
	Poles/Structures	4,800	2,400	400	600	0	8,200

* Count of retail customers either served directly at the designated voltage or by a distribution substation connected to that voltage.

Table 1: LG&E and KU transmission system characteristics.

Prior to the LG&E and KU merger in 1998, each transmission system was planned, designed, operated and maintained in accordance with regulations and typical industry practices and in a manner that met the unique needs of its respective customers and service area.

Following the merger, LG&E and KU reorganized and integrated transmission planning, operational and maintenance processes. However, the design of each utility transmission system remained the same, and LG&E and KU continued to design and install new infrastructure in a manner compatible with legacy systems.

2.1.2. Age of Transmission Infrastructure

Based on available asset information, the company has analyzed the age and condition of its transmission assets. As can be seen in Figure 2, and in line with other utilities, a large portion of LG&E and KU's assets were installed between 1950 and 1980, with significant portions constructed prior to 1950 still in service.

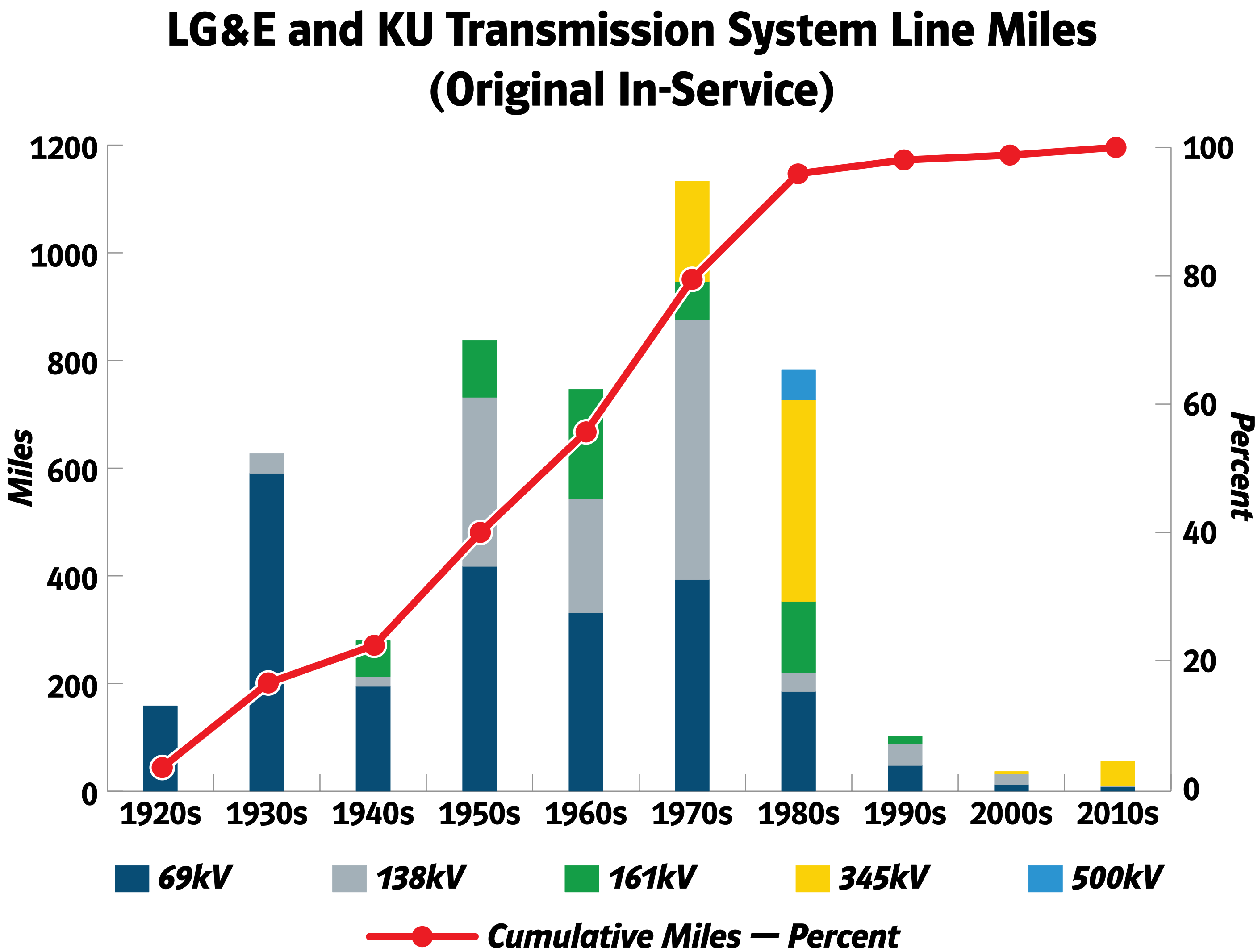

Figure 2: Transmission line miles added by voltage (1920 through 2010).

While the majority of the oldest (pre-1950) circuit breakers, transformers, protection systems and wood structures have since been replaced, a significant portion of the conductors, steel structures and insulators in the system are original. Most of the major equipment and protection systems in service today were installed between 1945 and 1990. As a result, many of these assets are reaching the end of their useful life, which would increase the number of failures and degrade system performance going forward unless they are replaced.

2.1.3. Transmission System Reliability

Catastrophic, in-service failures of key assets (e.g., transformers, switches, underground cable) present public and employee safety risks, and negatively impact customer reliability. Beyond direct customer impacts, such failures can increase system risk by reducing available system capacity, which in turn increases the probability for customer outages. Lastly, assets that fail while in-service are often more expensive to replace (as compared to proactive replacement) and can damage other assets and equipment in the immediate proximity.

Historically, both LG&E and KU transmission systems provided reliable service at a reasonable cost with total spending (capital and O&M) per line mile among the lowest of FERC regulated utilities in the country. Figure 3 provides a comparison of LG&E and KU transmission total spending (capital and O&M) costs per mile against other utilities based on FERC Form 1 data from 2011 through 2015. Similar analysis of total transmission spending (capital and O&M) per MWh (see Figure 4) indicates that LG&E and KU had the lowest cost among regulated utilities in the same period of time.

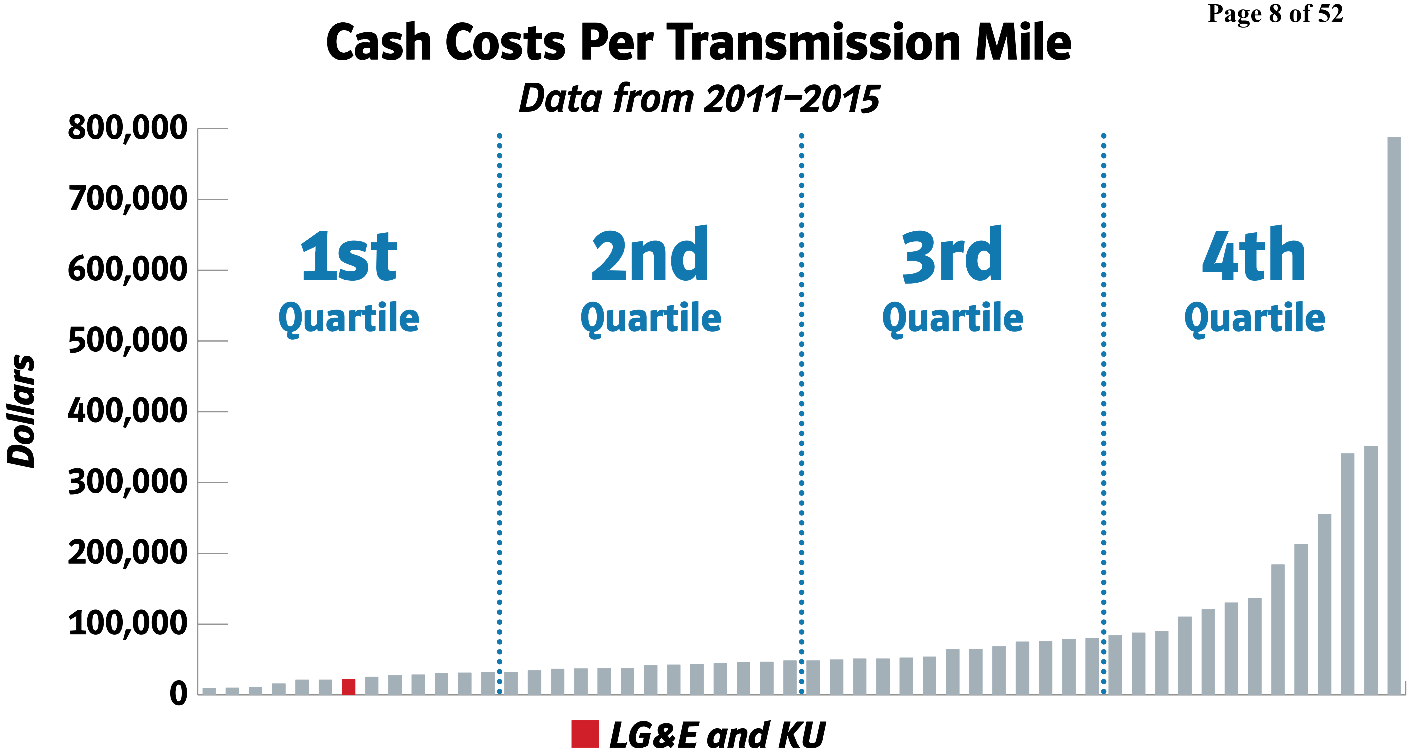

Figure 3: Industry comparison of LG&E and KU transmission total spending per mile (2011–2015).

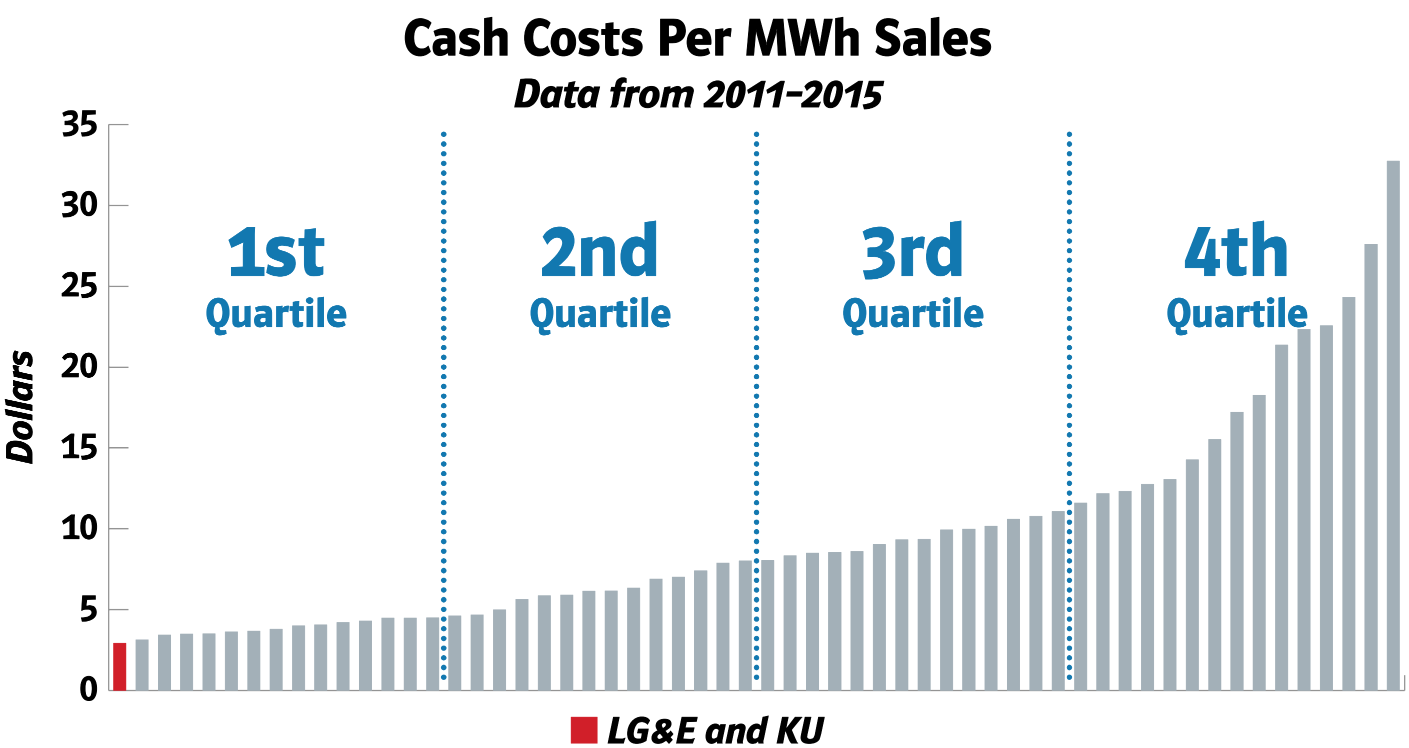

Figure 4: Industry comparison of LG&E and KU transmission total spending per MWh (2011–2015).

Over a six-month period, from September 2008 through January 2009, LG&E and KU's transmission and distribution systems were impacted by two significant weather systems and experienced the two largest outage events in the company's history. The September 2008 outage was caused by the remnants of Hurricane Ike that generated high-speed winds, which toppled trees into lines and knocked down transmission poles and structures. The Ice Storm of 2009 produced excessive ice loading on trees, structures and conductors and was particularly damaging to the transmission system. Both events required extensive efforts and support from neighboring utilities to restore service to customers. Subsequent to these events, the company began to notice increasing trends in transmission SAIDI (System Average Interruption Duration Index) performance as can be seen in Figure 5.

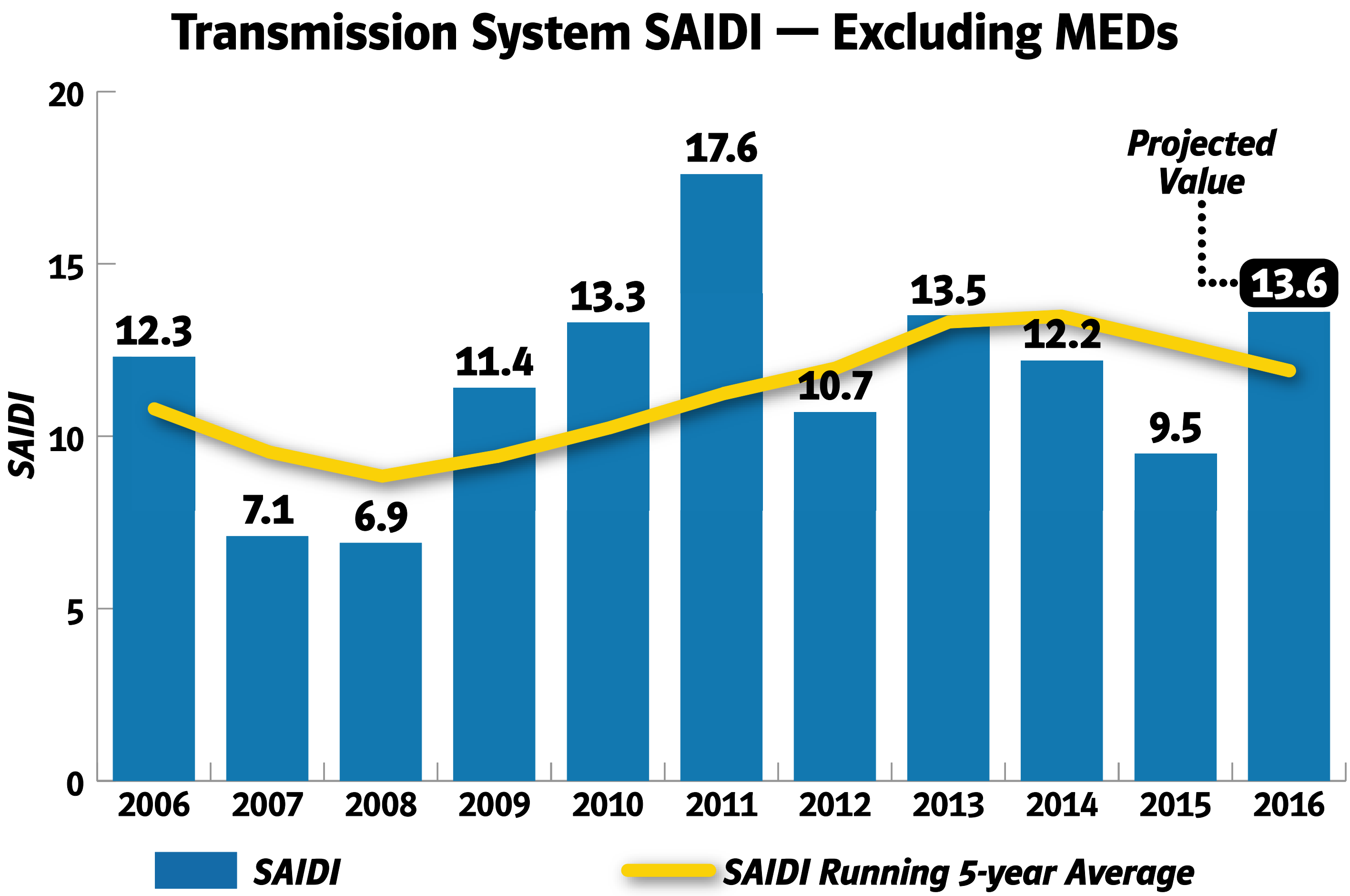

Figure 5: LG&E and KU transmission SAIDI performance (2006–2016).

SAIDI is a standard industry measure that indicates how long, expressed in number of minutes, an average customer has been out of service during a predefined period of time (most often in a year). This index is used to compare reliability performance across different utilities. In order to normalize reliability performance and account for differences across utilities (e.g., size and geography), the industry developed a standard methodology (IEEE 1366 2.5 β) which uses log standard deviation to establish a major event threshold for each utility in terms of SAIDI minutes. The threshold is unique to each utility, based on its SAIDI performance from the prior five years, but serves to normalize the data consistently across varying geographies, and major event frequencies and intensities experienced by each utility. Major Event Days (MEDs) that meet this data-driven threshold are removed to normalize the reliability performance so that "normal" performance is less skewed by unusual events.

In evaluating the annual SAIDI value excluding MEDs for the past 10 years, LG&E and KU has identified a slight upward trend, especially since 2008, when SAIDI has risen to the highest historical levels. The recent leveling in reliability performance (2012–2015) is mostly attributable to the lower number of moderate weather events below the IEEE 1366 normalization threshold and the decrease in the number of planned outages. The company believes that the general trend of increased SAIDI (deteriorated reliability) on the transmission system will not provide the level of service that customers require.

In April 2010, LG&E and KU joined the newly formed North American Transmission Forum (NATF). The NATF is a group of transmission owners and operators that had been operating as part of the North American Electric Reliability Corporation (NERC) since 2006 before becoming independent. NATF's purpose is to promote transmission reliability excellence through efforts by its members to help one another identify and correct problems in the areas of operating experience, physical and cyber security, and human performance through continuous improvement techniques.

Through discussions with peer utilities at NATF and other industry forums, LG&E and KU identified the need to improve its data reporting quality and accuracy of reliability information for transmission-related outages. To achieve this goal, the company created a department to formalize the reliability monitoring function, responsible for investigating each outage and gathering, analyzing and reporting transmission reliability performance data including root causes.

The data gathered through this process allows LG&E and KU to identify and analyze the underlying causes of outages in order to better understand reliability performance. For example, the company has been able to positively identify the cause of a greater percentage of sustained and momentary outages, decreasing the number of outages with unknown cause codes. As Figure 6 depicts, unknown outages have decreased from 58% of all outages in 2010 to 22% in 2015. Having an accurate cause code provides the necessary information to understand the underlying conditions that need to be addressed in order to reduce the frequency and duration of outages.

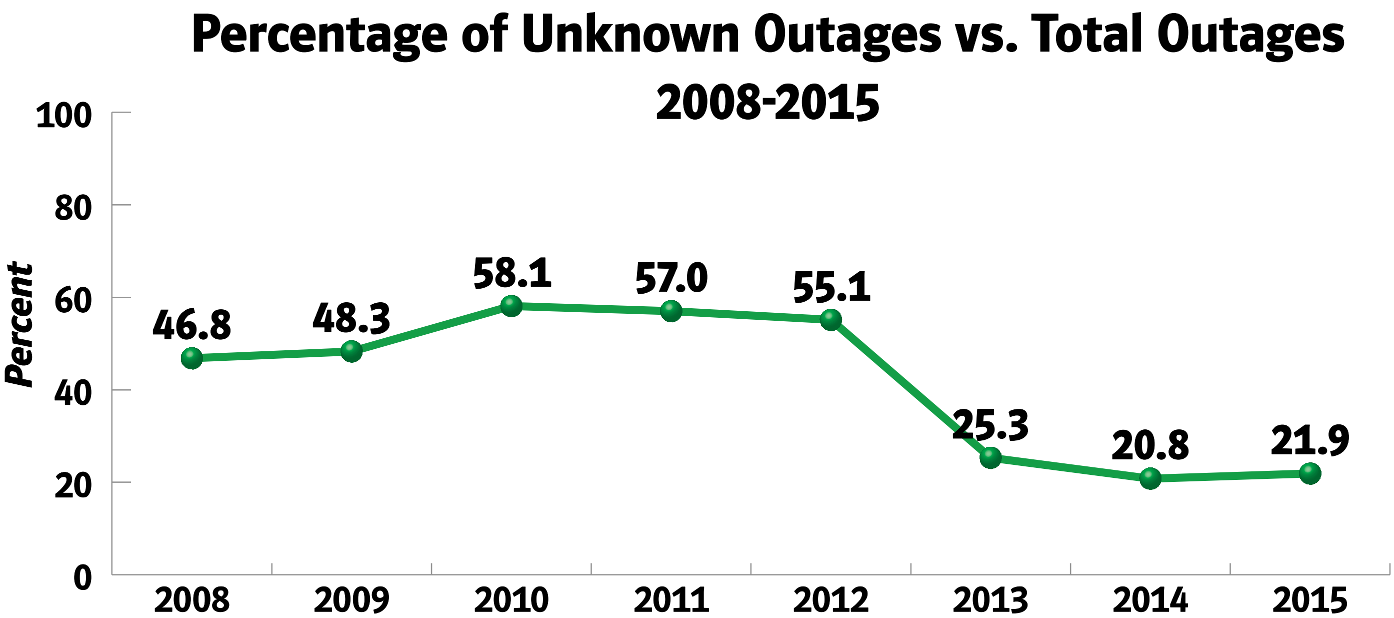

Figure 6: Percentage of unknown outages vs. total outages (2008-2015)

Customers cannot distinguish between outages on the transmission or distribution system. Transmission outages generally result in far fewer interruptions of service to customers than those that occur on the lower voltage distribution lines. However, the impact of transmission outages can be significant as they generally involve larger numbers of customers over a significant area.

2.1.4. Reliability Performance Industry Benchmarks

Joining the NATF provided the platform to compare transmission system reliability to peers at a detailed level on a more normalized basis. Specifically, in the NATF benchmark study comparing the number of sustained and momentary outages in 2011 and 2012, LG&E and KU[1] was in the fourth quartile for total system performance when compared to other transmission utilities across North America. This meant that the LG&E and KU transmission system experienced relatively more outages per mile of transmission line compared to most other utilities. REDACTED Pursuant to Third-Party Nondisclosure Agreement [redacted]

Figures 7–9 show that transmission SAIDI performance for the combined utilities is higher than average in benchmarking studies primarily driven by the number and duration of sustained outages on the KU transmission system. By contrast, the LG&E transmission system performs very well on this metric with first or second quartile performance in these years.

1. NATF Benchmarking study is conducted at the combined LG&E and KU level and it is not broken up by individual companies (LG&E vs. KU).

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2.1.5. LG&E and KU Transmission System Design

In order to better understand the differences between the KU and LG&E systems, it is helpful to compare outages per hundred miles (OHMY) on the KU and LG&E transmission systems. OHMY is calculated by dividing the total number of transmission outages, of any duration not normalized for weather, by the total transmission line miles, and then multiplying the result by 100. It provides a measure of the outage incident rate for every 100 miles of transmission line. OHMY is used by the NATF to help utilities compare outages across different transmission utilities to measure relative differences in performance. Based on this measure, as presented in Table 2, KU has averaged 10.21 outages per hundred miles compared to 12.01 for LG&E. Therefore, KU's per mile outage rate is slightly lower than LG&E's for the period 2008 thru June 30, 2016.

Table 2: LG&E and KU Outages by Hundred Miles of Lines (2008–2016)

Company	2008	2009	2010	2011	2012	2013	2014	2015	2016*	Average
KU	10.16	12.29	8.56	11.38	10.58	9.45	9.54	10.49	4.36	10.21
LG&E	9.70	14.33	14.11	11.96	13.03	8.62	14.43	11.31	4.63	12.01

*2016 thru June 30, 2016

Table 2: LG&E and KU Outages by Hundred Miles of Lines (2008-2016)

The OHMY metric demonstrates that KU and LG&E systems perform similarly based on the number of outages that they experience. However, when outage duration (SAIDI) is considered, KU's transmission SAIDI from 2009 through 2015 is about six times higher than LG&E's performance. This means that on an annual basis, KU customers experience longer transmission-related outages than LG&E's customers. While operations and maintenance programs are practically identical for the two transmission systems, the reason for the difference is in the legacy system design that was constructed to serve rural KU customers versus the LG&E design serving a more concentrated urban transmission load. Since LG&E serves the city of Louisville and surrounding counties, its service territory is more compact, allowing for a design that uses more redundancy through circuit ties to provide backup in case of an outage. Figure 10 demonstrates the typical design of the LG&E transmission system at the point of serving customers (Load A and Load B represent transmission customer connections). In the LG&E system, when a sustained outage occurs on a line between two substations, circuit

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8. 2016 value is projected based on year-to-date SAIDI performance as of 6/30/2016.

breakers isolate the fault and customers continue to receive power from redundant sources. In some cases, where circuit breakers are not practical, remotely controlled switches are sometimes used to isolate faults and/or quickly restore service from alternate sources.

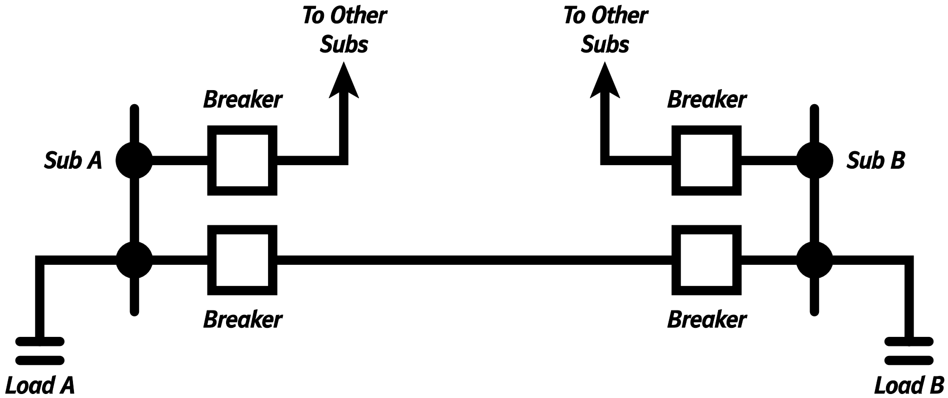

Figure 10: Typical LG&E transmission system circuit design.

The KU service territory is primarily rural, with low customer density and diverse geography, including mountainous areas, requiring longer circuits and more infrastructure per customer than in the LG&E territory. In many of the remote areas, the communications needed to allow for remote control of switches and circuit breakers at the time the system was constructed, was expensive and therefore very limited, or non-existent. Instead of a relatively few, large substations to serve customers, KU has built a large number of relatively small substations which are connected to the electric grid primarily through the 69kV transmission system.

As a result, most of the KU circuits to customer-serving substations are radial construction, meaning that equipment used to serve customers is directly connected to the transmission lines. An outage that occurs on the line between two circuit breakers interrupts service to all of the customers on that line until the service personnel can locate the problem, isolate or repair it and return service to customers. Figure 11 highlights this example of the typical design of the KU transmission system.

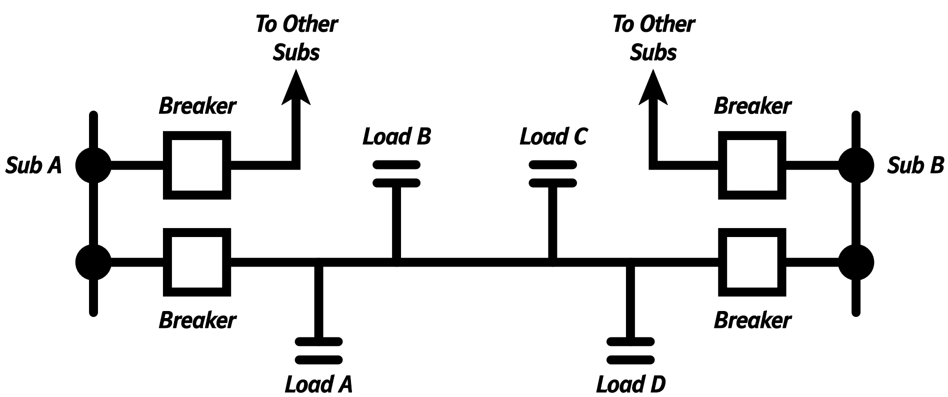

Figure 11: Typical KU transmission system circuit design.

Given these inherent differences in system design, the two systems perform differently from a customer reliability perspective, especially considering outage duration. The level of investment required to rebuild the KU system to resemble the LG&E system design is cost prohibitive (estimated to be in excess of $1 billion). Nevertheless, targeted investment and better availability and reliability of communications technology would allow noticeable improvement of KU system performance at a reasonable cost without a total system redesign. For example, installing remote switching equipment would improve restoration times, and where possible, deploying circuit breakers to shorten the length of long lines serving a large number of customers would decrease exposure to outages. LG&E and KU believe that through a targeted investment program, the company can, in a cost effective manner, significantly improve the SAIDI performance of the KU transmission system, and bring it to the second or third quartile among benchmarked utilities, while maintaining the first-quartile performance of the LG&E system. This investment program is presented in this paper and provides a reasonable approach to improve reliability to the company's customers.

While reducing restoration times will significantly improve SAIDI performance over time, it is also important to address the causes of outages and to minimize outages across both LG&E and KU. Large industrial customers directly served from the transmission system can be significantly impacted by both sustained and momentary interruptions. In order to eliminate outages, it is important to understand their root causes. This provides the basis for developing investment and maintenance programs to address the primary drivers of sustained and momentary outages which can be observed in Figures 12 and 13.

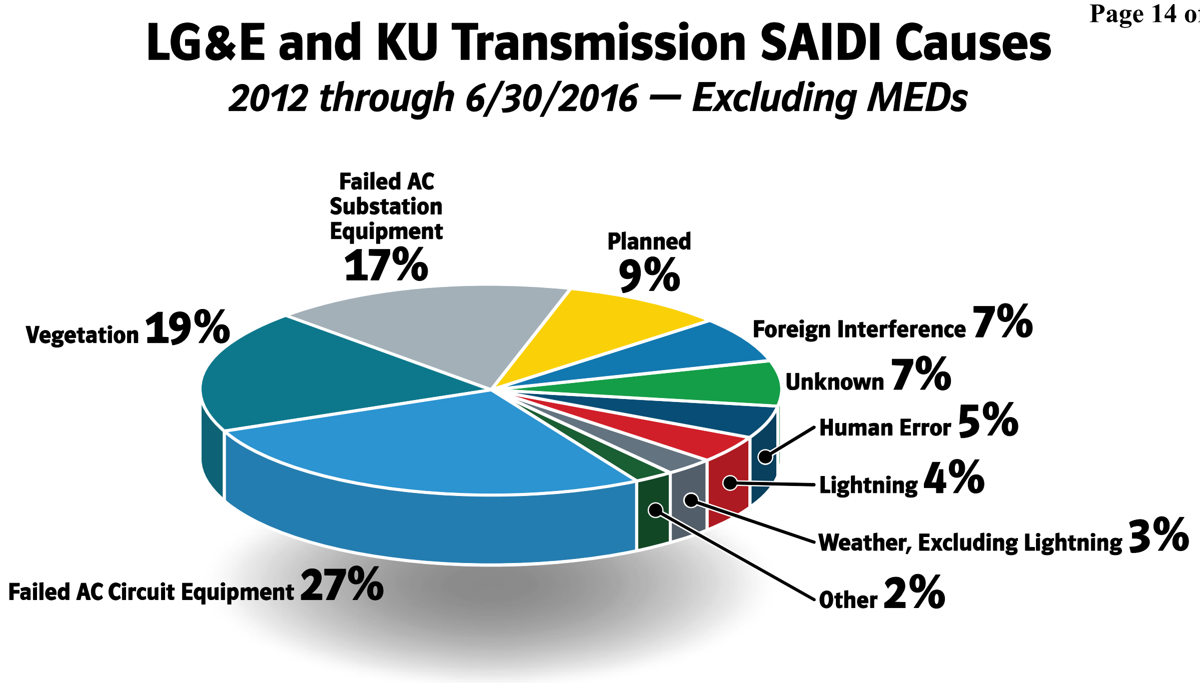

Figure 12: LG&E and KU transmission causes of outages by contribution to SAIDI excluding MEDs (2012-mid-2016).

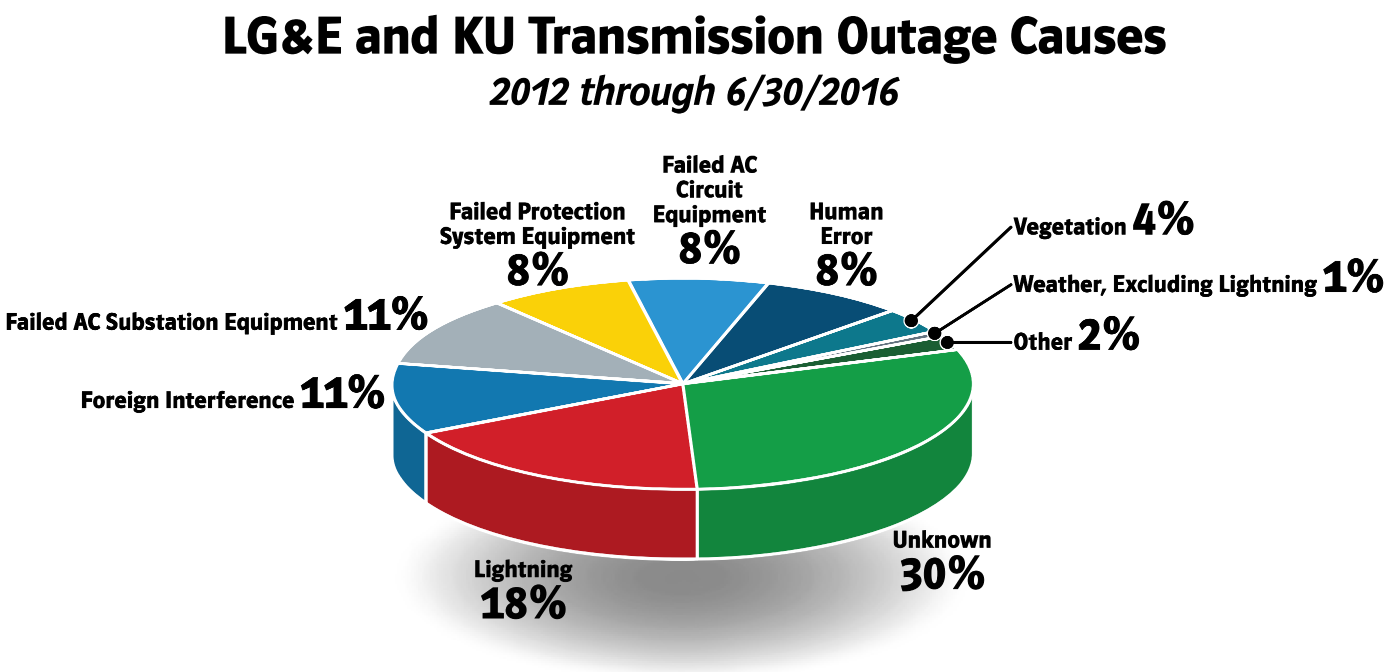

Figure 13: LG&E and KU transmission causes of outages (2012-mid 2016).

The charts in Figures 12 and 13 demonstrate that failed substation and line equipment and vegetation are the primary drivers of both outages and outage duration (SAIDI). It is important to note that often times, the cause of momentary outages cannot be determined, because they are typically caused by transient faults and the evidence is not easily determined after the fact. Based on company experience and field observations, the majority of "unknown" outages on the lower voltage lines (i.e., 69kV) appear to be caused by blowing trees and limbs that make contact with the energized conductors long enough to cause an outage. To address these outage causes and ultimately reduce the total number of momentary and sustained interruptions, the company seeks to enhance its existing vegetation clearing programs and to invest in proactive replacement of aging assets that are nearing the end of serviceable life and show deteriorated condition through inspections and analysis.

2.2. Initial Reliability Improvement Objectives and Steps

LG&E and KU's long-term goal (15-20 years) is to be in the first quartile of transmission reliability performance among its peers. As indicated above, the investment required to rebuild the KU transmission system similar to LG&E's is estimated at more than $1 billion.

Accordingly, in order to balance improvement with the cost of providing power to customers, LG&E and KU initially set a medium-term (5–10 years) objective to move the combined companies into the second quartile based on SAIDI performance among peer utilities.[9]

Using the results of the benchmark studies and the initial reliability analysis (see example of the cause code based breakdown of reliability in Figures 12 and 13), the company identified a set of the improvement initiatives, which included the following:

- join and actively participate in the North American Transmission Forum and provide data necessary to allow comparison of system performance with other utilities;
- design and implement an outage investigation process to ensure accuracy of the data;
- focus on researching and identifying root cause of outages, thus reducing the number of outages with unknown cause code;
- develop supporting tools and reporting for reliability analysis and outage investigations;
- reduce planned outages by performing more maintenance work while the circuits are energized, while ensuring that safety is not compromised; and
- improve reliability performance of an initial set of transmission circuits with significant contribution to past SAIDI performance.

In addition to the reliability improvement programs, LG&E and KU has increased spending on the inspection and replacement program targeting wood poles and structures, cross arms, insulators and other transmission assets.

2.3. Case for Change

Customers increasingly expect safe and reliable service due to their increasing dependency on an economy and society supported by electrical power. Increased reliance on mobile devices, participation in online commerce, and more people telecommuting or working from home all require uninterrupted electricity supply. LG&E and KU's leadership believes that the reliability performance must improve to meet increasing customer expectations, continue to serve and attract businesses and support the growth of the economy within its service territory. The most important driver of overall LG&E and KU customer satisfaction according to the Bellomy Research survey[10] is power quality and reliability (approximately 32% of the weight).

Specifically, the company's leadership has set a goal of maintaining first quartile performance on the LG&E transmission system, while moving the KU transmission system performance into second quartile over the next 5-10 years with the long term objective of becoming a first quartile performer. As other peer utilities also improve their performance, the SAIDI values for the second and first quartile performance will likely continue to decrease (get better) requiring LG&E and KU to further improve reliability performance. LG&E and KU leadership has established expectations for reliability improvement that are discussed in section 2.5.

In addition to improving reliability performance, LG&E and KU must address the risks associated with equipment failures due to aging assets. Over the past several years, the company has experienced several major equipment failures that have resulted in extended customer outages, expensive repairs, and environmental clean-up costs. In one instance, an older vintage coupling capacitor (a device needed to facilitate communications between substations for control purposes) catastrophically failed, resulting in extended customer outages, repair and clean up. In 2013, a 50-year-old breaker (installed in 1963) failed in service, resulting in an oil spill that cost $1.2 million to clean up. The picture in Figure 14 was taken following that outage.

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10. Since January 2010, Bellomy Research, Inc. has conducted and analyzed customer satisfaction research for residential customers of LG&E and KU and a peer group of 6 competitive investor-owned utilities in surrounding areas from Iowa to Georgia.

Figure 14: Example of a failed circuit breaker with oil release.

Despite the company's comprehensive inspection and maintenance programs, these types of failures occur, often without warning, as transmission equipment ages and experiences wear and tear. With the aging of infrastructure and key assets, the company believes that it has to develop, fund and implement asset renewal programs in order to minimize the number of asset failures in the future, improve reliability and reduce the risk to public and employee safety.

2.4. Recent Investments into System Improvement

In 2015 and 2016, LG&E and KU increased investment for several existing programs to improve reliability and replace underperforming, obsolete, and aging assets, including:

- wood structure and related equipment replacement programs investment doubled from 2014 levels;
- breaker replacement program increased significantly over 2014;
- protective relays, remote terminal units (RTU) and control house replacement programs significantly increased.

In addition to these asset replacements, LG&E and KU increased its capital investment in-line breaker installations on its worst performing lines to reduce the load exposure to line failures, and in remotely controlled switches to improve restoration times when an outage occurs, both of which are designed to improve system reliability.

Table 3 provides a summary of the incremental spending on the programs described above in 2015 and 2016.

Table 3: LG&E and KU Transmission Recent Capital Investments (MM USD)

		2014	2015	2016 (Projected)
Asset Replacement:	Wood Structures/Insulators/Cross Arms/Shield Wire	$18.0	$33.9	$44.2
	Circuit Breakers	$1.5	$5.0	$4.5
	Control Houses/Relays/RTUs	$2.5	$5.8	$7.0
Reliability:	Circuit Breakers	—	$3.2	$0.3
	Switches	—	$0.1	$1.7
	Protection and controls	—	—	$0.6

Table 3: LG&E and KU Transmission Recent Capital Investments (in millions of USD)

Since 2014,[11] LG&E and KU have replaced more than 1,400 wood poles, 250 defective cross arms, 450 insulators, 30 miles of shield wire, 75 circuit breakers, 60 relay panels, 35 remote terminal units, and 4 control houses.

Additionally, over this same time period, LG&E and KU improved reliability of 9 line segments by adding 3 breakers and 7 switches, reducing customer exposure to outages.

11. Based on projections for end of year 2016.

2.5. Performance Objectives

LG&E and KU leadership has set the goal to improve the overall transmission SAIDI performance excluding major outages by approximately 20-45% (3-6 minutes of SAIDI reduction) over the next 5-10 years. In order to achieve this goal, the number of outages must decline over this time period. The target level performance would most likely move the combined company into the second quartile SAIDI performance among its peers. The graph in Figure 15 depicts the overall projected improvement trend over that period of time.

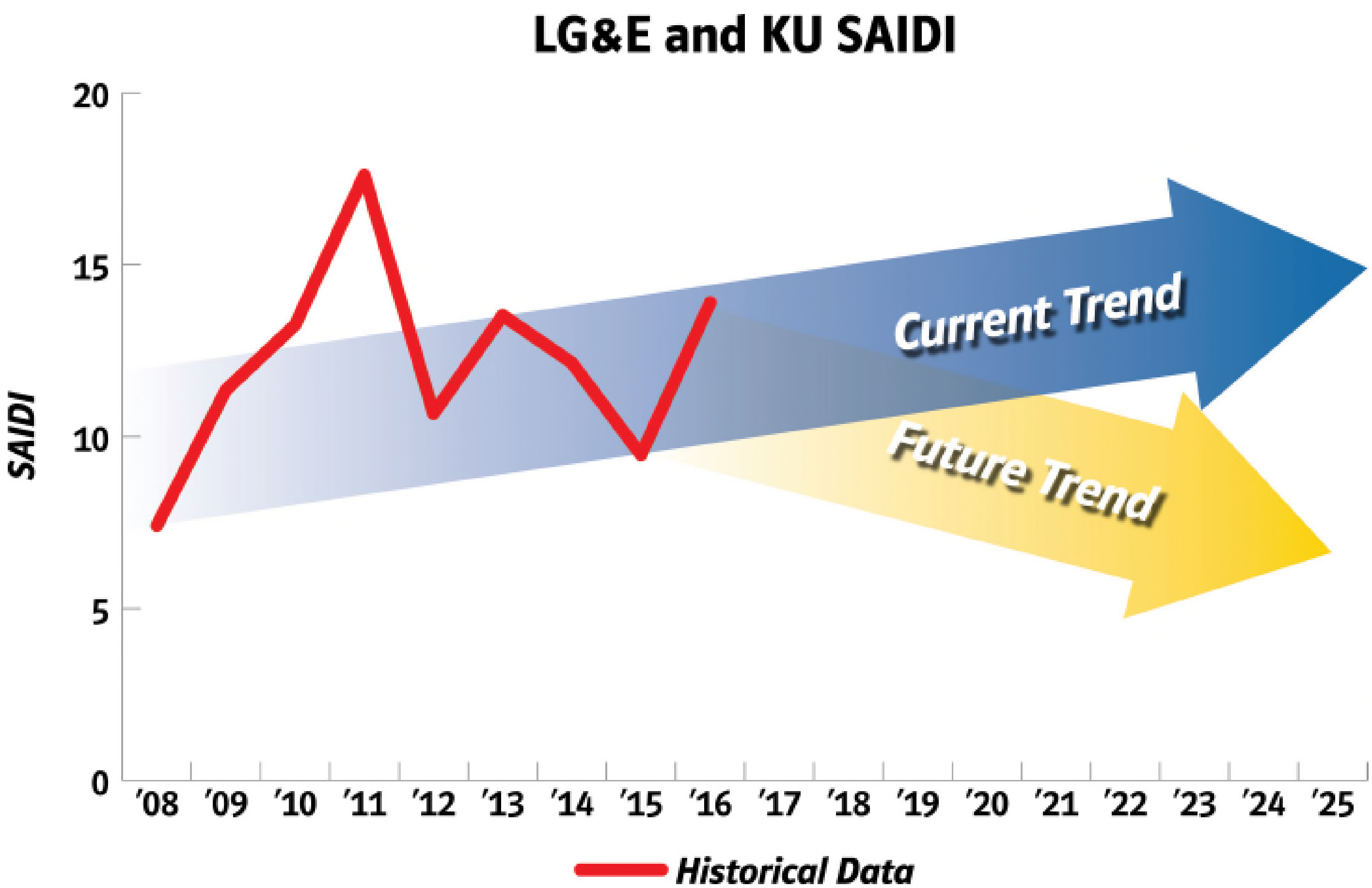


Figure 15: Projected 10-year LG&E and KU transmission SAIDI improvement trend.

In addition to the reliability targets, LG&E and KU plans to accelerate asset renewal programs so that the oldest assets within the asset class are younger than the expected useful age for that specific asset class. For example, if the expected life of a circuit breaker is 60 years, the company wants to minimize the population of circuit breakers on its system that are older than 60 years. However, age is not the only criteria as replacements will be prioritized on other factors such as condition, technical obsolescence, performance and consequence of failure. The company is targeting the following asset classes for replacement:

- wood structures and cross arms;
- insulators;
- overhead conductor and underground cable;
- shield wire;
- circuit breakers;
- control houses and related components: batteries, remote terminal units (RTU), digital fault recorders and protective relay panels; and
- coupling capacitors and instrument transformers.

3. Investment Selection Methodology

The focus of the increased investment is to improve and maintain high customer satisfaction by reducing the number of outages (sustained and momentary) over time and to significantly improve restoration time for sustained outages through a combination of O&M and capital programs. Without a focused investment in infrastructure replacement, the transmission system performance and reliability will deteriorate over time as the assets continue to age. In order to ensure system integrity and reliability in the future, a proactive approach to assessing the condition of and replacing critical transmission assets is needed.

The selection of the specific programs was based on the historical reliability performance and available asset failure data, as well as industry experience in managing specific asset classes.

3.1.Reliability Program Selection

LG&E and KU identified reliability enhancement programs based on historic reliability performance. The reliability performance team tracks the worst performing transmission circuits and analyzes the specific causes of failures on those circuits. Based on this research, the LG&E and KU transmission team identified specific reliability programs, such as enhanced vegetation clearing, switch maintenance, line sectionalizing and backbone protection, to best address these performance issues. LG&E and KU estimated the costs associated with each program based on experience or direct estimates from the vendors who would perform the maintenance or construction work.

In order to better understand the cost-benefit of alternatives and develop the most cost-effective approach to vegetation management challenges, the company retained Environmental Consultants Inc. (ECI).[12] ECI conducted a comprehensive assessment of the company's existing vegetation management program and costs, and made recommendations to enhance program management, reliability and cost effectiveness, to bring it in line with industry best practices.

3.2. System Integrity Program Selection

LG&E and KU selected system integrity programs based on the condition, technical obsolescence, age, and consequence of failure of the various assets within the transmission system. The company inspects and maintains assets (such as transformers) on a regular basis, and uses available diagnostics to determine the condition and replace or repair them before they deteriorate to the point of failure. However, condition data for other assets is not as readily available, so LG&E and KU uses asset age as well as historical performance and experience to estimate the condition of that asset. The company has developed a proactive targeted replacement program to reduce the average age of all assets and to replace poorly performing assets. As with the rest of the proposed programs, the costs associated with asset replacement were estimated based on historical experience.

Table 4 indicates which outage causes are addressed by the selected reliability and asset renewal programs.

12. ECI is a leading utility vegetation management consulting company and has been providing services to the industry for over 40 years.

Table 4: Programs for Targeted Causes of Outages (2012 thru mid-2016)				
Cause Code	SAIDI including MEDs	SAIDI excluding MEDs	Number of Outages*	Targeted Programs
Vegetation	15.92	10.44	102	Enhanced vegetation management, line sectionalization
Failed Pole/Structure/Tower	7.74	3.44	27	Pole replacement program, line sectionalization
Failed Breaker	5.81	4.34	105	Breaker replacement program
Unknown	5.78	3.37	555	Enhanced vegetation management, line sectionalization
Failed Insulator	5.10	4.13	76	Insulator replacement, pole replacement, line sectionalization
Planned	5.08	4.92	88	Revised work practices
Lightning	4.94	2.06	424	Overhead line replacement, line arrestor replacement, line sectionalization
Wind	4.04	1.24	14	Enhanced vegetation management, line sectionalization
Foreign Interference	3.85	3.10	246	Line sectionalization
Failed Conductor	3.51	2.17	34	Detailed line inspections, overhead line replacements, enhanced vegetation management, line sectionalization
Failed Shield Wire	3.09	1.90	34	Detailed line inspections, overhead line replacements, line sectionalization
Failed Cross Arm	2.64	2.64	29	Detailed line inspections, defective equipment replacement, line sectionalization
Failed CCVT/ Coupling Capacitor	1.41	1.41	13	Coupling capacitor replacements, line sectionalization
Failed Arrester	1.02	1.02	18	Replace line arresters, line sectionalization
Failed Substation Equipment (other)	0.54	0.54	31	Substation asset replacement (e.g., switches, insulators, coupling capacitors)

*Includes both momentary and sustained outages.

Table 4: Proposed programs for targeted causes of outages (2012-mid 2016).

4. Overview of Proposed Projects

4.1. Reliability Projects/Programs

4.1.1. Overview

Transmission reliability improvement is focused on enhancing customer experience by minimizing outages and the duration of those outages when they occur. The key program areas that LG&E and KU will focus on are reduction of vegetation as a cause of outages and minimizing the impact of outages through sectionalizing. Vegetation line clearance will be transitioned to a five-year cycle, and will include removal of hazard trees (those that are dead, dying, or diseased and at risk of falling into a line) and problem species, as well as applying maintenance spraying where feasible. Switches will be maintained for operational readiness to ensure they are a part of the solution and not a contributor to outages. Additional breakers, motor operated switches, and tap switches will be installed to break up the transmission circuits into smaller segments to minimize the impact of future outages and aid in faster restoration of service to customers when a sustained outage occurs.

4.1.2. Operations and Maintenance Reliability Projects/Programs

Vegetation Management

From 2012 to mid-2016, tree related outages caused 19% of all LG&E and KU transmission system SAIDI. These outages were caused by trees falling into the lines. In the same period, the cause for approximately 30% of all sustained and momentary outages could not be determined. As discussed earlier, the company believes that a majority of these "unknown" outages are in fact caused by vegetation, in particular by limbs and trees swaying or blowing into and making temporary contact with transmission lines. Narrow corridors are especially vulnerable to these types of outages.

Over the past several years, the company's vegetation clearing practices have effectively prevented grow-in outages through just-in-time vegetation management practices. LG&E and KU currently inspects transmission lines at least three times per year to identify locations where vegetation is approaching the conductors. These locations are then prioritized and maintained to reduce the risk of an outage caused by vegetation. However, the current approach of clearing based on frequent inspections is no longer sufficient to address the risk of grow-ins or danger trees falling on lines from outside the maintained boundaries of the easement. Danger trees include those that are dead, dying or diseased, including those trees impacted by the emerald ash borer. The proposed comprehensive vegetation improvements will enable LG&E and KU to restore established right-of-ways through tree trimming, herbicide application, hazard tree patrol and removal, and an emerald ash borer program. Starting in mid-2017, the company will establish an average five-year line clearance cycle, with the first cycle completion targeted by 2022.

The proposed investment will enable sustainable and ultimately less costly right-of-way maintenance in the future. In subsequent cycles, the focus can shift to herbicide application for maintaining the majority of the right-of-ways and reduce the on-going clearance costs.

The proposed program has been developed with input from Environmental Consultants, Inc. (ECI). ECI observed routine vegetation patrols and developed an estimate of the total work load necessary to carry out the additional work.

The program will address 4,800 circuit miles below 200 kV and 700 circuit miles above 200 kV.

Total five-year cost of the program will be $64.0 million.

Line Switch Maintenance

From 2013 to mid-2016, there were 14 outages related to failed switches. Additionally, switches have, at times, created delays in restoration due to operating malfunctions. With the addition of motor operated remote controlled switches to improve restoration times, it will be crucial to maintain these switches to ensure effective operation. Line switches today are routinely inspected visually, and are operated and adjusted only on an as-needed basis. Through the line switch maintenance program, LG&E and KU will systematically inspect air break line switches and motor operators to ensure consistent functionality when needed to sectionalize the circuit and reduce the impact of an outage to customers. This program entails a thorough inspection including any necessary repairs. Every switch in the system will be visually inspected every two years. Motor operated switches will be inspected every year to ensure proper operation including integrity of batteries. In addition, each switch will be operated, adjusted, and — if needed — repaired over a six-year cycle.

This program will align LG&E and KU with industry best practice and enhance operational integrity of the transmission system.

The total five-year cost of the line switch maintenance program is $3.8 million starting in 2017.

4.1.3. Capital Improvement Reliability Projects/Programs

More than 80% of customers are served from substations connected to the company's 69kV transmission system. As described previously for KU, many of the line segments on the 69kV system have multiple distribution substations directly connected to the lines with a radial

13. Emerald ash borer (EAB), or Agrilus planipennis, is a green jewel beetle native to eastern Asia that feeds on ash species. Outside its native range, it is invasive and highly destructive to ash trees. EAB has caused a number of ash trees to deteriorate and ultimately fall on transmission lines causing outages.

(one-way) feed to the substation. When an outage occurs on one of these sections interrupting service to customers, company personnel are typically dispatched to the area to locate the problem section, isolate through switching and then restore service to customers. This process is time consuming and can be significantly improved by reducing the average line segment length with circuit breakers and/or strategically installing remotely controlled, motor operated switches to allow for the impacted section to be isolated and many customers restored within minutes. This will also improve the time to find the damaged section and restore service to the remaining customers.

Line Sectionalization

The purpose of this program will be to install in-line breakers or switches on long lines with multiple load taps to decrease customer exposure to outages and reduce SAIDI associated with these lines. Installation of these breakers and switches will allow LG&E and KU to perform sectionalizing when there is an outage.

Priority of lines will be based on the amount of exposure (length of transmission line) and the number of customers or amount of energy demand served from each circuit, while focusing on lines with historically poor SAIDI or SAIFI performance.

Installation of automated switches, motor operated switches, and tap switches will be considered when installation of breakers is cost prohibitive. Switches will not reduce the number of outages but will reduce the overall duration (SAIDI) of those outages. Today's analysis shows that if the proposed projects and other completed improvements had been in place between 2012 and 2016, customers would likely have experienced approximately five (5) fewer minutes of SAIDI (interruption of service) annually during that period.

The total five-year line sectionalizing program cost is estimated at $40.5 million, starting in 2017.

4.1.4. Benefits and Costs

Reliability improvement projects will support both reduction in the number of customer outages (momentary and sustained) and reduction in outage duration (SAIDI), emphasizing those circuits known to cause problems and those with the highest combinations of line exposure and customer density. The reliability team at LG&E and KU has estimated that the implementation of the proposed reliability programs will improve the company's annual SAIDI performance by 3–6 minutes over the next five to ten years.

4.1.5. Costs

The five-year capital and O&M spend (2017–2021) in proposed reliability programs is expected to be $108.3 million. The breakdown in annual investment by program is provided in Table 5.

Table 5: LG&E and KU Proposed Reliability Investment (MM USD)

Reliability	2017	2018	2019	2020	2021	Total
Vegetation Management*	$9.4	$12.9	$13.7	$13.9	$14.1	$64.0
Switch Maintenance	$0.3	$0.8	$0.9	$0.9	$0.9	$3.8
Total O&M	**$9.7**	**$13.7**	**$14.6**	**$14.8**	**$15.0**	**$67.8**
Line Sectionalizing	$9.6	$9.3	$8.9	$7.0	$5.7	$40.5
Total Capital	**$9.6**	**$9.3**	**$8.9**	**$7.0**	**$5.7**	**$40.5**
Total Reliability						**$108.3**

* Vegetation Management spending includes the $21 million of incremental spending over five years for the enhanced programs, as compared to planned historical spend according to the 2015 business plan.

Table 5: LG&E and KU proposed reliability investment (in millions of USD).

4.2. System Integrity and Modernization Projects/Programs

4.2.1. Overview

Equipment failure was the cause of about 27% of all transmission system outages from 2012-mid 2016. The outages associated with these failures made up 44% of the SAIDI during that same period. In addition to causing customer outages, in-service equipment failures present public and employee safety, environmental and financial risks. System integrity and modernization projects and programs are designed to replace a comprehensive slate of poor performing, obsolete, and end-of-life assets. These programs will reduce the aggregate age of the inventory and ensure that critical assets remain serviceable to support the system. Programs are designed to remove and replace problem assets prior to failure through systematic replacement. Detailed inspections will serve as the central driver for logical and timely asset replacements. Replacement priorities will be determined through assessment of a number of conditional factors in addition to age and, when possible, replacement priorities will be determined by testing and inspections.

4.2.2. System Integrity and Modernization Projects/Programs

System integrity and modernization projects are designed to replace a wide range of poor performing, defective, and obsolete aging assets. These projects will renew the transmission system systematically over time, eliminating weak links that are beyond or close to the end of their useful lives and either known to be failure prone, difficult to maintain, adjust or operate, or discovered to be damaged or close to failure. Detail regarding each program or group of projects follow in section 5. This set of programs and projects will ensure the long-term operability of the transmission system. Near term priorities will be based on inspections, testing, asset experience and knowledge as well as potential for outages to customers.

The specific asset programs focused on system integrity and modernization will target the following asset classes.

- Defective line equipment
- Overhead lines
- Protection and Control Systems
  - Control houses
  - Relay panels
  - Remote terminal units
  - Power line carriers
  - Digital fault recorders (DFRs)
  - Battery sets
- Circuit breakers
- Underground lines
- Line switches
- Substation insulators
- Substation line arresters
- Coupling capacitors

4.2.3. Benefits and Costs

Overall, the system integrity and modernization programs and projects are vital to maintaining a reliable and a fully functional transmission system. Good stewardship of the transmission system requires that its many critical assets are maintained properly throughout their life span, inspected for proper operation and periodic adjustment, and replaced as they approach end of life or show signs for impending problems. As a group, this comprehensive set of projects and programs targets assets in a systematic and logical fashion. Individual asset replacement priorities may change over time, but will be based on the ability of the equipment to provide reliable customer service and effective system operations. Increased replacement should reduce the number of in service failures that affect public and employee safety risk and customer reliability over the long term. Inspection and replacement priorities will consider the recent reliability performance of the equipment. Properly maintained, physical assets can be employed for many years; however, mechanical and electronic equipment have a finite life. This set of programs prudently addresses the need to renew such assets in a proactive and coordinated manner.

4.2.4. Cost

The five-year capital and O&M spend (2017-2021) in proposed system integrity and modernization programs is expected to be $429.5 million. The breakdown in annual investment by program is provided Table 6.

Table 6: LG&E and KU Proposed System Integrity & Modernization Investment (MM USD)

System Integrity and Modernization	2017	2018	2019	2020	2021	Total
Replace Defective Line Equipment	$38.5	$40.8	$39.4	$36.6	$36.6	$191.9
Replace Line Switches	$1.2	$1.7	$1.8	$3.6	$3.9	$12.2
Replace Overhead Lines	$8.9	$2.9	$12.3	$18.8	$42.2	$85.1
Improve P&C Systems	$9.5	$11.8	$13.4	$14.8	$14.6	$64.1
Replace Circuit Breakers	$7.5	$8.4	$8.4	$5.3	$5.3	$34.9
Replace Underground Lines	$3.2	$10.2	$10.0	$0	$0	$23.4
Replace Subs Insulators	$2.7	$2.1	$2.1	$0.7	$0.8	$8.4
Corrosion Protection*	$0.5	$0.7	$0.9	$1.1	$1.1	$4.3
Replace Substation Line Arresters	$0.6	$0.6	$0.6	$0.6	$0.6	$3.0
Replace Coupling Capacitors	$0.6	$0.6	$0.6	$0.2	$0.2	$2.2
Total System Integrity and Modernization	**$73.2**	**$79.8**	**$89.5**	**$81.7**	**$105.3**	**$429.5**

* Corrosion protection program is an O&M expenditure.

Table 6: LG&E and KU proposed system integrity and modernization investment (in millions of USD).

The cost estimates for each program and project are based on previous similar projects and the ability to obtain outages to complete the work when scheduled. The actual costs may differ from the projections depending on the specific circumstances of each installation or replacement project.

5. Analysis of Proposed Projects

5.1. Reliability Improvement Projects

Below are details of the specific reliability programs and how they will be deployed to achieve improved reliability results.

5.1.1. Operations and Maintenance Reliability Projects/Programs

Program Title: Enhance Vegetation Management

Description: The transmission vegetation management program will transition from an inspection-driven maintenance approach to an average five-year cycle. The initial cycle will involve significant tree removal which will allow integration of herbicide applications on the majority of line segments in subsequent years. This approach will reduce costs significantly after the first cycle and over the long term. The company has already started to transition to the regular cycle for the 345kV and 500kV power lines to ensure cost effective compliance with NERC mandatory standards. The proposed plan begins the conversion for the rest of the transmission system. Figure 16 shows a transmission line easement before and after the enhanced trimming program application.

Figure 16: Before and after — example of the cleared transmission right-of-way.

The vegetation management program also includes a hazard tree patrol to assess and remove diseased or dying trees, and especially identify trees impacted by the Emerald Ash Borer (EAB) across the system. The EAB is an invasive species (see Figure 17) that has killed hundreds of millions of ash trees in North America that is now established in Kentucky and affecting ash trees throughout the Commonwealth.

Figure 17: Emerald ash borer. (Picture by David Cappaert, Michigan State University, Bugwood.org.)

Clearing efforts will be prioritized based on aerial inspection, hazard tree patrols, customer impact, and system impact. Higher voltages which can affect larger numbers of customers and radial lines will be emphasized.

Figure 18: Example of a hazard tree adjacent to a 69kV transmission line.

The five-year estimated cost of the program is $64.0 million.

Vegetation Management Program Cost (MM USD)	2017	2018	2019	2020	2021	Total
Base VM Spend	$7.2	$7.8	$8.2	$9.7	$9.9	$42.8
Incremental VM Spend	$2.2	$5.1	$5.5	$4.2	$4.2	$21.2
Total VM Spend	**$9.4**	**$12.9**	**$13.7**	**$13.9**	**$14.1**	**$64.0**

Benefits

This program will provide significant system benefits and long term assistance with managing our rights-of-way through:

- reduction in unknown momentary outages;
- reduced risk of wire damage and failure, associated outages, and public safety hazard;
- reduced SAIDI;
- improved management of vegetation growth and work;
- long-term lower cost to maintain easements and reliability;
- reduction of impacts to customers after initial cycle (more herbicide application and less clearing/removal); and
- improved system performance during weather outages.

Supporting Data

The enhanced Vegetation Management Program will reduce sustained and momentary outages. Historical data for the relevant cause codes is in the chart below. Based on company experience and field observations, the majority of "unknown" outages on the lower voltage lines (i.e., 69kV) appear to be caused by blowing trees and limbs that make contact with the energized conductors long enough to cause an outage. Enhanced tree removal programs as proposed will improve clearances, remove dead, dying and diseased trees that threaten the lines and reduce the likelihood of tree contacts. After the completion of the first full cycle, the company anticipates a 25-50% reduction in the number of vegetation-related outages.

Reliability Cause Code: Vegetation Management	2012	2013	2014	2015	2016*
Outage Counts	29	16	29	21	16
SAIDI incl. MEDs	2.57	3.12	6.56	0.88	2.85
SAIDI excl. MEDs	2.57	1.92	2.29	0.88	2.85

*2016 thru June 30, 2016.

Reliability Cause Code: Unknown	2012	2013	2014	2015	2016*
Outage Counts	329	128	117	127	51
SAIDI incl. MEDs	3.38	1.66	0.70	0.16	0.09
SAIDI excl. MEDs	1.61	1.03	0.70	0.16	0.09

*2016 thru June 30, 2016.

Program Title: Maintain Line Switches

Description

All air-break line switches (500 locations) and motor operators (40 locations) are currently visually inspected as part of routine line patrols. The proposed enhancement is to conduct detailed annual inspections of all automated and motor operated switches. This will include a voltage check on the batteries and verification of remote operation of the switch from the control center. All remaining manual switches will be subject to bi-annual comprehensive visual inspections. Additionally, all switches will be operated and aligned on a six-year cycle or as indicated through visual inspections. Crews will make minor repairs and adjustments as part of the inspection program as indicated.

All inspection cycles are within typical industry frequencies.

The five-year estimated cost of the program is $3.8 million.

Switch Maintenance Program Cost (MM USD)	2017	2018	2019	2020	2021	Total
Switch Maintenance	$0.3	$0.8	$0.9	$0.9	$0.9	$3.8

Benefits

Transmission line switches are used to isolate sections of lines in order to perform maintenance or, after an outage, to isolate the damaged section, restore service to customers and then make needed repairs. Therefore, proper line switch operation and functionality is critical for both routine operation of the system and to ensure timely restoration efforts during system outages. The proposed increase in the number of installed automated and motor operated switches necessitates a program to ensure these switches will operate properly when needed. This program will reduce the risk of equipment failure and associated system outages. In addition, the program will:

- ensure operational capability;
- reduce unplanned corrective maintenance; and
- reduce SAIDI and outages.

Supporting Data

The Switch Maintenance Program will improve restoration time and reduce outages related to switch failures. As can be seen below, SAIDI associated with switch failures has historically been low. However, there have been outages, while not frequent, in which an inoperable switch delayed service restoration. Switch maintenance, especially for motor operated switches, is important to ensure operability when needed, especially given the proposed installation of new switches throughout the service territory (discussed below).

Reliability Cause Code: Switch — Failed AC Circuit Equip.

	2012	2013	2014	2015	2016*
Outage Counts	4	0	1	4	2
SAIDI incl. MEDs	0.14	0.00	0.18	0.00	0.04
SAIDI excl. MEDs	0.14	0.00	0.18	0.00	0.04

*2016 thru June 30, 2016.

Environmental factors (e.g., weather) and frequency of switch operation can impact the alignment and functionality of line switches. Motor operated switches have batteries to ensure communications and switch operability when the power is out. These batteries must be routinely replaced so that they will operate reliably when needed. The photo in Figure 19, produced from a visual inspection, shows that the switch blade is not properly latched. While not obvious to the untrained eye, the switch contacts are not fully inserted into the jaws as compared to the same assembly on the left.

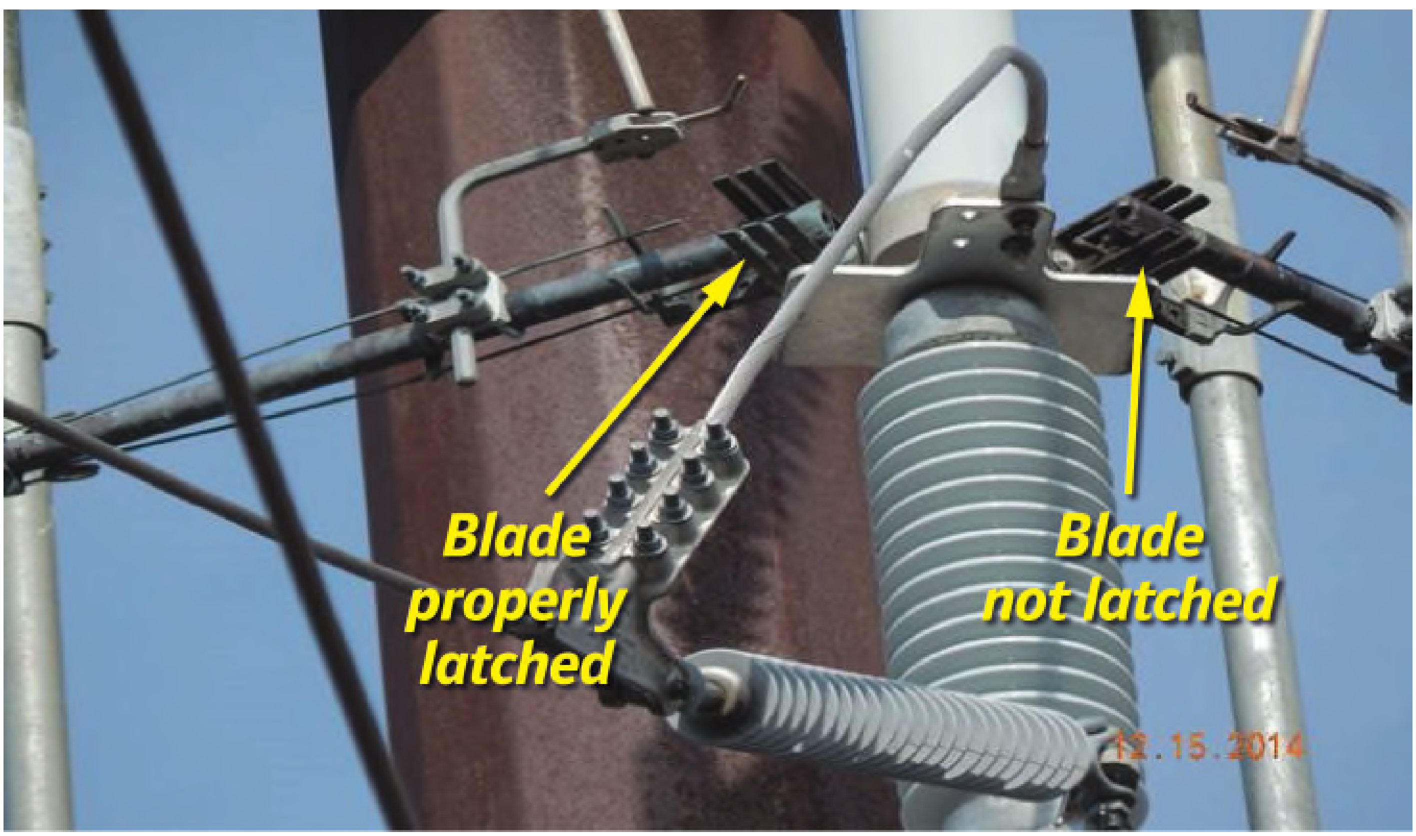


Figure 19: Example of the switch maintenance issue.

5.1.2. Capital Reliability Projects/Programs

As described in Section 2.1, the LG&E and KU transmission systems experience outages at a similar rate, with LG&E historically having slightly more outages per mile than KU. However, since the KU system has more than four times the length of transmission lines, it also has about four times as many outages in total. Built largely as a rural system, the KU transmission system connects relatively small distribution substations to the power grid through radial (one-way power feed) connections, with multiple distribution substations between circuit breakers. As a result, when an outage occurs on a transmission line, all of the distribution substations are affected. Service restoration requires service personnel to drive to switches along the line and manually isolate the damaged sections to restore service to customers. For the largely urban and customer dense LG&E transmission system, this functionality is for the most part automated with either circuit breakers or remotely controlled switches used to restore service without requiring manual operation. As a result, transmission outage durations on the LG&E system are much shorter. The work needed to upgrade the KU transmission system to provide the same level of restoration capability as LG&E's would include installation of two-way transmission feeds and associated circuit breakers and protection, control and metering devices to more than 600 distribution transformers. The cost of such an upgrade is estimated to be more than $1 billion. When originally designed and constructed, rural areas in KU's service territory did not have the telecommunication capacity and coverage found in the urban areas, so remote control was expensive or not available at all. Today, most areas are covered by some means of communications. The company proposes three programs to cost effectively improve the switching capability on the KU transmission system: (1) Install Automated Line Sectionalizing, (2) Install Motor Operated Switches, and (3) Install Tap Switches. These programs are designed to shorten the time to restore service on selected lines by installing the capability to automatically or remotely restore service to undamaged portions of transmission lines when an outage occurs. Once remote switching is complete, service personnel can be more precisely directed to the specific location of the damage to, if possible, restore additional customers through manual switching, isolate the damaged lines and make repairs.

Program Title: Install Line Sectionalizing

Program Description

The line sectionalization program will focus on installing in-line circuit breakers, automated switches, motor-operated switches (MOS) or tap switches on long lines with multiple distribution substations in order to decrease customer exposure to transmission outages. These installations will be prioritized based on historical SAIDI impacts and the number of outages that have occurred on each line. All lines with historical SAIDI of greater than 0.5 minutes between 2012 and first-quarter 2016 were candidates for sectionalization.

Constructing a circuit breaker in a transmission line effectively reduces the circuit length by creating two transmission lines segments out of one. If installed approximately in the middle of the circuit, half of the customers will avoid a service interruption during future outages (those on the undamaged side of the new breaker installation). However, depending on feasibility and cost (e.g., land acquisition or incremental transmission line and/or substation work required), circuit breaker installations can be quite expensive when compared to other options. For this reason, circuit breakers will be installed on longer lines with significant SAIDI history and significant exposure and customer count totals.

A cost-effective alternative to construction of circuit breakers is installation of an automated sectionalizing MOS. The MOS automatically opens when an outage occurs and isolates the line segment that was not directly impacted by the outage, restoring those customers served on the undamaged section of line. Customers who are restored this way will still experience a brief service interruption, but it many cases, the interruption will last a minute or less.

In locations where there is already an automated sectionalizing MOS or one is not feasible, the company will install motor operated switches, which provide a quick method for Transmission Control Center staff to remotely operate the switch and sectionalize the line to restore customers. While not providing for an automated operation, the remotely operated MOS can be deployed much faster than sending a service technician to the pole to operate a switch manually. This benefit is realized not only in rural areas, but also in urban locations where traffic light interruptions during power outages make it difficult to drive to switch locations. MOS will typically be utilized at points where distribution substations with more than 1,000 customers are directly connected to the transmission line. These installations will be prioritized based on historical reliability performance and exposure to outages.

Tap switches will be installed at locations without sectionalizing devices. They enable the company to isolate load connections from faulted sections of line and provide the ability to isolate loads during planned outages. Tap switches are installed at connection points on a single pole structure. Typically, the installation is a two-way switch that allows the load to be isolated from either side. These switches can be used during a situation where one side of the line has a fault or simply when a section of line needs isolation for maintenance work.

The five-year cost of the program is $40.5 million.

Line Sectionalization Program Cost (MM USD)	2017	2018	2019	2020	2021	Total
Install Auto Line Sectionalizing	$9.6	$9.3	$8.9	$7.0	$5.7	$40.5

Benefits

Installing additional sectionalizing devices on targeted transmission lines will:

- reduce the number of customers experiencing a sustained service interruption when an outage occurs on a transmission line; and
- significantly reduce the restoration time for those customers who are affected by the outage.

Supporting Data

Line sectionalizing minimizes the duration of customer interruptions for all outage causes that occur on a transmission line. The lines selected for the addition of circuit breakers and auto-switches have had a total SAIDI (excluding major outages) of 34 minutes from 2012 to June 30, 2016. The proposed improvements are estimated to reduce that SAIDI amount to just under 16 minutes for the same time period.

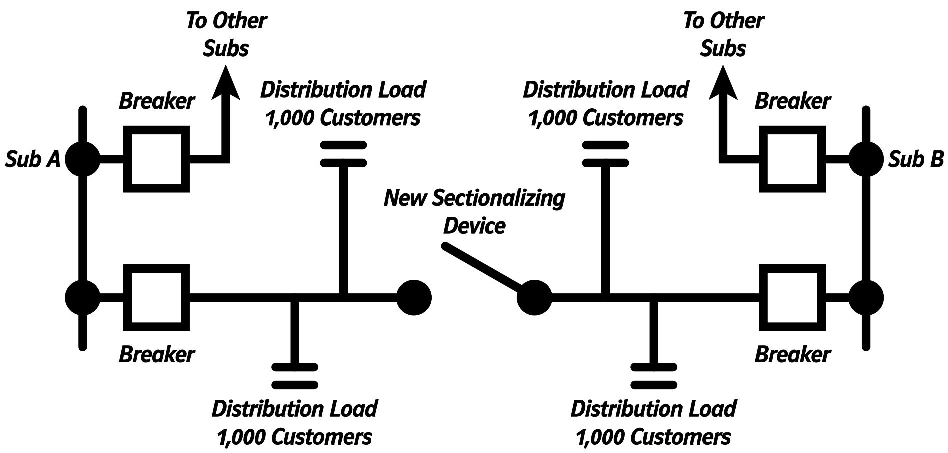


Figure 20: Example of the circuit with a new switch.

Figure 20 illustrates an example where a new sectionalizing device (a switch or a circuit breaker) is installed to reduce exposure to an outage. Prior to the device installation, a fault on this line would have interrupted 4,000 customers until service can be restored manually. With the new sectionalizing device installed, after an outage occurs this device will operate and the undamaged portion of line will be automatically restored so that only 2,000 customers experience an extended outage.

Figure 21: New circuit breaker installation inside the substation.

Figure 22 shows a recent MOS installation in the Lexington area.

Figure 22: Example of a recent MOS intallation in Lexington.

Figure 23 shows an example of a 2-way tap switch installation.

Figure 23: Example of a 2-way tap switch installed on a single phase.

5.2. System Integrity and Modernization Projects/Programs

Below are details of the many individual system integrity and modernization projects and programs that will be deployed.

5.2.1. Replace Defective Line Equipment

Description

Replace wood poles, cross-arms, and insulators identified as defective from system inspection programs. The company conducts climbing inspections to thoroughly assess the condition of its poles. The purpose of these inspections is to identify shell rot, wood checks, and woodpecker holes affecting the pole's strength. The results of the inspection are used to determine the pole's integrity and need for replacement. The initial scope of this program was developed based on historical inspection results and costs from 2013–2015. The company will complete the initial inspection cycle in 2018, and future inspections are expected to identify a lower number of assets for replacement. Development of this program will continue to be reviewed and adjusted with additional inspection results and historical costs.

The five-year cost of the program is $192 million.

Defective Line Replacement Program Cost (MM USD)	2017	2018	2019	2020	2021	Total
Replace Defective Line Equipment	$38.5	$40.8	$39.4	$36.6	$36.6	$191.9

Benefits

Proactive replacement of these assets will reduce the risk of failure and number of system outages. Additional program benefits include:

- reduction of associated outages and public safety hazards;
- reduction of emergency replacements which are costlier than planned replacements;
- reduction of outages and SAIDI with associated improvement to customer satisfaction; and
- improved durability and resiliency to better withstand severe weather.

Supporting Data

Defective equipment targeted in this program has historically had a significant impact on reliability. The following tables demonstrate this impact.

Reliability Cause Code: Cross Arm	2012	2013	2014	2015	2016*
Outage Counts	2	3	10	9	5
SAIDI incl. MEDs	0.12	0.50	0.32	1.33	0.37
SAIDI excl. MEDs	0.12	0.50	0.32	1.33	0.37

*2016 thru June 30, 2016.

Reliability Cause Code: Pole/Structure/Tower	2012	2013	2014	2015	2016*
Outage Counts	7	3	4	7	6
SAIDI incl. MEDs	4.40	0.67	1.10	1.29	0.27
SAIDI excl. MEDs	0.62	0.67	0.58	1.29	0.27

*2016 thru June 30, 2016.

Reliability Cause Code: Insulator — Failed AC Circuit Equip.	2012	2013	2014	2015	2016*
Outage Counts	4	4	12	5	10
SAIDI incl. MEDs	0.00	1.36	0.97	0.37	1.07
SAIDI excl. MEDs	0.00	1.36	0.00	0.37	1.07

*2016 thru June 30, 2016.

Figure 24: Examples of defective line equiment (deteriorated wood cross arm, damaged string of porcelain bell insulators and woodpecker damage on the pole).

Figure 25: Example of standard steel H-frame structure used to replace wood structure.

Supporting Data

Anticipated replacements for the five-year period are shown in Table 7.

Table 7: Transmission Defective Pole and Pole Equipment Replacement Schedule					
Replacements (in units)	2017	2018	2019	2020	2021
Cross Arms	200	200	150	50	50
Insulators	125	200	200	200	200
Poles	650	700	700	700	700

Table 7: Transmission defective pole and pole equipment replacement schedule.

Priorities for replacement will be based on customer impact, system impact (voltage and radial), and inspection age. Replacements are also coordinated with projects associated with the same asset or line.

5.2.2. Replace Overhead Lines

Description

Replace wires that are experiencing failure or have been identified as at risk on inspection. Many conductors are at or beyond their expected useful life, which is estimated to be 75 years, and are starting to perform poorly. Focus will be on single layer wires (copper, copper-weld, single layer ACSR) which are more prone to corrosion of the core (and subsequent failures) than multi-layer wires. There are 375 miles of such wire and 75 miles of shield wire beyond useful service life. Age, wire type, historical performance, and customer impact will determine replacement priorities. A total of 84 miles of conductor and shield wire will be replaced through this program over the next five years.

Development of this program will continue to be reviewed and adjusted with additional inspection results and historical costs. The five-year cost of this program is $85.1 million.

Overhead Line Replacement Program Cost (MM USD)	2017	2018	2019	2020	2021	Total
Replace Overhead Lines	$8.9	$2.9	$12.3	$18.8	$42.2	$85.1

Supporting Data

Replacing overhead lines will improve outages for the following cause codes.

Reliability Cause Code: Conductor	2012	2013	2014	2015	2016*
Outage Counts	5	10	8	10	1
SAIDI incl. MEDs	0.08	1.08	0.61	1.72	0.03
SAIDI excl. MEDs	0.08	1.08	0.61	0.37	0.03

*2016 thru June 30, 2016.

Reliability Cause Code: Shield Wire	2012	2013	2014	2015	2016*
Outage Counts	9	8	8	7	2
SAIDI incl. MEDs	0.80	0.49	1.65	0.04	0.11
SAIDI excl. MEDs	0.20	0.49	1.06	0.04	0.11

*2016 thru June 30, 2016.

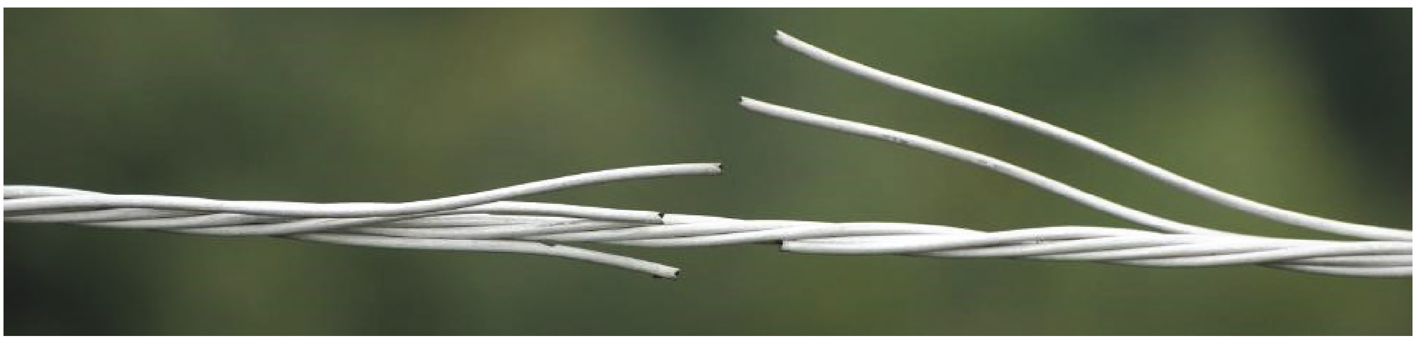


Figure 26: Example of a shield wire with broken strands.

5.2.3. Upgrade Protection and Control Systems

Protection and control (P&C) systems are used to identify power system disturbances, stop power system degradation, restore the system to a normal state, and minimize the impact of the disturbance. The P&C systems typically include relay panels, remote terminal units (RTUs), power line carriers (PLCs), digital fault recorders (DFRs) and batteries. All of these components are housed within the control house which is an enclosure inside a substation that protects these assets from external elements. The total proposed investment in P&C systems is $64.1 million over five years. The costs of each program are provided in Table 8. Each specific P&C program is described in further detail in this section.

Table 8: Total Protection & Controls Program Cost (MM USD)	2017	2018	2019	2020	2021	Total
Replace Control Houses	$3.1	$3.6	$3.5	$3.3	$4.9	$18.4
Replace Relay Panels	$1.8	$3.4	$5.1	$6.6	$5.0	$21.9
Replace RTUs	$2.9	$3.1	$3.2	$3.3	$3.2	$15.7
Replace PLCs	$0.6	$0.6	$0.6	$0.6	$0.6	$3.0
Install DFRs	$0.6	$0.6	$0.6	$0.6	$0.6	$3.0
Replace Battery Sets	$0.5	$0.5	$0.4	$0.4	$0.3	$2.1
Total P&C	$9.5	$11.8	$13.4	$14.8	$14.6	$64.1

Table 8: Proposed P&C investment (2017–2021).

Replace Control Houses

Description

The goal for this project is to replace two to four obsolete control houses each year that do not support upgraded technology and upgrade the full slate of equipment across the spectrum of protection and control projects accordingly.

Control House projects fall into two categories: blanket (e.g., control house upgrades) and uniquely identified (e.g., Finchville Control House). The blanket projects include the following items: environmental controls, batteries, AC/DC systems, control building shell, foundation, control cable and control cable trench system. This cost is estimated at $1.2 M per house. In addition to the items associated with the blanket projects, the uniquely identified projects also include relay panels, RTU, power line carriers (PLCs), and DFR (if necessary). The cost for these incremental items are included in the budget. Each individual component is to be funded through its associated program (these programs are detailed below). Many existing buildings need to be replaced based on condition, size, and outdated contents.

Figure 27: Modular control house being delivered.

Priorities for comprehensive replacement are based on the following factors.

- Age and health of the relays within the existing control house (CH)
- Age and priority of the remote terminal unit (RTU) located in the CH
- Physical condition of the control house, which is determined through inspections (ranked each CH based on overall condition)
- Age of the existing battery system

Those CHs with the most need based on these factors will receive the highest priority for replacement.

Figure 28: Example of an old control house that needs to be replaced.

Cost for the control house upgrades (CH only) is estimated to be $18.4 million, ramping up from two control houses per year in 2017 and 2018 to four per year by year five.

Control House Replacement Program Cost (MM USD)

	2017	2018	2019	2020	2021	Total
Replace Control Houses	$3.1	$3.6	$3.5	$3.3	$4.9	$18.4

In addition to the general cost estimating assumptions described in section 4.2.4 above, the projected costs for control house replacement are based on the following assumptions:

- new control house can fit within the existing footprint of the station;
- the average size of a control house is on the smaller end of the specifications;
- control house design will be outsourced;
- Transmission Engineering, Construction and Maintenance will be able to support the below-grade design and construction; and
- contract design and commissioning staff will be available.

Benefits

Replacing the control house affords a great opportunity to upgrade to modern standards all of the integrated equipment within the control house. Thus, the control house replacement project drives priorities for most of the other protection and control programs. The following benefits are expected to be achieved:

- reduced future building maintenance costs — new buildings with insulation and climate controls to ensure asset health and proper operation of the equipment contained within;
- reduced potential for mis-operations due to mechanical failure of the relays;
- improved communications to the energy management system;
- reduced O&M costs for relay testing because the test cycle can be extended from five to ten years;
- enhanced worker safety due to environmental controls and panic bars on the doors;
- improved working clearance for personnel; and
- enhanced data gathering due to new functionality of microprocessor relays and digital fault recorders.

Supporting Data

Since 2012, protection and control components have caused 200 outages, both sustained and momentary, on the transmission system. Replacement of control houses has the potential to reduce outages across all areas of impact in one project.

Outage Counts for P&C Reliablity Cause Codes		
Control House Asset	**Cause Code**	**Number of Outages**
Relay Panels	Relay/Malfunction	102
RTU, PLC	Communication Failure	66
Control House Building	AC System	17
DFR	Unknown	11
Batteries	DC System	4
	Grand Total	200

Replace Relay Panels

Description

Relays are devices that are designed to respond to abnormal system conditions. These devices use current and/or voltage measurements from the system to determine if the electrical system they are monitoring is in a normal or abnormal state. If the system is in an abnormal state, the relay issues a signal to a circuit interrupting device to open its contacts and interrupt the current flow on the system it oversees. A relay panel consists of multiple relays that oversee a specific transmission line, bus, or transformer. Many different types of relays are used on the transmission system for different functions.

The objective of this program is to replace obsolete and end of life relay panels to maintain integrity of the system protection. There are approximately 5,700 relays across the system in 1,500 panels.

Relay overreaches and mis-operations cause unneeded outages. The older units are electro-mechanical and, while still functional, are approaching end of life and are becoming obsolete compared to modern microprocessor relays. These older units have slower response times, are difficult to keep properly adjusted, do not have replacement parts available, and lack telemetry for diagnostics and real-time operation. The immediate goal of the program is to replace all the remaining electromechanical relays and eventually establish a 25-year replacement cycle once the entire fleet is composed of microprocessor relays. Microprocessor relays generally have a 20- to 30-year expected life. Initially, the pace of replacement will be 20 panels per year, but climb to 40 by 2020 and eventually reach the 50-60 per year pace needed to maintain a 25 to 30-year replacement cycle. Replacement priorities will be based on a health index indicating the worst performing relays. This will also factor prominently in determining control house replacement priorities.

Five-year program cost is estimated to be $21.9 million.

Relay Panel Replacement Program Cost (MM USD)						
	2017	**2018**	**2019**	**2020**	**2021**	**Total**
Replace Relay Panels	$1.8	$3.4	$5.1	$6.6	$5.0	$21.9

Figure 29: Electro-mechanical relay panels.

Figure 30: Microprocessor relay panels.

Benefits

Relay panels have a significant effect on the operation of the transmission system and protect the system from abnormal conditions. Replacements of the relay panels will provide the following benefits:

- reduced risk of relay failure (i.e., relay does not operate);
- reduced customer SAIDI and SAIFI (frequency) by preventing overreach to backup relay zones; and
- reduced mis-operations (i.e., relay fails to operate properly).

Supporting Data

While relay malfunctions are not a large contributor to overall transmission SAIDI, they account for 137 outages over the period from 2007 to June 30, 2016. Relay malfunctions reached a peak in 2014, which was the first year that the Protection and Control group started a targeted approach to relay replacements. The relays deemed as the worst performing in LG&E and KU were targeted for replacement. Relay failures have contributed to 102 outages over the past five years.

Replace Remote Terminal Units (RTUs)

Description

RTUs are the critical link between the control center and the transmission substations enabling real-time monitoring of the power grid and control of the circuit breakers, switches and other devices to ensure proper flow of power across the system. They generally reside in the control houses located at each substation. RTUs reduce SAIDI by allowing transmission operators to issue commands to open and close breakers thus restoring outages more quickly. RTUs bring back data to the state estimator and operator screens that provide for the reliable operation of the transmission system. Because of the criticality of the RTU to the reliable operation of the transmission system and based on the fact that many of these units are old, obsolete (no longer supported by the manufacturer) and do not have the necessary parts for repairs, these units are being targeted for replacement as part of the overall transmission reliability program.

The objective of this program will be to replace obsolete or end-of-life (20-year expected useful life) RTUs to support control, automation and telemetry. Beyond those units associated with control house upgrades, the RTUs targeted for replacement will be the 1970s vintage Leeds & Northrup (L&N) units that are obsolete and prone to failure as well as a few similar vintage Valmet units. Aside from manufacturer (and indirectly age), priorities for replacement follow these criteria in order.

1. RTUs associated with bulk electric system (BES)
2. RTUs associated with radial feeds from the BES
3. RTUs associated with the 69 kV system
4. RTUs associated with telemetry of transmission service customers
5. Telecommunication projects driven by telephone carriers moving to digital circuits from analog

It is expected that the new RTUs will have a similar expected useful life (20 years) and similar failure rates, as the current ones, and that the future changes in the operating system will not force early replacements. The ultimate goal of the RTU program is to establish a 20-year replacement cycle.

Figure 31: GE D20 remote terminal unit.

Five-year program cost is estimated to be $15.7 million replacing approximately 15 units annually.

RTU Replacement Program Cost (MM USD)	2017	2018	2019	2020	2021	Total
Replace RTUs	$2.9	$3.1	$3.2	$3.3	$3.2	$15.7

Benefits

The proposed replacements will have the following benefits:

- reduced risk of RTU failure;
- increased situational awareness of the BES and Non-BES lines to ensure that they will remain reliable; and
- improved SAIDI performance through remote control of the protective system.

Supporting Data

The data below shows the increasing number of false indications reported by the RTUs in the substations. False indications are erroneously reported breaker operations that are sent to the Energy Management System. Since 2012 there has been a large increase in the number of false indications. False indications occur when the RTU is not working properly and an incorrect signal is sent to the control center. This indicates that the health of many of these assets are in decline.

Reliability Cause Code: False Indication					
False Indication	2012	2013	2014	2015	2016*
Number of Outages	10	54	165	49	56

*2016 thru June 30, 2016.

Replace Power Line Carriers (PLCs)

Description

This program will replace PLCs across the system that are beyond or approaching end of service life, which is estimated to be 20 years. PLCs are used to provide high-speed communications path for certain system protection schemes. A PLC uses one of the phase conductors as a medium for transmitting the high-speed communications channel with power flowing on the conductor at 60 Hertz. These communications schemes are used to eliminate system stability issues and minimize the damage to expensive assets. In addition to the high speed communication path provided by PLCs integral to protection schemes, the new units include a check-back function that will greatly reduce maintenance from quarterly checks to once every 12-year maintenance intervals. The plan is to replace twelve (12) units annually for 22 years. Sixty (60) units (out of the total of 266 PLCs on the system) will be replaced over the next five years at a total cost of $3.2 million. Priorities for replacement are based on failed units and then sorted by age.

Figure 32: Power line carrier set.

Five-year program cost is estimated to be $3.0 million replacing approximately twelve (12) units annually.

Power Line Carrier Replacement Program Cost (MM USD)						
	2017	2018	2019	2020	2021	Total
Replace PLCs	$0.6	$0.6	$0.6	$0.6	$0.6	$3.0

Benefits

Replacement of the Power Line Carriers (PLCs) will:

- reduce the risk of relay mis-operation due to communication failure;
- facilitate NERC reporting requirements; and
- reduce maintenance costs by extending required maintenance intervals due to additional functionality of the units.

Supporting Data

Power Line Carrier systems can experience communications failures called carrier holes. Carrier holes are intermittent losses of signal.

Certain high-speed communications schemes are vulnerable to these carrier holes. This program will address 66 communications related outages that took place over the past five years.

Install or Replace Digital Fault Recorders (DFRs)

Description

DFRs are a subset of equipment called Disturbance Monitoring Equipment (DME). These devices actively monitor the transmission system at each substation control house in which they are installed. Pre-defined thresholds are set in the device and when the system conditions meet those thresholds the device takes samples of the voltages and currents and stores them internally for future retrieval. This data is used by the engineering staff to analyze the outages for proper operation of the relays.

The expected useful life for the DFR units is 20 years. This program will install four digital fault recorders annually, for a total of 20 units in the period 2017–2021. Priorities include replacement of the problematic Metatech units, expansion for NERC standards, installation of new units associated with control house upgrades, and upgrades of end-of-life units.

Benefits

The benefits associated with DFR upgrades include:

- increased ability to recreate outages; and
- compliance with NERC standards that require disturbance monitoring equipment to be installed according to certain standards.

Supporting Data

Since 2012, LG&E and KU has had to address 66 maintenance issues on Metatech DFRs. LG&E and KU operates a total of 18 Metatech units which were installed in the period from 1994-2013. Another 18 DFRs, manufactured by Tesla were installed since 2014.

Five-year budget for the DFR installation project is $3.0 million.

Digital Fault Recorder Installation Program Cost (MM USD)	2017	2018	2019	2020	2021	Total
Replace and Add New DFRs	$0.6	$0.6	$0.6	$0.6	$0.6	$3.0

Figure 33: Tesla digital fault recorder.

Replace Battery Sets

Description

The protective relays and their associated control circuits on the transmission system rely on DC currents and voltages supplied through a battery system or DC charger to perform their functions. The batteries in use are lead acid and similar to an automotive battery. The strings of 12 volt batteries are placed in series to provide 48 or 125 volt strings.

After accounting for the battery sets associated with a control house replacement program, this program will replace battery sets at or approaching end of useful life (estimated at 20 years). It is important to note that the pro-active battery replacement is currently in place and that this program will simply accelerate the existing replacement cycle. Ultimately, the intent of this program is to replace all battery sets on a 20-year cycle.

The scope of this project is to replace approximately ten battery sets including the charger annually in perpetuity. Priorities will be set beyond the 20-year mark and those set demonstrating need for replacement.

Benefits

Benefits related to the battery set replacement program include:

- reducing the risk of DC failure;
- reducing the risk of breaker mis-operation or failure to operate that can increase SAIDI; and
- reducing the safety risk associated with the failure of the breaker to isolate the fault because the batteries are dead.

Supporting Data

Batteries are routinely tested for condition on a quarterly and annual basis. They are replaced at the end of their 20-year warranty period due to their criticality in system protection, unless the testing indicates the need to replace sooner. The cost projection assumes no change in the battery disposal procedures in the future. Cost of the program is estimated to be $2.1 million over five years.

Battery Replacement Program Cost (MM USD)	2017	2018	2019	2020	2021	Total
Replace Battery Sets	$0.5	$0.5	$0.4	$0.4	$0.3	$2.1

Figure 34: Battery set.

5.2.4. Replace Circuit Breakers

Description

Circuit breakers are mechanical switching devices which connect and break current circuits (operating current and fault currents) and carry the nominal current in the closed position. A breaker that fails to operate properly when required can lead to unnecessary outages and delayed restoration times. A catastrophic failure of an oil-filled circuit breaker can have an environmental impact through an oil release.

Two circuit breaker replacement programs are planned.

1. 345kV Circuit Breakers — Replace a total of 12 effectively obsolete breakers that were manufactured before 1990 and have limited replacement parts, high SF6 leak rates, outdated operating specifications, and difficulties keeping in proper adjustment. The design and construction of these specific breakers prevent them from reaching an average 60 years of useful life that is expected from the remaining in-service breakers.
2. Oil Circuit Breakers — Proactively replace 69kV, 138kV and 161kV breakers based on inspection/test results. Replacement drivers

include insufficient continuous current capacity, insufficient interrupting current capability, repair vs. replace economics, and management of the age of the breaker fleet.

The expected replacements by voltage class are as follows.

- (125) 69kV circuit breakers
- (40) 138kV or 161kV circuit breakers
- (12) 345kV circuit breakers

The five-year cost of this program is $34.9 million.

Breaker Replacement Program Cost (MM USD)	2017	2018	2019	2020	2021	Total
Replace Circuit Breakers	$7.5	$8.4	$8.4	$5.3	$5.3	$34.9

The photo in Figure 35, taken in 2014 at an LG&E and KU station, shows a fire that started when a 69kV breaker failed to interrupt a fault.

Figure 35: 69kV circuit breaker failure.

Benefits

The benefits of this program are:

- reliability improvement by reducing the likelihood of breaker mis-operations and catastrophic failures;
- reduced environmental risks by replacing oil circuit breakers with gas (i.e., SF6) breakers thereby eliminating the possibility of a release of oil;
- reduced future maintenance costs; and
- more effective utilization of resources.

Supporting Data

Replacing breakers will lower the number of in-service failures and minimize customer outages.

Reliability Cause Code: Breaker	2012	2013	2014	2015	2016*
Outage Counts	21	27	37	18	2
SAIDI incl. MEDs	1.00	0.93	2.37	0.28	1.22
SAIDI excl. MEDs	1.00	0.93	0.90	0.28	1.22

*2016 thru June 30, 2016.

The following graphs reflect the age of the circuit breaker fleet. The bars indicates the number of breaker in service that were manufatured in a given year while the line shows the cumulative percentage of breakers that were installed prior to a specific year.

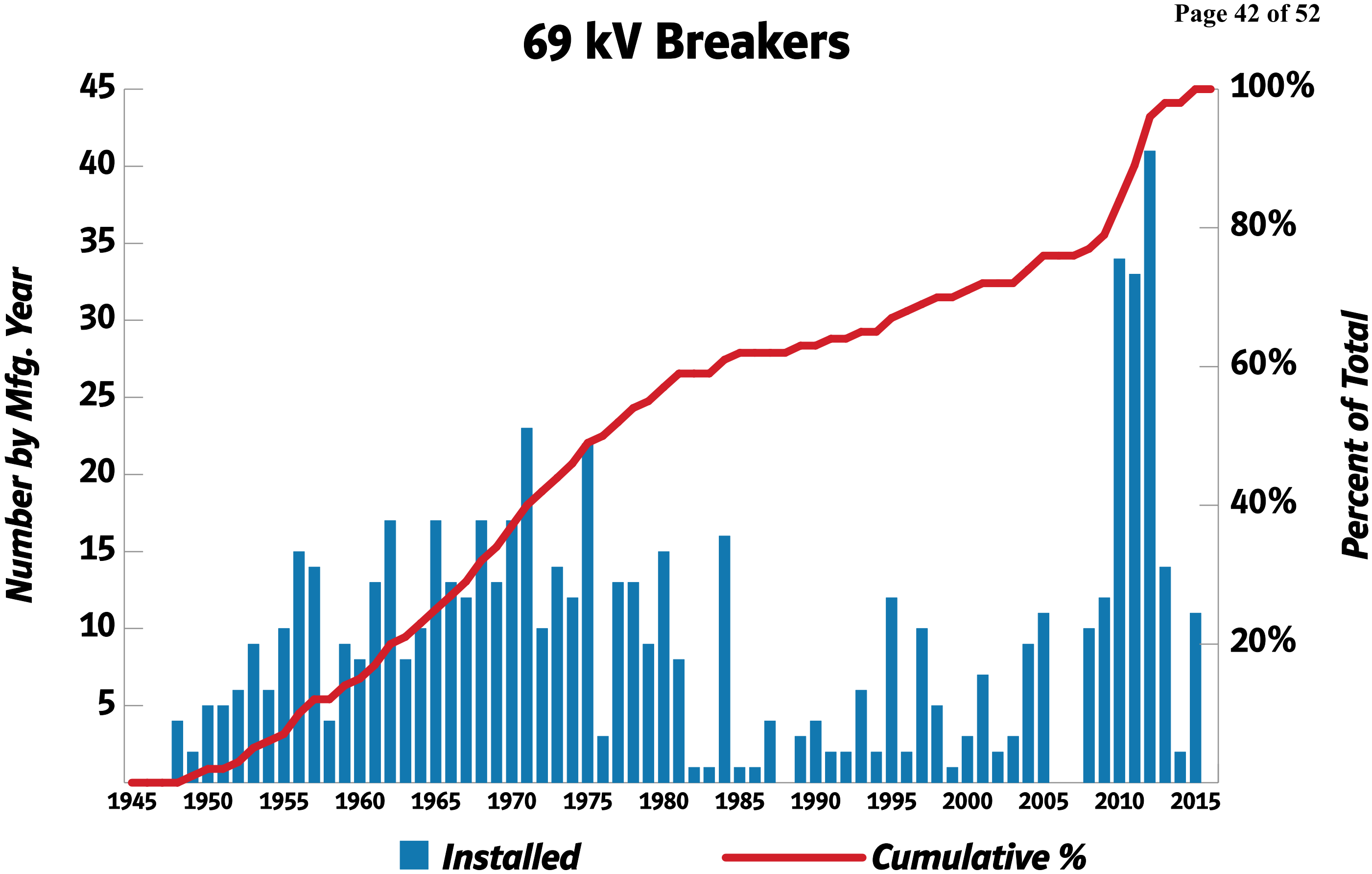


Figure 36a: Age profile of 69 kV breakers in service.

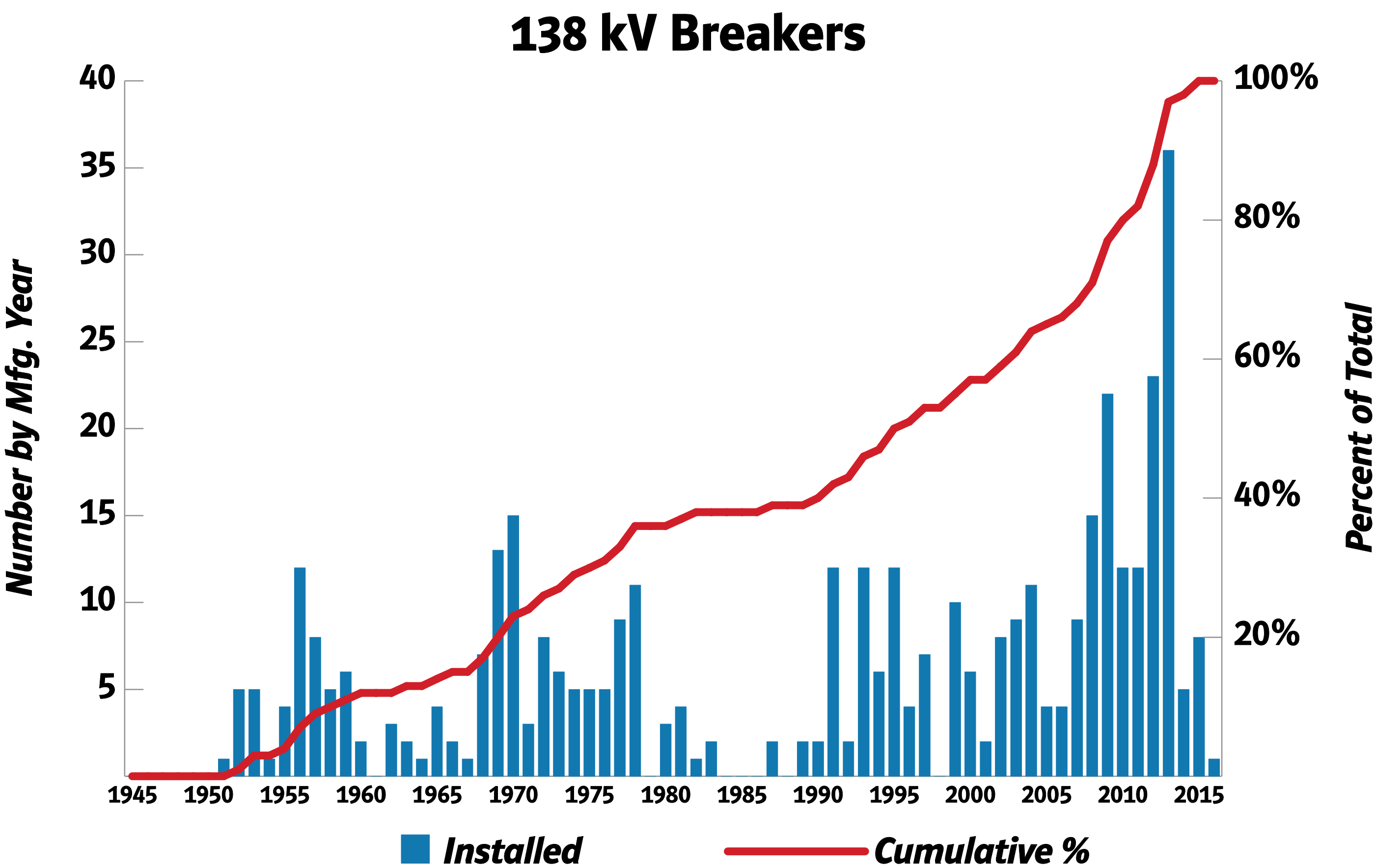


Figure 36b: Age profile of 138 kV breakers in service.

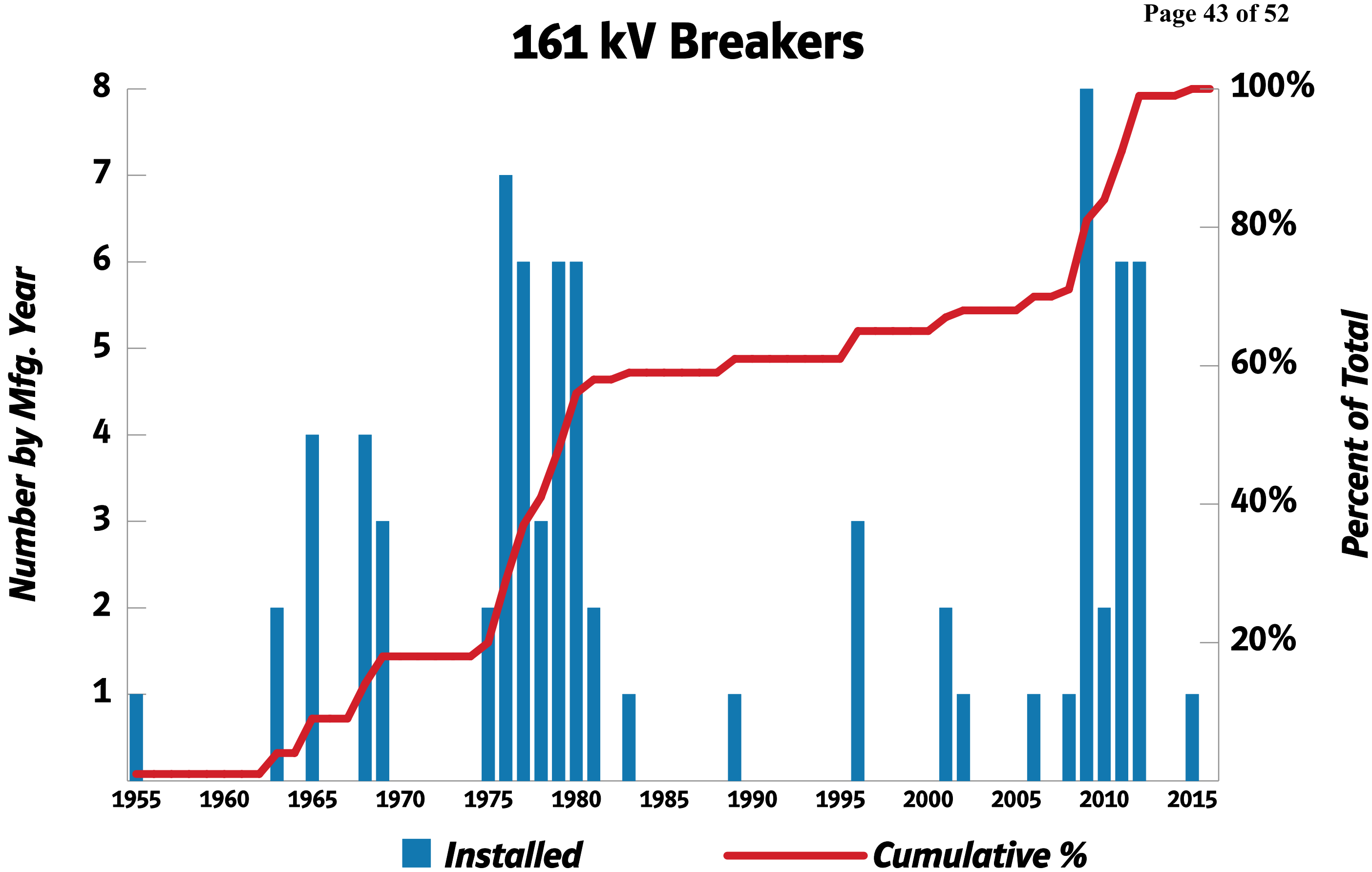


Figure 36c: Age profile of 161 kV breakers in service.

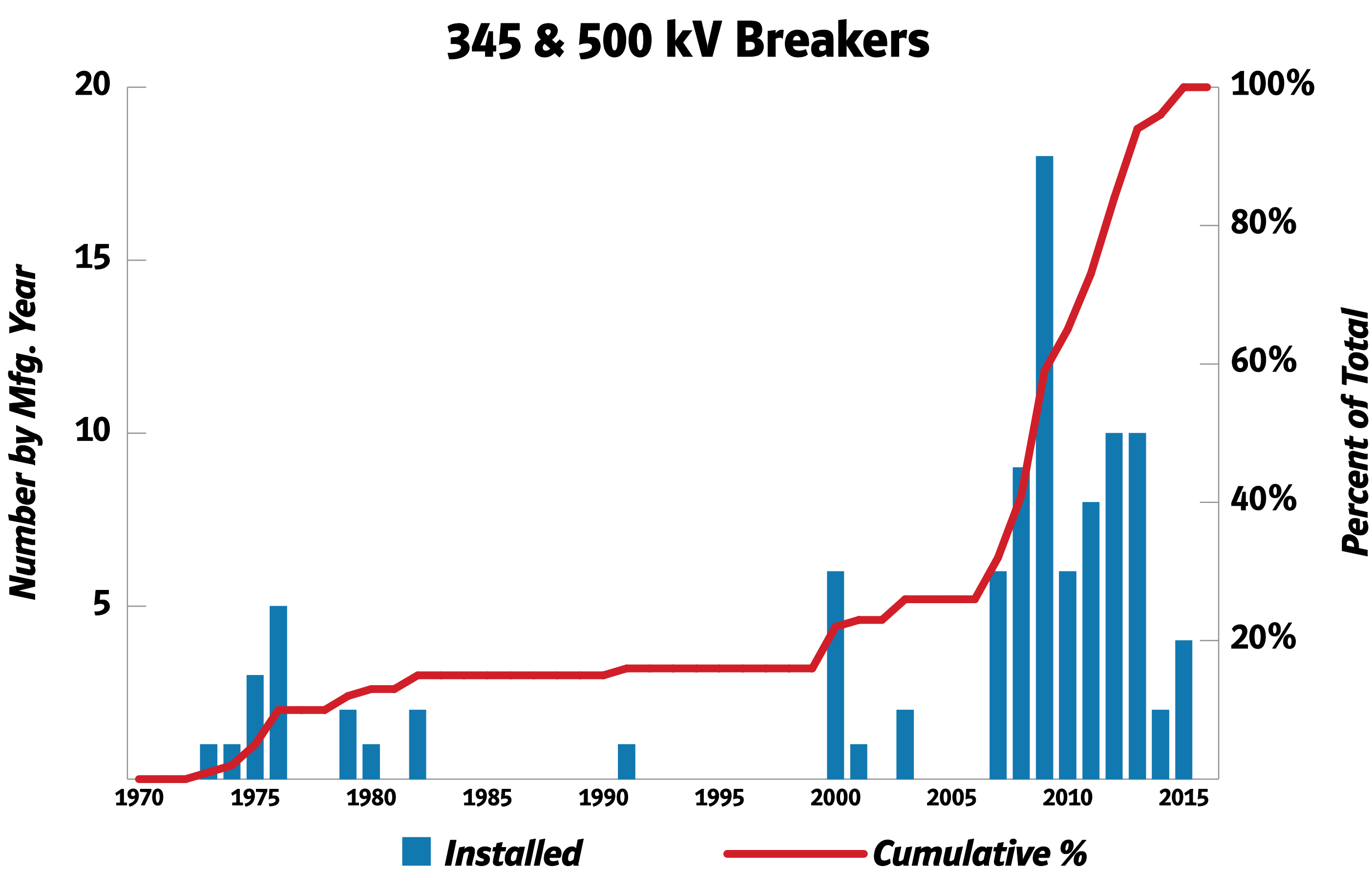


Figure 36d: Age profile of 345 and 500 kV breakers in service.

5.2.5. Replace Underground Lines

Description

Underground transmission can be utilized in locations where there is limited space to accommodate overhead transmission lines. It is often installed near airports and bridge crossings. The underground cables typically have a useful life of 35-40 years (the industry commonly considers underground cables to be half the life expectancy of an overhead transmission conductor). Many cables and fixtures in the company's transmission system are at or beyond their expected useful life and are starting to perform poorly. In order to sustain the reliability of the company's underground transmission system, it is necessary to monitor cable performance and plan for replacement of these facilities.

The five-year cost of this program is $23.4 million.

Underground Line Replacement Program Cost (MM USD)						
	2017	2018	2019	2020	2021	Total
Replace Underground Lines	$3.2	$10.2	$10.0	$0	$0	$23.4

Benefits

Replacement of underground components nearing the end of their useful life will lead to:
- reduction in risk of failure, associated outage, and public safety hazard;
- reduction in costly emergency repairs; and,
- reduction in risk of extended sustained outage.

Supporting Data

In the late 1960s, a 69 kV underground transmission circuit, approximately 3,200 feet in length, was installed in downtown Lexington feeding the Vine Street Substation. The cable in this line is composed of 1500 kcmil aluminum with XLPE insulation. The duct bank was built using Orangeburg pipe (fiber conduit). In 2012, this circuit experienced a splice failure where the three sections of underground cable are joined together. Another 69kV underground transmission circuit, approximately 3,600 feet in length, feeding the Vine Street Substation was installed in the early 1970s. The cable in this circuit is composed of 1500 kcmil aluminum with EPR insulation.
The Lexington Underground project will replace both underground transmission circuits serving the Vine Street substation, which serves approximately 5,200 customers, with a peak load of almost 27 MW. A majority of the businesses, government operations, and public transportation in the downtown area are served from the Vine Street substation. One underground line serving Vine Street substation has experienced a failure at a splice where two sections of underground cable are joined together.

Similarly, in the early 1970s, the company installed three 69kV underground dips into the Oxmoor Substation. The Oxmoor project will replace two of the underground dips (approximately 600 feet in length) into the Oxmoor substation in Louisville. These circuits are composed of 1250 kcmil copper with XLPE insulation. The termination for the underground feed on the Oxmoor-Aiken 69kV line at the Oxmoor Substation failed in 2015 and damaged a portion of the cable. The Oxmoor Substation serves approximately 6,300 customers in the Louisville area, including several businesses and a shopping mall along Shelbyville Road. The Oxmoor-Breckenridge underground segment will be replaced concurrently with the Oxmoor to Aiken underground segment due to the age of existing cable, and its inclusion in the existing duct bank that will be replaced as part of the proposed project. Over the past five years, the UG system has experienced four outages, but has not yet had a notable SAIDI impact because of the redundancy in the system.

Figure 37: Example of a failed underground transmission splice.

5.2.6. Replace Line Switches

Description

Line switches allow circuits to be sectionalized for isolating a fault and to facilitate line equipment maintenance, replacements, and upgrades. Proper operation and functionality of line switches is key to supporting restoration efforts during a system outage and supporting the capital replacement programs. This program will replace line switches identified as defective or obsolete from the switch maintenance programs that cannot be cost effectively repaired.

The projected spending on this program is based on historical costs. Development of this program will continue to be reviewed and adjusted with additional inspection results and historical costs. Replacements are prioritized based on known operational issues, availability of replacement components, and switch inspection results.

The five-year estimated cost of the program is $12.2 million.

Switch Replacement Program Cost (MM USD)	2017	2018	2019	2020	2021	Total
Replace Line Switches	$1.2	$1.7	$1.8	$3.6	$3.9	$12.2

Planned Switch Replacements	2017	2018	2019	2020	2021
Number of Switches	3	5	5	10	10

Benefits

Replacement of defective line switches will reduce the risk of failure and impacts from system outages. Additional program benefits include:

- reduction of associated outages and public safety hazards; and
- reduction of SAIDI.

Supporting Data

The Switch Replacement Program will improve outages for the following cause code.

Reliability Cause Code: Switch — Failed AC Circuit Equip.	2012	2013	2014	2015	2016*
Outage Counts	4	0	1	4	2
SAIDI incl. MEDs	0.14	0.00	0.18	0.00	0.04
SAIDI excl. MEDs	0.14	0.00	0.18	0.00	0.04

*2016 thru June 30, 2016.

5.2.7. Replace Substation Insulators

Description

Insulators are used to isolate from ground and support energized conductors and substation equipment such as disconnect switches. Bus insulator failures can lead to an outage on multiple radial lines, and to a loss of an autotransformer leaving the system at risk for the next contingency.

There are two specific types of insulators targeted for replacement based on failure history: cap and pin type, and hollow post type.

- Cap and Pin — The failure mode for this design is at the joint where the cement used to connect the metallic cap to the porcelain deteriorates. The insulators at the highest risk are those that are part cantilevered or underhung from the steel as well as those that are part of a disconnect switch.
- Hollow Post — Multiple past failures have been attributed to water ingress into the hollow portion of the insulator. A flashover occurs as a result of tracking internal to the insulator.

In cases where either of these insulator types are used for a disconnect switch, the entire switch will be replaced instead of only replacing the insulators.

Stations for replacement are prioritized based upon both criticality as well as past failures.

The five-year cost of this program will be $8.4 million.

Substation Insulator Replacement Program Cost (MM USD)	2017	2018	2019	2020	2021	Total
Replace Subs Insulators	$2.7	$2.1	$2.1	$0.7	$0.8	$8.4

Benefits

The key benefits related to the replacement of substation insulators include:

- reduced number of outages initiated by insulator failures, thereby improving SAIDI and reducing risk to system from failures; and
- reduced cost by replacing multiple insulators as part of a planned outage is more cost effective than continually replacing failed insulators as part of a forced outage.

Supporting Data

Proactively replacing both hollow post along with cap and pin insulators will reduce outages with the following cause code.

Reliability Cause Code: Insulator — Failed AC Substation Equip.	2012	2013	2014	2015	2016*
Outage Counts	4	9	8	12	8
SAIDI incl. MEDs	0.00	0.37	0.15	0.73	0.08
SAIDI	0.00	0.37	0.15	0.73	0.08

*2016 thru June 30, 2016.

Figure 38 shows a hollow post insulator as part of a disconnect switch assembly that violently failed, resulting in an outage.

Figure 38: Hollow post insulator after failure.

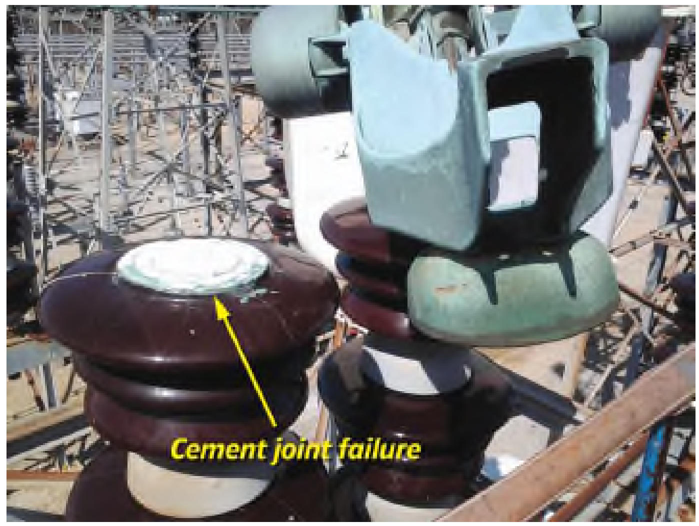


Figure 39: Failed cap and pin insulator.

5.2.8. Structure Corrosion Prevention and Coating

Description

Coating assessment will be performed on applicable assets, including lattice and tubular steel structures to assess corrosion activity and required actions, if any. Protective coatings will then be applied as required to prevent corrosion damage and extend the useful service life of these assets. When rust is discovered upon structure inspection, it is vital that protective coatings be applied in order to avoid loss of material thickness and subsequent structural failure.

Work will be prioritized based on observations from detailed inspections. The intent of the program is to establish and maintain a consistent coating cycle, which will be developed as part of the assessment program.

The five-year estimated cost of the corrosion protection program is $4.3 million.

Corrosion Prevention Program Cost (MM USD)	2017	2018	2019	2020	2021	Total
Corrosion Protections	$0.5	$0.7	$0.9	$1.1	$1.1	$4.3

Benefits

Corrosion prevention is imperative to extend the useful service life of steel assets. Coating these assets will maintain their integrity and functionality. This program will:

- reduce risk of structure damage and failure, associated outages, and public safety hazards;
- avoid costly replacement of structures (the higher the line voltage, the higher the costs); and
- improve system aesthetics, improving customer image.

Supporting Data

These are the types of structure and corrosion that this program is addressing.

Figure 40: Examples of poles and structures exepriencing corrosion activity.

5.2.9. Replace Substation Line Arresters

Description

Arresters are typically located where the incoming transmission line attaches to the substation steel as well as near the bushing terminals of power transformers. Their purpose is to clamp transient overvoltage caused by lightning, switching of electrical equipment and other causes to prevent transmission equipment dielectric failures. Older, obsolete arrestors are prone to failure, which will cause an outage on the line to which it is connected. In some cases, arrestors are made with porcelain and can fail violently, causing damage to surrounding equipment. Replacing them with modern arrestors without porcelain reduces the likelihood of failure and minimizes the possibility of collateral damage if they do fail.

Arrester types that will be targeted include spark gaps along with those utilizing silicon carbide technology which are obsolete and prone to premature failure. Arrester replacements will be prioritized based on age of terminal equipment at each substation. When possible, arresters will be replaced during other scheduled work to reduce installation costs.

The five-year cost of substation line arrester replacement program is $3.0 million.

Substation Arrester Replacement Program Cost (MM USD)						
	2017	2018	2019	2020	2021	Total
Replace Subs Line Arresters	$0.6	$0.6	$0.6	$0.6	$0.6	$3.0

Benefits

The benefits associated with the replacement of the substation line arresters include:

- reduced number of outages due to arrester failure, since the Metal Oxide Varistor (MOV) type arresters provide superior dielectric protection for station equipment and have lower failure rates, and thereby improving reliability and reducing SAIDI; and
- reduced cost of arrester replacement, since replacing line arresters as part of a planned outage is more cost-effective than continually replacing failed units due to forced outages.

Supporting Data

Proactively replacing both spark gap and silicon carbide type arresters will reduce outages with the following cause code.

Reliability Cause Code: Arrester — Failed AC Substation Equip.	2012	2013	2014	2015	2016*
Outage Counts	9	1	3	4	1
SAIDI incl. MEDs	0.00	0.00	0.26	0.00	0.76
SAIDI	0.00	0.00	0.26	0.00	0.76

*2016 thru June 30, 2016.

5.2.10. Replace Coupling Capacitors

Description

Coupling capacitors are utilized as part of a power line carrier protection scheme. They couple the signal from the carrier communication equipment to the transmission line.

It is difficult to detect a coupling capacitors that are trending to failure. Based on past experience, the failure of a coupling capacitor used to support associated equipment can result in significant collateral damage. The replacement program will be prioritized based on the criticality of the line, along with the age and type of coupling capacitor.

The five-year cost of the program is $2.2 million.

Coupling Capacitor Replacement Cost (MM USD)	2017	2018	2019	2020	2021	Total
Replace Coupling Capacitors	$0.6	$0.6	$0.6	$0.2	$0.2	$2.2

Benefits

Replacing coupling capacitors provides the following benefits:

- reduced risk of line outages due to violent failures of coupling capacitors that often lead to collateral damage to equipment located in the proximity; and
- reduced cost by replacing coupling capacitors as part of a planned outage instead of continually replacing failed units due to forced outages.

Supporting Data

Proactively replacing coupling capacitors will reduce outages with the following cause code.

Reliability Cause Code: CCVT Coupling Capacitor	2012	2013	2014	2015	2016*
Outage Counts	0	0	5	8	0
SAIDI incl. MEDs	0.00	0.00	1.08	0.33	0.00
SAIDI excl. MEDs	0.00	0.00	1.08	0.33	0.00

*2016 thru June 30, 2016.

6. Appendix A: Glossary of Terms

Batteries

A battery is a group of electrochemical cells that are used to store electricity and release it when needed. The cells can be recharged by passing a current through them in the direction opposite to the discharging flow of current. Batteries are used to supply power to the P&C systems if their primary power feed fails.

Breaker

A circuit breaker is a mechanical switching device which connects and breaks current circuits (operating current and fault currents) and carry the nominal current in the closed position.

Capacitor Bank

Capacitor banks are used to reduce system power losses, loading on substation transformers and raise voltage levels on the transmission system.

Circuit

A continuous flow of electricity from a source to a load or loads. In utility transmission, a circuit is the main line and all radial taps served by a single substation circuit breaker.

Circuit sectionalization

The practice used by utilities to break an electric circuit into sections that can be isolated from the rest of the circuit in case of an outage to protect all of the customers from getting an outage as a result. This also allows the utility to switch the source of power to the circuit from one feeder or substation to another during an outage, if another source is available.

Control House

A control house is an enclosure inside a substation that protects these P&C system assets (e.g., relay panels, remote terminal units (RTU), power line carriers (PLC) digital fault recorders (DFRs) and batteries) from external elements

Conductor

Conductor refers to a wire or cable that carry electricity across the transmission system.

Coupling Capacitors

Coupling capacitors are utilized as part of a power line carrier protection scheme. They couple the signal from the carrier communication equipment to the transmission line.

Cross Arm

Cross arms are used to support wires or equipment on top of a pole, providing clear area for linemen to climb around or past the electric equipment and to keep the phases separated

DC Current

One directional flow of electric charge.

Digital Fault Recorder

Devices that actively monitor the transmission system at each substation control house in which they are installed. Pre-defined thresholds are set in the device and when the system conditions meet those thresholds the device takes samples of the voltages and currents and stores them internally for future retrieval. This information is used by the engineering staff to analyze the outages for proper operation of the relays.

Easement

Easement is the right to cross or otherwise use someone else's land for a specified purpose.

Hazard Tree

A hazard tree is a tree with structural defects (disease or otherwise compromised structurally) likely to cause failure of all or part of the tree, which could strike a power line.

Insulator

Insulators provide an insulated point of attachment for wires that are under tension or not (such as jumper wires).

Lightning Arresters

Provide a path to the ground if lightning should strike the equipment. It diverts the current to the ground protecting the equipment from potential damage.

Major Event Day (MED)

Major Event Days (MEDs) are the days during which total SAIDI value exceeds a predetermined threshold indicating that the amount of outages is more than 2.5 standard deviations from the five-year mean. The outages that started on MED days are removed from the reliability index calculations in order to normalize the reliability performance and make it less skewed by unusual events.

Outage

Outage is a fault on the transmission line that may result in customer service interruption or take a circuit or a portion of circuit out of service.

Overhead Lines

Electric circuits that are placed above ground on poles, structures or to towers.

Pole

Utility pole is a column or post used to support overhead power lines and various other public utilities, such as cable, fiber optic cable, and related equipment.

Power Line Carrier (PLC)

PLC is a communication technology that enables sending data over existing power cables at high-speeds.

Radial (tap)

A section of the circuit constructed to extend to loads that are not directly in the path of the main line. Radials are typically connected to the main line through sectionalizing devices.

Recloser (circuit recloser)

Reclosers are designed to detect and clear momentary faults and to isolate line sections on which persistent failures have developed.

Relay

Relays are devices that are designed to respond to abnormal system conditions. These devices use current and/or voltage measurements from the system to determine if the electrical system they are monitoring is in a normal or abnormal state. If the system is in an abnormal state, the relay issues a signal to a circuit interrupting device to open its contacts and interrupt the current flow on the system it oversees.

Relay Panel

A relay panel consists of multiple relays that oversee a specific transmission line, bus, or transformer.

Reliability

Reliability can be defined as the ability of the transmission system to deliver electricity to all points of consumption, in the quantity and with the quality demanded by the customer. Reliability is often measured by outage indices defined by the Institute of Electrical and Electronics Engineers (IEEE) Standard 1366. These indices relate to customer satisfaction, and are based on both the total length of each service interruption and the frequency of interruptions.

Remote Terminal Unit

A remote terminal unit (RTU) is a microprocessor-controlled electronic device that interfaces objects in the physical world to a distributed control system or SCADA (supervisory control and data acquisition) system by transmitting telemetry data to a master system, and by using messages from the master supervisory system to control connected objects.

Right-of-Way

Right-of-way (ROW) is the legal right, established by usage or grant, to pass along a specific route through grounds or property belonging to another

SAIDI

SAIDI is a standard industry measure that indicates how long, expressed in number of minutes, an average customer has been out of service during a predefined period of time (most often in a year). This index is used to compare reliability performance across different utilities.

SCADA

The SCADA system allows for remote operation of overhead and underground switches, reclosers and capacitors via coded communications (telephone or radio) system by the system operator. SCADA features an alarm system to alert the operator to the problems and their approximate location, and data acquisition capability that provides detailed information on the phase, secondary voltage, type and magnitude of the fault.

Structure

*See definition of **Pole**.*

Shield Wire

Shield wire is a ground conductor usually at the top of the supporting structure designed to shield or protect the transmission line from lightning strikes.

Substation

Transmission substation connects two or more transmission lines. The substations can be simple with same voltage or include transformers to reduce voltage of the transmission line.

Switch

Switches are mechanisms to open up or close a section of a circuit. The switch also serves as an opening point to separate two different substation feeds.

Tap

*See **Lateral**.*

Tower

Transmission towers are metal pylons that support overhead transmission lines.

Transformer

Transformer converts electrical energy in an electric utility system to change the voltage.

Transmission Operations Center

A facility that houses system operators and data management system, providing real-time status and the ability to remotely operate the transmission system.

Underground Lines

Transmission lines that are buried underground, typically in conduit.

Vegetation Management (VM)

Refers to the cyclical and reactive program for maintaining trees and tree limbs at a safe distance from the transmission power lines. A VM program is guided by a set of industry standards, NERC requirements and transmission company guidelines.

Voltage

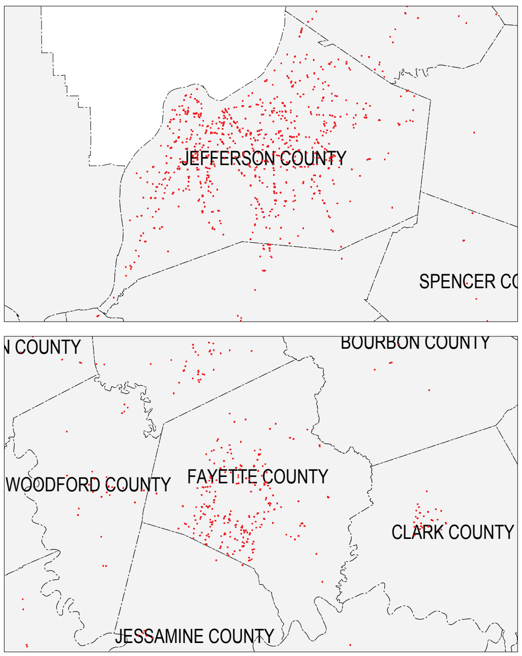
Voltage is the difference in electric potential energy between two points per unit electric charge. Transmission system operates the line with voltages over 69kV.

PPL companies

Exhibit PWT-3

Deployment Map

LG&E and KU
Distribution Automation Program
ELectronic Recloser Locations



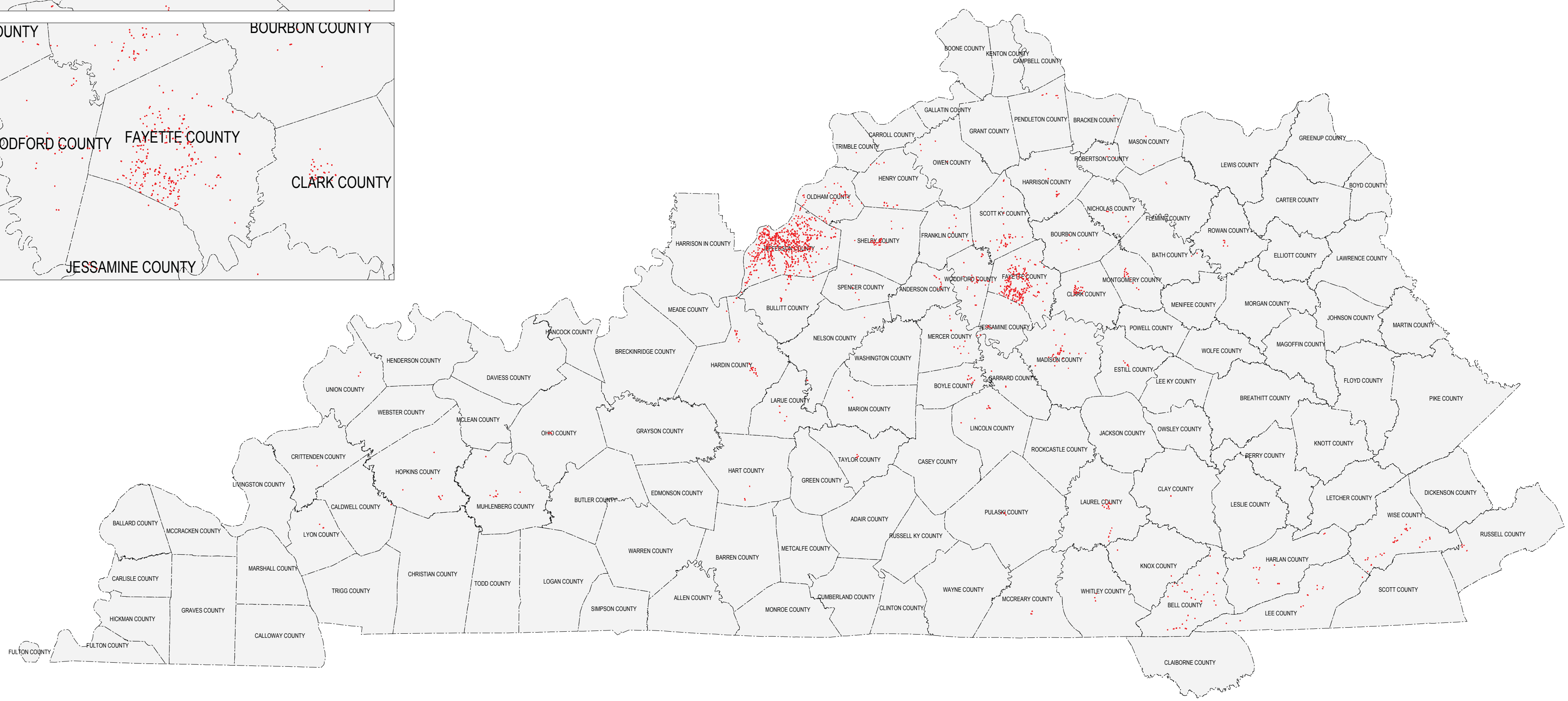
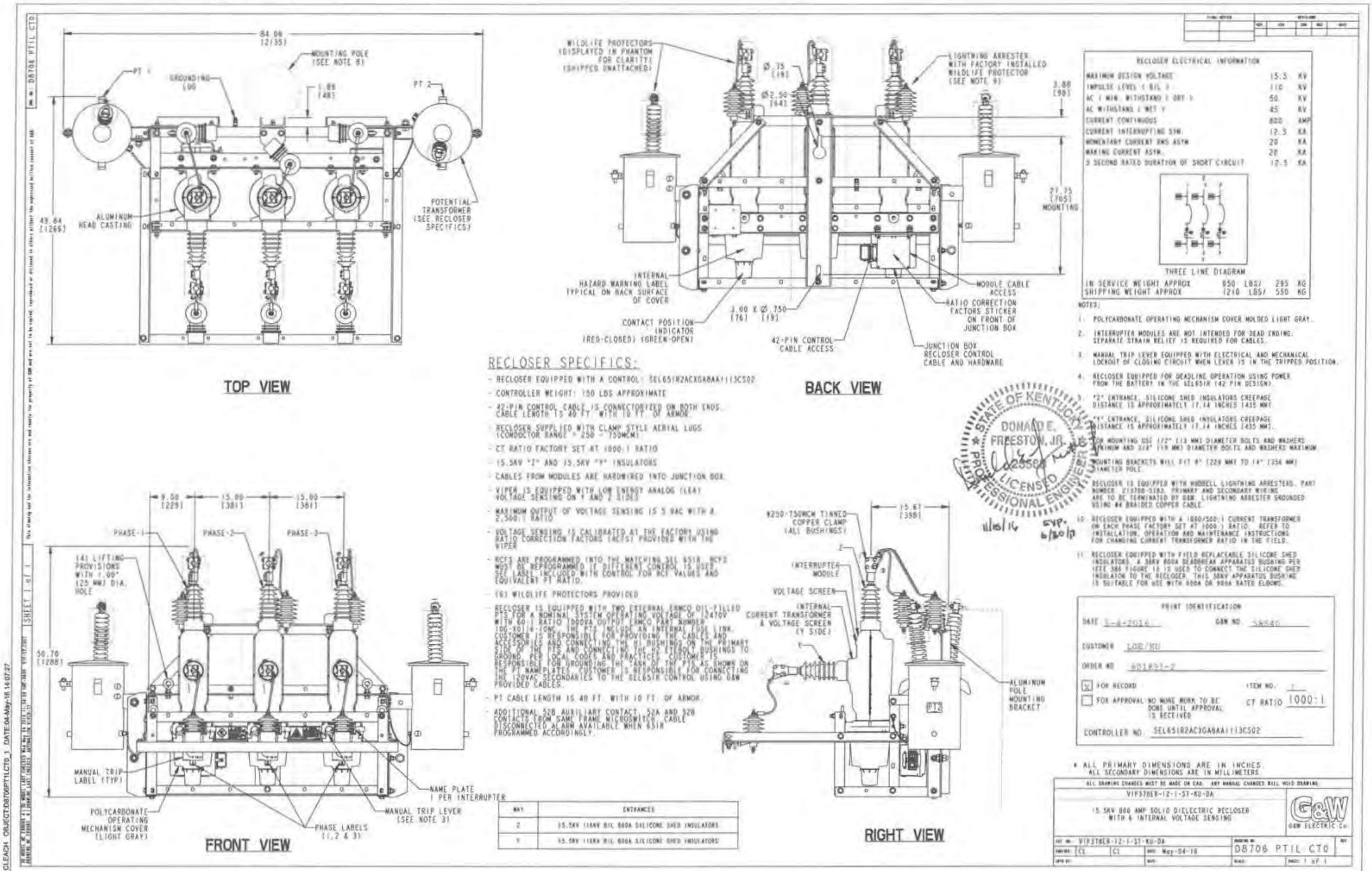


Exhibit PWT-4

Schematics of SCADA-capable reclosers, installation diagrams, wiring diagrams, a pole-mounted enclosure diagram, and recloser control diagram


TOP VIEW
84.06 [2135]
MOUNTING POLE (SEE NOTE 8)
PT 1
GROUNDING LUG
1.89 [48]
PT 2
POTENTIAL TRANSFORMER (SEE RECLOSER SPECIFICS)
49.84 [1266]
ALUMINUM HEAD CASTING
BACK VIEW
WILDLIFE PROTECTORS (DISPLAYED IN PHANTOM FOR CLARITY) (SHIPPED UNATTACHED)
Ø.75 [19]
Ø2.50 [64]
LIGHTNING ARRESTER WITH FACTORY INSTALLED WILDLIFE PROTECTOR (SEE NOTE 9)
3.88 [98]
27.75 [705] MOUNTING
INTERNAL HAZARD WARNING LABEL TYPICAL ON BACK SURFACE OF COVER
CONTACT POSITION INDICATOR (RED-CLOSED) (GREEN-OPEN)
3.00 X Ø.750 [76] [19]
42-PIN CONTROL CABLE ACCESS
MODULE CABLE ACCESS
RATIO CORRECTION FACTORS STICKER ON FRONT OF JUNCTION BOX
JUNCTION BOX RECLOSER CONTROL CABLE AND HARDWARE
RECLOSER SPECIFICS:
- RECLOSER EQUIPPED WITH A CONTROL: SEL651R2ACXGA8AA1113C502
- CONTROLLER WEIGHT: 150 LBS APPROXIMATE
- 42-PIN CONTROL CABLE IS CONNECTORIZED ON BOTH ENDS. CABLE LENGTH IS 40 FT. WITH 10 FT. OF ARMOR.
- RECLOSER SUPPLIED WITH CLAMP STYLE AERIAL LUGS (CONDUCTOR RANGE = 250 - 750MCM)
- CT RATIO FACTORY SET AT 1000:1 RATIO
- 15.5KV "Z" AND 15.5KV "Y" INSULATORS
- CABLES FROM MODULES ARE HARDWIRED INTO JUNCTION BOX.
- VIPER IS EQUIPPED WITH LOW ENERGY ANALOG (LEA) VOLTAGE SENSING ON Y AND Z SIDES
- MAXIMUM OUTPUT OF VOLTAGE SENSING IS 5 VAC WITH A 2,500:1 RATIO
- VOLTAGE SENSING IS CALIBRATED AT THE FACTORY USING RATIO CORRECTION FACTORS (RCFS) PROVIDED WITH THE VIPER
- RCFS ARE PROGRAMMED INTO THE MATCHING SEL 651R. RCFS MUST BE REPROGRAMMED IF DIFFERENT CONTROL IS USED. SEE LABEL INCLUDED WITH CONTROL FOR RCF VALUES AND EQUIVALENT PT RATIO.
- (6) WILDLIFE PROTECTORS PROVIDED
- RECLOSER IS EQUIPPED WITH TWO EXTERNAL ERMCO OIL-FILLED PTS FOR A NOMINAL SYSTEM OPERATING VOLTAGE OF 12470V WITH 60:1 RATIO 1000VA OUTPUT ERMCO PART NUMBER 10G-X0116-10NC. THE PTS INCLUDE AN INTERNAL FUSE LINK. CUSTOMER IS RESPONSIBLE FOR PROVIDING THE CABLES AND ACCESSORIES AND CONNECTING THE H1 BUSHINGS ON THE PRIMARY SIDE OF THE PTS AND CONNECTING THE H2 EYEBOLT BUSHINGS TO GROUND PER LOCAL CODES AND PRACTICES. CUSTOMER IS RESPONSIBLE FOR GROUNDING THE TANK OF THE PTS AS SHOWN ON THE PT NAMEPLATES. CUSTOMER IS RESPONSIBLE FOR CONNECTING THE 120VAC SECONDARIES TO THE SEL651R CONTROL USING G&W PROVIDED CABLES.
- PT CABLE LENGTH IS 40 FT. WITH 10 FT. OF ARMOR.
- ADDITIONAL 52B AUXILIARY CONTACT. 52A AND 52B CONTACTS FROM SAME FRAME MICROSWITCH. CABLE DISCONNECTED ALARM AVAILABLE WHEN 651R PROGRAMMED ACCORDINGLY.
RECLOSER ELECTRICAL INFORMATION
MAXIMUM DESIGN VOLTAGE 15.5 KV
IMPULSE LEVEL (BIL) 110 KV
AC (MIN. WITHSTAND (DRY) 50 KV
AC WITHSTAND (WET) 45 KV
CURRENT CONTINUOUS 800 AMP
CURRENT INTERRUPTING SYM. 12.5 KA
MOMENTARY CURRENT RMS ASYM 20 KA
MAKING CURRENT ASYM. 20 KA
3 SECOND RATED DURATION OF SHORT CIRCUIT 12.5 KA
THREE LINE DIAGRAM
IN SERVICE WEIGHT APPROX 650 LBS/ 295 KG
SHIPPING WEIGHT APPROX 1210 LBS/ 550 KG
NOTES:
1. POLYCARBONATE OPERATING MECHANISM COVER MOLDED LIGHT GRAY.
2. INTERRUPTER MODULES ARE NOT INTENDED FOR DEAD ENDING. SEPARATE STRAIN RELIEF IS REQUIRED FOR CABLES.
3. MANUAL TRIP LEVER EQUIPPED WITH ELECTRICAL AND MECHANICAL LOCKOUT OF CLOSING CIRCUIT WHEN LEVER IS IN THE TRIPPED POSITION.
4. RECLOSER EQUIPPED FOR DEADLINE OPERATION USING POWER FROM THE BATTERY IN THE SEL651R (42 PIN DESIGN).
5. "Z" ENTRANCE, SILICONE SHED INSULATORS CREEPAGE DISTANCE IS APPROXIMATELY 17.14 INCHES [435 MM]
"Y" ENTRANCE, SILICONE SHED INSULATORS CREEPAGE DISTANCE IS APPROXIMATELY 17.14 INCHES [435 MM].
FOR MOUNTING USE 1/2" [13 MM] DIAMETER BOLTS AND WASHERS MINIMUM AND 3/4" [19 MM] DIAMETER BOLTS AND WASHERS MAXIMUM.
MOUNTING BRACKETS WILL FIT 9" [229 MM] TO 14" [356 MM] DIAMETER POLE.
RECLOSER IS EQUIPPED WITH HUBBELL LIGHTNING ARRESTERS. PART NUMBER 213708-5183. PRIMARY AND SECONDARY WIRING ARE TO BE TERMINATED BY G&W. LIGHTNING ARRESTER GROUNDED USING #4 BRAIDED COPPER CABLE.
10. RECLOSER EQUIPPED WITH A 1000/500:1 CURRENT TRANSFORMER ON EACH PHASE FACTORY SET AT 1000:1 RATIO. REFER TO INSTALLATION, OPERATION AND MAINTENANCE INSTRUCTIONS FOR CHANGING CURRENT TRANSFORMER RATIO IN THE FIELD.
11. RECLOSER EQUIPPED WITH FIELD REPLACEABLE SILICONE SHED INSULATORS. A 38KV 600A DEADBREAK APPARATUS BUSHING PER IEEE 386 FIGURE 13 IS USED TO CONNECT THE SILICONE SHED INSULATOR TO THE RECLOSER. THIS 38KV APPARATUS BUSHING IS SUITABLE FOR USE WITH 600A OR 900A RATED ELBOWS.
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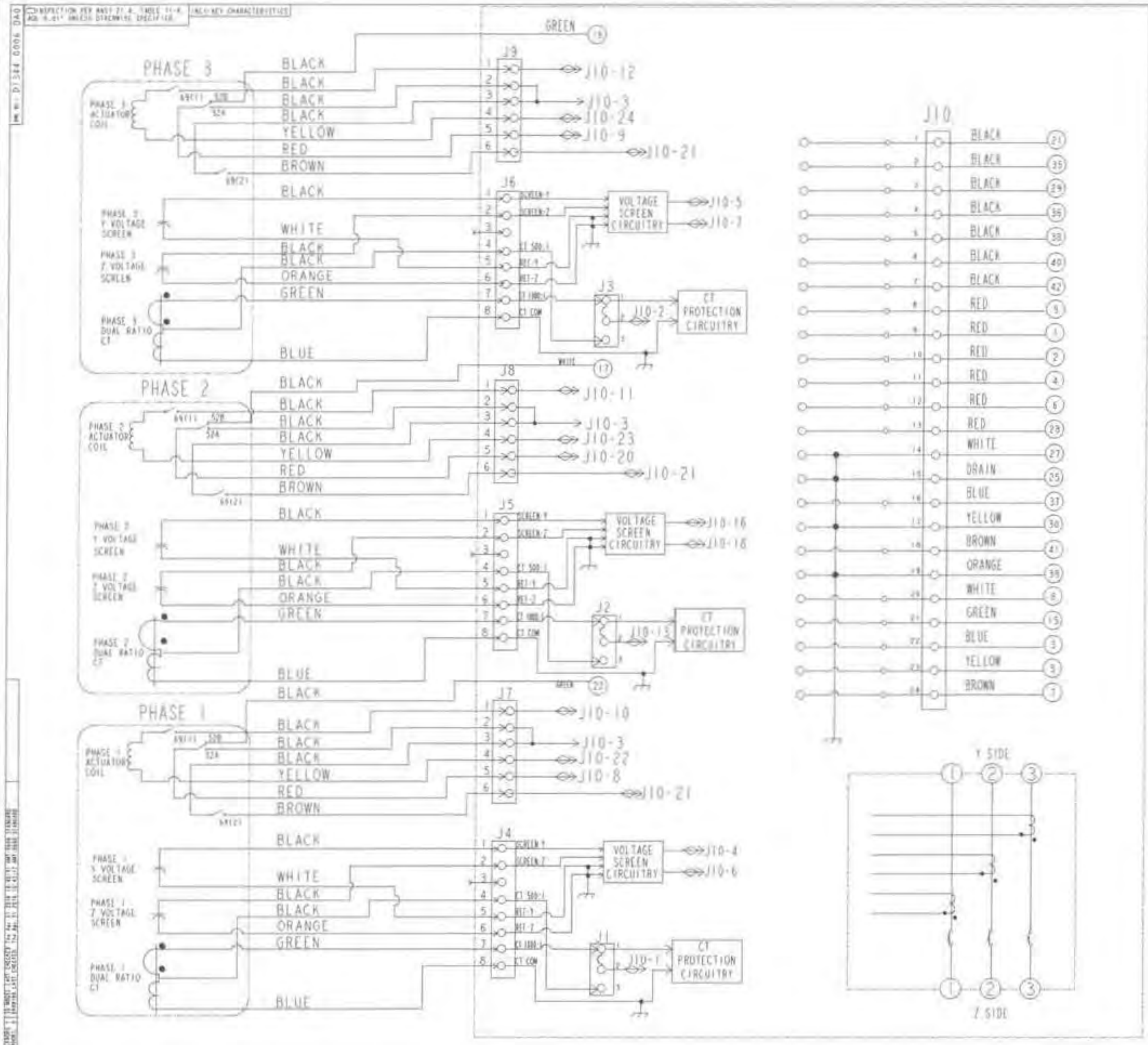
PROFESSIONAL ENGINEER
11/15/16
EXP. 6/30/17
FRONT VIEW
9.00 [229]
15.00 [381]
15.00 [381]
PHASE-1
PHASE-2
PHASE-3
(4) LIFTING PROVISIONS WITH 1.00" [25 MM] DIA. HOLE
50.70 [1288]
MANUAL TRIP LABEL (TYP)
POLYCARBONATE OPERATING MECHANISM COVER (LIGHT GRAY)
PHASE LABELS (1, 2 & 3)
MANUAL TRIP LEVER (SEE NOTE 3)
NAME PLATE 1 PER INTERRUPTER
WAY | ENTRANCES
Z | 15.5KV 110KV BIL 800A SILICONE SHED INSULATORS
Y | 15.5KV 110KV BIL 800A SILICONE SHED INSULATORS
RIGHT VIEW
15.67 [398]
#250-750MCM TINNED COPPER CLAMP (ALL BUSHINGS)
Z
INTERRUPTER MODULE
VOLTAGE SCREEN
INTERNAL CURRENT TRANSFORMER & VOLTAGE SCREEN (Y SIDE)
Y
PT3
ALUMINUM POLE MOUNTING BRACKET
PRINT IDENTIFICATION
DATE 5-4-2016
G&W NO. 58540
CUSTOMER LGE/KU
ORDER NO 801891-2
FOR RECORD
FOR APPROVAL NO MORE WORK TO BE DONE UNTIL APPROVAL IS RECEIVED
ITEM NO. 1
CT RATIO 1000:1
CONTROLLER NO. SEL651R2ACXGA8AA1113C502
* ALL PRIMARY DIMENSIONS ARE IN INCHES. ALL SECONDARY DIMENSIONS ARE IN MILLIMETERS.
ALL DRAWING CHANGES MUST BE MADE ON CAD. ANY MANUAL CHANGES WILL VOID DRAWING.
VIP378ER-12-1-ST-KU-DA
15.5KV 800 AMP SOLID DIELECTRIC RECLOSER WITH 6 INTERNAL VOLTAGE SENSING
G&W ELECTRIC Co.
VIP378ER-12-1-ST-KU-DA
CL
CL
May-04-16
D8706 PTIL CT0
1 of 1
SHEET 1 of 1
D8706 PTIL CT0



HARTING CONNECTOR 42 PIN	SIGNAL NAME (G & W USE)	JUNCTION BOARD J10	SINGLE PIN MOLEX COLOR	WIRE COLOR
1	52A-3	9		9-RED
2	MAG ACT PH1 A	10		10-RED
3	MAG ACT PH1 B	22		10-BLUE
4	MAG ACT PH2 A	11		11-RED
5	MAG ACT PH2 B	23		11-YELLOW
6	MAG ACT PH3 A	12		12-RED
7	MAG ACT PH3 B	24		12-BROWN
8	52A-2	20		8-WHITE
9	52A-1	8		8-RED
10	AUX RETURN			
11	AUX POWER			
12				
13				
14				
15	69	21		9-GREEN
16	52B-3		BLUE	15-GREEN
17	52B-2		RED	14-WHITE
18				
19				
20				
21	PH 1 CURRENT	1		1-BLACK
22	52B-1		BROWN	14-GREEN
23				
24				
25	GND	15		DRAIN
26				
27	CT N/GND	14		2-WHITE
28	PH 2 CURRENT	13		1-RED
29	+12V	3		3-BLACK
30	VIN	17		3-YELLOW
31				
32				
33				
34				
35	PH 3 CURRENT	2		2-BLACK
36	V1Y	4		4-BLACK
37	V2Y	16		4-BLUE
38	V3Y	5		5-BLACK
39	V2N	19		7-ORANGE
40	V1Z	6		6-BLACK
41	V2Z	18		6-BROWN
42	V3Z	7		7-BLACK

NOTES:

1. (XX) SHOWS PIN NUMBER OF 42 PIN CONNECTOR

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exp. 6/30/17

ALL DRAWING CHANGES MUST BE MADE ON CAD. ANY MANUAL CHANGES WILL VOID DRAWING

VIP ST 6LEA 42PIN 2PTS

VIPER ST 6LEA
WITH 42 PIN INTERFACE
AND 2PTS FOR POWER

G&W
G&W ELECTRIC Co.

08203 PTIL CTO

DJ | JC | Apr-21-16

01344 0006 DA0

SHEET 1 of 2

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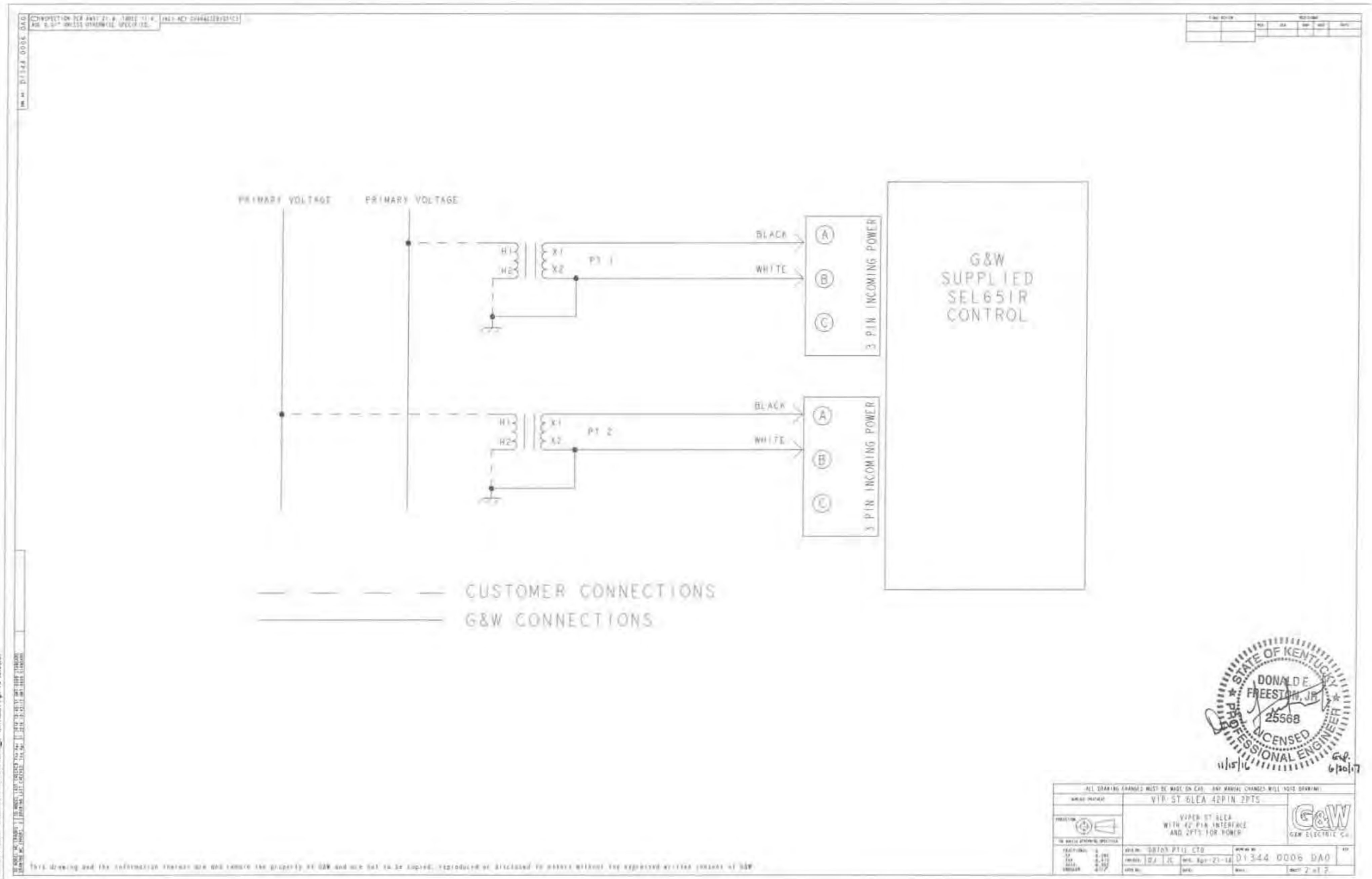
PRIMARY VOLTAGE
PRIMARY VOLTAGE
H1
H2
X1
X2
PT 1
BLACK
WHITE
A
B
C
3 PIN INCOMING POWER
G&W
SUPPLIED
SEL651R
CONTROL
H1
H2
X1
X2
PT 2
BLACK
WHITE
A
B
C
3 PIN INCOMING POWER
CUSTOMER CONNECTIONS
G&W CONNECTIONS
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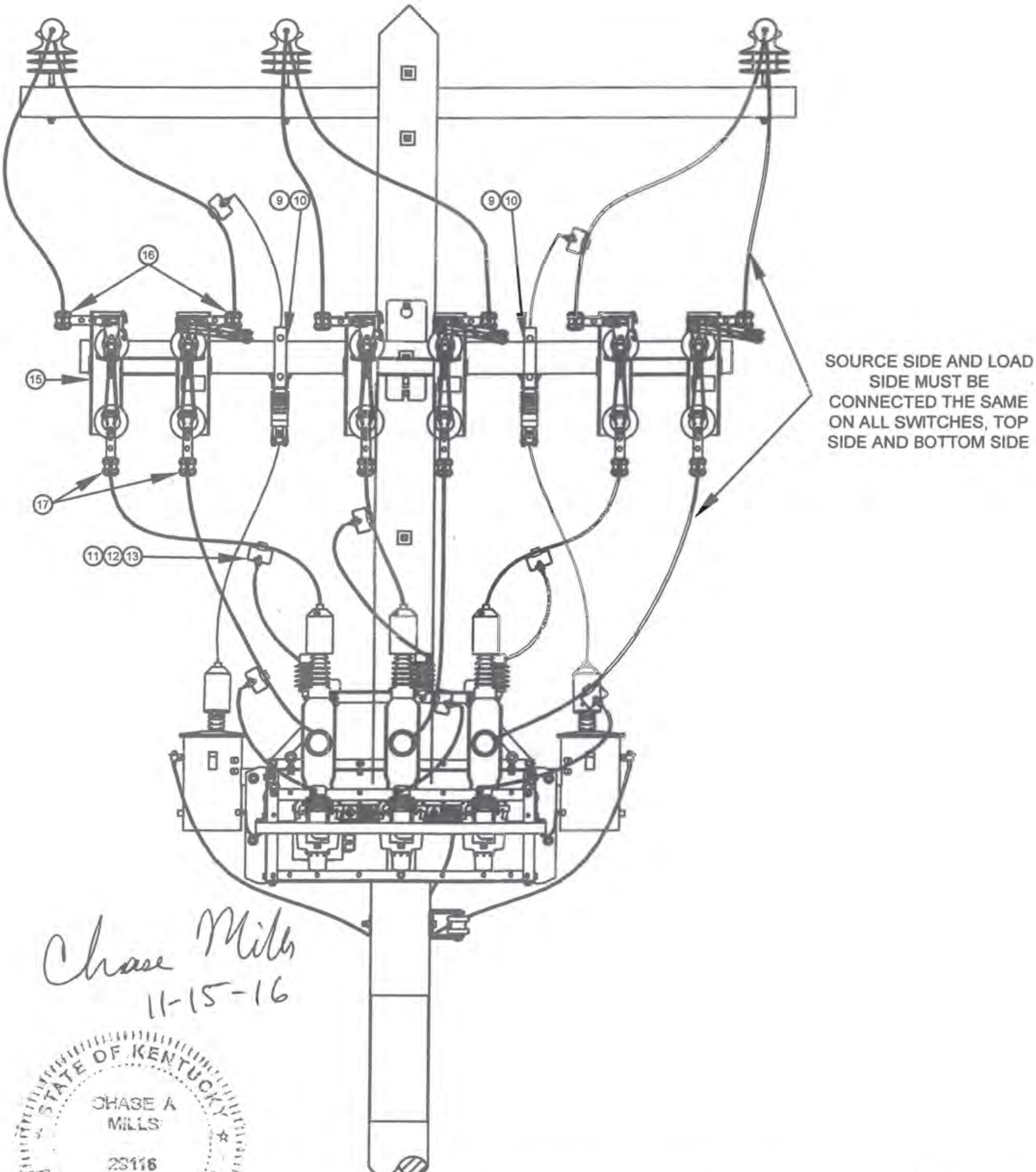
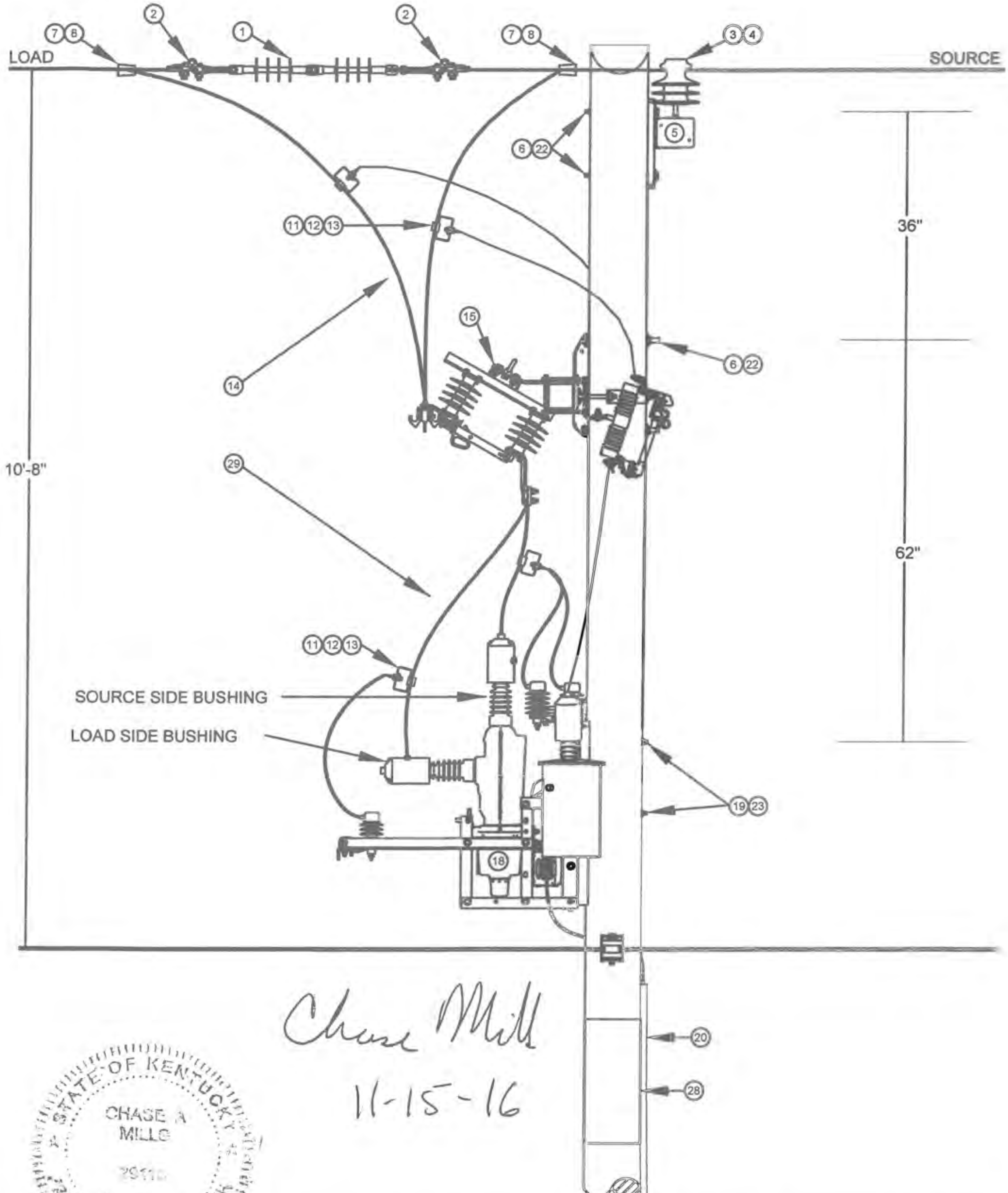
11/15/16
6/20/17
VIP ST 6LEA 42PIN 2PTS
VIPER ST 6LEA
WITH 42 PIN INTERFACE
AND 2PTS FOR POWER
G&W
G&W ELECTRIC CO.
D1344 0006 DA0



Chase Mills
11-15-16

STATE OF KENTUCKY
CHASE A. MILLS
23116
PROFESSIONAL ENGINEER



Chase Mill
11-15-16

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CHASE A. MILLS
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Notes:

1. BOTH THE TANK AND HEAD OF THE RECLOSER IS TO BE GROUNDED.

2. 12KV RECLOSERS SHOULD BE SET TO SINGLE PHASE TRIP SINGLE PHASE LOCKOUT.

3. 12KV TRANSFORMERS ARE TO BE CONNECTED TO A AND C PHASES. CONNECT ONE TRANSFORMER TO THE SOURCE SIDE AND THE OTHER TRANSFORMER TO THE LOAD SIDE.

4. ENSURE THAT THE BACKUP BATTERY IS CONNECTED.

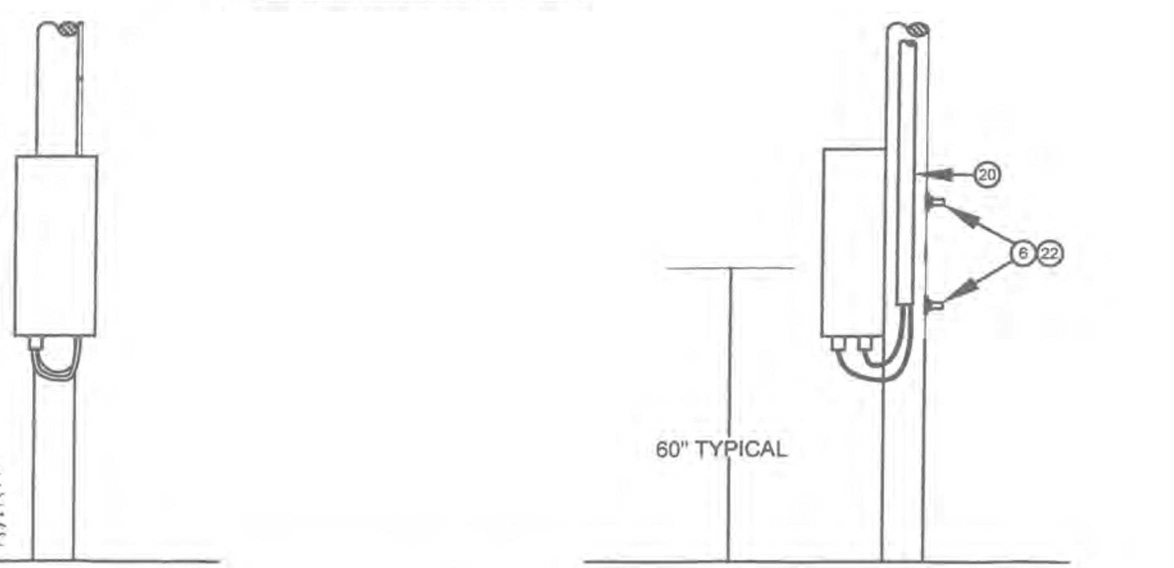
5. CONTROL SHALL BE MOUNTED TYPICALLY AT 60" AT CENTER OF CONTROL ABOVE GROUND LINE TO ALLOW EASE OF ACCESS.

6. THE FIRST 10' OF CONTROL AND POWER CABLE IS ARMORED. U-GUARD MUST BE INSTALLED TO COVER THE NON-ARMORED SECTION OF CABLE AND SHALL EXTEND A MINIMUM OF 40" PAST THE HIGHEST COMMUNICATION ATTACHMENT.

MATERIAL LIST

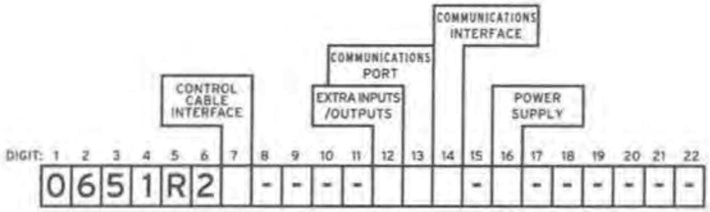
ITEM	IIN	DESCRIPTION	QTY
1	7001280	INSULATOR,SUSPENSION,15 KV,POLYMER	6
2	VARIES	DEADEND-VARIOUS SIZES	6
3	7001269	INSULATOR,PIN TYPE,15KV,POLYMER	3
4	7004088	PIN,INSULATOR,STRAIGHT,5/8"X6"	3
5	3015303	CROSSARM,FG,TANGENT,3-5/8"X4-5/8"X8'	1
6	VARIES	5/8" BOLT-VARIOUS SIZES	8
7	VARIES	FARGO CONNECTOR-VARIOUS SIZES	6
8	VARIES	FARGO COVER-VARIOUS SIZES	6
9	7000879	BRACKET,CUTOUT/ARRESTER,X-ARM	2
10	7001957	CUTOUT,FUSED,15KV,NON-LOADBREAK,W100A TUBE	2
11	1157894	CONNECTOR,PARALLEL,AL,336.4-795 MCM TO 8 SLD-2/0 STR COPPER	8
12	1159527	STIRRUP,BAIL,HOT LINE,COPPER,TIN PLATED	8
13	7000591	CLAMP,HOT LINE,8-2/0,CU	8
14	VARIES	POLY WIRE FOR JUMPERS-SIZED TO PRIMARY	20
15	3014901	SWITCH,RECLOSER BYPASS,14.4KV,900A,110KVBIL,3 PULL	1
16	3016577	LUG.TERMINAL.ALUMINUM.BOLTED.TEE CONNECTOR 336/795	6
17	3015376	500MCM BRONZE BOLTED CONNECTOR-SIZES VARY	6
18	3021740	RECLOSER,THREE SINGLE PHASE MODULES WITH SINGLE CONTROL	1
19	VARIES	3/4" SPACER BOLT-SIZES VARY	2
20	1160519	GUARD,CABLE,10'-2",U-SHAPED,PVC	3
21	1181001	LOCK,PAD,WITH 1-1/2" SHANK,BRASS	1
22	7000337	WASHER,FLAT,SQUARE,2-1/4" X 2-1/4" X 3/16",FOR 5/8" BOLT	8
23	1243701	WASHER,CURVED,SQUARE,4" X 4" X 3/4",GALV,FOR 3/4" BOLT	2
24	7000602	CLAMP,GROUND,TRANSFORMER TANK,BRZ,#8SLD TO 2/0 STR	1
25	7000303	BOLT,MACHINE,1/2",2",SS,SILICON BRONZE NUT,2 FLAT & 1 BELLVL W/	6
26	1159243	SCREW,LAG,1/2"X 4",GIMLET POINT,GALV STD PKG=250	8
27	7000302	BOLT,MACHINE,1/2",1-1/2",SS,SILICON BRONZE NUT,2 FLAT & 1 BELLVL	12
28	3000347	SLIDE,ANIMAL,25" X 48",POLYETHYLENE,POLE PROTECTION	1
29	7000401	CONDUCTOR,OH WIRE,500,CU-SD,XLPE,80 MIL,90-DEG C RATED,37 STR	20

CONTROL INSTALLATION DETAIL



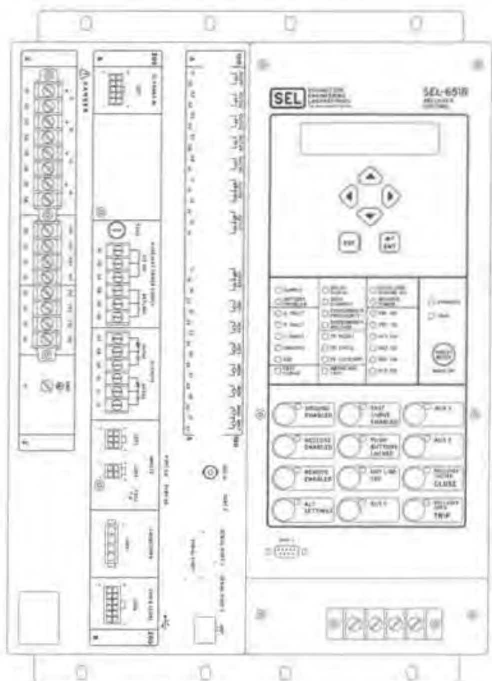
Chase Mills
11-16-15

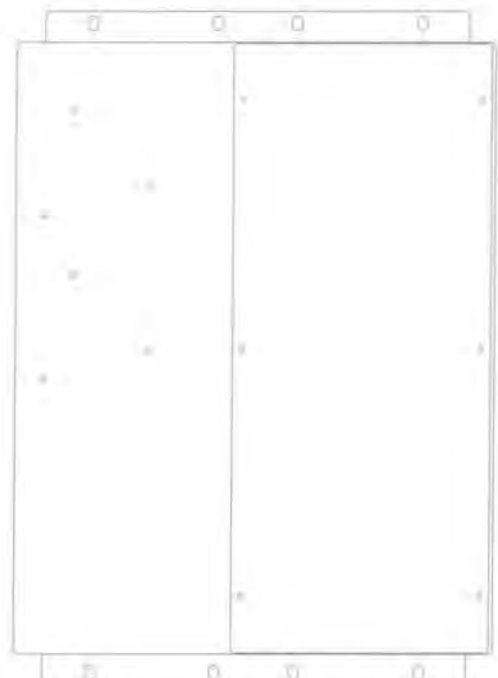
STATE OF KENTUCKY
CHASE A. MILLS
29115
PROFESSIONAL ENGINEER



NOTES:

1. IF YOU ARE NOT FAMILIAR WITH MASTER CONFIGURATION DRAWINGS, PLEASE SEE INSTRUCTIONS LOCATED FIRST IN THE SEL WEBSITE DRAWING LINKS.
2. THIS DRAWING IS FOR THE 651R-2, VERTICAL PRODUCT ONLY. THE ENCLOSURE IS STATIC.
3. USE LAYERS TO UPDATE VIEWS. SOME COMBINATIONS MAY NOT BE AVAILABLE. VERIFY PART NUMBER USING SEL WEBSITE.
4. ONLY SELECT ONE OPTION PER SLOT.
5. DRAWINGS ARE UPDATED FREQUENTLY, PLEASE USE CURRENT LINK FROM SEL WEBSITE.
6. DASHED SLOTS DO NOT AFFECT PRODUCT GRAPHICS AND ARE NOT SHOWN AS CONFIGURABLE OPTIONS.





STATE OF KENTUCKY
DONALD E. FREESTONE
25566
LICENSED PROFESSIONAL ENGINEER
11/15/16
EXP. 6/30/17

SINGLE DOOR POLE-MOUNT ENCLOSURE

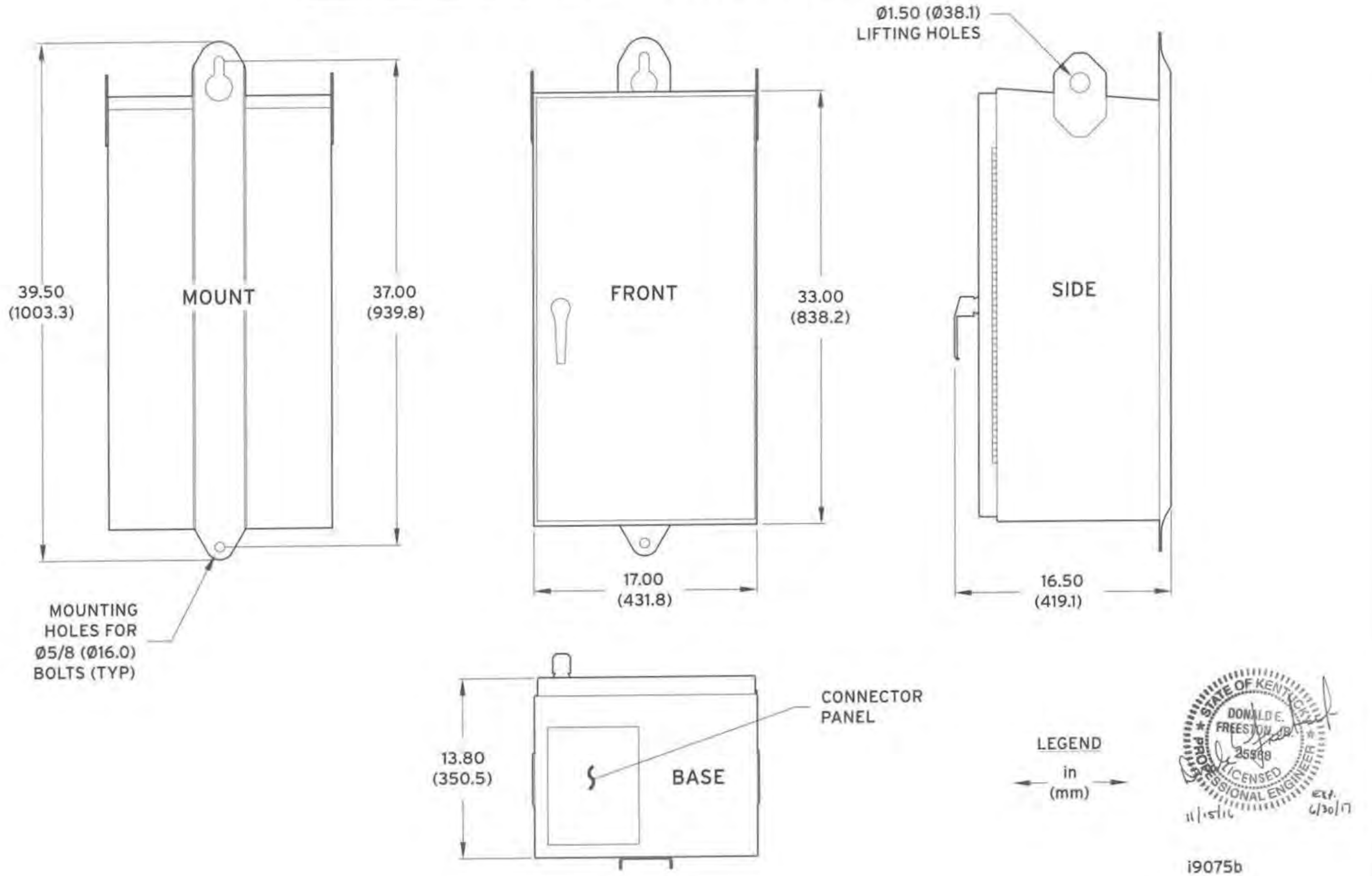


Exhibit PWT-5

LG&E and KU Electric Distribution Operations
Distribution Reliability and Resiliency Improvement Program

Electric Distribution Operations

Distribution Reliability & Resiliency Improvement Program

PPL companies

November 2016

Contents

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1. Executive Summary

Customer needs and expectations respective to electric service reliability, system resilience, outage response, and power quality continue to evolve and expand with advancements in grid and customer end-use technologies; electricity is increasingly entwined in nearly every aspect of their lives. Because of the broadening electrification of virtually everything, Louisville Gas and Electric Company (LG&E) and Kentucky Utilities Company (KU), along with the rest of the electric industry, must continually monitor and assess electric delivery performance, and adjust associated electric grid investments and sustainability programs as needed to align with changing customer requirements. Inadequate service reliability or power quality, and long duration outages, are no longer tolerable due to the significance of consequences on customers.

As stewards of the electric distribution system, Electric Distribution Operations (EDO) is responsible for assuring LG&E and KU serve customers with safe, reliable, resilient, and affordable electric service. Consistent with the industry, EDO monitors and benchmarks reliability performance using standard indices defined by the Institute of Electrical and Electronics Engineers (IEEE). REDACTED PU [redacted]

In the aftermath of the 2008 Hurricane Ike Wind Storm and 2009 Kentucky Ice Storm, which produced the most significant system damages and customer outages in company history, LG&E and KU electric service reliability and customer satisfaction levels declined. In response, EDO studied alternatives for enhancing electric system resiliency to guard against similar extensive and residual system damages and long duration outages for customers. As a result of these studies, EDO broadened and enhanced its portfolio of distribution system reliability and resiliency programs starting in 2010.

In total, LG&E and KU allocated more than $192 million in Capital and $36 million in Operations and Maintenance Expenses (OPEX) between 2010 and 2016 on incremental programs, including circuit hardening/reliability, pole inspection and treatment (PITP), aging infrastructure replacement (AIR), distribution substation transformer contingency (N1DT) and hazard tree mitigation. These programs produced significant improvements in LG&E's and KU's key reliability performance metrics (more than 22%) and contributed to improved customer satisfaction ratings (more than 16%) between 2010 and 2015.

As EDO's incremental reliability and resiliency programs have matured, step improvements in system performance and customer satisfaction levels have and will continue to become increasingly more difficult to attain. Expanded investment programs are necessary to further align system performance and service reliability with expanding customer expectations and needs.

In order to address evolving customer expectations and service challenges, EDO's 2017-2021 Business Plan allocates investment of approximately $352 million in capital and more than $29 million in OPEX on enhanced reliability and resiliency programs. The plan includes continued funding of EDO's existing circuit hardening (including the Circuits Identified for Improvement (CIFI) and Hazard Tree Programs), PITP, and AIR programs, as these programs continue to deliver system reliability and resiliency improvements. Substantial shifts in funding away from these programs would increase outages and decrease operational contingency. EDO's business plan also includes targeted incremental investments in the advancement of distribution automation (DA) and expansion of its distribution substation transformer contingency (N1DT) program.

Distribution Automation Program (DA)

EDO's proposed Distribution Automation (DA) Program includes $112.4M in investments between 2016 and 2022. EDO's proposed 2017 Business Plan allocates $94.1M between the plan years 2017 through 2021 for DA. The proposed DA program will provide for acquisition and deployment of Distribution Supervisory Control and Data Acquisition (DSCADA) and a Distribution Management System (DMS), and purchase and installation of approximately 1,400 electronic SCADA connected reclosers. Approximately 360 (20%) distribution circuits and 50% of LG&E and KU customers will be targeted by the program.

The advanced technology and functionality enabled by the DA program will significantly reduce the number of customers affected by outage events, reduce restoration times for customers affected by outages, and improve operational efficiency. SAIDI and SAIFI performance is expected to improve by 12% and 19% respectively, over the next six years (2017 – 2022). The DMS will provide advanced functionality required to achieve incremental DA benefits, including Power Flow (PF); Fault Location Analysis (FLA); Suggested Switching (SS); and Fault Location, Isolation and Service Restoration (FLISR). On circuits where DA is deployed, real time data from smart reclosers will provide intelligence and remote capabilities to support switching, safety, productivity and efficiency. The technology will also enable advanced monitoring and control of the distribution system, enhance crew dispatching processes, and reduce field crew truck rolls and mileage.

Distribution Substation Transformer Contingency (N1DT) Program

EDO's proposed Distribution Substation Transformer Contingency (N1DT) Program includes $175M in investments between 2015 and 2029. EDO's proposed 2017 Business Plan allocates $47.8M between the plan years 2017 through 2021 for this program. This funding level supports EDO's 15-year N1DT Contingency Program to further improve the integrity and recovery characteristics of LG&E and KU's distribution infrastructure and operations, through deployable or permanent "N-1" contingency design on its system. Approximately 63% of LG&E and KU's distribution power transformers do not have full contingency. If one of these substation transformers fails during high load or peak conditions, some customers will be without service until the transformer capacity is replaced, a process that can sometimes take multiple days. EDO's N1DT contingency program will mitigate potential high impact, long duration service interruptions which would likely result whenever a substation transformer fails, by making available either a permanent or deployable back-up source to support system and customer restoration.

The N1DT contingency program provides a three tiered approach for adding capacity in the event of a substation transformer failure: (1) the addition of permanent system capacity for full redundancy through switching. This includes substation transformer additions, circuit upgrades, and other system enhancements; (2) expanded use of mobile transformers; and (3) use of small localized spare distribution power transformers to restore service in the most efficient, and cost effective manner. Projects will be selected on a value-based approach, balancing the load density and customer impact with the cost of implementing the contingency enhancement.

EDO's investment strategies and programs referenced herein will advance grid intelligence, assure continued improvement in reliability performance and power quality, build additional contingency into critical assets, and provide for enhanced diagnostics capabilities, operational control, and system flexibility. These planned investment strategies align with industry best practices, and will modernize the grid and enable the company to satisfy expanding customer expectations.

2. Case for Action/Performance Objectives/Strategy

2.1 Background

Louisville Gas and Electric Company (LG&E) and Kentucky Utilities Company (KU) serve nearly 1.3 million customers, and consistently rank high in customer satisfaction among utilities. LG&E serves 403,000 electric customers in Louisville and 16 surrounding counties, and KU serves 546,000 electric customers in 77 Kentucky counties and five Virginia counties.

LG&E and KU participate in multiple industry accepted customer satisfaction surveys, the most recognizable of which is administrated by J.D. Power, which evaluates several key indices. Figure 1 displays LG&E and KU's nationwide customer satisfaction rankings based on the J.D. Power 2016 Electric Utility Residential Customer Satisfaction Study published in July 2016.

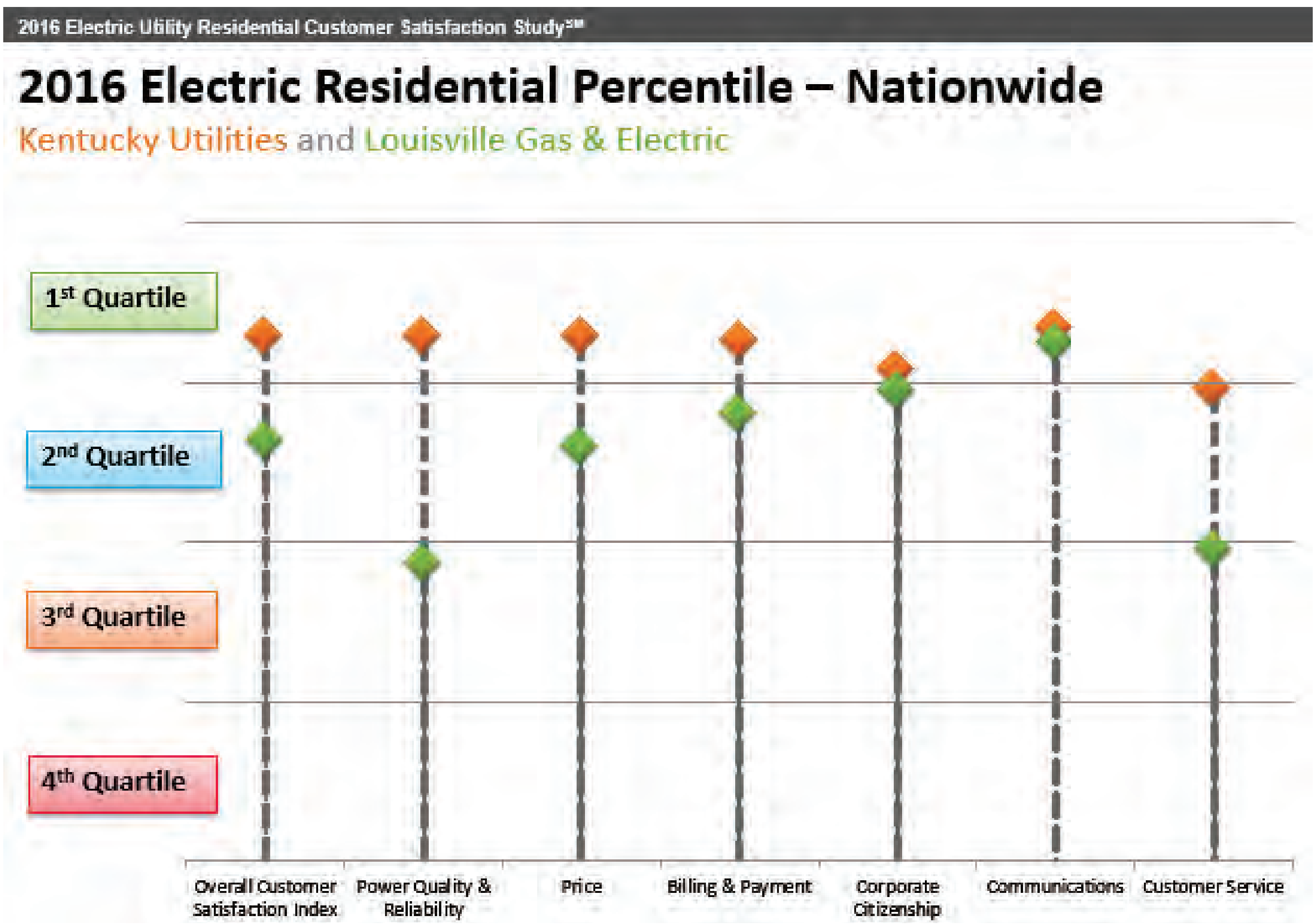

Figure 1: J.D. Power 2016 Electric Utility Customer Satisfaction Survey

LG&E and KU customer satisfaction ratings were first or second quartile in nearly every category within the survey, including the Overall Customer Satisfaction category. Customers' perception of LG&E and KU's power quality and reliability performance ranked in the first and at the top of the third quartile respectively, nationwide.

When evaluating LG&E and KU's customer satisfaction ratings compared to the industry, it is important to note two key characteristics of the J.D. Power Study (gleaned from an article published in Public Utilities Fortnightly,[1] January 2013):

1. First, geography appears to have the greatest impact on relative customer satisfaction across the United States. Utilities in the Northeast and Midwest consistently have lower customer satisfaction rankings than utilities in the Southwest, Northwest, and Southeast. LG&E and KU continues to realize customer service rankings which are first or upper second quartile nationally in overall customer satisfaction, despite being located in the Midwest, a geographical area with historically lower relative customer satisfaction rankings.
2. Second, and more importantly, other than geography, reliability performance appears to have the greatest influence on the relative value of other key electric utility customer satisfaction indexes in the J.D. Power survey. LG&E and KU's high rankings in overall customer satisfaction are likely reflective of LG&E and KU's continued strong reliability performance relative to the industry.

LG&E and KU also use a third party vendor (Bellomy Research) to conduct an annual Residential Customer Satisfaction polling study among all LG&E, KU, and ODP customers (Figure 2). Overall satisfaction is measured on a 10-point scale with 10 being the most satisfied. The customer satisfaction scores in Figure 2 represent the percentage of customers rating the utility a 9 or 10 since 2006.

Figure 2: LG&E and KU customer satisfaction ratings.

REDACTED Pursuant to Third-Party Nondisclosure Agreement [redacted]

1. Reference: Public Utilities Fortnightly; Rates, Reliability, and Region - Customer Satisfaction and Electric Utilities; By William Zarakas, Philip Hanser, and Kent Diep; Principals and Research Analysts — The Brattle Group; January 2013.

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LG&E and KU's SAIDI and SAIFI performance ranked REDACTED Pursuant to Third-Party Nondisclosure Agreement prior to the 2008 Hurricane Ike Wind Storm and 2009 Kentucky Ice Storm. Immediately following these storms, the most significant outage events in the combined utilities' histories,[7] LG&E and KU's actual and comparative reliability performance (Figures 3-6) and customer satisfaction levels (Figure 2) declined. Moreover, LG&E and KU customer satisfaction levels reached historically low levels between 2009 and 2011.

In response to the historical storms and reduced customer satisfaction levels, EDO studied alternatives for enhancing electric system resiliency[8] to guard against similar extensive system damages and long duration outages for customers. From this study, EDO implemented several system reliability and resiliency enhancement programs in 2010, including a Pole Inspection and Treatment Program (PITP) and Hazard Tree Program. EDO also increased investments in circuit hardening reliability programs that had proven valuable over time, namely the CIFI program. In subsequent years, EDO allocated incremental funding for Aging Infrastructure Replacement (AIR) and Distribution Substation Transformer Contingency (N1DT) programs.

Figure 7 displays EDO's electric distribution system reliability and resiliency capital investment allocations between 2006 and 2015.

REDACTED Pursuant to Third-Party Nondisclosure Agreement

7. The 2009 Kentucky Ice Storm ranks as the largest outage event in LG&E and KU history — 654k customer outages on 8.7k outage events; Hurricane Ike ranks second — 480k customers affected, on 6.1k outage events.

8. ***Definition:*** Resilience, is defined as "robustness and recovery characteristics of utility infrastructure and operations, which avoid or minimize interruptions of service during an extraordinary and hazardous event."
Source: National Association of Regulatory Utility Commissioners, Resilience in Regulated Utilities; Miles Keogh, Christina Cody, NARUC Grants and Research — with support from DOE; November 2013.

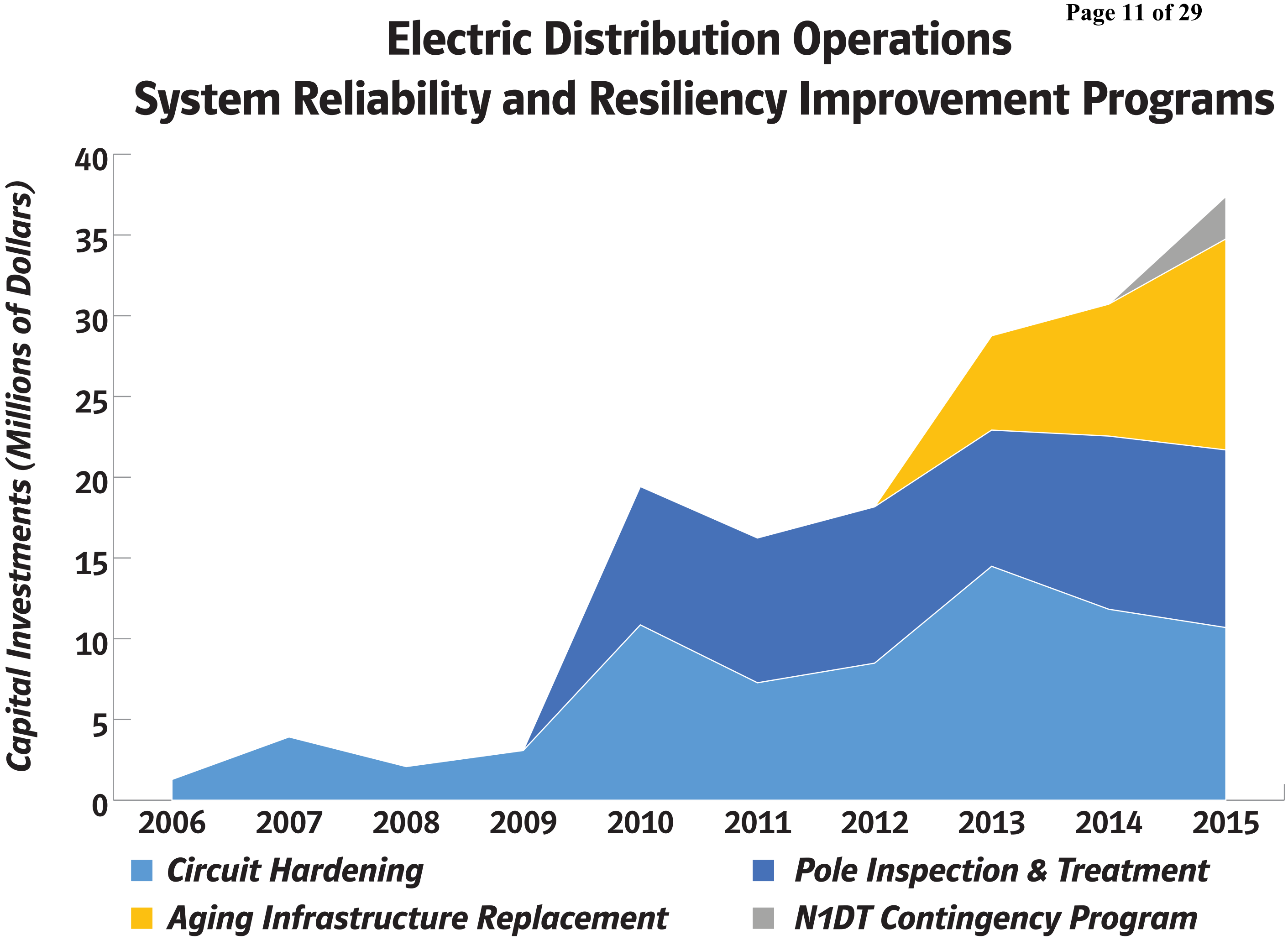

Figure 7: LG&E and KU electric distribution service reliability and system resiliency capital investment programs (2006-2015).

EDO's increased investments in reliability and resiliency produced significant improvements in LG&E and KU SAIDI (22%) and SAIFI (24%) between 2010 and 2015. Additionally, LG&E and KU's customer satisfaction ratings improved between 16 and 27 percent. EDO attributes much of its realized reliability improvements to its CIFI program. Between 2010 and 2015, EDO completed circuit hardening on 190 LG&E and KU circuits which were targeted for the CIFI program based on historical Customers Interrupted (CI). During the same period, 245 electronic reclosers were installed primarily through the CIFI program.

When the CIFI program was initiated, EDO understood that eventually, the same investment would yield progressively smaller reliability benefit per dollar invested. Figure 8 displays the average SAIFI contribution of circuits targeted for improvement since 2010. As the CIFI program has progressed, the average annual SAIFI contribution of circuits targeted for the program has steadily decreased, indicating reduced opportunity to realize further step improvements in SAIFI through the existing program. Realizing this, EDO assessed alternative investment strategies for achieving step improvements in reliability and customer satisfaction.

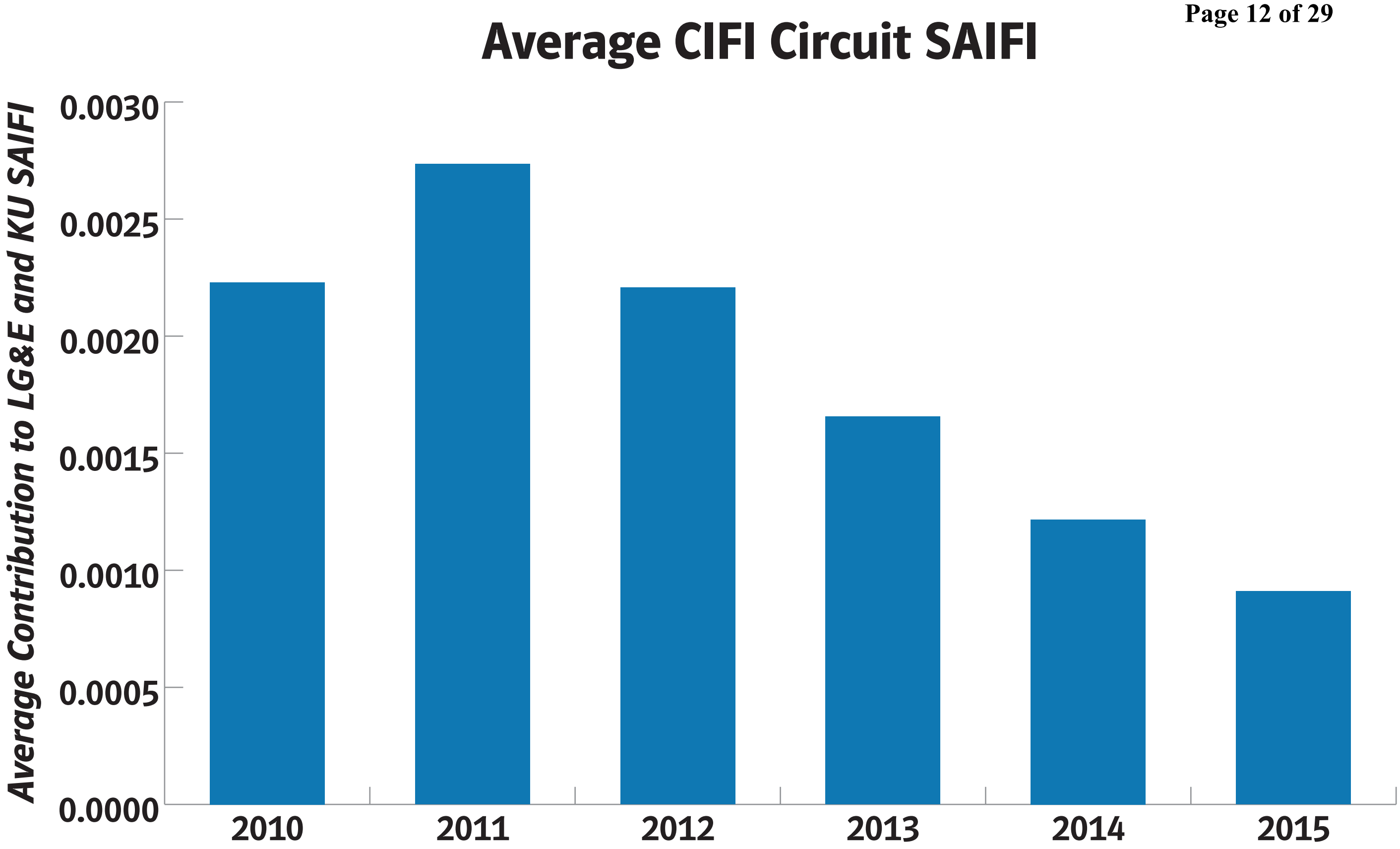

Figure 8: Average Circuit SAIFI Performance for LG&E and KU circuits selected for EDO CIFI Programs 2010–2015.

2.2. Industry Perspective

REDACTED Pursuant to Third-Party Nondisclosure Agreement [redacted] converging and enhanced reliability performance characteristics are being attributed to vastly increased capital investments and modernization of electric distribution systems across the industry.

In addition to its customer service and reliability performance benchmarking studies, EDO routinely surveys the electric industry to identify emerging and advancing technologies for improving distribution resiliency and reliability. Over the past decade, most leading electric utilities have focused on improving distribution reliability by increasing capital investments in circuit hardening and critical asset contingency. More recent trends in the industry point to accelerated investment strategies in grid intelligence technologies in response to increasing customer expectations for reliable power, and the proliferation of distributed energy resources (DER).

Based on EEI's analysis, annual capital investments in U.S. investor owned electric utilities have increased 67%–96% over the last ten years, and are projected to remain above $90 billion through 2018 (see Figure 9).

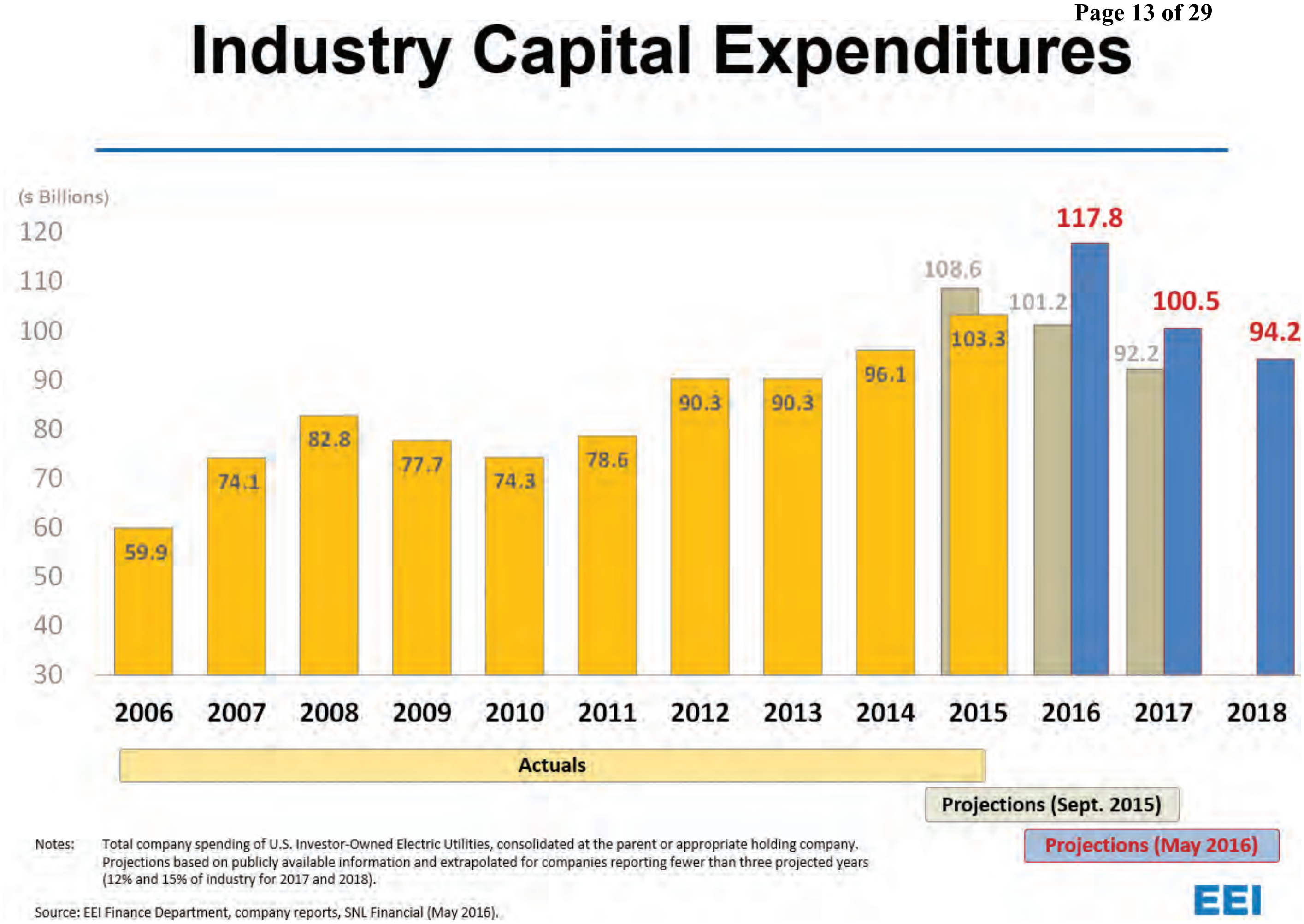

Figure 9: Annual Capital Expenditures of U.S. Investor Owned Utilities.[9]

It is important to note that in recent years, the capital investment across the industry is being shifted from generation to power delivery (i.e., transmission and distribution). In 2015, the percent of investor owned utility capital investments in distribution increased to 26% from 21% of total investment, when compared to 2013 capital allocations (see Figure 10).

9. Edison Electric Institute (EEI) — Electric Utility Industry Financial Data and Trend Analysis; May 2016; **http://www.eei.org/resourcesandmedia/industrydataanalysis/industryfinancialanalysis/QtrlyFinancialUpdates/Pages/default.aspx**.

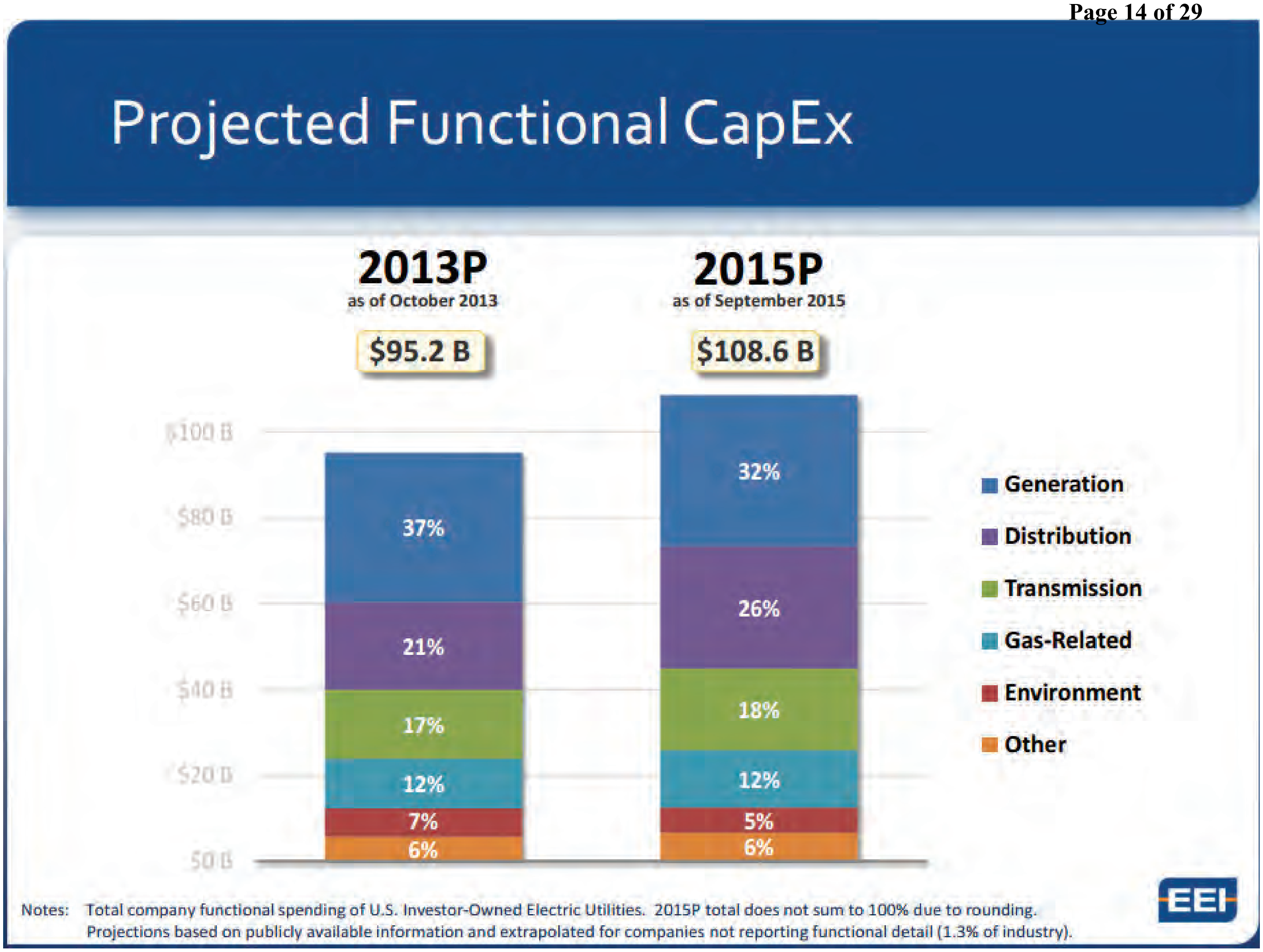

Figure 10: Projected Functional CapEx.[10]

The American Recovery and Reinvestment Act (ARRA) is a primary contributor and stimulant of increased investments in electric utility distribution assets since 2009. President Obama signed the ARRA into law on February 17, 2009.

The ARRA was implemented primarily to stimulate the economy, but included specific measures and funding designated to encourage private utility investment towards advancing grid intelligence and modernization. Approximately $4.5 billion was allocated to DOE for Smart Grid Investment Grant (SGIG), Smart Grid Demonstration Program (SGDP), Energy Storage Demonstration (ESD), Smartgrid Workforce Development and other miscellaneous programs. The SGIG program was funded at $3.4 billion. Grants under this program were awarded to approximately 99 utilities, and resulted in joint (public-private) investments of $8 billion[11] for DOE approved smart grid projects.

Figure 11 displays actual and estimated smart grid investments in the United States, since the ARRA was written into law, and since SGIG grants started being distributed. Figure 12 displays geographic locations of funded smart grid projects.

10. Edison Electric Institute (EEI) — Electric Utility Industry Financial Data and Trend Analysis; May 2016; **http://www.eei.org/resourcesandmedia/industrydataanalysis/industryfinancialanalysis/QtrlyFinancialUpdates/Pages/default.aspx**.

11. DOE, Office of Electricity Delivery and Energy Reliability; The American Recovery and Reinvestment Act Smart Grid Highlights, Jumpstarting a Modern Grid; October 2014.

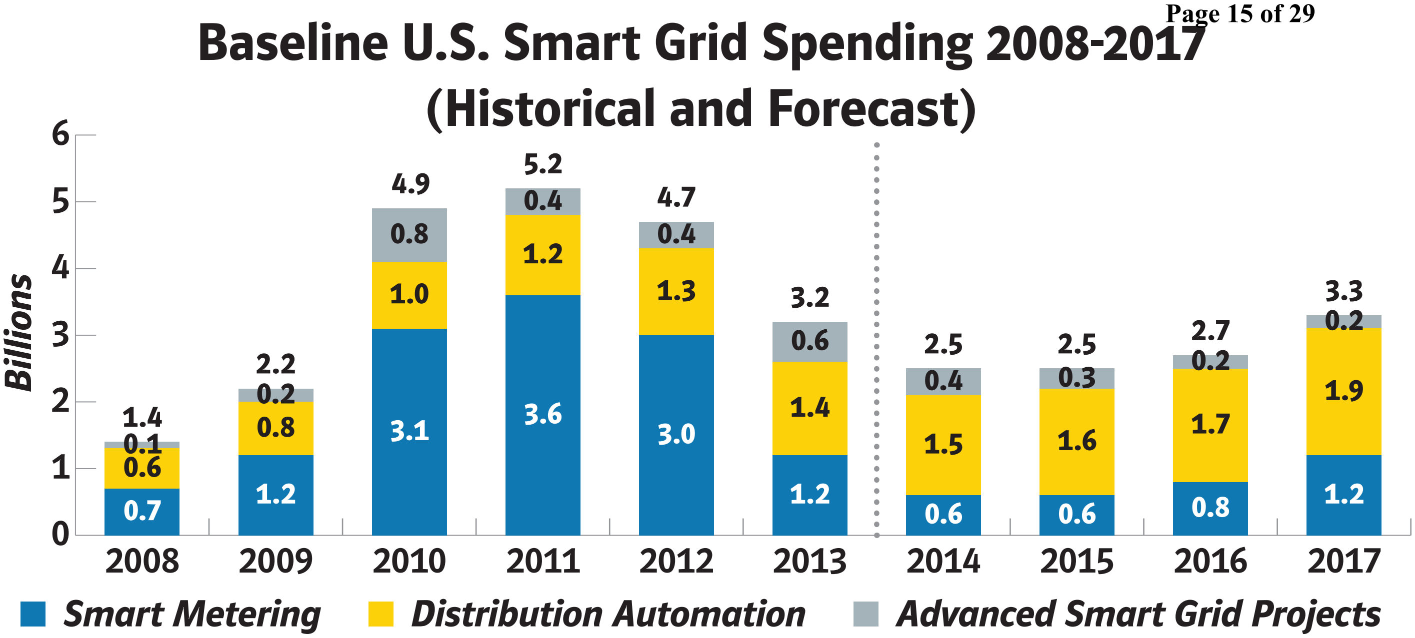

Figure 11: Baseline U.S. Smart Grid Spending 2008-2017 (Historical and Forecast).[12]

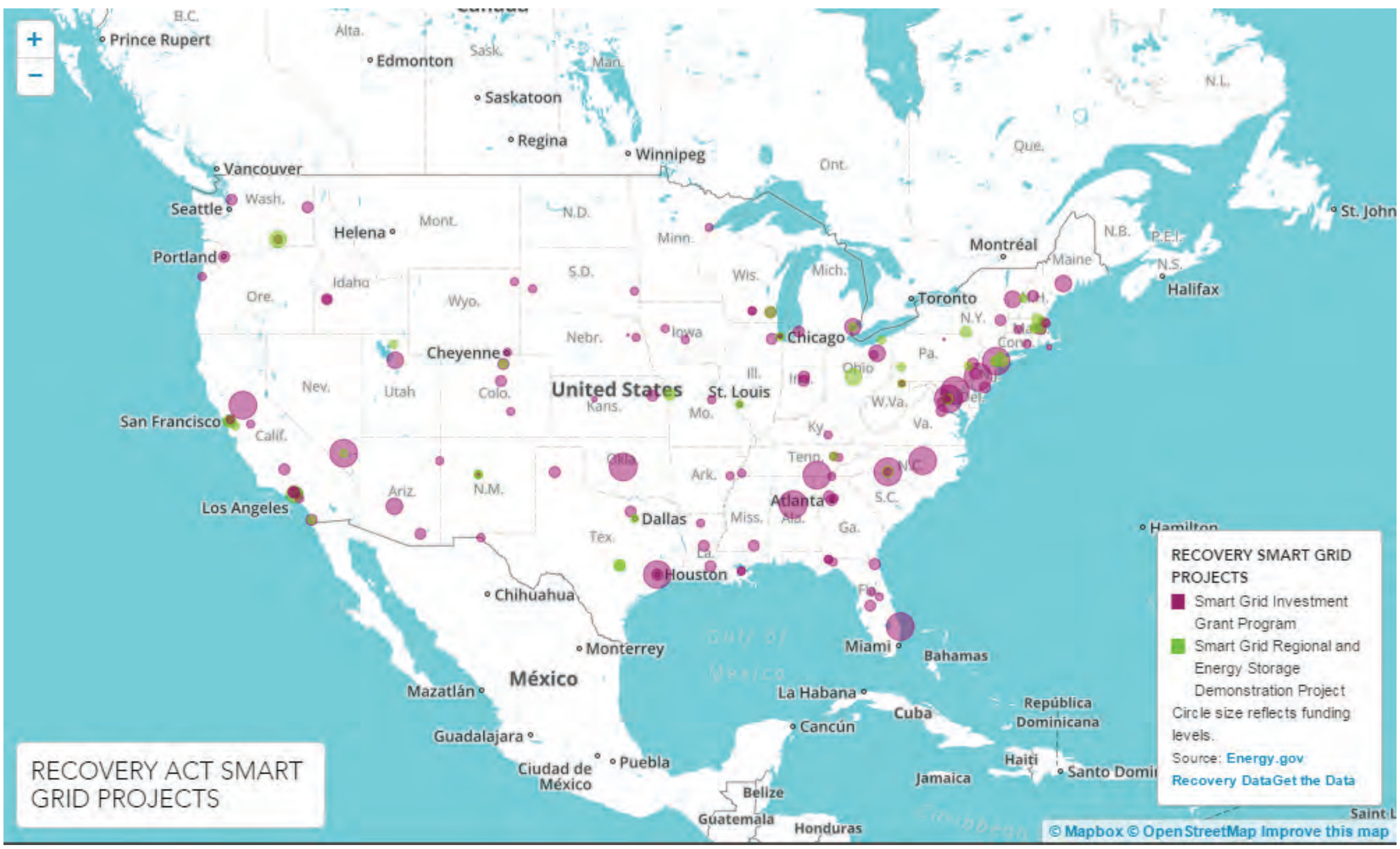

Figure 12: U.S. DOE map of American Recovery and Reinvestment Act (ARRA) Smart Grid Projects.[13]

Respective to smart grid deployments, utilities are generally deploying two key smart grid approaches: 1) distribution automation (DA), including automatic feeder switching (AFS) and fault location, isolation, and service restoration (FLISR), and 2) integrating advanced metering infrastructure (AMI)[14] capabilities with outage management systems.

12. DOE, 2014 Smart Grid System Report; August 2014, page 3.

13. DOE, Map of Recovery Act Smart Grid Projects; **http://energy.gov/maps/recovery-act-smart-grid-projects**.

14. An evaluation of LG&E and KU's Advanced Metering Infrastructure business case is currently underway and will be described in a separate report once completed.

DA refers to technologies and equipment that automatically operate to restore or minimize outages or that allow remote operation and optimization of the distribution grid. The spectrum of DA implementation options runs from installing automated reclosers that can segment feeders to reduce the impact of an outage, to implementing "self-healing" schemes using SCADA-operated reclosers and switches that allow remote monitoring, and remote control and automation of distribution line equipment. When combined with the implementation of AMI and advanced Distribution Management Systems (DMS), more advanced DA schemes can enable integration of DER by allowing bi-directional energy flow on the distribution network.

Current industry trends respective to deployments of DA technologies are difficult to obtain due to the accelerated pace of new projects by U.S. utilities. Figure 13 provides the most recent available geographical representation of DA deployments.

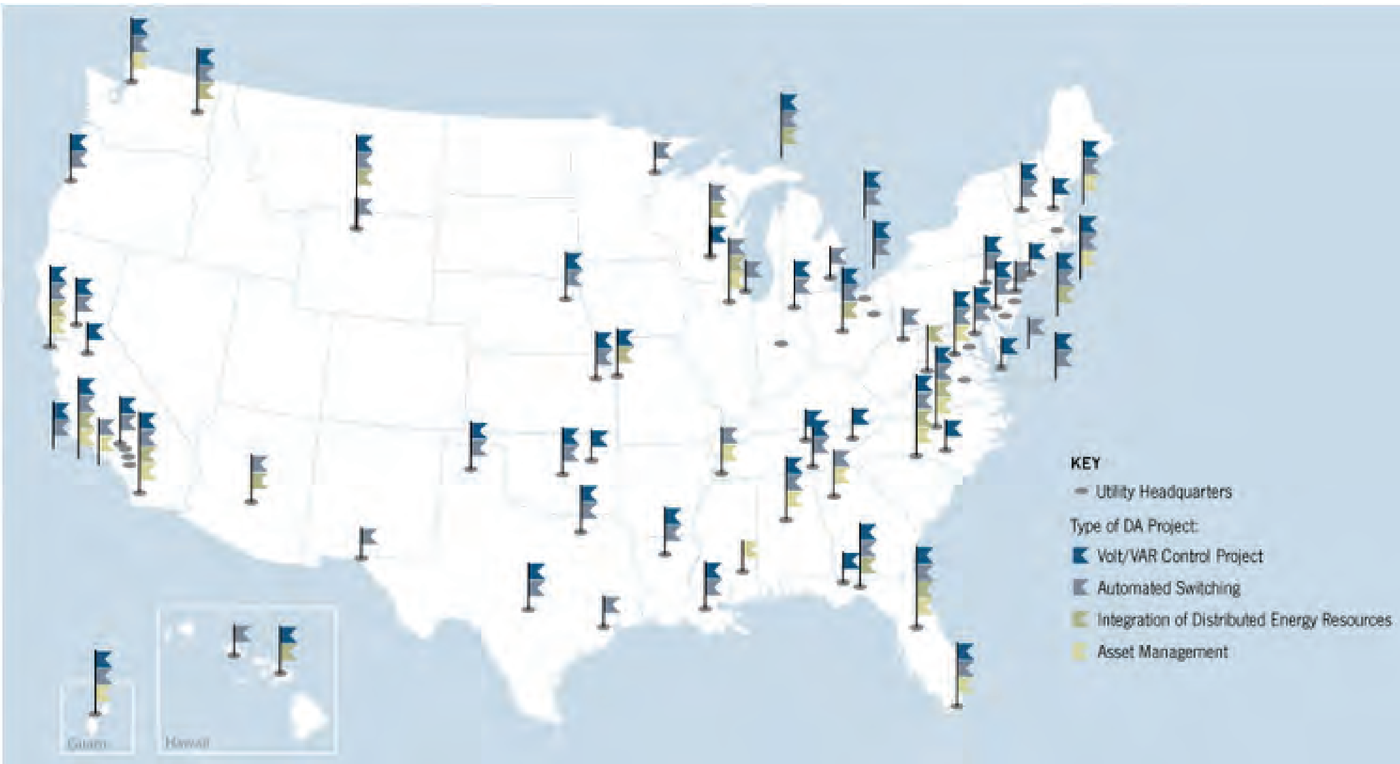

Figure 13: Distribution Automation (DA) Projects in the U.S. by utility and DA technology.[15]

In order to fully support DA implementation and allow sufficient capacity to operate the distribution grid, some utilities are increasing the capacity of their power transformers and distribution lines, especially in more densely populated areas.

Respective to reliability and resiliency, many utilities have acquired mobile transformers (Figure 14) for timely deployment and service restoration in the event of catastrophic equipment failure. Since long lead times exist to manufacture and deliver substation power transformers (6 months–1 year), mobile transformers can play a vital role in timely customer restoration. They can be rapidly deployed to replace damaged substation equipment, allowing time to procure long lead-time grid components, while minimizing the service interruption. In addition to improving reliability, investments in mobile transformers address security concerns such as natural disasters, sabotage, and acts of terrorism. Furthermore, lower rated distribution substation transformers are physically small in size and can be transported with relative ease, so utilities tend to adopt spare strategies for emergency response in these instances.

15. GTM Research, Distribution Automation 2012-2016, Technologies and Strategies for a Digital Grid.

Figure 14: Mobile Transformer owned by LG&E and KU.

2.3. Recent Investments into System Improvement

Following the historical storms and outage events of 2008 and 2009, EDO broadened and enhanced its portfolio of distribution system reliability and resiliency programs. These incremental investment and expense programs were designed to replace aging infrastructure, provide additional system contingency and flexibility, and harden the grid against physical exposures. Table 1 provides a summary of EDO's distribution reliability and resiliency centered programs that were expanded between 2010 and 2016.

Table 1: EDO Incremental System Reliability and Resiliency Program Funding — 2010–2016

					(Dollars in Thousands)			
	Program Description	2010	2011	2012	2013	2014	2015	2016 (Forecast)
Capital	Circuit Hardening/Reliability	$ 10,856	$ 7,273	$ 8,486	$ 14,484	$ 11,826	$ 10,692	$ 11,798
	Pole Inspection & Treatment Program	$ 8,568	$ 8,965	$ 9,680	$ 8,436	$ 10,723	$ 11,000	$ 10,902
	Aging Infrastructure Replacement				$ 5,838	$ 8,167	$ 13,063	$ 12,318
	N1DT Contingency Program						$ 2,632	$ 6,639
	Total Capital	**$ 19,424**	**$ 16,238**	**$ 18,166**	**$ 28,758**	**$ 30,716**	**$ 37,387**	**$ 41,657**
Expense	Hazard Tree Mitigation	$ 1,088	$ 5,852	$ 5,392	$ 5,020	$ 5,110	$ 5,458	$ 5,874
	Pole Inspection and Treatment	$ 328	$ 301	$ 472	$ 515	$ 631	$ 542	$ 314
	Total Expenses	**$ 1,416**	**$ 6,153**	**$ 5,864**	**$ 5,535**	**$ 5,741**	**$ 6,000**	**$ 6,188**

Table 1: EDO incremental system reliability and resiliency program funding — 2010–2016.

- ***Circuit Hardening/Reliability*** — system hardening investments (includes CIFI), targeted at circuits with high customer interruptions and pockets of poor performance; increased from $2M in 2008 to nearly $12M in 2016.
- ***Pole Inspection and Treatment (PITP)*** — program provides for annual inspection, treatment, reinforcement, and replacement, where necessary, of approximately 8% of LG&E and KU's wooden distribution poles. Expense allocations also provide for pole numbering, and anchor, grounding, and other ancillary maintenance.
- ***Aging Infrastructure Replacement (AIR)*** — programs provide for targeted replacement of critical distribution assets considered beyond their life expectancy and experiencing increasing failure or declining reliability rates. Primary assets included in this category are paper insulated lead cable, underground substation exit cables, legacy and problematic distribution circuit breakers, load tap changers, and pad mounted switchgears.

- ***Distribution Substation Transformer Contingency Program (N1DT)*** — program initiated in 2015 provides added contingency for critical substation transformers, targeting power transformer additions, circuit upgrades, distribution system enhancements, and mobile or spare transformer purchases.
- ***Hazard Tree Mitigation*** — program targets trimming or removal of out of right-of-way trees, with noticeable decay or damaged limbs; funding levels were enhanced substantially in late 2010, with annual hazard tree expense allocations of approximately five-to-six million dollars annually since 2011.

2.4. Case for Action

As stewards of the LG&E and KU electric distribution system, EDO is responsible for providing safe, reliable, resilient, high quality and valuable electric service to customers.

> ***"It is no secret that our society is more dependent than ever on electricity, and customers want safe, reliable, affordable, and clean energy. Tomorrow's customers will want even cleaner energy; greater grid reliability and resilience; increasingly individualized services; and the ability to connect more distributed energy resources and devices."***[16]
>
> — **Lisa Wood**, Vice President, Edison Foundation

LG&E and KU's recent reliability and resiliency investment strategies and programs have resulted in steady improvements in customer satisfaction and reliability performance since 2010, but step changes are diminishing as these programs mature. Supplemental and new investment strategies are needed for the following reasons:

- Advancement of technology and the adoption of more energy-efficient end-use technologies, will continue to increase customer expectations respective to service reliability and power quality;
- Expectations for grid resiliency and outage responsiveness continue to grow in the face of increasing incidences of severe and extreme weather, and threats of cyber and physical attacks (data from the U.S. Energy Information Administration provides that weather-related outages have increased significantly since 1992, and extreme weather will continue to increase due to climate change, further stressing aging electric infrastructure[17]);
- Electric industry capital investments in distribution continue to accelerate in response to evolving technologies and customer expectations, resulting in improvement and compression of benchmarking reliability performance quartile thresholds; and
- Customers, community leaders, and regulations across the industry continue to push for more effectively enabling interconnection of distributed energy resources (DER), improving energy efficiency, increasing operational flexibility, and enhancing customer communications.

In their September 2015 assessment of energy technologies and research opportunities, the DOE provided, "The distribution system, from distribution substations down to customers, was originally designed to be relatively passive. Typical distribution systems deliver electricity using distribution feeders and radial lines with control equipment operated through timed set points. While this design paradigm is sufficient to provide customers with basic, reliable electrical service at affordable costs, it cannot meet today's needs for greater resilience, power quality, and consumer participation."[18]

In a September 2015 Quadrennial Technology Review, the DOE again highlighted that, "utilities are adopting information and communication technologies to optimize operations and support decision making to improve system performance. Coupling high-resolution data streams with computational advances will enable faster, predictive capabilities. As the distribution system becomes more complex with more points of control and load becomes less predictable, new technologies and tools will be needed to help operators interpret data, visualize information, predict conditions, and make better and faster control actions to ensure reliability and safety."[19]

Future system reliability and resiliency investment strategies must account for evolving and converging technologies, customer expectations, and system threats. Outages will never be completely eliminated, so consideration must be given to enhancing the ability of the LG&E and KU electric system to more effectively detect outages, isolate damaged facilities, reroute power to undamaged feeders and circuits, and limit the exposure of critical asset failures. When outages do occur, whether due to extreme weather events, equipment failure, or other reasons, adequate utility infrastructure, redundant capacity, and superior recovery operations should be in place to minimize interruption durations.

EDO must continue to build redundancy into the LG&E and KU distribution system, where value is provided to customers, and must continue to advance the intelligence of the distribution grid, to meet growing customer expectations. EDO must continue to look beyond key reliability metrics such as SAIDI and SAIFI, to adequately account for and prevent long duration, high impact (affecting a large

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16. The Edison Foundation, Institute for Electric Innovation; Key Trends Driving Change in the Electric Power Industry, Volume II; Lisa Wood, Vice President, The Edison Foundation, and Executive Director, Institute for Electric Innovation; June 2016, page 3.

17. Economic Benefits of Increasing Electric Grid Resilience to Weather Outages, Executive Office of the President, August 2013; Prepared by the President's Council of Economic Advisers and the U.S. DOE's Office of Electricity Delivery and Energy Reliability, with assistance from the White House Office of Science and Technology; page 9.

18. DOE, Quadrennial Technology Review; An Assessment of Energy Technologies and Research Opportunities, Chapter 3: Enabling Modernization of the Electric Power System; September 2015; page 63.

19. DOE, Quadrennial Technology Review; An Assessment of Energy Technologies and Research Opportunities, Chapter 3: Enabling Modernization of the Electric Power System, September 2015; page 63.

number of customers or key customers) outages, such as those caused by substation power transformer failures. Substation transformer outages typically affect a large number of customers, are long in duration, and garner extreme customer scrutiny due to their community impact. Costs from a utility perspective range from $1,000/MWh for residential customers to more than $10,000/MWh for commercial and industrial customers.[20]

Further support for advancement of grid intelligence, specifically distribution automation, can be tied to documented industry results for distribution automation projects funded by the ARRA, under the DOE's SGIG program. "Utilities who have been awarded grants and executed smart grid projects have reported SAIFI improvements of 11-49 percent."[21] Furthermore, PPL Electric Utilities has reported SAIDI and SAIFI improvements of 21% and 31%, respectively, on circuits where DA has been deployed.

In addition to these stated reliability improvements, utilities have achieved operational and cost benefits, such as reduced restoration costs, truck rolls, and outage durations, and more efficient crew utilization. Financial impacts of outages on customers have also been reduced, due to reduced outages and outage durations, which improves public safety, reduces lost production, product losses, and other disruptions to businesses. For example, grid automation provides the ability to remotely de-energize a downed circuit, enhancing public safety.

2.5. Strategy

Utility industry customer satisfaction surveys consistently reveal that reliable service is a fundamental customer expectation that must be met before additional initiatives and service options can result in improved customer satisfaction ratings. As reliance on electricity increases, customer expectations respective to service reliability and power quality will continue to expand. Accordingly, EDO's 2017-2021 Business Plan includes the following high-level investment strategies for system reliability and resiliency:

- Advance automation on the distribution system;
- Accelerate funding for the distribution substation transformer contingency program;
- Continue existing reliability improvement programs; and
- Continue existing aging infrastructure replacement programs.

These investment strategies will advance grid intelligence, provide for increased operational control and flexibility, assure continued improvement in reliability performance and power quality, and build additional contingency into critical assets. These strategies also align with industry best practices and are comprehensive, continual, and flexible.

Reliability and Resiliency Programs

Table 2 provides a summary of EDO's strategic 2017-2021 reliability and resiliency capital and expense programs.

Table 2: EDO Primary Incremental System Reliability and Resiliency Improvement Programs

	Program Description	2017	2018	2019 (Dollars in Thousands)	2020	2021
Capital	Distribution Automation	$ 10,420	$ 25,250	$ 22,000	$ 18,203	$ 18,203
	Circuit Hardening/Reliability	$ 14,614	$ 13,235	$ 13,687	$ 14,666	$ 15,019
	Pole Inspection & Treatment Program	$ 11,573	$ 11,920	$ 12,278	$ 12,646	$ 13,026
	Aging Infrastructure Replacement	$ 15,577	$ 15,923	$ 16,286	$ 14,620	$ 15,003
	N1DT Contingency Program	$ 7,245	$ 7,506	$ 10,000	$ 10,000	$ 13,000
	Total Capital	**$ 59,429**	**$ 73,834**	**$ 74,251**	**$ 70,135**	**$ 74,251**
Expense	Hazard Tree Mitigation	$ 5,021	$ 4,303	$ 5,285	$ 5,719	$ 5,969
	Pole Inspection and Treatment	$ 579	$ 609	$ 625	$ 631	$ 638
	Total Expenses	**$ 5,600**	**$ 4,912**	**$ 5,910**	**$ 6,350**	**$ 6,607**

Table 2: EDO 2017-2021 Reliability and Resiliency Improvement Programs.

EDO's proposed investment strategy provides for continued funding of the existing circuit hardening (including CIFI and the Hazard Tree Program), PITP, and AIR programs. These existing programs continue to deliver system reliability and resiliency improvements. Any substantial shifts in funding away from them would increase outages, and decrease operational contingency. Program continuation is necessary to deliver maintenance, replacement, or upgrade on LG&E and KU system components not yet addressed and circuits not well suited for distribution automation (due to limited circuit ties, etc.). For example, the CIFI program has addressed only 190 of LG&E and KU's 1600 circuits. Over time, remaining circuits will ultimately require circuit hardening and aging infrastructure replacement to maintain and/or improve reliability performance. Likewise, the PITP has addressed only 366,925 of 663,173 (55%) LG&E and KU distribution poles. More than 14,000 poles have been replaced under this program, and the contribution of pole related outages to SAIDI has dropped by

20. Typically, reliability metrics alone "1) undervalue the impact of large-scale outage events and focus on normal operating conditions, and 2) price lost load at a flat rate, when in fact the value of lost load compounds the longer it's lost." Source: The Regulatory Assistance project and Synapse Energy Economics, Workshop on Risk in the Electricity Industry, a training provided to the Mid-Atlantic Conference of Public Utility Commissioners in Hershey, PA on June 14, 2013.

21. DOE QER Report: Energy Transmission, Storage, and Distribution Infrastructure, April 2015, Appendix C — Electricity, page 37.

approximately 40% on completed circuits. The remaining LG&E and KU distribution poles also need to be addressed under the program, and subsequent inspection cycles will be needed as the poles continue to age.

Distribution Automation (DA)

EDO's proposed Distribution Automation (DA) Program includes $112.4M in investments between 2016 and 2022. EDO's proposed 2017 Business Plan allocates $94.1M between the plan years 2017 through 2021 for DA. The proposed DA program will yield step-improvement in reliability performance and customer satisfaction, through enablement of remote monitoring and control, circuit segmentation, and "self-healing" of select electric distribution system circuits. More specifically, DA will provide for acquisition and deployment of a Distribution Supervisory Control and Data Acquisition (DSCADA) and Distribution Management System (DMS), and purchase and installation of approximately 1,400 electronic SCADA connected reclosers. Approximately 360 (20%) distribution circuits, and 50% of LG&E and KU customers, will be targeted by the proposed program. The DMS will provide advanced functionality required to achieve incremental DA benefits, such as Power Flow (PF), Fault Location Analysis (FLA); Suggested Switching (SS), and Fault Location, Isolation and Service Restoration (FLISR). The DMS will also be equipped with the functionality to support a potential future Volt Var Optimization (VVO) program. VVO involves a real-time system monitoring and dynamic control, and provides for increased system efficiency, improved power quality and reduced energy consumption. LG&E and KU is currently implementing a VVO pilot program at one substation in the LG&E territory and the results of this pilot will be used to determine the specific scope of a future VVO initiative.

From a grid modernization perspective, DA will provide the ability to monitor grid voltage and currents that have not been accessible in real time in the past. This window of awareness will not only support reliability, power quality, and efficiency initiatives, but will ultimately be required to support increased penetration of distributed generation in LG&E and KU service areas. (Sections 4 and 5 of this report provide additional detail on the DA strategy.)

Distribution Substation Transformer Contingency Program (N1DT)

EDO's proposed Distribution Substation Transformer Contingency (N1DT) Program includes $175M in investments between 2015 and 2029. EDO's proposed 2017 Business Plan allocates $47.8M between the plan years 2017 through 2021 for the N1DT Contingency Program.

The typical "N-1" industry design concept is that a single component failure will not affect electricity supply. The term "N-1" used here is relaxed in the sense that a distribution substation transformer failure will still cause an outage, but interruption of service can be minimized through adoption of different supply security (contingency) plans based on transformer size and number of customers impacted.

Approximately 63% of LG&E and KU's distribution power transformers do not have full contingency (See Figure 15). If one of these substation transformers fails during high load or peak conditions, some customers will be without service until the faulty transformer is replaced, a process that can sometimes take multiple days.

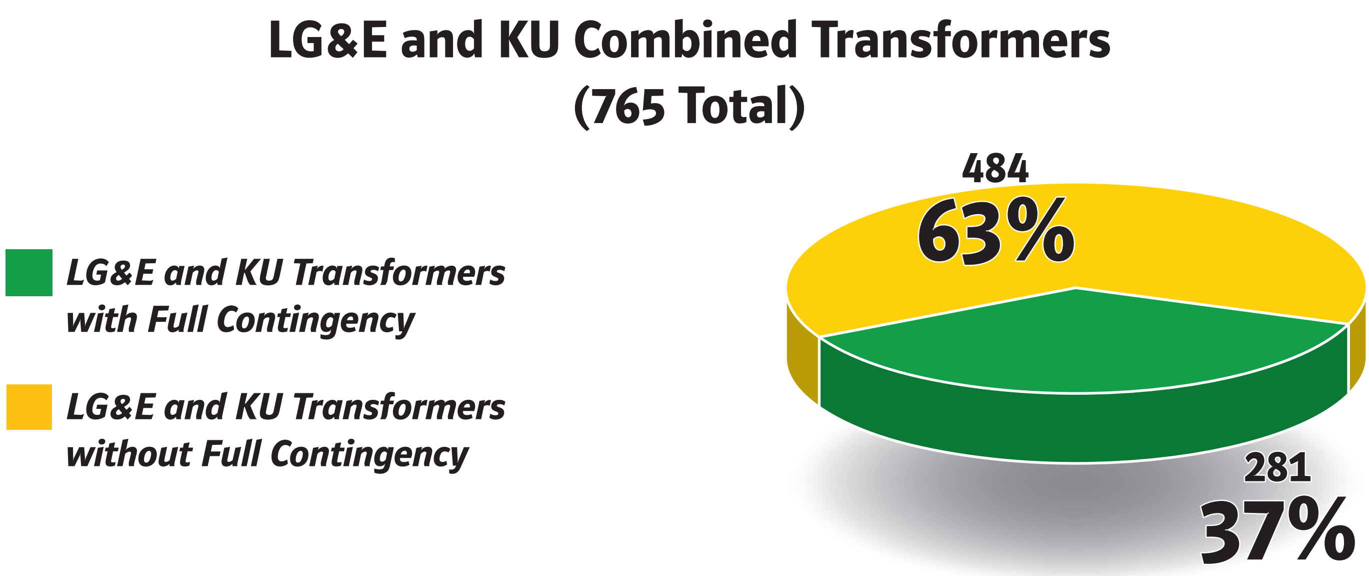

Figure 15: Transformer Contingency — as of June 2016.

EDO's planned N1DT Contingency Program will mitigate potential high impact, long duration service interruptions which would likely result whenever a transformer (without contingency) fails, by making available either a permanent or deployable back-up source to support system and customer restoration. Mitigation solutions for these transformers include substation/circuit upgrades, capacity additions, improved spare and mobile transformer strategies, and other distribution substation enhancements. EDO's proposed improvements will provide for N-1 contingency of larger substation transformer failures, and reduced outage durations on smaller substation transformers where providing full redundancy is not cost effective.

Large-scale power transformers are custom-made, require many months of lead time, and are not typically available locally. Strategic investment in permanent or deployable contingency will provide for increased system flexibility when high impact trouble strikes.

2.6. Performance Objectives

EDO's proposed capital investment strategies are designed to improve electric distribution system reliability and resiliency to meet expanding customer expectations respective to service quality and align with industry best practices.

Investments in traditional reliability programs will be maintained at current levels to sustain the improvements that have been achieved and to continue to improve reliability in areas that are not well suited for distribution automation.

As a result of its new DA program, LG&E and KU is projecting to improve its SAIDI performance by 12% over the next six years and SAIFI by 19% over the same period (2017–2022). Figure 16 shows the projected SAIDI/SAIFI improvement. In addition to reliability and power quality performance improvement, the implementation of DA will provide flexible monitoring and control of the distribution system and is expected to create future operating efficiencies in field crew dispatch, and reducing truck rolls and crew miles. Similarly, in areas where DA is implemented, real time data from smart reclosers will provide intelligence and remote capabilities to support switching, further supporting safety, productivity and efficiency.

Based on a cost/benefit analysis, EDO believes a strategic investment in DA will significantly reduce the number of customers affected by outage events and reduce restoration times for customers affected by outages. This strategic shift will enable the company to satisfy growing customer expectations respective to system reliability and resiliency, power quality, operational flexibility, and grid intelligence.

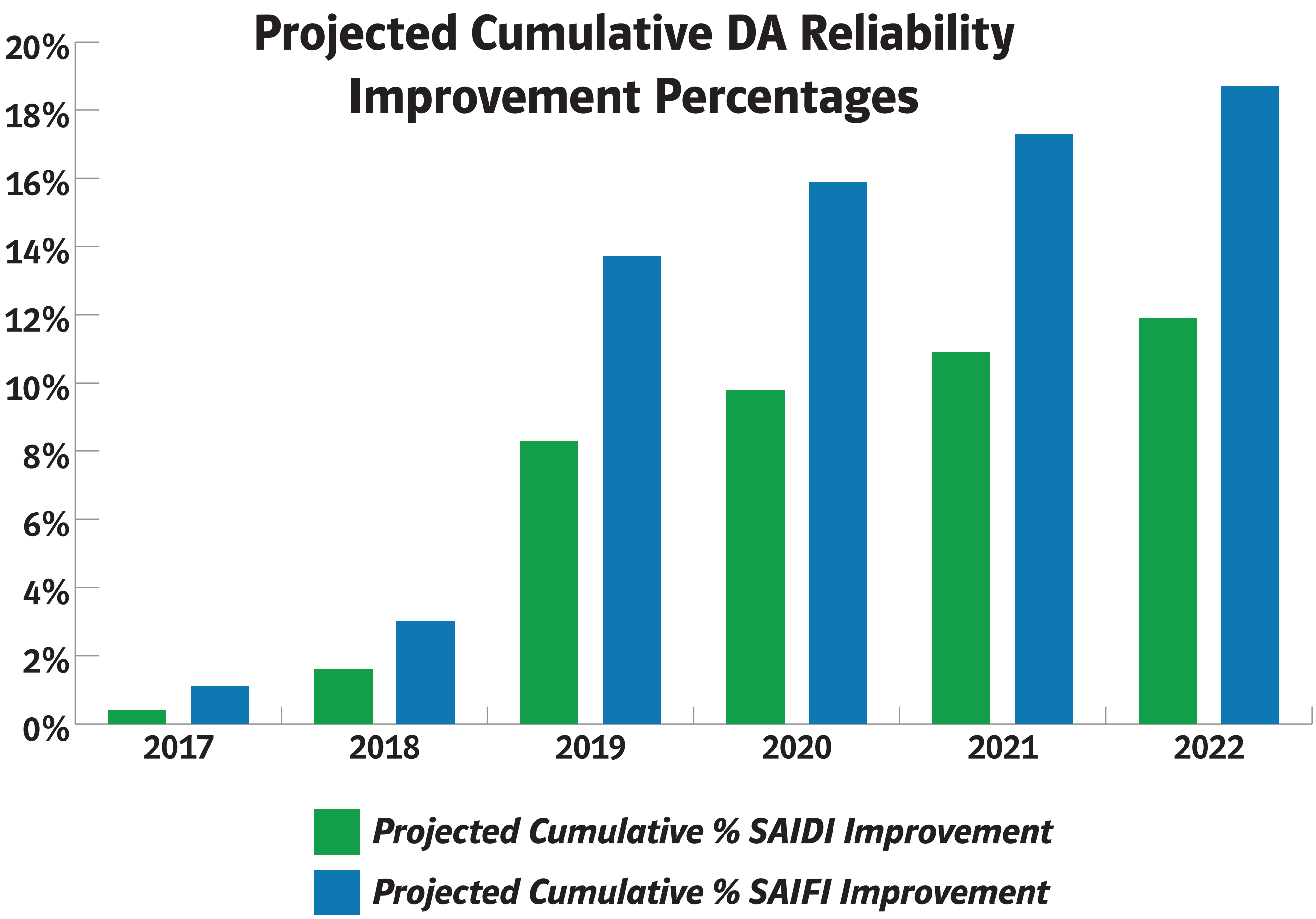

Figure 16: Projected Cumulative DA Reliability Improvement Percentages.

The company also expects the N1DT contingency program to minimize the impact of long duration service interruptions by providing either permanent or temporary contingency capacity into the system, rapidly restoring electric service to areas subjected to blackouts as a result of equipment failure, natural disaster, acts of terrorism, sabotage, or vandalism.

In critical high load density applications, where the distribution substation transformers are typically larger, this program aims to provide full back-up capacity (N-1 contingency) to roughly 60% of power transformers base 12MVA or larger that are currently "at-risk" (at-risk meaning that if the substation transformer were to fail, the company cannot restore service to all customers without installing additional capacity in the form of a replacement transformer or a mobile transformer).

Installation of permanent contingency into the system could reduce a multi-day outage event down to minutes with fast transfer to a redundant transformer within a SCADA equipped substation, or less than four hours if the contingency capacity requires manual switching to another alternate substation source.

In substations serving low load density areas there is typically not sufficient contingency to overcome the loss of a distribution substation transformer. Often the grid in these areas is topologically in a radial arrangement without circuit ties, and it is not cost effective to provide contingency. In these areas, the N1DT contingency program will enhance and expand the existing spare and mobile transformer strategy to provide accelerated restoration of electric service for less dense load centers. Utilizing localized mobile transformers and small spare units, multi-day outages will be reduced to between 12-24 hours in most cases. Although this approach provides a longer restoration than a permanent redundancy option (which is cost prohibitive), the disruption would be much longer if spares and mobiles were not available (e.g., estimated to be up to five days at some substations). Spare and mobile strategies in the case of equipment failure, natural disaster, sabotage or some other destructive event, play a critical role in reestablishing the connection to the grid.

A report completed by the DOE in 2005[22] detailing the benefits of mobile transformers supports the notion that in most high-load-density areas, which are indicative of urban areas, substation transformers are installed within the network in a manner that provides redundancy either within the substation or from a nearby substation (alternate source). The report refers to this redundancy as "modern utility practice in urban environments." In addition, the report references the fact that there are often spare power transformers stored in convenient central locations ready for transport. Furthermore, the report describes that in less customer dense rural areas, a substation may only have one transformer, and essentially no contingency, which means that the load served is at risk of long-term outage if the substation is damaged beyond repair.

22. DOE Report to US Congress Pursuant to Section 1816 of the Energy Policy Act of 2005: Benefits of Using Mobile Transformers and Mobile Substations for Rapidly Restoring Electric Service, August 2006.

3. Investment Selection Methodology

In 2011, EDO started using an Asset Investment Strategy (AIS) decision-support model and supporting business processes to help evaluate and prioritize distribution investment programs. The model and processes enable EDO to evaluate and prioritize proposed investments based on 1) a set of custom benefit criteria defined by EDO subject matter experts; and 2) estimated costs of proposed projects. The AIS prioritization algorithm sorts proposed investments based on a benefit/cost ratio, which in turn allows EDO to determine the best allocation of spending. EDO's management team then applies other criteria, such as resource availability and seasonality of work, to determine the ultimate set of investment projects to include in EDO's Business Plan.

As part of its annual business plan development, EDO has used the AIS approach to evaluate traditional reliability and asset replacement investment programs. During the 2016 business planning process, EDO utilized AIS and available industry data to assess DA against its existing portfolio of system reliability and resiliency capital programs, and concluded that DA provides LG&E and KU the best option for making step improvements in reliability performance, and maintaining or improving upon its relative peer group standing in reliability benchmarks. Figure 17 displays the EDO's past and projected reliability improvements per dollar invested for CIFI and DA.

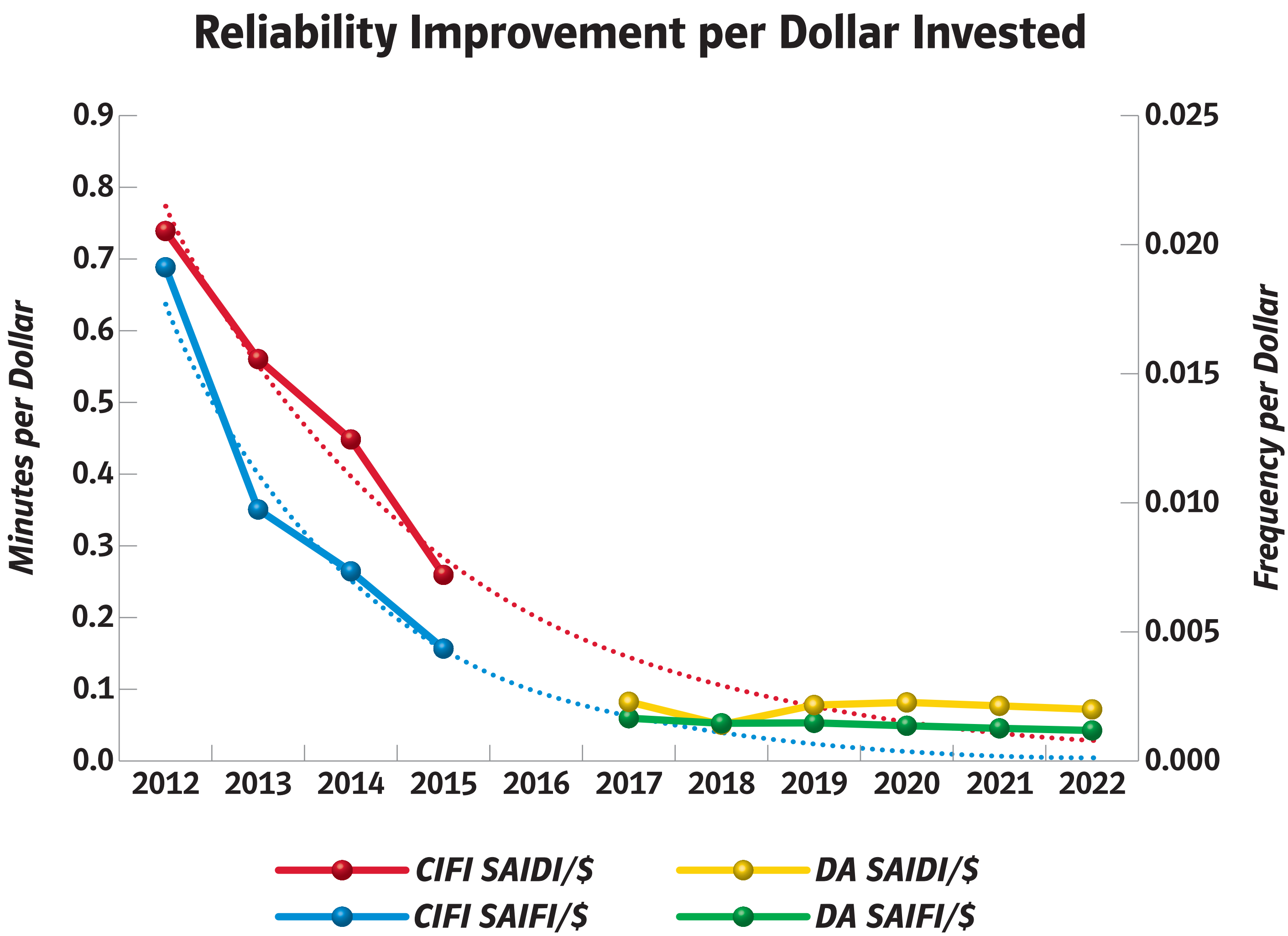

Figure 17: Reliability Improvement per Dollar Invested.

In order to get the most value for the investment in the N1DT contingency program, LG&E and KU expanded the AIS evaluation framework to include at-risk power transformers based on benefit/cost, which also identified the most vulnerable transformers that need to be addressed. Considerations include: the number of customers affected by a transformer failure, the amount of load at risk, the length of time to replace the capacity, the amount of time during the year the load is at risk, the age and health of the transformer, and the impact a long term outage may have on the surrounding community and critical infrastructure. Scaling factors were applied to the inputs to calculate the total benefit. This benefit was then divided by total project cost to determine the benefit/cost ratio.

4. Overview of Proposed Projects

4.1. Background

LG&E and KU has gained the expected reliability improvements on the distribution system from its existing reliability programs. Even considering these improvements, peer group reliability as observed through benchmarking continues to improve at an increasing pace, customer expectations on availability of service continue to increase, power transformers continue to age, and contingency margins continue to be reduced. The expectations of grid resilience and responsiveness continue to grow in the face of extreme weather, equipment failure, and potential high impact events such as sabotage and terrorism. The penetration of advanced technologies such as distributed generation will continue to demand reliability, power quality, and operational flexibility from the grid. Given the company's strong commitment to maximizing the customer experience, the company has made the decision to leverage the best practices in the industry to improve reliability, expand resiliency efforts, and prepare for the grid of the future. Substantial distribution infrastructure investments in both Distribution Automation and the Distribution Substation Transformer Contingency Program will be added to an already extensive portfolio of capital investments to meet these objectives.

4.2. Distribution Automation

The deployment of Distribution Automation (DA) involves the extension of intelligent control over electrical power grid functions to the distribution system level. The intelligent control of distribution equipment can provide real-time information and allow for the remote monitoring, remote control, and automation of distribution line equipment. This project is intended to leverage distribution automation technologies to improve the customer experience through enhanced reliability performance. The DA program will install electronic SCADA (Supervisory Control and Data Acquisition) capable reclosers enabling segmentation of feeders, and "self-healing" of the distribution system. This will result in fewer outages and faster restoration times for customers.

4.3. Distribution Substation Transformer Contingency Program (N1DT)

The purpose of the N1DT Contingency Program is to enhance the LG&E and KU customer experience through improved reliability and reduced exposure to low probability, high consequence, long duration service interruptions due to failure of a substation power transformer. There are a significant number of power transformers in the LG&E and KU system, 484 of 765 (63%), where service cannot be fully restored in the event of a transformer failure during heavy load periods without direct transformer replacement or the installation of a mobile transformer. This program is designed as a multi-tiered approach for adding contingency based on the anticipated value added in terms of customers impacted and load density versus the cost to implement the change. The tiered approach consists of three methodologies: 1) the build-out of permanent system capacity providing full redundancy through switching, 2) the expanded use of mobile transformers across the service territory, and 3) the use of small localized spare distribution power transformers to restore service in the most efficient, and cost effective manner.

The installation of additional substation and circuit capacity throughout the system will help facilitate the use of Distribution Automation and will support the implementation of a "self-healing" or smart grid system, year round. Investments for the N1DT Contingency Program will be coordinated with the DA Program where the programs intersect.

5. Analysis of Proposed Projects

5.1. Distribution Automation

At this time, approximately 25% of the LG&E and KU substations are connected to the Distribution SCADA System. From a load perspective, approximately 37% (i.e., 1294 MW) is SCADA connected on the KU system, with a higher concentration in the more metropolitan portions of the service territory. On the LG&E system, approximately 95% (i.e., 2498 MW) of system load is SCADA connected. Existing Distribution SCADA, which currently resides in the EMS (Energy Management System), will be migrated to a new, dedicated Distribution SCADA System. This will allow for a single interface to operate and control distribution equipment.

To date, 300 electronic reclosers have been installed on the LG&E and KU distribution system as part of existing reliability programs and projects, all of which will be connected to the new Distribution SCADA System. In addition to these existing devices, approximately 1,400 new electronic reclosers will be installed as a part of the proposed program.

A total of 360 circuits have been targeted for DA, representing approximately 20% of LG&E and KU circuits, 40% of LG&E and KU circuit miles, and 50% of LG&E and KU customers. Recloser installations are targeted for approximately one device for every 500 customers.

5.1.1. Benefits

DA is expected to result in fewer outages and faster restoration times for customers. The estimated benefits are a 12% improvement in SAIDI and a 19% improvement in SAIFI at the end of the 7-year period of the planned implementation. The program will also provide the potential for enhanced operational capabilities and efficiencies as a result of remote monitoring and resulting situational awareness.

5.1.2. Expected Cost

The prioritization of DA opportunities within the program is based on avoided customer outages as well as cost. Total estimated costs for the 2016-2022 period are provided in Table 3.

Table 3: Breakdown of Investments within DA Plan — 2016–2022

(All Dollars in Thousands)

DA Plan Detail	2016	2017	2018	2019	2020	2021	2022	Total Spend
Reclosers		$ 7,120	$ 21,672	$ 20,675	$ 17,608	$ 17,608	$ 17,617	$ 102,300
DMS/DSCADA		$ 2,500	$ 2,922	$ 700				$ 6,122
Communication	$ 80	$ 800	$ 656	$ 625	$ 595	$ 595	$ 584	$ 3,935
Total	**$ 80**	**$ 10,420**	**$ 25,250**	**$ 22,000**	**$ 18,203**	**$ 18,203**	**$ 18,201**	**$ 112,357**
SAIFI Reduction	0.0%	1.0%	1.9%	10.7%	2.2%	1.4%	1.4%	18.7%
SAIDI Reduction	0.0%	0.4%	1.2%	6.7%	1.5%	1.1%	1.0%	11.9%

Table 3: Breakdown of the Investments within the DA Plan (2016–2022).

5.1.3. Progress to Date

- An engagement with a telecommunications consultant began in 2016 to determine the optimal method to communicate with distribution equipment. Results from the telecommunications study are reflected in Table 3, above.
- Requirements for a DSCADA (Distribution Supervisory Control and Data Acquisition) system and a DMS (Distribution Management System) have been defined, and an RFP has been issued.

5.1.4. Timing of the Program

Distribution Automation is a seven-year program proposed to continue through 2022. DMS and DSCADA vendor evaluations were conducted during the first three quarters of 2016. Purchase and deployment of selected DMS and DSCADA systems will begin during the third quarter of 2017; deployment will continue into 2019. Electronic field devices (reclosers) will be installed between July 2017 and 2022.

5.1.5. Summary of Justification

Because of broadening electrification and advances in end-use technology, electric utility customer needs and expectations respective to service reliability, system resiliency, outage response, and power quality continue to evolve. As part of its routine review of system investment strategies, EDO assessed its system reliability and resiliency investment programs to identify opportunities for improving and aligning system performance with changing customer requirements. EDO added DA to its portfolio of programs for system reliability and resiliency because it is projected to provide SAIDI and SAIFI performance improvements of 12% and 19% respectively by the end of the planned seven year program. As indicated in section 2.4, the DOE has reported that DA has provided reliability performance improvements of 11-49 percent on deployments across the industry. Also, PPL has reported reliability performance improvements greater than 21%. In addition to these stated reliability improvements, utilities have reported DA associated operational and cost benefits, such as reduced restoration costs, truck rolls, and outage durations, and more efficient crew utilization. DA will facilitate similar opportunities for LG&E and KU, and was evaluated to be the most cost effective alternative for achieving step improvements in reliability performance over the planned program period.

5.2. Distribution Substation Transformer Contingency Program (N1DT)

The purpose of the N1DT Contingency Program is to enhance the LG&E and KU customer experience through improved reliability and reduced exposure to low probability, high consequence, long duration service interruptions due to failure of a substation power transformer. While the vast majority of power outages are due to power line related failures, the grid is highly vulnerable to substation failures, where multiple transmission and distribution lines intersect. A single failure inside an electric substation typically interrupts service to a large number of customers and typically takes a long time to restore.

Depending on the loading at the time of a substation transformer failure, there are 484 (out of the 765) distribution substation transformers operating on the LG&E and KU system that are considered "at-risk", meaning if they were to fail, the company cannot restore service to all customers without installing additional capacity. Among the large transformers (loads of base 12MVA or larger), 114 (out of 271) are considered at-risk.

The LG&E and KU distribution system is designed and operated as a radial system with open tie points between substations for load transfer in more urban parts of the service territory. Capacity and infrastructure, and thus tie points are limited or are non-existent in the more rural service areas making load transfer more difficult or impossible (181 of the 484 N1DT transformers have no ties).

In more urban areas of the LG&E and KU distribution system, with multiple transformers and/or circuit ties, some or most of the customers can be restored through switching. While some transformers may be at risk year round due to minimal or no circuit ties, many are only in this situation at peak load times, which is when customers typically need power the most (extreme heat and cold), and outages have the most community and corporate impact.

LG&E and KU is proposing to use three different contingency plans depending on the size of the substation transformers. Class I contingency plan will be used for power transformers sized at or below base 3750kVA, typically serving 300 customers or less. With Class I contingency, if a fault occurs on the substation transformer leading to failure, some or all customers will be without service until the failed transformer is replaced. The N1DT contingency program will increase the number of spare transformers as well as redistribute all spares throughout the state to reduce transportation and replacement time. As this size transformer typically serves less than 300 customers, buildout of additional infrastructure for contingency is not considered economically viable. Transformers sized at or below 3750kVA, typically, can be replaced as fast as or faster than a mobile transformer can be deployed and installed. There are 164 transformers rated 3750kVA or less in the LG&E and KU service territory, and 130 are considered at-risk.

Class II contingency will be used for power transformers at or between base 5MVA and 10MVA, typically serving less than 1000 customers. With Class II contingency, if a fault occurs on the power transformer leading to failure, some or all customers could be without service until the failed transformer is replaced or a mobile transformer is installed. The N1DT contingency program will provide for additional spare transformers of this size as well as a mobile transformer for the local area, which will be ready for transport. Since this size transformer typically serves less than 1,000 customers, build out of infrastructure for contingency is not considered economically viable. The station layout, seasonal loading considerations, and ease of access will determine whether the installation of a spare transformer or a mobile transformer will restore customers faster. If the restoration of the two options are comparable, the spare transformer installation will be chosen to avoid double installation costs. There are 330 transformers rated between base 5MVA and 10MVA in the LG&E and KU service territory, and 240 are considered at-risk.

Class III contingency will be used for power transformers base 12MVA and larger, on average serving 2,500 customers or more. With Class III contingency, if a fault occurs on the power transformer leading to failure, the corresponding customers will typically be without service between five minutes to less than 4 hours (some exceptions will apply) until the corresponding switching to the alternative source is completed. The N1DT contingency program will provide for an alternative source via normally open tie points to other substation transformers by investment in circuit upgrades, capacity additions, or other system enhancements. As transport of this size transformer involves transformer dress/undress and oil removal and processing, some customer outages can extend well beyond the 24-hour mark. There are 271 transformers rated base 12MVA or larger in the LG&E and KU service territory, and 114 are considered at-risk. Until Class III contingency is implemented in a targeted substation, the mobile/spare transformer strategy will be utilized. Which strategy will be applied is dependent on the system conditions and load at risk when the failure occurs.

Table 4 provides the number of transformers that are considered at-risk (N1DT) which are part of the N1DT contingency program.

Table 4: LG&E and KU Substation Transformer Counts and N1DT Detail

		Class I	Class II	Class III	Total
LG&E and KU Substation Transformer Count	KU Only	141	302	137	580
	LG&E Only	23	28	134	185
	Total	164	330	271	765
N1DT Transformer Count	KU Only	123	232	69	424
	LG&E Only	7	8	45	60
	Total	130	240	114	484
% N1DT	KU Only	87%	77%	50%	73%
	LG&E Only	30%	29%	34%	32%
	Total	79%	73%	42%	63%

Table 4: LG&E and KU Substation Transformer Counts and N1DT Detail.

In addition to the proposed tiered solutions, LG&E and KU considered other alternatives to address the potential gap in system flexibility and contingency, including:

- Mobile generation; and
- Operating equipment past current emergency ratings.

Mobile generation was ruled out as both insufficient and impractical. The largest mobile generation that can be practically mobilized is in the 2MVA range while LG&E's largest standard transformer is 44.8MVA. Also, other significant challenges associated with mobile generation are interconnection delays, air quality permitting, and objectionable noise in public areas near substations. Operating equipment beyond current emergency rating is considered an unacceptable practice as it reduces transformer life and causes equipment stress potentially resulting in additional outages. As a result, these alternatives were deemed not viable.

5.2.1. Benefits

Substation transformer failures and outages are not a significant contributor to SAIDI (less than 4%) or SAIFI (less than 6%). Eliminating or minimizing customer's exposure to long term outages greater than 24 hours due to substation transformer failures is the primary benefit of the program. Some improvement in SAIDI may be realized due to faster restoration times in areas where capacity is added.

Likewise, some improvement in SAIFI may be realized due to fewer customers being affected by a substation transformer failure.

The benefit of the tiered N1DT contingency program described above is the ability to minimize long duration service interruptions by providing either permanent or temporary contingency capacity into the system, more rapidly restoring electric service to areas subjected to blackouts as a result of equipment failure, natural disaster, acts of terrorism, sabotage, or vandalism. These benefits are especially evident in reducing the impact of larger power transformers failure, because their replacement requires complex transport, heavy lifting capabilities, detailed un-assembly/re-assembly, oil handling, drying, and filtering - a process that can take many days to accomplish.

Installation of permanent contingency into the system could reduce a multi-day outage event down to minutes with fast transfer to a redundant transformer within the substation through a remote SCADA controlled bus tie breaker, or less than four hours if the contingency capacity requires switching to another alternate substation source.

Since 2005, LG&E and KU has had 96 contingency outage events that resulted in long duration loss of a substation transformer. Causes ranged from winding or core failure of the transformer that led to replacement of the equipment, which historically has taken six months to a year, to load tap changer or bushing failures that were repaired in a few hours or days. On average, there are 1-2 power transformer failures per year in the LG&E system which has 185 transformers, and 5-6 power transformer failures per year in the KU system which has 580 transformers. In total, LG&E and KU expects failures on 1% of distribution substation transformers per year, which represents relatively low probability, but can have a significant impact on the customer and communities that the company serves.

Of the 185 LG&E transformers, 60 (or 32%) do not have sufficient capacity to support contingency transfers, and of the 580 KU transformers, 424 (or 73%) do not have sufficient capacity to support contingency transfers at some time during the year (see Figure 18 and Figure 19).

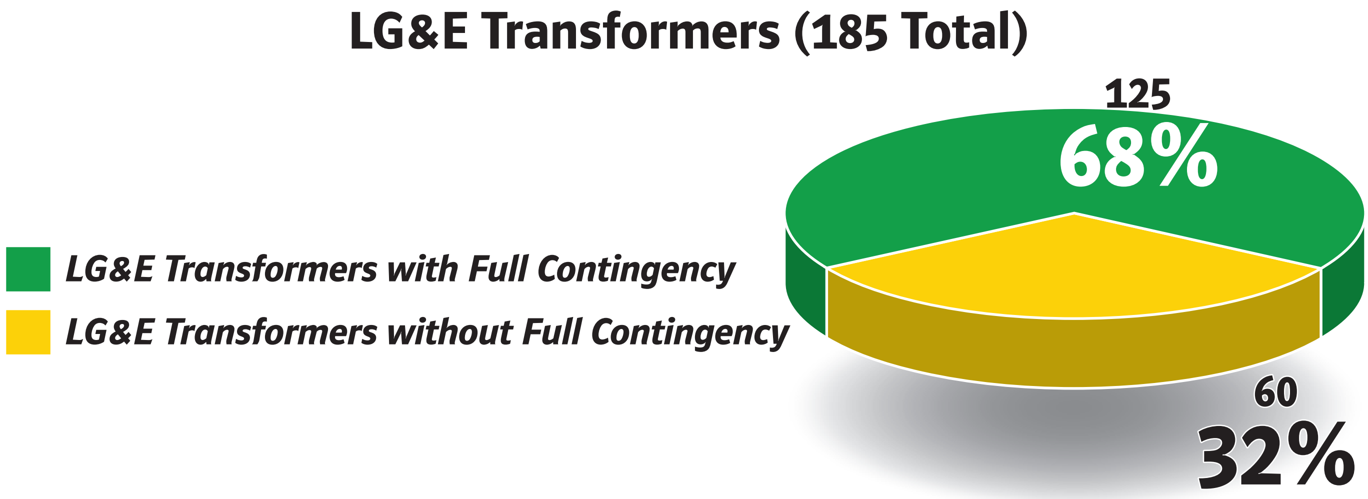

Figure 18: Portion of LG&E transformers without full contingency.

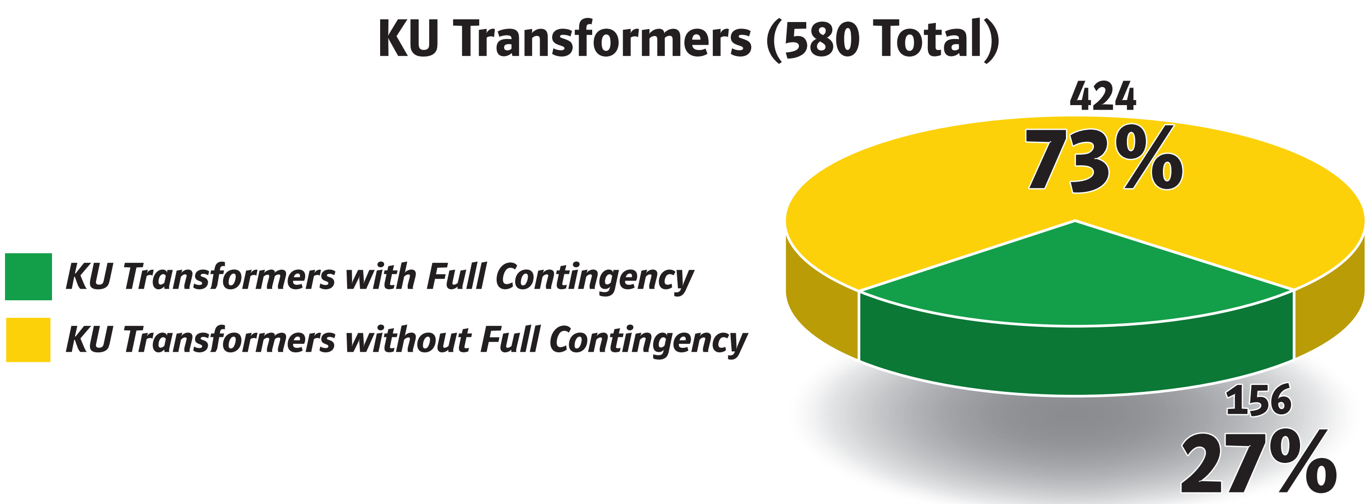

Figure 19: Portion of KU transformers without full contingency.

Investment in substation/distribution equipment is expected to have a 30-year life span and in most cases much longer. As transformers age, an increasing percentage of them face increased probability of failure. LG&E and KU monitors transformer conditions through routine diagnostic testing including dissolved gas analysis (DGA) to predict impending failure, but due to a number of factors, such as lightning exposure and through fault current, unexpected failures still occur. Decreasing the amount of load on transformers year-round and reducing the exposure to faults with shorter circuits will increase the life of the substation transformer assets whose average age is approaching 40 years old. Figure 20 shows the age distribution of transformers by class currently operating on the LG&E and KU system.

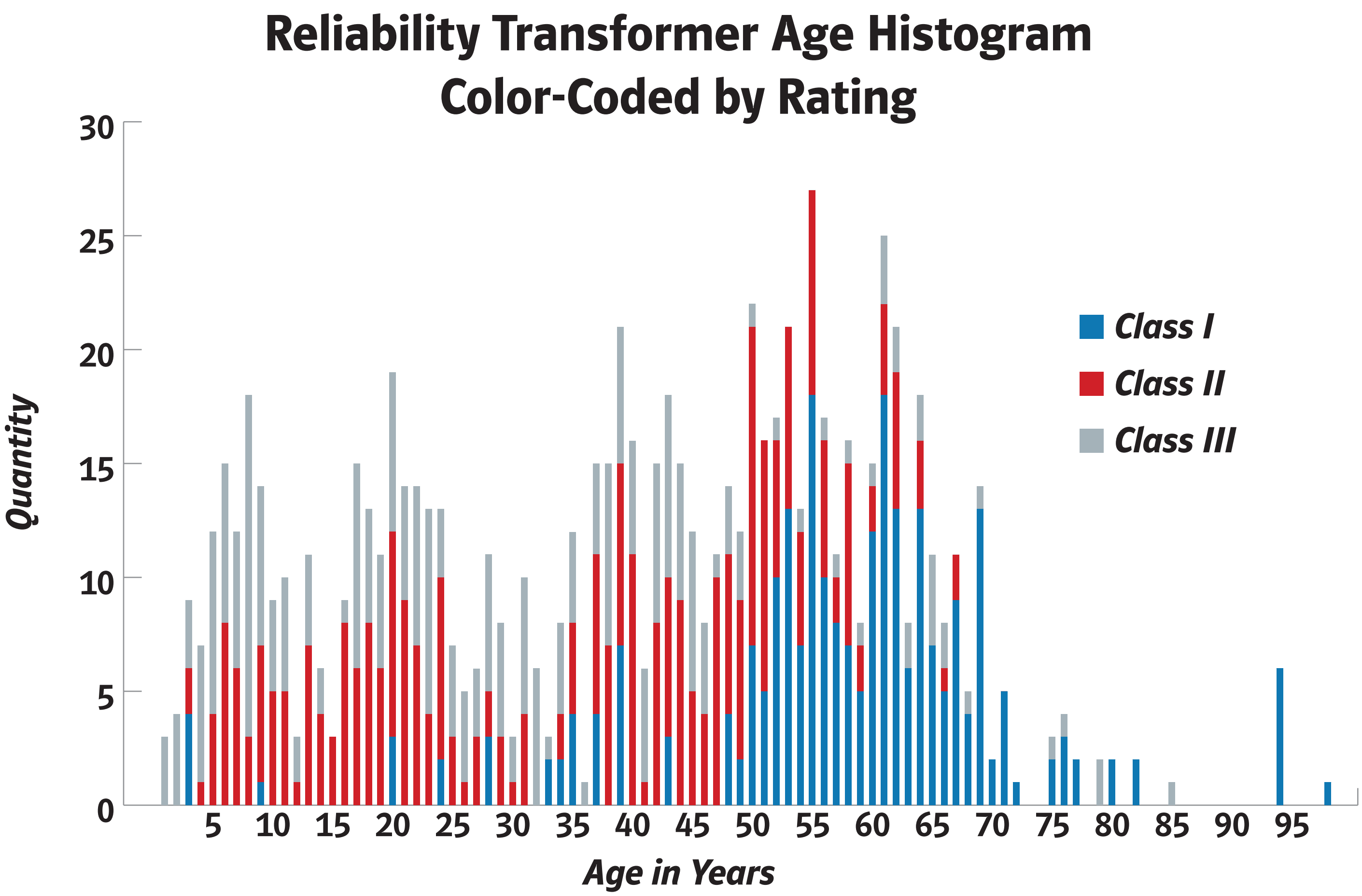

Figure 20: Age Distribution of Substation Transformers by Class Size.

Enhancing and expanding the existing spare and mobile transformer strategy will provide accelerated restoration of electric service for less dense load centers. Utilizing localized mobile transformers and small spare units, multi-day outages will be reduced, in most cases to between 12-24 hours for Class I and II Contingency transformers.

For the Class III Contingency transformers, the N1DT contingency program will eliminate long duration outages on the largest (by load) and most customer dense substations. While rare in occurrence, a long term loss of power to critical infrastructure, such as hospitals, schools, pumping stations, airports, communications, and traffic control, will negatively affect the community and interrupt local events. A long duration outage can also impact the reputation of the area and its ability to host events of regional or national significance.

The N1DT Contingency Program will also provide improved switching flexibility between substations in areas where capacity contingency is installed. The improved switching will also enable maintenance, planned and unplanned, of substation transformers and breakers. Eliminating the need to install a mobile or spare transformer under emergency conditions or scheduled maintenance will result in reduced operating costs. The current process requires many substation planned outages to be limited to off-peak times or weekends resulting in overtime expenses or requires the costly temporary installation of a mobile transformer. In contrast, in areas where permanent capacity contingency is not practical due to lack of circuit ties, mobile transformers will provide options beyond planned outages that leave customers in the dark and contribute to reliability metrics.

Installing enough substation and circuit capacity throughout the system will also help facilitate the use of Distribution Automation and is a critical component in being able to implement a "self-healing" system, year round.

5.2.2. Expected Costs

Program funding was originally approved in the 2014 Business Plan beginning in 2015 at $2.5M per year, escalating 2.5% annually. Additional funding was approved in the 2016 Business Plan to accelerate the program and fund on the schedule provided in Table 5.

EDO's proposed funding for its planned 15-year N1DT program is estimated at $175M. The 2017 Business Plan includes $47.8M funding for the next five years (2017-2021). $6.1M of the five-year investment is allocated to support the spare and mobile transformer strategy which includes two mobile transformers for the eastern and western service territory, two small spare power transformers, capital refurbishment of several existing spares, and construction of basic storage facilities to store the spare and mobile equipment closer to the substations that they are intended to back up.

Table 5: Business-Plan-Approved N1DT Spending

	(All Dollars in Thousands)												
15-Year Program	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026–2029	Total Spend
Program Cost	$ 2,600	$ 6,700	$ 7,200	$ 7,500	$ 10,000	$ 10,000	$ 13,000	$ 13,000	$ 15,000	$ 15,000	$ 15,000	$ 60,000	$ 175,000

Table 5: 2017 Business Plan Approved N1DT Spending.

5.2.3. Progress to Date

The N1DT contingency program began in 2015 with two substations, Lakeshore and Innovation Drive. The stations are in the Lexington Operations Center area and were initially identified as "high impact" targets that would require minimal investment. These projects include the removal of two large transformers from the N1DT list, eliminating the long term outage exposure to over 9,000 customers by the end of 2016. Also in 2015, funding was approved to address N1DT contingency while completing a load driven capacity upgrade for the Central City Substation in the Earlington Operation Center. The incremental cost to obtain N1DT benefit was funded through the N1DT contingency program. This project removed two transformers from the N1DT list, and benefit for nearly 3,000 customers was demonstrated. A similar process was followed to fund incremental N1DT improvements for the load driven capacity enhancement project at West Hickman Wastewater Treatment in 2016.

5.2.4. Timing of the Program

The N1DT Contingency Program is a 15-year program that began in 2015 and will continue to be implemented through 2029. The proposed timeline enables integration with other projects and programs.

5.2.5. Summary of Justification

When outages do occur, utility infrastructure and recovery operations should be in place to minimize interruptions as much as possible. "Bounce back", or resiliency strategies will strengthen both reliability and customer satisfaction. The Distribution Substation Transformer Contingency Program supports this mission through the mitigation of high-impact, long-duration service interruptions caused by substation power transformer failures. The program achieves this by making available either a permanent or deployable backup source to support customer restoration, thus minimizing the scale and duration of the outage in the most cost-effective manner. It also continues to improve the resiliency and recovery characteristics of LG&E and KU's distribution infrastructure in response to extreme weather, equipment failure and other potential high-impact events such as sabotage or terrorism, while supporting the mission of providing safe, reliable, resilient, high-quality energy at a reasonable cost to our customers.

Exhibit PWT-6

Distribution Automation
Estimated Annual O&M Expenses

Estimated Annual O&M Expenses for Proposed Implementation of DA (2023-2051) ($'000s)

Year	O&M Expense ($'000s)	Expected O&M Savings ($'000s)
2023	45	184
2024	46	188
2025	47	191
2026	48	195
2027	49	199
2028	50	203
2029	51	207
2030	52	211
2031	53	216
2032	54	220
2033	55	224
2034	56	229
2035	57	233
2036	58	238
2037	59	243
2038	61	248
2039	62	253
2040	63	258
2041	64	263
2042	66	268
2043	67	273
2044	68	279
2045	70	284
2046	71	290
2047	72	296
2048	74	302
2049	75	308
2050	77	314
2051	78	320

Exhibit PWT-7

Capital Evaluation Model (CEM) Results

Distribution Automation Alternatives	NPVRR ($000's)	
Recloser Only/Oracle NMS/OSI SCADA	LGE	$ 66,844
	KU	$ 43,919
	DMS/DSCADA	$ 11,959
	Total	**$ 122,722**
Circuit Upgrades/Reclosers/Oracle NMS/OSI SCADA	LGE	$ 73,593
	KU	$ 48,602
	DMS/DSCADA	$ 11,959
	Total	**$ 134,154**
Do Nothing	LGE	$ 81,435
	KU	$ 51,715
	DMS/DSCADA	--
	Total	**$ 133,150**

*Recommended DA Program in gray

Financial Summary for
Distribution Automation LGE
Project Number 1.49450149477153E+23
Electric Distribution: Denise Simon
LG&E

Financial Analysis - Project Summary	RECOMMEND-ATION	Recloser/Contingency Upgrades	Do Nothing	Alternative #3
Total Capital Expenditures Requested, $000s	**$63,741**	$60,660	$0	$0
Total Cost Savings/(Incremental Costs), $000s	**$3,426**	($25,991)	($264,428)	$0
NPV Revenue Requirements, $000s	**$66,844**	$73,593	$81,435	$0
ROE	**9.7%**	9.6%	0.0%	0.0%

	RECOMMENDATION						
Financial Analysis - By Year	5-Year Total 2016-2020	2016	2017	2018	2019	2020	Life 2016-2053
Capital Expenditures Requested, $000s	$41,899	$48	$4,752	$13,397	$12,780	$10,922	$63,741
Cost Savings/(Incremental Costs), $000s	$54	$0	($1)	($6)	$18	$43	$1,424
EBIT, $000s	$6,934	$1	$560	$991	$2,322	$3,060	$87,537
Net Income, $000s	$3,300	$0	$297	$430	$1,119	$1,455	$43,360
ROE	8.0%	0.0%	14.6%	7.4%	7.3%	8.1%	9.7%

NPVRR general rules:

The NPVRR is the present value of the cost to the customer, so the option with the lowest NPVRR is best. NPVRR can be negative if savings are put into the model, in which case the biggest negative number is best as it represents the most benefit to the customer.

LG&E KU

Financial Summary for
Distribution Automation KU
Project Number
Electric Distribution: Denise Simon
KU

Financial Analysis - Project Summary	RECOMMEND-ATION	Alternative #2 (Recloser/Contingency Upgrades)	Alternative #2	Alternative #3
Total Capital Expenditures Requested, $000s	**$42,494**	$40,440	$0	$0
Total Cost Savings/(Incremental Costs), $000s	**$2,310**	($18,763)	($176,285)	$0
NPV Revenue Requirements, $000s	**$43,919**	$48,602	$51,715	$0
ROE	**9.6%**	9.6%	0.0%	0.0%

	RECOMMENDATION						
Financial Analysis - By Year	**5-Year Total 2016-2020**	**2016**	**2017**	**2018**	**2019**	**2020**	**Life 2016-2051**
Capital Expenditures Requested, $000s	$27,932	$32	$3,168	$8,931	$8,520	$7,281	$42,494
Cost Savings/(Incremental Costs), $000s	$37	$0	$0	($4)	$12	$29	$960
EBIT, $000s	$4,601	$1	$375	$653	$1,541	$2,031	$54,240
Net Income, $000s	$2,188	$0	$199	$282	$742	$965	$26,852
ROE	7.9%	0.0%	14.7%	7.4%	7.3%	8.1%	9.6%

NPVRR general rules:
The NPVRR is the present value of the cost to the customer, so the option with the lowest NPVRR is best. NPVRR can be negative if savings are put into the model, in which case the biggest negative number is best as it represents the most benefit to the customer.

Financial Summary for
Distribution Automation DMS

Project Number 1.49450149447153E+23
Electric Distribution: Denise Simon
Servco

Financial Analysis - Project Summary	RECOMMEND-ATION	Alternative #1: GE DMS/GE SCADA	Alternative #2: OSI SCADA Only	Alternative #3
Total Capital Expenditures Requested, $000s	**$6,122**	$8,190	$4,650	$0
Total Cost Savings/(Incremental Costs), $000s	**($5,885)**	($7,792)	($11,198)	$0
NPV Revenue Requirements, $000s	**$11,959**	$15,522	$14,482	$0
ROE	**12.1%**	12.5%	17.3%	0.0%

	RECOMMENDATION						
Financial Analysis - By Year	**5-Year Total 2017-2021**	**2017**	**2018**	**2019**	**2020**	**2021**	**Life 2017-2025**
Capital Expenditures Requested, $000s	$6,122	$2,500	$2,922	$700	$0	$0	$6,122
Cost Savings/(Incremental Costs), $000s	($5,885)	($439)	($1,352)	($1,450)	($1,308)	($1,336)	($5,885)
EBIT, $000s	$2,386	$222	$453	$1,048	$387	$276	$2,607
Net Income, $000s	$1,233	$106	$212	$584	$193	$138	$1,343
ROE	12.5%	8.0%	7.6%	14.9%	17.6%	10.0%	12.1%

NPVRR general rules:
The NPVRR is the present value of the cost to the customer, so the option with the lowest NPVRR is best. NPVRR can be negative if savings are put into the model, in which case the biggest negative number is best as it represents the most benefit to the customer.

Exhibit PWT-8

Smart Grid Investments

Smart Grid Investments
2017 BP
$000s

Project	2017	2018	2019	2020	2021	Inception - 6/30/2018
LG&E						
Distribution and Customer Services:						
Advanced Metering Systems	$ 24,220	$ 71,780	$ 62,055	$ 1,750	$ -	$ 60,110
Distribution Automation / DMS	$ 5,182	$ 14,730	$ 13,168	$ 12,600	$ 12,390	$ 13,262
AMS Opt-in Program (DSM)	$ 226	$ 228	$ -	$ -	$ -	$ 2,268
VOLT/VAR Optimization (DSM)	$ -	$ -	$ 1,000	$ 1,000	$ 1,000	$ -
VOLT/VAR Optimization Pilot (Non-DSM)	$ 500	$ -	$ -	$ -	$ -	$ 600
Transmission:						
Control Houses	$ -	$ -	$ 1,318	$ 1,343	$ 1,617	$ -
Fiber/Telecom	$ -	$ -	$ -	$ -	$ -	$ -
Relay Panels	$ 820	$ 1,130	$ 1,720	$ 2,180	$ 1,650	$ 1,326
RTU's	$ 965	$ 1,020	$ 1,070	$ 1,080	$ 1,075	$ 2,294
Switch - Auto	$ -	$ 201	$ -	$ -	$ -	$ 174
Switch - Motor Operated	$ -	$ -	$ -	$ -	$ -	$ -
Total LG&E	$ 31,913	$ 89,089	$ 80,331	$ 19,953	$ 17,732	$ 80,034
KU						
Distribution and Customer Services:						
Advanced Metering Systems	$ 24,220	$ 71,780	$ 62,055	$ 1,750	$ -	$ 60,110
Distribution Automation / DMS	$ 4,068	$ 10,520	$ 8,832	$ 8,400	$ 8,260	$ 9,894
AMS Opt-in Program (DSM)	$ 227	$ 228	$ -	$ -	$ -	$ 1,491
VOLT/VAR Optimization (DSM)	$ -	$ -	$ 1,000	$ 1,000	$ 1,000	$ -
KU SCADA Meter Expansion	$ 499	$ -	$ -	$ -	$ -	$ 499
Transmission:						
Control Houses	$ 3,112	$ 3,644	$ 2,179	$ 2,000	$ 3,282	$ 13,354
Fiber/Telecom	$ 280	$ 280	$ 280	$ 340	$ 340	$ 551
Relay Panels	$ 960	$ 2,270	$ 3,390	$ 4,405	$ 3,350	$ 1,290
RTU's	$ 1,920	$ 2,050	$ 2,105	$ 2,190	$ 2,120	$ 5,958
Switch - Auto	$ 1,713	$ 2,727	$ 200	$ -	$ -	$ 2,898
Switch - Motor Operated	$ 1,737	$ 801	$ 1,867	$ 1,768	$ 2,217	$ 2,084
Total KU	$ 38,736	$ 94,300	$ 81,908	$ 21,853	$ 20,569	$ 98,129

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

APPLICATION OF KENTUCKY	**)**	
UTILITIES COMPANY FOR AN	**)**	**CASE NO. 2016-00370**
ADJUSTMENT OF ITS ELECTRIC	**)**	
RATES AND FOR CERTIFICATES	**)**	
OF PUBLIC CONVENIENCE	**)**	
AND NECESSITY	**)**	

TESTIMONY OF
DANIEL K. ARBOUGH
TREASURER
KENTUCKY UTILITIES COMPANY

Filed: November 23, 2016

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

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

Q. Have you previously testified before the Commission?

A. Yes. I testified in KU's and LG&E's last several base rate cases.[1] Since 2000, I have also attested to the factual representations in each of KU's financing applications filed with the Kentucky Public Service Commission ("Commission") and have appeared before Commission Staff on behalf of the Company on a regular basis at informal conferences or Commission-scheduled meetings.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to (1) describe the business and planning process used in preparing the Companies' base and forecast periods; (2) present KU's capital structure; (3) describe KU's cost of debt and debt issuances since the last rate case; and (4) support several of KU's filing requirements.

Q. Have your duties as Treasurer changed since KU's last rate case?

---

[1] Case No. 2014-00371, *In the Matter of: Application of Kentucky Utilities Company for an Adjustment of Its Electric Rates*; Case No. 2014-00372, *In the Matter of: Application of Louisville Gas and Electric Company for an Adjustment of Its Electric and Gas Rates*; Case No. 2012-00221, *In the Matter of: Application of Kentucky Utilities Company, for an Adjustment of Its Electric Rates*; Case No. 2012-00222, *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.*

A. Yes, they have. Since becoming Treasurer in 2001, my responsibilities have included cash management, corporate finance, credit risk management, insurance, and pension fund management oversight. Since the last rate case, my duties also include overseeing the Company's forecasting and business planning processes.

<u>Business Planning Process Resulting in the Forecasted Test Period</u>

Q. Can you please describe the business planning processes the Company utilized in preparing the forecasted test period in this case?

A. Certainly. The Company's business planning processes remain very similar to those explained in detail by Mr. Blake in Case No. 2014-00371, which was KU's most recent rate case. Each year, KU prepares a five-year business plan containing projected income statements, cash flow statements, and balance sheets. The Company's budget is set forth in the first year of the five-year plan. Significant effort is involved in preparing the five-year plan, which includes the use of econometric models, variables, assumptions, and changes in activity levels. In addition to my testimony, a description of these tools and how they are utilized are set forth in Filing Requirement Schedule 807 KAR 5:001 Section 16(7)(c) at Tab 16, as well as in the testimony of Mr. Sinclair. Mr. Thompson and Mr. Blake also discuss assumptions in their testimony.

Attached as Exhibit DKA-1 is a visual description of the planning process, and Exhibit DKA-2 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 financial planning process and to develop the fully forecasted test period in this case.

Q. Can you describe the two computer programs the Company chiefly utilizes in its business planning process?

A. Yes, the two programs are UIPlanner and PowerPlan. KU is able to extract and import data from the two programs, which aids in the efficiency and continuity of business planning and forecasting. The Company utilizes UIPlanner's financial planning software, which is used by 19 of the largest 25 utilities in the United States. The Company utilized UIPlanner in Case No. 2014-00371, and updates to the program since then have increased its capabilities. In 2015, the UIPlanner system was upgraded from Version 5.07 to Version 8.11 in order to utilize functionality and efficiency improvements in the newer version. An additional upgrade to Version 9.12 was done in 2016. This version is functionally more compatible with EXCEL 2013 than the previous version.

In addition to these upgrades, the UIPlanner system has been updated to better perform certain calculations automatically, such as permanent versus temporary tax differences and capital structure targeting for debt and equity. These updates eliminate the need for outside calculations that previously were manually input. There have also been efforts to streamline the import processes from

PowerPlan and the General Ledger system to further reduce manual inputs and the time required to import data.

Similarly, PowerPlan is the leading utility software that allows the Company to robustly manage its assets. Since the last rate case, KU has purchased a new PowerPlan module that automates the process of tracking repair costs that can be deducted for tax purposes, but are capitalized for book accounting purposes. The module reduces the time required to manually track these items and may enable the Company to capture tax savings.

We have also automated the plant-in-service unitizations of distribution mass assets. This automation reduces the manual efforts previously. This systematic auto-unitization process is a best practice utilized by other utilities.

Q. Please explain the steps involved in KU's annual business planning process.

A. In May of each year, the Company finalizes its workforce plan and loads the labor forecast into PowerPlan. After this, the corporate burdens for employee benefits are calculated and entered into PowerPlan. Next, the electric sales and commodity price forecasts are completed and loaded into UIPlanner. At this point, which is normally during July and August, the capital plan is prepared, reviewed, and entered into PowerPlan.

Next, the Generation forecast is completed, reviewed, and loaded into UIPlanner. After this, Operations and Maintenance, Costs of Sales, and Other expense budgets are completed, reviewed, and loaded into PowerPlan. The data from PowerPlan is then extracted and imported into UIPlanner. Once this is completed, Business Plan presentations are conducted involving each line of business, reviews are completed, and necessary changes are made. At this point, which is typically in September, other revenue calculations, depreciation, financing and tax calculations are finished in UIPlanner.

Next, the Business Plan is reviewed with senior officers. In the final steps, the Business Plan is submitted to PPL for inclusion in the PPL consolidated financial projections and ultimately reviewed and approved by the LKE Board and the PPL Board Finance Committee.

Q. Please explain how the labor forecasts that you mentioned are developed.

A. The Company's Human Resources Department works closely with each business segment to identify future personnel needs, and explore planning assumptions for existing employees' development, retention, and expected staffing changes. As part of this process, open positions and anticipated needs are analyzed. As discussed in Mr. Blake's testimony, the Company uses annual benchmarking studies to determine salaries for new hires.

Information and data regarding KU's current workforce are housed in PeopleSoft, which is a computer software program the Company uses for many of its human resources functions. KU extracts from PeopleSoft information regarding wages, vacation hours, personal days, and sick time, and then imports the data into PowerPlan. Adjustments are then applied based on expected changes in the workforce, union contracts, retirements and pay adjustments based on the salary benchmarking surveys discussed above. The resulting change in average wage rates between the previous test year ending June 30, 2016 and the forecasted test year ending June 30, 2018 is 3.6% over a two-year period, or 1.8% on an average annual basis. Estimates are made for the amount of time each department will spend each month working on capital projects. Labor costs are split between capital and operating and maintenance expense based on these estimates.

Q. How does KU determine the capital projects that are included in the Company's business plan and in the forecasted test period in this case?

A. Each line of business prepares a detailed list of capital projects that includes the expected investment over time, when construction would begin, and the expected in-service date. The Company's Resource Allocation Committee ("RAC") is comprised of leaders from across the Company and it ensures that the Company's capital budgets are prepared based on the needs of the business and our customers. The RAC serves under the direction of, and makes recommendations to, the Investment Committee. Under the supervision of the RAC, changes in the five-year capital plan must be based on new facts and circumstances that are supportable based on the need for and cost effectiveness of the impacted projects.

Q. Can you provide an overview of how the electric sales, generation and off-system sales forecasts are developed?

A. Yes. KU develops its electric sales, generation, and off-system sales forecasts through the business processes described in the Company's integrated resource plans and certificate of public convenience and necessity cases for generation resources filed with the Commission. Additionally, Mr. Sinclair's testimony provides a more thorough description of the assumptions, software, and methodology utilized in developing these forecasts.

Q. Please explain how operation and maintenance expenses are developed through business planning and for inclusion in the forecasted test period in this case.

A. For many years, the Company has budgeted its operation and maintenance expenses through a "bottom-up" approach that begins with each line of business. The Company used the same "bottom up" approach to prepare the operation and maintenance budgets for this case. The expenses are budgeted to the corresponding Federal Energy Regulatory Commission ("FERC") account. These costs, along with labor, capital, and other costs, are thoroughly reviewed by various levels of management and presented to and approved by the Company's senior officers. A copy of the current year's presentations is included at Tab 16 of the Company's application.

Q. Was this business planning process used to develop the fully forecasted test period ending June 30, 2018, for this application?

A. Yes. The fully forecasted test period supporting this rate application was developed through the Company's business process described above under my supervision and direction subject to Mr. Blake's oversight. The testimony of Mr. Garrett presents the financial forecast in this case, which includes the Company's requested annual increase in revenues.

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

A. Yes, KU included assumptions concerning its capital structure, cost of equity, and cost of debt in developing the forested test period supporting the rate applications in this case.

Capital Structure

Q. Please explain KU's capital structure.

A. A significant indicator of a company's financial strength is its level of debt as compared to total capitalization. A lower proportion of debt signals that a company should have sufficient cash flow to meet its interest and other debt obligations when they are due. Also, maintaining a moderate level of existing debt affords a company greater flexibility to raise additional funds when such needs arise. Cumulatively, this leads to higher credit ratings and lower interest costs.

KU maintains its capital structure in adherence with these bedrock principles. For the forecasted period, KU has projected a debt-to-capitalization ratio of 46.72 percent. This is consistent with KU's quarter-end ratios since 2007, which have stayed within 45.7 to 47.9 percent.[2] Maintaining these ratios is consistent with KU's long-standing targeted bond rating of "A."

Q. Please explain how Moody's evaluates a utility's capital structure.

A. Moody's approach is set forth in its *Rating Methodology, Regulated Electric and Gas Utilities,* dated December 23, 2013, a copy of which is attached to my testimony as Exhibit DKA-3. Moody's approach considers four factors: (1) regulatory framework; (2) ability to recover costs and earn returns; (3) diversification; and (4) financial strength.

The financial metrics Moody's evaluates in assigning a credit rating include the entity's debt-to-capitalization ratio. Moody's states, "High debt levels in comparison to capitalization can indicate higher interest obligations, can limit the

[2] These quarter-end ratios exclude purchase accounting adjustments reflected in federal GAAP filings.

ability of a utility to raise additional financing if needed, and can lead to leverage covenant violations in credit facilities or other financing agreements."[3]

KU continues to aim for an "A" rating from Moody's. This rating is consistent with a debt-to-capitalization ratio of 35 percent to 45 percent as calculated by Moody's. Moody's, like other credit rating agencies, makes various adjustments in computing a company's debt and capitalization. As an example, long-term obligations under pensions, and leases are considered "debt" obligations, and deferred taxes are included as part of capitalization. With Moody's adjustments, KU's debt-to-capitalization ratio for the base period is 37.5 percent; for the forecasted period it is 37.8 percent, both within Moody's range for an "A" rating. Moody's includes deferred taxes in its definition of capitalization, and the passage of bonus depreciation has caused a significant increase in the Company's deferred tax balance to approximately $1.3 billion. The growth in the deferred taxes is the cause for the debt/total capitalization ratio being slightly below the mid-point of the range. The Company cannot simply incorporate deferred taxes into its target ratios because other agencies do not include deferred taxes in their ratios as discussed below.

Q. Please explain how other rating agencies evaluate capital structures.

A. Like Moody's, Standard & Poor's ("S&P") adopted a revised rating methodology, which is described in the *S&P Corporate Methodology and Key Credit Factors for the Regulated Utilities Industry*, dated November 19, 2013. A copy is attached to my testimony as Exhibit DKA-4. S&P's revised methodology assigns values to the following: Country Risk, Industry Risk, and Competitive Position, each of which is

[3] Moody's *Rating Methodology, Regulated Electric and Gas Utilities,* Dec. 23, 2013 at 23.

considered in establishing a "Business Risk Profile." The "Business Risk Profile" is considered with a company's "Financial Risk Profile," which is based on a company's cash flow as compared to its obligations.

The result is adjusted by "modifiers" that include capital structure and beyond the standard cash flow adequacy and leverage analysis (such as debt maturities, interest-rate volatility, and currency issues). An additional modifier is corporate financial policy, which is S&P's positive or negative assessment of the company's management. Another S&P modifier is liquidity, which is a company's ability to meet its obligations in the event of an earnings decline, or other low probability negative events.

A company's debt/(debt + equity) ratio affects both its Financial Risk Profile regarding its cash flow, as well as the Capital Structure and Liquidity modifiers. Although S&P's methodology does not establish a direct correlation between a certain debt/(debt + equity) ratio and a particular rating, a company's capital structure has a direct impact on the requirements to meet S&P's rating guidelines. Unlike Moody's, S&P does not include deferred taxes in its ratio. Using S&P's adjustments, the Company's debt/(debt + equity) ratio is 46.9 percent for the base period and 47.8 percent for the forecasted period. The Company's current capital structure keeps the Financial Risk Profile in the "Intermediate" category (based on S&P's low volatility table) which, when combined with its "Excellent" Business Risk Profile is consistent with KU's target "A" rating.

Q. Why do credit rating agencies such as Moody's and S&P adjust a utility's debt balance when determining the capital structure?

A. Credit rating agencies view certain obligations, such as leases, pensions and post-retirement benefit obligations, as fixed obligations that are equivalent to debt. The Company accordingly makes corresponding adjustments when calculating the debt in its target capital structure.

Credit Ratings

Q. What are KU's current credit ratings?

A. Filing requirement 807 KAR 5:001 Section 16(8)(k) at Tab 64 shows the current credit ratings for KU. Presently, Moody's rating is A3 (with the first mortgage bonds rated A1), and S&P's rating is A- (with first mortgage bonds rated A). These strong credit ratings enable the Company to continue to raise debt capital at very reasonable costs.

Q. Please describe the recent changes to the Company's credit ratings.

A. On June 1, 2015, during the course of KU's most recent rate case, S&P upgraded the Company's credit ratings from BBB to A-, while also upgrading the first mortgage bonds from A- to A. The change was made following PPL Corporation completing its spinoff of its merchant generation business. This caused S&P to move the business risk profile to the "excellent" category from "strong." S&P also favorably noted that KU benefits from operating in a constructive, stable and transparent regulatory environment. In part because of the Commission's regulatory environment, the Company's credit ratings were upgraded which can help lower borrowing costs for customers. A copy of the news release announcing the upgrade is attached to my testimony as Exhibit DKA-5.

Moody's has not changed its rating of the Companies since the January 31, 2014 upgrade described in KU's most recent rate case.

Q. Does KU have sufficient access to capital?

A. Yes, it does. KU has authority from the FERC to issue up to $500 million in short-term debt,[4] and also maintains a $400 million line of credit. In addition, KU maintains a commercial paper program of $350 million.[5]

<u>Return on Common Equity</u>

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

A. Yes, I have.

Q. Do you believe Mr. McKenzie's proposed return on common equity is reasonable?

A. Yes, I do. I have reviewed his analyses that support his recommendation and, especially when considered with the operational challenges discussed in Mr. Thompson's testimony, find Mr. McKenzie's proposed return on common equity of 10.23% percent to be fair and reasonable.

<u>Cost of Debt and Debt Issuance</u>

Q. How does KU's cost of debt compare to other utility companies?

A. KU closely monitors its cost of debt as compared to a peer of group of other utility companies on a quarterly basis. As shown on Exhibit DKA-6, KU's cost of debt (combined taxable and tax-exempt debt) is second lowest of the twenty-five member group for the twelve months ending June 30, 2016. LG&E has the third lowest debt costs of the group. This comparison further demonstrates KU's reasonable cost of debt.

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[4] FERC Docket No. ES15-68-000, November 25, 2015.
[5] Kentucky Utilities Company FERC Form No. 1 for 2014/Q4.

Q. What debt issuance activities have occurred since the filing of the last rate case in November 2014?

A. In September 2015, the Company issued $500 million of new first mortgage bonds and repaid $250 million of maturing bonds in November 2015. A portion of the proceeds from the new bonds was used to repay the maturing bonds. The $500 million of new bonds was split between $250 million issued for ten years at 3.30% and $250 million issued for thirty years at 4.375%. There were a series of interest rate swaps with notional amounts totaling $500 million hedging this issuance which were settled at the time of the pricing of these bonds. The termination of these swaps resulted in a cost of $43 million which is being amortized into interest expense over the life of the bonds. In August 2016, the Company refinanced a floating rate tax-exempt bond totaling $96 million into a fixed rate for three years at an interest rate of 1.05%.

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, I am sponsoring (or co-sponsoring) the schedules required by 807 KAR 5:001 Section 16(7)(c); (7)(h)(11); (7)(j); (7)(t); and (8)(j). These schedules are filed with and in support of KU's application in this case.

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 63 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
- 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-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.

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. As indicated on Schedule J-1.1/J-1.2, the requested rate of return on capitalization is 7.29 percent, based on the proposed 10.23% percent return on common equity proposed by the Company, which is the return on common equity recommended by 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. 2014-00371, 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.

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 10.23 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, 7.29 percent, appears in Line 4 of Schedule A.

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, 2017. The second page provides the short-term debt information as of the end of the forecasted test period, June 30, 2018. The third page provides the 13-month-average short-term debt information for the forecasted test period.

Q. Please explain how KU's cost of short-term debt was calculated on Schedule J-2.

A. Short-term debt costs are based on interest expense from commercial paper issuances. For future periods, the interest rate is based on forward LIBOR curves. At the end of the base period, there is no short-term debt expected to be outstanding, and for the forecasted period the 13-month average rate is calculated to be 0.74 percent. The base period calculation of short-term debt costs are shown on page 1 of Filing Schedule J-2 while the 13-month average is calculated on page 3 of Schedule J-2 as required by 807 KAR 5:001 Section 16(8)(j). KU expects to provide updates on the cost of short-term debt as the case develops.

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, 2017. The second page provides the long-term debt information as of the end of the forecasted test period, June 30, 2018. The third page provides the 13-month-average long-term debt information for the forecasted test period.

Q. Please describe how KU's cost of long-term debt was calculated on Schedule J-3.

A. The Company's weighted-average cost of long-term debt at the end of the base period is projected to be 4.10 percent. Consistent with prior rate cases, this includes all components of interest expense for each bond, including the interest paid to bondholders, amortization of bond issuance costs, amortization of losses on reacquired debt, amortization of debt discounts, amortization of credit facility costs, fees for credit enhancements such as bond insurance fees and letters of credit where applicable, and amortization of pre-issuance hedging gains or losses. The unamortized pre-issuance hedge losses shown on Schedule J-3 are accounted for as regulatory assets and pre-issuance hedge gains are accounted for as regulatory liabilities and the balances in both instances are amortized straight-line over the life of the corresponding bond to interest expense.

KU's weighted-average cost of long-term debt for the forecasted test period is calculated as 4.12 percent. The calculation of KU's cost of long-term debt is detailed on Filing Schedule J-3 required by 807 KAR 5:001, Section 16(8)(j).

Q. Please describe Supporting Schedule B-1.1.

A. Supporting Schedule B-1.1 consists of four pages which were developed using information from Schedule B supported by Mr. Garrett. The first two show the calculations of net original cost rate base and cash working capital as of the end of the base period and the next two show the same calculations for the 13-month-average as of the end of the forecasted test period. The percentages shown on Line 21, "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. Does this conclude your testimony?

A. Yes, it does.

VERIFICATION

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

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

Daniel K. Arbough

Daniel K. Arbough

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 18th day of November 2016.

Judy Schooler (SEAL)

Notary Public

My Commission Expires:

JUDY SCHOOLER
Notary Public, State at Large, KY
My commission expires July 11, 2018
Notary ID # 512743

APPENDIX A

Daniel K. Arbough

Treasurer
Kentucky Utilities Company
LG&E and KU Services Company
220 West Main Street
Louisville, Kentucky 40202
(502) 627-4956

Previous Positions

E.ON U.S. LLC

Director, Corporate Finance and Treasurer	January 2001 – September 2007

LG&E Energy Corp.

Director, Corporate Finance	May 1998 – January 2001
Manager, Corporate Finance	August 1996 – May 1998

LG&E Power Inc.

Manager, Project Finance	June 1994 - August 1996

Conoco Inc., Houston, Texas

Corporate Finance, Project Finance, and Credit Management	June 1988 - May 1994

Boise Cascade Office Products, Denver, Colorado

Inventory Management	November 1983 - September 1987

Professional/Trade Memberships

National Association of Corporate Treasurers
Association for Financial Professionals
Financial Executives International

Education

Master of Business Administration – Finance - May 1988 – University of Denver
Bachelor of Science Business Administration – General Business – June 1983
University of Denver

Civic Activities

Louisville and Jefferson County Metropolitan Sewer District –Board of Directors – April 2012 – current (currently Vice-Chair)
Leadership Louisville – Bingham Fellows – Class of 2012
National Center for Families Learning – Endowment Oversight Committee Member
Louisville Central Community Centers – Past President of Board of Directors

Exhibit DKA-1

Visual description of the planning process

Financial Planning Software

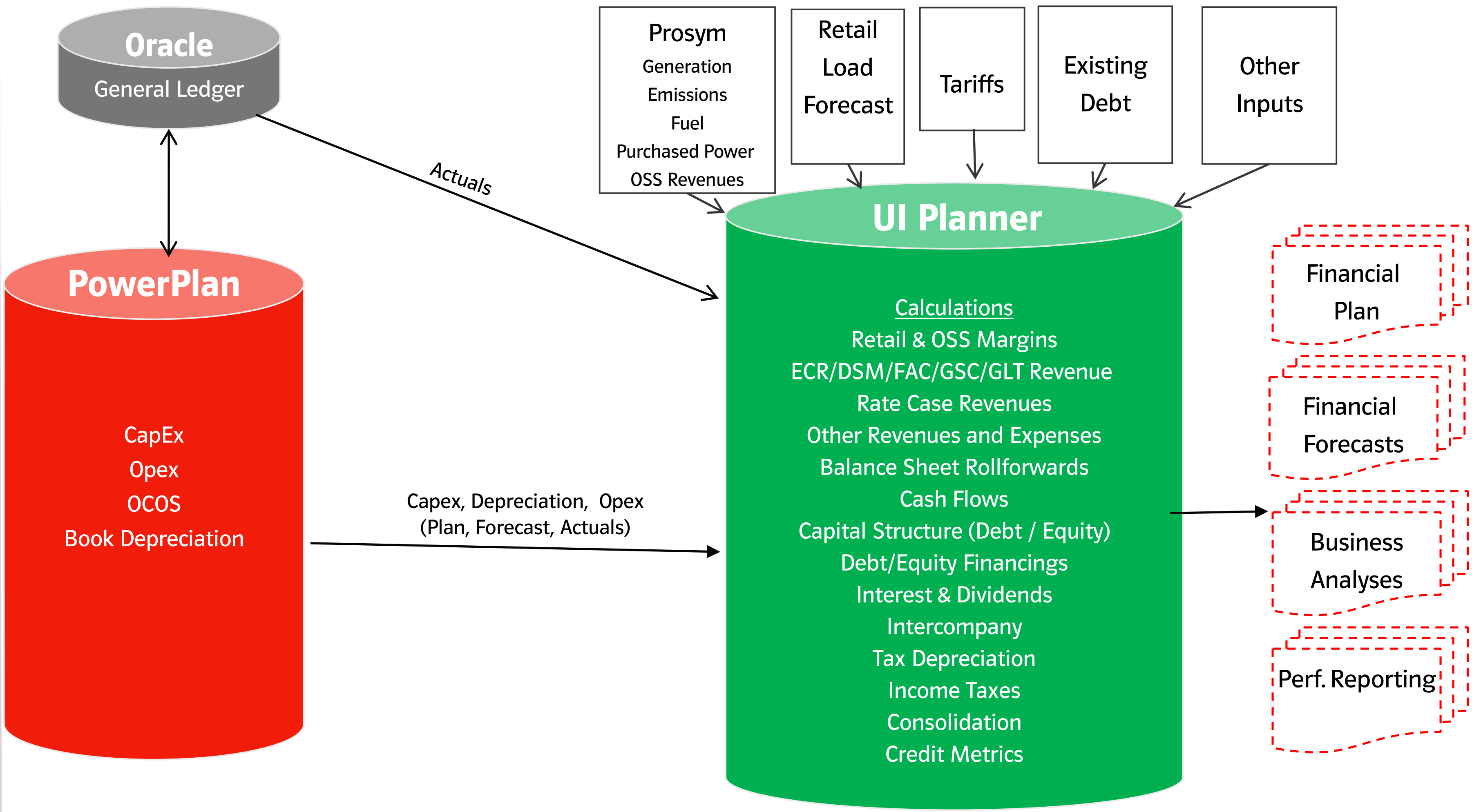


Exhibit DKA-2

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 PowerPlan 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 PowerPlan
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 PowerPlan and calculated deferred income taxes; cost of capital computed within UIPlanner using weighted average cost of debt, authorized ROE and target capital structure	UIPlanner PowerPlan
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) InterCompany costs brought in via PowerPlan	EXCEL PowerPlan
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

Income Statement

Line Item	*Basis to Derive*	*System Employed*
Gas Supply	Gas load forecast priced out at contracted rates and market prices for open/indexed positions	EXCEL
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	PowerPlan
Rate Mechanism Expenses	Projected O&M costs and depreciation by approved project	PowerPlan
Other Operating & Maintenance Expenses	Detailed "bottoms up" aggregation by department	PowerPlan
Taxes Other Than Income	Based on capital plan, classifications of property and property tax rates	EXCEL UIPlanner PowerPlan
Depreciation & Amortization	Based on capital plan, including property classifications and in service dates, and approved depreciation rates	PowerPlan
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 PowerPlan
Other Assets	Current levels only adjusted for known changes	
Accounts Payable	Function of capital and O&M spend, adjusted for some	UIPlanner

Balance Sheet

Line Item	*Basis to Derive*	*System Employed*
	payment lag	
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 PowerPlan
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	PowerPlan
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 DKA-3

Moody’s Rating Methodology

MOODY'S INVESTORS SERVICE

Regulated Electric and Gas Utilities

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.

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

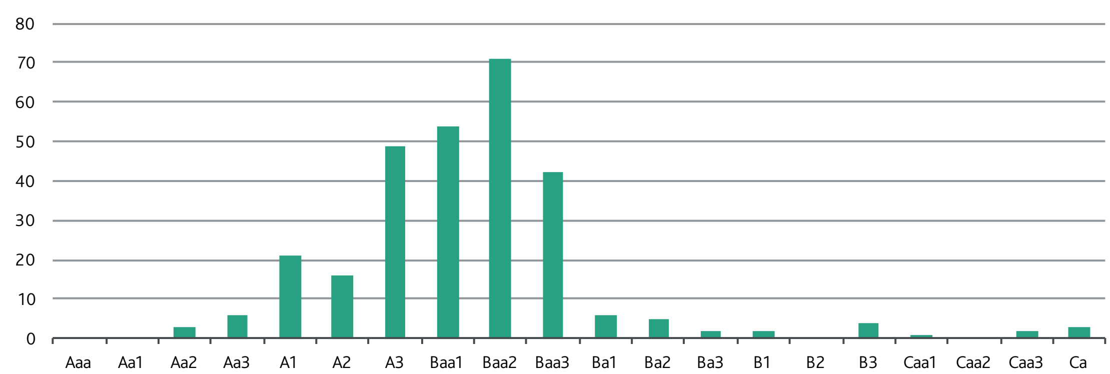
» Global Regulated Water Utilities

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

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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Exhibit DKA-4

S&P Corporate Methodology and Key Credit Factors

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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.

Exhibit DKA-5

S&P Upgrade of PPL and Subsidiaries

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Research Update:

PPL Corp. Rating Raised To 'A-' From 'BBB' On Improved Business Risk Profile; Stable Outlook

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Research Update:

PPL Corp. Rating Raised To 'A-' From 'BBB' On Improved Business Risk Profile; Stable Outlook

Overview

- U.S. utility company PPL Corp. (PPL) has completed the spin-off of its merchant generation assets leading to a material improvement to the company's business risk profile.
- PPL will now focus on regulated utility operations in the US and the UK.
- We are raising the issuer credit rating on PPL and its U.S.-based subsidiaries to 'A-' from 'BBB' and removing the ratings from CreditWatch with positive implications. The outlook is stable.

Rating Action

On June 1, 2015, Standard & Poor's Ratings Services raised its issuer credit rating on PPL Corp. and its U.S.-based subsidiaries to 'A-' from 'BBB' and removed the ratings from CreditWatch, where they were placed with positive implications on June 10, 2014 . The outlook is stable.

Rationale

PPL has completed the spin-off of its merchant generation assets resulting in sufficient improvement in business risk to move the company's business risk profile to the "excellent" category from "strong". We are raising the issuer credit rating on PPL and its US-based subsidiaries PPL Electric Utilities Corp. (PPLEU), LG&E and KU Energy LLC (LKE), Louisville Gas & Electric Co. (LG&E) and Kentucky Utilities Co. (KU) to 'A-' from 'BBB'.

PPL's "excellent" business risk profile accounts for the company's ownership of solely regulated utility operations, both integrated as well as lower risk transmission and distribution utilities. PPL's regulated subsidiaries benefit from operations under constructive, transparent and generally stable regulatory frameworks and they take full advantage of all constructs available within the respective regulatory framework to consistently earn returns that are close to or at the authorized levels. Moreover, PPL's business risk profile benefits from scale, serving more than 10 million customers in two countries and and two states, and operating and regulatory diversity, although the service territory demonstrates only modest growth.

We assess PPL's financial risk profile as being in the "significant" category using the medial volatility financial ratio benchmarks. Under our base-case scenario, we project that PPL will achieve funds from operations (FFO) to debt of 14% to 15% over the next few years, benefiting from pending rate case decisions and the timely recovery of invested capital, primarily in transmission investments. We anticipate that the company's debt leverage will remain elevated with debt to EBITDA that is close to 5x, in large part influenced by the capitalization of the U.K. subsidiaries.

Liquidity

We assess PPL's liquidity as "adequate" to cover its needs over the next 12 months. We expect the company's liquidity sources to exceed its uses by 1.1x or more, the minimum threshold for regulated utilities under our criteria, and that the company will also meet our other requirements for such a designation. We expect that PPL's liquidity will benefit from stable cash flow generation, ample availability under the revolving credit facilities, and manageable debt maturities over the next few years.

The PPL group has about $4 billion in revolving credit facilities, with $815 million available at the parent, $300 million available at PPLEU, $500 million available at Louisville Gas & Electric, $598 million available at Kentucky Utilities, and about $1.75 billion available at the U.K. operations. The facilities mature from 2016 through 2019.

Principal liquidity sources:

- Revolving credit facilities totaling about $3.3 billion.
- Cash on hand of about $1.5 billion.
- Cash from operations of about $2.5 billion to $2.7 billion.

Principal liquidity uses:

- Debt maturities of about $2.2 billion, including commercial paper.
- Maintenance capital spending averaging about $2.3 billion.
- Dividends of about $1 billion annually.

Outlook

The stable outlook on PPL and its subsidiaries is based on the company's "excellent" business risk profile that we view at the upper end of the range and "significant" financial risk profile, which is at the lower end of the range. Under our base case scenario we expect that FFO to debt will range from 14% to 15% while debt to EBITDA will remain elevated at about 5x.

Downside Scenario

We could lower the ratings on PPL and its subsidiaries if core credit ratios weaken such that FFO to debt is below 13% and debt to EBITDA exceeds 5x on a consistent basis.

Upside Scenario

Given our assessment of business risk and our base-case scenario for financial performance, we do not anticipate higher ratings during the outlook period. However, higher ratings would largely depend on PPL achieving FFO to debt of more than 18% on a consistent basis, while maintaining the current level of business risk.

Ratings Score Snapshot

	To	From
Corporate Credit Rating	A-	BBB
Business Risk	Excellent	Strong
Country Risk	Very Low	Very Low
Industry Risk	Very Low	Low
Competitive Position	Strong	Strong
Financial Risk	Significant	Significant
Cash Flow/Leverage	Significant	Significant
Anchor	a-	bbb
Modifiers		
Diversification/Portfolio effect	Neutral	Neutral
Capital structure	Neutral	Neutral
Financial policy	Neutral	Neutral
Liquidity	Adequate	Adequate
Management and Governance	Satisfactory	Satisfactory
Comparable rating analysis	Neutral	Neutral

Related Criteria And Research

Related Criteria

- Criteria - Corporates - General: Methodology And Assumptions: Liquidity Descriptors For Global Corporate Issuers - December 16, 2014
- Criteria - Corporates - Utilities: Key Credit Factors For The Regulated Utilities Industry - November 19, 2013
- Criteria - Corporates - General: Corporate Methodology: Ratios And Adjustments - November 19, 2013
- General Criteria: Methodology: Industry Risk - November 19, 2013
- General Criteria: Group Rating Methodology - November 19, 2013
- Criteria - Corporates - General: Corporate Methodology - November 19, 2013
- General Criteria: Country Risk Assessment Methodology And Assumptions - November 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 - February 14, 2013

- General Criteria: Methodology: Management And Governance Credit Factors For Corporate Entities And Insurers - November 13, 2012
- General Criteria: Use Of CreditWatch And Outlooks - September 14, 2009
- Criteria - Corporates - Utilities: Notching Of U.S. Investment-Grade Investor-Owned Utility Unsecured Debt Now Better Reflects Anticipated Absolute Recovery - November 10, 2008
- Criteria - Corporates - General: 2008 Corporate Criteria: Rating Each Issue - April 15, 2008

Ratings List

	Ratings	
	To	From
PPL Corp.		
Corporate credit rating		
Foreign and Local Currency	A-/Stable/--	BBB/Watch Pos/--
Kentucky Utilities Co.		
Corporate credit rating		
Foreign and Local Currency	A-/Stable/A-2	BBB/Watch Pos/A-2
Senior Secured		
Local Currency [#1]	A/A-2	A-/Watch Pos/A-2
Recovery Rating [#1]	1+	1+
Local Currency [#2]	A/A-2	A-/Watch Pos/A-2
Recovery Rating [#2]	1+	1+
Local Currency [#3]	A/A-2	A-/Watch Pos/A-2
Recovery Rating [#3]	1+	1+
Local Currency [#4]	A/A-2	A-/Watch Pos/A-2
Recovery Rating [#4]	1+	1+
SPUR [#4]	A/A-2	A-/Watch Pos/A-2
Local Currency [#5]	A	A-/Watch Pos
Recovery Rating [#5]	1+	1+
SPUR [#5]	A	A-/Watch Pos
Local Currency [#4]	A	A-/Watch Pos
Recovery Rating [#4]	1+	1+
SPUR [#4]	A	A-/Watch Pos

Ratings List Continued...

Local Currency	A	A-/Watch Pos
Recovery Rating	1+	1+
Commercial Paper		
Local Currency	A-2	A-2
LG&E and KU Energy LLC		
Corporate credit rating		
Foreign and Local Currency	A-/Stable/--	BBB/Watch Pos/--
Senior Unsecured		
Local Currency	BBB+	BBB-/Watch Pos
Louisville Gas & Electric Co.		
Corporate credit rating		
Foreign and Local Currency	A-/Stable/A-2	BBB/Watch Pos/A-2
Senior Secured		
Local Currency [#6]	A/A-2	A-/Watch Pos/A-2
Recovery Rating [#6]	1+	1+
Local Currency [#7]	A	A-/Watch Pos/NR
Recovery Rating [#7]	1+	1+
Local Currency [#6]	A	A-/Watch Pos/NR
Recovery Rating [#6]	1+	1+
Local Currency [#7]	A/A-2	A-/Watch Pos/A-2
Recovery Rating [#7]	1+	1+
Local Currency [#6]	A	A-/Watch Pos
Recovery Rating [#6]	1+	1+
Local Currency [#7]	A	A-/Watch Pos
Recovery Rating [#7]	1+	1+
Local Currency	A	A-/Watch Pos
Recovery Rating	1+	1+

Ratings List Continued...

Commercial Paper		
Local Currency	A-2	A-2
PPL Capital Funding Inc.		
Senior Unsecured		
Local Currency[1]	BBB+	BBB-/Watch Pos
Junior Subordinated		
Local Currency[1]	BBB	BB+/Watch Pos
PPL Electric Utilities Corp.		
Corporate credit rating		
Foreign and Local Currency	A-/Stable/A-2	BBB/Watch Pos/A-2
Senior Secured		
Local Currency [#8]	A	A-/Watch Pos
Recovery Rating [#8]	1+	1+
Local Currency [#9]	AA-/Stable	AA-/Stable
Recovery Rating [#9]	1+	1+
SPUR [#9]	A	A-/Watch Pos
Local Currency [#10]	AA-/Stable	AA-/Stable
Recovery Rating [#10]	1+	1+
SPUR [#10]	A	A-/Watch Pos
Local Currency[2]	A	A-/Watch Pos
Recovery Rating	1+	1+
SPUR	A	A-/Watch Pos
Local Currency	A	A-/Watch Pos
Recovery Rating	1+	1+
Commercial Paper		
Local Currency	A-2	A-2

[1] Dependent Participant(s): PPL Corp.

[2] Dependent Participant(s): Ambac Assurance Corp.

[#1] Issuer: Carroll Cnty, OBLIGOR: Kentucky Utilities Co.

[#2] Issuer: Mercer Cnty, OBLIGOR: Kentucky Utilities Co.

[#3] Issuer: Muhlenberg Cnty, OBLIGOR: Kentucky Utilities Co.

[#4] Issuer: Carroll Cnty, INSPRO: Ambac Assurance Corp., OBLIGOR: Kentucky Utilities Co.

[#5] Issuer: Trimble Cnty, INSPRO: Ambac Assurance Corp., OBLIGOR: Kentucky Utilities Co.

[#6] Issuer: Louisville & Jefferson Cnty Metro Govt, OBLIGOR: Louisville Gas & Electric Co.

[#7] Issuer: Trimble Cnty, OBLIGOR: Louisville Gas & Electric Co.

[#8] Issuer: Pennsylvania Econ Dev Fing Auth, OBLIGOR: PPL Electric Utilities Corp.

[#9] Issuer: Lehigh Cnty Indl Dev Auth, INSPRO: National Public Finance Guarantee Corp., OBLIGOR: PPL Electric Utilities Corp.

[#10] Issuer: Lehigh Cnty Indl Dev Auth, INSPRO: MBIA Insurance Corp., INSPRO: National Public Finance Guarantee Corp., OBLIGOR: PPL Electric Utilities Corp.

Complete ratings information is available to subscribers of RatingsDirect at www.globalcreditportal.com and at spcapitaliq.com. All ratings referenced herein can be found on Standard & Poor's public Web site at www.standardandpoors.com. Use the Ratings search box located in the left column.

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Exhibit DKA-6

Utility Peer Group Cost of Debt Comparison (June 2016)

Utilty Cost of Debt Comparison
12 Months Ending June 2016

Rank	Company	Source: 10-Q, 10-K, or Company Websites
1.	Dayton Power and Light	3.534%
2.	**KU**	**3.894%**
3.	**LG&E**	**3.924%**
4.	Public Service Electric and Gas Company	4.017%
5.	Indiana Michigan Power Company	4.025%
6.	AEP Texas North Company	4.040%
7.	NiSource	4.365%
8.	AEP Texas Central Company	4.370%
9.	DTE Electric Company	4.410%
10.	Appalachian Power Company	4.568%
11.	PECO Energy Company	4.584%
12.	Duke Energy Indiana Inc.	4.633%
13.	Commonwealth Edison	4.667%
14.	PPL Electric Utilities	4.673%
15.	Duke Energy Ohio	4.690%
16.	Kentucky Power Company	5.086%
17.	Union Electric Company	5.189%
18.	DTE Gas Company	5.410%
19.	Metropolitan Edison Company	5.559%
20.	Ameren Illinois Company	5.627%
21.	Pennsylvania Electric Company	5.934%
22.	Jersey Central Power & Light Co.	5.934%
23.	Ohio Power Company	6.002%
24.	Toledo Edison Company	7.787%
25.	Ohio Edison Company	9.139%

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

APPLICATION OF KENTUCKY UTILITIES	)	
COMPANY FOR AN ADJUSTMENT OF ITS	)	**CASE NO. 2016-00370**
ELECTRIC RATES AND FOR	)	
CERTIFICATES OF PUBLIC	)	
CONVENIENCE AND NECESSITY		

TESTIMONY OF

ADRIEN M. MCKENZIE, CFA

on behalf of

KENTUCKY UTILITIES COMPANY

Filed: November 23, 2016

DIRECT TESTIMONY OF
ADRIEN M. MCKENZIE, CFA

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I. INTRODUCTION

Q1. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A1. My name is Adrien M. McKenzie, and by business address is 3907 Red River, Austin, Texas 78751.

Q2. IN WHAT CAPACITY ARE YOU EMPLOYED?

A2. I am a Vice President with Financial Concepts and Applications, Inc. ("FINCAP"), a firm engaged in financial, economic, and policy consulting to business and government.

Q3. PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND AND PROFESSIONAL EXPERIENCE.

A3. A description of my background and qualifications, including a resume containing the details of my experience, is attached as Exhibit No. 1.

Q4. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A4. The purpose of my testimony is to present to the Kentucky Public Service Commission ("KPSC") my independent assessment of the fair rate of return on equity ("ROE") that Kentucky Utilities Company ("KU" or "the Company") should be authorized to earn on its investment in providing electric utility service. In addition, I also examined the reasonableness of KU's capital structure, considering both the specific risks faced by the Company, as well as other industry guidelines.

Q5. PLEASE SUMMARIZE THE INFORMATION AND MATERIALS YOU RELIED ON TO SUPPORT THE OPINIONS AND CONCLUSIONS CONTAINED IN YOUR TESTIMONY.

A5. To prepare my testimony, I referenced information from a variety of sources that would normally be relied upon by a person in my capacity. I am familiar with the organization, finances, and operations of KU from my participation in prior proceedings before the KPSC, the Virginia State Corporation Commission ("VSCC"), and the Federal Energy Regulatory Commission ("FERC"). In connection with this filing, I considered and relied upon corporate disclosures, publicly available financial reports and filings, and other published information relating to KU. I also reviewed information relating generally to capital market conditions and specifically to investor perceptions, requirements, and expectations for utilities. These sources, coupled with my experience in the fields of finance and utility regulation, have given me a working knowledge of the issues relevant to investors' required return for KU, and they form the basis of my analyses and conclusions.

Q6. HOW IS YOUR TESTIMONY ORGANIZED?

A6. After first summarizing my conclusions and recommendations, I briefly review KU's operations and finances. I then examine current conditions in the capital markets and their implications in evaluating a fair ROE for KU. With this as a background, I conduct well-accepted quantitative analyses to estimate the current cost of equity for a reference group of comparable-risk utilities. These included the discounted cash flow ("DCF") model, the Capital Asset Pricing Model ("CAPM"), the empirical form of Capital Asset Pricing Model ("ECAPM"), an equity risk premium approach based on allowed ROEs, and reference to expected earned rates of return for utilities, which are all methods that are commonly relied on in regulatory proceedings.

Based on the cost of equity estimates indicated by my analyses, I evaluate a fair ROE for KU, taking into account the specific risks for its jurisdictional utility operations in Kentucky and the Company's requirements for financial strength, which are properly considered in setting a fair ROE. Further, I corroborate my utility quantitative analyses by applying the DCF model to a group of low risk non-utility firms.

II. RETURN ON EQUITY FOR KU

Q7. WHAT IS THE PURPOSE OF THIS SECTION?

A7. This section presents my conclusions regarding the fair ROE applicable to KU's electric utility operations. This section also discusses the relationship between ROE and preservation of a utility's financial integrity and the ability to attract capital.

A. Importance of Financial Strength

Q8. WHAT IS THE ROLE OF THE ROE IN SETTING A UTILITY'S RATES?

A8. The ROE is the cost of attracting and retaining common equity investment in the utility's physical plant and assets. This investment is necessary to finance the asset base needed to provide utility service. Investors commit capital only if they expect to earn a return on their investment commensurate with returns available from alternative investments with comparable risks. Moreover, a fair and reasonable ROE is integral in meeting sound regulatory economics and the standards set forth by the U.S. Supreme Court in the *Bluefield*[1] and *Hope*[2] cases. A utility's allowed ROE should be sufficient to: 1) fairly compensate the utility's investors, 2) enable the utility to offer a return adequate to attract new capital on reasonable terms, and 3) maintain the utility's financial integrity. These standards should allow the utility to fulfill its obligation to provide reliable service while meeting the needs of customers through necessary system replacement and expansion, but they can only be met if the utility has a reasonable opportunity to actually earn its allowed ROE.

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[1] *Bluefield Water Works & Improvement Co. v. Pub. Serv. Comm'n*, 262 U.S. 679 (1923).
[2] *Fed. Power Comm'n v. Hope Natural Gas Co.*, 320 U.S. 591 (1944).

While the *Hope* and *Bluefield* decisions did not establish a particular method to be followed in fixing rates, these and subsequent cases enshrined the importance of an end result that meets the opportunity cost standard of finance. Under this doctrine, the required return is established by investors in the capital markets based on expected returns available from comparable risk investments. Coupled with modern financial theory, which has led to the development of formal risk-return models (*e.g.,* DCF and CAPM), practical application of the *Bluefield* and *Hope* standards involves the independent, case-by-case consideration of capital market data in order to evaluate an ROE that will produce a balanced and fair end result for investors and customers.

Q9. WHAT PART DOES REGULATION PLAY IN ENSURING THAT KU HAS ACCESS TO CAPITAL UNDER REASONABLE TERMS AND ON A SUSTAINABLE BASIS?

A9. Regulatory signals are a major driver of investors' risk assessment for utilities. Investors recognize that constructive regulation is a key ingredient in supporting utility credit ratings and financial integrity, particularly during times of adverse conditions. Security analysts study commission orders and regulatory policy statements to advise investors about where to put their money. As Moody's Investors Service ("Moody's") noted, "the regulatory environment is the most important driver of our outlook because it sets the pace for cost recovery."[3] Furthermore, the ROE set by the Commission impacts investor confidence in not only the jurisdictional utility, but also in the ultimate parent company that is the entity that actually issues common stock.

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[3] Moody's Investors Service, "Regulation Will Keep Cash Flow Stable As Major Tax Break Ends," *Industry Outlook* (Feb. 19, 2014).

Q10. DO CUSTOMERS BENEFIT BY ENHANCING THE UTILITY'S FINANCIAL FLEXIBILITY?

A10. Yes. Providing an ROE that is sufficient to maintain KU's ability to attract capital under reasonable terms, even in times of financial and market stress, is not only consistent with the economic requirements embodied in the U.S. Supreme Court's *Hope* and *Bluefield* decisions, it is also in customers' best interests. Customers enjoy the benefits that come from ensuring that the utility has the financial wherewithal to take whatever actions are required to ensure safe and reliable service.

B. Recommended ROE

Q11. WHAT IS YOUR RECOMMENDATION AS TO A FAIR RATE OF RETURN ON EQUITY FOR KU?

A11. I recommend an ROE of 10.23% for KU's electric utility operations. The bases for my conclusion are summarized below:

- In order to reflect the risks and prospects associated with KU's jurisdictional utility operations, my analyses focused on a proxy group of twenty-two other utilities with both electric and gas operations.
- Because investors' required return on equity is unobservable and no single method should be viewed in isolation, I applied the DCF, CAPM, ECAPM, and risk premium methods to estimate a fair ROE for KU, as well as referencing the expected earnings approach.
- As summarized on Exhibit 2, considering the results of these analyses, and giving less weight to extremes at the high and low ends of the range, I concluded that the cost of equity for the proxy group of utilities is in the 9.5% to 10.7% range.
- Adding a flotation cost adjustment of 13 basis points to this bare bones cost of equity range resulted in an ROE range for the proxy group of 9.63% to 10.83%;
- An ROE of 10.23% is equal to the midpoint of the proxy group range.

- Considering capital market expectations and the economic requirements necessary to maintain financial integrity and support additional capital investment even under adverse circumstances, an ROE of 10.23% at the midpoint of the proxy group range represents a fair ROE for KU.

Q12. WHAT ELSE SHOULD BE CONSIDERED IN WEIGHING YOUR QUANTITATIVE RESULTS?

A12. 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 are not representative of what is likely to prevail over the near-term future. As a result, the DCF results for utilities may be affected by potentially unrepresentative financial inputs. In this light, it is important to consider alternatives to the DCF model. As shown in Exhibit No. 2, alternative risk premium models (*i.e.,* the CAPM, ECAPM and utility risk premium approaches) produce ROE estimates that generally exceed the DCF results. My expected earnings approach corroborated these outcomes.

Q13. HAVE SUCH ALTERNATIVE ROE METHODS BEEN ACCEPTED BY OTHER REGULATORS?

A13. Yes. In its recent Opinion 551, issued September 28, 2016, FERC reiterated its support for several of the very same methodologies relied on in my testimony. For example, FERC determined:

> For the reasons discussed below, we conclude that the record in this proceeding demonstrates the presence of unusual capital market conditions, such that we have less confidence that the central tendency of the DCF zone of reasonableness (the midpoint in this case) accurately reflects the equity returns necessary to meet *Hope* and *Bluefield*.[4]

[4] Opinion No. 551, 156 FERC ¶ 61,234 at P 119 (2016).

> Rather, that finding supports a consideration of other cost of equity estimation methodologies in determining whether mechanically setting the ROE at the central tendency satisfies the capital attraction standards of *Hope* and *Bluefield*.[5]
>
> We therefore find it necessary and reasonable to consider additional record evidence, including evidence of alternative methodologies and state-commission approved ROEs, to gain insight into the potential impacts of these unusual capital market conditions on the appropriateness of using the resulting midpoint.[6]

The "alternative methodologies" referred to above include the CAPM, utility risk premium, and expected earnings approaches summarized on Exhibit No. 2. After considering the results of these methods, FERC established an ROE for electric transmission services at the middle of the upper half of the DCF range, or 10.32%.[7]

Q14. WHAT DID THE DCF RESULTS FOR YOUR SELECT GROUP OF NON-UTILITY FIRMS INDICATE WITH RESPECT TO YOUR EVALUATION?

A14. Average DCF estimates for a low-risk group of firms in the competitive sector of the economy ranged from 10.0% to 11.2%, and averaged 10.4% before consideration of flotation costs. While I did not base my recommendation on these results, they confirm that a 10.23% ROE falls in a 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.

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[5] *Id.* at P 120.
[6] *Id.* at P 122.
[7] *Id.* at P 9.

C. Other Factors

Q15. ARE THERE REGULATORY MECHANISMS THAT AFFECT KU'S RATES FOR UTILITY SERVICE?

A15. 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.

Q16. DOES THE FACT THAT KU OPERATES UNDER CERTAIN REGULATORY MECHANISMS WARRANT ANY ADJUSTMENT IN YOUR EVALUATION OF A FAIR ROE?

A16. 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. Similarly, KU's election to employ a future test year is supportive of the Company's financial integrity, but it does not constitute a dramatic change in the investment risk that investors associate with KU.

Q17. DO THESE MECHANISMS SET KU APART FROM OTHER FIRMS OPERATING IN THE UTILITY INDUSTRY?

A17. 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.

Q18. HAVE YOU SUMMARIZED THE VARIOUS REGULATORY MECHANISMS AVAILABLE TO THE OTHER FIRMS IN THE UTILITY GROUP?

A18. Yes. 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, fifteen of the twenty-two utilities benefit from mechanisms that permit 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.

Q19. IS THE USE OF A FUTURE TEST YEAR ALSO A COMMON FEATURE ON THE REGULATORY LANDSCAPE?

A19. Yes. With respect to future test years, a 2015 study by the Edison Electric Institute concluded that "the ranks of US jurisdiction that allow the use of forward test years have swollen and now encompass about half of the total."[8] With respect to the twenty-two firms in the utility Group, seventeen operate in jurisdictions that allow for the use of a forward-looking test year. 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.

Q20. WHAT IS YOUR CONCLUSION REGARDING THE IMPACT OF REGULATORY MECHANISMS IN EVALUATING A FAIR ROE FOR KU?

A20. 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 my 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 my 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 on equal footing with its peers in the industry. As a result, no adjustment to the ROE is justified or warranted.

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[8] *Alternative Regulation for Emerging Utility Challenges: 2015 Update*, Edison Electric Institute (Nov. 11, 2015).

Q21. WHAT IS YOUR CONCLUSION AS TO THE REASONABLENESS OF THE COMPANY'S CAPITAL STRUCTURE?

A21. Based on my evaluation, I concluded that a common equity ratio of 53.28% 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 2015 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

Q22. WHAT IS THE PURPOSE OF THIS SECTION?

A22. 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

Q23. BRIEFLY DESCRIBE KU.

A23. Along with Louisville Gas and Electric Company ("LGE"), KU is a wholly owned subsidiary of LG&E and KU Energy LLC ("LKE"), which in turn 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 518,000 retail customers in central, southeastern, and western Kentucky, KU also provides service to approximately 28,000 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 ownership or interests in approximately 5,078 megawatts ("MW") of generating capacity. Coal-fired generating stations account for approximately 61% of KU's total generating capacity and produced approximately 83% of the electricity generated by the Company in 2015. KU's transmission and distribution system includes approximately 20,500 miles of lines. As of December 31, 2015, the Company had total assets of $8.0 billion, with annual revenues totaling approximately $1.7 billion. KU's retail electric operations are subject to the jurisdiction of the KPSC, the VSCC, and the Tennessee Regulatory Authority, with FERC regulating the Company's interstate transmission and wholesale operations.

Q24. HOW ARE FLUCTUATIONS IN THE COMPANY'S OPERATING EXPENSES CAUSED BY VARYING ENERGY MARKET CONDITIONS ACCOMMODATED IN ITS RATES?

A24. KU's retail electric rates in Kentucky contain a fuel adjustment clause ("FAC"), whereby increases and decreases in the cost of fuel for electric generation are reflected in the rates charged to retail electric customers. The KPSC requires public hearings at six-month intervals to examine past fuel adjustments, and at two-year intervals to review past operations of the fuel clause and transfer of the then current fuel adjustment charge or credit to the base charges. The KPSC also requires that

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[1] KU also serves a limited number of customers in Tennessee.

electric utilities, including KU, file documents relating to fuel procurement and the purchase of power and energy from other utilities.

Q25. WHERE DOES KU OBTAIN THE CAPITAL USED TO FINANCE ITS INVESTMENT IN UTILITY PLANT?

A25. As a wholly-owned subsidiary, KU's common equity capital is provided through 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.

Q26. DOES KU ANTICIPATE THE NEED FOR ADDITIONAL CAPITAL GOING FORWARD?

A26. 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 2015-2019. Total capital expenditures are expected to be $2.8 billion, with $1.1 billion related to environmental. The total estimated amount represents about 42% of its net book value of property, plant and equipment …[9]

Moody's noted the challenges associated with the Company's "[l]arge capital expenditure program," and "[h]igh coal concentration."[10] 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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[9] Moody's Investors Service, "Credit Opinion: Kentucky Utilities Company.," *Global Credit Research* (Dec. 11, 2015).

[10] *Id.*

Q27. WHAT CREDIT RATINGS ARE ASSIGNED TO KU?

A27. Currently, KU is assigned a corporate credit rating of A- by Standard & Poor's Corporation ("S&P"), while Moody's has assigned the Company an issuer rating of A3.

B. Outlook for Capital Costs

Q28. WHAT ARE THE IMPLICATIONS OF CURRENT CAPITAL MARKET CONDITIONS IN EVALUATING A FAIR ROE?

A28. Current capital market conditions continue to be deeply affected by the Federal Reserve's unprecedented monetary policy actions, which were designed to push interest rates to historically and artificially low levels in an effort to stimulate the economy and bolster employment. Since the Great Recession, investors have also had to contend with a heightened level of economic uncertainty. The ongoing potential for renewed turmoil in the capital markets has been seen repeatedly and investors have reacted to such periods of "risk off" behavior by seeking 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. While serving as President of the Federal Reserve Bank of Philadelphia, Charles Plosser observed that U.S. interest rates were unprecedentedly low, and "outside historical norms."[11]

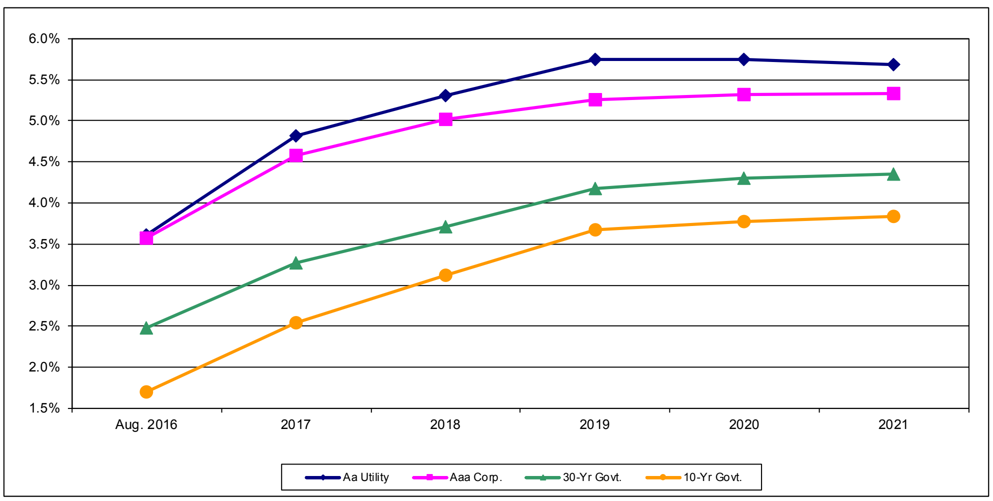
Q29. ARE THESE VERY LOW INTEREST RATES EXPECTED TO CONTINUE?

A29. No. Investors continue to anticipate that interest rates will increase significantly from present levels. For example, the June 3, 2016 quarterly economic review from

[11] Barnato, Katy, "Fed's Plosser: Low rates 'should make us nervous'," CNBC (Nov. 11, 2014). The average yield on 10-year Treasury bonds for the six-months ended August 2016 was 1.7%, which is even lower than the 2.3% yields prevailing at the time of Mr. Plosser's observations.

the Value Line Investment Survey ("Value Line") anticipates that corporate bond yields will increase 140 basis points between then and 2018. Figure 3 below compares six-month average interest rates on 10-year and 30-year Treasury bonds, triple-A rated corporate bonds, and double-A rated utility bonds as of August 2016 with the respective near-term projections from Value Line, IHS Global Insight, Blue Chip Financial Forecasts ("Blue Chip"), and the Energy Information Administration ("EIA"), which are sources that are highly regarded and widely referenced:

FIGURE 3
INTEREST RATE TRENDS



Source:

Value Line Investment Survey, Forecast for the U.S. Economy (Sep. 2, 2016)
IHS Global Insight (Apr. 6 & Jun. 27, 2016)
Energy Information Administration, Annual Energy Outlook 2016 Early Release (May 17, 2016)
Wolters Kluwer, Blue Chip Financial Forecasts, Vol. 35, No. 6 (Jun. 1, 2016)

As evidenced above, projections by investment advisors, forecasting services, and government agencies support the general consensus in the investment community that the present artificial low level of long-term interest rates will not be sustained.

Q30. DOES THE FEDERAL RESERVE'S DECEMBER 16, 2015 DECISION TO RAISE THE TARGET RANGE FOR THE FEDERAL FUNDS RATE BY ONE-QUARTER PERCENTAGE POINT ALTER THESE CONDITIONS?

A30. No. The Federal Reserve's long-anticipated move to increase the federal funds rate represents a first, and very modest, step towards implementing the process of monetary policy normalization outlined in its September 17, 2014 press release.[12] While the Federal Reserve's action marks the onset of the normalization process, this first move does not result in a fundamental alteration of its highly accommodative monetary policy. Nor does it remove uncertainty over the trajectory of further interest rate increases or the overhanging implications of the Federal Reserve's enormous holdings of long-term securities.

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. Table 1 below charts the course of the Federal Reserve's asset purchase program:

[12] Press Release, Fed. Reserve Sys., Policy Normalization Principles and Plans, (Sept. 17, 2014), http://www.federalreserve.gov/newsevents/press/monetary/20140917c.htm.

TABLE 1
FEDERAL RESERVE BALANCES OF
TREASURY BONDS AND MORTGAGE-BACKED SECURITIES
(BILLION $)

2008	$ 458
2009	$ 1,668
2010	$ 1,993
2011	$ 2,501
2012	$ 2,598
2013	$ 3,702
2014	$ 4,211
2015	$ 4,215
2016*	$ 4,215

* at Sep. 22, 2016.

Far from representing a return to normal, the Federal Reserve's holdings of Treasury bonds and mortgage-backed securities continue to exceed $4.2 trillion.[13] The Federal Reserve has announced its intention to maintain these balances by reinvesting principal payments from these securities "until normalization of the level of the federal funds rate is well under way."[14]

Of course, the corollary to these observations is that changes to this policy of reinvestment would further reduce stimulus measures and 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. 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

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[13] Federal Reserve Statistical Release, "Factors Affecting Reserve Balances of Depository Institutions and Condition Statement of Federal Reserve Banks," H.4.1.

[14] Press Release, Fed. Reserve, FOMC Statement at 2 (Sept. 21, 2016), http://www.federalreserve.gov/newsevents/press/monetary/20160921a.htm.

> developed nations' central banks have grown massively since 2008, and the timing of when the banks will unwind those positions is uncertain.[15]

With expectations for higher interest rates, concerns about the implications of Britain's departure from the European Union, uncertain growth in China's economy, and fears of a global economic slowdown, coupled with dramatic decreases in oil and commodities prices, ongoing concerns over political stalemate in Washington, and political and economic unrest in the Middle East, the potential for significant volatility and higher capital costs is clearly evident to investors.

Q31. WHAT DO THESE EVENTS IMPLY WITH RESPECT TO THE ROE FOR KU MORE GENERALLY?

A31. 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. As a result, current capital costs are not representative of what is likely to prevail over the near-term future. As FERC 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 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 …[16]

This conclusion continues to be supported by comparisons of current conditions to the historical record and independent forecasts. As demonstrated above, recognized economic forecasting services project that long-term capital costs will increase from present levels.

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[15] Poole, William, "Prospects for and Ramifications of the Great Central Banking Unwind," Financial Analysts Journal (November/December 2013).

[16] Opinion No. 531, 147 FERC ¶ 61,234 at P 41 (2014).

Thus, while the DCF model is a recognized approach to estimating the ROE, it is not without shortcomings and does not otherwise eliminate the need to ensure that the "end result" is fair. The Indiana Utility Regulatory Commission has also recognized this principle:

> There are three principal reasons for our unwillingness to place a great deal of weight on the results of any DCF analysis. One is . . . the failure of the DCF model to conform to reality. The second is the undeniable fact that rarely if ever do two expert witnesses agree on the terms of a DCF equation for the same utility – for example, as we shall see in more detail below, projections of future dividend cash flow and anticipated price appreciation of the stock can vary widely. And, the third reason is that the unadjusted DCF result is almost always well below what any informed financial analysis would regard as defensible, and therefore require an upward adjustment based largely on the expert witness's judgment. In these circumstances, we find it difficult to regard the results of a DCF computation as any more than suggestive.[17]

Given investors' expectations for rising interest rates and capital costs, the Commission should consider near-term forecasts for higher public utility bond yields in assessing the reasonableness of individual cost of equity estimates and in evaluating the ROE for KU. 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 UTILITY PROXY GROUP

Q32. HOW DID YOU IMPLEMENT QUANTITATIVE METHODS TO ESTIMATE THE COST OF COMMON EQUITY FOR KU?

A32. 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

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[17] *Ind. Michigan Power Co.*, Cause No. 38728, 116 PUR4th, 1, 17-18 (IURC 8/24/1990).

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 to a proxy group of publicly traded companies that investors regard as risk-comparable.

Q33. WHAT SPECIFIC PROXY GROUP OF UTILITIES DID YOU RELY ON FOR YOUR ANALYSIS?

A33. In order to reflect the risks and prospects associated with KU's jurisdictional utility operations, my analyses focused on a reference group of other utilities composed of those companies in Value Line's electric utility industry groups, and including Avangrid, Inc.,[18] 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.[19]
4. No cuts in dividend payments during the past six months and no announcement of a dividend cut since that time.

Q34. HOW DID YOU EVALUATE THE RISKS OF THE UTILITY GROUP RELATIVE TO KU?

A34. My 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

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[18] Avangrid, Inc. was formed in December 2015 as a spin-off from Iberdrola USA, Inc. and is major publicly-traded electric and gas utility operating in New York and New England.

[19] Dominion Resources, Inc., Duke Energy Corporation, and Empire District Electric Company were eliminated due to ongoing involvement in a major merger or acquisition.

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 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 my 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.[20]

Q35. HOW DO THE OVERALL RISKS OF YOUR PROXY GROUP COMPARE TO KU?

A35. Table 2 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 ultimate parent, PPL:

[20] Roger A. Morin, "New Regulatory Finance," *Public Utilities Reports* at 71 (2006).

TABLE 2
COMPARISON OF RISK INDICATORS

	Credit Rating		Value Line		
	S&P	**Moody's**	**Safety Rank**	**Financial Strength**	**Beta**
Utility Group	BBB+	Baa1	2	A	0.70
KU	A-	A3	2	B++	0.70

Q36. WHAT DOES THIS COMPARISON INDICATE REGARDING INVESTORS' ASSESSMENT OF THE RELATIVE RISKS ASSOCIATED WITH YOUR UTILITY GROUP?

A36. As shown above, KU's credit ratings fall one notch above the average for the utility group, which suggests slightly less risk. Meanwhile, the Safety Rank and beta value corresponding to the Company are identical to the average for the Utility Group, while the Financial Strength Rating suggests greater risk. Considered together, this comparison of 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.

Q37. IS AN EVALUATION OF THE CAPITAL STRUCTURE MAINTAINED BY A UTILITY RELEVANT IN ASSESSING ITS RETURN ON EQUITY?

A37. 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.

Q38. WHAT COMMON EQUITY RATIO IS USED IN KU'S CAPITAL STRUCTURE?

A38. The Company's capital structure is discussed in the testimony of Daniel K. Arbough. As summarized there, common equity as a percent of the capital sources used to compute the overall rate of return for KU was 53.28%.

Q39. HOW DOES THIS COMPARE TO THE AVERAGE CAPITALIZATION MAINTAINED BY THE UTILITY GROUP?

A39. 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 30.3% to a high of 76.1% at year-end 2015, and averaged 47.7%. Excluding the highest and lowest results, and adjusting this average capitalization to include short-term debt in the same proportion as KU, would result in an adjusted equity ratio of 46.0%. Meanwhile, Value Line's three-to-five year forecast indicates an average common equity ratio of 46.9% for the Utility Group, with the individual equity ratios ranging from 31.5% to 56.0%.[21]

Q40. WHAT CAPITALIZATION RATIOS ARE MAINTAINED BY OTHER UTILITY OPERATING COMPANIES?

A40. Pages 2 and 3 of Exhibit No. 4 displays capital structure data at year-end 2015 for the group of electric utility operating companies owned by the firms in the Utility Group used to estimate the cost of equity.[22] As shown there, common equity ratios for these utilities averaged 51.9%,[23] with 22 of the 50 operating companies having equity ratios equal to or greater than the 53.28% common equity requested by KU.

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[21] Removing the highest and lowest values from Value Line's projections and reflecting the same proportion of short-term debt included in KU's capitalization would also produce an adjusted equity ratio of 46.0%.

[22] I excluded LGE and KU from this analysis.

[23] Excluding the highest and lowest results, and adjusting this average capitalization for the electric operating companies to include short-term debt in the same proportion as KU, would result in an adjusted equity ratio of 50.4%.

Q41. WHAT OTHER FACTORS DO INVESTORS CONSIDER IN THEIR ASSESSMENT OF A COMPANY'S CAPITAL STRUCTURE?

A41. 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 the need to maintain the continuous access to capital that is required to fund operations and necessary system investment.

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.

Q42. WHAT DID YOU CONCLUDE REGARDING THE REASONABLENESS OF KU'S REQUESTED CAPITAL STRUCTURE?

A42. Based on my evaluation, I concluded that the 53.28% 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 and consistent with the capitalization maintained by other utility operating companies. 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. The Company's capital structure reflects the need to support the credit standing and financial flexibility of KU as it seeks to fund system investments and meet the needs of customers.

V. CAPITAL MARKET ESTIMATES

Q43. WHAT IS THE PURPOSE OF THIS SECTION?

A43. This section presents capital market estimates of the cost of equity. First, I address the concept of the cost of common equity, along with the risk-return tradeoff principle fundamental to capital markets. Next, I describe various quantitative analyses conducted to estimate the cost of common equity for the proxy group of comparable risk firms. Finally, I examine flotation costs, which are properly considered in evaluating a fair rate of return on equity.

A. Economic Standards

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.

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 ULTIMATELY 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 ultimately its only shareholder, this does not change the standards governing the determination of a fair ROE for the Company. The common equity that is required to support the utility operations of KU must be raised by PPL 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. Unless there is a reasonable expectation that the Company can earn a return that is commensurate with the underlying risks, capital will be allocated elsewhere, KU'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 are based on the assumption that the price of a share of common stock is equal to the present value of the expected cash flows (i.e., future dividends and stock price) that will be received while holding the stock, discounted at investors' required rate of return. Rather than developing annual estimates of cash flows into perpetuity, the DCF model can be simplified to a "constant growth" form:[24]

[24] 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. Nevertheless, the DCF method provides a workable and practical approach to estimate investors' required return that is widely referenced in utility ratemaking.

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

where: P_0 = Current price per share;
D_1 = Expected dividend per share in the coming year;
k_e = Cost of equity; and,
g = Investors' long-term growth expectations.

The cost of common equity (k_e) can be isolated by rearranging terms within the equation:

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

This constant growth form of the DCF model recognizes that the rate of return to stockholders consists of two parts: 1) dividend yield (D_1/P_0); and, 2) growth (g). In other words, investors expect to receive a portion of their total return in the form of current dividends and the remainder through price appreciation.

Q51. WHAT STEPS ARE REQUIRED TO APPLY THE CONSTANT GROWTH DCF MODEL?

A51. 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.

Q52. HOW DID YOU DETERMINE THE DIVIDEND YIELD FOR THE UTILITY GROUP?

A52. Estimates of dividends to be paid by each of these utilities over the next twelve months, obtained from Value Line, served as D_1. This annual dividend was then divided by a 30-day average stock price for each utility to arrive at the expected dividend yield. The expected dividends, stock prices, and resulting dividend yields for the firms in the 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 3.0% to 4.6%.

Q53. WHAT IS THE NEXT STEP IN APPLYING THE CONSTANT GROWTH DCF MODEL?

A53. The next step is to evaluate 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.

Q54. WHAT ARE INVESTORS MOST LIKELY TO CONSIDER IN DEVELOPING THEIR LONG-TERM GROWTH EXPECTATIONS?

A54. Implementation of the 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 and capital requirements in the industry, with the payout ratios falling significantly from historical levels. As a result, dividend growth in the utility industry has lagged growth in earnings as utilities conserve financial resources.

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.

Q55. DO THE GROWTH RATE PROJECTIONS OF SECURITY ANALYSTS CONSIDER HISTORICAL TRENDS?

A55. 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.

Q56. DID PROFESSOR MYRON J. GORDON, WHO ORIGINATED THE DCF APPROACH, RECOGNIZE THE PIVOTAL ROLE THAT EARNINGS PLAY IN FORMING INVESTORS' EXPECTATIONS?

A56. 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."[25]

Q57. ARE ANALYSTS' ASSESSMENTS OF GROWTH RATES APPROPRIATE FOR ESTIMATING INVESTORS' REQUIRED RETURN USING THE DCF MODEL?

A57. 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

[25] Myron J. Gordon, "The Cost of Capital to a Public Utility," *MSU Public Utilities Studies* at 89 (1974).

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>.[26]

Q58. HAVE REGULATORS ALSO RECOGNIZED THAT ANALYSTS' GROWTH RATE ESTIMATES ARE AN IMPORTANT AND MEANINGFUL GUIDE TO INVESTORS' EXPECTATIONS?

A58. 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

[26] Roger A. Morin, "New Regulatory Finance," *Public Utilities Reports, Inc.* at 298 (2006) (emphasis added).

> investors' forward-looking expectations than relying on historical performance…[27]

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:

> 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 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."[28]

The Public Utility Regulatory Authority of Connecticut has also noted that "there is not growth in DPS without growth in EPS," and concluded that securities analysts' growth projections have a greater influence over investors' expectations and stock prices.[29]

Q59. WHAT ARE SECURITY ANALYSTS CURRENTLY PROJECTING IN THE WAY OF GROWTH FOR THE FIRMS IN THE UTILITY GROUP?

A59. The earnings growth projections for each of the firms in the Utility Group reported by Value Line, IBES, and Zacks Investment Research ("Zacks") are displayed on page 2 of Exhibit No. 5.[30]

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[27] *Case No. 2009-00548*, Final Order at 30-31.

[28] *Kern River Gas Transmission Co.*, 126 FERC ¶ 61,034at P 121 (2009) (footnote omitted).

[29] *Decision*, Docket No. 13-02-20 (Sept. 24, 2013).

[30] Formerly I/B/E/S International, Inc., IBES growth rates are now compiled and published by Thomson Reuters.

Q60. HOW ELSE ARE INVESTORS' EXPECTATIONS OF FUTURE LONG-TERM GROWTH PROSPECTS OFTEN ESTIMATED WHEN APPLYING THE CONSTANT GROWTH DCF MODEL?

A60. 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 "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, $g = \text{br+sv}$, 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.[31]

Q61. ARE THERE SIGNIFICANT SHORTCOMINGS ASSOCIATED WITH THE "BR+SV" GROWTH RATE?

A61. 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

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[31] 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.

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.[32] 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, I give less weight to cost of equity estimates based on br+sv growth rates in evaluating the results of the DCF model.

Q62. WHAT COST OF COMMON EQUITY ESTIMATES WERE IMPLIED FOR THE UTILITY GROUP USING THE DCF MODEL?

A62. 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.

Q63. IN EVALUATING THE RESULTS OF THE CONSTANT GROWTH DCF MODEL, IS IT APPROPRIATE TO ELIMINATE ESTIMATES THAT ARE EXTREME LOW OR HIGH OUTLIERS?

A63. 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.

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[32] Roger A. Morin, "New Regulatory Finance," *Public Utilities Reports, Inc.*, at 307 (2006).

Q64. HOW DID YOU EVALUATE DCF ESTIMATES AT THE LOW END OF THE RANGE?

A64. I based my 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.

Q65. HAVE SIMILAR TESTS BEEN APPLIED BY REGULATORS?

A65. 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. [33] FERC affirmed that:

> The purpose of the low-end outlier test is to exclude from the proxy group those companies whose ROE estimates are below the average bond yield or are above the average bond yield but are sufficiently low that an investor would consider the stock to yield essentially the same return as debt. In public utility ROE cases, the Commission has used 100 basis points above the cost of debt as an approximation of this threshold, but has also considered the distribution of proxy group companies to inform its decision on which companies are outliers. As the Presiding Judge explained, this is a flexible test.[34]

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[33] *See, e.g., Southern California Edison Co.*, 131 FERC ¶ 61,020 at P 55 (2010).

[34] Opinion No. 531, 147 FERC ¶ 61,234 at P 122 (2014).

Q66. WHAT INTEREST RATE BENCHMARK DID YOU CONSIDER IN EVALUATING THE DCF RESULTS FOR THE UTILITY GROUP?

A66. The average corporate credit ratings for the Utility Group are BBB+ and Baa1 by S&P and Moody's, respectively, which are considered part of the triple-B rating category. Baa utility bonds represent the lowest ratings grade for which Moody's publishes index values, and the closest available approximation for the risks of common stock, which are significantly greater than those of long-term debt. The average of Moody's monthly yields for Baa utility bonds was 4.41% over the six months ended September 2016.[35]

Q67. WHAT ELSE SHOULD BE CONSIDERED IN EVALUATING DCF ESTIMATES AT THE LOW END OF THE RANGE?

A67. As indicated earlier, it is generally expected that long-term interest rates will rise as the Federal Reserve normalizes monetary policies. As shown in Table 3 below, forecasts of IHS Global Insight and the EIA imply an average triple-B bond yield of 6.34% over the period 2017-2021:

[35] Moody's Investors Service, *CreditTrends.*

TABLE 3
IMPLIED BBB BOND YIELD

	2017-21
Projected Aa Utility Yield	
IHS Global Insight (a)	5.41%
EIA (b)	5.50%
Average	5.46%
Current Baa - Aa Yield Spread (c)	0.88%
Implied Baa Utility Yield	**6.34%**

(a) IHS Global Insight (Apr. 6 & Jun. 27, 2016).
(b) Energy Information Administration, Annual Energy Outlook 2016 Early Release (May 17, 2016).
(c) Based on monthly average bond yields from Moody's Investors Service for the six-month period Apr. - Sep. 2016.

The increase in debt yields anticipated by IHS Global Insight and EIA is also supported by the widely-referenced Blue Chip, which projects that yields on corporate bonds will climb on the order of 180 basis points through 2021.[36]

Q68. WHAT DOES THIS TEST OF LOGIC IMPLY WITH RESPECT TO THE DCF RESULTS FOR THE UTILITY GROUP?

A68. Adding a 100 basis-point premium to the historical and projected average utility bond yields implies a low-end threshold on the order of 5.4% to 7.3%. As highlighted on page 3 of Exhibit No. 5, after considering this test and the distribution of individual estimates, I eliminated low-end DCF estimates ranging from 0.1% to 6.9%. Based on my professional experience and the risk-return tradeoff principle that is fundamental to finance, it is inconceivable that investors are not requiring a substantially higher rate of return for holding common stock. As a result, consistent with the threshold established by historical and projected utility

[36] Wolters Kluwer, *Blue Chip Financial Forecasts*, Vol. 35, No. 6 (Jun. 1, 2016).

bond yields, these values provide little guidance as to the returns investors require from utility common stocks and should be excluded.

Q69. DO YOU ALSO RECOMMEND EXCLUDING ESTIMATES AT THE HIGH END OF THE RANGE OF DCF RESULTS?

A69. While it is just as important to evaluate DCF estimates at the upper end of the range, there is no objective benchmark analogous to the bond yield averages used to eliminate illogical low-end values. In response, FERC has consistently applied a two-pronged test for high-end values based on the magnitude of the cost of equity estimate and its underlying growth rate. As FERC observed:

> The Presiding Judge found that the [utilities'] criteria for screening high-end outliers substantially complies with Commission precedent. . . The Presiding Judge further stated that the Commission's high-end outlier test since 2004 has been to exclude from the proxy group any company whose cost of equity estimate is at or above 17.7 percent and whose growth rate is at or above 13.3 percent.[37]

The upper end of the DCF results for the Utility Group is set by a cost of equity estimate of 15.3%. This cost of equity estimate, and the underlying growth rate, falls well below the threshold tests employed by FERC. Moreover, while a 15.3% cost of equity estimate may exceed the majority of the remaining values, remaining low-end estimates in the 7.0% range are assuredly far below investors' required rate of return. Nevertheless, considering the dispersion of the DCF results in this case, I elected to exclude the 15.3% DCF estimate from my analysis. Taken together and considered along with the balance of the results, the remaining values provide a reasonable basis on which to frame the range of plausible DCF estimates and evaluate investors' required rate of return.

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[37] Opinion No. 531, 147 FERC ¶ 61,234 at P 115 (2014)(footnotes omitted).

Q70. WHAT COST OF COMMON EQUITY ESTIMATES ARE IMPLIED BY YOUR DCF RESULTS FOR THE UTILITY GROUP?

A70. As shown on page 3 of Exhibit No. 5 and summarized in Table 4, below, after eliminating illogical values, application of the constant growth DCF model resulted in the following average cost of common equity estimates:

TABLE 4
DCF RESULTS – UTILITY GROUP

	Cost of Equity	
Growth Rate	**Average**	**Midpoint**
Value Line	9.5%	9.7%
IBES	9.3%	10.2%
Zacks	9.2%	10.4%
br + sv	8.4%	8.9%

C. Capital Asset Pricing Model

Q71. PLEASE DESCRIBE THE CAPM.

A71. The CAPM is a theory of market equilibrium that measures risk using the beta coefficient. Assuming investors are fully diversified, the relevant risk of an individual asset (*e.g.*, common stock) is its volatility relative to the market as a whole, with beta reflecting the tendency of a stock's price to follow changes in the market. 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 CAPM is an *ex-ante,* or forward-looking model based on expectations of the future. As a result, in order to produce a meaningful estimate of investors' required rate of return, the CAPM must be applied using estimates that reflect the expectations of actual investors in the market, not with backward-looking, historical data.

Q72. WHY IS THE CAPM APPROACH A RELEVANT COMPONENT WHEN EVALUATING THE COST OF EQUITY FOR KU?

A72. The CAPM approach (which also 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, the CAPM (and ECAPM) provides important insight into investors' required rate of return for utility stocks, including KU.

Q73. HOW DID YOU APPLY THE CAPM TO ESTIMATE THE COST OF COMMON EQUITY?

A73. Application of the CAPM 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 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 earnings growth projections for each firm published by IBES and Value Line, with each firm's dividend yield and growth rate being weighted by its proportionate share of total market value. Based on the weighted average of the projections for the individual firms, current estimates imply an average growth rate over the next five years of 8.8%. Combining this average growth rate with a year-ahead dividend yield of 2.5% results in a current cost of common equity estimate for the market as a whole (R_m) of approximately 11.3%. Subtracting a 2.4% risk-free rate based on the average yield on 30-year Treasury bonds for the six months ending August 2016 produced a market equity risk premium of 8.9%.

Q74. WHAT WAS THE SOURCE OF THE BETA VALUES YOU USED TO APPLY THE CAPM?

A74. As indicated earlier in my discussion of risk measure for the Utility Group, I relied on the beta values reported by Value Line, which in my experience is the most widely referenced source for beta in regulatory proceedings.

Q75. WHAT ELSE SHOULD BE CONSIDERED IN APPLYING THE CAPM?

A75. Financial research indicates that the CAPM does not fully account for observed differences in rates of return attributable to firm size. Accordingly, a modification is required to account for this size effect. As explained by *Morningstar*:

> One of the most remarkable discoveries of modern finance is that of a relationship between company size and return. … The relationship between company size and return cuts across the entire size spectrum; it is not restricted to the smallest stocks. … This size-rated phenomenon has prompted a revision to the CAPM, which includes a size premium.[38]

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[38] *Morningstar*, "Ibbotson SBBI 2015 Classic Yearbook," at pp. 99, 108.

According to the CAPM, the expected return on a security should consist of the riskless rate, plus a premium to compensate for the systematic risk of the particular security. The degree of systematic risk is represented by the beta coefficient. The need for the size adjustment arises because differences in investors' required rates of return that are related to firm size are not fully captured by beta. To account for this, researchers have developed size premiums that need to be added to the theoretical CAPM cost of equity estimates to account for the level of a firm's market capitalization in determining the CAPM cost of equity.[39] Accordingly, my CAPM analyses also incorporated an adjustment to recognize the impact of size distinctions, as measured by the average market capitalization for the Utility Group.

Q76. ARE YOU RECOMMENDING THAT THE COMMISSION AWARD KU A PREMIUM TO THE ROE BECAUSE OF ITS SIZE?

A76. Absolutely not. I am not proposing to apply a general size risk premium in evaluating a fair ROE for KU; rather, the size adjustment merely corrects for an observed inability of the beta measure used in the CAPM to fully reflect the risks perceived by investors <u>for the firms in the Utility Group</u>. As FERC has recognized, "This type of size adjustment is a generally accepted approach to CAPM analyses."[40]

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[39] Originally compiled by Ibbotson Associates and published in their annual yearbook entitled, "Stocks, Bonds, Bills and Inflation," these size premia are now developed by Duff & Phelps and presented in its "Valuation Handbook – Guide to Cost of Capital."

[40] Opinion No. 531-B, 150 FERC ¶ 61,165 at P 117 (2015).

Q77. WHAT IS THE IMPLIED ROE FOR THE UTILITY GROUP USING THE CAPM APPROACH?

A77. As shown on page 1 of Exhibit No. 7, a forward-looking application of the CAPM approach resulted in an average unadjusted ROE estimate of 8.6%.[41] After adjusting for the impact of firm size, the CAPM approach implied an average cost of equity of 9.2% for the Utility Group, with a midpoint cost of equity estimate of 9.9%.

Q78. DID YOU ALSO APPLY THE CAPM USING FORECASTED BOND YIELDS?

A78. Yes. As discussed earlier, there is general consensus that interest rates will increase materially as the Federal Reserve normalizes its monetary policies going forward. Accordingly, in addition to the use of current bond yields, I applied the CAPM based on the forecasted long-term Treasury bond yields developed based on projections published by Value Line, IHS Global Insight, and Blue Chip. As shown on page 2 of Exhibit No. 7, incorporating a forecasted Treasury bond yield for 2017-2021 implied a cost of equity of approximately 9.0% for the Utility Group, or 9.6% after adjusting for the impact of relative size. The midpoint of the size adjusted cost of equity range was 9.9%.

D. Empirical Capital Asset Pricing Model

Q79. HOW DOES THE ECAPM APPROACH DIFFER FROM TRADITIONAL APPLICATIONS OF THE CAPM?

A79. 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

[41] The midpoint of the unadjusted ECAPM range was 8.9%.

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 returns than predicted by the CAPM.[42] 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.[43]

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 equation and its associated weighting factors recognize the observed relationship between standard CAPM estimates and the cost of capital documented in the financial research, and corrects for the understated returns that would otherwise be produced for low beta stocks.

Q80. WHAT COST OF EQUITY ESTIMATES WERE INDICATED BY THE ECAPM?

A80. My applications of the ECAPM were based on the same forward-looking market rate of return, risk-free rates, and beta values discussed earlier in connections with

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[42] Because the betas of utility stocks, including those in the Utility Group, are generally less than 1.0, this implies that cost of equity estimates based on the traditional CAPM would understate the cost of equity.

[43] Roger A. Morin, "New Regulatory Finance," *Public Utilities Reports* at 189 (2006).

the CAPM. As shown on page 1 of Exhibit No. 8, applying the forward-looking ECAPM approach to the firms in the Utility Group results in an average unadjusted cost of equity estimate of 9.3%, or 9.8% after incorporating the size adjustment corresponding to the market capitalization of the individual utilities.[44]

As shown on page 2 of Exhibit No. 8, incorporating a forecasted Treasury bond yield for 2017-2021 implied a cost of equity of approximately 9.6% for the Utility Group, or 10.1% after adjusting for the impact of relative size.[45]

E. 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 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

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[44] The midpoint of the size adjusted ECAPM range was 10.0%.

[45] After incorporating forecasted bond yields, the midpoint of the size adjusted ECAPM range was 10.3%.

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. 9, 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 2015.[46] As shown on page 3 of Exhibit No. 9, over this period, these equity risk premiums for electric utilities averaged 3.62%, and the yield on public utility bonds averaged 8.48%.

Q86. IS THERE ANY CAPITAL MARKET RELATIONSHIP THAT MUST BE CONSIDERED WHEN IMPLEMENTING THE RISK PREMIUM METHOD?

A86. Yes. The magnitude of equity risk premiums is not constant and equity risk premiums tend to move inversely with interest rates. In other words, when interest rate levels are relatively high, equity risk premiums narrow, and when interest rates are relatively low, equity risk premiums widen. The implication of this inverse relationship is that the cost of equity does not move as much as, or in lockstep with, interest rates. Accordingly, for a 1% increase or decrease in interest rates, the cost of equity may only rise or fall, say, 50 basis points. Therefore, when implementing the risk premium method, adjustments may be required to incorporate this inverse relationship if current interest rate levels have diverged from the average interest rate level represented in the data set.

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.[47] This inverse relationship between equity risk premiums

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[46] My analysis encompasses the entire period for which published data is available.

[47] *See, e.g.,* E. F. Brigham, D. K. Shome, and S. R.Vinson, "The Risk Premium Approach to Measuring a Utility's Cost of Equity," *Financial Management* (Spring 1985); R. S. Harris and F. C. Marston, "Estimating Shareholder Risk Premia Using Analysts' Growth Forecasts," *Financial Management* (Summer 1992).

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.[48]

Other regulators have also recognized that the cost of equity does not move in tandem with interest rates.[49]

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 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. 9, the equity risk premium for electric utilities increased approximately 43 basis points for each percentage point drop in the yield on average public utility bonds. As illustrated on page 1 of Exhibit No. 9, with an

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[48] Roger A. Morin, "New Regulatory Finance," Public Utilities Reports, at 128 (2006).

[49] *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).

average yield on public utility bonds for the six-months ending September 2016 of 3.90%, this implied a current equity risk premium of 5.58% for electric utilities. Adding this equity risk premium to the average yield on triple-B utility bonds of 4.41% implies a current cost of equity of 9.99%.

Q90. WHAT RISK PREMIUM COST OF EQUITY ESTIMATE WAS PRODUCED AFTER INCORPORATING FORECASTED BOND YIELDS?

A90. As shown on page 2 of Exhibit No. 9, incorporating a forecasted yield for 2017-2021 and adjusting for changes in interest rates since the study period implied an equity risk premium of 4.75% for electric utilities. Adding this equity risk premium to the implied average yield on triple-B public utility bonds for 2017-2021 of 6.34% resulted in an implied cost of equity of 11.09%.

F. Expected Earnings Approach

Q91. WHAT OTHER ANALYSES DID YOU CONDUCT TO ESTIMATE THE COST OF COMMON EQUITY?

A91. As I noted earlier, I also evaluated the cost of common equity using the expected earnings method. Reference to rates of return available from alternative investments of comparable risk can provide an important benchmark in assessing the return necessary to assure confidence in the financial integrity of a firm and its ability to attract capital. This expected earnings approach is consistent with the economic underpinnings for a fair rate of return established by the U.S. Supreme Court in *Bluefield* and *Hope*. Moreover, it avoids the complexities and limitations of capital market methods and instead focuses on the returns earned on book equity, which are readily available to investors.

Q92. WHAT ECONOMIC PREMISE UNDERLIES THE EXPECTED EARNINGS APPROACH?

A92. The simple, but powerful concept underlying the expected earnings approach is that investors compare each investment alternative with the next best opportunity. If the utility is unable to offer a return similar to that available from other opportunities of comparable risk, investors will become unwilling to supply the capital on reasonable terms. For existing investors, denying the utility an opportunity to earn what is available from other similar risk alternatives prevents them from earning their opportunity cost of capital.

Q93. HOW IS THE EXPECTED EARNINGS APPROACH TYPICALLY IMPLEMENTED?

A93. The traditional comparable earnings test identifies a group of companies that are believed to be comparable in risk to the utility. The actual earnings of those companies on the book value of their investment are then compared to the allowed return of the utility. While the traditional comparable earnings test is implemented using historical data taken from the accounting records, it is also common to use projections of returns on book investment, such as those published by recognized investment advisory publications (*e.g.*, Value Line). Because these returns on book value equity are analogous to the allowed return on a utility's rate base, this measure of opportunity costs results in a direct, "apples to apples" comparison.

Moreover, regulators do not set the returns that investors earn in the capital markets, which are a function of dividend payments and fluctuations in common stock prices- both of which are outside their control. Regulators can only establish the allowed ROE, which is applied to the book value of a utility's investment in rate base, as determined from its accounting records. This is directly analogous to the expected earnings approach, which measures the return that investors expect the utility to earn on book value. As a result, the expected earnings approach provides a meaningful guide to ensure that the allowed ROE is similar to what other utilities of comparable risk will earn on invested capital. This expected earnings test does not require theoretical models to indirectly infer investors' perceptions from stock prices or other market data. As long as the proxy companies are similar in risk, their expected earned returns on invested capital provide a direct benchmark for investors' opportunity costs that is independent of fluctuating stock prices, market-to-book ratios, debates over DCF growth rates, or the limitations inherent in any theoretical model of investor behavior.

Q94. WHAT RATES OF RETURN ON EQUITY ARE INDICATED FOR BASED ON THE EXPECTED EARNINGS APPROACH?

A94. Value Line's projections imply an average rate of return on common equity for the electric utility industry of 10.7% over its 2019-2021 forecast horizon.[50] 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 11.3%, with a midpoint value of 12.2%.

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[50] The Value Line Investment Survey (Aug. 19, Sep. 16, & Oct. 15, 2016). Recall that Value Line reports return on year-end equity so the equivalent return on average equity would be higher.

G. Flotation Costs

Q95. WHAT OTHER CONSIDERATIONS ARE RELEVANT IN SETTING THE RETURN ON EQUITY FOR A UTILITY?

A95. 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.

Q96. IS THERE AN ESTABLISHED MECHANISM FOR A UTILITY TO RECOGNIZE EQUITY ISSUANCE COSTS?

A96. 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.

Q97. THE KPSC HAS NOT ROUTINELY APPROVED A FLOTATION COST ADJUSTMENT FOR KU. WHY DO YOU CONTINUE TO RECOMMEND AN ADJUSTMENT IN THIS CASE?

A97. I am 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.[51] 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,

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[51] E. F. Brigham, D. A. Aberwald, and L. C. Gapenski, "Common Equity Flotation Costs and Rate Making," *Public Utilities Fortnightly,* May, 2, 1985.

> 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.[52]

Q98. CAN YOU ILLUSTRATE WHY INVESTORS WILL NOT HAVE THE OPPORTUNITY TO EARN THEIR REQUIRED ROE UNLESS A FLOTATION COST ADJUSTMENT IS INCLUDED?

A98. 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 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 5 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 5
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

[52] Roger A. Morin, "New Regulatory Finance," *Public Utilities Reports, Inc.* (2006) at 335.

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 6 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 6
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.

Q99. WHAT IS THE MAGNITUDE OF THE ADJUSTMENT TO THE "BARE BONES" COST OF EQUITY TO ACCOUNT FOR ISSUANCE COSTS?

A99. 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.[53]

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%.[54] Applying a 3.6% expense percentage to a representative dividend yield of 3.7% implies a minimum flotation cost adjustment on the order of 13 basis points.

VI. NON-UTILITY BENCHMARK

Q100. WHAT IS THE PURPOSE OF THIS SECTION OF YOUR TESTIMONY?

A100. This section presents the results of my DCF analysis applied to a group of low-risk firms in the competitive sector, which I refer to as the "Non-Utility Group." This analysis was not directly considered in arriving at my recommended ROE range of reasonableness; however, it is my opinion that this is relevant consideration in evaluating a fair ROE for the Company.

Q101. DO UTILITIES HAVE TO COMPETE WITH NON-REGULATED FIRMS FOR CAPITAL?

A101. 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

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53 *Id.* at 323.

54 *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).

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.

Q102. IS IT CONSISTENT WITH THE *BLUEFIELD* AND *HOPE* CASES TO CONSIDER INVESTORS' REQUIRED ROE FOR NON-UTILITY COMPANIES?

A102. 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.[55]

As in the *Bluefield* decision, there is nothing to restrict "other enterprises" solely to the utility industry.

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[55] *Federal Power Comm'n v. Hope Natural Gas Co.* 320 U.S. 391, (1944).

Q103. DOES CONSIDERATION OF THE RESULTS FOR THE NON-UTILITY GROUP HELP TO IMPROVE THE RELIABILITY OF DCF RESULTS?

A103. 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 more than one industry, it helps to insulate against any possible distortion that may be present in results for a particular sector.

Q104. WHAT CRITERIA DID YOU APPLY TO DEVELOP THE NON-UTILITY GROUP?

A104. My low-risk group of competitive firms 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 and Moody's.[56]

Q105. HOW DO THE OVERALL RISKS OF THIS NON-UTILITY GROUP COMPARE WITH THE UTILITY GROUP?

A105. Table 7 compares the Non-Utility Group with the Utility Group and KU across the four key risk measures discussed earlier:

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[56] Credit rating firms, such as S&P, 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.

TABLE 7
COMPARISON OF RISK INDICATORS

	Credit Rating		Value Line		
	S&P	Moody's	Safety Rank	Financial Strength	Beta
Non-Utility Group	A-	A3	1	A+	0.69
Utility Group	BBB+	Baa1	2	A	0.70
KU	A-	A3	2	B++	0.70

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 companies that make up the Non-Utility Group are representative of the pinnacle of corporate America. These firms, which include household names such as Coca-Cola, McDonalds, 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.

Q106. DO THE BETA VALUES FOR THE NON-UTILITY GROUP ADDRESS THE CONCERNS EXPRESSED BY THE KPSC IN A PRIOR RATE PROCEEDING FOR KU?

A106. Yes. The KPSC concluded in Case No. 2009-00548 that utilities must compete with non-regulated firms for capital and recognized that investors consider the opportunity costs associated with investment alternatives outside the utility industry.

However, the KPSC found that lower beta values for utility common stocks supported a finding that the non-utility companies were "riskier alternatives."[57] My 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 0.69 being slightly lower than the 0.70 value for the Utility Group and corresponding to KU.

Q107. WHAT WERE THE RESULTS OF YOUR DCF ANALYSIS FOR THE NON-UTILITY GROUP?

A107. I 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 8, below, application of the constant growth DCF model resulted in the following cost of equity estimates:

TABLE 8
DCF RESULTS – NON-UTILITY GROUP

	Cost of Equity	
Growth Rate	**Average**	**Midpoint**
Value Line	10.0%	10.8%
IBES	11.2%	11.2%
Zacks	10.1%	10.0%

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. Because the actual cost of equity is unobservable, and DCF results inherently incorporate a degree of error, cost of equity estimates for the Non-Utility Group provide an important benchmark in evaluating a fair ROE for KU.

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[57] *Case No. 2009-00548*, Final Order at 31.

Q108. DOES THIS CONCLUDE YOUR PRE-FILED DIRECT TESTIMONY?

A108. Yes.

VERIFICATION

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

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 14th day of November 2016

Notary Public (SEAL)

My Commission Expires:

04/17/2019

ROBERT LEE MARTINEZ
NOTARY PUBLIC STATE OF TEXAS
MY COMM. EXP. 4/17/2019
NOTARY ID 13018381-2

Exhibit No. 1

Qualifications of Adrien M. McKenzie

EXHIBIT NO. 1

QUALIFICATIONS OF ADRIEN M. MCKENZIE

Q. WHAT IS THE PURPOSE OF THIS EXHIBIT?

A. This exhibit describes my background and experience and contains the details of my qualifications.

Q. PLEASE DESCRIBE YOUR QUALIFICATIONS AND EXPERIENCE.

A. I received 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. 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 proceedings filed with the Federal Energy Regulatory Commission ("FERC"), the Regulatory Commission of Alaska, the Colorado Public Utilities Commission, the Hawaii Public Utilities Commission, the Idaho Public Utilities Commission, the Indiana Utility Regulatory Commission, the Iowa Utilities Board, the Kansas State Corporation Commission, the Kentucky Public Service Commission, the Maryland Public Service Commission, the Montana Public Service Commission, the Nebraska Public Service Commission, the Ohio Public Utilities Commission, the Oregon Public Utilities Commission, the South Dakota Public Utilities Commission, the Virginia State Corporation Commission, the Washington Utilities and

Transportation Commission, the West Virginia Public Service 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, gas, and water utility operations. In connection with these assignments, my responsibilities have included critically evaluating the positions of other parties and preparation of rebuttal testimony, representing clients in settlement negotiations and hearings, and assisting in the preparation of legal briefs.

In addition, over the course of my career I have worked with Dr. William Avera to prepare prefiled direct and rebuttal testimony in over 250 regulatory proceedings before FERC, the Canadian Radio-Television and Telecommunications Commission, and regulatory agencies in over 30 states.[1] Prior to joining FINCAP, I was employed by an oil and gas firm and was responsible for operations and accounting. A resume containing the details of my qualifications and experience is attached below.

[1] This testimony was sponsored by Dr. William Avera, who is President of FINCAP, Inc.

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

Vice President, 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 over thirty state jurisdictions, Mr. McKenzie has considerable expertise in preparing expert analyses and testimony before the Federal Energy Regulatory Commission ("FERC") on the issue of ROE, and has 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

Witness: Adrien M. McKenzie

ROE ANALYSES

SUMMARY OF RESULTS

	Average		Midpoint
DCF			
Value Line	9.5%		9.7%
IBES	9.3%		10.2%
Zacks	9.2%		10.4%
Internal br + sv	8.4%		8.9%
CAPM			
Current Bond Yield	9.2%		9.9%
Projected Bond Yield	9.6%		9.9%
Empirical CAPM			
Current Bond Yield	9.8%		10.0%
Projected Bond Yield	10.1%		10.3%
Utility Risk Premium			
Current Bond Yield		10.0%	
Projected Bond Yields		11.1%	
Expected Earnings			
Industry		10.7%	
Proxy Group	11.3%		12.2%
Recommended Cost of Equity Range			
Cost of Equity Range	9.5%	--	10.7%
Flotation Cost Adjustment			
Dividend Yield		3.7%	
Flotation Cost Percentage		3.6%	
Adjustment		0.13%	
Return on Equity			
Range	**9.63%**	**--**	**10.83%**
Midpoint		**10.23%**	

Exhibit No. 3

Regulatory Mechanisms

Witness: Adrien M. McKenzie

REGULATORY MECHANISMS

UTILITY GROUP

	Company	AMS	BDR	DSM	ECA	ESM	FCA	FRP	FTY	ICR	NDT	PCR	PGA	RDM	SCR	TAX	TCR	WNA	Other
1	Alliant Energy			√			√		√	√			√				√		
2	Ameren Corp.		√	√	√		√	√	√	√		√	√	√					
3	Avangrid, Inc.					√	√		√	√			√	√					
4	Avista Corp.						√		√				√	√					Attrition adjustment
5	Black Hills Corp.		√	√	√		√		√	√			√			√	√	√	Vegetation mgmt. tracker
6	CenterPoint Energy	√	√					√		√	√		√	√	√	√	√	√	
7	CMS Energy Corp.						√		√	√			√	√					
8	Consolidated Edison				√		√		√			√	√	√	√	√		√	
9	DTE Energy Co.				√		√		√	√	√		√	√					
10	Entergy Corp.			√			√	√	√	√		√	√		√		√		
11	Eversource Energy		√	√	√		√	√	√	√		√	√	√			√		
12	Exelon Corp.	√	√	√	√		√	√	√	√			√	√			√	√	
13	NorthWestern Corp.						√						√			√			
14	PG&E Corp.			√	√		√	√	√		√			√					
15	PPL Corp.	√		√	√		√	√	√	√			√		√		√		
16	Pub Sv Enterprise Group		√	√	√		√	√		√		√	√		√			√	
17	SCANA Corp.		√	√			√					√	√	√				√	
18	Sempra Energy			√	√		√	√	√				√						
19	Southern Company			√	√		√	√	√	√					√	√			
20	Vectren Corp.		√	√			√			√			√	√			√	√	
21	WEC Energy Group		√	√	√		√		√	√			√	√					
22	Xcel Energy Inc.			√	√		√		√	√			√				√		

Sources: 2015 Form 10-K Reports; *Alternative Regulation for Emerging Utility Challenges: 2015 Update* , Edison Electric Institute (Nov. 11, 2015).

AMS--Advanced Metering System Recovery Rider
BDR -- Bad Debt Cost Recovery Rider
DSM -- Demand Side Management / Conservation / Energy Efficiency Adjustment Clause
ECA -- Environmental and/or Emissions Cost Adjustment Clause
ESM -- Earnings Sharing Mechanism
FCA -- Fuel and/or Power Cost Adjustment Clause
FRP--Formula Rate Plan
FTY - Jurisdiction allows for future test year
ICR -- Infrastructure Investment / Renewables Cost Recovery Mechanism
NDT -- Nuclear Decomissioning Tracker
PCR -- Pension Cost Recovery Mechanism
PGA -- Gas Cost Adjustment Clause
RDM -- Revenue Decoupling Mechanism
SCR - Storm Cost Recovery Tracker
TAX--Property / Franchise Tax Recovery Mechanism
TCR -- Transmission Cost Recovery Tracker
WNA -- Weather Normalization Adjustment or other mitigants

Exhibit No. 4
Capital Structure

Witness: Adrien M. McKenzie

CAPITAL STRUCTURE

UTILITY GROUP

		At Fiscal Year-End 2015 (a)			Value Line Projected (b)		
	Company	Debt	Preferred	Common Equity	Debt	Other	Common Equity
1	Alliant Energy	49.4%	2.6%	48.0%	49.5%	1.0%	49.5%
2	Ameren Corp.	50.7%	0.0%	49.3%	49.5%	0.5%	50.0%
3	Avangrid, Inc.	23.9%	0.0%	76.1%	NA	NA	NA
4	Avista Corp.	50.7%	0.0%	49.3%	50.0%	0.0%	50.0%
5	Black Hills Corp.	56.0%	0.0%	44.0%	48.5%	0.0%	51.5%
6	CenterPoint Energy	63.2%	0.0%	36.8%	68.5%	0.0%	31.5%
7	CMS Energy Corp.	69.7%	0.0%	30.3%	65.5%	0.0%	34.5%
8	Consolidated Edison	49.4%	0.0%	50.6%	45.5%	0.0%	54.5%
9	DTE Energy Co.	51.4%	0.0%	48.6%	53.5%	0.0%	46.5%
10	Entergy Corp.	59.0%	0.0%	41.0%	54.0%	1.0%	45.0%
11	Eversource Energy	46.2%	0.0%	53.8%	46.0%	1.0%	53.0%
12	Exelon Corp.	48.0%	0.4%	51.7%	50.0%	0.0%	50.0%
13	NorthWestern Corp.	52.7%	0.0%	47.3%	50.5%	0.0%	49.5%
14	PG&E Corp.	49.0%	0.8%	50.2%	49.0%	0.5%	50.5%
15	PPL Corp.	65.8%	0.0%	34.2%	62.0%	0.0%	38.0%
16	Pub Sv Enterprise Grp.	42.3%	0.0%	57.7%	44.0%	0.0%	56.0%
17	SCANA Corp.	52.4%	0.0%	47.6%	56.0%	0.0%	44.0%
18	Sempra Energy	52.7%	0.1%	47.2%	58.0%	0.0%	42.0%
19	Southern Company	55.5%	0.0%	44.5%	60.0%	2.0%	38.0%
20	Vectren Corp.	51.6%	0.0%	48.4%	49.0%	0.0%	51.0%
21	WEC Energy Group	51.7%	0.2%	48.2%	48.0%	0.0%	52.0%
22	Xcel Energy Inc.	55.4%	0.0%	44.6%	52.5%	0.0%	47.5%
	Average	**52.1%**	**0.2%**	**47.7%**	**52.8%**	**0.3%**	**46.9%**
	Excluding High and Low	**52.7%**	**0.2%**	**47.1%**	**52.5%**	**0.3%**	**47.2%**

(a) Company Form 10-K and Annual Reports.
(b) The Value Line Investment Survey (Aug. 19, Sep. 16, & Oct. 28, 2016).

ELECTRIC OPERATING COS.

		At Fiscal Year-End 2015 (a)		
	Company	**Debt**	**Preferred**	**Common Equity**
1	Alabama Power Co.	52.2%	2.1%	45.6%
2	Ameren Illinois Co.	46.0%	1.2%	52.8%
3	Atlantic City Electric Co.	51.7%	0.0%	48.3%
4	Baltimore Gas & Electric Co.	39.2%	4.0%	56.7%
5	Black Hills Power	46.7%	0.0%	53.3%
6	Black Hills/Colorado Electric Utility Co	49.2%	0.0%	50.8%
7	CenterPoint Energy Houston Electric, LLC	55.6%	0.0%	44.4%
8	Central Maine Power Co.	39.7%	0.0%	60.3%
9	Cheyenne Light Fuel & Power	46.7%	0.0%	53.3%
10	Commonweath Edison Co.	44.1%	0.0%	55.9%
11	Connecticut Light & Power	45.9%	1.9%	52.2%
12	Consolidated Edison of NY	50.0%	0.0%	50.0%
13	Consumers Energy Co.	49.5%	0.3%	50.2%
14	Delmarva Power & Light Co.	48.4%	0.0%	51.6%
15	DTE Electric Co.	49.8%	0.0%	50.2%
16	Entergy Arkansas Inc.	58.2%	0.0%	41.8%
17	Entergy Louisiana LLC	50.2%	0.0%	49.8%
18	Entergy Mississippi Inc.	49.6%	2.4%	48.0%
19	Entergy New Orleans Inc.	47.6%	0.0%	52.4%
20	Entergy Texas Inc.	60.2%	0.0%	39.8%
21	Georgia Power Co.	48.5%	1.2%	50.3%
22	Gulf Power Co.	46.5%	5.2%	48.3%
23	Interstate Power & Light	45.8%	4.9%	49.2%
24	Kansas Gas & Electric	27.6%	0.0%	72.4%
25	Mississippi Power Co.	52.2%	0.7%	47.1%

(a) Form 10-K Reports, Annual Reports, and FERC Form 1 Annual Reports.

ELECTRIC OPERATING COS.

		At Fiscal Year-End 2015 (a)		
	Company	**Debt**	**Preferred**	**Common Equity**
26	New York State Electric & Gas Corp.	45.2%	0.0%	54.8%
27	Northern States Power Co. (MN)	46.8%	0.0%	53.2%
28	Northern States Power Co. (WI)	45.8%	0.0%	54.2%
29	NSTAR Electric Co.	43.4%	0.9%	55.7%
30	Orange & Rockland	52.2%	0.0%	47.8%
31	Pacific Gas & Electric Co.	48.1%	0.8%	51.1%
32	PECO Energy Co.	44.4%	0.0%	55.6%
33	Potomac Electric Power Co.	50.7%	0.0%	49.3%
34	PPL Electric Utilities Corp.	47.6%	0.0%	52.4%
35	Pub Service Electric & Gas Co.	47.4%	0.0%	52.6%
36	Public Service Co. of Colorado	44.7%	0.0%	55.3%
37	Public Service Co. of New Hampshire	46.4%	0.0%	53.6%
38	Rochester Gas & Electric Corp.	48.3%	0.0%	51.7%
39	San Diego Gas & Electric	46.1%	0.0%	53.9%
40	South Carolina Electric & Gas	48.1%	0.0%	51.9%
41	Southern California Gas Co.	44.2%	0.4%	55.5%
42	Southern Indiana Gas & Electric Co.	44.6%	0.0%	55.4%
43	Southwestern Public Service Co.	46.2%	0.0%	53.8%
44	Union Electric Co.	50.2%	1.0%	48.9%
45	United Illuminating Co.	50.0%	0.0%	50.0%
46	Westar Energy	37.8%	0.0%	62.2%
47	Western Massachussetts Electric Co.	46.4%	0.0%	53.6%
48	Wisconsin Electric Power Co. (We Energies)	60.4%	0.3%	39.3%
49	Wisconsin Power & Light	46.5%	0.0%	53.5%
50	Wisconsin Public Service Corp.	46.5%	0.0%	53.5%
	Average	**47.6%**	**0.5%**	**51.9%**
	Excluding High and Low	**47.7%**	**0.6%**	**51.7%**

(a) Form 10-K Reports, Annual Reports, and FERC Form 1 Annual Reports.

Exhibit No. 5

DCF Model – Utility Group

Witness: Adrien M. McKenzie

CONSTANT GROWTH DCF - UTILITY GROUP

DIVIDEND YIELD

	Company	(a) Price	(b) Dividends	Yield
1	Alliant Energy	$ 37.93	$ 1.18	3.1%
2	Ameren Corp.	$ 48.96	$ 1.76	3.6%
3	Avangrid, Inc.	$ 41.03	$ 1.73	4.2%
4	Avista Corp.	$ 40.96	$ 1.41	3.4%
5	Black Hills Corp.	$ 59.61	$ 1.80	3.0%
6	CenterPoint Energy	$ 22.89	$ 1.06	4.6%
7	CMS Energy Corp.	$ 41.73	$ 1.30	3.1%
8	Consolidated Edison	$ 74.54	$ 2.74	3.7%
9	DTE Energy Co.	$ 93.24	$ 3.12	3.3%
10	Entergy Corp.	$ 76.45	$ 3.48	4.6%
11	Eversource Energy	$ 53.98	$ 1.87	3.5%
12	Exelon Corp.	$ 33.22	$ 1.28	3.9%
13	NorthWestern Corp.	$ 56.79	$ 2.06	3.6%
14	PG&E Corp.	$ 61.11	$ 2.04	3.3%
15	PPL Corp.	$ 33.92	$ 1.57	4.6%
16	Pub Sv Enterprise Grp.	$ 41.75	$ 1.68	4.0%
17	SCANA Corp.	$ 71.23	$ 2.39	3.4%
18	Sempra Energy	$105.75	$ 3.22	3.0%
19	Southern Company	$ 51.23	$ 2.28	4.5%
20	Vectren Corp.	$ 49.12	$ 1.66	3.4%
21	WEC Energy Group	$ 59.37	$ 2.06	3.5%
22	Xcel Energy Inc.	$ 40.86	$ 1.42	3.5%
	Average			**3.7%**

(a) Average of closing prices for 30 trading days ended Oct. 24, 2016.

(b) Yahoo!Finance (Oct. 25, 2016). Avangrid based on annualized current quarterly dividend per share of $0.432.

CONSTANT GROWTH DCF - UTILITY GROUP

GROWTH RATES

		(a)	(b)	(c)	(d)
		Earnings Growth			br+sv
	Company	V Line	IBES	Zacks	Growth
1	Alliant Energy	6.0%	6.6%	6.1%	5.0%
2	Ameren Corp.	6.0%	5.2%	6.1%	3.6%
3	Avangrid, Inc.	NA	9.0%	9.0%	NA
4	Avista Corp.	5.0%	5.0%	5.3%	3.6%
5	Black Hills Corp.	7.5%	6.7%	5.8%	7.7%
6	CenterPoint Energy	2.0%	5.3%	5.5%	2.8%
7	CMS Energy Corp.	6.0%	7.3%	6.6%	5.6%
8	Consolidated Edison	2.5%	2.1%	2.8%	3.2%
9	DTE Energy Co.	6.0%	5.5%	5.8%	4.5%
10	Entergy Corp.	2.0%	-2.6%	-4.4%	3.6%
11	Eversource Energy	6.0%	5.4%	6.1%	4.0%
12	Exelon Corp.	7.0%	2.7%	3.7%	5.9%
13	NorthWestern Corp.	6.5%	5.0%	5.0%	4.5%
14	PG&E Corp.	12.0%	5.7%	4.3%	5.1%
15	PPL Corp.	NA	2.5%	3.5%	4.5%
16	Pub Sv Enterprise Grp.	3.0%	1.5%	4.4%	4.8%
17	SCANA Corp.	4.5%	6.0%	5.5%	4.6%
18	Sempra Energy	8.0%	7.7%	6.9%	5.7%
19	Southern Company	4.0%	3.2%	3.9%	4.2%
20	Vectren Corp.	9.0%	5.0%	5.3%	6.3%
21	WEC Energy Group	6.0%	6.7%	6.2%	3.4%
22	Xcel Energy Inc.	5.5%	5.3%	5.4%	4.2%

(a) The Value Line Investment Survey (Aug. 19, Sep. 16, & Oct. 28, 2016).

(b) www.finance.yahoo.com (Oct. 15, 2016).

(c) www.zacks.com (Oct. 20, 2016).

(d) See Exhibit No. 6.

COST OF EQUITY ESTIMATES

		(a)	(a)	(a)	(a)
		Earnings Growth			br+sv
	Company	**V Line**	**IBES**	**Zacks**	**Growth**
1	Alliant Energy	9.1%	9.7%	9.2%	8.1%
2	Ameren Corp.	9.6%	8.8%	9.7%	7.2%
3	Avangrid, Inc.	NA	13.2%	13.2%	NA
4	Avista Corp.	8.4%	8.4%	8.7%	7.1%
5	Black Hills Corp.	10.5%	9.7%	8.9%	10.7%
6	CenterPoint Energy	6.6%	9.9%	10.1%	7.4%
7	CMS Energy Corp.	9.1%	10.4%	9.7%	8.7%
8	Consolidated Edison	6.2%	5.8%	6.5%	6.9%
9	DTE Energy Co.	9.3%	8.9%	9.1%	7.8%
10	Entergy Corp.	6.6%	2.0%	0.1%	8.2%
11	Eversource Energy	9.5%	8.9%	9.5%	7.5%
12	Exelon Corp.	10.9%	6.5%	7.5%	9.7%
13	NorthWestern Corp.	10.1%	8.6%	8.6%	8.2%
14	PG&E Corp.	15.3%	9.0%	7.6%	8.4%
15	PPL Corp.	NA	7.1%	8.2%	9.2%
16	Pub Sv Enterprise Grp.	7.0%	5.5%	8.5%	8.8%
17	SCANA Corp.	7.9%	9.4%	8.8%	8.0%
18	Sempra Energy	11.0%	10.7%	10.0%	8.8%
19	Southern Company	8.5%	7.6%	8.4%	8.6%
20	Vectren Corp.	12.4%	8.4%	8.7%	9.7%
21	WEC Energy Group	9.5%	10.2%	9.7%	6.9%
22	Xcel Energy Inc.	9.0%	8.8%	8.9%	7.7%
	Average (b)	**9.5%**	**9.3%**	**9.2%**	**8.4%**
	Midpoint (c)	**9.7%**	**10.2%**	**10.4%**	**8.9%**

(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

Witness: Adrien M. McKenzie

BR+SV GROWTH RATE

UTILITY GROUP

		(a)	(a)	(a)			(b)	(c)		(d)	(e)		
		2020					Adjustment			"sv" Factor			
	Company	EPS	DPS	BVPS	b	r	Factor	Adjusted r	br	s	v	sv	br + sv
1	Alliant Energy	$2.45	$1.50	$20.00	38.8%	12.3%	1.0086	12.4%	4.8%	0.0047	0.4286	0.20%	**5.0%**
2	Ameren Corp.	$3.25	$2.05	$34.00	36.9%	9.6%	1.0173	9.7%	3.6%	-	0.2842	0.00%	**3.6%**
3	Avangrid, Inc.	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	**NA**
4	Avista Corp.	$2.50	$1.60	$28.50	36.0%	8.8%	1.0223	9.0%	3.2%	0.0172	0.2400	0.41%	**3.6%**
5	Black Hills Corp.	$4.25	$2.20	$39.00	48.2%	10.9%	1.0479	11.4%	5.5%	0.0572	0.3760	2.15%	**7.7%**
6	CenterPoint Energy	$1.40	$1.19	$9.00	15.0%	15.6%	1.0112	15.7%	2.4%	0.0064	0.6400	0.41%	**2.8%**
7	CMS Energy Corp.	$2.50	$1.60	$19.25	36.0%	13.0%	1.0344	13.4%	4.8%	0.0150	0.4867	0.73%	**5.6%**
8	Consolidated Edison	$4.50	$3.00	$53.50	33.3%	8.4%	1.0235	8.6%	2.9%	0.0145	0.2621	0.38%	**3.2%**
9	DTE Energy Co.	$6.25	$3.70	$61.00	40.8%	10.2%	1.0245	10.5%	4.3%	0.0072	0.3029	0.22%	**4.5%**
10	Entergy Corp.	$6.25	$4.00	$64.00	36.0%	9.8%	1.0210	10.0%	3.6%	0.0009	0.2686	0.03%	**3.6%**
11	Eversource Energy	$3.75	$2.20	$39.50	41.3%	9.5%	1.0185	9.7%	4.0%	-	0.3417	0.00%	**4.0%**
12	Exelon Corp.	$3.50	$1.50	$35.75	57.1%	9.8%	1.0287	10.1%	5.8%	0.0096	0.1063	0.10%	**5.9%**
13	NorthWestern Corp.	$4.00	$2.32	$40.00	42.0%	10.0%	1.0214	10.2%	4.3%	0.0079	0.3043	0.24%	**4.5%**
14	PG&E Corp.	$4.50	$2.70	$42.25	40.0%	10.7%	1.0292	11.0%	4.4%	0.0201	0.3500	0.70%	**5.1%**
15	PPL Corp.	$2.50	$1.76	$19.25	29.6%	13.0%	1.0300	13.4%	4.0%	0.0111	0.5188	0.57%	**4.5%**
16	Pub Sv Enterprise Grp.	$3.50	$2.00	$32.25	42.9%	10.9%	1.0224	11.1%	4.8%	0.0004	0.3550	0.02%	**4.8%**
17	SCANA Corp.	$4.75	$2.80	$47.75	41.1%	9.9%	1.0273	10.2%	4.2%	0.0143	0.3179	0.45%	**4.6%**
18	Sempra Energy	$7.50	$4.00	$54.75	46.7%	13.7%	1.0117	13.9%	6.5%	(0.0126)	0.5944	-0.75%	**5.7%**
19	Southern Company	$3.50	$2.54	$32.00	27.4%	10.9%	1.0350	11.3%	3.1%	0.0273	0.3905	1.06%	**4.2%**
20	Vectren Corp.	$3.35	$1.95	$26.15	41.8%	12.8%	1.0288	13.2%	5.5%	0.0153	0.5019	0.77%	**6.3%**
21	WEC Energy Group	$3.50	$2.40	$32.75	31.4%	10.7%	1.0174	10.9%	3.4%	(0.0000)	0.4304	0.00%	**3.4%**
22	Xcel Energy Inc.	$2.75	$1.70	$25.50	38.2%	10.8%	1.0209	11.0%	4.2%	0.0003	0.4000	0.01%	**4.2%**

(a) The Value Line Investment Survey (Aug. 19, Sep. 16, & Oct. 28, 2016).
(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 2020 and Adjustment Factor.
(d) Product of change in common shares outstanding and M/B Ratio.
(e) Computed as 1 - B/M Ratio.

BR+SV GROWTH RATE

UTILITY GROUP

		(a)	(a)	(f)	(a)	(a)	(f)	(g)	(a)	(a)		(h)	(a)	(a)	(g)
		2015			2020			Chg	2020 Price				Common Shares		
	Company	Eq Ratio	Tot Cap	Com Eq	Eq Ratio	Tot Cap	Com Eq	Equity	High	Low	Avg.	M/B	2015	2020	Growth
1	Alliant Energy	51.4%	$7,246	$3,725	49.5%	$8,200	$4,059	1.7%	$40.00	$30.00	$35.00	1.750	226.92	230.00	0.27%
2	Ameren Corp.	49.7%	$13,968	$6,942	50.0%	$16,500	$8,250	3.5%	$55.00	$40.00	$47.50	1.397	242.63	242.63	0.00%
3	Avangrid, Inc.	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
4	Avista Corp.	50.0%	$3,060	$1,530	50.0%	$3,825	$1,913	4.6%	$45.00	$30.00	$37.50	1.316	62.31	66.50	1.31%
5	Black Hills Corp.	44.0%	$3,333	$1,466	51.5%	$4,600	$2,369	10.1%	$70.00	$55.00	$62.50	1.603	51.19	61.00	3.57%
6	CenterPoint Energy	30.5%	$11,362	$3,465	31.5%	$12,300	$3,875	2.3%	$30.00	$20.00	$25.00	2.778	430.00	435.00	0.23%
7	CMS Energy Corp.	31.4%	$12,534	$3,936	34.5%	$16,100	$5,555	7.1%	$45.00	$30.00	$37.50	1.948	277.16	288.00	0.77%
8	Consolidated Edison	52.1%	$25,058	$13,055	54.5%	$30,300	$16,514	4.8%	$80.00	$65.00	$72.50	1.355	293.00	309.00	1.07%
9	DTE Energy Co.	49.8%	$17,607	$8,768	46.5%	$24,100	$11,207	5.0%	$100.00	$75.00	$87.50	1.434	179.47	184.00	0.50%
10	Entergy Corp.	40.8%	$22,714	$9,267	45.0%	$25,400	$11,430	4.3%	$105.00	$70.00	$87.50	1.367	178.39	179.00	0.07%
11	Eversource Energy	53.6%	$19,313	$10,352	53.0%	$23,500	$12,455	3.8%	$65.00	$55.00	$60.00	1.519	317.19	317.19	0.00%
12	Exelon Corp.	51.3%	$50,272	$25,790	50.0%	$68,700	$34,350	5.9%	$50.00	$30.00	$40.00	1.119	919.92	960.00	0.86%
13	NorthWestern Corp.	46.9%	$3,409	$1,599	49.5%	$4,000	$1,980	4.4%	$70.00	$45.00	$57.50	1.438	48.17	49.50	0.55%
14	PG&E Corp.	50.4%	$32,858	$16,560	50.5%	$43,900	$22,170	6.0%	$80.00	$50.00	$65.00	1.538	492.03	525.00	1.31%
15	PPL Corp.	34.8%	$28,482	$9,912	38.0%	$35,200	$13,376	6.2%	$45.00	$35.00	$40.00	2.078	673.86	692.00	0.53%
16	Pub Sv Enterprise Grp.	59.7%	$21,900	$13,074	56.0%	$29,200	$16,352	4.6%	$55.00	$45.00	$50.00	1.550	505.28	506.00	0.03%
17	SCANA Corp.	48.1%	$11,325	$5,447	44.0%	$16,275	$7,161	5.6%	$80.00	$60.00	$70.00	1.466	142.90	150.00	0.97%
18	Sempra Energy	47.3%	$24,963	$11,807	42.0%	$31,600	$13,272	2.4%	$155.00	$115.00	$135.00	2.466	248.30	242.00	-0.51%
19	Southern Company	44.0%	$46,788	$20,587	38.0%	$76,900	$29,222	7.3%	$60.00	$45.00	$52.50	1.641	911.72	990.00	1.66%
20	Vectren Corp.	49.4%	$3,407	$1,683	51.0%	$4,400	$2,244	5.9%	$60.00	$45.00	$52.50	2.008	82.80	86.00	0.76%
21	WEC Energy Group	48.6%	$17,809	$8,655	52.0%	$19,800	$10,296	3.5%	$65.00	$50.00	$57.50	1.756	315.68	315.65	0.00%
22	Xcel Energy Inc.	45.9%	$23,092	$10,599	47.5%	$27,500	$13,063	4.3%	$45.00	$40.00	$42.50	1.667	507.54	508.00	0.02%

(a) The Value Line Investment Survey (Aug. 19, Sep. 16, & Oct. 28, 2016).
(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 2020 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 in common equity.
(h) Average of High and Low expected market prices divided by 2020 BVPS.

Exhibit No. 7

Capital Asset Pricing Model

Witness: Adrien M. McKenzie

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	2.5%	8.8%	11.3%	2.4%	8.9%	0.75	9.1%	$ 8,484.1	0.86%	9.9%
2	Ameren Corp.	2.5%	8.8%	11.3%	2.4%	8.9%	0.70	8.6%	$ 11,795.2	0.57%	9.2%
3	Avangrid, Inc.	2.5%	8.8%	11.3%	2.4%	8.9%	NA	NA	$ 11,880.0	0.57%	NA
4	Avista Corp.	2.5%	8.8%	11.3%	2.4%	8.9%	0.70	8.6%	$ 2,578.1	1.49%	10.1%
5	Black Hills Corp.	2.5%	8.8%	11.3%	2.4%	8.9%	0.90	10.4%	$ 3,121.1	1.49%	11.9%
6	CenterPoint Energy	2.5%	8.8%	11.3%	2.4%	8.9%	0.80	9.5%	$ 9,759.2	0.57%	10.1%
7	CMS Energy Corp.	2.5%	8.8%	11.3%	2.4%	8.9%	0.65	8.2%	$ 11,549.1	0.57%	8.8%
8	Consolidated Edison	2.5%	8.8%	11.3%	2.4%	8.9%	0.55	7.3%	$ 20,687.2	0.57%	7.9%
9	DTE Energy Co.	2.5%	8.8%	11.3%	2.4%	8.9%	0.70	8.6%	$ 16,707.2	0.57%	9.2%
10	Entergy Corp.	2.5%	8.8%	11.3%	2.4%	8.9%	0.65	8.2%	$ 13,329.5	0.57%	8.8%
11	Eversource Energy	2.5%	8.8%	11.3%	2.4%	8.9%	0.70	8.6%	$ 17,167.2	0.57%	9.2%
12	Exelon Corp.	2.5%	8.8%	11.3%	2.4%	8.9%	0.70	8.6%	$ 29,161.9	-0.36%	8.3%
13	NorthWestern Corp.	2.5%	8.8%	11.3%	2.4%	8.9%	0.70	8.6%	$ 2,900.7	1.49%	10.1%
14	PG&E Corp.	2.5%	8.8%	11.3%	2.4%	8.9%	0.65	8.2%	$ 30,307.0	-0.36%	7.8%
15	PPL Corp.	2.5%	8.8%	11.3%	2.4%	8.9%	0.70	8.6%	$ 22,752.1	-0.36%	8.3%
16	Pub Sv Enterprise Grp.	2.5%	8.8%	11.3%	2.4%	8.9%	0.70	8.6%	$ 20,846.4	0.57%	9.2%
17	SCANA Corp.	2.5%	8.8%	11.3%	2.4%	8.9%	0.70	8.6%	$ 10,079.9	0.57%	9.2%
18	Sempra Energy	2.5%	8.8%	11.3%	2.4%	8.9%	0.80	9.5%	$ 26,337.5	-0.36%	9.2%
19	Southern Company	2.5%	8.8%	11.3%	2.4%	8.9%	0.55	7.3%	$ 47,737.7	-0.36%	6.9%
20	Vectren Corp.	2.5%	8.8%	11.3%	2.4%	8.9%	0.75	9.1%	$ 4,019.1	0.99%	10.1%
21	WEC Energy Group	2.5%	8.8%	11.3%	2.4%	8.9%	0.65	8.2%	$ 18,324.9	0.57%	8.8%
22	Xcel Energy Inc.	2.5%	8.8%	11.3%	2.4%	8.9%	0.60	7.7%	$ 20,516.2	0.57%	8.3%
	Average (g)							**8.6%**			**9.2%**
	Midpoint (h)							**8.9%**			**9.9%**

(a) Weighted average for dividend-paying stocks in the S&P 500 based on data from www.valueline.com (Sep. 3, 2016).

(b) Average of weighted average earnings growth rates from IBES and Value Line Investment Survey for dividend-paying stocks in the S&P 500 based on data from http://finance.yahoo.com (retrieved Sep. 5, 2016). and www.valueline.com (Sep. 3, 2016).

(c) Average yield on 30-year Treasury bonds for the six-months ending Sep. 2016 based on data from the Federal Reserve at http://www.federalreserve.gov/releases/h15/data.htm.

(d) The Value Line Investment Survey (Aug. 19, Sep. 16, & Oct. 28, 2016).

(e) www.valueline.com (retrieved Oct. 25, 2016); Yahoo! Finance (Oct. 25, 2016).

(f) Duff & Phelps, "2016 Valuation Handbook - Guide to Cost of Capital," John Wiley & Sons (2016) at Table 7.3.

(g) Excludes highlighted figures.

(h) 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	2.5%	8.8%	11.3%	3.9%	7.4%	0.75	9.5%	$ 8,484.1	0.86%	10.3%
2	Ameren Corp.	2.5%	8.8%	11.3%	3.9%	7.4%	0.70	9.1%	$ 11,795.2	0.57%	9.7%
3	Avangrid, Inc.	2.5%	8.8%	11.3%	3.9%	7.4%	NA	NA	$ 11,880.0	0.57%	NA
4	Avista Corp.	2.5%	8.8%	11.3%	3.9%	7.4%	0.70	9.1%	$ 2,578.1	1.49%	10.6%
5	Black Hills Corp.	2.5%	8.8%	11.3%	3.9%	7.4%	0.90	10.6%	$ 3,121.1	1.49%	12.1%
6	CenterPoint Energy	2.5%	8.8%	11.3%	3.9%	7.4%	0.80	9.8%	$ 9,759.2	0.57%	10.4%
7	CMS Energy Corp.	2.5%	8.8%	11.3%	3.9%	7.4%	0.65	8.7%	$ 11,549.1	0.57%	9.3%
8	Consolidated Edison	2.5%	8.8%	11.3%	3.9%	7.4%	0.55	8.0%	$ 20,687.2	0.57%	8.5%
9	DTE Energy Co.	2.5%	8.8%	11.3%	3.9%	7.4%	0.70	9.1%	$ 16,707.2	0.57%	9.7%
10	Entergy Corp.	2.5%	8.8%	11.3%	3.9%	7.4%	0.65	8.7%	$ 13,329.5	0.57%	9.3%
11	Eversource Energy	2.5%	8.8%	11.3%	3.9%	7.4%	0.70	9.1%	$ 17,167.2	0.57%	9.7%
12	Exelon Corp.	2.5%	8.8%	11.3%	3.9%	7.4%	0.70	9.1%	$ 29,161.9	-0.36%	8.7%
13	NorthWestern Corp.	2.5%	8.8%	11.3%	3.9%	7.4%	0.70	9.1%	$ 2,900.7	1.49%	10.6%
14	PG&E Corp.	2.5%	8.8%	11.3%	3.9%	7.4%	0.65	8.7%	$ 30,307.0	-0.36%	8.4%
15	PPL Corp.	2.5%	8.8%	11.3%	3.9%	7.4%	0.70	9.1%	$ 22,752.1	-0.36%	8.7%
16	Pub Sv Enterprise Grp.	2.5%	8.8%	11.3%	3.9%	7.4%	0.70	9.1%	$ 20,846.4	0.57%	9.7%
17	SCANA Corp.	2.5%	8.8%	11.3%	3.9%	7.4%	0.70	9.1%	$ 10,079.9	0.57%	9.7%
18	Sempra Energy	2.5%	8.8%	11.3%	3.9%	7.4%	0.80	9.8%	$ 26,337.5	-0.36%	9.5%
19	Southern Company	2.5%	8.8%	11.3%	3.9%	7.4%	0.55	8.0%	$ 47,737.7	-0.36%	7.6%
20	Vectren Corp.	2.5%	8.8%	11.3%	3.9%	7.4%	0.75	9.5%	$ 4,019.1	0.99%	10.4%
21	WEC Energy Group	2.5%	8.8%	11.3%	3.9%	7.4%	0.65	8.7%	$ 18,324.9	0.57%	9.3%
22	Xcel Energy Inc.	2.5%	8.8%	11.3%	3.9%	7.4%	0.60	8.3%	$ 20,516.2	0.57%	8.9%
	Average							**9.0%**			**9.6%**
	Midpoint (g)							**9.3%**			**9.9%**

(a) Weighted average for dividend-paying stocks in the S&P 500 based on data from www.valueline.com (Sep. 3, 2016).

(b) Average of weighted average earnings growth rates from IBES and Value Line Investment Survey for dividend-paying stocks in the S&P 500 based on data from http://finance.yahoo.com (retrieved Sep. 5, 2016). and www.valueline.com (Sep. 3, 2016).

(c) Average yield on 30-year Treasury bonds for 2017-21 based on data from the Value Line Investment Survey, Forecast for the U.S. Economy (Sep. 2, 2016); IHS Global Insight (Apr. 6 & Jun. 27, 2016); & Wolters Kluwer, Blue Chip Financial Forecasts, Vol. 35, No. 6 (Jun. 1, 2016).

(d) The Value Line Investment Survey (Aug. 19, Sep. 16, & Oct. 28, 2016).

(e) www.valueline.com (retrieved Oct. 25, 2016); Yahoo! Finance (Oct. 25, 2016).

(f) Duff & Phelps, "2016 Valuation Handbook - Guide to Cost of Capital," John Wiley & Sons (2016) at Table 7.3.

(g) Average of low and high values.

Exhibit No. 8

Empirical Capital Asset Pricing Model

Witness: Adrien M. McKenzie

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	2.5%	8.8%	11.3%	2.4%	8.9%	25%	2.2%	0.75	75%	5.0%	7.2%	9.6%	$ 8,484.1	0.86%	10.5%
2	Ameren Corp.	2.5%	8.8%	11.3%	2.4%	8.9%	25%	2.2%	0.70	75%	4.7%	6.9%	9.3%	$11,795.2	0.57%	9.9%
3	Avangrid, Inc.	2.5%	8.8%	11.3%	2.4%	8.9%	25%	2.2%	NA	75%	NA	NA	NA	$11,880.0	0.57%	NA
4	Avista Corp.	2.5%	8.8%	11.3%	2.4%	8.9%	25%	2.2%	0.70	75%	4.7%	6.9%	9.3%	$ 2,578.1	1.49%	10.8%
5	Black Hills Corp.	2.5%	8.8%	11.3%	2.4%	8.9%	25%	2.2%	0.90	75%	6.0%	8.2%	10.6%	$ 3,121.1	1.49%	12.1%
6	CenterPoint Energy	2.5%	8.8%	11.3%	2.4%	8.9%	25%	2.2%	0.80	75%	5.3%	7.6%	10.0%	$ 9,759.2	0.57%	10.5%
7	CMS Energy Corp.	2.5%	8.8%	11.3%	2.4%	8.9%	25%	2.2%	0.65	75%	4.3%	6.6%	9.0%	$11,549.1	0.57%	9.5%
8	Consolidated Edison	2.5%	8.8%	11.3%	2.4%	8.9%	25%	2.2%	0.55	75%	3.7%	5.9%	8.3%	$20,687.2	0.57%	8.9%
9	DTE Energy Co.	2.5%	8.8%	11.3%	2.4%	8.9%	25%	2.2%	0.70	75%	4.7%	6.9%	9.3%	$16,707.2	0.57%	9.9%
10	Entergy Corp.	2.5%	8.8%	11.3%	2.4%	8.9%	25%	2.2%	0.65	75%	4.3%	6.6%	9.0%	$13,329.5	0.57%	9.5%
11	Eversource Energy	2.5%	8.8%	11.3%	2.4%	8.9%	25%	2.2%	0.70	75%	4.7%	6.9%	9.3%	$17,167.2	0.57%	9.9%
12	Exelon Corp.	2.5%	8.8%	11.3%	2.4%	8.9%	25%	2.2%	0.70	75%	4.7%	6.9%	9.3%	$29,161.9	-0.36%	8.9%
13	NorthWestern Corp.	2.5%	8.8%	11.3%	2.4%	8.9%	25%	2.2%	0.70	75%	4.7%	6.9%	9.3%	$ 2,900.7	1.49%	10.8%
14	PG&E Corp.	2.5%	8.8%	11.3%	2.4%	8.9%	25%	2.2%	0.65	75%	4.3%	6.6%	9.0%	$30,307.0	-0.36%	8.6%
15	PPL Corp.	2.5%	8.8%	11.3%	2.4%	8.9%	25%	2.2%	0.70	75%	4.7%	6.9%	9.3%	$22,752.1	-0.36%	8.9%
16	Pub Sv Enterprise Grp.	2.5%	8.8%	11.3%	2.4%	8.9%	25%	2.2%	0.70	75%	4.7%	6.9%	9.3%	$20,846.4	0.57%	9.9%
17	SCANA Corp.	2.5%	8.8%	11.3%	2.4%	8.9%	25%	2.2%	0.70	75%	4.7%	6.9%	9.3%	$10,079.9	0.57%	9.9%
18	Sempra Energy	2.5%	8.8%	11.3%	2.4%	8.9%	25%	2.2%	0.80	75%	5.3%	7.6%	10.0%	$26,337.5	-0.36%	9.6%
19	Southern Company	2.5%	8.8%	11.3%	2.4%	8.9%	25%	2.2%	0.55	75%	3.7%	5.9%	8.3%	$47,737.7	-0.36%	7.9%
20	Vectren Corp.	2.5%	8.8%	11.3%	2.4%	8.9%	25%	2.2%	0.75	75%	5.0%	7.2%	9.6%	$ 4,019.1	0.99%	10.6%
21	WEC Energy Group	2.5%	8.8%	11.3%	2.4%	8.9%	25%	2.2%	0.65	75%	4.3%	6.6%	9.0%	$18,324.9	0.57%	9.5%
22	Xcel Energy Inc.	2.5%	8.8%	11.3%	2.4%	8.9%	25%	2.2%	0.60	75%	4.0%	6.2%	8.6%	$20,516.2	0.57%	9.2%
	Average												**9.3%**			**9.8%**
	Midpoint (h)												**9.5%**			**10.0%**

(a) Weighted average for dividend-paying stocks in the S&P 500 based on data from www.valueline.com (Sep. 3, 2016).

(b) Average of weighted average earnings growth rates from IBES and Value Line Investment Survey for dividend-paying stocks in the S&P 500 based on data from http://finance.yahoo.com (retrieved Sep. 5, 2016). and www.valueline.com (Sep. 3, 2016).

(c) Average yield on 30-year Treasury bonds for the six-months ending Sep. 2016 based on data from the Federal Reserve at 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. 19, Sep. 16, & Oct. 28, 2016).

(f) www.valueline.com (retrieved Oct. 25, 2016); Yahoo! Finance (Oct. 25, 2016).

(g) Duff & Phelps, "2016 Valuation Handbook - Guide to Cost of Capital," John Wiley & Sons (2016) at Table 7.3.

(h) Average of low and high values.

EMPIRICAL CAPM - PROJECTED 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	2.5%	8.8%	11.3%	3.9%	7.4%	25%	1.9%	0.75	75%	4.2%	6.0%	9.9%	$ 8,484.1	0.86%	10.8%
2	Ameren Corp.	2.5%	8.8%	11.3%	3.9%	7.4%	25%	1.9%	0.70	75%	3.9%	5.7%	9.6%	$ 11,795.2	0.57%	10.2%
3	Avangrid, Inc.	2.5%	8.8%	11.3%	3.9%	7.4%	25%	1.9%	NA	75%	NA	NA	NA	$ 11,880.0	0.57%	NA
4	Avista Corp.	2.5%	8.8%	11.3%	3.9%	7.4%	25%	1.9%	0.70	75%	3.9%	5.7%	9.6%	$ 2,578.1	1.49%	11.1%
5	Black Hills Corp.	2.5%	8.8%	11.3%	3.9%	7.4%	25%	1.9%	0.90	75%	5.0%	6.8%	10.7%	$ 3,121.1	1.49%	12.2%
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9	DTE Energy Co.	2.5%	8.8%	11.3%	3.9%	7.4%	25%	1.9%	0.70	75%	3.9%	5.7%	9.6%	$ 16,707.2	0.57%	10.2%
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12	Exelon Corp.	2.5%	8.8%	11.3%	3.9%	7.4%	25%	1.9%	0.70	75%	3.9%	5.7%	9.6%	$ 29,161.9	-0.36%	9.3%
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20	Vectren Corp.	2.5%	8.8%	11.3%	3.9%	7.4%	25%	1.9%	0.75	75%	4.2%	6.0%	9.9%	$ 4,019.1	0.99%	10.9%
21	WEC Energy Group	2.5%	8.8%	11.3%	3.9%	7.4%	25%	1.9%	0.65	75%	3.6%	5.5%	9.4%	$ 18,324.9	0.57%	9.9%
22	Xcel Energy Inc.	2.5%	8.8%	11.3%	3.9%	7.4%	25%	1.9%	0.60	75%	3.3%	5.2%	9.1%	$ 20,516.2	0.57%	9.7%
	Average												**9.6%**			**10.1%**
	Midpoint (h)												**9.8%**			**10.3%**

(a) Weighted average for dividend-paying stocks in the S&P 500 based on data from www.valueline.com (Sep. 3, 2016).

(b) Average of weighted average earnings growth rates from IBES and Value Line Investment Survey for dividend-paying stocks in the S&P 500 based on data from http://finance.yahoo.com (retrieved Sep. 5, 2016). and www.valueline.com (Sep. 3, 2016).

(c) Average yield on 30-year Treasury bonds for 2017-21 based on data from the Value Line Investment Survey, Forecast for the U.S. Economy (Sep. 2, 2016); IHS Global Insight (Apr. 6 & Jun. 27, 2016); & Wolters Kluwer, Blue Chip Financial Forecasts, Vol. 35, No. 6 (Jun. 1, 2016).

(d) Morin, Roger A., "New Regulatory Finance," *Public Utilities Reports, Inc.* at 190 (2006).

(e) The Value Line Investment Survey (Aug. 19, Sep. 16, & Oct. 28, 2016).

(f) www.valueline.com (retrieved Oct. 25, 2016); Yahoo! Finance (Oct. 25, 2016).

(g) Duff & Phelps, "2016 Valuation Handbook - Guide to Cost of Capital," John Wiley & Sons (2016) at Table 7.3.

(h) Average of low and high values.

Exhibit No. 9
Risk Premium Method

Witness: Adrien M. McKenzie

CURRENT BOND YIELD

Current Equity Risk Premium

(a)	Avg. Yield over Study Period	8.48%
(b)	Average Utility Bond Yield	3.90%
	Change in Bond Yield	-4.58%
(c)	Risk Premium/Interest Rate Relationship	-0.4281
	Adjustment to Average Risk Premium	1.96%
(a)	Average Risk Premium over Study Period	3.62%
	Adjusted Risk Premium	**5.58%**

Implied Cost of Equity

(b)	Baa Utility Bond Yield	4.41%
	Adjusted Equity Risk Premium	5.58%
	Risk Premium Cost of Equity	**9.99%**

(a) Exhibit No. 9, page 3.
(b) Average bond yield on all utility bonds and Baa subset for six-months ending Sep. 2016 based on data from Moody's Investors Service at www.credittrends.com.
(c) Exhibit No. 9, page 4.

PROJECTED BOND YIELD

Current Equity Risk Premium		
(a)	Avg. Yield over Study Period	8.48%
(b)	Average Utility Bond Yield 2017-2021	5.83%
	Change in Bond Yield	-2.65%
(c)	Risk Premium/Interest Rate Relationship	-0.4281
	Adjustment to Average Risk Premium	1.13%
(a)	Average Risk Premium over Study Period	3.62%
	Adjusted Risk Premium	**4.75%**
Implied Cost of Equity		
(b)	Baa Utility Bond Yield 2017-2021	6.34%
	Adjusted Equity Risk Premium	4.75%
	Risk Premium Cost of Equity	**11.09%**

(a) Exhibit No. 9, page 3.

(b) Yield on all utility bonds and Baa subset based on data from IHS Global Insight (Apr. 6 & Jun. 27, 2016); Energy Information Administration, Annual Energy Outlook 2016 Early Release (May 17, 2016); & Moody's Investors Service at www.credittrends.com.

(c) Exhibit No. 9, 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%
2014	9.92%	4.41%	5.51%
2015	9.85%	4.37%	5.48%
Average	12.10%	8.48%	3.62%

(a) Major Rate Case Decisions, *Regulatory Focus* , Regulatory Research Associates; *UtilityScope Regulatory Service* , Argus.

(b) Moody's Investors Service.

REGRESSION RESULTS

SUMMARY OUTPUT

Regression Statistics	
Multiple R	0.9270912
R Square	0.8594981
Adjusted R Square	0.8559856
Standard Error	0.0050171
Observations	42

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	0.006159143	0.006159	244.6937	1.2107E-18
Residual	40	0.001006833	2.52E-05		
Total	41	0.007165976			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
Intercept	0.0725018	0.002446981	29.62907	7.81E-29	0.06755625	0.07744732	0.067556248	0.077447316
X Variable 1	-0.4281032	0.027367621	-15.6427	1.21E-18	-0.48341523	-0.37279118	-0.48341523	-0.37279118

Exhibit No. 10

Expected Earnings Approach

Witness: Adrien M. McKenzie

EXPECTED EARNINGS APPROACH

UTILITY GROUP

	Company	(a) Expected Return on Common Equity	(b) Adjustment Factor	(c) Adjusted Return on Common Equity
1	Alliant Energy	12.5%	1.0086	12.6%
2	Ameren Corp.	9.5%	1.0173	9.7%
3	Avangrid, Inc.	NA	NA	NA
4	Avista Corp.	8.5%	1.0223	8.7%
5	Black Hills Corp.	10.5%	1.0479	11.0%
6	CenterPoint Energy	15.5%	1.0112	15.7%
7	CMS Energy Corp.	13.5%	1.0344	14.0%
8	Consolidated Edison	8.5%	1.0235	8.7%
9	DTE Energy Co.	10.0%	1.0245	10.2%
10	Entergy Corp.	10.0%	1.0210	10.2%
11	Eversource Energy	9.5%	1.0185	9.7%
12	Exelon Corp.	10.0%	1.0287	10.3%
13	NorthWestern Corp.	10.0%	1.0214	10.2%
14	PG&E Corp.	11.0%	1.0292	11.3%
15	PPL Corp.	13.0%	1.0300	13.4%
16	Pub Sv Enterprise Grp.	10.5%	1.0224	10.7%
17	SCANA Corp.	10.0%	1.0273	10.3%
18	Sempra Energy	14.0%	1.0117	14.2%
19	Southern Company	10.5%	1.0350	10.9%
20	Vectren Corp.	13.0%	1.0288	13.4%
21	WEC Energy Group	11.0%	1.0174	11.2%
22	Xcel Energy Inc.	11.0%	1.0209	11.2%
	Average			**11.3%**
	Midpoint (d)			**12.2%**

(a) The Value Line Investment Survey (Aug. 19, Sep. 16, & Oct. 28, 2016).
(b) Adjustment to convert year-end return to an average rate of return from Exhibit No. 6.
(c) (a) x (b).
(d) Average of low and high values.

Exhibit No. 11

DCF Model – Non-Utility Group

Witness: Adrien M. McKenzie

DIVIDEND YIELD

	Company	Industry Group	(a) Price	(b) Dividends	Yield
1	Church & Dwight	Household Products	$ 47.45	$ 0.71	1.5%
2	Coca-Cola	Beverage	$ 42.08	$ 1.46	3.5%
3	ConAgra Foods	Food Processing	$ 45.76	$ 1.00	2.2%
4	Costco Wholesale	Retail Store	$ 150.71	$ 1.80	1.2%
5	Gen'l Mills	Food Processing	$ 63.28	$ 1.94	3.1%
6	Kellogg	Food Processing	$ 76.63	$ 2.09	2.7%
7	Kimberly-Clark	Household Products	$ 122.68	$ 3.68	3.0%
8	Procter & Gamble	Household Products	$ 87.91	$ 2.68	3.0%
9	Smucker (J.M.)	Food Processing	$ 134.36	$ 3.00	2.2%
10	Sysco Corp.	Wholesale Food	$ 48.73	$ 1.27	2.6%
11	Verizon Communic.	Telecommunications	$ 50.93	$ 2.31	4.5%
12	Wal-Mart Stores	Retail Store	$ 70.43	$ 2.03	2.9%
	Average				**2.7%**

(a) Average of closing prices for 30 trading days ended Oct. 24, 2016.

(b) The Value Line Investment Survey, *Summary & Index* (Oct. 28, 2016).

GROWTH RATES

		(a)	(b)	(c)
		Earnings Growth		
	Company	**V Line**	**IBES**	**Zacks**
1	Church & Dwight	7.50%	9.78%	9.59%
2	Coca-Cola	4.00%	2.59%	5.95%
3	ConAgra Foods	6.00%	10.33%	8.82%
4	Costco Wholesale	9.00%	10.21%	10.61%
5	Gen'l Mills	7.00%	6.95%	8.18%
6	Kellogg	5.50%	7.13%	6.28%
7	Kimberly-Clark	10.00%	7.20%	7.11%
8	Procter & Gamble	9.00%	8.60%	6.90%
9	Smucker (J.M.)	7.50%	9.08%	7.18%
10	Sysco Corp.	11.50%	10.03%	8.83%
11	Verizon Communic.	3.00%	1.68%	4.13%
12	Wal-Mart Stores	2.00%	1.81%	5.28%

(a) The Value Line Investment Survey (Aug. 19, Aug. 26, Sep. 16, Sep. 23, Oct. 7, Oct. 21, & Oct. 28, 2016).

(b) www.finance.yahoo.com (retrieved Oct. 26, 2016).

(c) www.zacks.com (retrieved Oct. 26, 2016).

DCF COST OF EQUITY ESTIMATES

		(a)	(a)	(a)
		Earnings Growth		
	Company	**V Line**	**IBES**	**Zacks**
1	Church & Dwight	9.0%	11.3%	11.1%
2	Coca-Cola	7.5%	6.1%	9.4%
3	ConAgra Foods	8.2%	12.5%	11.0%
4	Costco Wholesale	10.2%	11.4%	11.8%
5	Gen'l Mills	10.1%	10.0%	11.2%
6	Kellogg	8.2%	9.9%	9.0%
7	Kimberly-Clark	13.0%	10.2%	10.1%
8	Procter & Gamble	12.0%	11.6%	9.9%
9	Smucker (J.M.)	9.7%	11.3%	9.4%
10	Sysco Corp.	14.1%	12.6%	11.4%
11	Verizon Communic.	7.5%	6.2%	8.7%
12	Wal-Mart Stores	4.9%	4.7%	8.2%
	Average (b)	**10.0%**	**11.2%**	**10.1%**
	Midpoint (c)	**10.8%**	**11.2%**	**10.0%**

(a) Sum of dividend yield (Exhibit No. 11, p. 1) and respective growth rate (Exhibit No. 11, p. 2).

(b) Excludes highlighted figures.

(c) 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 ADJUSTMENT OF ITS ELECTRIC RATES AND FOR CERTIFICATES OF PUBLIC CONVENIENCE AND NECESSITY	)))))	**CASE NO. 2016-00370**

In the Matter of:

APPLICATION OF LOUISVILLE GAS AND ELECTRIC COMPANY FOR AN ADJUSTMENT OF ITS ELECTRIC AND GAS RATES AND FOR CERTIFICATES OF PUBLIC CONVENIENCE AND NECESSITY	))))))	**CASE NO. 2016-00371**

TESTIMONY OF
DAVID S. SINCLAIR
VICE PRESIDENT, ENERGY SUPPLY AND ANALYSIS
LOUISVILLE GAS AND ELECTRIC COMPANY
KENTUCKY UTILITIES COMPANY

Filed: November 23, 2016

Table of Contents

Section 1 – Introduction and Overview

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

A. My name is David S. Sinclair. I am Vice President, Energy Supply and Analysis for 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 LG&E and KU. 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 have testified before the Commission numerous times in a variety of cases, including in the Companies' most recent base-rate cases.[1] I testified most recently in Case No. 2015-00194, *In the Mater of: Investigation of Kentucky Utilities Company's and Louisville Gas and Electric Company's Respective Need for and Cost of Multiphase Landfills at the Trimble County and Ghent Generating Stations*.

Q. Please describe your job responsibilities.

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[1] Case No. 2014-00371, *Application of Kentucky Utilities Company for an Adjustment of Its Electric Rates*; Case No. 2014-00372, *Application of Louisville Gas and Electric Company for an Adjustment of Its Electric and Gas Rates*. Among other cases, I testified before the Commission in the following cases: 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*; 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. 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*.

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 it pertains to this proceeding, the Sales Analysis and Forecasting group prepared the electric and gas load forecasts and the Generation Planning group prepared the generation forecast as well as the analysis of the Curtailable Service Rider. All of this work was done under my direction and overall supervision.

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' gas and electric sales forecasts; (3) explain the Companies' forecast of generation; (4) explain changes from the base period to the forecasted test period for operating revenues, sales for resale, and purchased power; and (5) provide the basis for closing the Companies' Curtailable Service Rider ("CSR") schedule to new customers and to incremental curtailable demand by existing CSR customers.

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' forecasts: (1) Annual Electric Sales & Demand Forecast Process; (2) 2017 Business Plan Electric Sales Forecast; (3) Annual Natural Gas Volume Forecast Process; (4) 2017 Business Plan Gas Volume Forecast; (5) Annual Generation Forecast Process; and (6) 2017 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 created for the most recent business plan that I will be discussing is referred to as the "2017 Load Forecast". 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.[2]

Q. Have the Companies materially changed their approach to electric load forecasting since their 2014 rate cases?

A. No. While each year we try to improve our models, these changes are typically incremental and do not depart from methods that have been utilized for decades. 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

[2] 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.

and cooling components of sales – which recognize expectations with regard to appliance saturation trends, efficiencies, and price or income effects.

The methods used to prepare the 2017 Load Forecast are not materially different from those discussed in Section 7 of the 2014 Integrated Resource Plan ("IRP"), which is the Companies' most recent triennial Kentucky IRP. In the 2014 IRP case, Commission Staff stated, "Staff is generally satisfied with LG&E/KU's load forecasting approach, which is both thorough and well documented. The load forecasting model and its results are reasonable …."[3] Commission Staff also stated:

> Staff is generally satisfied with LG&E/KU's analysis of the many uncertainties it will be facing over the planning period. The improvements to its load forecasting processes are vital to improving the planning necessary to meet customers' load requirements and service expectations in the most cost-effective manner in both the short- and long-term planning horizon. The scope and depth of their reserve margin analysis, as well as the supply-side and demand-side screening analysis, were comprehensive and well developed.[4]

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 as "Major Accounts." This process allows for market intelligence to be directly incorporated into the sales forecast.

Q. What are some examples of how recent developments regarding large customers are reflected in the electric load forecast?

[3] *In the Matter of: 2014 Joint Integrated Resource Plan of Louisville Gas and Electric Company and Kentucky Utilities Company*, Case No. 2014-00131, Commission Staff's Report at 17 (Mar. 1 , 2016).
[4] *Id.* at 59.

A. The forecast reflects both known positive and negative events that have recently impacted large customers in the Companies' service territories. For example, in late 2015, a paper mill in western Kentucky closed which reduced load by approximately 50 MW of peak demand and 360 GWh annually. Similarly, a number of coal mines have closed in the last few years. These customers have been explicitly removed from the forecast.

A positive example of how specific customer actions are reflected in the electric load forecast relates to the automotive industry. A number of the Companies' automotive manufacturing and parts suppliers have been expanding their operations, resulting in increased demand and energy consumption being reflected in the electric load forecast.

Q. Does the Companies' load forecast capture the extent economic activity may vary across the state?

A. Yes. The Companies use economic inputs to specifically capture development appropriate to the parts of the state being served. Factors such as household formation and population growth, which have a strong correlation with the number of customers the Companies serve, can vary significantly within the service territory. Recent trends show continued steady growth in the urban centers of Louisville and Lexington, while the rural areas are either experiencing limited growth or declining sales and customers, primarily driven by recent challenges facing the coal industry.

Q. Does the Companies' load forecast reflect the impact of the Companies' demand side management and energy efficiency ("DSM-EE") programs?

A. Yes. The Companies have a number of DSM-EE programs that reduce the peak demand and energy usage of residential and commercial customers, the most current suite of which the Commission approved in the Companies' 2014 DSM-EE Program Plan proceeding.[5] The Companies' forecasts reflect the forecasted impact of these programs.

Q. In addition to the Companies' DSM programs, does the electric load forecast reflect other changes in end-use energy efficiency?

A. Yes. The Companies incorporate specific end-use assumptions covering base load, heating, and cooling components into residential and small commercial forecasts. These end-use assumptions incorporate the impact of legislation that has reduced energy requirements through increased efficiencies. Lighting accounts for a significant portion of usage for both residential and commercial customers. Current projections of LED lighting adoption show saturation increasing at a much faster rate than previously forecasted. Lighting is 20-30% of small commercial load; therefore, LEDs that average 7.6 watts per bulb as compared to 40 to 60 watts for incandescent alternatives and 15 to 18 watts for a comparable CFL bulb have the ability to significantly impact sales over time. In addition, federal energy-efficiency standards for commercial refrigeration equipment, which take effect in March 2017, contribute to slower sales growth in the 2017 Load Forecast.[6]

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[5] *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).

[6] *See* the U.S. Department of Energy's *Energy Conservation Standards for Commercial Refrigeration Equipment*, available at: http://www.regulations.gov/docket?D=EERE-2010-BT-STD-0003.

Q. Does the electric load forecast reflect the impact of the Companies' newly created programs to expand solar energy and electric vehicle charging?

A. The Commission approved the Companies' proposal to install up to 20 electric vehicle charging stations in their service territories, as well as to provide business customers the opportunity to host charging stations.[7] In addition, the Commission recently approved the Companies' application concerning their subscription-based Solar Share Program proposal.[8] While the 2017 Load Forecast reflects recent trends in solar and electric vehicle adoption, the specific impact of these programs is likely too small and uncertain to warrant an adjustment to the forecast, especially during the forecasted test period. For example, as of June 2016, approximately 700 plug-in electric vehicles have been registered in the Companies' Kentucky service territories. Assuming each car uses about 30 kWh per 100 miles and is driven 10,000 miles annually, then sales would only increase by 3 MWh annually per vehicle. Similarly, the Companies have a relatively small number of net metering customers - a combined total of 364 net metering customers as of August 2016. Assuming the average size of a residential PV system is 3 to 5 kW, then each system would produce approximately 4 to 7 MWh annually. Based on the handful of customers that currently use these technologies, their impact on overall system sales is very small and is likely to remain so in the foreseeable future.

Q. Please explain how weather is reflected in the electric load forecast.

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[7] *In the Matter of: Application of Louisville Gas and Electric Company and Kentucky Utilities Company to Install and Operate Electric Charging Stations in their Certified Territories, for Approval of an Electric Vehicle Supply Equipment Rider, an Electric Vehicle Supply Equipment Rate, an Electric Vehicle Charging Rate, Depreciation Rate, and for a Deviation from the Requirements of Certain Commission Regulations*, Case No. 2015-00355, Order (Apr. 11, 2016).
[8] *In the Matter of: Joint Application of Kentucky Utilities Company and Louisville Gas and Electric Company for Approval of an Optional Solar Share Program Rider*, Case No. 2016-00274, Order (Nov. 4, 2016).

A. Outside air temperature impacts customers' demand for heating and air conditioning in order to maintain a comfortable indoor living environment. Therefore, the forecasting process includes information that reflects historical monthly temperatures. 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 IRP filings.[9] It is also consistent with a standard electric utility industry practice of using the average of historical weather as the basis for determining the "normal" weather when preparing a load forecast. This helps ensure there is an approximately equal chance that actual weather will be warmer or cooler than the "normal" period, thereby avoiding weather bias in the forecast.

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 2017 business plan?

A. The load forecast that was used in preparing the 2017 business plan ("2017 Load Forecast") was completed in the summer of 2016. The electric load forecasts for LG&E and KU that were used in the 2017 business plan are attached at Tab 26 to the Applications.

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[9] *See*, *e.g.*, *In the Matter of: The 2014 Joint Integrated Resource Plan of Louisville Gas and Electric Company and Kentucky Utilities Company*, Case No. 2014-00131, Integrated Resource Plan at 5-19 (Apr. 21, 2014) ("In addition, all forecasts of energy sales/requirements, peak demand, and use per customer assume normal weather – based on the 20-year period (through 2012) average of daily temperatures in each month."); *In the Matter of: The 2011 Joint Integrated Resource Plan of Louisville Gas and Electric Company and Kentucky Utilities Company*, Case No. 2011-00140, Integrated Resource Plan at 6-19 (Apr. 21, 2011) ("For both KU and LG&E, the most recent 20-year average of heating degree days ("HDDs") and cooling degree days ("CDDs") is used to represent the weather conditions that are likely to be experienced on average over the forecast horizon. "Normal" weather in the 2011 IRP forecast is based on the weather in the 20-year period ending in 2009; the weather in the 2008 IRP was based on the weather in the 20-year period ending in 2006.").

<u>Section 3 – LG&E Electric Load Forecast</u>

Q. Please provide an overview of the 2017 Load Forecast for LG&E.

A. As can be seen in Exhibit DSS-1, from the Base Period (March 2016 through February 2017) to the Forecasted Test Period (July 2017 through June 2018), total LG&E calendar-adjusted electric sales increase by 65 GWh (0.5 percent) and total customers increase by an average of 2,125 (0.5 percent). These changes are very consistent with what one would expect given the economic and other assumptions underlying the forecast, namely that, as shown in Exhibit DSS-4, projected growth in Kentucky population is approximately 0.5 percent annually and Real Gross State Product is averaging around 2.3 percent annual growth.

Q. What accounts for the sales growth between the Base Period and the Forecasted Test Period?

A. After taking into account unbilled sales, large industrial customers in the RTS rate class account for 53 GWh of the 65 GWh total sales growth between the Base Period and the Forecasted Test Period. Most RTS customers are billed on the last billing cycle which closely aligns with the calendar month so there is little need to adjust for unbilled sales.

Q. What is driving the changes in the RTS rate class forecasts?

A. Much of the forecasted growth is being driven by specific expansion projects at these customers' facilities. 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. Individually forecasted major accounts are approximately 95% of LG&E RTS sales with two companies driving the majority of the 53 GWh increase. In one case, the sales growth is due to increased production while the other reflects completion and full utilization of a 9 MVA expansion.

Q. What is the impact of the unbilled sales adjustment on other customer classes?

A. Unbilled sales are not determined by rate class but rather by revenue class. The majority of the RS rate class is in the Residential revenue class with the remaining rate classes distributed amongst the Commercial, Industrial, and Other revenue classes. Adding the Residential portion of the unbilled adjustment (140 GWh) to the Base Period energy of the RS rate class decreases the change in energy from the Base Period to the Forecasted Test Period decreases to -19 GWh. Adding the total unbilled adjustment (216 GWh) to the Base Period energy total for all rate classes except RTS, results in sales that are essentially flat for these rate classes between the Base Period and Forecasted Test Period, increasing only 12 GWh.

Q. How are customers and sales changing in the residential and general service classes?

A. Exhibit DSS-1 shows that the majority of LG&E's customer growth is coming from the residential and general service (GS) rate classes. Assuming each new customer is using about the same amount of energy as the average customer, new customers would add about 21 GWh annually to residential sales and 9 GWh annually to GS sales. However, some of this potential growth is being offset by energy efficiency efforts by all customers related to lighting and general appliance replacement. Furthermore, customer growth in both residential RS and GS rate classes has been the strongest in and around the urban centers of Louisville and Lexington. In general, urban customers exhibit lower use per customer than rural regions (often linked to the availability of natural gas heating) which further dampens the forecasted sales growth, therefore residential sales are decreasing by the 19 GWh previously mentioned.

Q. Does weather explain any of the difference between the sales in the Base Period and the Forecasted Test Period?

A. Yes, but not very much. 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 territory 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. March 2016 was much warmer than average based on lower than average HDDs while the summer months of June, July, and August were also warmer with higher than average CDDs. The net result is that weather sensitive load should be slightly higher in the Forecasted Test Period as compared to the Base Period for the months of March through May and somewhat lower in June through August.

Table 1 - Comparison of Actual and 20-year Average Weather for the LG&E Service Area

	Actual	Average	Difference
March (HDD)	362	564	-202
April (HDD)	230	240	-10
May (CDD)	109	134	-25
June (CDD)	376	312	64
July (CDD)	469	409	60
August (CDD)	482	396	86

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, certificates of public convenience and necessity ("CPCNs"), environmental cost recovery ("ECR") filings, and the Companies' 2014 base-rate cases. 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 2017 Load Forecast for KU.

A. As shown in Exhibit DSS-2, from the Base Period (March 2016 through February 2017) to the Forecasted Test Period (July 2017 through June 2018), total KU calendar-adjusted electric sales increase by 129 GWh (0.7 percent) and total customers increase by 2,530 (0.5 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.[10] Modest economic growth in Lexington and the areas around Louisville served by KU is partially offset by the impact of slower growth in the rural areas KU serves, which have been heavily impacted by depressed mining activity. For example, eastern Kentucky coal production declined over 20 million tons (43 percent) between 2012 and 2015 while western Kentucky coal

[10] See Exhibit DSS-4 for detailed assumptions for the Forecasted Test Period.

production declined by roughly 8.5 million tons (21 percent) over the same period.[11] This reduction in coal production has impacted not only sales to coal mines but also reduced the number of residential and commercial customers and sales in these areas.

Q. What accounts for the sales growth between the Base Period and the Forecasted Test Period?

A. Including unbilled sales, large industrial customers in the RTS and TOD-Primary rate classes account for the majority of the 129 GWh sales growth between the Base Period and the Forecasted Test Period. Many of the largest customers on the RTS and TOD-Primary rate classes are billed on the last billing cycle, which closely aligns with the calendar month, so there is little need to adjust for unbilled sales.

Q. What is driving the changes in the large industrial forecasts?

A. Just like with LG&E's larger industrial customers, much of the forecasted growth is being driven by specific expansion projects at KU's larger industrial customer's facilities. For example, one customer is forecasting a 13 MVA expansion in March 2017 and another one is forecasting a 20 percent increase on a production line beginning in late 2016.

Q. What is the impact of the unbilled sales adjustment on other customer classes?

A. Similar to LG&E, the majority of the RS rate class is in the Residential revenue class with remaining rate classes distributed amongst the Commercial, Industrial, and Other revenue classes. Adding the Residential portion of the unbilled adjustment (49 GWh) to the Base Period energy total for the RS rate class decreases energy from the Base Period to the Forecasted Test Period from 64 GWh to 16 GWh. Adding the total

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[11] *See* the Kentucky Energy and Environment Cabinet's *Kentucky Quarterly Coal Report* , available at: http://energy.ky.gov/.

unbilled adjustment (155 GWh) to the Base Period energy total for all rate classes except RTS and TOD-Primary results in sales that are essentially flat for these rate classes between the Base Period and Forecasted Test Period, decreasing 4 GWh.

Q How are customers and sales changing in the residential and general service classes?

A. Exhibit DSS-2 shows that the majority of KU's customer growth is coming from the residential class. Assuming each new customer is using about the same amount of energy as the average customer, new customers would add about 28 GWh annually to residential sales. However, just as with LG&E's residential customers, some of this potential growth is being offset by energy efficiency efforts by all customers related to lighting and general appliance replacement, therefore residential sales are only growing by the 16 GWh previously mentioned.

Q. Does weather explain any of the difference between the sales in the Base Period and the Forecasted Test Period?

A. Yes, but not very much. 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. March 2016 was much warmer than average based on lower than average HDDs, while the summer months of June, July, and August were also warmer with higher than average CDDs. The net result is that weather sensitive load should be slightly higher in the

Forecasted Test Period as compared to the Base Period for the months of March through May and somewhat lower in June through August.

Table 2 - Comparison of Actual and 20-year Average Weather for the KU Service Area

	Actual	Average	Difference
March (HDD)	392	619	-227
April (HDD)	262	289	-27
May (CDD)	86	99	-13
June (CDD)	313	248	65
July (CDD)	417	342	75
August (CDD)	432	332	100

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, ECR filings, and the Companies' 2014 base-rate cases. 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 2017 Load Forecast 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 2016 through February 2017) to the Forecasted Test Period (July 2017 through June 2018), natural gas sales increase by 1,117,082 Mcf (3.7 percent) and total customers increase by 507 (0.2 percent). Comparing the same time periods, volumes for transportation customers decrease by 555,312 Mcf (4.1 percent).

Q. What explains the 3.7% increase in gas sales from the Base Period to the Forecasted Test Period?

A. Extremely mild weather in March 2016 depressed sales in the Base Period. The increase from the Base Period to the Forecasted Test Period is almost entirely explained by low sales in the Base Period that resulted from this mild weather. As shown in Table 3, the total HDDs in March 2016 were almost 40 percent lower than the 30-year normal values used in developing the forecast volumes for the same months in the Forecasted Test Period.[12] This milder weather in March 2016 caused gas sales in the Base Period to be 1,283,462 Mcf lower than March 2018 sales in the Forecasted Test Period. Ninety-seven percent of this variance is from the Residential and Commercial customer classes, which are the most weather-sensitive with usage driven by space heating. Further evidence of the mild nature of March 2016 was that the Weather Normalization Adjustment (WNA) for that month was approximately 577,690 Mcf, or about half of the difference between March 2016 and March 2018.

Table 3 - Comparison of Actual and 30-year Average Weather for the LG&E Service Area

	Actual	**Average**	**Difference**
March (HDD)	334	545	-211
April (HDD)	203	236	-33

[12] 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. Weather variances for May through August are not listed because weather variances in these months have little impact on gas volumes.

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. Major accounts forecasted for natural gas volumes are all on transport service. As shown in Exhibit DSS-3, the "Gas Transport Service, FT Industrial" rate class decreased by 476,453 Mcf (3.9 percent) in the Forecasted Test Period. This reduction is driven by a temporary large increase in gas usage at a Major Account that occurred through the first six months of Base Period that is forecasted to return to normal levels.

Q. Besides the Major Account customers, are there any other aspects of the Forecasted Test Period compared to the Base Period that are of interest?

A. Yes. Exhibit DSS-3 shows no volumes in the Forecasted Test Period for Gas Transport Service to Paddy's Run simple cycle gas turbines. A gas pipeline tie-in with the Cane Run 7 pipeline will remove the Paddy's Run units from the LG&E gas distribution system and will be completed during the Base Period.

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, ECR filings, and in LG&E's 2014 gas base-rate case.

Section 6 – Electric and Gas Forecast Summary

Q. Please summarize your thoughts on the 2017 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 2017 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 2017 Load Forecast a reasonable forecast that can be relied upon in the development of the 2017 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 2017 Load Forecast fully meets the criteria I just discussed and is a reasonable forecast upon which to base the business plan.

<u>Section 7 – Generation Forecast</u>

Q. Please describe how the generation forecast is 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 operations and maintenance, 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 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. Generation volume is forecasted to increase by approximately 0.3 percent in the Forecasted Test Period compared to the Base Period, primarily due to slightly higher load. Unsurprisingly, 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 91 percent of the Companies' native load; the Companies' total native load includes retail customers in Virginia and Tennessee, as well as wholesale sales to eleven cities in Kentucky.[13] But as Exhibit DSS-5 shows, the generation volume from a particular unit can vary greatly from the Base Period to the Forecasted Test Period. The combined Companies' total generation from coal-fired and natural gas combined-cycle units is relatively flat between the two periods, with unit-by-unit differences primarily attributable to the timing and duration of outages. Generation from simple-cycle combustion turbines increases by 6 percent, as these marginal units are increasing output to compensate for differences in actual and forecasted load and unit availability.

Q. In your professional opinion, is the 2017 generation forecast reasonable and can it be relied upon in the development of the 2017 business plan?

A. Yes. The forecast was 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. The

[13] The wholesale contract with the City of Paris, Kentucky will terminate on April 30, 2017. Paris's peak load is approximately 14 MW and the annual energy is approximately 63,000 MWh. Service to the remaining ten cities will terminate on April 30, 2019.

processes and software were also reviewed in the Companies' 2014 base-rate cases. Using sound models and assumptions will produce reasonable forecasts.

<u>Section 8 – Schedule D-1 Support</u>

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. Off-System Sales ("OSS") revenues recorded to account 447 have been removed with a pro forma adjustment. Purchased Power contains intercompany purchased power expense, market economy purchased power expense, Ohio Valley Electric Corporation purchase power expense, and (for LG&E) non-fuel expenses associated with the Bluegrass tolling agreement. OSS-related purchased power expenses recorded to account 555 have been removed with a pro forma adjustment. 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 increase by $12.7 million, from $30.3 million to $43 million; KU's Sales for Resale are expected to decrease by $1.7 million, from $10.1 million to $8.4 million. The primary driver of LG&E's $12.7 million increase is the increase in intercompany sales from LG&E to KU during the planned turbine overhauls of Brown Unit 2 (owned by KU) and Trimble County Unit 2 (60.8 percent owned by KU).

Compared to the Base Period, LG&E's Purchased Power in the Forecasted Test Period is expected to be higher by $273,000; KU's Purchased Power is expected to be higher by $11 million. KU's change is explained almost entirely by the increase in intercompany purchased power expense associated with the aforementioned planned turbine overhauls of Brown Unit 2 and Trimble County Unit 2.

<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 provides a credit against a customer's demand charge in exchange for the customer agreeing to reduce its demand in accordance with its agreement with the serving utility when the serving utility requests such curtailment. The CSR allows the Companies to physically curtail service for up to 100 hours per year when "(1) all available units have been dispatched or are being dispatched and (2) all off-system sales have been or are being curtailed." By being able to request curtailment under CSR, the Companies are able to avoid incurring costs to procure peaking generating capacity that otherwise would be required to serve the curtailable demand. As such, the Companies model curtailable demand under CSR as a peaking capacity resource in their business plans and IRP.

Q. How many CSR customers are there, who are they, how long have they been a CSR customer, and how much load can potentially be curtailed?

A. LG&E has two CSR customers and KU has nine CSR customers in the Forecasted Test Period. Table 6 shows the contract capacity and reducible amounts by company.

Table 6 – CSR Customers

Utility	Company	CSR Date	Units	Contract Capacity	Reducible To
LG&E	Company 1	Jul-14	kVA	46,000	4,500
LG&E	Company 2	Jul-10	kVA	30,000	6,000
KU	Company 3	Jul-10	kVA	195,000	2,000
KU	Company 4	May-14	kVA	9,000	3,500
KU	Company 5	Jan-13	kVA	7,000	3,000
KU	Company 6	Jan-14	kVA	10,722	4,000
KU	Company 7	Jun-14	kVA	12,000	6,500
KU	Company 8	Jul-16	kVA	31,600	9,000
KU	Company 9	Jul-16	kVA	9,950	2,250
KU	Company 10	Jul-16	kVA	12,750	3,500
KU	Company 11	Jul-16	kVA	15,450	10,500

Note: Table lists CSR customers included in the development of the generation forecast. After the generation forecast was completed, a third CSR customer was added for LG&E with a contract capacity of 14,000 kVA reducible to 9,000 kVA.

Q. Since the current CSR went into effect in July 2015, how many times have CSR customers been asked to physically curtail load and how long did each curtailment last?

A. The Companies have not called any curtailments from CSR customers, with or without a buy-through option, since July 2015. The last CSR curtailment occurred on January 30, 2014 and lasted 0.5 hours for three CSR customers. The key condition for calling CSR curtailments, namely all available units have been dispatched, is not a typical event. Since July 1, 2015, the Companies' secondary CTs have operated during 9 events (excluding unit testing), which averaged 3 hours long and ranged between 1 and 7 hours long.[14] System conditions at these times did not require the need to call a physical CSR curtailment.

Q. How many times are the Companies forecasting to call a physical curtailable event in the Forecasted Test Period?

A. The Companies' Annual Generation Forecast I just discussed would indicate the need to call eight CSR curtailment events in the Forecasted Test Period, with three events in July 2017, one event in August 2017, and four events in March 2018. Whether these events occur will be subject to actual load and system conditions.

Q. What changes are the Companies proposing to the CSR?

A. The Companies are not proposing any structural or operational changes to the CSR, but they are proposing to close the rider to any new customers or increases in the volume of load that can be curtailed by an existing CSR customer. The Companies are also proposing to reduce the CSR credit to reflect the costs of the Companies' primary CTs and to change the gas price index used to determine the buy-through electricity price.[15]

Q. Why are the Companies proposing to close the CSR schedule to new customers?

A. As the Companies discussed in their most recent IRP, the optimal reserve margin (i.e., capacity in excess of peak load) that balances reliability benefits with the cost of

[14] The Companies' secondary CTs are Cane Run Unit 11, Haefling Units 1 and 2, Paddy's Run Units 11 and 12, and Zorn.
[15] The Companies' primary CTs are Brown Units 5-11, Paddy's Run Unit 13, and Trimble County Units 5-10.

providing that reliability is between 16 percent and 21 percent.[16] Based on the Companies' existing generation resources, DSM programs, and CSR volumes, the Companies do not need additional capacity in order to maintain an adequate reserve margin to meet peak demand in the Forecasted Test Period.

Q. Why are the Companies proposing to base the CSR credit on the costs of the Companies' primary combustion turbines ("CTs")?

A. A customer's base rates include the cost of all of the Companies' generation fleet that is used to reliably serve their needs every hour of the year. A customer that agrees to make part of its load curtailable is, in effect, agreeing to not utilize a portion of that generation fleet for up to 100 hours a year. As I previously mentioned, the circumstances when the Companies are allowed to call a physical CSR curtailment will likely be at peak times when the primary CTs would be expected to operate. Thus, the CSR customer would not be getting to utilize energy from the primary CTs during peak events, so it is reasonable to base the credit on the cost of the capacity CSR customers are agreeing not to use.

Q. Is basing the CSR credit on the actual cost of the primary CTs a change from the past?

A. Yes. In the past, when the Companies were experiencing meaningful annual load growth, the CSR credit was based on the cost of avoiding new capacity. However, as I have previously discussed, a combination of greater energy efficiency and the loss of major customers has resulted in no need for incremental capacity through the end

[16] Case No. 2014-00131, *The 2014 Integrated Resource Plan of Louisville Gas and Electric Company and Kentucky Utilities Company*. See "2014 Reserve Margin Study," LG&E/KU 2014 IRP, Volume III, March 2014.

of the Forecasted Test Period. Therefore, it makes economic sense to base the credit on the cost of the portion of the Companies' generation fleet (the primary CTs) that CSR customers will be unable to utilize during peaking conditions.

Q. Do the Companies propose any other change to Rider CSR?

A. Yes. The Companies propose to change the natural gas price index ("NGP" in the Rider CSR) used to determine the Automatic Buy-Through Price. The Automatic Buy-Through Price applies to the energy provided to CSR participants should they elect not to curtail load during any of the up to 275 hours each year the Companies may request curtailment with a buy-through option.

Q. What NGP do the Companies recommend using and why is this change appropriate?

A. The Companies recommend using the daily spot price at Henry Hub as published in The Wall Street Journal to replace the current Dominion South Point. The Dominion South Point is located in southwestern Pennsylvania and was selected prior to the tremendous expansion of natural gas resources in the Marcellus shale region. The large volume of gas now being produced in that area, combined with limited pipeline capacity to get the gas to where the demand is located, has resulted in pricing at the Dominion South Point that has grown increasingly discounted from the prices paid by the Companies to get gas for our generating units. The Companies are recommending changing the NGP to the Henry Hub spot price because that point is highly liquid and prices are consistent with those paid by the Companies' for our own natural gas supply.

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 18th day of November 2016.

Judy Schooler (SEAL)

Notary Public

My Commission Expires:
JUDY SCHOOLER
Notary Public, State at Large, KY
My commission expires July 11, 2018
Notary ID # 512743

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 (4^{th} 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

Comparison of LG&E Electric Customers, Billing Demand, and Energy: Base Period vs. Forecasted Test Period

Comparison of LG&E Electric Customers, Billing Demand, and Energy by Rate Classes: Base Period vs Test Period

Rate	Category	Values		Period	Base Period: Billed Actual (Mar '16 - Aug '16)*	Base Period: Calendar Forecasted (Sep '16 - Feb '17)	Base Period: Total (Mar '16 - Feb '17)	Forecasted Test Period (Jul '17 - Jun '18)	Delta	% Delta
PS-Pri	Customers	Avg Number of Customers			73	75	74	72	(2)	-2.6%
	Demand	Sum of Volume	MW	Base	199	191	390	399	9	2.4%
	Energy	Sum of Volume	GWh		76	78	154	165	12	7.6%
PS-Sec	Customers	Avg Number of Customers			2,851	2,842	2,847	2,824	(22)	-0.8%
	Demand	Sum of Volume	MW	Base	2,557	2,518	5,075	4,961	(114)	-2.3%
	Energy	Sum of Volume	GWh		962	907	1,868	1,874	6	0.3%
TOD-Pri	Customers	Avg Number of Customers			107	104	106	106	(0)	-0.2%
	Demand	Sum of Volume	MVA	Base	2,219	2,165	4,385	4,359	(26)	-0.6%
	Demand	Sum of Volume	MVA	Intermediate	2,114	2,051	4,165	4,143	(22)	-0.5%
	Demand	Sum of Volume	MVA	Peak	2,069	2,016	4,085	4,078	(7)	-0.2%
	Energy	Sum of Volume	GWh		938	873	1,811	1,849	38	2.1%
TOD-Sec	Customers	Avg Number of Customers			371	370	371	370	(1)	-0.2%
	Demand	Sum of Volume	MW	Base	1,342	1,297	2,640	2,592	(48)	-1.8%
	Demand	Sum of Volume	MW	Intermediate	1,217	1,160	2,377	2,345	(32)	-1.4%
	Demand	Sum of Volume	MW	Peak	1,187	1,134	2,321	2,290	(31)	-1.3%
	Energy	Sum of Volume	GWh		556	510	1,065	1,075	10	0.9%
Special Contract #1	Customers	Avg Number of Customers			1	1	1	1	-	0.0%
	Demand	Sum of Volume	MW	Base	102	94	196	185	(10)	-5.3%
	Energy	Sum of Volume	GWh		63	56	120	110	(10)	-8.2%
GS	Customers	Avg Number of Customers			44,840	45,043	44,941	45,237	296	0.7%
	Energy	Sum of Volume	GWh		678	631	1,309	1,358	49	3.7%
Special Contract #2	Customers	Avg Number of Customers			2	1	2	1	(1)	-33.3%
	Demand	Sum of Volume	MW	Base	56	57	113	114	1	0.9%
	Energy	Sum of Volume	GWh		27	30	57	58	1	2.2%
RS	Customers	Avg Number of Customers			362,426	362,085	362,256	364,109	1,853	0.5%
	Energy	Sum of Volume	GWh		2,146	1,913	4,059	4,180	121	3.0%
RTS	Customers	Avg Number of Customers			13	13	13	13	-	0.0%
	Demand	Sum of Volume	MVA	Base	1,162	1,159	2,321	2,424	102	4.4%
	Demand	Sum of Volume	MVA	Intermediate	1,109	1,087	2,195	2,289	93	4.2%
	Demand	Sum of Volume	MVA	Peak	1,080	1,056	2,136	2,201	65	3.1%
	Energy	Sum of Volume	GWh		570	525	1,095	1,148	53	4.8%
Lighting	Customers	Avg Number of Customers			1,066	1,070	1,068	1,070	2	0.2%
	Energy	Sum of Volume	GWh		48	58	106	108	2	2.1%
LG&E Unbilled Adjustment**										
Residential	Energy	Sum of Volume	GWh		140		140		(140)	-100.0%
Other	Energy	Sum of Volume	GWh		76		76		(76)	-100.0%
Total LG&E Unbilled	Energy	Sum of Volume	GWh		216		216		(216)	-100.0%

Total LG&E Energy - Calendar Adjusted	Energy	Sum of Volume	GWh		6,280	5,581	11,861	11,926	65	0.5%
Total LGE Customers	Customers	Avg Number of Customers			411,752	411,604	411,678	413,803	2,125	0.5%

*All customers are assigned to one of twenty billing cycles. Because the beginning and end of most billing cycles do not coincide directly with the beginning and end of calendar months, most customers' monthly bills include energy that was consumed in more than one calendar month.

**Billed sales in March include a portion of the energy consumed in March and a portion of the energy consumed in February. Likewise, billed sales for August include a portion of the energy consumed in August and a portion of the energy consumed in July. The portion of the energy consumed in August but not included in August billed sales is the "unbilled" portion of calendar-month ("calendar") sales for August. To properly compare the Base Period to the Forecasted Test Period (which includes twelve months of calendar sales), unbilled sales for August must be added to the Base Period and unbilled sales for February (which are included in March billed sales) must be subtracted from the Base Period. Because August unbilled sales are greater than February unbilled sales, the total unbilled sales adjustment is positive.

Exhibit DSS-2

**Comparison of KU Electric Customers, Billing Demand, and Energy:
Base Period vs. Forecasted Test Period**

Comparison of KU Electric Customers, Billing Demand, and Energy by Rate Classes: Base Period vs Test Period

Rate	Category	Values		Period	Base Period: Billed Actual (Mar '16 - Aug '16)*	Base Period: Calendar Forecasted (Sep '16 - Feb '17)	Base Period: Total (Mar '16 - Feb '17)	Forecasted Test Period (Jul '17 - Jun '18)	Delta	% Delta
AES	Customers	Avg Number of Customers			580	602	591	593	2	0.4%
	Energy	Sum of Volume	GWh		64	79	143	152	9	6.3%
FLS	Customers	Avg Number of Customers			1	1	1	1	-	0.0%
	Demand	Sum of Volume	MVA	Base	1,157	1,146	2,303	2,292	(12)	-0.5%
	Demand	Sum of Volume	MVA	Intermediate	1,157	1,146	2,303	2,292	(12)	-0.5%
	Demand	Sum of Volume	MVA	Peak	829	813	1,642	1,625	(17)	-1.0%
	Energy	Sum of Volume			294	271	565	553	(12)	-2.2%
GS	Customers	Avg Number of Customers			82,492	82,942	82,717	83,329	612	0.7%
	Energy	Sum of Volume	GWh		885	900	1,785	1,805	20	1.1%
PS-Pri	Customers	Avg Number of Customers			210	192	201	173	(29)	-14.2%
	Demand	Sum of Volume	MW	Base	224	233	457	487	29	6.4%
	Energy	Sum of Volume	GWh		75	82	157	170	13	8.2%
PS-Sec	Customers	Avg Number of Customers			4,642	4,625	4,633	4,503	(131)	-2.8%
	Demand	Sum of Volume	MW	Base	2,968	3,272	6,240	6,098	(142)	-2.3%
	Energy	Sum of Volume	GWh		1,010	1,083	2,093	2,147	54	2.6%
RS	Customers	Avg Number of Customers			428,557	428,721	428,639	430,654	2,015	0.5%
	Energy	Sum of Volume	GWh		2,797	3,229	6,026	6,092	66	1.1%
RTS	Customers	Avg Number of Customers			29	30	30	30	0	1.4%
	Demand	Sum of Volume	MVA	Base	1,611	1,601	3,211	3,346	135	4.2%
	Demand	Sum of Volume	MVA	Intermediate	1,565	1,597	3,163	3,292	130	4.1%
	Demand	Sum of Volume	MVA	Peak	1,536	1,563	3,098	3,234	136	4.4%
	Energy	Sum of Volume	GWh		725	708	1,433	1,498	64	4.5%
TOD-Pri	Customers	Avg Number of Customers			248	264	256	277	21	8.1%
	Demand	Sum of Volume	MVA	Base	4,886	4,819	9,705	9,458	(247)	-2.5%
	Demand	Sum of Volume	MVA	Intermediate	4,504	4,463	8,966	9,098	132	1.5%
	Demand	Sum of Volume	MVA	Peak	4,419	4,400	8,819	8,970	150	1.7%
	Energy	Sum of Volume			2,072	1,977	4,049	4,118	69	1.7%
TOD-Sec	Customers	Avg Number of Customers			619	608	614	618	4	0.7%
	Demand	Sum of Volume	MW	Base	2,186	2,193	4,379	4,421	42	1.0%
	Demand	Sum of Volume	MW	Intermediate	1,973	1,992	3,965	4,013	48	1.2%
	Demand	Sum of Volume	MW	Peak	1,927	1,945	3,872	3,909	37	0.9%
	Energy	Sum of Volume	GWh		859	812	1,671	1,671	0	0.0%
Lighting	Customers	Avg Number of Customers			718	774	746	780	34	4.6%
	Energy	Sum of Volume	GWh		54	69	123	126	2	1.8%
KU Unbilled Adjustment**										
Residential	Energy	Sum of Volume	GWh		49		49		(49)	-100.0%
Other	Energy	Sum of Volume	GWh		106		106		(106)	-100.0%
Total KU Unbilled	Energy	Sum of Volume	GWh		155		155		(155)	-100.0%
Total KU Energy - Calendar Adjusted	Energy	Sum of Volume	GWh		8,991	9,210	18,201	18,330	129	0.7%
Total KU Customers	Customers	Avg Number of Customers			518,096	518,758	518,427	520,957	2,530	0.5%

*All customers are assigned to one of twenty billing cycles. Because the beginning and end of most billing cycles do not coincide directly with the beginning and end of calendar months, most customers' monthly bills include energy that was consumed in more than one calendar month.

**Billed sales in March include a portion of the energy consumed in March and a portion of the energy consumed in February. Likewise, billed sales for August include a portion of the energy consumed in August and a portion of the energy consumed in July. The portion of the energy consumed in August but not included in August billed sales is the "unbilled" portion of calendar-month ("calendar") sales for August. To properly compare the Base Period to the Forecasted Test Period (which includes twelve months of calendar sales), unbilled sales for August must be added to the Base Period and unbilled sales for February (which are included in March billed sales) must be subtracted from the Base Period. Because August unbilled sales are greater than February unbilled sales, the total unbilled sales adjustment is positive.

Exhibit DSS-3

Comparison of LG&E Gas Customers and Volume:
Base Period vs. Forecasted Test Period

Comparison of LG&E Gas Customers, and Volumes by Rate Classes: Base Period vs Test Period

				Base Period					
Rate	Category	Volume Type	Values	Billed Actual (Mar '16 - Aug '16)*	Calendar Forecasted (Sep '16 - Feb '17)	Total (Mar '16 - Feb '17)	Test Period (Jul '17 - Jun '18)	Delta	% Delta
As-Available Gas Service, Commercial	Gas Volumes	Sales	Volume (Mcf)	21,862	37,971	59,833	57,567	(2,266)	-3.8%
	Customers	Sales	Average Number of Customers	2	2	2	2	-	0.0%
As-Available Gas Service, Industrial	Gas Volumes	Sales	Volume (Mcf)	32,343	40,694	73,037	70,866	(2,171)	-3.0%
	Customers	Sales	Average Number of Customers	2	2	2	2	-	0.0%
Firm Commercial Gas Service	Gas Volumes	Sales	Volume (Mcf)	3,285,509	7,088,200	10,373,709	10,137,906	(235,803)	-2.3%
	Customers	Sales	Average Number of Customers	25,002	25,081	25,041	24,947	(94)	-0.4%
Firm Industrial Gas Service	Gas Volumes	Sales	Volume (Mcf)	496,936	901,622	1,398,558	1,488,806	90,248	6.5%
	Customers	Sales	Average Number of Customers	240	256	248	262	14	5.7%
Gas Special Contracts - LG&E Generation	Gas Volumes	Generation	Volume (Mcf)	159,193	71,837	231,030	154,580	(76,450)	-33.1%
	Customers	Generation	Average Number of Customers	1	1	1	1	-	0.0%
Gas Transport Service, FT Commercial	Gas Volumes	Transport	Volume (Mcf)	291,291	441,481	732,772	688,457	(44,315)	-6.0%
	Customers	Transport	Average Number of Customers	10	10	10	10	-	0.0%
Gas Transport Service, FT Industrial	Gas Volumes	Transport	Volume (Mcf)	4,861,779	7,240,105	12,101,885	11,625,431	(476,453)	-3.9%
	Customers	Transport	Average Number of Customers	69	63	66	63	(3)	-4.4%
Gas Transport Service, Paddy's Run	Gas Volumes	Generation	Volume (Mcf)	777,906	58,775	836,681	-	(836,681)	-100.0%
	Customers	Generation	Average Number of Customers	1	0	1	-	(1)	-100.0%
Residential Gas Service	Gas Volumes	Sales	Volume (Mcf)	5,807,308	14,414,085	20,221,393	19,516,322	(705,071)	-3.5%
	Customers	Sales	Average Number of Customers	295,994	295,584	295,789	296,376	588	0.2%
TS-2: Gas Trans/Firm Balancing (AAGS In)	Gas Volumes	Transport	Volume (Mcf)	110,110	154,784	264,894	255,683	(9,211)	-3.5%
	Customers	Transport	Average Number of Customers	2	2	2	2	-	0.0%
TS-2: Gas Transport/Firm Balancing (IGS)	Gas Volumes	Transport	Volume (Mcf)	259,229	226,031	485,260	459,927	(25,333)	-5.2%
	Customers	Transport	Average Number of Customers	7	5	6	5	(1)	-16.7%
LG&E Gas Unbilled Adjustment**									
Residential	Gas Volumes	Sales	Volume (Mcf)	(1,353,218)		(1,353,218)		1,353,218	-100.0%
Other	Gas Volumes	Sales	Volume (Mcf)	(618,927)		(618,927)		618,927	-100.0%
Total LGE Gas Unbilled	Gas Volumes	Sales	Volume (Mcf)	(1,972,145)		(1,972,145)		1,972,145	-100.0%

Total Volumes - Calendar Adjusted	Gas Volumes	Total	Volume (Mcf)	14,131,323	30,675,584	44,806,907	44,455,546	(351,361)	-0.8%
Total Customers	Customers	Total	Average Number of Customers	321,330	321,005	321,167	321,670	503	0.2%
Total Sales Volumes - Calendar Adjusted	Gas Volumes	Sales	Volume (Mcf)	7,671,814	22,482,571	30,154,385	31,271,467	1,117,082	3.7%
Total Customers	Customers	Sales	Average Number of Customers	321,240	320,924	321,082	321,589	507	0.2%
Total Transport Volumes	Gas Volumes	Transport	Volume (Mcf)	5,522,410	8,062,401	13,584,811	13,029,499	(555,312)	-4.1%
Total Customers	Customers	Transport	Average Number of Customers	88	80	84	80	(4)	-4.7%
Total Generation Volumes	Gas Volumes	Generation	Volume (Mcf)	937,099	130,612	1,067,711	154,580	(913,131)	-85.5%
Total Customers	Customers	Generation	Average Number of Customers	2	1	2	1	(1)	-36.8%

*All customers are assigned to one of twenty billing cycles. Because the beginning and end of most billing cycles do not coincide directly with the beginning and end of calendar months, most customers' monthly bills include energy that was consumed in more than one calendar month.

**Billed sales in March include a portion of the energy consumed in March and a portion of the energy consumed in February. Likewise, billed sales for August include a portion of the energy consumed in August and a portion of the energy consumed in July. The portion of the energy consumed in August but not included in August billed sales is the "unbilled" portion of calendar-month ("calendar") sales for August. To properly compare the Base Period to the Forecasted Test Period (which includes twelve months of calendar sales), unbilled sales for August must be added to the Base Period and unbilled sales for February (which are included in March billed sales) must be subtracted from the Base Period. Because August unbilled sales are greater than February unbilled sales, the total unbilled energy adjustment is positive.

Exhibit DSS-4

Economic Inputs to Electric and Gas Forecasts

	US Real Gross Domestic Product Billions of Chained 2009 Dollars, SAAR	KY Real Gross State Product (GSP) Millions of 2009 US$, SAAR	KY Employment, Retail Trade (NAICS 44-45) Thousand	KY Employment, Wholesale Trade (NAICS 42) Thousand	KY Industrial Production Index, Total (2012=100)
2005 Q1	14,099.10	157,942.00	212.67	74.40	99.60
2005 Q2	14,172.70	160,267.00	212.13	74.43	100.43
2005 Q3	14,291.80	161,134.00	212.40	74.70	99.67
2005 Q4	14,373.40	161,532.00	211.80	74.60	101.54
2006 Q1	14,546.10	163,825.00	212.77	75.20	102.52
2006 Q2	14,589.60	165,223.00	212.03	76.10	102.72
2006 Q3	14,602.60	164,643.00	210.60	76.07	102.82
2006 Q4	14,716.90	163,571.00	211.80	76.57	102.55
2007 Q1	14,726.00	161,705.00	214.03	77.13	103.92
2007 Q2	14,838.70	162,368.00	214.27	77.27	105.55
2007 Q3	14,938.50	162,241.00	213.00	77.00	105.02
2007 Q4	14,991.80	163,938.00	212.97	76.63	104.72
2008 Q1	14,889.50	163,536.00	212.93	76.93	104.87
2008 Q2	14,963.40	164,931.00	211.63	76.57	103.66
2008 Q3	14,891.60	162,233.00	210.50	76.20	99.53
2008 Q4	14,577.00	158,753.00	207.47	75.50	95.24
2009 Q1	14,375.00	155,212.00	203.27	73.50	89.17
2009 Q2	14,355.60	154,044.00	202.07	72.40	87.04
2009 Q3	14,402.50	155,776.00	201.30	71.73	88.29
2009 Q4	14,541.90	158,612.00	200.40	71.80	89.43
2010 Q1	14,604.80	158,742.00	200.10	71.67	90.72
2010 Q2	14,745.90	162,935.00	200.40	71.60	93.13
2010 Q3	14,845.50	165,048.00	200.60	71.80	94.72
2010 Q4	14,939.00	165,178.00	201.13	71.77	95.17
2011 Q1	14,881.30	163,856.00	201.03	71.77	94.86
2011 Q2	14,989.60	165,010.00	201.03	71.70	94.80
2011 Q3	15,021.10	166,122.00	201.00	72.47	96.24
2011 Q4	15,190.30	169,015.00	201.70	72.33	97.49
2012 Q1	15,291.00	168,247.00	202.43	72.40	98.46
2012 Q2	15,362.40	168,595.00	203.00	72.67	99.43
2012 Q3	15,380.80	167,028.00	202.70	72.83	101.01
2012 Q4	15,384.30	164,602.00	202.70	73.17	101.11
2013 Q1	15,457.20	169,007.00	202.60	73.70	101.39
2013 Q2	15,500.20	167,919.00	202.67	73.80	101.78
2013 Q3	15,614.40	168,935.00	203.47	73.90	102.57
2013 Q4	15,761.50	169,397.00	204.33	73.87	102.89
2014 Q1	15,724.90	168,349.00	203.93	74.13	103.53
2014 Q2	15,901.50	170,641.00	204.90	74.27	105.31
2014 Q3	16,068.80	171,624.00	205.43	73.97	107.33
2014 Q4	16,151.40	173,049.00	206.90	74.13	107.36
2015 Q1	16,177.30	172,289.00	208.70	74.13	106.86
2015 Q2	16,333.60	173,876.00	209.50	74.53	106.09
2015 Q3	16,414.00	174,859.00	210.17	74.73	107.73
2015 Q4	16,442.30	175,435.90	211.57	75.33	107.58
2016 Q1	16,538.06	176,048.12	216.78	75.40	106.79
2016 Q2	16,659.65	176,867.34	217.97	75.48	107.04
2016 Q3	16,789.69	177,875.57	218.90	75.58	107.05
2016 Q4	16,921.55	179,063.75	219.61	75.78	107.40
2017 Q1	17,024.95	180,031.02	219.54	75.93	108.30
2017 Q2	17,152.78	181,405.41	219.34	76.07	109.14
2017 Q3	17,263.47	182,488.57	219.21	76.22	109.91
2017 Q4	17,357.47	183,642.64	218.62	76.36	110.59
2018 Q1	17,485.49	184,993.75	217.90	76.51	111.44
2018 Q2	17,596.68	185,998.02	217.12	76.65	112.11
2018 Q3	17,705.85	187,021.95	216.41	76.80	112.61
2018 Q4	17,798.87	187,795.14	215.73	76.98	113.01
2019 Q1	17,912.66	188,927.47	215.28	77.16	113.55
2019 Q2	18,019.05	189,969.85	214.85	77.34	114.13
2019 Q3	18,129.53	191,110.53	214.72	77.52	114.76
2019 Q4	18,234.79	192,178.52	214.47	77.70	115.39
2020 Q1	18,352.44	192,981.70	214.31	77.88	116.26
2020 Q2	18,464.27	194,009.68	214.09	78.06	116.87
2020 Q3	18,562.61	194,901.88	213.99	78.24	117.40
2020 Q4	18,660.43	195,756.88	213.86	78.42	117.98
2021 Q1	18,761.41	196,721.82	213.54	78.60	118.56
2021 Q2	18,861.04	197,674.35	213.38	78.72	119.21
2021 Q3	18,965.22	198,675.92	213.14	78.83	119.84
2021 Q4	19,073.42	199,616.67	212.97	78.95	120.37

	KY Industrial Production Index, Fabricated Metal Products (2012=100)	KY Real Personal Income Millions of 2009 US$, SAAR	KY Population Thousand	KY Households, Total Thousand	KY Household Average Size Persons
2005 Q1	103.03	148,132.64	4,173.58	1,654.71	2.52
2005 Q2	103.97	149,441.58	4,182.74	1,657.96	2.52
2005 Q3	105.45	149,717.42	4,191.87	1,657.65	2.53
2005 Q4	107.58	150,012.47	4,200.99	1,657.35	2.53
2006 Q1	110.40	153,107.28	4,210.11	1,657.04	2.54
2006 Q2	110.66	153,489.58	4,219.24	1,656.74	2.55
2006 Q3	110.37	153,461.60	4,228.60	1,657.90	2.55
2006 Q4	111.38	155,082.73	4,237.96	1,659.06	2.55
2007 Q1	112.55	156,160.14	4,247.31	1,660.22	2.56
2007 Q2	114.20	156,695.72	4,256.67	1,661.38	2.56
2007 Q3	117.35	156,667.90	4,264.97	1,669.17	2.56
2007 Q4	117.48	157,056.64	4,273.28	1,677.01	2.55
2008 Q1	117.95	158,299.03	4,281.58	1,684.88	2.54
2008 Q2	115.16	162,982.92	4,289.88	1,692.78	2.53
2008 Q3	109.67	157,495.55	4,296.68	1,694.96	2.53
2008 Q4	102.26	158,718.92	4,303.48	1,697.15	2.54
2009 Q1	88.53	157,113.28	4,310.28	1,699.33	2.54
2009 Q2	80.90	158,247.60	4,317.07	1,701.52	2.54
2009 Q3	80.39	157,115.53	4,324.50	1,707.50	2.53
2009 Q4	81.38	157,530.77	4,331.92	1,713.64	2.53
2010 Q1	83.42	157,127.83	4,339.35	1,719.97	2.52
2010 Q2	87.34	159,446.58	4,347.94	1,722.13	2.52
2010 Q3	91.12	160,698.83	4,352.92	1,719.08	2.53
2010 Q4	93.13	160,944.66	4,357.91	1,716.02	2.54
2011 Q1	93.83	163,434.45	4,362.90	1,712.97	2.55
2011 Q2	95.50	163,405.73	4,367.88	1,709.92	2.55
2011 Q3	97.14	164,495.30	4,371.58	1,718.64	2.54
2011 Q4	97.83	164,931.31	4,375.27	1,727.36	2.53
2012 Q1	98.14	166,226.86	4,378.97	1,736.07	2.52
2012 Q2	99.66	167,114.90	4,382.67	1,744.79	2.51
2012 Q3	101.37	166,287.72	4,386.63	1,744.44	2.51
2012 Q4	100.80	168,400.08	4,390.58	1,744.09	2.52
2013 Q1	102.74	165,644.40	4,394.54	1,743.74	2.52
2013 Q2	101.53	165,624.06	4,398.50	1,743.39	2.52
2013 Q3	101.96	165,914.40	4,402.03	1,745.01	2.52
2013 Q4	104.21	165,594.05	4,405.56	1,746.63	2.52
2014 Q1	105.75	168,332.80	4,409.09	1,748.24	2.52
2014 Q2	107.09	169,515.77	4,412.62	1,749.86	2.52
2014 Q3	108.02	170,369.92	4,415.74	1,750.59	2.52
2014 Q4	107.45	172,966.75	4,418.85	1,751.60	2.52
2015 Q1	106.79	175,454.48	4,421.97	1,752.90	2.52
2015 Q2	106.73	176,892.22	4,425.09	1,753.97	2.52
2015 Q3	108.31	177,857.23	4,428.61	1,756.43	2.52
2015 Q4	107.64	179,817.36	4,432.55	1,759.62	2.52
2016 Q1	107.26	180,752.14	4,436.65	1,762.42	2.52
2016 Q2	107.32	181,797.73	4,440.91	1,765.82	2.51
2016 Q3	107.33	182,509.01	4,445.35	1,768.65	2.51
2016 Q4	107.89	183,261.10	4,449.99	1,771.34	2.51
2017 Q1	108.26	185,073.65	4,454.76	1,774.80	2.51
2017 Q2	108.64	186,315.66	4,459.65	1,778.03	2.51
2017 Q3	109.19	187,127.91	4,464.68	1,781.38	2.51
2017 Q4	109.90	188,300.36	4,469.86	1,785.00	2.50
2018 Q1	110.77	189,920.96	4,475.08	1,789.04	2.50
2018 Q2	111.66	190,802.83	4,480.35	1,793.17	2.50
2018 Q3	112.51	191,734.74	4,485.67	1,797.38	2.50
2018 Q4	113.29	192,728.28	4,491.04	1,801.63	2.49
2019 Q1	114.02	194,388.95	4,496.44	1,805.90	2.49
2019 Q2	114.65	195,443.21	4,501.90	1,810.51	2.49
2019 Q3	115.24	196,417.05	4,507.39	1,815.27	2.48
2019 Q4	115.85	197,386.00	4,512.94	1,820.11	2.48
2020 Q1	116.52	199,173.18	4,518.49	1,824.90	2.48
2020 Q2	117.09	200,286.40	4,524.05	1,829.66	2.47
2020 Q3	117.57	201,311.10	4,529.62	1,834.42	2.47
2020 Q4	118.08	202,080.37	4,535.18	1,838.99	2.47
2021 Q1	118.62	203,677.39	4,540.72	1,843.47	2.46
2021 Q2	119.13	204,629.72	4,546.24	1,847.85	2.46
2021 Q3	119.61	205,559.62	4,551.75	1,852.14	2.46
2021 Q4	120.02	206,561.35	4,557.24	1,856.47	2.45

Exhibit DSS-5

Comparison of Generation Volume by Unit,
Base Period vs. Forecasted Test Period

Generation Differences by Unit, Base Period vs. Forecasted Test Period, KU[1]

GWh	**Base Period**	**Forecasted Test Period**	**Difference**	**% Difference**
Coal				
Brown 1	219	134	(85)	-39%
Brown 2	436	337	(99)	-23%
Brown 3	997	837	(160)	-16%
Ghent 1	3,275	2,984	(291)	-9%
Ghent 2	3,102	2,927	(175)	-6%
Ghent 3	2,756	2,893	137	5%
Ghent 4	3,124	2,929	(195)	-6%
Mill Creek 1	N/A	N/A		
Mill Creek 2	N/A	N/A		
Mill Creek 3	N/A	N/A		
Mill Creek 4	N/A	N/A		
OVEC	247	201	(46)	-18%
Trimble County 1	N/A	N/A		
Trimble County 2	2,217	2,728	511	23%
SCCT				
Bluegrass/EKPC[2]	N/A	N/A		
Brown 5	29	18	(11)	-37%
Brown 6	12	44	32	255%
Brown 7	12	58	46	385%
Brown 8	77	18	(59)	-77%
Brown 9	98	12	(86)	-88%
Brown 10	97	10	(88)	-90%
Brown 11	61	13	(48)	-79%
Cane Run 11	N/A	N/A		
Haefling	0	0	(0)	0%
Paddy’s Run 11	N/A	N/A		
Paddy’s Run 12	N/A	N/A		
Paddy’s Run 13	69	91	22	31%
Trimble County 05	222	293	70	32%
Trimble County 06	153	242	89	58%
Trimble County 07	157	136	(21)	-13%
Trimble County 08	34	46	12	36%
Trimble County 09	109	130	22	20%
Trimble County 10	46	30	(16)	-35%
Zorn 1	N/A	N/A		
NGCC				
Cane Run 7	3,856	3,808	(49)	-1%
Hydro				
Dix Dam	81	76	(5)	-6%
Ohio Falls	N/A	N/A		
Solar				
Brown Solar	10	12	2	23%
Total Coal	16,373	15,970	(404)	-2%
Total SCCT	1,178	1,140	(38)	-3%
Total NGCC	3,856	3,808	(49)	-1%
Total Hydro	81	76	(5)	-6%
Total Solar	10	12	2	23%
Grand Total	21,498	21,005	(493)	-2%

[1] Generation volumes reflect KU’s ownership share of the unit. “N/A” is shown for units with no KU ownership share.
[2] Capacity Purchase and Tolling Agreement with Bluegrass Generation/EKPC

Generation Differences by Unit, Base Period vs. Forecasted Test Period, LG&E[3]

GWh	Base Period	Forecasted Test Period	Difference	% Difference
Coal				
Brown 1	N/A	N/A		
Brown 2	N/A	N/A		
Brown 3	N/A	N/A		
Ghent 1	N/A	N/A		
Ghent 2	N/A	N/A		
Ghent 3	N/A	N/A		
Ghent 4	N/A	N/A		
Mill Creek 1	1,781	1,893	112	6%
Mill Creek 2	1,615	1,578	(37)	-2%
Mill Creek 3	1,902	2,296	394	21%
Mill Creek 4	2,714	3,206	491	18%
OVEC	558	470	(87)	-16%
Trimble County 1	2,585	2,064	(521)	-20%
Trimble County 2	520	640	120	23%
SCCT				
Bluegrass/EKPC[4]	33	56	22	67%
Brown 5	33	20	(12)	-37%
Brown 6	8	27	19	255%
Brown 7	7	35	28	385%
Brown 8	N/A	N/A		
Brown 9	N/A	N/A		
Brown 10	N/A	N/A		
Brown 11	N/A	N/A		
Cane Run 11	0	0	(0)	0%
Haefling	N/A	N/A		
Paddy's Run 11	0	0	0	0%
Paddy's Run 12	0	0	0	0%
Paddy's Run 13	78	102	24	31%
Trimble County 05	91	119	29	32%
Trimble County 06	63	99	36	58%
Trimble County 07	92	80	(12)	-13%
Trimble County 08	20	27	7	36%
Trimble County 09	64	77	13	20%
Trimble County 10	27	18	(10)	-35%
Zorn 1	0	0	0	0%
NGCC				
Cane Run 7	1,088	1,074	(14)	-1%
Hydro				
Dix Dam	N/A	N/A		
Ohio Falls	288	284	(5)	-2%
Solar				
Brown Solar	6	8	2	23%
Total Coal	11,675	12,147	471	4%
Total SCCT	516	661	145	28%
Total NGCC	1,088	1,074	(14)	-1%
Total Hydro	288	284	(5)	-2%
Total Solar	6	8	1	23%
Grand Total	13,573	14,173	600	4%

[3] Generation volumes reflect LG&E's ownership share of the unit. "N/A" is shown for units with no LG&E ownership share.
[4] Capacity Purchase and Tolling Agreement with Bluegrass Generation/EKPC

Generation Differences by Unit, Base Period vs. Forecasted Test Period, Combined Company[5]

GWh	**Base Period**	**Forecasted Test Period**	**Difference**	**% Difference**
Coal				
Brown 1	219	134	(85)	-39%
Brown 2	436	337	(99)	-23%
Brown 3	997	837	(160)	-16%
Ghent 1	3,275	2,984	(291)	-9%
Ghent 2	3,102	2,927	(175)	-6%
Ghent 3	2,756	2,893	137	5%
Ghent 4	3,124	2,929	(195)	-6%
Mill Creek 1	1,781	1,893	112	6%
Mill Creek 2	1,615	1,578	(37)	-2%
Mill Creek 3	1,902	2,296	394	21%
Mill Creek 4	2,714	3,206	491	18%
OVEC	805	672	(133)	-17%
Trimble County 1	2,585	2,064	(521)	-20%
Trimble County 2	2,737	3,368	630	23%
SCCT				
Bluegrass/EKPC[6]	33	56	22	67%
Brown 5	62	39	(23)	-37%
Brown 6	20	71	51	255%
Brown 7	19	93	74	385%
Brown 8	77	18	(59)	-77%
Brown 9	98	12	(86)	-88%
Brown 10	97	10	(88)	-90%
Brown 11	61	13	(48)	-79%
Cane Run 11	0	0	(0)	0%
Haefling	0	0	(0)	0%
Paddy’s Run 11	0	0	0	0%
Paddy’s Run 12	0	0	0	0%
Paddy’s Run 13	147	193	46	31%
Trimble County 05	313	412	99	32%
Trimble County 06	216	341	125	58%
Trimble County 07	249	217	(33)	-13%
Trimble County 08	54	73	20	36%
Trimble County 09	173	207	34	20%
Trimble County 10	73	48	(26)	-35%
Zorn 1	0	0	(0)	0%
NGCC				
Cane Run 7	4,944	4,882	(62)	-1%
Hydro				
Dix Dam	81	76	(5)	-6%
Ohio Falls	288	284	(5)	-2%
Solar				
Brown Solar	16	20	4	23%
Total Coal	28,048	28,116	68	0%
Total SCCT	1,693	1,801	108	6%
Total NGCC	4,944	4,882	(62)	-1%
Total Hydro	369	360	(10)	-3%
Total Solar	16	20	4	23%
Grand Total	35,071	35,178	107	0%

[5] Generation volumes reflect the Companies’ ownership share of the unit.
[6] Capacity Purchase and Tolling Agreement with Bluegrass Generation/EKPC