COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

ELECTRONIC APPLICATION OF KENTUCKY UTILITIES COMPANY FOR AN ADJUSTMENT OF ITS ELECTRIC RATES	)))	**CASE NO. 2018-00294**

In the Matter of:

ELECTRONIC APPLICATION OF LOUISVILLE GAS AND ELECTRIC COMPANY FOR AN ADJUSTMENT OF ITS ELECTRIC AND GAS RATES	))))	**CASE NO. 2018-00295**

TESTIMONY OF
PAUL W. THOMPSON
PRESIDENT, CHAIRMAN AND CHIEF EXECUTIVE OFFICER
KENTUCKY UTILITIES COMPANY AND
LOUISVILLE GAS AND ELECTRIC COMPANY

Filed: September 28, 2018

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

A. My name is Paul W. Thompson. I am Chairman, Chief Executive Officer and President 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 the Companies. My business address is 220 West Main Street, Louisville, Kentucky 40202.

Q. Please describe your educational and professional background.

A. I earned 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. In 1991, I joined the Companies as the Director, Business Development. Since then I have held a number of positions at KU and LG&E, including Senior Vice President, Energy Services from 2000 to 2012. I served as Chief Operating Officer from 2012 until March 2018 when I received my current position. I began serving as the President in an interim role in January 2017. A complete statement of my work experience and education is contained in Appendix A.

Q. Have you previously testified before this Commission?

A. Yes. I have testified in numerous proceedings before the Commission. Most recently, I testified in KU's and LG&E's 2016 base rate cases.[1]

[1] *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, Application Testimony (Ky. PSC Nov. 23, 2016); *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, Application Testimony (Ky. PSC Nov. 23, 2016).

Q. Please describe how the common ownership of KU and LG&E by LG&E and KU Energy LLC impacts the Companies' operations.

A. KU and LG&E are regulated utilities that collectively serve nearly 1.3 million customers and are consistently ranked among the best companies for customer service in the United States. KU serves approximately 553,000 customers in 77 Kentucky counties and five counties in Virginia; LG&E serves approximately 326,000 natural gas and 411,000 electric customers in Louisville and 16 surrounding counties. Prior to 1997, KU and LG&E were stand-alone utilities and each operated independently. However, in 1997, the Commission approved the merger of the two utilities, which have since been owned by our Kentucky-based parent company now known as LG&E and KU Energy LLC.[2] Almost 20 years of common ownership has allowed KU and LG&E to streamline and fully integrate their operations, and jointly plan all aspects of their business, including safety, electric generation, transmission, distribution, customer service, information technology, and all service functions. Joint operations, planning, and performance have resulted in continuous cost-efficiencies that could not otherwise be achieved by the respective Companies on their own. Indeed, in approving the change in control resulting from the merger of the Companies, this Commission recognized that "integrated system planning may be the single most important benefit of the merger."[3]

Q. Have there been any noteworthy changes in management since the Companies' last rate cases?

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[2] *In the Matter of: Joint Application of Louisville Gas and Electric Company and Kentucky Utilities for Approval of Merger*, Case No. 97-300, Order (Ky. PSC Sept. 12, 1997).
[3] *Id*. at 21.

A. Yes. On March 8, 2018, Mr. Staffieri retired as Chairman and Chief Executive Officer. I was named his successor. My direct reports now include Kent W. Blake (Chief Financial Officer), Lonnie E. Bellar (Chief Operating Officer), Gregory J. Meiman (Vice President, Human Resources), John R. Crocket, III (General Counsel, Chief Compliance Officer and Corporate Secretary), and Chris Whelan (Vice President, Communications and Corporate Responsibility). Mr. Bellar addresses additional management changes related to the operation of the businesses in his testimony.

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 KU's and LG&E's Applications and our decision to file these applications. I will also highlight our Companies' outstanding performance before discussing our efforts with respect to efficiency and productivity, economic development, and sustainability. Finally, I will close with a discussion of KU's and LG&E's ongoing commitment to the communities we serve, including our assistance to low-income customers.

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

- Kent W. Blake, Chief Financial Officer. Mr. Blake will describe why KU and LG&E require the requested increases in base rates, and will discuss efforts in the financial and administrative areas of our Companies to achieve improvements in efficiency and productivity.
- Lonnie E. Bellar, Chief Operating Officer. Mr. Bellar will report on the Companies' operations and provide operational context to support the Companies' applications for an increase in base rates. He describes the Companies' performance in each operational area and how we are striving to meet future challenges and the expectations of customers for safe, reliable, and reasonably priced gas and electric service. He also presents how and why the Companies are making strategic capital investments in operations and leveraging smart, effective use of technology to manage costs and achieve operational efficiencies and productivity.
- David S. Sinclair, Vice President, Energy Supply and Analysis. Mr. Sinclair will describe the Companies' gas and electric sales forecasts including the impact of the wholesale municipal contract termination; explain the Companies' forecast of generation and future resource mix; and explain changes from the base period to the forecasted test period for operating revenues, sales for resale, and purchased power. Mr. Sinclair further notes that the Companies will be filing a joint Integrated Resource Plan ("IRP") and reserve margin study with the Commission no later than November 1, 2018.

The IRP will address the changes in the Companies' supply resources and load.

- Gregory J. Meiman, Vice President, Human Resources. Mr. Meiman will discuss the Companies' analysis of salary and benefits.
- 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 filing requirement schedules.
- Adrien McKenzie, FINCAP, Inc. Mr. McKenzie presents his analysis of a reasonable return on equity, which demonstrates that a range of 9.92 percent to 10.92 percent is reasonable and provides his recommendation that 10.42 percent is a reasonable return on equity for the Companies.
- Christopher M. Garrett, Controller. Mr. Garrett will present the revenue requirement analysis for the electric operations of KU and LG&E and LG&E's gas operations.
- John J. Spanos, Senior Vice President, Gannett Fleming Valuation and Rate Consultants, LLC will present his studies supporting the proposed changes in depreciation rates.
- 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. Mr. Conroy will present and explain the proposed changes to the tariff terms and conditions for service. He will also address the issue of assistance to low income customers.

- William Steven Seelye, Managing Partner, The Prime Group, LLC. Mr. Seelye will discuss and present his cost of service studies, rate designs and other analyses for KU and LG&E.

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. 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. And, as discussed in the testimony of Mr. Bellar and Mr. Blake, the Companies must continue to invest capital to meet all of their obligations in the most reasonable cost effective manner possible. As described in detail in Mr. Sinclair's testimony, we continue to see only nominal customer growth and a small but steady decline in electric sales. As a result, for the reasons presented in Mr. Blake's testimony, 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 KU and LG&E 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. KU is requesting approximately a $112 million a year increase in its electric revenue. LG&E is requesting approximately a $35 million a year increase in its electric revenue, and approximately a $25 million a year increase in its gas revenue. The testimony of our witnesses submitted with the Companies' applications demonstrate that KU's and LG&E'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. What is your view on the current state of the Companies' business and its relationships with customers?

A. I believe we have a strong business that has and will continue to take the right actions for our customers. Since 2016, both KU and LG&E have been named top ranking utilities in the Midwest/Midsize segment among electric and gas utilities for business and residential customer satisfaction. Just a few months ago, KU was again recognized by J.D. Power, the global market research company, as a leader in customer satisfaction among mid-sized Midwest electric utilities. That being said, there are opportunities for the Companies to evolve and adapt by continually recognizing and evaluating changes in our industry, technology and customer expectations.

Q. What are your views on the Companies' operational performance?

A. The Companies are performing well and have continued to build on their history of operational excellence in an increasingly complex environment. The objective metrics discussed in detail in Mr. Bellar's testimony demonstrate that the Companies are performing safely and reliably in all operational areas of the business.

The storms beginning on July 20, 2018, caused approximately 174,000 customers to lose service due to severe tree and structure damage caused by near-hurricane-force wind gusts of 70 mph, numerous lightning strikes, and heavy downpours. In terms of number of customers affected, this was the fifth worst storm outage event in the Companies' recorded history. I am especially proud of the hardworking men and women who endured adverse conditions and worked around the clock to restore power in the aftermath of the storm. The Companies' response as described in detail in Mr. Bellar's testimony was outstanding.

Also providing noteworthy benefits during the storm outage were the 350 electronic reclosers on circuits the Companies installed, which the Commission reviewed and approved in our last rate cases. The reclosers avoided 3,019 customer interruptions and prevented 4,831,448 customer minutes of service from being lost during this outage. In other words, the performance of the electronic reclosers during the July 2018 storms amounts to beneficial impacts of 0.017 on the System Average Interruption Frequency Index ("SAIFI") and 6.4 on the System Average Interruption Duration Index ("SAIDI").

I am also very proud of our excellent results from the recent on-site audit by SERC Reliability Corporation for compliance with Critical Infrastructure Protection and Operations and Planning mandatory reliability standards. The audits were performed from February 28, 2018, through June 4, 2018. The results demonstrate a commitment to excellence in cybersecurity at a time when nation-state actors and state-sponsored hackers threaten the country's electrical system through cyberattacks. Mr. Bellar discusses these results in detail in his testimony.

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

A. We continuously strive to operate our business in the most efficient and productive manner 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 and produce results. As discussed in the testimony of Mr. Blake, the results of the most current benchmarking study demonstrate that the Companies remain a top quartile performer with respect to O&M per megawatt hour sold. Furthermore, when looking at 2017 in isolation, the Companies ranked 6th among 41 vertically-integrated utility holding companies.

The testimony of Messrs. Blake, Meiman, and Bellar provide an extensive description of many of the Companies' existing programs and practices to achieve efficiency and productivity. This focus on efficiency, along with our focus on safety and wellness, reliability, and customer service and satisfaction, are core principles of our business culture that we continue to reinforce with our employees and contractors.

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

A. Yes. Our Companies are long-standing supporters of and leaders in economic development in Kentucky. The Companies were recognized in September 2017 as a top 10 utility for support of economic growth by *Site Selection* magazine. In 2017, the Companies' economic development rider provided more than $1.2 million in support through bill credits to assist with customer expansions. Overall, our Economic Development team was honored for helping bring to fruition 155 announcements of new or expanding businesses within the Companies' service territories during 2017, resulting in nearly 7,500 jobs and over $4 billion in investments.

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

A. Yes. The Companies' efforts are part of PPL Corporation's company-wide commitment to advancing a cleaner energy future. In November 2017, PPL Corporation released its "Climate Assessment" report, detailing its plan to deliver, consistent with approved regulatory frameworks, industry-leading service and reliability while also investing in a sustainable energy future that is economically justifiable to this Commission.

The Commission is aware of the actions we have taken in recent years to construct additional environmental controls at our coal-fired generation plants, retire older coal-fired generation such as E.W. Brown Generating Station Units 1 and 2, and put into service the first combined-cycle gas plant and largest utility-scale solar facility in the state of Kentucky. Currently, the Companies are eliminating the use of ash ponds and other storage impoundments and transitioning to dry storage facilities.

The E.W. Brown, Ghent, and Mill Creek Generating Stations currently operate using dry storage, and a new dry storage facility is under construction at the Trimble County Generating Station. These actions ensure compliance with expanded environmental regulations, allowing us to continue to provide safe, reliable energy for our customers in the most economical manner possible, as we have for over one hundred years.

The Companies also continue to expand their renewable energy portfolio. In 2017, LG&E completed the project to increase by nearly 27 percent its generation capacity at the Ohio Falls Generating Station, which has been in operation since the 1920s. KU also completed a comparable renovation project for the three Dix Dam Generating Units at the Brown Station that increased their total generation capacity by approximately 27 percent. In addition, the Companies are expanding their solar offerings, achieving full enrollment of the first 500-kilowatt increment for the Companies' voluntary Solar Share Program. And in May 2018, the Companies secured their first Business Solar customer, with LG&E and the Archdiocese of Louisville partnering to operate the first diocesan-based solar array in the greater Kentucky region. The Green Tariff filing and modifications to our Solar Share program in these proceedings represents a continuation of these efforts.

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

A. Our commitment to the communities we serve is another critical component of the culture we have developed over many decades. The LG&E and KU Foundation reflects that commitment by supporting Kentucky nonprofits that focus on education, the environment, diversity, or health and safety. Since its establishment in 1994, the Foundation has awarded more than $27 million dollars to support such endeavors across the Commonwealth. Our community contributions from the Foundation and directly from the Companies have exceeded $5 million in each of the past four years. All of these contributions are funded solely by our shareholders. This commitment was recognized in 2017 by the *Business First* newspaper when it presented us with another "Partners in Philanthropy Award" for being an outstanding corporate citizen. This was the sixth year in a row we have been recognized by *Business First* as one of the area's top socially responsible organizations.

Our employees have also demonstrated a strong commitment to donating their time and money to worthy causes. For example, since 2005, the Companies' voluntary employee-giving campaign, Power of One, has raised more than $20 million to support hundreds of nonprofit organizations. And in 2017, the Power of One campaign surpassed $2 million, the highest amount in the 13 years of the program's history. Nearly 70 percent of employees participate in this effort, which is twice the national average for employee participation in charitable giving.

In addition to these donations, the Companies' employees donate their valuable time in community support efforts. For the last fourteen years, the Companies have sponsored a "Day of Caring" during which employees collectively volunteer at locations across the service territories. In addition, the Companies' officers and upper level managers currently serve on more than eighty-five community boards in the Companies' service territories.

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. The Companies are aware of their low-income customers' needs through direct contact with such customers and through the Companies' relationships with a number of organizations engaged in community-assistance programs and efforts, including the Community Action Council for Lexington-Fayette, Bourbon, Harrison, and Nicholas Counties, Inc. ("CAC") and the Association of Community Ministries ("ACM"). The Companies meet and communicate with these groups on a regular basis to understand low-income customers' needs, how community organizations are working to meet those needs, and how the Companies can help. In doing so, the Companies have used the experience and knowledge gained from these interactions as they have worked on their own and in conjunction with community groups to provide various forms of assistance to low-income customers over the years.

For example, we helped found and have been involved with Project Warm (www.projectwarm.org) since its inception in 1982 and have provided over $2 million to support the project. Project Warm is a nonprofit that serves elderly, disabled, and economically challenged citizens in Louisville. Each year, volunteers for the Winter Blitz in the KU service area and Project Warm in the LG&E service area weatherize hundreds of homes of our low-income customers before the heating season. KU and LG&E provide the weatherization supplies for the effort, and our employees support this initiative by volunteering their time and through their donations.

Another example is the Companies' Low-Income Weatherization Program ("WeCare"), an education and weatherization program designed to reduce the energy consumption of low-income customers.[4]

As explained more fully in the testimony of Mr. Conroy, the Companies currently make $1.45 million in shareholder contributions to low-income assistance programs ($570,000 per year for KU and $880,000 per year for LG&E). 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. Typically, the Companies match customer contributions, dollar for dollar, as a way to help customers in need. But in early 2018, the Companies doubled their annual support, matching $2 for every $1 donated by residential customers through April 30, 2018. Over the last ten years, customer donations and matching funds from the Companies have raised nearly $10.7 million to help customers who need it most with their utility bills.

As discussed in detail in Mr. Conroy's testimony, the Companies also provide a wide array of assistance to their fixed- and low-income customers starting before a customer uses energy until after the Companies issue a bill. One example is, as more

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

fully described by Mr. Conroy, the Companies' 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. Over 30,000 KU and LG&E 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. In closing, the Companies continue their focus on the delivery of reliable energy services to our customers. We are engaged with our customers and the communities in which we serve across our service territories. Our Companies are leaders in economic development in Kentucky to encourage growth and the availability of reasonably-priced energy. To continue to serve our customers with reliable energy services requires the funding described in our rate applications. For these reasons and the evidence presented in our applications, the Commission should authorize the requested increase in revenues.

Q. Does this conclude your testimony?

A. Yes, it does.

VERIFICATION

COMMONWEALTH OF KENTUCKY)
)
COUNTY OF JEFFERSON)

The undersigned, **Paul W. Thompson**, being duly sworn, deposes and says that he is Chairman Chief Executive Officer and President 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.

Paul W. Thompson

Paul W. Thompson

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 19th day of September 2018.

Judy Schooler

Notary Public

My Commission Expires:

Judy Schooler
Notary Public, ID No. 603967
State at Large, Kentucky
Commission Expires 7/11/2022

APPENDIX A

Paul W. Thompson
President, Chairman and Chief Executive Officer
Louisville Gas and Electric Company
Kentucky Utilities Company
220 West Main Street
Louisville, KY 40202
(502) 627-3324

Education

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

Professional Experience

LG&E and KU Energy LLC
- 2017-2018 President and Chief Operating Officer
- 2012-2017 Chief Operating Officer
- 2000-2012 Senior Vice President, Energy Services

LG&E Energy Marketing, Louisville, KY
- 1998–1999 – Group Vice President

Louisville Gas and Electric Company, Louisville, KY
- 1996–1999 – Vice President, Retail Electric Business

LG&E Energy Corp., Louisville, KY
- 1994–1996 (Sept.) – Vice President, Business Development
- 1994–1994 (July) – Louisville Gas & Electric Company, Louisville, KY
  General Manager, Gas Operations
- 1991–1993 – Director, Business Development

Koch Industries Inc.
- 1990–1991 Koch Membrane Systems, Boston, MA
  National Sales Manager, Americas
- 1989–1990 John Zink Company, Tulsa, OK
  Vice President, International

Lone Star Technologies (a former Northwest Industries subsidiary)
- 1988–1989 John Zink Company, Tulsa, OK
  Vice Chairman
- 1986–1988 Hydro-Sonic Systems, Dallas, TX
  General Manager
- 1986–1986 (July) Ft. Collins Pipe, Dallas, TX
  General Manager
- 1985–1986 Lone Star Technologies, Dallas, TX
  Assistant to Chairman
- 1980–1985 Northwest Industries, Chicago, IL
  Manager, Financial Planning

Professional Memberships

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

Kentucky Chamber of Commerce, Chair-Elect 2019
Fund for the Arts Board
    2017 Campaign Chair
Greater Louisville Inc. Board (2005-2016)
Trees Louisville (2016-2018)
Louisville Downtown Development Corporation Board (2006-2017)
Louisville Free Public Library Foundation Board (1997-2018)
    Advocacy Committee Chairman (2012-2018)
    Chairman of the Board (2006–2012)
    Chair, Annual Appeal (2002–2003)
    Co-Chair, Annual Children's Reading Appeal (1999–2001)
Jefferson County Public Education Foundation Board (2008–2013)
University of Kentucky College of Engineering, Project Lead The Way, Council Member (2007–2012)
March of Dimes, Honorary Chair (1997–1998)
Habitat for Humanity, Representing LG&E as co-sponsor
Friends of the Waterfront Board (1998–2002)
Leadership Louisville (1997–1998)

COMMONWEALTH OF KENTUCKY

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

Filed: September 28, 2018

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I. BACKGROUND

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

A. My name is Kent 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 KU and LG&E. My business address is 220 West Main Street, Louisville, Kentucky 40202. In my role, I have oversight responsibility for treasury, financial planning and analysis, accounting and reporting, tax and payroll, 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 in numerous proceedings before the Commission. Most recently, I testified in the case addressing the effects of the Tax Cuts and Jobs Act ("TCJA") on the Companies' rates,[1] the case involving PPL Corporation's corporate reorganization,[2] and in KU's and LG&E's 2016 base rate cases.[3]

Q. What are the purposes of your testimony?

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[1] *In the Matter of: Kentucky Industrial Utility Customers, Inc. v. Kentucky Utilities Company and Louisville Gas and Electric Company*, Case No. 2018-00034, Direct Testimony of Kent W. Blake (Ky. PSC Jan. 29, 2018), Direct Testimony on Rehearing of Kent W. Blake (Ky. PSC Apr. 6, 2018).

[2] *In the Matter of: Joint Application of PPL Corporation, PPL Subsidiary Holdings, LLC, PPL Energy Holdings, LLC, LG&E and KU Energy LLC, Louisville Gas and Electric Company and Kentucky Utilities Company for Approval of an Indirect Change of Control of Louisville Gas and Electric Company and Kentucky Utilities Company*, Case No. 2017-00415, Direct Testimony of Kent W. Blake (Ky. PSC Mar. 13, 2018).

[3] *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.

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. Lonnie Bellar and Mr. Greg Meiman will also address efficiency and productivity efforts in their respective areas); and (3) to sponsor a schedule required by 807 KAR 5:001 Section 16 filed with this application.

Q. Please provide an overview of KU's and LG&E's base rate applications in these proceedings.

A. KU's application requests Commission approval of rates to reflect an increase in the cost-based revenue requirement of $112 million. LG&E's application requests Commission approval of rates to reflect an increase in the cost-based revenue requirements of $35 million for its electric operations and $25 million for its gas operations. These revenue requirement calculations are based on a twelve-month forecasted test period beginning May 1, 2019, and ending April 30, 2020.

II. RATE CASE DRIVERS

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

A. Consistent with most of the Companies' rate cases, this case is driven by investments associated with providing safe, reliable service to customers. The thirteen-month average combined capitalization of KU and LG&E for the forecasted test period ended April 30, 2020, is more than $900 million greater than the thirteen-month average capitalization for the forecasted test period ended June 30, 2018, from the Companies' last rate case filing. In addition, KU and LG&E have both experienced an increase in their costs of capital. Both utilities also project increases in depreciation and property tax expenses resulting from additional Plant in Service and the depreciation rates discussed in the testimonies of Mr. Chris Garrett and Mr. John Spanos. These factors account for a combined increase in the Companies' revenue requirements attributable to investment of $197 million (KU: $107 million, LG&E Electric: $72 million, and LG&E Gas: $18 million).

Q. Does the impact of investments on the Companies' revenue requirements include the implementation of Advanced Metering Systems ("AMS"), which was the subject of Case No. 2018-00005?

A. No. Upon receipt of the Commission's Order dated August 30, 2018, in Case No. 2018-00005, the Companies removed from their calculations the forecasted capital, expenses and operational savings associated with the project.

Q. Can you please explain why the increase in the Companies' revenue requirements attributable to investments actually exceeds the Companies' request in these proceedings?

A. Certainly. Other factors that have increased the Companies' revenue requirements since their last rate cases are more than offset by the positive effects of state and federal tax reform, with the latter being in the form of the TCJA.

Q. Will you please describe the TCJA?

A. Yes. The TCJA reduces the maximum federal corporate income tax rate from 35% to 21% effective January 1, 2018 and also includes other changes which impact the Companies' revenue requirements, including the elimination of bonus depreciation and the corporate alternative minimum tax ("AMT") provision, and the repeal of various other deductions including the Section 199 domestic manufacturing deduction. The TCJA retained the corporate deduction for state income taxes and the interest deductibility for utilities, and provided modifications for how companies can still utilize net operating losses and existing AMT credit carryforwards.

Q. Has the TCJA impacted the Companies' capitalization?

A. Yes. Prior to the TCJA, both KU and LG&E had a tax net operating loss carryforward and thus were not cash taxpayers due to years of a provision previously in the tax code known as "bonus depreciation." With the TCJA, however, both KU and LG&E will be cash taxpayers for the foreseeable future. As noted in Case No. 2018-00034, the resulting increases in cash taxes paid, coupled with the amounts being returned to customers through the TCJA Surcredit and other rate mechanisms, represent an additional cash outlay resulting from the TCJA that did not exist before.[4] The cost of this incremental capitalization partially offsets the benefits from the reduction in tax rates and amortization of excess accumulated deferred income taxes resulting from the TCJA. The increase in the Companies' jurisdictional adjusted capitalization caused by the TCJA is $192 million (KU: $101 million, LG&E Electric Operations: $75 million, and LG&E Gas Operations: $16 million).

Going forward from May 1, 2019, with the change in base rates, the effects of the TCJA, as well as state tax reform, will be fully reflected in the Companies' base rates. As a result, and as further explained in the testimony of Mr. Robert Conroy and consistent with the terms of the Commission-approved *Offer and Acceptance of*

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[4] *In the Matter of: Kentucky Industrial Utility Customers, Inc. v. Kentucky Utilities Company, and Louisville Gas and Electric Company*, Case No. 2018-00034, Direct Testimony on Rehearing of Kent W. Blake at 8 (Ky. PSC Apr. 6, 2018).

Satisfaction, the Companies are requesting the termination of the TCJA Surcredit when base rates are reset effective with service rendered on May 1, 2019.

Q. Please discuss the other factors contributing to the increase in the Companies' capitalization.

A. Capitalization changes reflect the difference between cash provided by operations and cash used in investing. KU and LG&E have and will both continue to experience capital expenditures in excess of cash flow from operations through the forecasted period. This includes the $192 million discussed above associated with the TCJA, as well as the Companies' January 2018 contribution to their pension fund noted in Case No. 2018-00034, which increased the Companies' adjusted jurisdictional capitalization by $77 million (KU: $34 million, LG&E Electric Operations: $36 million, and LG&E Gas Operations: $7 million).[5]

Q. Please discuss the capital expenditures since the Companies' last base rate cases.

A. First, it is important to note that a forecasted test period rate case is based on thirteen-month average capitalization for the forecasted test period rather than end of test period capitalization. That means that there will be some capital expenditures in this forecasted test period that are not being recovered in rates just like there were capital expenditures in the Companies' last forecasted test period rate case that are not currently embedded in rates. This complicates the consideration of which time period to use when determining which capital expenditures are contributing to an increase in

[5] *In the Matter of: Kentucky Industrial Utility Customers, Inc. v. Kentucky Utilities Company, and Louisville Gas and Electric Company*, Case No. 2018-00034, Response to AG's Initial Data Requests for Information, Item 1 (Ky. PSC Apr. 20, 2018), Response to KIUC's Post-Hearing Data Requests, Item 2 (Ky. PSC June 11, 2018).

average capitalization between rate cases. As capitalization is generally increasing over the forecasted test period, it is reasonable to utilize capital expenditures from the middle of the previous forecasted test period to the middle of the current forecasted test period. That period would be from January 1, 2018, to October 31, 2019. As detailed in the tables below, for the period January 1, 2018, to October 31, 2019, the Companies had capital expenditures of over $2.2 billion (KU: $1.1 billion, LG&E: $1.1 billion). Of that amount, over $1.5 billion (KU: $0.8 billion, LG&E: $0.7 billion) were projects not subject to recovery through other mechanisms but rather only through base rate cases.

Total capital spend Jan 1, 2018 - Oct 31, 2019

$ millions	**KU**	**LG&E**	**Total**
Generation	$590	$437	$1,027
Electric Transmission	224	63	287
Electric Distribution	252	230	482
Gas Operations	-	236	236
Customer Service	32	35	67
Other	52	49	101
Total	**$1,150**	**$1,050**	**$2,200**

Total capital spend not subject to recovery through mechanisms Jan 1, 2018 - Oct 31, 2019

$ millions	**KU**	**LG&E**	**Total**
Generation	$254	$208	$462
Electric Transmission	224	63	287
Electric Distribution	252	230	482
Gas Operations	-	120	120
Customer Service	31	35	66
Other	52	49	101
Total	**$813**	**$705**	**$1,518**

The "Other" category above consists principally of capital spend on information technology. This would include both hardware and software additions, upgrades and replacements.

Q. Please discuss the increase in the Companies' cost of capital.

A. Market interest rates have increased significantly since the Companies' last base rate cases. These market movements have impacted interest rates on the Companies' debt issuances since their last rate cases as well as all variable rate debt instruments. As detailed on the schedule filed to comply with 807 KAR 5:001 Section 16(8)(j) shown at Tab 63, KU's weighted average cost of long-term debt and short-term debt are now 4.38% and 3.23%, respectively, as compared to 4.12% and 0.74% in KU's last rate case. LG&E's weighted average cost of long-term debt and short-term debt are now 4.53% and 3.25%, respectively, as compared to 4.12% and 0.72% in LG&E's last rate case. Likewise, as supported by the testimonies of Mr. Arbough and Mr. Adrien McKenzie, the Companies are requesting a return on equity investment of 10.42% compared to the 9.70% authorized in the Companies' last rate cases.

Q. Can you detail and discuss the impact of depreciation expense on the Companies' revenue requirement?

A. Yes. Depreciation expense for the forecasted test period in these proceedings is higher than that of the forecasted test period in the Companies' last rate cases by $74 million (KU: $44 million, LG&E Electric Operations: $28 million, and LG&E Gas Operations: $2 million). Of this amount, $51 million (KU: $34 million, LG&E Electric Operations: $17 million) is a result of the proposed depreciation rate changes supported by the depreciation study discussed in the testimonies of Mr. Garrett and Mr. Spanos. These depreciation rate changes are focused on the Companies' steam plant.

Q. Why is it appropriate for the Companies to seek a change in depreciation rates in this proceeding?

A. Depreciation expense is simply the recovery of the capital investments made by the Companies. If one uses a discount rate equal to the Companies' authorized weighted average cost of capital, any change in depreciation rates produces a present value economic equivalent cost for customers. However, it is important that depreciation rates be set at a level that minimizes inter-generational inequities. In other words, the customers who benefit from the energy produced by the Companies' power plants should pay for the cost of those plants as opposed to leaving that cost to be borne by future generations. Given the Companies' experience with retirements of power plants and the fact that most of the Companies' coal-fired generation is expected to be economically retired by 2050,[6] the Companies commissioned Mr. Spanos to perform a depreciation study to ensure depreciation rates are set at a level that minimizes inter-generational inequities and provides for the full recovery of the cost of these power plants.

Q. Is KU's requested rate increase partially driven by the departure of nine Kentucky municipals that will cease taking supply service from KU under a full requirements contract?

A. It is true that the termination of those supply contracts by certain Kentucky municipals resulted in a larger share of KU's fixed costs of operation being allocated to its remaining customers, including its Kentucky retail customers. During KU's last rate case, approximately $47 million of KU's total revenue requirement was attributed to these terminated municipal contracts. However, it is important to

[6] PPL Corporation, *PPL Corporation Climate Assessment*, Potential LG&E and KU Generation Mix (Figure 18) at p. 14, https://www.pplweb.com/wp-content/uploads/2017/12/Climate-Assessment-Report.pdf (November 2017).

remember that, upon receiving notification on April 21, 2014 of the municipals' execution of their contractual right to terminate their supply arrangement, KU promptly moved for an abeyance of the procedural schedule to consider the impact of the potential departure of the municipals on its case requesting a certificate of public convenience for a new combined-cycle power plant ("GR5 CPCN").[7] On August 22, 2014, KU withdrew its request for the GR5 CPCN.[8] As discussed in the testimony of Mr. David Sinclair, the GR5 CPCN withdrawal, coupled with the Commission-approved *Capacity Purchase and Tolling Agreement* with Bluegrass Generation Company, LLC through April 30, 2019, more than balanced out generation capacity resources and the loss of load due to the municipals' departure.[9] Using the estimated construction costs per the GR5 CPCN, the cost of capital in this proceeding and the annual operating and maintenance expenses and depreciation rates for Cane Run Unit 7 as a combined-cycle gas plant proxy, the annual base rate revenue requirement in these proceedings attributed to Green River Unit 5 would have been $85 million (KU: $49 million, LG&E: $36 million). This is significantly greater than the incremental base rate revenue requirement in this proceeding caused by a higher jurisdictional

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[7] *In the Matter of: Joint Application of Louisville Gas and Electric Company and Kentucky Utilities Company for a Certificate of Public Convenience and Necessity 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, Louisville Gas and Electric Company's and Kentucky Utilities Company's Motion to Hold Procedural Schedule in Abeyance (Ky. PSC Apr. 30, 2014).

[8] *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*, Case No. 2014-00002, LG&E and KU Notice of Withdrawal of Their Application for a Certificate of Public Convenience and Necessity for the Construction of Green River NGCC and Motion for Resumption of this Proceeding for Brown Solar Facility (Ky. PSC Aug. 22, 2014).

[9] *In the Matter of: Application of Louisville Gas and Electric Company and Kentucky Utilities Company for a Declaratory Order and Approval Pursuant to KRS 278.300 for a Capacity Purchase and Tolling Agreement*, Case No. 2014-00321, Order (Ky. PSC Nov. 24, 2014).

factor for KU's Kentucky retail operations. KU's Kentucky retail customers are essentially bearing a larger percentage of a smaller total revenue requirement due to the termination of the municipal contracts and the offsetting reduction in generation resources.

Q. Have other changes in sales volumes impacted the Companies' revenue requirement in this proceeding?

A. Yes. Both KU and LG&E Electric Operations have seen reductions in retail load billing determinants since their last rate cases. On the residential side, an increase in the number of customers has been more than offset by reductions in usage per customer due to customers' use of energy efficiency measures. In addition, commercial and industrial customers have continued to implement measures to reduce their peak capacity demand, thereby reducing billing determinants for demand charges. Such customer initiatives increased KU's revenue requirement in this case by $31 million and LG&E's electric revenue requirement by $13 million. These same initiatives, however, were also significant contributors to the Companies' ability to retire E.W. Brown Units 1 and 2 and remove certain energy efficiency programs which were no longer economically effective for socialization through the Demand Side Management ("DSM") rider on customers' bills.

Q. Does the loss of the Kentucky municipal supply contracts impact these proceedings in any other manner?

A. The changes in sources of generation supply for the nine departing municipals, as well as changes being made by other municipal utilities in Kentucky, are projected to add costs for KU under its Merger Mitigation Depancaking ("MMD") transmission rate mechanism. These changes are projected to add $13 million (KU: $8 million, LG&E: $5 million) to the Companies' revenue requirements in these proceedings. On August 3, 2018, the Companies made a filing with the Federal Energy Regulatory Commission to eliminate these MMD charges.[10] Due to the development of robust, accessible energy markets over time, the Companies believe these merger mitigation commitments are no longer relevant or appropriate. Due to the early stages of this proceeding, the Companies cannot predict its outcome. However, as detailed in Exhibit LEB-2 to the testimony of Mr. Bellar, the Companies have determined that the benefits of the 1998 LG&E-KU Merger[11] and their subsequent withdrawal from the Midcontinent Independent System Operator ("MISO"),[12] remain the best economic decision for their retail customers even if such MMD charges remain in place.

Q. Have the Companies experienced any other increases in operating and maintenance expenses which are adding to the Companies' revenue requirements?

A. For LG&E Gas Operations, there is an increase of approximately $22 million which is attributed to safety, reliability, and regulatory compliance. These include in-line gas inspections ($10 million), line locating expenses ($3 million) and other safety,

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[10] *Joint Application Under FPA Section 203 and Section 205 of Louisville Gas and Electric Company and Kentucky Utilities Company*, FERC Docket Nos. EC98-2-00 and ER18-2162-000 (FERC application filed Aug. 3, 2018).

[11] The Commission authorized the LG&E-KU Merger in Case No. 1997-00300. *Joint Application of Louisville Gas and Electric Company and Kentucky Utilities Company for Approval of Merger*, Case No. 1997-00300, Order (Ky. PSC Sept. 12, 1997).

[12] The Commission authorized the Companies' withdrawal from MISO in Case No. 2003-00266. *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, Order (Ky. PSC May 31, 2006).

technical training, and regulatory compliance initiatives and customer services (collectively $9 million). These items are discussed in more detail in the testimony of Mr. Bellar. For KU and LG&E Electric Operations, other operation and maintenance expenses in the forecasted test period ending April 30, 2020, are consistent with those included in the forecast test period ended June 30, 2018, used in the Companies last base rate case.

III. EFFICIENCY AND PRODUCTIVITY

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

A. Yes. 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. Bellar'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 fifteen years where we compare our costs to other utilities using publicly-available FERC Form 1 information using a five-year average to smooth out single year anomalies. The results of the most current study are shown in Exhibit KWB-1. The Companies remain a top quartile performer with respect to O&M per megawatt hour sold. Furthermore, when looking at 2017 in isolation, the Companies ranked 6th among 41 vertically-integrated utility holding companies.

The analysis shows that the Companies are a top quartile performer on both an overall basis, as well as separately in Generation, Transmission, and Distribution. The Companies are also near the top of the second quartile in the Administrative and General ("A&G") and Customer Service categories. 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. Has the Companies' focus on efficiency and productivity led to savings for customers?

A. Yes. Demonstration of the benefits to customer rates derived from the Companies' continued focus on efficiency can be found in the attachment to Filing Requirement 807 KAR 5:001 Section 16(7)(h)(1). The sum of the line items for Other Operation Expenses and Maintenance for the Companies for the year 2019 is $829 million. The sum of those same line items in that filing requirement from the Companies' last base rate case for the year 2019 was $893 million. This is a reduction in the cost of providing service of $64 million. Since the Companies retail rates are cost-based, such expense savings are passed on to customers.

Of that $64 million of savings, $14 million is a result of the ratemaking normalization for major generation plant outages agreed to by the Companies in the settlement of their last rate cases.[13] Another $27 million comes from the Companies' proposal to eliminate certain demand side management programs that are no longer

[13] Case No. 2016-00370 & 2016-00371, Stipulation and Recommendation, Article II, Section 2.2(F) (Ky. PSC Apr. 19, 2017).

cost beneficial for customers.[14] The remaining efficiencies are being passed on to customers through a combination of the Environmental Cost Recovery Mechanism ($7 million), LG&E gas rate mechanisms ($1 million), and base rates ($15 million). While the referenced savings are for calendar 2019 since those amounts can be found in the record of the Companies' last base rate cases, the savings for the forecasted test period in the current cases are relatively consistent. The Companies' continuous efforts to find efficiencies also yield savings in other line items of the Companies' income statements including Fuel for Electric Generation and Property and Other Taxes. For example, the Companies' efficiency efforts with respect to fuel handling and ash disposal have lowered those 2019 forecasted expenses by $2 million. In addition, since some of the efficiency initiatives have come in the form of labor, the Companies' forecast for 2019 employment taxes, included in Property and Other Taxes, is $1 million lower. These reductions in forecast expenses clearly reflect the Companies' continued efforts to keep its costs and rates as low as possible while continuing to provide the safe, 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. KU and LG&E continually look for more efficient ways to deliver service. All financial and administrative areas have continued to implement technology to

[14] In Case No. 2017-00441, the Companies proposed the retirement of three programs which failed to meet the cost-benefit threshold: the Residential Conservation Program/Home Energy Performance Program, the Residential Refrigerator Removal Program, and the Customer Education and Public Information Program. *In the Matter of: Joint Application of Louisville Gas and Electric Company and Kentucky Utilities Company for Review, Modification, and Continuation of Certain Existing Demand-Side Management and Energy Efficiency Programs*, Case No. 2017-00441, Direct Testimony of Gregory S. Lawson (Ky. PSC Dec. 6, 2017). The Companies also proposed the modification of several other DSM programs. *Id.*

automate manual processes and identify other opportunities for savings. Improved software to house accounting data, intercompany database preparation and analysis, and projects to automate journal entries and account reconciliations, have led to fewer man hours necessary to complete tasks in the financial area. As evidence of automating efficiencies, headcount for my areas of responsibility outside of IT have declined by five full-time equivalents since our last rate proceedings, and there has been no net headcount additions across our General Counsel's and VP-Corporate Communications' areas of responsibility. The testimony of Mr. Bellar and Mr. Meiman also discuss how automation has benefited their efficiency efforts.

With the continued automation enhancements, more significant data processing and growing cybersecurity threats, the Companies have continued to seek out efficiencies in information technology services to help mitigate cost increases. For example, the Companies have migrated to a Hyperconverged Infrastructure for data processing and storage which has reduced the capital cost of storage and computation infrastructure from $4,951 to $2,817 per terabyte and the annual operating cost from $482 to $354 per terabyte. In addition, the Companies' information technology group has automated some of its own systems and processes, including the Oracle database and server patching.

The Companies also continue to enhance their cybersecurity defense mechanisms and security awareness through programs such as ongoing employee education and mandatory annual security awareness training. The Companies recently presented some of these initiatives at the Commission.[15]

Finally, the Companies also continue to explore technology and methods to further increase efficiency in the future. For instance, the Companies have researched and conducted a pilot study of Robotic Process Automation ("RPA"). The Companies believe that RPA could potentially create efficiencies in many business areas, including customer service, accounting, and supply chain management. RPA has the potential to create capacity, allowing our workforce to focus on the innovative and critical thought work required for the future.

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

[15] KU and LG&E Cybersecurity Update, Kentucky Public Service Commission Meeting No. 886 (Aug. 6, 2018).

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. Has the Companies' approach to cost efficiency lead to lower rates for customers?

A. Yes. Because the Companies have cost-based rates, the savings resulting from efficiencies translate into rate benefits for customers. As described in the testimony of Mr. Conroy, KU's and LG&E's current average electric residential rates are approximately 23 and 18 percent lower, respectively, than the average residential electric rate of investor-owned utilities across the United States. In Kentucky, further evidence of the Companies' efficient operations is shown by the fact that the Companies' average residential rates remain some of the lowest in the state.

IV. SCHEDULE REQUIRED BY 807 KAR 5:001 SECTION 16

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

A. Yes. I am co-sponsoring Section 16(7)(c), the complete description of all factors used to prepare the forecasted test period.

V. CONCLUSION

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:

- $35 million for LG&E’s electric operations,
- $25 million for LG&E’s gas operations, and
- $112 million for KU’s operations.

Q. Does this conclude your testimony?

A. Yes.

VERIFICATION

COMMONWEALTH OF KENTUCKY)
)
COUNTY OF JEFFERSON)

The undersigned, **Kent W. Blake**, being duly sworn, deposes and says he is the Chief Financial Officer for Kentucky Utilities Company and Louisville Gas and Electric Company and an employee of LG&E and KU Services Company, that he has personal knowledge of the matters set forth in the foregoing testimony, and 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 25th day of September 2018.

Judy Schooler

Notary Public

My Commission Expires:

Judy Schooler
Notary Public, ID No. 603967
State at Large, Kentucky
Commission Expires 7/11/2022

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-Feb 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/Certifications

University of Kentucky, B.S. in Accounting
Certified Public Accountant, Kentucky
Leadership Louisville, 2007

Current Professional and Community Affiliations

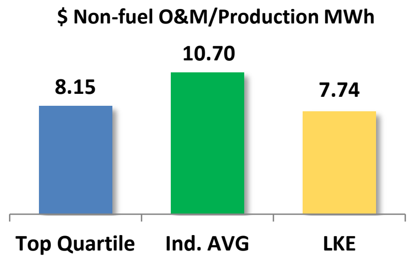
American Institute of Certified Public Accountants
Kentucky State Society of Certified Public Accountants
Edison Electric Institute
Metro United Way, Board Chair Elect
Louisville Downtown Development Corporation, Board Member
Stage One Family Theatre, Board Member

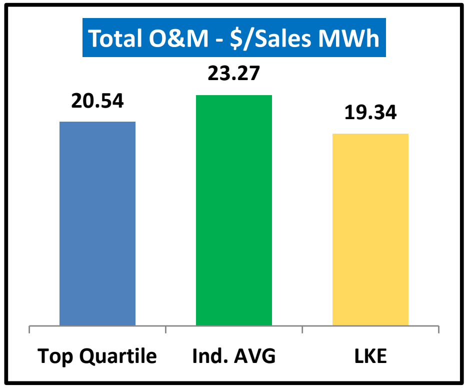
Exhibit KWB-1

FERC Form 1 Benchmark Five Year Average

FERC Form 1 Benchmarking Five Year Average [2013-2017]: Top Quartile Performance

Generation





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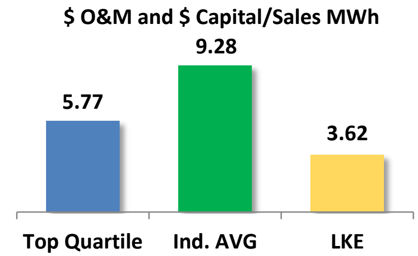
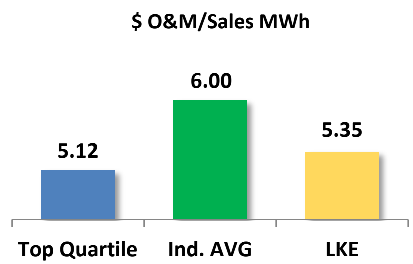


A&G



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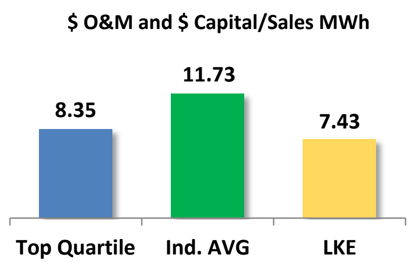
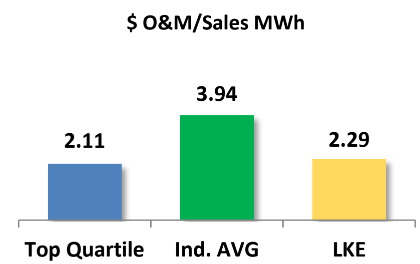


Customer Service



COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

ELECTRONIC APPLICATION OF	**)**	
KENTUCKY UTILITIES COMPANY FOR AN	**)**	**CASE NO. 2018-00294**
ADJUSTMENT OF ITS ELECTRIC RATES	**)**	

In the Matter of:

ELECTRONIC APPLICATION OF	**)**	
LOUISVILLE GAS AND ELECTRIC	**)**	**CASE NO. 2018-00295**
COMPANY FOR AN ADJUSTMENT OF ITS	**)**	
ELECTRIC AND GAS RATES	**)**	

TESTIMONY OF
LONNIE E. BELLAR
CHIEF OPERATING OFFICER
KENTUCKY UTILITIES COMPANY AND
LOUISVILLE GAS AND ELECTRIC COMPANY

Filed: September 28, 2018

TABLE OF CONTENTS

I. BACKGROUND

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

A. My name is Lonnie E. Bellar. I am the Chief Operating Officer for 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. My business address is 220 West Main Street, Louisville, Kentucky 40202.

Q. Please describe your educational and professional background.

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

Q. How long have you served in the role of COO of the Companies?

A. I was promoted to Chief Operating Officer of the Companies in March 2018.

Q. Please briefly describe your professional history with the Companies.

A. My career with KU dates back to 1987, where I started as an electrical engineer with the generation system planning group. From there, I have served in various management positions within generation planning and generation services, financial planning and controlling, electric transmission, and state regulation and rates. In February 2013, I was promoted to Vice President, Gas Distribution, and I served in that capacity until January 2017, when I was promoted to Senior Vice President of Operations. I served in that position until my most recent promotion to COO earlier this year.

Q. What are your responsibilities as COO of the Companies?

A. As COO, I am responsible for oversight and direction of all operational areas of the Companies' business, including power generation, energy supply and analysis, electric distribution and transmission, gas distribution and storage, safety, environmental affairs and customer services.

Q. In addition to your new role, have there been other changes to management of the Companies' operations since the filing of the last rate case?

A. Yes, in January 2017, when I was promoted to Senior Vice President of Operations, there were a number of leadership changes to the operational side of the business. John Malloy assumed my former responsibilities as Vice President, Gas Operations. Beth McFarland was promoted to the position vacated by Mr. Malloy – Vice President, Customer Services. John Voyles, a 40-plus year veteran with the Companies, retired from his role as Vice President, Transmission and Generation Services in March 2017. Gary Revlett, Director, Environmental Affairs now reports directly to me. And Eileen Saunders, formerly the Director of Generation Services, now Director, Safety and Technical Training, also reports directly to me.

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

A. I report directly to Paul Thompson, Chairman, President and Chief Executive Officer of the Companies. In addition to Mr. Revlett and Ms. Saunders, six other members of our management team report directly to me: Ralph Bowling, Vice President, Power Production, Tom Jessee, Vice President, Transmission, John Malloy, Vice President, Gas Distribution, Beth McFarland, Vice President, Customer Services, David Sinclair, Vice President, Energy Supply and Analysis, and John Wolfe, Vice President, Electric Distribution.

Q. Have you previously testified before this Commission?

A. Yes. I have testified in numerous proceedings before the Commission. Most recently, I testified in KU's and LG&E's 2016 base rate cases.[1]

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

A. The purpose of my testimony is to report on the Companies' operations and to provide operational context to support the Companies' applications for an increase in base rates. I will describe the Companies' performance in each operational area and how we are striving to meet future challenges and the expectations of customers for safe, reliable, and reasonably priced gas and electric service. I will describe how and why the Companies are making strategic capital investments in operations and leveraging technology to achieve operational efficiencies.

II. OVERVIEW

Q. How are the Companies' operations performing?

A. Broadly speaking, the Companies are performing well and have continued to build on their history of operational excellence in an increasingly complex environment. Objective metrics demonstrate that the Companies are performing safely and reliably in all operational areas. The Companies have embraced technological advancements to improve the safety, efficiency, and reliability of their power generation and delivery systems – and in fact the Companies themselves are both the source of and champions for some of those technological advancements. The Companies are in the vanguard of innovative and responsible ways to serve their customers at a reasonable cost. Several recent projects to promote solar generation are good examples.

[1] *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.

Investments in smart grid technologies continue to improve customer experience with power delivery systems, and the Companies strive for industry leadership in Kentucky in implementing those technologies. The Companies' focus on serving customers with safe, reliable and reasonably priced power is consistently rewarded with high customer satisfaction results.

Q. Why is additional investment needed?

A. The Companies must continually invest in their operations both to meet existing obligations to customers and to plan for the future. Aging and outdated infrastructure poses both safety and reliability risks to customers and must be responsibly managed and, when necessary, replaced. As customer expectations for power quality and reliability continue to increase, so too does the Companies' obligation to meet or exceed those expectations. The investments I describe here are needed to maintain operational excellence and to modernize the Companies' systems to meet the challenges ahead. The amount of these capital expenditures are summarized by business line in Mr. Blake's testimony. I will present the details of the capital expenditures using the period January 1, 2018, to October 31, 2019 for the generation, transmission, distribution, customer service and gas operations in my testimony.

III. SAFETY

Q. What is the Companies' philosophy regarding safety?

A. The safety of the Companies' employees, contractors and the general public in generation and delivery of power and gas is a core business expectation and is considered in the Companies' operations and decision-making at every level. The Companies do not compromise on safety and health. The Companies have worked hard to create and maintain a top-led, employee-driven safety culture. This means that all employees and contractors are mutually responsible for safe work practices, and those practices are implemented and supported by management.

The expectation is that all levels of the organization must adhere to safe work practices even in extreme work conditions, such as those following the severe storms across Kentucky that began on July 20, 2018. Those storms contributed to one of the top five worst outages in the Companies' history with approximately 174,000 customers without power. Employees, contractors, and mutual assistance personnel worked long hours in challenging conditions to restore service as quickly and safely as possible. Throughout thousands of hours of restoration work in these difficult conditions, only one minor recordable incident occurred. Safe work practices are most critical at these moments, and the Companies' safety program is designed to ensure that all such practices are followed in emergency response situations.

Strategic safety initiatives are guided by an internal Safety Governance Council, on which I have served for the past two years. The Companies believe strongly in empowering their employees and contractors to adhere to safe work practices and to report unsafe working conditions. These core principles and many others not only foster the primary goal of minimizing the risk of injury, they also enhance the Companies' business operations. Safe work contributes to positive employee morale, minimizes injury-related expenses and absenteeism, and assists the Companies in recruiting highly qualified candidates.

Q. How are the Companies demonstrating their commitment to safety?

A. Each January the Companies hold an annual safety summit to highlight the paramount importance of safety and safe work practices. Nearly 1,200 employees and business partners attended the 2018 safety summit. During the summit, the Companies' executive leadership reviews safety performance from the preceding year, provides their expectations for safe work in the coming year, and reinforces the themes and core elements upon which the Companies' safety program is built. Attendees have the opportunity to build their safety skills through participation in workshops and through various safety presentations and exhibits, and are encouraged to apply and share those skills with others in their workplace.

The Companies are also investing in modern training facilities to meet the safety and training needs of their workforce. A new power generation technical training center located at the Trimble County generating station was completed at the end of 2017. The Companies are also building a new safety and technical training center at the LG&E East Operations Center which is slated for completion in early 2019. Both new training facilities are designed for classroom and hands-on instruction involving new techniques and equipment. The combination of conventional and practical instruction enhances real time learning, shortens the learning curve, and allows for the development of critical safety skills in a controlled environment. These training innovations further promote a safety culture dedicated to continuous learning and reinforcement of core safety practices, rather than isolated training experiences which can be disassociated from real world working conditions and forgotten over time.

Q. Describe the Companies' recent safety performance.

A. Objective data demonstrates that the Companies' commitment to safety translates into excellent safety achievement. One key metric the Companies use to monitor safety performance is the Recordable Injury Incident Rate ("RIIR"), which measures the rate of recordable injuries per 200,000 employee hours worked. In calendar year 2017, the RIIR for the Companies' employees was just 0.97, or a total of 33 injuries over 6.7 million employee hours worked. This rate puts the utilities in the top quartile of utilities according to industry benchmarking data, and far below the utility national average of 1.7. The 2017 RIIR for the Companies' contractors was just 1.99, far below the national general industrial contractor average of 3.6. Through July, contractor RIIR for calendar year 2018 is just 1.19, just over half of the 2017 rate. Employee RIIR through July 2018 is 1.42 on a total of 28 employee recordable incidents.[2]

Days Away/Restricted/Transferred ("DART") is another metric that tracks the rate of recordable injuries resulting in a day away, transferred, or restricted in duty over 200,000 employee hours worked. The Companies' DART was just 0.36 for employees through July 2018, putting the Companies well within first quartile performance against benchmarked utilities according to industry survey data. Contractors have sustained only four lost time injuries through July 2018. These objective metrics are a strong reflection of the Companies' dedication to workplace safety and their ongoing commitment to a robust safety culture.

Q. Have the Companies been recognized for their safety performance?

[2] 11 of the 28 employee recordable incidents in 2018 through July are for hearing loss. The non-hearing loss RIIR through July is 0.86 which tracks closely to the 2017 non-hearing loss RIIR of 0.85 (29 of 33).

A. Yes. A diverse group of the Companies' operational centers have been recognized for safety achievements and milestones over the past eighteen months. Employees at Cane Run and Paddy's Run generating stations have gone more than a year without a recordable injury and were recognized in 2017 with the Governor's Safety and Health Award. LG&E's gas operations employees were recognized for the nineteenth consecutive year with the Kentucky Gas Association's Accident Prevention Award for Excellence in Safety for maintaining the lowest DART among peer companies and groups. The Companies' transmission operations were recognized with an EEI safety award for 3.6 million hours worked without a lost time incident. The Lexington Substation and Maintenance Department, Pineville Electric Distribution, and Elizabethtown Operations have all been recently recognized with EEI Safety Achievement Awards for hundreds of thousands of employee hours without a recordable incident.

Q. How are the Companies achieving operational efficiencies through safety programs?

A. The Companies are leveraging several information technology platforms to achieve operational efficiencies in safety. In April 2016, LG&E implemented a training tracker system to electronically log and track all training received by gas distribution employees. The system not only provides a centralized mechanism for tracking formal employee training but also allows for mobile entry of on the job training and enhanced reporting capabilities for supervisors and management. The Companies are currently implementing the training tracker program for use in all operational areas, with full functionality expected by early 2019. The Companies are also utilizing a contractor health and safety database to track the safety performance of all contractors. Data from this system allows for early identification of safety issues and early interventions to address those issues. The system further enhances the Companies' ability to ensure that its business partners are complying with their safety programs and policies.

IV. ELECTRIC POWER GENERATION

Q. Please describe the Companies' generation systems.

A. Generation output is jointly dispatched between KU and LG&E to achieve operational efficiencies. Pursuant to the Companies' *Power Supply System Agreement* filed with the Federal Energy Regulatory Commission ("FERC"), the joint planning objectives of the Companies are to maximize the economy, efficiency, and reliability of their combined systems as a whole. Dispatch of generation, whether from the Companies' own generating plant or from purchased power, is determined by lowest variable operating cost regardless of ownership.

The Companies own and operate approximately 7,844 MW of summer net generating capacity in Kentucky with a net book value of approximately $ 6.5 billion. The combined Companies serve approximately 936,000 electric customers across a footprint of 79 Kentucky counties.[3] The generating system consists of coal-fired generating stations in four locations: Brown, Ghent, Mill Creek, and Trimble County. The Companies own and operate Cane Run Unit 7, a natural gas combined-cycle generating unit located in Louisville. The Companies also own and operate multiple natural-gas-fired combustion turbines, which supplement the system during peak

[3] KU also serves electric customers in five Virginia counties.

periods, hydroelectric generating stations at Dix Dam and Ohio Falls, which provide base load supply subject to river flow constraints, and the Brown Solar generating plant. The Companies also purchase power from the Ohio Valley Electric Corporation ("OVEC") through a long-existing *Inter-Company Power Agreement*,[4] and pursuant to a short-term agreement with Bluegrass Generation Company, LLC ("Bluegrass").[5] A complete list of the Companies' current generating units and associated capacity is attached to my testimony as Exhibit LEB-1.

Q. Is the fleet mix of the Companies' generating units changing?

A. Yes. Each year the Companies prepare a detailed load forecast to determine anticipated demand over a 30-year planning period. David Sinclair, the Companies' Vice President of Energy Supply and Analysis, discusses the load forecasting process in detail in his testimony. Based on the load forecasts from Mr. Sinclair's group and myriad other factors, including environmental regulations and current and projected energy costs, the Companies continuously assess their need for generating capacity and the best and most efficient resources to meet projected load. In the past decade, that process has resulted in the construction of Cane Run 7, Kentucky's first natural gas combined cycle generating unit, which began commercial operation in June 2015.

[4] The Commission approved the Inter-Company Power Agreement between KU and LG&E and OVEC in *In the Matter of: Application of Kentucky Utilities Company for an Order Pursuant to KRS 278.300 and for Approval of Long-Term Purchase Contract*, Case No. 2004-00395 (Ky. PSC Dec. 30, 2004), and *In the Matter of: Application of Louisville Gas & Electric Company for an Order Pursuant to KRS 278.300 and for Approval of Long-Term Purchase Contract*, Case No. 2004-00396 (Ky. PSC Dec. 30, 2004).

[5] The Commission approved the four-year *Capacity Purchase and Tolling Agreement* with Bluegrass Generation in Case No. 2014-00321. *In the Matter of: Application of Louisville Gas and Electric Company and Kentucky Utilities Company for a Declaratory Order and Approval Pursuant to KRS 278.300 for a Capacity Purchase and Tolling Agreement*, Case No. 2014-00321, Order (Ky. PSC Nov. 24, 2014). The agreement is set to expire in April 2019.

This process has also resulted in the retirement of several older coal fired units, including three coal-fired generating units at Cane Run and, more recently, the decision to retire two coal-fired generating units at the Brown generating station. The costs associated with regulatory compliance and maintenance of older coal-fired generation plants, as well as recent changes in projected load growth, has led to the decision to retire some of those older assets and put heavier reliance on newer generating technology like that incorporated into Cane Run 7. For similar reasons, the Companies plan to limit spending on six secondary combustion turbines and retire the units when significant investment is needed for their continued operation. As evidenced by the 2013 retirement of Haefling 3 and plans to retire Zorn 1 within the next three years, the remaining useful lives of these combustion turbines are limited.[6]

Q. What were the driving factors behind the Companies' decision to retire Brown Units 1 and 2?

A. Environmental regulations imposed on older coal-fired generating plant – particularly those relating to coal combustion residuals – adds cost to the continued operation of such units. Brown Units 1 and 2 (generating 106 MW and 166 MW of summer net capacity, respectively) are good examples of this dynamic and are in fact the most expensive units to operate in the Companies' coal-fired fleet on a dollars-per-megawatt of generation basis. Those costs in combination with lower forecasted load growth caused the Companies to plan for retirement of these two units. The Companies concluded that retirement of Brown 1 and 2 in February 2019 is the least

[6] The referenced units include Paddy's Run Units 11 and 12, Haefling Units 1 and 2, Zorn 1, and Cane Run 11.

cost solution for customers compared to continuing to operate these units at continually increasing cost.

Q. Please give a brief background on the departure of wholesale municipal customers in 2019.

A. In April 2014, the Companies received notice of termination from nine municipal customers representing a combined load of approximately 325 MW.[7] The final terminations will take effect at the end of April 2019. Upon receiving notice in 2014, the Companies quickly responded by withdrawing their pending application for Commission approval to construct Green River 5, a 670 MW Combined Cycle Generating Turbine ("CCGT") unit.[8] The decision not to build Green River 5 saved customers over $700 million in capital construction costs. As shown in Mr. Blake's testimony, the annual base rate revenue requirement for Kentucky retail customers would have been $85 million (KU: $49 million, LG&E: $36 million) higher if the municipal customers had remained with KU and the Green River 5 Certificate of Public Convenience and Necessity ("CPCN") had been approved, more than offsetting the impact of the incremental base rate revenue requirement in this proceeding caused by a higher jurisdictional factor for KU's Kentucky retail operations. As referenced earlier, the Companies also secured with Commission approval 165 MW of short-term capacity through a power purchase contract with

[7] Under the terms of the contracts between the Companies and these municipal customers, the customers were required to provide five years' notice before termination.

[8] *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*, Case No. 2014-00002, LG&E and KU Notice of Withdrawal of Their Application for a Certificate of Public Convenience and Necessity for the Construction of Green River NGCC and Motion for Resumption of this Proceeding for Brown Solar Facility (Ky. PSC Aug. 22, 2014).

Bluegrass Generation. Since that time, the Companies have employed existing business and planning processes to assess the effect of the loss of load from these municipal customers and how to adjust accordingly.

Q. What did the Companies conclude regarding the effect of the departure of the wholesale municipal customers?

A. In short, the Companies accounted for the departure of the municipal customers in their 2014 Integrated Resource Plan ("IRP") and determined at that time that additional generating capacity would still be needed by 2020 to maintain optimal reserve margins. However, overall load growth forecasts dipped sharply between 2014 and 2016, resulting in an almost 500 MW decrease in projected 2020 load. The decrease in overall load growth has had a much greater impact on the Companies' capacity reserves than the loss of 325 MW of load from the wholesale municipal customers.

Q. What steps are the Companies taking to address the changes in their supply resources and load in the forecasted test year?

A. The Companies have outlined their planning processes to address this situation in response to a Commission request from the 2016 base rate case.[9] To summarize, the Companies will file a new IRP and reserve margin study with the Commission no later than November 1, 2018; they submitted a review of their Demand Side Management ("DSM") programs to the Commission, reducing their size and scope

[9] Case No. 2016-00370, Kentucky Utilities Company's Response to the June 22, 2017 Order of the Kentucky Public Service Commission, filed September 20, 2017.

significantly;[10] they completed a study on the costs and benefits of joining a Regional Transmission Organization ("RTO") which is attached to my testimony; they are seeking out opportunities to sell excess capacity in energy markets, and they continue to engage in efforts to grow load and benefit the economy. Mr. Thompson and Mr. Sinclair describe these efforts in their respective testimony.

The net difference in the change in available capacity from the retirement of the units at Brown and the expiration of the 165 MW contract capacity coincident with the termination of the municipal customer load is a 112 megawatt decrease.[11]

Q. What have the Companies concluded regarding the costs and benefits of RTO membership to customers?

A. The Companies have closely studied the issue and concluded that the cost and uncertainties associated with RTO membership currently exceed the known potential benefits, and will not seek RTO membership at this time. The Companies' complete analysis is attached to my testimony as Exhibit LEB-2. At its core, RTO membership is an agreement to relinquish functional control of most of the utility's critical generation and transmission operations, and corresponding loss of control over those operations by the utility's management, state regulators, and ultimately native load customers. Given the Companies' current situation, the benefits of RTO membership do not offset the costs, are too uncertain, and are too dependent on external factors to

[10] In Case No. 2017-00441, the Companies proposed the retirement of three programs which failed to meet the cost-benefit threshold: the Residential Conservation Program/Home Energy Performance Program, the Residential Refrigerator Removal Program, and the Customer Education and Public Information Program. *In the Matter of: Joint Application of Louisville Gas and Electric Company and Kentucky Utilities Company for Review, Modification, and Continuation of Certain Existing Demand-Side Management and Energy Efficiency Programs*, Case No. 2017-00441, Direct Testimony of Gregory S. Lawson (Ky. PSC Dec. 6, 2017). The Companies also proposed the modification of several other DSM programs. *Id.*

[11] 325 MW (departure of municipal load) - 165 MW (expiration of *Capacity Purchase and Tolling Agreement*) - 272 MW (retirement of Brown Units 1 and 2) = (112) MW.

justify this fundamental and essentially almost permanent loss of control. Those uncertainties are discussed in detail in Appendix E of the RTO analysis attached to my testimony.

Q. How are the Companies' generation units performing overall?

A. Very well. The Companies (and the industry as a whole) measure the reliability of steam generating units through a metric called weighted average equivalent forced outage rate ("EFOR"). EFOR measures the percentage of steam generation that is unavailable due to forced outages or derates. The Companies' average EFOR for calendar year 2018 through the end of July is just 2.54 percent, far better than the top quartile performance of 4.7 percent according to industry benchmarks. Furthermore, the incidence of boiler tube failures on the Companies' generating units, a common cause of unplanned generation outages, has decreased dramatically over the past decade, from a rate of roughly 8 per month in 2008 to an average of under 2 per month in 2018. The Companies' excellent generation reliability performance is largely attributable to carefully planned and well executed engineering and maintenance operations, and a highly skilled and hard-working team of employees and business partners who operate and maintain the generation units on a daily basis.

Q. Please describe some of the capital investments the Companies are making in their generating stations.

A. The Companies are not currently planning for the construction of a new generating plant. However, they are continuing to invest in regular maintenance of existing generation plant and other projects to improve overall generation performance and reliability. Specifically, the Companies plan to invest $184 million in planned capital outage maintenance expense from January 1, 2018 through October 31, 2019. These investments include $21 million in capital for a combustion inspection of combustion turbine unit 6 at the Brown generating station. This inspection involves changing out all hot gas path components, replacement of turbine blades and vanes, and replacement of 56 total burners. The Companies also plan to spend $12 million for rebuilding the cooling towers on Ghent Units 3 and 4, and $6 million on the first overhaul of combustion turbine 11 of the Brown generating station since it went into commercial operation. The overhaul on Brown CT 11 involves changing out the majority of the hot gas path inspection components, replacement of the first three rows of turbine blades and vanes, and replacement of heat shields and combustor components.

The Companies will also be investing approximately $63 million from January 1, 2018 through October 31, 2019 for demolition of retired coal-fired generating units at Cane Run, Green River, Pineville, and Tyrone. Capital expenses for the demolition of coal-fired units are as follows for the capitalization period from January 1, 2018 through October 31, 2019: $32 million at Cane Run, $14 million at Green River, $10 million at Tyrone, and $7 million at Pineville. Demolition of units at Pineville and Tyrone are scheduled to be completed late in 2019. Demolition of retired generating plant has numerous advantages over mothballing these facilities, as the Companies recently experienced through the demolition of retired generation plant at Paddy’s Run. The Paddy’s Run demolition was completed in the spring of 2018 and was both under budget and on time. Photographs comparing the Paddy’s Run generation plant before and after the demolition was completed are attached collectively as Exhibit LEB-3 to my testimony. Demolition provides for better long term safety and security at the Companies' generating stations, eliminates trailing maintenance costs for long-retired plant, and allows the Companies added flexibility in utilizing space at generating stations.[12]

Another planned capital project to support power generation is the replacement of a portion of the gas transmission line servicing the Brown CT units with a new transmission line buried beneath the Dix River. The projected capital cost of this project is $20.8 million, almost all of which will be incurred in the period from January 1, 2018 through October 31, 2019. The existing line runs on top of Dix Dam, and the parapet wall of the dam must be replaced to maintain standard of care criteria for the dam structure. The new line will be placed underneath the riverbed. The project is expected to be completed by fall 2019.

The gypsum dewatering project at Mill Creek, on which the Companies reported in the last rate case, is scheduled to begin operation in October 2018. The total cost of this project is $78 million, $46 million of which is expected to be incurred between January 1, 2018 and October 31, 2019. This system will allow Mill Creek to beneficially use coal combustion residuals to produce gypsum with a moisture content suitable for commercial applications such as wallboard, reducing reliance on the Mill Creek landfill, extending the life of the landfill, and reducing the overall environmental impact. The Companies' effort to proactively manage and

[12] The Commission has recognized that space at existing generation stations is both valuable and finite. *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, at 6 (Ky. PSC June 11, 2002).

generate revenue from byproducts of generation for the benefit of customers is discussed later in my testimony.

Q. Please provide an update on the performance of the Brown Solar generating plant.

A. The Brown Solar generating plant, located on the banks of Herrington Lake in Mercer County, went into service in June 2016. The plant has a total of 44,500 individual 315 watt direct current solar panels on fixed rack frames, capable of a combined output of 14 MW. The panels are connected to 10 separate DC to AC inverters capable of 10.24 MW AC, for a nameplate capacity of 10MW. It is the largest solar electric generation facility in Kentucky. For calendar year 2017, Brown Solar achieved a 19.8 percent capacity factor, generating a total of 17,336 MWh during the year.

Q. What have the Companies' learned from operating this first-of-its-kind solar generation facility for the past two years?

A. The Companies have learned immensely valuable information from their experience to date with solar generation at Brown. For example, nameplate capacity can only be achieved during peak sunlight hours, from roughly 10:00 a.m. to 3:00 p.m. each day. The facility operated at nameplate capacity for a total of 94 hours during 2017, or approximately one percent of the time the facility was running. The facility was offline due to darkness or weather conditions 51.6 percent of the time. Furthermore, the timing of generation does not necessarily coincide with peak demand – particularly in the winter season. Monthly generation varies significantly by season, with monthly output as low as 497 MWh in January to as high as 2,157 MWh in June.

As these statistics demonstrate, the generation output from Brown Solar varies widely depending on season, light conditions, and cloud cover, and such variances are unpredictable for purposes of supply planning.

Q. What do the Companies plan to do with the information learned from operation of Brown Solar?

A. The Companies have publicly shared it. A vast amount of data and research has been collected in the two-plus years of operating Brown Solar. The Companies made the data and their analyses publicly available on their website on August 31, 2018.[13] The data provided on the website is comprehensive, detailed, and provides near real-time information about unit's solar generation capacity. It is the Companies' hope that this information will be used in further research and development efforts to advance the frontier of renewable energy production.

Q. Please provide an update on the Companies' programs to generate revenue from generating facilities for the benefit of customers.

A. In calendar year 2018, the Companies have generated more than $11.4 million for the benefit of customers as a result of Off-System Sales ("OSS") of power produced by the Companies' generation facilities.

Also, as implementation of the gypsum dewatering facility at Mill Creek demonstrates, the Companies are focusing on a strategy for beneficial use of generating plant by-products that provides numerous cost saving benefits. Use of by-products such as Coal Combustion Residuals ("CCR"), fly ash, and bottom ash reduces overall disposal costs, conserves landfill space, and creates revenues which

[13] The Live Solar Generation Data website is available at: https://lge-ku.com/live-solar-generation.

are passed directly on to customers. For example, while the permanent gypsum dewatering facility at Mill Creek is being implemented, the Companies have used portable dewatering systems, which have allowed the Companies to preserve 700,000 tons of landfill space over a two-year period. The Companies have also entered into new contracts for the sale of fly ash from Mill Creek, Brown, and Trimble County generating stations. These contracts will result in the sale of nearly 400,000 tons of fly ash from Mill Creek over two years, and the sale of half or more of the fly ash from Brown Unit 3's operation over a two year period. The Mill Creek fly ash contract is expected to produce a minimum of nearly $4 million in revenue over a two year period. The Trimble County fly ash contract is expected to produce approximately $9 million in revenue over a five year period. All revenue from these activities will be passed directly on to customers through the operation of the Companies' environmental surcharge mechanisms.

In the last base rate case, the Companies reported on a new refined coal project under which a third-party company, Tinuum, planned to set up refined coal facilities at Ghent, Trimble County, and Mill Creek and pay reservation fees, site license fees, and coal yard service fees to the Companies.[14] Refined coal production involves chemical treatment of feedstock coal to reduce nitrogen oxide (NOx) and mercury emissions without affecting thermal output. The Companies generate reservation fees from Tinuum prior to the facility being installed and operational. Tinuum then sells or leases the facility to a tax equity investor, who may claim tax

[14] The Companies' contracts for refined coal production were approved by the Commission by Order entered November 24, 2015 in *In re: Application of Louisville Gas and Electric Company and Kentucky Utilities Company Regarding Entrance into Refined Coal Agreements, for Proposed Accounting and Fuel Adjustment Clause Treatment, and for Declaratory Ruling*, Case No. 2015-00264.

credits from the refined coal process to offset income taxes. Once a tax equity investor is found, the reservation fees cease and the Companies generate revenue from site license fees and coal yard service fees.

The first of the refined coal facilities went into operation at Ghent in March 2017, and that facility alone is producing $9.8 million in annual revenues from site license and coal yard service fees to the Companies, all of which is being passed on to customers. The refined coal facilities at Trimble County recently became operational in September 2018 and are expected to provide approximately $4.6 million in annual site license and coal yard service fees, 75% of which will be passed on to customers based upon the Companies' share of ownership of the plant. The refined coal facility at Mill Creek generating station may be operational during the first quarter of 2019, subject to successful completion of construction, testing, contract negotiation and execution. The same tax equity investor may be available for Trimble County and Mill Creek. Prior to the respective operational dates for these facilities, the Companies continue to receive aggregate site reservation fees in the amount of $660,000 annually for these two facilities. These fees are passed along to customers based on the Companies' respective ownership of the generating facilities.

Q. How are the Companies utilizing new programs to reduce costs and achieve operational efficiencies in power generation?

A. Recently the Companies have implemented an improved performance program housed at the Trimble County generating station. This program monitors unit and equipment performance at Trimble County and analyzes that monitoring data to provide early diagnosis of potential issues. The data from this program allows the

Companies to make informed decisions regarding repairs, improvements, and planned outages for this generating station. Performance optimization lowers fuel costs and improves the overall reliability of power generation operations.

Another new program implemented in 2017 is an alarm testing and tracking program related to voltage control policies and procedures required by North American Electric Reliability Corporation ("NERC"). This program involves an alarm protocol and annual testing to ensure that all necessary alarms are functioning within voltage requirements. The program adds efficiencies to the Companies' compliance procedures and avoids future costs associated with unplanned outages or loss of available generating capacity.

The Companies also completed an important upgrade at the Trimble County generating station in 2017 that will improve the efficiency of generation operations. Specifically, the boiler firing systems on Trimble County 1 and Trimble County 2 were upgraded to fire with natural gas instead of fuel oil. Natural gas is more readily available and is less costly than fuel oil and provides immediate savings to customers. Natural gas boiler firing also increases the life of the air heater baskets and the pulse jet fabric filter bags designed to collect particulate from the boilers, as well as improving startup efficiency.

Q. Please summarize the capital investment the Companies plan to make in their generation operations.

A. The following chart summarizes non-mechanism capital expenses in generation, by company, from January 1, 2018 through October 31, 2019 (in millions):

	KU	**LG&E**	**Total**
Outage Related Investments	$107	$77	$184

Demolition of Retired Coal Plants at Cane Run, Tyrone, Pineville, and Green River	$31	$32	$63
Mill Creek Gypsum Dewatering Facility	$0	$46	$46
Ohio Falls Rehabilitation and Unit 7 Rewind	$0	$10	$10
Ghent Stacker Reclaimer Certification	$9	$0	$9
Brown Combustion Turbine Site Gas Pipeline Relocation	$21	$0	$21
All Other	$85	$43	$128
Total	$253	$208	$461

V. CUSTOMER SERVICES

Q. Describe how the Companies provide superior service to their customers.

A. The Companies are focused every day on the total customer experience of each customer. Although utility customer service is commonly associated with reading meters, billing customers, collecting payments, and answering customer phone calls, the Companies' customer service operation extends far beyond that and touches nearly every aspect of the Companies' business. For example, the customer services team is charged with managing not only those operations identified above, but also the Companies' renewable energy offerings, customer assistance programs, outreach to stakeholder groups, responses to customer input and inquiries, customer energy efficiency programs, electric vehicle charging stations, and many other economic development services.

Delivery of these services with paramount focus on customer experience creates and maintains concrete value for customers and fosters continuous improvement in customer offerings. Dedication to the customer continues to garner positive results. As of the second quarter of 2018, the combined Companies exceeded peer mean customer service satisfaction ratings 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 have consistently achieved a high level of customer satisfaction while efficiently allocating funds used for Customer Services programs.

Q. How do the Companies measure customer satisfaction and their own performance in this area?

A. The Companies use a number of surveys to measure customer satisfaction. Customer satisfaction for contacts to the Residential Service Center, Business Service Center, customer walk-in Business Offices, and online self-service ("My Account") is measured by customer experience transactional surveys conducted by an independent third-party vendor. Using a scale of 1 to 10 (1 being the poorest and 10 being the best), the scores from these surveys are averaged and designated as the Combined Customer Experience Rating. The average rating is consistently above an 8.5 and was 9.0 for calendar year 2018 through July. The Companies also measure customer perception of ease in conducting business. Scoring is on a scale of 1 to 5 (1 being very difficult and 5 being very easy). The average rating is consistently over 4.0 and was 4.5 for the calendar year 2018 through July.

The Companies also track numerous operational metrics on a monthly basis to evaluate performance against customer expectations, including "service level" attained for phone and email contacts and resolution of customer inquiries brought forward to the Commission. The phone service level goal, for example, refers to the percentage of customer calls answered within thirty seconds. The Companies have achieved a year-to-date rate in excess of eighty percent (80%) for calendar year 2018 through July. Ninety-nine percent (99%) of Commission inquiries were resolved within three days for calendar year 2018 through July.

Q. Have the Companies been recognized by third-parties for their superior customer service performance?

A. Yes. Mr. Thompson's testimony describes some of these recognitions, including multiple J.D. Power awards earned by the Companies in the past three years for customer service achievement. There are several others. For example, Chartwell, a leading research provider to the utility industry, recognized the Companies as a Bronze Award winner for their initiative related to providing customers with improved Estimated Restoration Times ("ERTs") during electric outages. This cross-functional initiative began in 2015 with the goal of providing customers with a more accurate ERT as well as the cause of service interruption by leveraging technology, data analytics, and process monitoring and management. The improvements in ERTs have enhanced the customer experience during outages and enabled customers to make more informed personal or business decisions based on the latest information.

In the last two years, the Companies have been recognized with awards at the Better Communication Competition from Utilities Communicators International. These awards recognize the Companies' commitment to innovative and effective customer communication about energy programs and assistance through several different media.

The Companies recently won two awards for their Interactive Voice Recognition ("IVR") system used in the contact centers. First, the Companies won the IVR Doctors and Market Strategies International 2018 Gold Stethoscope Award as a "Balanced Company" for top quartile ratings in Functionality, Usability and Aesthetics. Second, the Companies won Chartwell's Bronze Best Practice Award in the self-service category for a project to automate customer payment time extensions. The project enabled eligible customers to request more time to pay their bill through the IVR system without speaking to a customer service representative. Customers also can hear details of any existing payment arrangement and whether they are eligible for an extension.

Q. Have the Companies experienced difficulty in recruiting, hiring and retaining call center and business office customer service representatives due to changes in the economy?

A. Yes. The Companies continue to face upward pressure in the job market as unemployment rates decrease and wages increase. The unemployment rate has dropped below four percent for the first time in 18 years.[15] This decrease in the unemployment rate has occurred rapidly; in January 2017, the unemployment rate was nearly 5 percent.[16] Additionally, the Companies have observed market increases in wages, especially among hourly employees.[17]

As a result, it has become more difficult to recruit and retain qualified applicants to work in Customer Representative positions in call centers and walk-in business offices. Attrition has increased and the Companies have experienced

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[15] Josh Mitchell, *U.S. Jobless Rate Falls Below 4% For First Time Since Late 2000*, The Wall Street Journal, (May 4, 2018), https://www.wsj.com/articles/u-s-adds-164-000-jobs-in-april-unemployment-falls-to-3-9-1525437126.

[16] *Id.*

[17] Case No. 2018-00005, Live Testimony of John P. Malloy, VR 1:45:12 (Ky. PSC July 24, 2018).

difficulty in filling new hire classes. These issues have increased costs and administrative burden associated with recruiting, hiring and training these employees. Specifically, given the length of time required to train a representative in all needed skills, higher attrition rates result in fewer full service employees to serve customers.[18] Not being fully staffed also results in more overtime and training cost, higher wait times, undesirable customer experience, and a negative impact to performance metrics such as service level, customer effort, and first contact resolution.

Q. How are the Companies addressing these hiring, recruitment and retention challenges?

A. Difficulty in hiring and retention of qualified call center and business office employees caused the Companies to examine the pay rates for existing and new employees in those positions. Advertised starting pay for the Companies' Customer Representatives has not changed since 2010. In early 2018, the Companies conducted an analysis of market data which revealed that entry level wages for similar positions were higher than what the Companies have been offering to new Customer Representatives and certain hourly rates required adjustment to be competitive with companies hiring for similar positions. The Companies considered several options for wage increases, and ultimately elected to apply location-based increases in wages

[18] The Companies’ hiring process spans approximately 90 days and includes reviewing resumes, facilitating personality testing, conducting interviews (including phone, video and in person), and other standard pre-employment testing such as EEI Customer Service Representative skill assessments, background check, and drug/alcohol screenings. Once hired, Customer Representatives are tasked with challenging responsibilities which include detailed knowledge of the Companies, high level understanding of rates and tariffs, complex billing and customer relationship management systems, and customer interaction skills including negotiation, problem solving and soft skills. These positions require working in a structured environment where calls and adherence to fixed schedules are monitored and quality checks are frequent. Training is offered in segments based on the type of customer interaction and it takes approximately 18 months to become proficient.

for new hires and existing employees. The advertised starting hourly wages for Louisville and surrounding areas where competition for talent is strong and the market data indicates wages are highest, have been increased from $12.00 to $16.00 per hour; Lexington and surrounding areas have been increased from $12.00 to $15.50 per hour; and Pineville, Morganfield and surrounding areas have been increased from $12.00 to $14.50 per hour. All Customer Representatives received a wage increase to maintain equity to the advertised starting rates for the region in which they work.

Q. What benefits will these wage increases provide?

A. The Companies expect to achieve a number of benefits from the wage increases. First, given the competition for skilled resources, the Companies expect to be able to attract a greater number of qualified candidates and successfully meet recruitment targets. Paying competitive wages will also assist in the retention of more experienced and longer tenured Customer Representatives, who can successfully become full service. This will enable the Companies to meet the increasing complexity of customer needs, improve services to customers, and result in more effective operations. Moreover, the wage increase is expected to aid in reducing unwanted attrition and unplanned absences of Customer Representatives.

Q. Please describe how the Companies provide meter reading and field services to customers.

A. Meter reading and field service functions are staffed primarily with contractors.[19] As of June 2018, the Companies' optimal contract staffing level is 143 meter readers and 63 field service contract positions. Contracts for these services were entered into in 2014 with two different business partners and are set to expire in May 2019.

Q. How are these two functions performing with regard to optimal staffing levels?

A. The Companies' have faced recent challenges with their business partners in maintaining an adequate number of qualified meter reading and field service technicians. Contractor turnover has increased and the Companies' business partners are experiencing difficulty attracting and maintaining a qualified workforce. Labor shortages and wage pressures in the market are causing these issues. While staffing has improved in 2018, challenges persist in meeting optimum contract staffing levels.

Q. What have the Companies done to address these staffing issues?

A. Beginning in 2016, upon recognizing a decline in contract staffing and associated meter reading metrics, the Companies' business partners, at the request of the Companies and with the Companies' involvement, initiated a series of incremental measures to address retention, performance, and training of meter readers and field service technicians. These measures included incentives, marginal pay increases and retention bonuses. Mitigation plans have resulted in some improvements but inconsistency in staffing levels persisted. As part of the Companies' business planning process, the Companies initiated a Request for Information ("RFI") to determine whether compensation rates for meter readers and field service technicians were competitive with industry averages. Responses to the RFI indicated current

[19] As of August 2018, there are 11 meter readers and 61 field service technicians who are employed by the Companies. The rest are third party contractors.

wage rates were well below market. Accordingly, when the current contracts expire in May 2019, the Companies project operating expenses related to meter readers and field service contracts to significantly increase over current spending on these services.

Q. What programs have the Companies implemented recently to achieve efficiencies and improve efficiency in customer service operations?

A. The Companies have implemented additional customer options and enhanced programs and services in recent years aimed at saving customers money, shifting transactions to technology solutions, and further enhancing the overall customer experience. For example, in January 2018, the Companies entered into a new agreement with their existing payment processor to reduce convenience fees customers must pay when using a credit or debit card to pay bills from $2.25 to $2.00.

The Companies continually work to enhance the call center's IVR system to allow more transactions to be completed without the need for a customer representative's involvement. Recent improvements include allowing eligible customers to request more time to pay their bill without speaking to a customer service representative. Since this function went live in May 2017, nearly 445,000 additional calls were handled using the IVR system through July 2018. Customers can now also use the IVR to request service to be reconnected once they have paid the necessary amount following a disconnection of service for non-payment. Other IVR improvements include direct connections to a representative for emergency calls, such as a wire down.

Customers who call during particularly busy times of day can now take advantage of "call back assist," which allows customers to hang up and receive a call back without losing their place in line. In the first year of operation, over 7,000 customers have opted for call backs using this feature.

The Companies have also improved the mobile device view for the "My Account" customer self-service feature and continually review and update internal and external security for "My Account" customers. Landlords or property managers using the "My Account" feature can now verify online whether a particular meter at their property is active or inactive.

The Companies have also recently implemented a new Meter Asset Management ("MAM") system to track metering assets across their full life cycle. The system will unify all meter records under one platform and will improve the Companies' ability to respond to customer requested meter tests.

Q. Please summarize the Companies' recent efforts to promote renewable energy.

A. The Companies are in the midst of several exciting developments in the ongoing effort to promote and attract renewable energy production and consumption in Kentucky, particularly solar energy. The Companies have achieved major milestones in their solar share and business solar programs, and are actively seeking more opportunities to develop and provide solar energy in the Commonwealth. Furthermore, the Companies are proposing a new tariff, called the "Green Tariff," which will allow customers to experience the full benefits of a renewable power project.

Q. What is the solar share program?

A. The solar share program is a means for customers to participate in community solar power generation without installing equipment at their homes or businesses. The Companies have purchased a dedicated site for the purpose of building a 4 MW solar array. The array will be built in eight (8) sections totaling 500 kW each. Each section represents 2,000 solar shares, and will be built as the Companies receive customer commitments filling the capacity for each section. Customers pay a monthly fee per share with no up-front enrollment fees, and are required to make a 12-month commitment to the program upon enrollment. Customers are credited a pro rata share of the energy on their bill based on the energy actually generated by the facility.

Q. What is the status of the program?

A. The first section of the project has full commitment and the Companies are seeking enrollments to fill capacity for the second section. As part of this rate case, the Companies are proposing changes to the solar share program to allow customers to purchase a complete 25-year subscription up front and to be able to transfer such subscribed capacity to another customer at the same utility company. The proposed revisions to the tariff also provides for net billing, in which credits for any power generated by the customer's share in the solar project are applied directly to offset that customer's monthly usage. The Companies anticipate that the proposed tariff revisions will better meet customer expectations for participation in the solar share program.

Q. What is the business solar program?

A. The business solar program is offered to non-residential customers seeking to have solar generation facilities constructed and owned by the Companies. Upon reaching an agreement, the Companies will install a solar array for a business customer. Upfront costs to the business are typically minimal and are associated with permitting and feasibility. Once installation of the array is complete, the business customer pays a monthly solar fee as agreed by contract and the Companies maintain and operate the equipment. The monthly solar fee is partially offset by credits for power generated by the array. In addition to benefitting from the value of the solar facility's output, business solar customers also benefit by causing new renewable generation facilities to be constructed.

Q. Have the Companies completed any projects for the business solar program?

A. Yes. In summer 2018, the Companies completed installation of the inaugural business solar project at the Archdiocese of Louisville office on Poplar Level Road in Louisville. The installed array includes 100 solar panels with the capacity to generate 30 kW of energy. The project is performing as expected and the Companies are regularly discussing opportunities with other businesses to initiate similar business solar projects.

Q. The Companies are proposing a new green energy tariff as part of these proceedings. What is a green energy tariff?

A. Green energy tariffs, or riders, are a mechanism for customers who desire to meet corporate sustainability objectives by playing a direct financial role in supporting renewable generation and having the energy from specific resources delivered to their particular facilities. Unlike green energy programs, which allow customers to claim the environmental attributes of a renewable energy project through purchasing Renewable Energy Certificates ("RECs"), green energy tariffs meet the customer's desire for renewable energy. This is typically accomplished through a series of back-to-back renewable power purchase agreements ("RPAs") wherein the utility acquires power from a renewable generator and resells the exact same resource to a particular customer or group of customers. Mr. Conroy's testimony presents the green energy tariff and describes the details.

Q. How will the Companies' proposed green energy tariff encourage economic development and investment in renewable energy in Kentucky?

Green tariffs encourage economic development by attracting or supporting large companies that have sustainability goals and targets in the utility's service area. Organizations that have taken advantage of green energy tariffs include Apple, Google, Amazon Web Services, Walmart, and Target. The Companies currently offer a green energy program, a solar share program, and business solar program to meet customer needs and to encourage growth and development of renewable energy generation. The proposed green energy tariff combines the green energy program and the business solar program with a third option, RPAs, under a single tariff.[20]

By streamlining the manner in which renewable energy programs are billed and by offering more choices for support of renewable energy generation to individuals and businesses in Kentucky, the Companies hope to stimulate further economic growth and development of new sources of renewable energy generation.

[20] Projects operated under the business solar program and RPAs would be subject to individual approval by the Commission as special contracts.

Q. Will you please summarize the capital investment the Companies plan to make in customer services operations for the period from January 1, 2018 to October 31, 2019?

A. The combined Companies plan to spend a total of $66 million in non-mechanism capital investment in customer services from January 1, 2018 through October 31, 2019. This spending includes $34 million for facility and site improvements, $12 million for meters, $5 million for facility consolidations, and $15 million for all other projects.

VI. ELECTRIC TRANSMISSION

Q. Please describe the Companies' electric transmission system.

A. LG&E and KU jointly plan and operate their combined transmission system as a single interconnected and centrally controlled system pursuant to the Transmission Coordination Agreement filed with FERC at the time the Companies merged in 1998. Joint operation of the system allows the Companies to achieve greater efficiencies and reliability benefits than could be achieved with separately operated systems.

The Companies' combined transmission system serves approximately 936,000 electric customers in a total of 79 Kentucky counties. The Companies' transmission plant in Kentucky covers more than 5,000 circuit miles and has a net book value of approximately $845 million.

Q. How do the Companies measure performance of the transmission system?

A. Transmission System Average Interruption Duration Index ("SAIDI") measures transmission reliability by quantifying the average electric service interruption in minutes per customer for a particular system. Because SAIDI measures average minutes of interruption, lower numbers are better. 2017 SAIDI for the combined

Companies was just 5.98 minutes, compared to 12.19 minutes in 2016. 2018 SAIDI is 2.97 minutes through July, which projects out to an annualized SAIDI of approximately 5.3 minutes. The combined Companies are also showing marked improvement in outages per hundred line miles per year ("OHMY"), a standard metric used for benchmarking by the North American Transmission Forum ("NATF"), a leading industry organization whose membership represents the vast majority of the transmission mileage in the United States and Canada. The Companies' combined Transmission OHMY improved by nearly twenty percent (20%) in a two year span - from 11.17 in 2015 to 9.07 in 2017, significantly improved from the average for either utility as described in the Transmission System Improvement Plan ("TSIP").[21] On transmission lines operating at greater than 200 kV, the Companies' OHMY performance has improved from fourth quartile in 2015 to first quartile in 2017.

Q. Given the Companies' recent improvement in transmission system reliability, is continued investment in transmission system modernization and reliability improvements needed?

A. Absolutely. While the year over year improvement in the SAIDI metric in 2017 is encouraging and indicates that investments are having a positive impact, one or two years of better results do not suggest our work is done. In order to meet customer expectations and to keep pace with improving transmission reliability industry-wide, the Companies must continue to invest in their transmission system, including those projects covered under the TSIP. As described in the TSIP, beginning in 2016, the

[21] The TSIP was submitted as Exhibit PWT-2 to Paul Thompson's testimony in the 2016 rate cases.

Companies set a goal of achieving and maintaining a 20 to 45 percent reduction in transmission SAIDI over the following decade. To meet that goal, investment in targeted asset replacement and system reliability is required. Aging and deteriorated equipment poses both a safety and reliability risk to customers. The Companies have an obligation to their customers and the public to proactively replace this equipment, particularly equipment beyond its useful life, to minimize the risk of equipment failure and consequent outages. This is a major component of the TSIP and following through on those system improvement programs is critical to the long term health of the transmission system. Likewise, the Companies have an obligation to continue investment in reliability programs like line sectionalizing, which can have a major reliability impact on individual lines and, eventually, the entire system.

Q. What investments are the Companies making in the transmission system to improve reliability and resiliency?

A. Starting in 2016, the Companies began implementation of the TSIP, a program to systematically replace aging and deteriorated transmission system infrastructure and add new equipment to the system to improve reliability. In response to the Commission's Order from the 2016 rate cases, the Companies recently submitted a comprehensive update on the progress of TSIP implementation and capital spending.[22]

In short, the Companies are executing on their proposed capital investments in the TSIP. The asset replacements include line equipment (poles, switches, overhead lines), underground lines, substation equipment (circuit breakers, insulators, line

[22] Case No. 2016-00370, Annual TSIP Report filed June 1, 2018; Case No. 2016-00371, Annual TSIP Report filed June 1, 2018.

arresters, capacitors), and protection and control equipment. In 2017, the Companies invested $96.6 million in these system integrity replacement projects, the majority of which was used to address aging wood utility poles and structures identified for replacement through detailed inspections with better performing and longer lasting structures. From January 1, 2018 through October 31, 2019, the Companies plan to spend an additional $192.8 million in capital on these replacement projects.

The TSIP also includes investments in line sectionalizing equipment – namely in-line breakers and switches – to improve reliability by reducing customer exposure to outages and shortening restoration time on long transmission lines with multiple load taps. The Companies spent a total of $8.5 million on line sectionalizing in 2017. From January 1, 2018 through October 31, 2019, the Companies plan to spend an additional $22.1 million in capital on line sectionalizing and other reliability improvement projects.

Q. Are the Companies achieving improved transmission system reliability as a result of these investments?

A. The Companies are seeing recent improvements in overall transmission system reliability as demonstrated by the SAIDI and OHMY metrics discussed previously. The dramatic impact of the Companies' investments can also be seen on specific lines where these improvements have been made. For example, the Lexington Plant to Pisgah line was previously KU's worst performing transmission line as measured by SAIDI. The line experienced eleven sustained outages and contributed 8.6 minutes of SAIDI since 2012. In 2016, as part of the line sectionalizing project, KU added switching equipment to reduce the number of customers exposed to outages on this transmission line. In addition, several miles of the line were replaced and rebuilt due to the condition and performance of the structures and conductors. Since the completion of these improvements to the date of this filing, there have been no sustained customer outages on this line.

Likewise, in 2016 KU added a motor operated switch and in 2017 added automation at the Irvine tap point of the Beattyville to West Irvine line. Prior to installation of this switch, this circuit experienced fourteen sustained events and accounted for 2.7 minutes of SAIDI over a four year period for an average SAIDI of 0.19 minutes per event. After these projects were completed, this circuit experienced four sustained events, but collectively those events accounted for only 0.03 minutes of SAIDI impact for an average SAIDI of 0.008 minutes per event. These projects demonstrate that new switching equipment has significantly reduced the time it takes to restore service when an outage occurs.

Q. What other capital projects are planned to ensure the transmission system will reliably serve expected customer demand?

A. As part of the annual long term planning process, the Companies conduct studies and analysis of the electric transmission system to ensure the expected demand levels and power flows will be adequately accommodated without exceeding system limits based on NERC requirements and the Companies' planning guidelines. This process is approved by the Independent Transmission Organization ("ITO") and the results are documented in the Transmission Expansion Plan ("TEP"). A number of projects are planned as a result of the latest TEP. The projects are determined after considering various alternatives to mitigating system constraints found in the analysis for the system under various demands, seasons and operating conditions.

For example, in the current TEP, the Companies identified a need to add 345kV reactors to the Trimble County transmission substation. The reactors will help to prevent an overload of the Trimble County to Clifty Creek 345kV line during an outage of a neighboring system's transmission line, which would jeopardize reliability and violate planning guidelines approved by the Companies' ITO. The Trimble County to Clifty Creek line is approximately 12.5 miles long, crosses the Ohio River, and connects the Trimble County generating station with OVEC's Clifty Creek generating station. This is a major transmission line impacting power flows to and from other regional transmission systems. The reactor project will have the effect of reducing power flow on the line by diverting it to other transmission lines with available capacity while maintaining the flow of this line below its summer rating. The total capital cost for this project is estimated at $2.9 million, and was identified as the lowest cost solution, which avoids a much more extensive reconductor project estimated to cost nearly $20 million.

Q. Please provide an update on the Companies' 5-year cycled approach to vegetation management and hazard tree removal.

A. Beginning in 2014, the Companies initiated a 5-year cycled approach to line clearing on extra high voltage ("EHV") transmission lines that operate at 345kV and 500kV. In mid-2017, the Companies began conversion to a cycle based line clearing program for transmission lines operating from 69-161kV and implemented a hazard tree removal program on lines operating from 69-500kV. ECI, an independent third-party consultant, recently completed a report on the status of the Companies' vegetation management and hazard tree programs, and that report dated August 2, 2018, is attached to my testimony as Exhibit LEB-4.

The ECI report notes that as of March 2018, the Companies had completed cycled line clearing on approximately 63 percent of the EHV lines and 13 percent of the lower voltage lines. Since 2014, the Companies have made great strides implementing industry best practices for line clearing and hazard tree patrols. The Companies' combined transmission system in Kentucky spans more than 5,000 line miles. Thus, over 1,000 line miles per year must be cleared to complete the cycle. In addition to implementing the cycled vegetation management plan at a rate of over 1,000 line miles per year, the Companies must continue with aerial inspections and "just in time" removal practices until the first cycle is complete. Once the first cycle is fully complete, the Companies expect that not only will system reliability be improved, but reliability will be maintained cost effectively by the use of industry standard integrated vegetation maintenance methods. These methods include a balance of herbicides and manual removal of vegetation on regular maintenance cycles.

Q. How are the Companies utilizing technology to improve vegetation management?

A. The Companies continue to use Light Detection and Ranging ("LiDAR") technology on EHV transmission lines to identify trees that pose a reliability risk. Use of LiDAR allows the Companies to survey transmission lines to precisely confirm line clearances and maintain compliance with federal reliability standards. In urban areas for transmission lines operating from 69-161kV, the companies are planning to utilize tree species surveys and LiDAR technology to identify necessary actions required for trees within the right of way. Using this technology, the Companies can better assess risks posed by trees and take actions necessary to protect the lines and maintain easements, which may include trimming rather than removal, or deferral of trimming or removal until the next inspection cycle.

Q. Have the Companies been subject to recent audits imposed by NERC reliability standards?

A. Yes. Southeast Electric Reliability Corporation ("SERC"), the entity responsible for monitoring and enforcing NERC reliability standards throughout the Southeast, including most of Kentucky, recently conducted two audits of the Companies to assess compliance with Critical Infrastructure Protection ("CIP") and Operations and Planning standards. These audits are conducted every three years and were performed from February 28, 2018 through June 4, 2018. There are a total of 39 CIP and 347 operations and planning requirements with which the Companies must comply. Based on an assessment of risk, SERC narrowed the scope to audit the Companies for compliance with 29 of the CIP requirements and 79 of the Operations and Planning requirements. The assessment was conducted to determine CIP compliance for the period from July 1, 2016 through June 4, 2018 and for Operations and Planning compliance for the period June 24, 2015 through June 4, 2018.

Q. What were the results of the CIP compliance audit?

A. The results were excellent. Across all 29 CIP requirements, SERC did not identify any findings or areas of concern within the scope of the audit. SERC made numerous positive observations in the audit report regarding the Companies' CIP compliance, including the observation that physical security enhancements are being implemented by the Companies at key transmission substations.

Q. What were the results of the Operations and Planning audit?

A. The results of the Operations and Planning audit were also excellent. SERC noted only one potential finding of non-compliance out of 79 compliance requirements, relating to analyses of contingencies in a specific delayed fault clearing situation. The SERC audit found that while the specified situation was not studied, more severe contingencies were likely studied, and accordingly found this potential non-compliance issue presented a low risk to the Bulk Electric System. The Companies have already implemented controls to address and correct this finding. The audit also included a number of positive observations, including the comment that system operators in the primary and backup control centers exhibited a "high level of skill and system understanding."

Q. What do the results of these compliance audits indicate?

A. These audits are objective proof of the Companies' commitment to physical and cyber security, while maintaining compliance with reliability standards imposed by regulation. They also demonstrate that the Companies prudently continue to do what is required by the standards and have implemented practices consistent with industry efforts to ensure the security and reliability of the bulk electric system for the safety and benefit of customers.

Q. What initiatives are the Companies pursuing to reduce cost and increase the efficiency of transmission operations?

A. Since the LG&E-KU merger and until recently, LG&E's distribution Supervisory Control and Data Acquisition ("SCADA") function was operated out of the Transmission Control Center. In the past year, the Companies have relocated the LG&E SCADA function to the Distribution Control Center. This move consolidates all distribution functions to the same facility and allows transmission to focus solely on transmission functions, including compliance with NERC reliability standards. This reorganization has contributed to more balanced allocation of operator workload.

In addition to support of vegetation management described above, the Companies use LiDAR technology instead of costly and time consuming manual field surveys to verify line ratings. Conducting these line surveys using LiDAR to match with the wood pole inspection cycle has resulted in efficiencies.

The Companies employ a number of software systems to streamline and improve transmission operations. The Transmission Reliability Outage Database System ("TRODS"), first implemented in 2014, has been continuously refined to simplify engineer access to disparate data to more readily determine the source of outages and prevent future outages. The TRODS data warehouse combined with business intelligence tools has facilitated the development of detailed metrics used to prioritize projects and track system performance. A new system was implemented in 2017 and has created process efficiencies for the balancing authority function in addition to automating most revenue calculations for third-party billing.

Q. Please summarize the capital investment the Companies plan to make in their transmission business.

A. The following chart summarizes capital expenses in transmission, by company, from January 1, 2018 through October 31, 2019 (in millions):

	KU	LG&E	Total
Proactive Replacement of Equipment, Including Poles	$160	$42	$202
Reliability Including Line Sectionalizing	$17	$5	$22
Transmission Expansion Plan	$18	$6	$24
All Other	$29	$10	$39
Total	$224	$63	$287

VII. ELECTRIC DISTRIBUTION

Q. Please describe the Companies' electric distribution system.

A. As with the other operational areas, the Companies' electric distribution system is jointly operated, planned and maintained to achieve efficiencies and maximize resource allocation. The electric distribution system serves a total of approximately 936,000 customers in 79 Kentucky counties. The Companies' electric service area covers approximately 5,200 square miles. Electric distribution facilities in Kentucky include a total of 520 substations (86 of which are shared with transmission), 16,772 miles of overhead electric lines, and 4,995 miles of underground electric lines. The net book value of the Companies' distribution plant in Kentucky is approximately $2 billion.

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

A. The Companies track reliability of their distribution facilities using performance metrics such as distribution SAIDI and distribution System Average Interruption Frequency Index ("SAIFI"). Distribution SAIDI measures the average electric service interruption duration in minutes per customer for the specified period and distribution system. SAIFI measures the average electric service interruption frequency per customer for the specified period and distribution system.

Q. How is the distribution system performing according to these metrics?

A. The system is performing very well. SAIDI for the Companies' combined distribution system was just 69.4 total minutes in 2017, its lowest (best) total in more than a decade. The Companies' 2017 SAIDI ranked in the first quartile of all benchmarked utilities according to 2017 industry data. Likewise, the Companies' distribution SAIFI has steadily improved since 2010, for a total of 0.743 in 2017, which ranked in the second quartile of benchmarked utilities according to 2017 industry data.

Q. Are there examples of the Companies' operational excellence that are not captured in these metrics?

A. Yes. Most industry metrics like SAIDI and SAIFI exclude what are called "major event days" **–** days in which outages are so far outside standard performance that they disproportionally skew reliability metrics. These are typically days involving widespread severe storms and high winds causing outages for a large number of customers. As I mentioned previously, the storms beginning on July 20, 2018 caused such a day, when service to approximately 174,000 customers was lost due to severe tree and structure damage caused by winds in excess of 70 mph, prolific lightning, and heavy downpours. This was the fifth worst storm outage event in the Companies' recorded history measured by number of customers affected. The Companies take great pride in the hardworking men and women who endured adverse conditions and worked around the clock to restore power to tens of thousands of Kentuckians in the aftermath of the storm.

In total, damage from the storms caused 4,600 cases of trouble, 108 circuit lockouts, over 200 broken poles, and over 1,200 wires down. More than 1,200 individuals, including the Companies' employees, contractors, and mutual assistance workers from other states, worked quickly and safely to restore power in the wake of the storm. The Companies' performance in the storm recovery was recently recognized by Kentucky Emergency Management, which commended the Companies' Storm Restoration Team for the "efficient and timely" restoration of these customers through an "all-hands and multi-state mutual aid" effort.

Q. Please describe the Mutual Assistance Program and how it adds value for Kentucky customers.

A. As demonstrated above, large-scale emergency recovery efforts would not be possible without the Companies' involvement in several regional mutual assistance groups. Through mutual assistance, the Companies can quickly increase the size of their workforce to respond to severe weather and outage events by accessing skilled labor and equipment from other utilities. As an example, over 500 of the 1,200 responders to the July 20, 2018 storm recovery were mutual assistance resources.

Periodically, the Companies release their own personnel, business partners, and resources to other utilities in need of assistance, always ensuring that adequate resources are available to serve native load customers in Kentucky. For example, In January 2018, the Companies sent more than twenty vehicles and thirty of its employees to assist with restoration of power to Puerto Rico after Hurricane Maria.

The Companies' employees spent nine weeks in Puerto Rico working 16-hour days in hot conditions and difficult terrain to assist with the recovery effort.

Membership and active participation in mutual assistance partnerships ensures the availability of support to the Companies' customers in times of need – including safe and timely recovery from major outage events. It also contributes to the development of strong interdependent relationships among partner utilities and facilitates the sharing of best practices for emergency response and management among members.

Q. What capital investments are contributing to the reliability of the Companies' distribution system?

A. The Companies have implemented a number of capital programs that have greatly improved the reliability and resiliency of the distribution system. These programs and their impact on system reliability and resiliency are discussed in detail in the Distribution Reliability and Resiliency Improvement Plan ("Distribution Plan"), attached as Exhibit LEB-5 to my testimony. As the plan document describes, the Circuits Identified for Improvement ("CIFI") program, first introduced in 2010, continues to contribute significantly to the reliability of the system. CIFI is a circuit hardening program which targets underperforming circuits for improvements – typically through installation of electronic reclosers. CIFI improvements have been made on 234 circuits since project inception, serving over 320,000 of the Companies' customers. Following CIFI investments, individual circuits averaged a 45 percent reduction in SAIDI and a 35 percent reduction in SAIFI. The Companies estimate that CIFI investments had a total SAIDI impact of 14.67 minutes in 2017, meaning the system performed over twenty percent (20%) better with the CIFI improvements than without them. Other investments to replace deteriorating or aging infrastructure, including wood poles, cables, legacy circuit breakers, load tap changers, and pad mounted switchgears, have likewise contributed to significant improvements in distribution reliability.

Q. The Companies requested and were granted a CPCN for the Distribution Automation ("DA") project in the 2016 rate cases. Please provide a status update on the project.

A. DA is a multi-component project involving the extension of intelligent control over the electrical power grid at the distribution system level. It provides capabilities for real time information gathering, remote monitoring and control, and "self-healing" of distribution circuits. The first component involves installation of electronic SCADA capable reclosers on the distribution system. The second component involves implementation of a distributed SCADA ("DSCADA") system that will monitor and communicate with these electronic reclosers. Upon connection to DSCADA, reclosers can be remotely operated by distribution system operators to restore service to as many customers as possible after assessment of faults on a particular circuit. The final component involves installation and deployment of a Distribution Management System ("DMS") that will interface with the DSCADA system to provide intelligent control over the electronic reclosers.

Since the inception of the project in July 2017 through August 2018, the Companies have installed a total of 413 of a planned 1,400 electronic reclosers, against a targeted 313 for the same time period. The Companies have been able to install reclosers faster than anticipated and are now targeting full implementation of the project by 2021. DA equipped circuits are now serving more than 200,000 of the Companies' customers. Twenty-nine of the reclosers have been connected to the DSCADA system and verified, and more will be added as the capabilities of the DSCADA system continue to be tested. The Companies have invested approximately $25.3 million in the DA project to date. The Companies plan to invest an additional approximately $86.9 million in the project through completion, with $52 million of this amount incurred January 1, 2018 through October 31, 2019.

Q. What reliability benefits are being realized through installation of the reclosers?

A. Even without being connected to DSCADA, the electronic reclosers provide immediate reliability benefits to customers through their ability to isolate faults on the distribution system. The reclosers installed to date have avoided service interruptions and customer outage minutes. Specifically, from July 2017 through August 2018, electronic reclosers installed as part of the DA implementation have avoided 16,763 service interruptions and a total of more than 6.3 million outage minutes. In the wake of the July 20, 2018 storms alone, these reclosers avoided 3,000 customer interruptions and 4.8 million customer outage minutes. The reliability impact of DA will continue to increase as more reclosers are added and DSCADA becomes more widespread on the system. Indeed, the significant reliability benefits demonstrated from installation of the reclosers to date have led the Companies to consider expanding the implementation of the program in the future to benefit a greater percentage of the Companies' customers. A proposed expansion of DA is discussed in the Distribution Plan attached to my testimony.

Q. How will Distribution Automation lead to greater efficiencies in operating the distribution control systems?

A. Once the program is fully functional with complete SCADA connectivity, DA will add numerous efficiencies to the Companies' operations. The system will be capable of identifying fault locations, and reduce the need for field technicians to search for and physically locate the source of faults on covered circuits. Automated switching from feeder line faults reduces the need for human involvement in fault switching and manual operation of the system. DA's system monitoring capabilities will enable early assessment of potential outages so they can be addressed before unplanned outages occur. Implementation of DA also provides the smart grid platform to support other centralized grid operations across multiple distribution lines and substations.

Q. Please provide an update on the Distribution Substation Transformer Contingency program.

A. This program provides for improved redundancy for substation transformers on the distribution system. The nature of the redundancy is three-tiered and depends on load density, customer impact, and cost. Transformer redundancy reduces the risk of extended outages associated with substation transformer failures. Contingency solutions may take the form of full redundancy through switching, use of mobile transformers, or localized spare transformers. Since program inception in 2015 through the end of 2017, the Companies have invested a total of approximately $15 million to provide contingency for fifteen transformers, reducing the risk of long term outage exposure due to transformer and associated equipment failure. Another $22 million in capital investment is budgeted for this program for the period between January 1, 2018 and October 31, 2019.

Q. How will the Companies continue to invest in the distribution system to improve reliability and resiliency?

A. In short, the Companies plan to continue investment in programs that have a demonstrated impact on system reliability and resiliency, including investments in circuit hardening and reliability (CIFI and related investments), strategic pole inspection and replacement, and replacement of aging infrastructure. The plan attached to my testimony as Exhibit LEB-5 explains these programs in detail. At the same time, the Companies will focus investment on technology-driven projects that support centralized grid operations. These investments include advancement of DA and networking systems that leverage SCADA functionality. These investments will give the Companies more control over grid operations, leading to increased reliability, greater operational efficiencies, more sophisticated emergency response, and enhanced worker safety.

Q. What other distribution capital projects are in progress?

A. A new Distribution Control Center ("DCC") adjacent to the existing Transmission Control Center ("TCC") in Simpsonville is currently under construction and is expected to be completed in mid-2019. The new control center brings under one roof the Companies' distribution control operations, including LG&E SCADA operators previously housed within transmission operations. The new DCC will have redundant electrical and mechanical systems to ensure uptime as the Companies move toward centralized grid operations. The projected capital cost of the DCC is approximately $13 million, $11.2 million of which will be incurred between January 1, 2018 and October 31, 2019.

Q. Are other new facilities planned?

A. Yes. To provide the collaborative workspace and engineering laboratory space needed for the various initiatives detailed throughout my testimony concerning electric transmission and distribution, the Companies are planning to construct an additional building on existing property at the South Service Center in Louisville. This will address inadequacies in current facilities and allow the Companies to co-locate substation engineering and design, distribution planning, asset management and reliability engineering personnel in a synergistic location. Although in the early stages, the Companies have allocated roughly $10.5 million for this facility. In addition, the Companies plan to construct or buy a new facility in Elizabethtown. This project will combine the Companies' two existing, separate locations into a single location for electric distribution and customer services personnel. Site procurement and improvements for this facility are expected to cost approximately $5 million.

Q. In addition to DA, what other initiatives are the Companies pursuing to increase the efficiency of distribution operations?

A. The consolidation of the DCC described above will lead to a number of added efficiencies. The new facility is specifically designed to house 12-hour shift employees. It will provide for increased operational efficiencies, and improved scheduling and training synergies as the DCC workforce turns over due to retirement of several experienced operators. Additionally, the new building will contain advanced technology and communications infrastructure needed to support ongoing and planned smart grid investments, including DA.

A mobile damage assessment application first implemented in 2015 and now fully deployed and operational provides for the timely and efficient exchange of information by off-system resources during a major outage event. Use of the mobile application reduces the need for radio and telephone communications, facilitates collection and sharing of damage data to safety response teams and the DCC, and permits response teams to effectively allocate resources based on the type and extent of reported damage.

The Companies are also working to expand the use of substation monitoring and controls systems to fifteen existing substations by 2020. Through the use of these control systems, the Companies can remotely monitor and control certain substation functions that currently require manual intervention, including reclosing in and out functions, ground relaying, and load tap in and out functions. By enabling remote control, fewer trips by field service personnel will be required to these substations, resulting in operational efficiencies including reduced personnel hours and reduced standby time for distribution crews.

Q. Do the Companies' distribution operations generate any revenue that is credited against the cost of providing service to customers?

A. Yes. The Companies permit third parties like cable and telecommunications providers to use their network of approximately 500,000 distribution poles to attach equipment. In exchange, those companies pay fees which are applied as credit to the cost of service for the benefit of the Companies' other customers. As a result of the last base rate proceedings, the Companies implemented Rate Pole and Structure Attachment ("PSA") to govern these third-party pole attachments. Rate PSA identified and standardized the conditions and terms of service for attachments. The Companies have continued to review administrative and operational procedures regarding pole attachments with a view to expanding that service, reducing the operational and financial risks to the Companies' electric service customers, and ensuring attachment services are reasonably, uniformly and fairly provided. The Companies have identified and propose several revisions to Rate PSA to further those goals. Mr. Conroy's testimony addresses these proposed revisions in detail.

Q. Please summarize the capital investment the Companies plan to make in their distribution operation business.

A. The following chart summarizes distribution capital expenditures by company from January 1, 2018 through October 31, 2019 (in millions):

	KU	**LG&E**	**Total**
Connect New Customers	$73	$55	$128
Enhance the Network			
Distribution Automation	*$24*	*$28*	*$52*
Circuit Hardening/ Reliability	*$23*	*$13*	*$36*
Transformer Contingency	*$6*	*$16*	*$22*
Other	*$44*	*$15*	*$59*
Maintain the Network	$67	$85	$152
Repair the Network	$12	$16	$28
Miscellaneous	$3	$2	$5
Total	$252	$230	$482

VIII. SMART GRID INVESTMENT SUMMARY

Q. Please summarize the Companies' smart grid investments.[23]

A. A document detailing the Companies' smart grid investments by project is included as Exhibit LEB-6 to my testimony. KU plans to spend approximately $55.8 million in smart grid investments from January 1, 2018 through October 31, 2019, and LG&E plans to spend approximately $42.2 million in smart grid investments during the same time period.

IX. GAS OPERATIONS

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

A. LG&E's gas distribution business serves approximately 326,000 customers in Jefferson and sixteen surrounding counties in Kentucky. LG&E owns significant infrastructure used to distribute gas to its customers, including five underground storage fields and three compressor stations. LG&E operates an approximate total of 4,300 miles of gas distribution pipe and 400 miles of gas transmission pipe on its system. The net book value of LG&E's gas system assets in Kentucky is approximately $843 million. LG&E's total annual throughput for 2018 is estimated to be 45 billion cubic feet (Bcf).

Q. Please describe the safety performance of LG&E's gas distribution operations.

A. The safety of LG&E's employees, business partners, and the general public is the first priority of LG&E's gas distribution operations. LG&E's performance in several key safety metrics reflects that commitment. Starting in January 2018, LG&E assigned additional resources to handle non-emergency orders such as turn ons/turn offs and

[23] This section is included to comply with the Commission's Order in *In the Matter of: Consideration of the Implementation of Smart Grid and Smart Meter Technologies*, Case No. 2012-00428 (Ky PSC Apr. 13, 2016).

low pressure reports in order to free up additional capacity for employees qualified to handle emergency orders. Emergency orders include reports of odor, carbon monoxide investigations, fires, and excavation damage. Those changes have resulted in significant reduction of emergency response times, from an average of 37.1 minutes in 2017 to an average of 31.1 minutes through July 2018.

The RIIR for contractors within Gas Distribution is 0.55 for 2018 through July, better than LG&E's target rate of 1.89. The RIIR for employees through July 2018 is 3.21 on a total of five recordable incidents, with none of these incidents resulting in a Lost Work Day case.

Q. Is LG&E performing projects to enhance public safety?

A. Yes. Due to the nature of the gas distribution business, nearly all projects undertaken by LG&E have a significant public safety component. However, several projects are worthy of mention here. In response to new U.S. Department of Transportation Pipeline and Hazardous Materials Safety Administration ("PHMSA") regulations, LG&E has developed a comprehensive Storage Integrity Management Plan ("SIMP") to address critical safety issues relating to downhole facilities, including wells, wellbore tubing, and casing at LG&E's underground gas storage facilities. The program enhances safety through monitoring and verifying the integrity of LG&E's underground storage fields. The comprehensive plan addresses numerous functional areas, including engineering analysis, risk and threat assessment, monitoring, testing, preventative measures, quality assurance, and emergency communications and planning.

LG&E is also implementing a gas inspection tracking and traceability program to electronically track plastic pipeline components using barcode scanners and upload those electronic records to a database, with some component and location information available to the Geospatial Information System ("GIS"). This program will not only assist LG&E in complying with the tracking and traceability portion of PHMSA's pending Plastic Pipeline Rule, which may be finalized this year, but will also provide more timely location information to the GIS when new plastic facilities are installed. Phase 1 of the project is for gas mains and associated services installed with mains. The first phase is currently in testing and is scheduled for rollout in late 2018 or the first quarter of 2019. Phase 2 is for services installed through dispatch system orders, and is planned for rollout by the middle of 2019.

LG&E is also undertaking additional transmission pipeline replacements to achieve uniformity in pipeline diameter and facilitate the use of enhanced inline inspections. This work is described later in my testimony. LG&E is utilizing additional inline inspection tools as technology evolves, and those tools provide a better understanding of the threats to the pipeline and its condition. The inline inspection tools now being used include geometry, axial magnetic flux leakage, circumferential magnetic flux leakage, electromagnetic acoustic transducer, and pipe grade sensors. Leveraging an expanded set of technologies enables LG&E to achieve a higher overall level of pipeline safety.

Q. What capital investment is LG&E making to ensure the reliable and safe operations into the future?

A. LG&E is engaged in a number of capital projects to expand and improve safe and reliable gas service to its customers. Future phases of the Transmission Pipeline Modernization Program, initiated in 2017, will add capability for enhanced inline inspections on a greater portion of LG&E's transmission infrastructure. LG&E is also engaged in a number of projects in the distribution system that will enhance reliability and ensure service to support growth in Jefferson and surrounding counties. This includes a project to add 10-12 miles of natural gas pipeline in Bullitt County, a reinforcement project to add 3 to 3.5 miles of high pressure distribution steel pipeline in Nelson County, and reliability upgrades to the elevated pressure system in Jefferson County. LG&E is also implementing a dry treatment process to improve the efficiency of gas treatment from underground storage, which also provides environmental benefits.

Q. Please provide an overview of LG&E's plan to add or replace gas transmission lines.

A. LG&E plans to replace approximately 13.2 miles of transmission line segments on the Western Kentucky A and B transmission lines to achieve uniform diameter and better facilitate enhanced inline inspection capabilities. Current technology for the enhanced inline inspection tools does not allow for continuous inspection of multi-diameter pipeline. LG&E will replace segments of predominantly 16-inch pipeline with 20-inch diameter pipeline to achieve the uniform diameter. Inline inspections will support compliance with proposed PHMSA regulations relating to expanding construction documentation requirements for natural gas transmission pipelines. In addition, use of an expanded set of inline inspection technologies enables LG&E to achieve a higher overall level of pipeline safety. Another 1.45 miles of nominal 12-inch transmission pipeline are being installed to replace the existing pipeline connecting the Western Kentucky and Magnolia pipelines to the Dixie Highway area. A total of eight road crossings on the Magnolia pipeline will also be replaced to better facilitate the use of enhanced inline inspection tools on the Magnolia line.

The total capital cost of the line replacements is expected to be $91.2 million. Most of the planned capital expenditure for these pipeline replacements is scheduled to occur outside the forecasted test period.

Q. Please provide a status report on the Bullitt County pipeline project.

A. The new natural gas pipeline in Bullitt County has been in the planning stages since 2016. The pipeline will be approximately 10-12 miles long and will improve reliability by supplementing the existing feed, mostly one-way, with additional gas supplies from the new pipeline. This new pipeline will mitigate the exposure of approximately 9,500 customers to a loss of gas supply from the current pipelines. It will also allow LG&E to serve future residential, commercial and industrial growth in Bullitt County by providing additional gas supply from the Calvary gas transmission pipeline to existing gas infrastructure. The project is currently in the design and engineering stage. Surveying work necessary to obtain federal, state and local permits has been completed and LG&E is in the process of applying for the permits. LG&E has obtained over one-half of the easements required to build the project. Total project cost is currently estimated to be $38.7 million with $25.5 million to be incurred for the period from January 1, 2018 through October 31, 2019.

Q. Please provide an overview of the Elevated System Pressure project in Jefferson County.

A. The Elevated Pressure System consists of four separate pressure systems within Jefferson County which normally operate at 2.0 psig. Combined, these systems make up approximately 160 miles of gas mains serving approximately 14,000 customers, and are surrounded by medium pressure systems. Over time the load on these systems has continued to grow, and reinforcement work is needed to continue to safely and reliably serve these customers.

Proposed work to these systems includes converting existing sections of the elevated pressure system to medium pressure. Work is expected to include uprating existing plastic service lines and plastic main lines, replacing steel service lines with polyethylene service lines, replacing steel main lines, and installing new regulator facilities. Much of the steel pipe in the elevated pressure area dates back to the early 1950s and will be replaced when reinforcement work occurs in those areas. LG&E expects to spend $4 million in capital on this project from January 1, 2018 through October 31, 2019.

Q. Please provide an overview of the Nelson County Reinforcement Project.

A. LG&E plans to construct an approximately 2.5 to 3.5 mile, likely 12-inch, steel high pressure distribution pipeline that will extend from the Calvary Transmission pipeline from north of the Bardstown Operations Center on Bloomfield Road to the Highway 245 area on the west side of the system. The primary driver for this project is to extend an additional gas supply to the west side of the existing distribution system to accommodate additional growth. The additional supply also reinforces the existing system making it more reliable in the event of issues at one of the existing regulator stations supplying the system. The existing system could support some modest commercial and residential growth, but is limited hydraulically by pressure and population growth not in proximity to the existing supply system. The new pipeline will provide additional capacity to serve an area that cannot be adequately served with existing infrastructure if commercial or industrial demand grows, supporting the Companies' objective of facilitating economic development overall. The estimated cost of the new pipeline is $12.5 million. Route selection will occur in 2019, with engineering and real estate work in 2020 and construction in 2021.

Q. Please describe the new amine treatment process to be used at Magnolia and Muldraugh compressor stations.

A. Gas removed from underground storage must be treated to remove hydrogen sulfide to ensure the safety of the gas and to comply with federal regulations for gas quality. In the past, LG&E has achieved this removal through a wet amine chemical process. The wet process is complex and requires extensive equipment, including boilers, pumps, coolers, heat exchanges, and filtration systems. LG&E will replace this amine treatment process with a dry treatment system at Magnolia and Muldraugh compressor stations. The new system will simplify gas treatment processes, reduce manpower required to operate processing equipment, increase reliability, and eliminate safety risks associated with the wet chemical process. The capital cost of these systems is expected to be $18.9 million, of which $7.6 million will be incurred for the period between January 1, 2018 and October 31, 2019.

Q. What actions has LG&E taken in response to recently proposed or promulgated federal gas regulations?

A. Two of the larger projects undertaken by LG&E to meet regulatory requirements are described earlier in my testimony. The SIMP and the gas inspection tracking and traceability program are both designed to meet PHMSA regulations. Furthermore, PHMSA finalized new gas Control Room Management ("CRM") team-based training requirements in early 2017. These rules require team-based training for all company employees who communicate with gas control operations on a normal, abnormal, or emergency basis. LG&E has developed and will support a training program compliant with the new regulations. Implementation of these programs and other safety and reliability programs will result in some increase in LG&E's operations and maintenance costs for gas distribution operations.

LG&E has also increased inspections of farm taps connected to transmission pipelines from a ten year interval to a three year interval in response to a rule change that became effective in 2017. 275 farm taps in the LG&E system are affected by the new inspection requirements.

Q. Have these actions resulted in increased headcount and other incremental costs to LG&E?

A. Yes. In addition to cost and time incurred in creating the program, LG&E added three incremental positions in 2018 solely to support the development and implementation of the SIMP to ensure compliance with PHMSA regulations. LG&E added another two incremental positions to Gas Control in 2018 to support the CRM compliance program.

The burden imposed by increased regulatory requirements is not limited to increased headcount. The compressed inspection cycle imposed by the farm tap rule will increase LG&E's inspection costs as well. Additionally, new fees such as the Gas Storage Annual Safety Assessment Fee, first effective in 2017, increased nearly threefold in 2018. Department of Transportation gas transmission annual safety assessment fees also continue to increase and impose more costs on LG&E.

Q. Why are LG&E's gas operations and maintenance expenses expected to increase?

Mr. Blake notes in his testimony that LG&E expects an increase in operations and maintenance expenses related to safety, reliability, and regulatory compliance measures for the gas business. A portion of this increase is attributable to the planned use of enhanced inline inspection tools for gas transmission lines. As I described earlier in my testimony, use of enhanced inline inspection tools promotes a higher level of overall pipeline safety and assists LG&E in complying with pipeline safety regulations. LG&E also expects to incur additional operations and maintenance expenses associated with complying with line locating requirements and the use of new business partners to perform line locating starting in 2019. These cost increases are related directly to line safety and the performance of functions required by state regulation. Other expected increases pertain to improvements to emergency response, safety, technical training, regulatory compliance initiatives and increased labor costs for customer service operations, including meter reading,[24] described elsewhere in my testimony.

Q. What programs has LG&E implemented to increase operational efficiency and productivity in gas distribution?

A. The Gas Training Tracking program enables LG&E to record and track all external and on the job training for gas distribution employees. The centralized database facilitates supervisor and management access to training records and provides enhanced reporting for developmental training. As I previously mentioned, the program has been successful and the Companies are now scaling it for use in other operational areas. LG&E is also developing a means to transition its mobile dispatch system – central to the company's field operations – to a tablet platform for implementation by 2020. This transition will provide a mobile-friendly interface and should result in operational efficiencies and productivity by streamlining the field equipment used across the Companies' operations.

The first amine hydrogen sulfide ("H_2S") Scavenging System I describe above was installed at the Magnolia gas storage fields in 2017. Scavenger towers ensure that gas withdrawn from underground storage meets gas quality regulatory requirements. During certain peak periods, the gas flow rates from storage can exceed the capacity of the amine H_2S removal systems. In those instances, the scavenging system can process the excess flow and prevent reduction in gas supply, thereby increasing the reliability of processing systems.

[24] Hourly wage growth in Louisville is up 3.1 percent year over year for July in Louisville, compared to 2.9 percent nationally in August. Louisville Business First, *Why Louisville's Unemployment Lags Behind the Rest of the U.S.*, Sept. 11, 2018..

The Gas Inspection Tracking and Traceability program is discussed in detail earlier in my testimony. It improves operational efficiency both by increasing the amount of location information captured for plastic pipelines while decreasing the amount of time it takes to provide location information to the GIS. LG&E is also implementing a mobile mapping framework for tablets that will be used in several operational areas. This program will standardize equipment used by field technicians and provide a more mobile-friendly interface leading to more efficient and productive work.

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

A. Yes, I am co-sponsoring, along with Mr. Blake, the schedules required by Section 16(7)(c). These documents are submitted with the Companies' applications. I am also sponsoring the schedule required by Section 16(7)(h)(8), mix of gas supply forecast for 2019, 2020 and 2021. This schedule is submitted with LG&E's application.

Q. Please summarize the capital investments that LG&E will make in its gas business.

A. The following chart summarizes the non-mechanism gas capital expenditures by LG&E from January 1, 2018 through October 31, 2019 (in millions):

	LG&E Total
Connect New Customers	$9
Enhance the Network	
Bullitt County Line	*$26*
East End Reinforcement	*$6*
Elevated Pressure Upgrade	*$4*

Replace Pad Meters	*$4*
Other	*$12*
Maintain the Network	$56
Repair the Network	$1
Miscellaneous	$2
Total	$120

X. RESEARCH AND DEVELOPMENT

Q. Please describe the Companies' research and development program.

A. The LG&E and KU research and development team investigates and evaluates a range of new technology applications to find ways to better serve their customers. Frequently, the Companies partner with organizations like the Electric Power Research Institute ("EPRI") to participate in collaborative studies in which the costs and benefits of research and development are shared with other utilities. The Companies' historical research initiatives are extremely diverse – addressing issues such as solar generation, energy storage, smart grid technologies, and environmental controls.

Q. How are the Companies working to develop and encourage others to develop further research in solar generation?

A. As indicated earlier in my testimony, the Companies have generated valuable data in developing, constructing, and operating a first-of-its-kind commercial solar generation facility in Kentucky. The solar dashboard now publicly available on the Companies' website is an effort by the Companies to share that information with others to advance solar generation research and encourage customer adoption of solar as a complement to fossil-fuel generation. By publicly sharing this valuable research, the Companies hope to play an integral role in development of solar technology in Kentucky and beyond.

Q. Have the Companies recently been recognized for research and development achievements?

A. Yes, in June 2018, research teams at the Companies received three different technology transfer awards presented by EPRI. The first was the Power Delivery Award for the Companies' work on the Energy Storage Research and Demonstration Test Site at the Brown generating station. This unique test site provides the Companies with a testbed for evaluating utility-scale energy storage technologies in conjunction with other utilities, educational institutions, and storage providers.

The Environmental Affairs and Research and Development Teams were awarded the Environment Award for their work on the Ohio River Ecological Research Program. This is a collaboration between the Companies, EPRI and several other utilities to establish the world's largest and longest-maintained freshwater database to monitor the effects of power generation on the surrounding environment, including wildlife.

Finally, a research project at Ghent generating station involving selective catalytic reduction systems ("SCRs") received an EPRI technology transfer award for Generation. LG&E and KU engineers involved in this project studied SCR performance at temperatures below minimum operating temperatures per vendor specifications, and concluded that SCRs will work as designed at lower temperatures.

Q. Do you have a recommendation pertaining to the Companies' applications?

A, Yes. For the reasons presented in my testimony and the testimony of the other witnesses, LG&E and KU respectfully request that the Commission enter orders approving the present applications of each company for an increase in base rates.

Q. Does this conclude your testimony?

A. Yes, it does.

VERIFICATION

COMMONWEALTH OF KENTUCKY)
)
COUNTY OF JEFFERSON)

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

Lonnie E. Bellar

Lonnie E. Bellar

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 19th day of September 2018.

Judy Schooler

Notary Public

My Commission Expires:
Judy Schooler
Notary Public, ID No. 603967
State at Large, Kentucky
Commission Expires 7/11/2022

APPENDIX A

Lonnie E. Bellar
Chief Operating Officer
Louisville Gas & Electric Company
Kentucky Utilities Company
220 West Main Street
Louisville, Kentucky 40202
Telephone: (502) 627-4830

Education

Bachelors in Electrical Engineering;
University of Kentucky, May 1987
Bachelors in Engineering Arts;
Georgetown College, May 1987
E.ON Academy, Intercultural Effectiveness Program: 2002-2003
E.ON Finance, Harvard Business School: 2003
E.ON Executive Pool: 2003-2007
E.ON Executive Program, Harvard Business School: 2006
E.ON Academy, Personal Awareness and Impact: 2006
Tuck Executive Education Program, Dartmouth University: 2015

Professional Experience

Louisville Gas & Electric Company
Kentucky Utilities Company

Chief Operating Officer	Mar. 2018 - Present
Sr. Vice President – Operations	Jan. 2017 – Mar. 2018
Vice President, Gas Distribution	Feb. 2013 –Jan. 2017
Vice President, State Regulation and Rates	Nov. 2010 – Jan. 2013

E.ON U.S. LLC

Vice President, State Regulation and Rates	Aug. 2007 – Nov. 2010
Director, Transmission	Sept. 2006 – Aug. 2007
Director, Financial Planning and Controlling	April 2005 – Sept. 2006
General Manager, Cane Run, Ohio Falls and Combustion Turbines	Feb. 2003 – April 2005
Director, Generation Services	Feb. 2000 – Feb. 2003
Manager, Generation Systems Planning	Sept. 1998 – Feb. 2000
Group Leader, Generation Planning and Sales Support	May 1998 – Sept. 1998

Kentucky Utilities Company

Manager, Generation Planning	Sept. 1995 – May 1998
Supervisor, Generation Planning	Jan. 1993 – Sept. 1995
Technical Engineer I, II and Senior, Generation System Planning	May 1987 – Jan. 1993

Professional Memberships

Institute of Electrical and Electronics Engineers

Civic Activities

E.ON U.S. Power of One Co-Chair – 2007
Kentucky Science Center – Board of Directors – 2008–Present
Metro United Way Campaign – 2008
UK College of Engineering Advisory Board – 2009 – Present
American Gas Association – Board of Directors – 2013 – Present
Southern Gas Association – Board of Directors – 2013 – Present
Greater Louisville, Inc. – Board of Directors, Executive Committee – 2016–Present

Exhibit LEB-1

Summary of Generation Plant

Summary of Generation Plant of KU & LG&E

Generating Facilty/Unit	Unit Type	Summer Net Capacity (MW)*	KU Ownership (%)	LG&E Ownership (%)
Brown 1,2,3	Coal-Fired	681	100%	n/a
Brown 5	CT	130	47%	53%
Brown 6	CT	146	62%	38%
Brown 7	CT	146	62%	38%
Brown 8, 9, 10, 11	CT	484	100%	n/a
Brown Solar	Solar	8	61%	39%
Cane Run 7	CCGT	662	78%	22%
Cane Run 11	CT	14	n/a	100%
Dix Dam 1, 2, 3	Hydroelectric	31.5	100%	n/a
Ghent 1, 2, 3, 4	Coal-Fired	1,919	100%	n/a
Haefling 1, 2	CT	24	100%	n/a
Mill Creek 1, 2, 3, 4	Coal-Fired	1,465	n/a	100%
Ohio Falls 1-8	Hydroelectric	64	n/a	100%
Paddy's Run 11, 12	CT	35	n/a	100%
Paddy's Run 13	CT	147	47%	53%
Trimble County 1	Coal-Fired	370	n/a	100%[1]
Trimble County 2	Coal-Fired	549	81%	19%[2]
Trimble County 5, 6	CT	318	71%	29%
Trimble County 7, 8, 9, 10	CT	636	63%	37%
Zorn 1	CT	14	n/a	100%

* Represents the net summer, 2018 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 relative to KU and LG&E. 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] KU and LG&E 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 LEB-2

2018 RTO Membership Analysis

2018 RTO Membership Analysis
September 2018

Contents

1 Executive Summary

This analysis was performed to determine whether membership in the Midcontinent Independent System Operator ("MISO") or the PJM Interconnection ("PJM") Regional Transmission Organizations ("RTOs") may provide potential benefits to Louisville Gas and Electric Company ("LG&E") and Kentucky Utilities Company's ("KU") (collectively "Companies") retail and wholesale requirements customers. The Companies last performed a similar analysis in 2012, which showed that membership in MISO or PJM was not beneficial at that time.

The decision to join an RTO is a significant long-term commitment that requires careful consideration of many variables and assumptions, including whether operation under the rules of the RTO is consistent with the Companies' obligations to their customers. RTOs continue to evolve, which complicates analyses of whether RTO membership would be beneficial. RTO policies, requirements, and operations are driven by the changing regulatory landscape, variable market conditions, and diverse stakeholder groups that represent varying interests across multiple states.[1] Though much about RTOs is in flux, this analysis weighs the potential benefits, costs, and uncertainties of RTO membership based on our understanding today.

As in the previous analysis, a cross-functional team was organized to identify the major costs, benefits, opportunities, and uncertainties compared to the status quo operations of the Companies. Where possible, the team quantified components that would be expected to have financial impacts, with this quantifiable analysis based on and limited to the specific underlying assumptions described below. In addition, the team identified and addressed non-quantifiable considerations and uncertainties that have the potential to materially impact the decision, and provided a list and brief summary herein.

This analysis concludes that the costs and uncertainties of membership in either MISO or PJM currently exceed the known potential benefits, but it also suggests that there is merit to periodically reevaluating the potential costs or benefits of RTO membership in the future.

[1] MISO operates over 15 US states and one Canadian province to manage approximately 65,000 miles of high voltage transmission and 200,000 MW of generating resources. PJM operates over 13 states and the District of Columbia to manage over 84,000 miles of high voltage transmission lines and 178,560 MW of generating resources.

2 Objective

As described in this report, a thorough review was undertaken using available information and existing modeling functionality to determine whether RTO membership in MISO or PJM may provide potential net benefits to the Companies' customers.

For purposes of this membership analysis, RTO membership includes transferring functional control of transmission assets and mandatory participation by the Companies' generation and load in the various markets administered by the RTO.

3 Background

The Companies were founding members of MISO, operating within MISO from 2002 until 2006. In 2003, the Kentucky Public Service Commission ("Commission") initiated on its own motion an investigation into the Companies' membership in MISO to determine if that membership provided net benefits to customers.[2] The Commission ultimately determined in late May 2006 that ongoing MISO membership was not likely to provide ongoing net benefits to customers and authorized the Companies to terminate their MISO membership.[3] The Companies completed their withdrawal from MISO as transmission-owning members effective September 1, 2006.[4] Note that this withdrawal does not mean that the Companies cannot participate in the MISO or PJM markets; rather, the Companies are market participants in, and regularly transact in, both RTOs.

Since exiting MISO, the Companies have periodically conducted high-level analyses to evaluate whether full membership in an RTO might be beneficial to its customers. Most notably, the Companies conducted a 2012 RTO Membership Analysis, which showed RTO membership was not then in customers' interests. The Companies submitted the 2012 analysis to the Commission during their 2016 Kentucky base-rate cases. In those cases, the Companies further committed to completing their then-ongoing RTO

[2] *In the Matter of: Investigation of the Membership of Louisville Gas and Electric Company and Kentucky Utilities Company in the Midwest Independent Transmission System Operator, Inc.*, Case No. 2003-00266, Order (July 17, 2003).

[3] Case No. 2003-00266, Order (May 31, 2006).

[4] The withdrawal from MISO is associated with certain transmission "depancaking" arrangements for a number of customers exporting to or importing from MISO as well as commitments to retain a Reliability Coordinator and Independent Transmission Organization. These elements are treated as costs for the purpose of this analysis and the impact of RTO membership to these costs is explained in both the description of assumptions and the analysis results.

membership analysis and providing results no later than the end of calendar year 2018.[5] This report is the result of that commitment.

In preparing this report, the Companies reviewed the PSC filings and RTO analyses performed by the Kentucky entities operating in an RTO, including their primary drivers of membership. The Companies determined that the Companies' current situation is different from the circumstances and drivers that led to those entities decisions to join their respective RTOs. A brief summary of this research is provided in Appendix D.

4 Methodology

Similar to previous analyses, a cross–functional team of LG&E and KU staff updated the previous RTO Membership Analysis while considering recent RTO operational changes and other new information. The team consisted of representatives from Corporate Compliance, Energy Planning Analysis & Forecasting, Federal Policy, Legal, Power Supply, Transmission, and State Regulation and Rates.

The Companies performed a ten-year analysis focused on estimating the net financial impact to customers by comparing the status quo operations of LG&E and KU to estimated incremental benefits and costs of RTO membership.

To determine which components of RTO membership might have a material impact, the team:

- Reviewed relevant material, including MISO and PJM tariffs and business practices, rate and pricing information, market data, industry publications, EKPC cost-benefit analysis, and the BREC filing to join MISO;
- Met other RTO market participants to discuss their experiences; and
- Drew from the Companies' previous experience as MISO members and their current experience as MISO and PJM market participants.

Estimates of the cost and benefit components provide a view of future financial annual impacts of RTO membership. Because it is not possible to predict with certainty many components, the team developed and studied three scenarios using different projections and assumptions to provide a range of potential outcomes. The High Case uses assumptions most supportive of RTO membership, such as lower administration

[5] *In the Matter of: Electronic Application of Kentucky Utilities Company for an Adjustment of Its Electric Rates and for Certificates of Public Convenience and Necessity*, Case No. 2016-00370, Kentucky Utilities Company's Response to the June 22, 2017 Order of the Kentucky Public Service Commission in Case No. 2016-00370 at 10 (Sept. 20, 2017).

costs, higher energy and capacity prices, and lower transmission expansion costs. The Mid Case uses assumptions and forecasts reflective of limited volatility using published forecasts for administration costs, historic market performance information, and transmission expansion costs based on published MISO rates and the use of a neighboring PJM utility as a proxy. The Low Case captures the downside risk of RTO membership uncertainty and volatility by assuming poor market performance and increased costs. Appendix A contains a description of the methodology used to develop the underlying assumptions that differ between the three scenarios.

Although the scenarios apply the underlying assumptions across all ten years, it is possible that actual performance across the ten-year period could be of mixed results with some years more consistent with the High Case, with others more consistent with the Low or Mid Case. In other words, the purpose of the three cases is to provide a reasonable range of possible outcomes across ten years, not to say that there are only three sets of possible outcomes.

5 Key Assumptions and Methodology

- The time period of the analysis was 2020 through 2029. A 10-year term is consistent with the term used in the 2012 analysis and the term analyzed in association with other analyses provided to the Commission.
- The total financial impact of Firm Transmission Rights ("FTR"), Auction Revenue Rights ("ARR"), and congestion costs over the ten-year period have net zero cost. When the Companies were MISO members, the congestion management strategy was to hedge congestion costs, seeking to minimize such costs and not speculate. It is assumed this will be the approach if the Companies were RTO members in the future.
- The purchase or sale of ancillary services has net zero cost because the Companies are both buyers and sellers of these products and any charges are offset by credits. This assumption is consistent with other analyses provided to the Commission.
- The Companies estimated potential trade benefits using their commodity price forecasts, generation available for sales, and native load forecasts used for annual business planning.
- The Companies did not use generator-specific or load-specific Locational Marginal Pricing ("LMP") models.
- No changes to the Companies' generating fleet occurring during the analysis time period.
- The analysis focuses on impacts to the Companies' native load customers only and not third party generators, loads, or other potentially impacted parties.

- Quantifiable items do not include any value adjustments to account for potential future changes in policy or market rules.
- Merger mitigation depancaking ("MMD") costs are included under the status quo case.[6] The impact to MMD costs as a result of joining an RTO is estimated. MMD costs are assumed to be completely eliminated with MISO membership. The majority of MMD costs are assumed to be eliminated with PJM membership but certain such costs (i.e., MISO Rate Schedule 26A) are assumed to remain because all PJM members pay such costs.
- Generating capacity above the RTO Planning Reserve Margin results in a benefit and is quantified in the Capacity Auction Benefits.
- Uplift costs are based on RTOs' estimates of costs to load.
- Some reallocation of human resources is assumed to be necessary, but it is assumed that there is no change in overall headcount.
- No financial impacts from deviations between day ahead and real time energy markets, operations, and load are included in the analysis.

6 RTO Cost Components

6.1 Allocation of Transmission Expansion Costs

Transmission planning and the allocation of expansion costs are major activities for each RTO. A significant cost in this analysis is the allocation of transmission expansion costs allocated to RTO members.

- For MISO membership, the Companies' annual costs would range from $52 million to $56 million in the Mid Case.
- For PJM membership, the Companies' annual transmission expansion costs would range from of $24 million to $36 million in the Mid Case.

6.1.1 MISO

Under current MISO policy, the cost of new transmission projects that address energy policy or provide widespread benefits across the footprint are considered "multi-value projects" ("MVP"). The cost of MVP are allocated 100% to load using a "postage stamp" methodology, i.e., all load pays the same rate for MVP irrespective of where located in the footprint, and are recovered under Schedule 26A of the MISO Tariff. LG&E and KU's estimated share of the $6.7 billion in MVP projects currently identified in the MISO

[6] Although the Companies have filed with FERC to eliminate this obligation no order has been received to date granting this request. *See*, Docket Nos. EC98-2-001 and ER18-2162-000.

Transmission Expansion Planning ("MTEP") process is based on the "indicative annual charges for approved MVP" published on the MISO website applied to the Companies' forecasted loads.[7] There could be transmission expansion costs allocated to the Companies' loads beyond MVP cost.

The annual expansion costs were reduced by 20% from the Mid Case to assign a value for the High Case and increased by 20% from the Mid Case to assign a value to the Low Case. The Companies used 20% as reasonable variance in cost due to increased construction cost of MVP projects or possibility that one or more MVP projects would not be completed. Historically, MISO's MVP projects have increased in cost roughly 20% from their initial projected costs since their inception in 2011.

6.1.2 PJM

Under current PJM policy, the cost of new high voltage transmission projects approved under its annual Regional Transmission Expansion Planning ("RTEP") process is allocated based on a combination of zonal load ratio share and flow-based calculation. These charges are recovered under Schedule 12 of the PJM tariff. The Companies estimated their allocation for projects documented in the RTEP within this analysis period using PJM's publicly posted RTEP project information.

The annual expansion costs were reduced by 20% from the Mid Case to assign a value for the High Case and increased by 20% from the Mid Case to assign a value to the Low Case. The Companies used the same variance assumptions they applied concerning MISO because there was no publicly available PJM proxy regarding such data. The lack of a proxy means the variance is more uncertain, but it is not possible to know and quantify the magnitude of that additional uncertainty. Therefore, the Companies used the same variance for both MISO and PJM.

6.2 Administrative Charges

MISO and PJM have various tariff schedules to recover the administrative cost of operating the markets and providing services to their respective members. Each RTO forecasts that their administration costs will increase around 2.5% each year.

MISO annual cost in the Mid Case is $12 million beginning in 2020 and increases to $15 million by 2029. MISO's 2016 forecasted administrative rate for 2020 was escalated 2.5% each year and then applied to the Companies' annual load forecast to estimate annual MISO administration expense. The administration rates are based on cost projections contained in MISO's 2016 revenue requirement forecast.

[7] https://www.midwestiso.org/_layouts/MISO/ECM/Redirect.aspx?ID=135589

PJM annual cost in the Mid Case is $17 million beginning in 2020 and increases to $22 million by 2029. The Companies based these estimates on 2017 state-of-the-market reports submitted by PJM's market monitor.

Although revenue requirements for administrative costs are expected to increase between 2% to 3% each year, the average cost to load can be more volatile, driven by the amount of load (weather and demand dependent) and the number of customers to allocate expense, which can vary by RTO membership entries and exits. Prior year results show at times double-digit year-over-year changes to the cost per MWh to load, both positive and negative, e.g., ranging from 17% lower to 15% higher. To reflect forecast rate volatility compared to Mid Case results, the annual administration costs were reduced by 20% from the Mid Case to assign a value for the High Case and increased by 20% from the Mid Case to assign a value to the Low Case.

6.3 Uplift Costs

MISO and PJM have various mechanisms for allocating uplift costs that result from operations of the markets and payments made to others that are not offset by revenues. Typically, these costs for both RTOs are the result of committing units in real-time that were not committed in the day-ahead market. MISO refers to uplift costs as "revenue sufficiency guarantee" ("RSG") costs; PJM refers to such costs as "balancing operating reserve" ("BOR") expense. MISO RSG expense is expected to average about $7 million per year and PJM BOR expense is expected to average about $6 million per year. Rates are based on state-of-the-market reports submitted by each RTO's market monitor.

Although uplift costs have declined year-over-year since 2014, there remains a risk of material additional cost assignment driven by extreme weather events and unplanned outage risk.

In 2014 PJM collected $960 million in uplift, with an average cost to load of $1.15 per MWh. PJM then took steps to address issues contributing to uplift, including implementation of enhanced testing requirements for generators receiving capacity payments, increased penalties for non-performance, and the shift of reserve capacity from the West Region to the East. As a result, in 2015 uplift cost declined 67% to $0.38 per MWh and then saw another 55% decrease in 2016 to $0.17 per MWh. While the 2017 cost was $0.14 per MWh, the Companies used PJM's 2016 uplift cost to load for this study to account for potential market volatility.

MISO uplift costs have also decreased since 2014, although on a less extreme and more stable basis as compared to PJM, resulting from a combination of RTO improvements related to cost causation and lower fuel expense. Uplift cost of $0.40 per MWh to load in 2014 declined to $0.22 per MWh in 2015 and then decreased further to $0.20 in 2016. MISO's 2017 cost increased to $0.25 per MWh, but the Companies used MISO's 2016 rate for this study to be consistent with the time period used in PJM's analysis.

Planning for and managing through extreme weather and unplanned outage events is difficult, particularly because the response would be directed by the RTO juggling resource, market, and other considerations over a wide area. Therefore, uplift costs are a potentially material expense risk for RTO participants.

6.4 Lost Transmission Revenue

The analysis reflects an expected decrease in the sale of point-to-point transmission service resulting from RTO membership, and this lost revenue is included in the analysis. The forecasted lost annual revenue ranges from $3.2 to $6.2 million

6.5 Lost Joint Party Settlement Revenue

An additional $1.2 million of lost revenue was also included because of the existing settlement agreement between MISO, SPP, and the Joint Parties (including the Companies). This joint party settlement agreement addressed issues identified by SPP and the Joint Parties that arose from MISO's southern expansion to include Entergy and operate as a single Balancing Authority Area. Under the settlement agreement, MISO compensates SPP and the Joint Parties for the use of these parties' systems. It is not clear that the Joint Parties agreement as applied to the Companies would terminate as a result of RTO membership, but the Companies determined that it was reasonable to assume for the purposes of this analysis that compensation to the Companies under the settlement agreement would stop if the Companies were to integrate into MISO or PJM. The Companies did not include in this analysis an assumption that if they were to join MISO, they would potentially be asked to contribute an as-yet unknown amount to the compensation paid by MISO to SPP and the Joint Parties.

6.6 Implementation Costs

The Companies would incur costs to fully integrate their operations into an RTO. These costs are approximately $1 million to $2 million per year and reflect upgrades for generation meters and computer hardware and software.

7 RTO Benefit Components

7.1 Trade Benefits

The Companies estimated trade benefits using the Companies' existing planning models, which required only minimal changes to estimate the trade benefit components. These models are of the Companies' system; they are not RTO-wide regional models. An analysis using a complete RTO-wide regional market model may be advisable before making any decision to join an RTO based on expected trade benefits. The results of this analysis do not support incurring the expense of such further market analysis at this time.

The Companies used their production cost software tool, PROSYM, to forecast the potential trade benefits of joining an RTO by estimating the potential net impacts to (1) market energy purchase costs for retail and wholesale requirements customers and (2) market energy sales margins that resulted from the following model revisions to reflect RTO membership:

- Dispatching/selling generating units into the RTO energy market and purchasing native load energy from the RTO energy market.
- The Companies' normal business plan assumptions include constraints on starting combustion turbines for the sole purpose of making market sales to model the typical dispatch of these units. The analysis of RTO membership eliminated these constraints on dispatch because the RTO would be directing dispatch decisions.
- The Companies' assumption for the spinning reserve requirement (excluding 100 MW of quick-start combustion turbine capacity) was reduced from 225 MW in the business plan to 145 MW in the RTO analysis based on the Companies' projected load ratio share of the estimated spinning reserve requirements in the RTO.
- The Companies eliminated the assumed need in the Companies' current business plan to hold a relatively small amount of additional spinning capacity to allow for intra-hour load fluctuations, which averages 0.9% of load.
- The Companies eliminated several expenses applied to market sales and purchases in the Companies' current business plan.
    - **RTO expenses**. RTO balancing operating reserve charges on sales and purchases are included in the business plan to cover deviations between the day-ahead and real-time market. The average of these RTO expenses that were eliminated in the RTO analysis over the 2020-2029 study period were assumed to be $0.80/MWh with an average annual increase of 6%. Initial RTO expenses (Peak: $0.64/MWh, Off-Peak: $0.59/MWh, Weekend: $0.45/MWh) were in 2018 dollars based on recent historical averages.

- **RTO transmission**. RTOs charge for transmission to “drive-out” energy from the RTO footprint for expenses for purchases made by the Companies. The average of these RTO transmission charges that were eliminated in the RTO analysis over the 2020-2029 study period were assumed to be $1.45/MWh with an average annual increase of 1%. Initial RTO transmission rates (Peak: $1.37/MWh, Off-Peak: $1.37/MWh, Weekend: $1.37/MWh) were in 2018 dollars and reflect the current rates as of the 2019 business plan.
- **LG&E-KU transmission.** The Companies also charge for transmission for market sales made by the Companies. The average of these transmission charges that were eliminated in the RTO analysis over the 2020-2029 study period were assumed to be $4.55/MWh with an average annual increase of 1%. Initial LG&E-KU transmission rates (Peak: $5.89/MWh, Off-Peak: $2.869/MWh, Weekend: $2.869/MWh) were in 2018 dollars and reflect the current rates in the 2019 Business Plan.
- **Losses**. When generating energy for market sales, the Companies must generate additional electricity above the transacted volume to compensate for losses on the transmission lines. The Companies’ 2019 Business Plan estimated the cost associated with losses to be 0.5% of the fuel cost to generate the energy sold. In an RTO, the Companies’ generation would be sold at the generator bus versus the RTO interface. The RTO analysis assumes that over the 2020-2029 study period the average cost of losses eliminated is $0.11/MWh with an average annual increase of 1%.
- **Market price buffer**. To manage the uncertainty that exists between real-time market electricity prices and aggregated hourly settled prices, the Companies’ normal business plan assumes that energy sales and purchases will not be transacted unless a minimum of a $2/MWh hurdle can be achieved. Under the RTO analysis, this hurdle rate is eliminated.

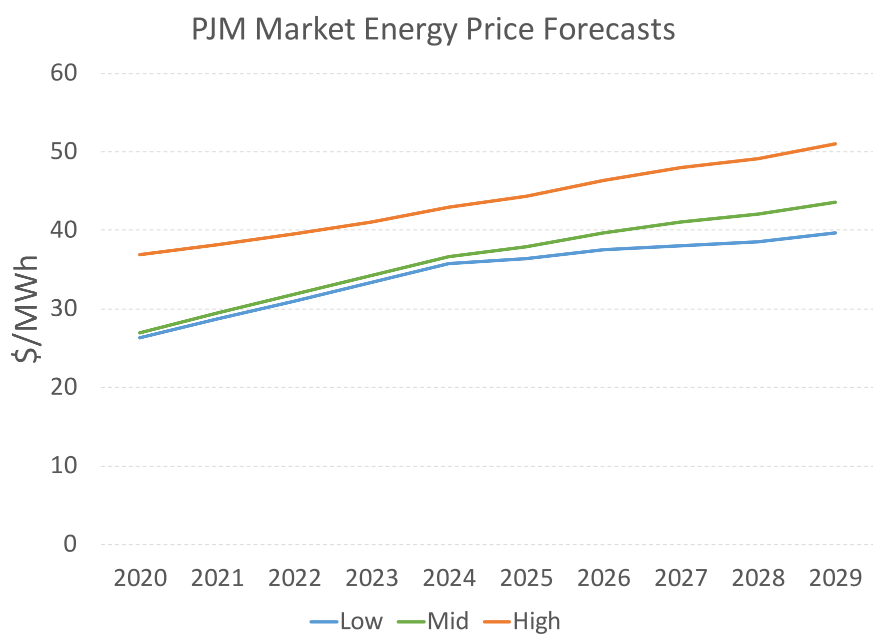
The PJM and MISO analyses used low, mid, and high electricity price forecasts specific to each RTO. The table below summarizes the minimum and maximum estimated annual trade benefits over the ten-year period of 2020-2029.

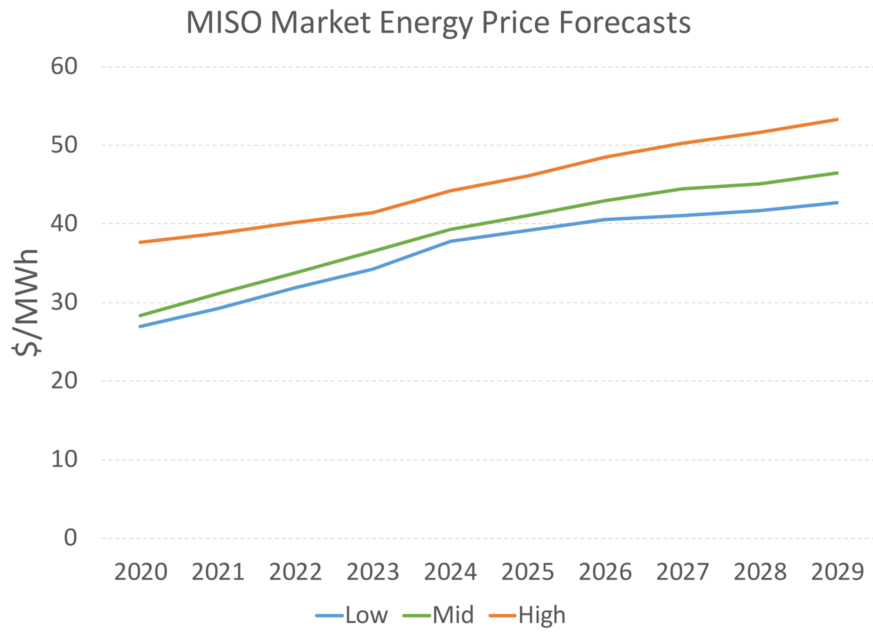
Range of Annual Net Trade Benefits ($ millions)						
	Low Electricity Prices		Mid Electricity Prices		High Electricity Prices	
	Min	Max	Min	Max	Min	Max
PJM	12	25	13	31	26	41
MISO	13	35	13	41	30	51

As detailed in Appendix C, the net trade benefits figures reflect the sum of (1) the potential favorable incremental benefits of selling energy into the RTO market and (2) the potential incremental costs or benefits of purchasing market-priced energy for the Companies' retail and wholesale requirements customers, relative to the Companies' business plan. In all scenarios, the estimated benefit of additional energy sales margin was greater than the additional cost of purchasing market energy for native load.

The trade benefits estimates are highly uncertain as they depend on the level of market electricity prices, which directly depend on many uncertain variables including fuel costs, weather, and RTO-wide load and generation performance. They may also be indirectly influenced by many external factors, including state and federal policy.

The following charts display the low, mid, and high market energy price forecasts used in the analysis for PJM and MISO.





7.2 Capacity Auction Benefits[8]

Both PJM and MISO take the position that they are able to provide appropriate generation reliability with a lower target annual peak reserve margin as compared to the Companies' target summer reserve margin of 16 percent to 21 percent. Therefore, to the extent that the Companies forecast their reserve margin to be above the RTO target, the potential exists to sell capacity into the RTO capacity auctions. This analysis evaluates the potential value of capacity available for auction within both the PJM and MISO capacity market constructs assuming the following:

- Forecasted demand based upon normal weather and other economic assumptions,
- Capacity less the forecasted load obligation is assessed for value in the market,
- The Companies' capacity offered into the capacity market may not clear at 100 percent, and
- Capacity pricing is consistent with historical auction results.

Inputs to this analysis are sensitive to these assumptions and deviations would result in material impacts to the projected results.

[8] While this cost-benefit analysis is based upon RTO membership, membership is not required to participate in PJM or MISO capacity markets.

7.2.1 PJM Reliability Pricing Model ("RPM")

Inputs to estimating the value of the PJM capacity market are as follows:

- Installed Capacity ("ICAP")[9] – excludes small-frame combustion turbines,[10] Curtailable Service Rider ("CSR") load, Demand Conservation Program ("DCP"),[11] Bluegrass tolling agreement (contract expires in 2019), and E.W. Brown units 1 & 2 (planned retirement in 2019), but includes capacity available through the Companies' ownership share of Ohio Valley Electric Corporation ("OVEC").
- Unforced Capacity ("UCAP")[12] – calculated by adjusting ICAP for the business plan forced outage and maintenance outage rates for coal and natural gas units. Hydro and solar units were adjusted to the average of their winter and summer ratings.[13]
- Cleared Capacity – three levels of capacity clearance rate were considered based on PJM's historical capacity clearance rate by fuel type.
- Capacity Need – based upon the Companies' joint system peak using the business plan base load forecast, adjusted for 1) peak diversity between LG&E and KU and PJM RTO based upon a normal weather year and 2) PJM's applicable Forecast Pool Requirement factor.
- Capacity Prices – three capacity price cases representing low, mid, and high price ranges were examined against a base load forecast for the analysis period.

7.2.2 The MISO Planning Resource Auction ("PRA")

Inputs to estimating the value of the MISO capacity market to the Companies are as follows:

- ICAP – excludes small-frame combustion turbines, CSR load and DCP,[14] Bluegrass tolling agreement, and E.W. Brown units 1 & 2, but includes capacity available through the Companies' ownership share of OVEC.

[9] ICAP is defined by RTOs as a unit's net summer capability.
[10] The Companies have six small-frame natural gas-fired peaking units. Because of their age, the Companies plan to limit spending on the small-frame SCCTs and retire the units when significant investment is needed for their continued operation.
[11] CSR load reduction was excluded due to uncertainty as to whether rights under the retail CSR tariff would be consistent with RTO capacity performance obligations. DLC load reduction is seasonal and therefore does not appear to meet RTO capacity performance requirements.
[12] Unforced capacity is defined as installed capacity rated at summer conditions that are not on average experiencing a forced outage or forced derating. For this analysis, Unforced Capacity is calculated as the Installed Capacity adjusted for 5 year average $EFOR_d$ plus 25% of EMOR or UCAP=ICAP*[1-(EFORd+0.25*EMOR)].
[13] PJM Manual 18: Capacity Market," Section 5.4.1; *see*: http://pjm.com/-/media/documents/manuals/m18.ashx?la=en
[14] CSR and DCP load reductions were excluded due to uncertainty as to whether these retail programs would be consistent with MISO tariff requirements.

- UCAP – same as PJM UCAP input.
- Cleared Capacity – all capacity bid is assumed to clear the auction given MISO's Zone 6 historical clearance rate for all resource types.[15]
- Capacity Need – based upon the Companies' joint system peak using the business plan base load forecast adjusted for 1) normal weather peak diversity between LG&E and KU and MISO, 2) MISO's UCAP planning reserve margin, and 3) MISO's transmission loss factor.
- Capacity Prices – same as PJM Capacity Prices inputs.

7.2.3 Projected Results

For both RTOs, capacity available to auction is estimated as a function of cleared UCAP minus Capacity Need. With no plans for resource additions or retirements over this review period, installed capacity, and consequently unforced capacity, remains relatively flat across the planning period. Peak loads are also relatively flat across the period. As a result, it is possible that the Companies could have a consistent amount of capacity, above the amount they would need to purchase to serve load, available to offer into each RTO's capacity auction, although the level of availability differs due to each RTO's reserve margin requirements.

Even though the Companies may have a consistent amount of capacity available to offer in each market, PJM has a rate of capacity clearance by fuel type that varies from year to year, but is less than 100% of the capacity offered into the market. For example, coal capacity clearing the auction has ranged from 83% to 91% of coal capacity offered since the 2016/17 auction. For natural gas capacity, this range is 90% to 94%.

MISO data on capacity clearance rates is not provided with the granularity of PJM data, so clearance rates could not be applied by fuel type; however, clearance data provided by zone indicates nearly 100% of all offered resources have cleared the auction for Zone 6, which is adjacent to the Companies' service area, since 2016. Therefore, under the MISO capacity auction construct, 100% of capacity offered is assumed to clear the auction.

Across all price cases, the calculated annual capacity value for PJM's RPM ranges from ($4M) to $36M annually. For MISO, with a more limited auction history and typically significantly lower auction clearing price results, the calculated annual capacity value ranges from $0.2M to $9M across all price cases.

[15] MISO data summarized at the zonal level without specificity by fuel type.

7.2.4 Performance Risks

PJM has established stringent Capacity Performance ("CP") requirements for generator performance. All generation capacity resources that are capable or can reasonably become capable of qualifying as CP resources must be offered into the capacity market as CP resources. Exceptions are permitted if the seller can demonstrate that a resource is reasonably expected to be physically incapable of meeting CP requirements. A resource that requires substantial investment to qualify as a CP resource is not excused from the CP must-offer requirement, but is expected to include such costs in its CP sell offer.

Generators must be capable of sustained, predictable operation that allows the resource to be available to provide energy and reserves during performance assessment hours throughout the Delivery Year. Penalties are applied when actual performance is less than expected performance. The non-performance charge rate for capacity performance is a function of the net cost of new entry ("CONE") for the particular delivery area in which the resource is located, based upon PJM's modeling. For 2018/2019, this rate is estimated to be $3,293 per MWh.[16] As an example, one hour of unplanned outage for the Companies' natural gas combined cycle with a UCAP of 620 MWh, could result in a non-performance charge in excess of $2M.[17]

MISO has not designated capacity performance requirements in the same manner as PJM; however, Planning Resources are obligated to provide capacity to their designated zone for the entire planning year, as well as to perform during system emergencies.[18] If a load-serving entity does not achieve resource adequacy for the planning year, a capacity deficiency charge will be assessed based upon 2.7548 times the CONE. MISO's CONE for Zone 6 for the 2018 planning year was $7,070 per MWh.[19] Though this analysis does not quantify these non-performance charges, the risk associated with non-performance is significant.

7.3 Transmission Revenue

In both MISO and PJM, the Companies would have a "zonal" transmission rate that would be calculated in a similar fashion to how their transmission rate is calculated

[16] Non-Performance Charge Rate estimated using the value of net CONE for PJM Zone 6 which includes EKPC and DEOK.
[17] Non-Performance Charge = Performance Shortfall MW *Non-Performance Charge Rate
[18] A resource may be designated as a Planning Resource either through the MISO PRA or as part of a fixed resource adequacy plan for a load serving entity (LSE). Only Planning resources cleared through the PRA are subject to capacity credits and penalties.
[19] Non-Performance Charge Rate estimated using the value of net CONE for MISO Zone 6 Indiana and the northwestern portion of Kentucky, which includes BREC, DUK(IN), and SIGE.

currently with the Companies as stand-alone transmission providers. In an RTO, the zonal transmission rate would apply to any Network or Point-to-Point ("PTP") transmission that sinks in the zone and the rate would continue to be based on the Companies' transmission revenue requirements.

The Companies would also potentially receive an allocation of revenues from each RTO based on the revenues that each RTO collects for PTP transmission service that does not sink within the RTO (i.e., drive-out and drive-through transmission service). Both PJM and MISO have a mechanism for this allocation based on combinations of transmission plant in service ratio and flow based derivations. Due to the difficulties in projecting drive-through and drive-out transmission use as well as flows and ratios that would drive the Companies' allocation of revenues, the Companies did not attempt to determine the potential projected value of this allocation and therefore did not include it in this analysis. When the Companies were previously members of MISO, revenues for drive-through and drive-out transmission use were around $1M annually. Due to the passage of time and changes in transmission facilities and use since the Companies' exit, the Companies did not use this historical performance value as a proxy but do believe it indicates that revenue from this service is not likely to be significant.

7.4 FERC Charges

Under FERC regulations, the annual FERC charge is assessed to all RTO energy for load, and not just "wholesale" load as the Companies are assessed outside of an RTO. For this analysis, the projected FERC assessment charges were included in RTO administrative charges. The amount that the Companies currently pay is included as a projected benefit to quantify properly the net change in cost.

7.5 Eliminated Administration Charges

Membership in either PJM or MISO would result in cost savings from the elimination of certain third-party services. For the purposes of this analysis, the Companies assumed they would no longer need the current Independent Transmission Organization ("ITO") or Reliability Coordinator ("RC") services provided by TranServ and TVA, respectively. In addition, the analysis assumes the current reserve-sharing contract with TVA would no longer be needed.

7.6 Elimination of De-Pancaking Expense

The Companies currently provide MMD credits to certain entities exporting to or importing from MISO.[20] The Companies assumed all credits for MISO charges and waiving of their transmission charges would cease if they joined MISO and all but MISO Schedule 26A would be eliminated if the Companies joined PJM.[21] The benefit amount from eliminating MMD expense is based on such expenses included in the Business Plan and allocated to LG&E and KU retail and wholesale requirement customers.

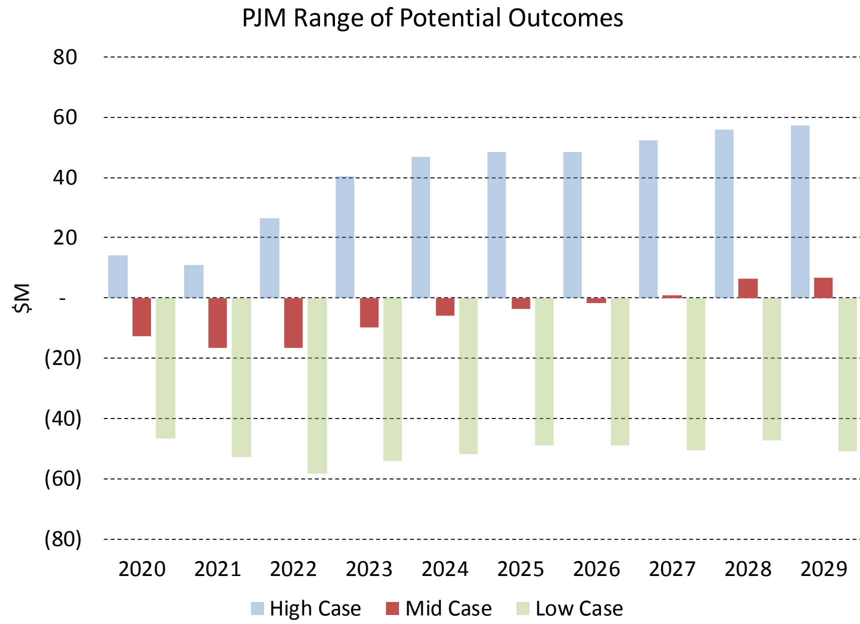
The Companies have filed with FERC to eliminate the MMD obligation and associated expense; however, as the litigation of this filing is ongoing and in the preliminary stages, the outcome of this effort is unknown. For the purposes of this analysis, the Companies decided to address the risk associated with MMD by taking a conservative approach and studying this issue as though the filing at FERC had not been made. As such, MMD costs are treated as an expense in the status quo case and their full or partial elimination is treated as a benefit of joining an RTO.

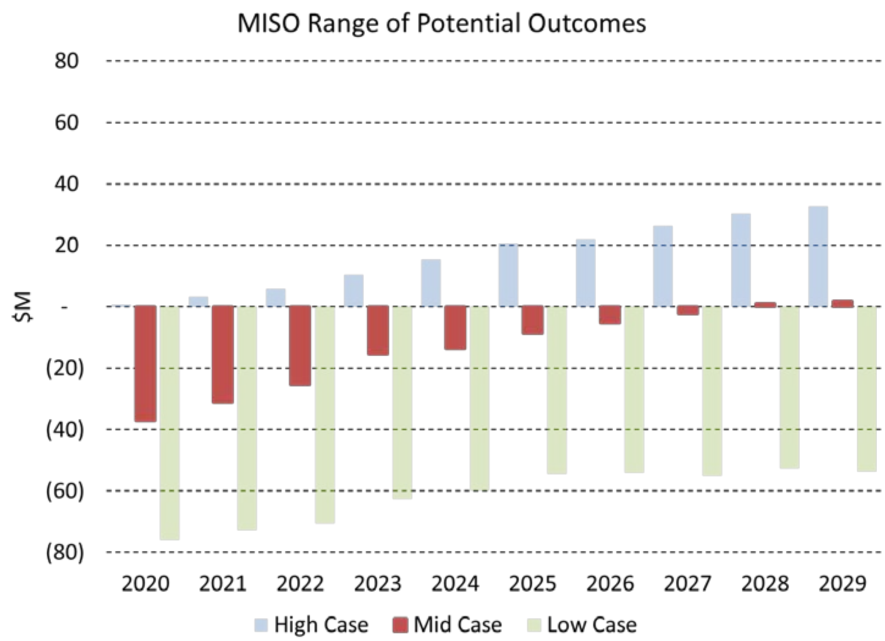
8 Quantitative Results

The following charts display the values for all three cases (Low, Mid, High) by year for both MISO and PJM (See Appendix B for detailed annual values):

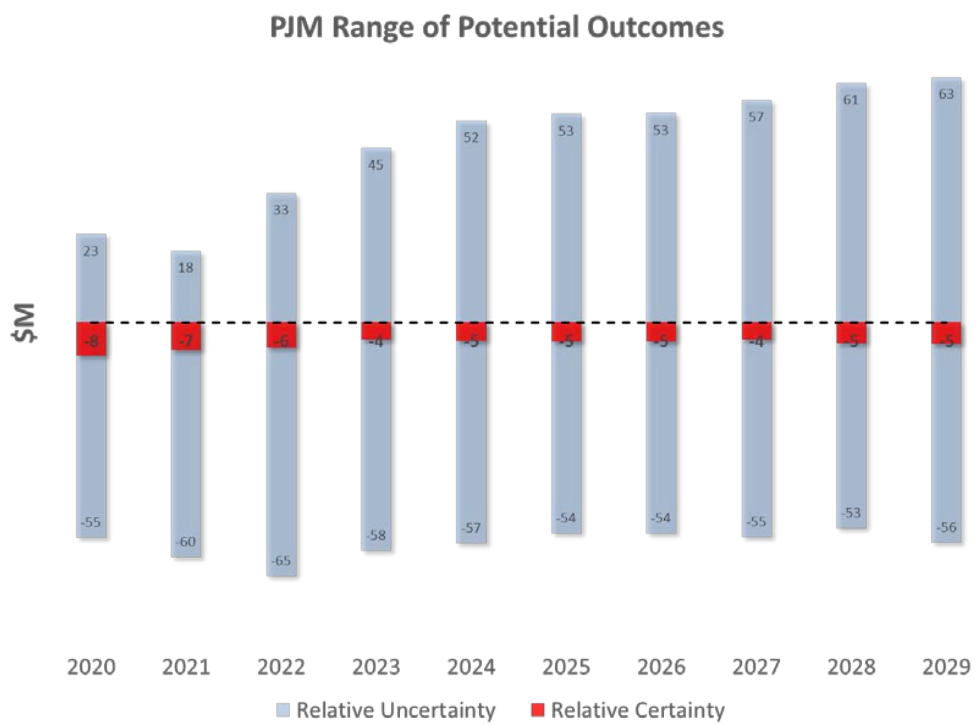
[20] The Companies waive their transmission charges for exports to MISO and credits MISO transmission charges for imports from MISO for certain customers pursuant to a FERC filed agreement, LG&E/KU FERC First Revised Rate Schedule No. 402, relating to the Companies' 1998 merger and 2006 exit from MISO. *See*, *E.ON U.S., LLC, et al.*, Docket No. ER06-1279-000. Although the Companies have filed with FERC to eliminate this obligation, FERC has not yet ruled on the filing. *See*, Docket Nos. EC98-2-001 and ER18-2162-000.

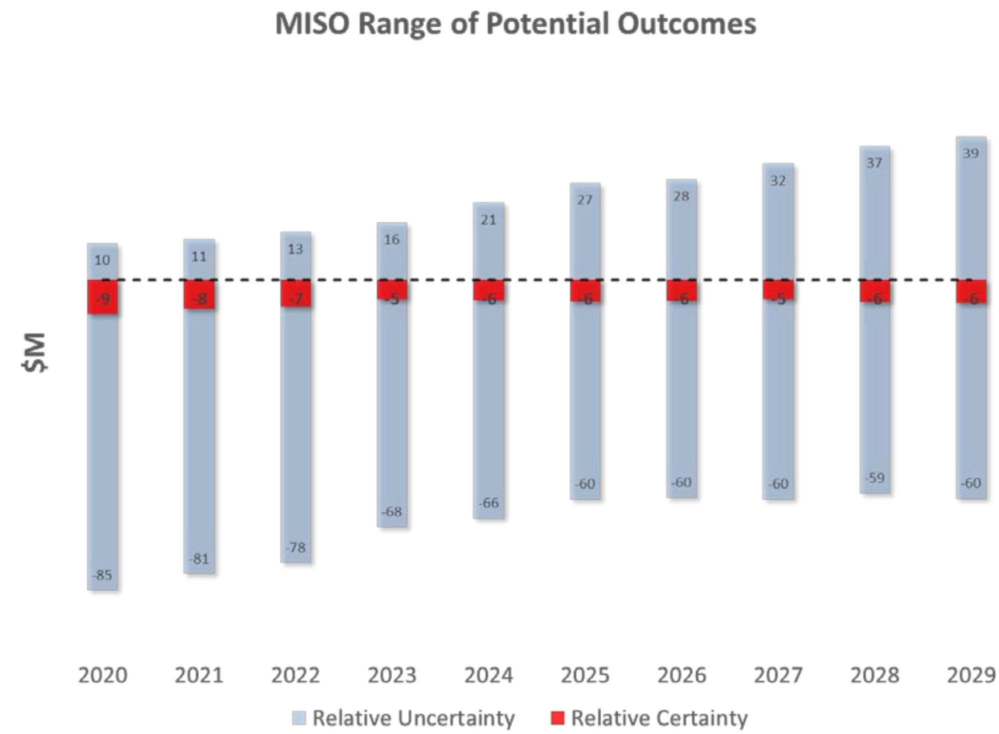
[21] FERC has required that transmission across the MISO-PJM be depancaked through the use of license plate rates. An exception to this general depancaking rule was created for MISO Schedule 26A in 2016. *See*, *Midwest Independent Transmission System Operator, Inc.*, 156 FERC ¶61,034 (2016) ("Order on Remand from the Seventh Circuit finding that, in light of current conditions, the limitation on export pricing to PJM is no longer justified for MISO Schedule 26A charges.)


PJM Range of Potential Outcomes
80
60
40
20
-
(20)
(40)
(60)
(80)
$M
2020
2021
2022
2023
2024
2025
2026
2027
2028
2029
High Case
Mid Case
Low Case


MISO Range of Potential Outcomes
80
60
40
20
-
(20)
(40)
(60)
(80)
$M
2020
2021
2022
2023
2024
2025
2026
2027
2028
2029
High Case
Mid Case
Low Case

The following graphs separate potential outcomes into components that are relatively certain versus components that are relatively uncertain. The grey range for individual years represents the spread between the highest estimated benefits to the highest estimated cost from the Low, Mid, and High case scenarios. Although benefits are possible in all years for both markets, the earlier years of the study period indicate downside risk is likely to outweigh upside potential, with the largest driver for uncertainty in outcomes coming from the potential capacity market and trade benefits considerations and the larger upside potential is indicated when high capacity and energy price are forecasted. The RTO costs represented in red below are relatively certain and remain constant between Low, Mid, and High scenarios.





The MISO membership analysis indicates an expected net cost each year for the entire ten-year term in the Low Case and for the first eight years, i.e., through 2027, in the Mid Case. Even when comparing the High case to the Low Case in MISO, estimated net benefits in the High Case are significantly lower than the net costs of the Low Case.

The wide range of potential high and low outcomes annually in the PJM membership analysis results is indicative of the uncertainty involved. The range of difference between the Low and High Case results is in excess of $90 million in most years. This extreme difference in potential results is an expression of the risks involved in relying on either of the two outlying cases as a basis for any determination. The results of the Mid Case present a more reasonable basis for reviewing the net value of membership. Notably, that case indicates a net cost of PJM membership each year through 2026.

9 Risk & Uncertainty

The decision to join an RTO is a long-term commitment that is complex and costly to attempt to reverse. Fundamentally, it is a decision to transfer functional control to the RTO and participate in RTO-administered wholesale markets for generation and load. RTO members, their stakeholders, and state regulators cede control over significant revenue streams, cost incurrence and allocation, and decisions impacting the transmission system and generation fleet – and ultimately cost of service to customers.

Although this report quantifies projected potential benefits and costs of integration into the RTOs utilizing assumptions to anticipate financial impacts, the estimates of potential benefits in this analysis are uncertain. Numerous external factors can and will impact pricing in the RTO markets, including fuel costs, weather events, load reductions, incremental resource additions, transmission performance, changes in suppliers, forced or unplanned outages, and federal policy and regulatory changes (e.g., changing environmental regulations or FERC-directed changes in market compensation or requirements). Transmission expansion costs remain an evolving area as transmission planning requirements continue to change and RTO cost allocation provisions are revisited.

Fully integrating into an RTO would commit the Companies to comply with RTO requirements as a supplier, a load, and a transmission owner. Therefore, the potential for material changes and unanticipated costs, as well as the uncertainty of any potential benefits, should be considered in making a decision to integrate. Though the Companies focused on quantifiable elements in performing this analysis, certain non-quantifiable considerations were also reviewed. An initial list of non-quantifiable considerations that would need to be considered further before integrating into an RTO are provided in Appendix E.

10 Conclusion

The current analysis does not indicate net benefits from RTO membership within the timeframe analyzed. In addition, downside risk is estimated to outweigh upside opportunities. The analysis indicates that potential net benefits are not likely achievable for a number of years, providing time to monitor and study the RTOs to see how market dynamics and uncertainties evolve over time. Therefore, RTO membership is not recommended at this time; however, the Companies will continue to monitor RTO operations and periodically refresh this analysis.

Appendix A – Scenario Inputs

	Low Case	Mid Case	High Case
PJM			
Reliability Pricing Model (RPM)			
All cases: Year 1 (2019/2020) uses actual average incremental auction value. Year 2 and Year 3 use estimate of average incremental auction value. Capacity clearance rates for hydroelectric and solar units of 100%.	Price constant at 2016/17 auction value (lowest value since 2016/17). Capacity clearance rate for coal- and gas-fired based upon historical low clearance rate since 2016/17 auction.	Price constant at average of results for 2016/17-2021/22 auctions. Capacity clearance rate based upon the average observed for coal- and gas-fired unit clearance rate since 2016/17 auction.	Price constant at 2018/19 auction value (highest value since 2016/17). Capacity clearance rate of 100% for all resource types.
Trade Benefits – Assumed Price Forecast			
All cases are based on Companies' electricity market price forecasts	Electricity market price forecast based on Companies' low natural gas price forecast	Electricity market price forecast based on Companies' mid natural gas price forecast	Electricity market price forecast based on Companies' high natural gas price forecast
Transmission Expansion Costs			
	Annual expansion costs were increased by 20% from the Mid Case.	Used PJM's "tcic" spreadsheet applied to forecasted load and project load-ratio share.	Annual expansion costs were reduced by 20% from the Mid Case.
Administrative Charges			
	Costs were increased by 20% from the Mid Case.	Based on 2017 state of the market reports submitted by PJM's market monitor.	Costs were reduced by 20% from the Mid Case.
MISO			
Planning Resource Auction (PRA)			
All prices are from Zone 6 auction results. Capacity clearance rate of 100% assumed for all cases based upon historical Zone 6 clearance rates since 2016/17 auction.	Price constant at 2017/18 auction value (lowest value since 2016/17).	Price constant at last known auction value from 2018/19 auction.	Price constant at 2016/17 auction value (highest value since 2016/17).

Trade Benefits – Assumed Price Forecast			
All cases are based on Companies' electricity market price forecasts	Electricity market price forecast based on Companies' low natural gas price forecast	Electricity market price forecast based on Companies' mid natural gas price forecast	Electricity market price forecast based on Companies' high natural gas price forecast
Transmission Expansion Costs			
	Annual expansion costs were increased by 20% from the Mid Case.	MISO published indicative annual charges for approved MVP applied to forecasted loads.	Annual expansion costs were reduced by 20% from the Mid Case.
Administrative Charges			
	Costs were increased by 20% from the Mid Case.	Based on cost projections contained in MISO's 2016 revenue requirement forecast.	Costs were reduced by 20% from the Mid Case.

Appendix B – Cost Analyses

Tables of rolled up components for all three scenarios.

MISO Membership Cost Analysis - Mid Case

Costs ($M)	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
MISO Admin Cost	-12.1	-12.4	-12.7	-13.0	-13.4	-13.7	-14.0	-14.4	-14.8	-15.2
MISO Uplift Cost - Revenue Neutrality Uplift	-6.6	-6.5	-6.5	-6.5	-6.5	-6.6	-6.5	-6.6	-6.6	-6.6
MISO Transmission Expansion Cost (MVP)	-54.5	-54.1	-54.2	-54.1	-56.4	-54.7	-54.1	-53.6	-53.1	-52.5
LG&E/KU Internal Staffing & Implementation	-1.7	-0.9	-0.9	-0.9	-0.9	-0.8	-0.8	-0.8	-0.8	-0.8
LG&E/KU Lost XM Revenue	-6.2	-5.7	-5.2	-3.2	-3.7	-4.1	-4.2	-3.9	-4.7	-5.0
LG&E/KU Lost Joint Party Settlement Revenue	-1.2	-1.2	-1.2	-1.2	-1.2	-1.2	-1.2	-1.2	-1.2	-1.2
Sum of Cost	-82.3	-80.9	-80.8	-79.1	-82.2	-81.2	-81.0	-80.5	-81.2	-81.3

Benefits ($M)	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
MISO Trade Benefits	13.2	17.1	21.9	28.4	31.7	34.6	36.6	37.7	40.6	41.5
MISO Capacity Auction Benefits	1	1	1	1	1	1	1	1	1	1
LG&E/KU Avoided Fees (FERC, TVA RC, ITO, TEE)	6.2	6.3	6.5	6.6	6.7	6.8	6.9	7.1	7.1	7.1
LG&E/KU Elimination of De-Pancaking	24.5	25.0	25.9	27.5	28.7	29.8	30.9	32.1	33.4	33.4
Sum of Benefits	45.1	49.6	55.5	63.7	68.4	72.4	75.7	78.1	82.2	83.1

Net of Cost + Benefits	-37.1	-31.3	-25.3	-15.3	-13.8	-8.7	-5.3	-2.4	1.0	1.9

MISO Membership Cost Analysis - High Case

Costs ($M)	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
MISO Admin Cost	-9.7	-9.9	-10.2	-10.4	-10.7	-11.0	-11.2	-11.5	-11.8	-12.1
MISO Uplift Cost - Revenue Neutrality Uplift	-6.6	-6.5	-6.5	-6.5	-6.5	-6.6	-6.5	-6.6	-6.6	-6.6
MISO Transmission Expansion Cost (MVP)	-43.6	-43.3	-43.4	-43.3	-45.1	-43.8	-43.3	-42.9	-42.5	-42.0
LG&E/KU Internal Staffing & Implementation	-1.7	-0.9	-0.9	-0.9	-0.9	-0.8	-0.8	-0.8	-0.8	-0.8
LG&E/KU Lost XM Revenue	-6.2	-5.7	-5.2	-3.2	-3.7	-4.1	-4.2	-3.9	-4.7	-5.0
LG&E/KU Lost Joint Party Settlement Revenue	-1.2	-1.2	-1.2	-1.2	-1.2	-1.2	-1.2	-1.2	-1.2	-1.2
Sum of Cost	-68.9	-67.6	-67.4	-65.6	-68.2	-67.5	-67.3	-66.9	-67.6	-67.7

Benefits ($M)	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
MISO Trade Benefits	30.2	30.7	31.9	32.6	39.0	42.8	42.9	45.4	49.0	51.5
MISO Capacity Auction Benefits	8.6	9.0	9.0	9.3	9.2	8.8	8.6	8.6	8.4	8.5
LG&E/KU Avoided Fees (FERC, TVA RC, ITO, TEE)	6.2	6.3	6.5	6.6	6.7	6.8	6.9	7.1	7.1	7.1
LG&E/KU Elimination of De-Pancaking	24.5	25.0	25.9	27.5	28.7	29.8	30.9	32.1	33.4	33.4
Sum of Benefits	69.5	70.9	73.2	75.9	83.6	88.2	89.4	93.2	97.9	100.4

Net of Cost + Benefits	0.6	3.3	5.8	10.3	15.4	20.7	22.0	26.3	30.3	32.7

MISO Membership Cost Analysis - Low Case

Costs ($M)	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
MISO Admin Cost	-14.5	-14.9	-15.2	-15.6	-16.0	-16.5	-16.9	-17.3	-17.8	-18.2
MISO Uplift Cost - Revenue Neutrality Uplift	-6.6	-6.5	-6.5	-6.5	-6.5	-6.6	-6.5	-6.6	-6.6	-6.6
MISO Transmission Expansion Cost (MVP)	-65.4	-64.9	-65.1	-65.0	-67.7	-65.6	-64.9	-64.3	-63.7	-63.0
LG&E/KU Internal Staffing & Implementation	-1.7	-0.9	-0.9	-0.9	-0.9	-0.8	-0.8	-0.8	-0.8	-0.8
LG&E/KU Lost XM Revenue	-6.2	-5.7	-5.2	-3.2	-3.7	-4.1	-4.2	-3.9	-4.7	-5.0
LG&E/KU Lost Joint Party Settlement Revenue	-1.2	-1.2	-1.2	-1.2	-1.2	-1.2	-1.2	-1.2	-1.2	-1.2
Sum of Cost	-95.6	-94.2	-94.2	-92.5	-96.1	-94.8	-94.6	-94.1	-94.8	-94.8

Benefits ($M)	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
MISO Trade Benefits	13.2	14.8	17.1	23.0	29.3	33.3	33.4	31.7	34.8	33.8
MISO Capacity Auction Benefits	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
LG&E/KU Avoided Fees (FERC, TVA RC, ITO, TEE)	6.2	6.3	6.5	6.6	6.7	6.8	6.9	7.1	7.1	7.1
LG&E/KU Elimination of De-Pancaking	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Sum of Benefits	19.6	21.4	23.7	29.8	36.2	40.3	40.5	39.0	42.1	41.1

Net of Cost + Benefits	-76.0	-72.9	-70.5	-62.7	-59.9	-54.5	-54.1	-55.1	-52.7	-53.7

PJM Membership Cost Analysis - Mid Case

Costs ($M)	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
PJM Admin Fee Cost	-17.4	-17.8	-18.2	-18.7	-19.2	-19.6	-20.1	-20.6	-21.2	-21.7
PJM Energy Uplift (BOR) Cost	-5.6	-5.6	-5.6	-5.6	-5.6	-5.6	-5.6	-5.6	-5.6	-5.6
PJM Transmission Expansion Cost	-24.2	-29.1	-34.7	-35.5	-34.8	-34.4	-33.4	-32.6	-31.9	-31.9
LG&E/KU Internal Staffing & Implementation	-1.7	-0.9	-0.9	-0.9	-0.9	-0.8	-0.8	-0.8	-0.8	-0.8
LG&E/KU Lost Transmission Revenue	-6.2	-5.7	-5.2	-3.2	-3.7	-4.1	-4.2	-3.9	-4.7	-5.0
LG&E/KU Lost Joint Party Settlement Revenue	-1.2	-1.2	-1.2	-1.2	-1.2	-1.2	-1.2	-1.2	-1.2	-1.2
Sum of Cost	-56.2	-60.3	-65.7	-65.1	-65.4	-65.8	-65.4	-64.8	-65.4	-66.2

Benefits ($M)	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
PJM Trade Benefits (Production Costs)	13.9	13.4	15.7	19.0	22.0	23.8	24.5	25.3	30.2	31.1
PJM Capacity Auction Benefits	1.4	1.5	3.8	5.4	5.5	5.0	4.6	4.5	4.4	4.3
Avoided Fees (FERC, TVA RC, ITO, TEE)	6.2	6.3	6.5	6.6	6.7	6.8	6.9	7.1	7.1	7.1
LG&E/KU Elimination of De-Pancaking	22.0	22.4	23.4	24.3	25.4	26.5	27.8	29.0	30.2	30.2
Sum of Benefits	43.5	43.6	49.3	55.3	59.5	62.2	63.8	65.8	71.9	72.8

Net of Cost + Benefits	-12.7	-16.7	-16.5	-9.8	-5.9	-3.6	-1.6	1.0	6.5	6.6

PJM Membership Cost Analysis - High Case

Costs ($M)	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
PJM Admin Fee Cost	-13.9	-14.2	-14.6	-14.9	-15.3	-15.7	-16.1	-16.5	-17.0	-17.4
PJM Energy Uplift (BOR) Cost	-5.6	-5.6	-5.6	-5.6	-5.6	-5.6	-5.6	-5.6	-5.6	-5.6
PJM Transmission Expansion Cost	-19.4	-23.3	-27.7	-28.4	-27.9	-27.5	-26.7	-26.1	-25.5	-25.5
LG&E/KU Internal Staffing & Implementation	-1.7	-0.9	-0.9	-0.9	-0.9	-0.8	-0.8	-0.8	-0.8	-0.8
LG&E/KU Lost Transmission Revenue	-6.2	-5.7	-5.2	-3.2	-3.7	-4.1	-4.2	-3.9	-4.7	-5.0
LG&E/KU Lost Joint Party Settlement Revenue	-1.2	-1.2	-1.2	-1.2	-1.2	-1.2	-1.2	-1.2	-1.2	-1.2
Sum of Cost	-47.9	-50.9	-55.2	-54.3	-54.6	-55.0	-54.7	-54.1	-54.7	-55.5

Benefits ($M)	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
PJM Trade Benefits (Production Costs)	26.7	26.1	27.7	28.1	33.7	35.0	34.2	36.3	39.3	41.4
PJM Capacity Auction Benefits	7.2	7.2	24.2	35.4	35.7	34.9	34.3	34.1	34.0	33.9
Avoided Fees (FERC, TVA RC, ITO, TEE)	6.2	6.3	6.5	6.6	6.7	6.8	6.9	7.1	7.1	7.1
LG&E/KU Elimination of De-Pancaking	22.0	22.4	23.4	24.3	25.4	26.5	27.8	29.0	30.2	30.2
Sum of Benefits	62.1	62.0	81.7	94.5	101.4	103.3	103.2	106.5	110.7	112.6

Net of Cost + Benefits	14.2	11.1	26.5	40.2	46.8	48.3	48.5	52.3	55.9	57.2

PJM Membership Cost Analysis - Low Case

Costs ($M)	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
PJM Admin Fee Cost	-20.8	-21.3	-21.8	-22.4	-23.0	-23.6	-24.1	-24.8	-25.4	-26.0
PJM Energy Uplift (BOR) Cost	-5.6	-5.6	-5.6	-5.6	-5.6	-5.6	-5.6	-5.6	-5.6	-5.6
PJM Transmission Expansion Cost	-29.0	-34.9	-41.6	-42.6	-41.8	-41.2	-40.1	-39.2	-38.2	-38.2
LG&E/KU Internal Staffing & Implementation	-1.7	-0.9	-0.9	-0.9	-0.9	-0.8	-0.8	-0.8	-0.8	-0.8
LG&E/KU Lost Transmission Revenue	-6.2	-5.7	-5.2	-3.2	-3.7	-4.1	-4.2	-3.9	-4.7	-5.0
LG&E/KU Lost Joint Party Settlement Revenue	-1.2	-1.2	-1.2	-1.2	-1.2	-1.2	-1.2	-1.2	-1.2	-1.2
Sum of Cost	-64.5	-69.7	-76.3	-75.9	-76.2	-76.6	-76.1	-75.4	-76.0	-76.9

Benefits ($M)	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
PJM Trade Benefits (Production Costs)	13.7	12.3	14.2	18.3	20.6	23.9	23.5	21.4	25.0	22.5
PJM Capacity Auction Benefits	-2.0	-1.8	-2.7	-2.9	-2.9	-3.1	-3.3	-3.4	-3.5	-3.5
Avoided Fees (FERC, TVA RC, ITO, TEE)	6.2	6.3	6.5	6.6	6.7	6.8	6.9	7.1	7.1	7.1
LG&E/KU Elimination of De-Pancaking	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Sum of Benefits	17.9	16.8	18.0	22.0	24.4	27.6	27.1	25.1	28.6	26.1

Net of Cost + Benefits	-46.6	-52.8	-58.4	-54.0	-51.8	-49.0	-48.9	-50.4	-47.3	-50.8

Appendix C – Trade Benefits

The tables below show the projected incremental total system trade benefits and costs from joining MISO and PJM compared to the Companies' current business plan. Negative figures reflect net benefits; positive figures reflect net costs.

PJM $M		2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Low Price	Market Energy Sales	-181	-243	-304	-372	-429	-443	-466	-459	-466	-476
	Native Load Cost	167	231	290	353	409	419	442	437	441	454
	Total	-14	-12	-14	-18	-21	-24	-23	-21	-25	-22
Mid Price	Market Energy Sales	-201	-264	-327	-396	-453	-480	-520	-538	-559	-582
	Native Load Cost	187	251	312	377	431	456	496	513	529	551
	Total	-14	-13	-16	-19	-22	-24	-24	-25	-30	-31
High Price	Market Energy Sales	-512	-530	-557	-587	-638	-662	-711	-736	-769	-810
	Native Load Cost	486	504	530	559	605	627	677	700	729	769
	Total	-27	-26	-28	-28	-34	-35	-34	-36	-39	-41

MISO $M		2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Low Price	Market Energy Sales	-201	-270	-344	-415	-521	-560	-593	-587	-597	-604
	Native Load Cost	188	255	327	392	492	527	559	555	562	571
	Total	-13	-15	-17	-23	-29	-33	-33	-32	-35	-34
Mid Price	Market Energy Sales	-245	-328	-408	-494	-566	-615	-661	-682	-691	-709
	Native Load Cost	232	311	386	465	535	580	625	644	650	668
	Total	-13	-17	-22	-28	-32	-35	-37	-38	-41	-41
High Price	Market Energy Sales	-548	-564	-589	-613	-698	-741	-808	-841	-881	-916
	Native Load Cost	517	533	557	580	659	698	765	796	832	865
	Total	-30	-31	-32	-33	-39	-43	-43	-45	-49	-51

Appendix D – Kentucky Entities in RTOs

The Companies and the Tennessee Valley Authority are transmission-owning entities operating in Kentucky that are not currently members of an RTO. Big Rivers Electric Corporation, Duke Energy Kentucky, East Kentucky Power Cooperative, and Kentucky Power are currently transmission-owning entities in the Commonwealth that are RTO members.

As part of this analysis, the Companies reviewed prior PSC filings and orders to understand the primary circumstances and drivers that indicated RTO membership was beneficial for the Kentucky entities operating within an RTO. The Companies determined that the Companies' current situation is different from the circumstances and drivers that led to these entities deciding to join their respective RTOs. A brief summary of each entity is provided below to support that view.

Big Rivers Electric Corporation ("BREC")

BREC joined MISO in 2010 primarily to comply with NERC's contingency reserve requirement (i.e., to ensure supply resources and demand are balanced following a contingency event). In its Order granting MISO membership to BREC, the PSC noted that MISO membership could carry substantial financial risks for BREC, its members, and their retail customers. Therefore, the PSC required BREC to file annually with the PSC a report that: (1) evaluates available options to BREC for complying with NERC's contingency reserve requirement, and (2) reviews and analyzes future short-term and long-term costs and benefits of continued membership in MISO. The report to the PSC filed by BREC on September 28, 2017, noted the only viable option for BREC to continue to satisfy its NERC requirements is continued MISO membership.

In comparison, the Companies are currently satisfying NERC requirements without RTO membership. The Companies can continue to meet the NERC reliability standards contingency reserve requirements, and there is no evidence that meeting the contingency reserve requirement is having an appreciably negative impact on the Companies' ability to optimize the dispatch of their generation fleet. Further, although RTO membership is assumed to result in a decrease in the reserves necessary to meet the contingency reserve requirement, the benefit of this reduction in the reserves requirement alone is not a major driver of net costs or benefits.

Duke Energy Kentucky ("Duke KY")

Duke KY joined MISO in 1997 and moved to PJM in 2012. Duke KY is a transmission-dependent utility heavily interconnected with Duke Energy Ohio. In requesting PSC approval of the transfer into PJM, Duke KY stated that the move into PJM would allow it to participate fully in PJM markets and avoid potential inefficiencies, operational complexities, and additional costs that would result from creating a MISO/PJM seam that would affect Duke KY's generation and load. The PSC approved of Duke KY following Duke Energy Ohio in joining MISO and subsequently PJM because of Duke KY's reliance on Duke Energy Ohio and associated transmission interconnectivity. In granting Duke KY's request to transfer function control of its transmission assets from MISO to PJM, the PSC stated that had Duke KY not been so dependent on Duke Energy Ohio transmission for serving its Kentucky load, they would have expected a more in-depth analysis of the costs and benefits of the transfer before approving it.

The Companies do not depend on another entity for transmission to serve native load. While transmission line maintenance or outages may effect customers located in areas connecting with adjoining transmission systems, these limited transmission dependencies are adequately addressed under existing arrangements. Furthermore, unlike the circumstances facing Duke KY at the time of its requested transfer into PJM, the complex issues associated with the MISO/PJM seam are not at issue in the Companies' arrangements with adjoining transmission systems.

East Kentucky Power Cooperative ("EKPC")

EKPC fully integrated into PJM in 2013. In the PSC proceeding, EKPC provided a ten year cost-benefit study conducted by Charles River Associates (CRA). The CRA analysis indicated that joining PJM presented a net expected economic benefit of $142 million over the ten-year period of 2013-2022. The CRA study identified three key benefits that EKPC could achieve through PJM membership:

(1) A decrease in production costs;
(2) Peak load diversity resulting in a decrease in needed planning reserves and cost avoidance as a result of the lower planning reserve margin needed for its winter peaking load; and
(3) Elimination of the cost of long-term, firm point-to-point transmission service.

EKPC noted that fully integrating into PJM also would ameliorate three other challenges to its operations at that time:

(1) Increasing challenges of operating as a stand-alone Balancing Authority;
(2) Increased firm transmission costs to the regional markets necessary for the sale of excess capacity or purchase of economic energy; and
(3) Limited ability to optimize its fleet due to the capacity reserves requirement.

EKPC also argued that there were qualitative benefits to joining PJM, namely that it would be better positioned to respond to future environmental and regulatory requirements and that PJM had structural protections to safeguard the integrity and stability of the market. Major costs included PJM administration and transmission charges. CRA also noted key risks, including transmission cost allocation, capacity market diversity benefits, exit costs, and financial transmission rights. The PSC approved EKPC's integration into PJM and noted that PJM membership does present some degree of risk. EKPC was required to submit reports to the PSC addressing some of these risks on an annual basis to ensure that EKPC's continued membership in PJM is beneficial to its members and consumers.

In contrast to EKPC, the Companies' RTO membership analyses over more than a decade have consistently shown net costs of membership. The Companies are not experiencing difficulties operating as a stand-alone Balancing Authority, nor are there concerns around increasing transmission costs or planning reserve margins. The Companies further believe that they have adequate ability to optimize the Companies' generation fleet outside of an RTO and have plans and processes in place to address current and future environmental and regulatory requirements.

Kentucky Power Company (KY Power)

KY Power joined PJM in 2004. KY Power's holding company, American Electric Power Company (AEP), had been ordered to join an RTO by FERC as a condition of a merger approval and FERC had conditionally approved AEP's plan to join PJM in 2002, subsequently issuing a final order approving the PJM membership in 2003. In 2002, KY Power filed an application with the PSC for approval to join PJM in 2003 in an effort to have all approvals in place prior to a transfer of functional control of its facilities. KY Power pointed to the fact that FERC's approval of the AEP-CSW merger was conditioned on AEP joining an RTO and argued that AEP therefore had no discretion on whether to become part of an RTO. The PSC denied the application, primarily for not demonstrating benefits to Kentucky customers, among other things. FERC moved to override the PSC action. The PSC granted rehearing requests and the parties reached a stipulation that addressed the PSC's concerns. The PSC approval of the stipulation was based, in part, on a cost-benefit study that compared a scenario in which AEP and Kentucky Power were not part of PJM to one in which they were fully integrated into PJM. The study found net economic benefits in the period of 2004-2008 of greater off-system sales, net revenues from the sale of financial rights to transmit power on the AEP-East transmission system,[22] and avoided costs associated with contracts for services that would instead be performed by PJM.

[22] AEP-East is a collection of five AEP subsidiaries in Indiana, Michigan, Kentucky, Ohio, Tennessee, Virginia, and West Virginia.

In contrast to KY Power, the Companies' RTO membership analyses over more than a decade have consistently shown net costs of membership. Furthermore, the Companies have not been ordered by FERC to join an RTO as a merger condition or otherwise.

Summary

In all of the situations described above, transmission-owning entities in Kentucky that sought and received PSC approval to integrate into an RTO did so as a result of circumstances, drivers, and expected costs and benefits from membership unique to each entity. The diversity in these prior decisions, as well as the PSC's approach in determining whether to approve the transfer of functional control to an RTO, demonstrates that membership should be evaluated individually and determined on a case-by-case basis. As discussed above, the key drivers and net benefits that led to the request for and approval of the entities' integration into RTOs outlined above are not present when evaluating the position of the Companies.

Appendix E – Non-Quantifiable Considerations

Consideration	Stability	Description
Governance		
Stakeholder Process – Tariff Filings and Operating Decisions	Continues to Evolve and Change	Although the structure of the two RTOs differ, both RTOs have defined rules with respect to regulatory filing rights. This means that certain stakeholders have considerably more power than others to push RTO policy and RTO requirements.
Stakeholder Mix – Weighted Voting Rights	Continues to Evolve and Change	MISO has approximately 186 voting members in ten different stakeholder sectors with weighted voting rights, including but not limited to sectors for Transmission Owners, Marketers, Public Consumer Advocates, Environmental and other groups, and Transmission Developers. PJM has approximately 536 voting members in five different sectors for transmission owners, generation owners, retail end-use customers, electric distributors, and suppliers who do not qualify for any of the other four sectors.[23]
Policy Impact	Stable	The RTOs have demonstrated considerable impact on the creation and implementation of federal energy, environmental, and market policy. To the extent that the RTO position aligns with the interests of the Companies and their customers, an RTO can be a very effective advocate in managing an evolving federal regulatory landscape. Given the diversity among stakeholders and their and the RTO's own interests, such alignment cannot be assumed.
FERC Oversight of Tariff and Markets	Continues to Evolve and Change	Although FERC review of RTO tariff filings is subject to the statutory authorities conveyed in the Federal Power Act, the implementation of this statutory authority to further federal policy objectives continues to evolve. The PJM and MISO tariffs, including the market rules and requirements, are complex, and

[23] Because of the size of the Companies, it is unlikely that the Companies would fall into the small group of stakeholders able to essentially unilaterally move or strongly influence RTO policy. Therefore, simply joining an RTO would eliminate a significant amount of the control that the Companies have to manage costs and operations to the benefit of their customers.

		some of the most significant changes in RTO tariffs are often driven by FERC initiative and mandate rather than stakeholder proposals.[24]
Markets		
Market Structure	Continues to Evolve and Change	Market structure and market prices administered by RTOs are subject to change over time from various drivers, including FERC-directed market changes (which can include such things as changes to market compensation structures, performance requirements, and participant responsibilities), stakeholder initiatives, independent market monitor recommendations, or actions from the RTOs themselves.
Default of Other Market Participants	Unpredictable	Both RTOs have established credit policies consistent with FERC requirements designed to limit the potential impacts of default, but a degree of default risk remains. Developers, choice marketers, independent generation, and demand resources participate in the markets alongside traditional load-serving utilities. Entity defaults and bankruptcies present a potential risk that the costs of such behavior will fall to other market participants. When entities default in excess of the financial security held by the RTO or enter into a bankruptcy proceeding that disrupts or prevents recovery through collateral, other RTO members are allocated a portion of the default.[25]
Misconduct of Other Market Participants	Unpredictable	Entities' market activities designed to suppress or inflate market prices can directly impact other market participants' opportunities and market performance. Although there are processes at FERC to disgorge amounts if there is a finding of unlawful manipulation, recovery of disgorged profits is not guaranteed and takes significant time.

[24] For example, in February 2018, PJM presented two alternatives for a rule change to FERC and requested the Commission determine between these alternatives the appropriate approach since PJM, its market monitor, and its stakeholder committee were unable to agree. FERC rejected both proposals in June 2018 and recommended PJM pursue a third alternative.

[25] For example, PJM recently provided notice that an FTR market participant, GreenHat Energy, LLC, had defaulted on a $1.2 million invoice and that PJM intended to liquidate the entity's FTR portfolio in upcoming FTR auctions. PJM advised that it intended to add the net gain or net loss from the liquidation to the unpaid net charges or net credits that accumulate on the FTR positions prior to liquidation. Any remaining deficit is allocated to PJM's members in accordance with the PJM Operating Agreement. In this notice, PJM stated: "PJM is not able to predict the prices at which these positions will liquidate or the net charges that may accumulate on the positions prior to liquidation. Hence, at this time, PJM cannot estimate the amount of the default allocation assessment but believes it is likely to be in the tens of millions of dollars."

Market Maturity	Continues to Evolve and Change	PJM's RPM is a relatively more mature market with a forward-looking approach. Looking at historical performance, future market prices are subject to volatility and remain changeable as PJM market rules continue to evolve. MISO offers a short-term, "prompt" year capacity procurement approach in which capacity is procured in April for the planning year beginning in June. In February 2018, FERC rejected MISO's "Competitive Retail Solution," which proposed a bifurcated approach to resource adequacy that would have created a three-year forward market, but for only a small portion of the footprint. Although MISO has indicated it will not request rehearing on the matter, MISO's market monitor is advocating for action in development of a true capacity market.
Market Efficiency	Continues to Evolve and Change	PJM issued a Problem Statement in 2017 identifying a concern that the current Locational Marginal Prices ("LMP") do not accurately represent the true incremental cost of generation or send the right price signals. In its "Proposed Enhancements to Energy Price Formation", PJM credits changes in fuel and technology and declining natural gas prices and demand for bringing to light the opportunity to enhance energy market pricing so that prices accurately reflect the true incremental cost of serving load and minimize the need to recover those costs through out-of-market uplift payments.[26] Though MISO and its Independent Market Monitor believe MISO's energy market to be efficient, MISO faces the same market forces and changes that have affected other RTOs (including declining LMP prices).[27]

[26] Proposed Enhancements to Energy Price Formation, PJM Interconnection, November 15, 2017; *see* http://pjm.com/~/media/library/reports-notices/special-reports/20171115-proposed-enhancements-to-energy-price-formation.ashx

[27] "MISO: Avoiding the Mess Facing Other Wholesale Competitive Electric Markets", Power Magazine; *see* http://www.powermag.com/miso-avoiding-the-mess-facing-other-wholesale-competitive-electric-markets/

Future Costs and Cost Allocation		
Cost Allocation	Continues to Evolve and Change	Cost allocation methods are periodically revisited and can potentially change in the future. An individual RTO member has little control over cost-related decisions and challenges to those decisions can be lengthy and unproductive.[28]
Transmission Expansion Costs	Continues to Evolve and Change	RTOs have seen consistent growth in transmission projects and development. In RTOs, determinations as to whether projects are built and who bears the costs associated with the projects are subject to still evolving RTO rules.[29] In both RTOs load is typically assigned some, if not most, of the costs associated with transmission expansion. Factors that trigger the need for projects, how those projects are designated, who is awarded the option to build, and the percentage of expansion cost assigned locally rather than across the RTO footprint is governed by the RTO's tariff and transmission planning processes. Individual transmission owners within an RTO have limited power to control these costs.[30]
Planning and Operational Control		
Functional Control of Generation Assets	Stable	RTO integration requires the Companies to transfer functional control of their transmission system to an RTO in addition to committing the Companies' generation assets and load to participation in the RTO administered markets. The transfer of control and commitment of generation means that the RTO makes both planning and operating decisions for the Companies' assets that affect reliability, asset performance and longevity, and costs borne by load. This extends to the approval of outages and maintenance, determinations impacting fuel supply and fuel supply arrangements, and dispatch decisions.

[28] For example, there is ongoing litigation between MISO, the Wisconsin Public Service Commission, the Michigan Public Service Commission, and several cities, tribes, industrial customers, load serving entities, and public interest organizations regarding the allocation of cost associated with a System Support Resource Agreement to maintain the Wisconsin Electric Power Company's Presque Isle generation.

[29] MISO changed aspects of its transmission cost allocation in 2003, 2007, 2009, and 2012, and recently started another stakeholder project to review cost allocation.

[30] See, e.g., FERC's approval of the PJM filing associated with the assignment of cost responsibility for 39 baseline upgrades from the 2017 Regional Transmission Expansion Plan, rejecting a challenge to the allocation of several projects by Old Dominion Electric Cooperative who had argued that PJM provided an inadequate basis for the allocation. FERC approved PJM's use of a proxy in assigning the costs entirely to the local zone. *PJM Interconnection, LLC*, 161 FERC ¶ 61,190 (2017).

Drivers Behind Generation Dispatch Decisions	Unpredictable	The RTO would make the decisions on when to start the Companies' generating units. RTO dispatch decisions in normal conditions are driven by market indicators rather than practices focused on ensuring load service as performed today by the Companies.[31]
Transmission Planning	Continues to Evolve and Change	Transmission Owners and Transmission Planners in an RTO are subject to the RTO's transmission planning criteria. Although some limited authority remains with the Transmission Owners and Transmission Planners, the RTO would be the Planning Authority for the region and planning studies would need to conform to the RTO's criteria. Transmission Owners who integrate into an RTO assume an obligation to build in accordance with the applicable RTO's tariff and agreements.
Other/Optional Upgrades	Continues to Evolve and Change	In RTOs, market participants and transmission developers are able to propose and build transmission projects that do not otherwise pass transmission-planning criteria in order to obtain Financial Transmission Rights.
Right of First Refusal	Continues to Evolve and Change	FERC directed transmission providers to eliminate provisions in FERC jurisdictional tariffs and agreements that granted incumbent Transmission Owners a right of first refusal to transmission facilities in their respective service territories or have a right to build regional transmission projects when the costs of those projects would be assigned to the incumbent's load. Transmission development is a competitive process in RTOs, which has led to considerable litigation. Though these issues continue to be litigated, appellate courts have recently upheld the removal of the federal right of first refusal by FERC.
Resource Adequacy	Continues to Evolve and Change	The PJM states are deregulated, with the RTO setting resource adequacy requirements and procuring capacity through auction to meet projected need. MISO states, on the other hand, have typically been regulated, with state commissions setting resource adequacy. Therefore, MISO currently has a fixed resource plan that allows a load serving entity to demonstrate that it has designated capacity to meet all or a portion of its reserve requirement.
Regional Operations	Stable	RTOs are able to leverage resources and redispatch options across a broad

[31] For example, while the Companies are currently able to plan for the risks associated with extreme cold weather events by starting units early and reducing the risk of non-performance, RTO membership would limit this discretion and authority.

		region, which may provide efficiencies and flexibility in mitigating operating issues and resource optionality.
Regional Coordination	Stable	Integrated operations across the different Transmission Owner systems within the RTO region is well established and centralized operations and formal dispute processes have eliminated many of the coordination issues between systems within the RTO.
Interregional Coordination	Continues to Evolve and Change	Interregional coordination between the RTOs and neighboring external systems is structured but also subject to frequent litigation and change. Issues along the RTO seams, both between markets and between markets and non-RTO areas, remain problematic, and any integration that may change or impact an existing seam is likely to pose additional issues that would require resolution.

Compliance		
Compliance Program Costs	Continues to Evolve and Change	An analysis of the NERC Compliance impact of RTO membership found the impact to be cost-neutral, with a slight potential that it could actually increase compliance costs. Although responsibility for compliance with some standards and requirements is transferred to the RTO, the member companies retain responsibility for most compliance, and may still be required to provide evidence of compliance with standards for which the RTO is responsible.
Audits	Stable	Membership in an RTO does not alleviate any of the burden and expenses related to periodic audits. Member companies would still be subject to periodic regulatory audits by the regional entity, and may also be subject to additional audits by the RTO to ensure compliance with standards and RTO-specific manuals or processes.
Fine and Penalties	Unpredictable	For any fines and penalties that result from the failure of a member to comply with a standard or requirement, the cost of the fine is allocated back to that member. For any fines or penalties assessed based on the RTO's failure to comply, the cost of the penalty is allocated to all member companies. For any violations where the RTO assigned responsibility for the standard or requirement, or there is joint responsibility between the RTO and the member company, the RTO retains all control over decisions to self-report and negotiate penalties.
Exit Fees		
Costs to Exit	Stable	MISO's and PJM's transmission owner agreements provide a mechanism for a transmission-owning member of either RTO to withdraw from the RTO. The notice period and requirements of such withdrawals vary with the RTOs, but both contain language that the withdrawing member shall remain liable for obligations undertaken while under the respective RTO agreement.[32]

[32] As the Companies experienced with its MISO withdrawal in 2006, exiting an RTO can be complex and time consuming, and may result in a significant level of financial obligation.

Exhibit LEB-3

Paddy's Run

PADDY'S RUN - Feb. 2017

PADDY'S RUN - Sept. 2017

Exhibit LEB-4

Transmission Program Review

Louisville Gas & Electric and Kentucky Utilities Transmission Program Review

Prepared for
Louisville Gas & Electric
Kentucky Utilities
Lexington, KY

August 2, 2018

Prepared by
Environmental Consultants, LLC
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Table of Contents

Executive Summary

At the request of Louisville Gas & Electric (LG&E) and Kentucky Utilities (KU), Environmental Consultants, LLC (ECI) has completed a re-survey of transmission rights-of-way and the re-assessment of the vegetation management program. The primary goal of the evaluation was to re-assess the vegetation workload on the LG&E and KU overhead transmission system to validate the budget to support the vegetation management program for the remaining first-cycle and develop a second-cyle budget. The secondary objective was to conduct a re-assessment of the vegetation management program and identify general opportunities to enhance program management, reliability and cost effectiveness.

The workload survey was performed while accompanying LG&E and KU during aerial inspection. ECI's program re-assessment consisted of a review of available program documentation provided by LG&E and KU and interviews with key personnel involved with the program. The survey and program review was a cooperative effort between LG&E, KU and ECI.

Since ECI's 2014 assessment, LG&E and KU has implemented a cyclical maintenance strategy; begun a hazard tree ground patrol; and continues to re-establish the transmission ROW to the legal easement boundaries where appropriate. Metrics collected from contract tree-crew timesheets have increased allowing LG&E and KU to begin building historical productivity metrics for evaluating crew proformance and determine future budget requirements. Overall, LG&E and KU have made great strides since 2014 to implement many of the industries best management practices.

Program strengths and opportunities for improvement were identified. Based on the results of the review and ECI's experience with industry best practices, recommendations have been developed to provide LG&E and KU with a general plan for program improvement.

Key Metrics

Vegetation conditions were sampled on approximately 14 percent (791 miles) of the total transmission line miles. The field data collected was used to estimate the total transmission system vegetation workload, maintenance budget and resource requirements. Table 1 presents a system summary of these results. The cost presented in Table 1 does not include "just-in-time" maintenance activities or hazard trees. Table 2 presents the estimated number of hazard trees on the transmission system and the associated cost.

Table 1. Total Tree and Brush Workload Summary for the LG&E and KU Transmission System.

Voltages (kV)	*System Miles*	*Yard Trees*	*Edge Pruning – Mechanical (ft.)*	*Edge Pruning – Manual (ft.)*	*Re-Clear (ft.)*	*Manageable Brush Acres*	*[1]Total System Cost (Millions)*
69	2,738	11,100	6,280,400	1,690,700	128,700	11,560	$23.66
138	1,298	4,100	4,914,400	372,600	15,500	10,720	$15.68
161	657	400	1,515,400	698,200	66,900	6,450	$7.98
345	677	600	2,578,000	334,800	90,700	5,140	$8.55
500	57	-------	11,700	38,700	6,000	700	$0.43
System:	**5,427**	**16,200**	**15,299,900**	**3,135,000**	**307,800**	**34,570**	**$56.30**

Table 2. Total Transmission Hazard Tree Count and Budget By Voltage.

Voltages (kV)	*Hazard Trees*	*Estimated Total Cost*
69	8,900	$1,914,600
138	1,700	$365,700
161	600	$129,100
345	200	$43,000
500	20	$4,300
System	**11,420**	**$2,456,700**

LG&E and KU began transitioning to the recommend five-year cycle in July 2017 for non-NERC transmission lines (i.e. <200 kV) and have completed approximately 631 miles or 13.4 percent as of March 2018. NERC line cycle maintenance began in July 2014 and is at approximately 464 miles or 63.2 percent complete as of March 2018. The estimated cost to complete the remaining miles is presented in Table 3.

Table 3. Progress of Completed Cycle Work and Estimated Cost to Complete Fist-Cycle.

Voltages (kV)	*Sytem Miles*	*Completed Miles*	*Percent Complete*	*Estimated Cost to Complete Cycle[2]*
69	2,738	220	8.0%	$21,757,600
138	1,298	307	23.6%	$11,972,000
161	657	104	15.8%	$6,721,200
345	677	421	62.2%	$3,233,600
500	57	43	76.2%	$103,300
Total	**5,427**	**1,095**	**20.2%**	**$43,787,700**

[1] Reflects the cost to maintain the entire system. The exact cycle length to distribute the cost will need to be determined by LG&E and KU.
[2] The estimated cost to complete the remaining miles on the LG&E and KU transmission system does not include the hazard trees since this is a separate program initiative and just-in-time vegetation maintenance activities.

The estimated second-cycle budget is presented in Table 4. The second-cycle budget is an estimated $52,443,000, a reduction of $3.86M from the first-cycle. The second-cycle budget is an estimated $1,228,400 for hazard trees, a reduction of $1,228,300. Work unit density reductions and unit type conversions account for decrease in estimated costs.

Table 4. Estimated **Second-cycle** Tree and Brush Workload Summary on the LG&E and KU Transmission System *(based upon 2018 dollars)*.

Voltages (kV)	*System Miles*	*Yard Trees*	*Edge Pruning – Mechanical (ft.)*	*Edge Pruning – Manual (ft.)*	*Re-Clear (ft.)[3]*	*Manageable Brush Acres*	*[4]Total System Cost (Millions)*
69	2,738	11,100	6,381,800	1,718,000	-------	11,560	$22.31
138	1,298	4,100	4,928,800	373,700	-------	10,720	$14.44
161	657	400	1,561,200	719,300	-------	6,450	$7.53
345	677	600	2,658,300	345,200	-------	5,140	$7.74
500	57	-------	13,100	43,300	-------	700	$0.42
System:	**5,427**	**16,200**	**15,543,200**	**3,199,500**	-------	**34,570**	**$52.44**

Table 5. Estimated **Second-cycle** Hazard Tree Budget by Voltage for the LG&E and KU Transmission System *(based upon 2018 dollars)*.

Voltages (kV)	*Hazard Trees*	*Total Cost*
69	4,450	$957,300
138	850	$182,900
161	300	$64,500
345	100	$21,500
500	10	$2,200
Total	**5,710**	**$1,228,400**

[3] The workload categorized as re-clear was proportionately moved into mechanical and manual categories as LG&E and KU re-establishes legal ROW.
[4] Reflects the cost to maintain the entire system. The exact cycle length to distribute the cost will need to be determined by LG&E and KU.

General Assessment

GAP ANALYSIS

Gap Analysis From 2014 Report Recommendations		
Recommendation	**Current UTILITY Program**	**Gaps/Clarification**
1. Transition maintenance program to cyclical maintenance.	LG&E and KU began transitioning to a 5-year maintenance cycle in July of 2017 for non-NERC transmission line sections and July of 2014 for NERC transmission line sections.	ECI recommended an annual budget of $11.26M for routine cycle maintenance only and $491,340 for hazard trees. Of the $15.28M budgeted in 2018 and $10.582M actual in 2017, a large portion of these dollars were earmarked for just-in-time work to avoid losing the gains achieved on other parts of the system. LG&E and KU should continue focusing a majority of the resources on establishing the cycle and completing 1,085 miles per year.
2. Continue to remove incompatible trees within the ROW and particularly under the conductors (within the wire zone corridor).	The removal of incompatible species is evident throughout the system exemplified in the work completed to date.	☑ Good
3. LG&E and KU has legal easement documentation for transmission ROWs but the information is not readily available.	Currently in the process of working with the asset management group to update GIS information that clearly define the ROW edges for each circuit.	Continue to develop asset inventory to document ROW widths for each circuit.
4. Develop a hazard tree ground patrol to address potential risk from trees that may not be visible through normal routine aerial inspections.	LG&E and KU begun a 5-year hazard tree inspection program in 2017.	Consider developing an annual ground patrol inspection process specific to identifying hazard trees to supplement the two annual aerial patrols particularly on NERC lines to document compliance mandates.

Gap Analysis From 2014 Report Recommendations		
Recommendation	**Current UTILITY Program**	**Gaps/Clarification**
5. Establish a list or database of hazard tree locations and develop a priority program to determine which trees should be removed first. This database may include ash trees that could be affected by the emerald ash borer (EAB).	Began ground patrols in 2017 to identify hazard trees and ash trees.	Continue to collect the hazard tree location data and develop the mitigation strategy for addressing the removals.
6. Continue to enforce vegetation maintenance clearance specifications for transmission voltages and the policies and standards specific to LG&E and KU needs and conditions. Current specifications appear adequate to maintain vegetation on the transmission system.	ECI field inspection and survey results indicate clearances meet or exceed LG&E and KU specifications.	☑ Good
7. Ensure that vegetation maintenance crews exhibit reasonable production levels by implementing a work reporting/ measurement system and utilize the records to evaluate crews and compare contractor performance.	LG&E and KU has begun to capture additional work unit metrics from tree crew timesheets. These metrics are being compilded in a database that is being used to calculate unit costs.	Continue to build upon the breadth of data available to improve upon the accuracy of production reports and metrics. Consider developing a formal QA/QC process to evaluate crews and contractor performance.

Gap Analysis From 2014 Report Recommendations		
Recommendation	**Current UTILITY Program**	**Gaps/Clarification**
8. Implement Integrated Vegetation Management (IVM) as the guiding maintenance principle on the LG&E and KU transmission system.	LG&E and KU currently inspects and develops site specific recommendations for the maintenance of its ROW's including the proper selection and utilization of herbicides.	☑ Good
9. Re-establish the transmission corridor ROW edges wherever practical to bring the corridors back to specification by voltage.	ECI field review and survey results indicate that ROW corridors are being significantly widened in accordance with the established ROW widths.	☑ Good
10. Continue to maximize herbicide use where practical to minimize future vegetation management costs and better manage for compatible plant communities.	Aerial spray and high-volume foliar are used extensively and should result in significant brush density reductions in future cycles.	☑ Good
11. Once established, maintain consistent transmission vegetation maintenance program funding to maximize overall program effectiveness and ensure compliance with NERC Standards FAC-003.	Budgets increased from \$7.1M in 2014 to \$15.28M in 2018.	Once the transition is completed (completion of just-in-time work), the focus should be on levelizing and maintaining a consistent annual budget.

Gap Analysis From 2014 Report Recommendations		
Recommendation	**Current UTILITY Program**	**Gaps/Clarification**
12. Consider increasing vegetation management oversight to address the addition of approximately 46 crews to meet workload requirement for a 5-year cycle.	The Manager of Transmission Line Services is supported by the Team Leader of Transmission Line Assest Management and by three Transmission Right-Of-Way Coordinators with the plan to add an additional Coordinator in the West.	☑ Good

STRENGTHS

Key strengths from the 2018 re-assessment of the LG&E and KU vegetation maintenance program include the following:

- LG&E and KU management is supportive of program improvements.
- The Manager of Transmission Line Services is supported by the Team Leader of Transmission Line Asset Management and by three Transmission Right-of-Way (ROW) Coordinators with the plan to add an additional Coordinator in the West
- The program is focused on reliability and regulatory compliance.
- A centralized management structure is in place.
- Aerial inspections occur on a quarterly basis to observe the majority of transmission ROW conditions.
- Action Threshold Clearances are established to ensure minimum acceptable clearances are not encroached, providing an increased margin of safety regarding reliability.
- Tree-caused outages are formally investigated and documented, with trained personnel.
- Aerial herbicide applications are effectively used to control brush in rural ROW areas.
- The removal of incompatible species is evident throughout the system.
- Continues to enforce vegetation maintenance clearance specifications, policies and standards.
- Inspects and develops site specific recommendation for the vegetation maintenance, including proper selection and utilization of herbicides.

RECOMMENDATIONS

ECI recommends the following program specific items based on the field data collection and observations of current vegetation practices on the LG&E and KU transmission system:

1. While LG&E and KU began transitioning to a five-year maintenance cycle in July of 2017 on non-NERC transmission lines, an annual budget of approximately $11.26M should be established for routine cycle maintenance only. The estimated annual cost is based only upon work performed as routine cycle maintenance (i.e. pre-identified circuit maintenance) and does not include just-in-time work, reactive work, hazard tree removals, or program oversite. Each one of these categories should be listed and budgeted as a separate line item for the system as a whole and each region individually.
2. Once the full transition to a cyclical maintenance strategy is complete (completion of just-in-time work), the focus should be on levelizing and maintaining a consistent annual budget based upon the number of miles to complete each year to achieve a 5-year maintenance cycle.
3. Continue to develop asset inventory to document ROW widths for each circuit.
4. Develop annual ground patrol inspection process specific to identifying hazard trees to supplement the aerial patrols particulary on NERC transmission lines (i.e., 345 and 500 kV).
5. Continue to collect hazard tree locations and develop prioritization metrics to determine which trees should be removed first.
6. Continue to work towards developing tree crew production reports and metrics to ensure that vegetation maintenance crews exhibit reasonable production levels.
7. Once sufficient unit and time data has been collected to develop accurate circuit cost history, consider moving towards a T&M with incentives contract (target pricing) to begin sharing the cost of production risk with contracted tree vendors.
8. Develop a formal QA/QC process to inspect completed work – specifically to document any inefficiency in herbicide applications and to validate the quality of the completed work.
9. Consider limiting the use of Tordon® for cut/stubble application to only those areas of high customer visibility due to potential liability for off-site woody vegetation kill.
10. Begin to utilize LiDAR data to assist with documenting yard trees to store in a database and the development of separate maintenance cycle.

11. Yard tree issues appear to be minimum and within reasonable expectations for a utility transmission system. LG&E and KU should develop a program to decrease the number of yard trees for the purpose of reducing public risk, maintaining reliability, and reducing long term cost.

Introduction

At the request of LG&E and KU, ECI has documented the quantity and characteristics of the existing tree and brush workload that currently exists on the transmission system. In preparation for the survey:

- LG&E and KU supplied GPS transmission structure locations, flight schedule and helicopter for the vegetation survey, which included the states of Indiana, Kentucky, and Virginia.
- ECI provided the methodology, field personnel, and expertise necessary to conduct the study.

The fieldwork consisted of a sample survey of vegetation conditions on 14 percent (791 miles) of the transmission line miles throughout the service areas of two Pennsylvania Power and Light Corporation operating companies (OPCOs). These OPCOs are LG&E and KU. LG&E and KU supply power to 98 counties with a combined total just under one-million customers. The aerial survey was conducted between March 5th and March 29th, 2018. All data was collected on a span-by-span basis. Aerial data collection included: brush maintenance recommendations (mow, hand cut, foliar spray), edge tree maintenance workload, accessibility, and notations on danger[5] and hazard[6,7] trees adjacent to the ROW corridor (dead, dying, severe lean toward line, etc.). This report includes the following areas of evaluation:

1. Evaluation of field conditions designed to quantify the extent of maintenance required and recommended maintenance practices.
2. Evaluation of vegetation management practices, efficiencies and effectiveness compared to industry best practice methods.

Through face-to-face interviews, field review and email questionnaires, the current operation procedures and vegetation management practices were discussed with LG&E and KU staff.

[5] Danger tree: any tree that could contact the conductor if it fell or fall within the action threshold.
[6] Hazard tree: a danger tree predisposed to failure due to disease, structure, dead or in decline, lean or soil conditions.
[7] The hazard trees observed during the aerial workload survey were reported to the LG&E and KU ROW Coordinator present during the flight.

Current Operating Practices

This section presents general findings from the ECI's interview with LG&E and KU staff and documents program information (i.e., historical budget, reliability, staffing level, etc.). On the basis of ECI's review, program strengths and opportunities for improvement were identified. Based on the results of the review and ECI's experience with industry best practices, recommendations were developed to provide LG&E and KU with a general plan for program improvement.

Program Management and Supervision

LG&E and KU has a centralized staff that manages vegetation along 5,427 miles of transmission circuits. Supervision over the vegetation management group is the responsibility of the Transmission Line Services department. The overall transmission vegetation management program goals are based on safety, reliability, cost effectiveness, fire safety and the incorporation of industry best management practices. LG&E and KU currently posesses a comprehensive vegetation management plan and documented clearance specifications document which includes all transmission voltages and in accordance with FAC-003-4. The vegetation management group began moving toward a five-year cycle program for the non-NERC transmission lines (i.e., 69, 138, and 161 kV) in July of 2017, with an estimated completion of the first-cycle by 2022. LG&E and KU began a five-year cycle program on NERC transmission line (i.e., 345 and 500 kV) in July of 2014 and have completed 63.2 percent of the miles. Currently, there are three ROW Coordinators who are each assigned to a specific region (East, Mountain, Central, Louisville and West). LG&E and KU has begun the process of adding an additional ROW coordinator, who will be assigned the West. Currently, the Patroller assists with the management of the West Region and is responsible for scheduling vegetation maintenance, monitoring contract tree crew progress, performing QA/QC of completed work, and interacting with with landowners along the ROW. There are two Inspectors that perform similar roles and assist with work in the East, Mountain, and Central regions. LG&E and KU expressed potential plans to hire additional Inspectors to assist in other regions due to the current and future increase in contract tree crews. The geographic dispersion of work makes it difficult for the vegetation management staff to efficiently supervise the contract tree crews. The Patroller and Inspectors do not currently perform aerial inspections.

Vegetation maintenance needs are determined by LG&E and KU ROW Coordinators based upon quarterly inspections performed. The patrol of transmission lines is predominately performed by helicopter. The ROW Coordinators and other experienced staff have received training on recognizing vegetation maintenance priorities or conditions that require immediate attention. The aerial inspections were used to determine circuit priority and the annual work plan for the first-year (July 2017) of the five-year maintnenace cycle strategy on non-NERC transmission lines.

Contract Crews

ROW Coordinators oversee vegetation maintenance performed by three vendors under a T&M contract. Asplundh Tree Expert, Co. and Phillips Tree Experts, Inc. are the primary tree contractors used for vegetation maintenance ground activities. Summit Helicopters, Inc. performs herbicide aerial spray treatments. Haverfield Aviation, Inc. was contracted to provide aerial inspection support.

Asplundh Tree Expert, Co. and Phillips Tree Experts, Inc. have a five-year T&M contract with LG&E and KU. Maintenance is equally split between the two contractors. Phillips Tree Experts, Inc. works in the eastern half of the transmission system where the terrain is steeper because of the rolling foothills and mountain ridges common to the Appalachian Mountain Range.

Customer Interface

LG&E and KU provides notification to land owners regarding impending maintenance activities based upon the location of the transmission line within the state. Customers abutting rural sections of transmission line typically do not receive notification in the eastern half of Kentucky. Landowners of agricultural land and horse farms and those located in urban areas generally receive notifications. Special notification and access permission to ROW corridors is provided when working on USDA Forest Service lands, military bases (Fort Knox) and other government owned land.

LG&E and KU staff stated that land owner issues, skips and special areas are not documented or tracked in database format. Tracking customer issues or special previsions can help with reliability improvements, work planning, cycle selection, and tracking resolution status of refusals.

Regulatory Agencies

LG&E and KU follow the Kentucky Public Service Commission regulation pertaining to tree energized electrical equipment limits of approach. If these limits are breached by tree(s), lines are de-energized to perform vegetation maintenance. LG&E and KU have guidelines to determine immediate maintenance requirements (emergency or high priority due to vegetation proximity) versus scheduled maintenance. LG&E and KU are subject to the North American Electric Reliability Corporation (NERC) reliability standards and practice due diligence in complying with NERC FAC-003 standards. LG&E and KU transmission systems are specifically regulated by SERC Reliability Corporation, a regional entity of NERC. The LG&E and KU transmission system is comprised of approximately 734 miles of NERC regulated lines (345 and 500kV system) and 4,693 miles of non-NERC regulated lines (69, 138 and 161 kV system). LIDAR is performed on 50 percent of the NERC lines each year. Even though NERC FAC 003-4[8] standards require

[8] Each applicable Transmission Owner and applicable Generator Owner shall perform a Vegetation Inspection of 100% of its applicable transmission lines (measured in units of choice – circuit, pole line, line miles of kilometers, etc.) at least once per calendar year and with no more than 18 calendar months between inspections on the same ROW. FAC 003-4 R6. 2016

only one inspection per calendar year of vegetation conditions, LG&E and KU performs two vegetation only patrols during May and July. In addition, LG&E and KU performs aerial patrols each quarter for critical visual equipment inspection, the ROW Coordinator will document any vegetation that may have been missed during the vegetation only patrols in May and July.

Tree-Related Interruptions

LG&E and KU reliability staff perform an in-depth post-outage investigation of vegetation-caused outages. Outages listed as "vegetation" are separated by a secondary cause code (i.e., grow-in, fall-in from off-ROW, and fall-in from inside-ROW). The specific reason for a tree-caused outage is limited to three codes, but could be expanded to include additional cause codes for further reliability analysis. The additional secondary cause codes (i.e., hazard tree, mode of tree failure, etc.) would assist in further diagnosis of tree-caused outage root causes. Currently, LG&E and KU uses an internal program called Transmission Reliability Outage Data System (TRODS) to capture and store reliability data.

A continued major concern for LG&E and KU are tree-caused outages caused from hazard and danger trees (125 fall-ins on 69, 138 and 161kV lines between 2012 and 2017). LG&E and KU observed very few sustained "grow-in" outages on the 69kV between 2012 and 2014, and sustained "grow-in" outages have not occurred between 2015 and 2017. No vegetation outages have been recorded on 345 and 500kV lines between 2008 and 2018 YTD. Figure 1 shows the number of tree-caused outages for 2012 through 2014 and 2015 through 2017 for each of the secondary cause codes. Tree fall-ins, outside of the ROW, account for 85 percent from 2012 through 2014 and 98 percent from 2015 through 2017 of all tree-caused outages.

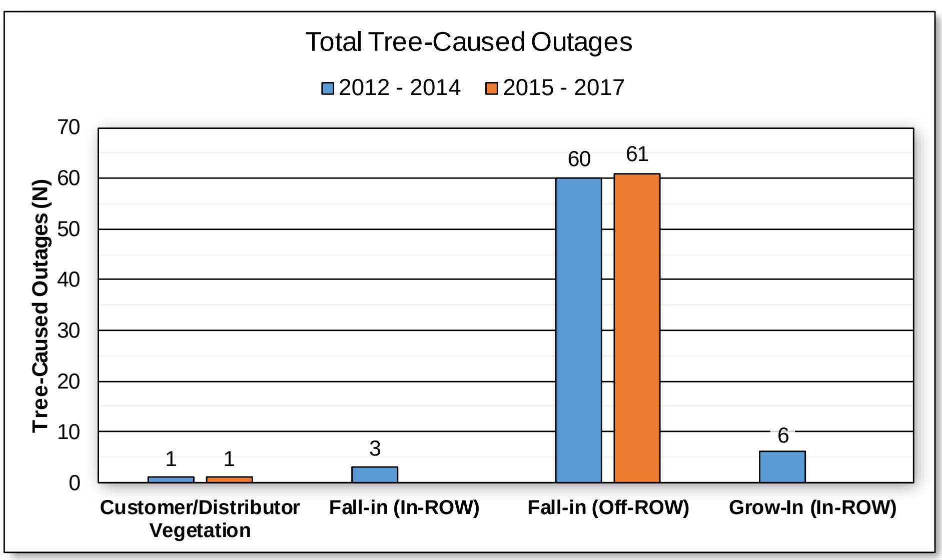


Figure 1. Total number tree-caused outages by secondary caused.

Hazard trees are removed when found following aerial inspections. However, since the number of fall-in outages continue to be the major source of tree-caused outages, there appears to be hazard trees that are possibly being missed during aerial inspections. LG&E and KU should continue the ground patrol to identify hazard trees that are hidden under the canopy of larger mature trees and to identify trees with structural defects that may be missed in aerial patrols.

Recordkeeping and Crew Productivity

A comprehensive recordkeeping and reporting system is an essential component of an effective line clearance program. A record keeping system should be capable of providing management with the following information:

- Justification of management decisions.
- Projections of annual budget requirements.
- Determination of the most cost effective crew type for various locations and work types.
- Prioritizing work by analysis of tree-caused outages and the inclusion of other metrics important to the utility.
- Detailed monitoring of crew productivity.
- Establishment of guidelines for tree removal and replacement (if implemented).
- Establishing a tracking process for customer refusals and hazard trees.

A comprehensive line clearance record keeping system depends on recording four components of all field activities: work location (i.e. circuit number), description of work completed (number of trims, removals, etc.), time required to complete the activity and any required materials (man and equipment hours). Time report verification, evaluation of crew productivity and accumulation of cost and production data all depend on these elements of activity reporting.

Recording crew time by specific work units and work related activities will provide the means to (1) examine detailed costs, (2) evaluate productivity, and (3) initiate appropriate changes to maximize the efficiency of the program. All record keeping should be adjusted to conform to the type of contract in place and the desired system metrics for LG&E and KU.

Time Utilization

Time utilization measures can be used to evaluate crew time and production figures: time utilization, performance, and effectiveness.

Time utilization calculations allow a utility to determine what each crew does with the time it controls on a daily basis. For example, if time utilization is low, it indicates that the crew has excessive nonproductive time.

Performance

Performance is a measure that compares the actual time required to prune or remove a tree to the expected or standard time. Standards are developed from actual local data and are periodically evaluated for accuracy. The performance rating provides a good means for evaluating the production rates of each crew relative to an established set of standards. If performance is too high, it may suggest that a crew is inaccurately reporting work, obtaining inadequate clearance, or trimming brush (rather than removing brush). If performance is too low, it may suggest that the need for increased supervision and/or training.

Effectiveness

Effectiveness is calculated as a product of time utilization and performance (time utilization X performance/100). It provides a relative measure of what the return on expenditures is for each contract crew. Effectiveness ratings can be used to compare individual crews.

LG&E and KU has an electronic record keeping system to track circuit history, crew number, man hours, start and stop pole locations, labor cost, material cost, equipment cost, brush and tree units, aerial spray acres and aerial spray cost. LG&E and KU record keeping system has improved and now tracks the appropiate information for crew production analysis. The start/stop pole information does include a linear distance and type of work performed (i.e., number of trims, linear distance mechanically pruned, removal, brush acres mowed, etc.).

In the 2014 assessment, ECI noted that LG&E and KU did not possess the metrics necessary to effectively and efficiently manage the program. Data collected from contractor timesheets were limited to only man-hours and equipment-hours.

LG&E and KU has made significant improvements, since 2014, by requiring additional work units to be recorded on timesheets, which is allowing the development of productivity metrics that are necessary to begin effectively and efficiently managing the program. Work categorized on the LG&E and KU contractor timesheet include the following classifications:

- Man-hours for each employee and equipment
    - Daily Hours (RT, OT, and DT)
    - Holiday
    - Vacation
    - Other
- Crew #
- Type of work (Scheduled vs Just-in-Time/Workorder)
- Circuit
- Type of crew (Tree or Other)
- Contract Number

- Work Performed
    - Trees Trimmed
    - Removals
        - Yard Trees (by D.B.H.)
        - Non-Yard Trees (by D.B.H.)
        - Ash Trees
        - Hazard Trees
    - Brush
        - Acres
        - Herbicide Amount & Mixture
    - Fence Row (Linear Feet)
    - Creek Bank (Linear Feet)
    - Vines
- Travel Time

Unit data (i.e. number of trees by maintenance type) is recorded on the timesheet and is captured as part of the current process for the electronic record keeping system. The continued development of productivity metric and circuit trim history/cost will allow movement toward a performance-based component within a T&M contract, or become a basis for a unit cost component of firm priced contracts (Appendix B). At a minimum, the detailed production data will provide an accurate assessment of production cost for various work-types for both internal and external comparisons.

Vegetation Work Practices

As noted in the 2014 study, LG&E and KU have performed admirably in managing transmission vegetation with a limited budget. Historically, the size of the annual budget necessitated a "just-in-time" approach to vegetation maintenance that has resulted in a patch work of various vegetation conditions on non-NERC lines. During ECI's 2014 workload survey, vegetation conditions on any given line ranged from clear (just maintained) to very tall brush or edge trees on low voltage lines requiring immediate attention. Figure 2 presents an example of the vegetation conditions on a circuit that has not been recently maintained. However, during the workload re-survey in 2018, vegetation on completed circuits appeared to be more uniform and did not exhibit the incontinuity as previously noted (Figure 3). Circuits that have not been worked in their entirety still exhibited the patch work observed in 2014.

Figure 2. Example of Vegetation Conditions on a Circuit Observed During 2018 Aerial Workload Suvery that has not been Recently Maintained.

Figure 3. Example of Vegetation Conditions on Completed Circuits Observed During 2018 Aerial Workload Suvery.

During ECI's field review, yard trees (Figure 4) were observed to be within the ROW that may require a separate cycle length that is shorter than the target five-year cycle strategy used on rural segments of the transmission system or a mid-cycle strategy. When plausible LG&E and KU should seek to have these yard trees removed from within ROW. LG&E and KU may find it beneficial to utilize LiDAR data to map out and develop a database documenting the location of yard trees. Leveraging the data from LiDAR may be useful when developing a separate cycle or mid-cycle strategy for yard trees. After collecting LiDAR data, LG&E and KU could pursue idenifying the species classification for every yard tree and the average re-growth rates for the dominate tree species. The LiDAR data, tree species classification, and average re-growth rate could be analyzed to determine which trees on within the ROW pose the greatest risk and should be removed.

Figure 4. Example of Yard Trees within the ROW under the Transmission Conductors.

Utilitzing the data gathered through ECI's aerial patrols, the vegetation workload was quantified, and together with historical maintenance cost supplemented with industry cost data, a maintenance budget was established for the remaining miles to achieve completion of the first-cycle of a five-year cyle strategy by 2022. Because of the extensive "just-in-time" maintenance employed prior to July 2017, conversion to a more efficient and cost effective cyclic maintenance schedule will require several years to implement. During this implementation phase, "just-in-time" maintenance will be required to maintain system reliability until cycles can be established. In addition, the early years of the conversion to cyclic maintenance may require a higher budget. Converting to a cyclical maintenance schedule will reduce unit production cost (lower density and shorter height brush), provide for reduced planning effort each year through reducing the number of aerial inspections, and provide for a sound basis to consider other contracting strategies. LG&E and KU are developing a detailed database to track line maintenance history, determine the efficiency of the vendors (production reports) and forecast future work efforts and costs.

Brush Maintenance

LG&E and KU effectively utilize herbicides as part of its overall IVM program to prevent re-sprouting on mowed (cut/stubble application) locations and manually removed trees as well as foliar applications to encourage the growth of low growing herbaceous vegetation. The mixtures used for herbicide application are listed in Table 6. Caution should be used with Tordon® K due to soil persistence and the potential for off-ROW leaching that may affect nontarget vegetation[9]. The ROW Coordinators explained that herbicide efficacy was not acceptable for some trouble species (i.e., sweetgum, redcedar – eastern, and American Holly). ECI recommends reaching out to the manufacturers of the herbicides such BASF Corp., Monsanto, or Bayer to provide additional information about alternative herbicides that maybe more effective.

Table 6. Herbicide Mixtures Used by LG&E and KU to Target Tall Growing Woody Vegetation within the Transmission ROW.

Aerial Spray	Aerial Spray - Wetland Areas	Ultra-Low Volume	High-Volume Foliar
• Krenite® • Viewpoint® • Milestone®	• Glyphosate (AquaNeat®) • Polaris®	• Tordon® K • Method® • Milestone®	• Garlon® 3A • Tordon® K • Freelex® • Clean Cut®

Vegetation Maintenance Expenditures

The vegetation maintenance budget is presented to LG&E and KU senior management on an annual basis for approval. Vegetation funding has historically been based on past funding levels, not specific to addressing cyclical maintenance requirements. However, the budget in 2017 was funded to begin a cyclical maintenance strategy. The annual budget/actuals remained fairly flat prior to 2014. The budget increased in 2014, with much larger increases in 2017 and 2018.

[9] PennState Extension. *Herbicide Summary – Tordon K*. Retrieved from https://extension.psu.edu/herbicide-summary-tordon-k.

Table 7. LG&E and KU Historical Transmission Vegetation Maintenance Expenditures.

Year	ROW Actuals	CPI[10] Adjusted[11]
2009	$4,425,830.31	$5,061,896.73
2010	$4,616,948.52	$5,195,265.14
2011	$5,313,879.93	$5,796,524.85
2012	$4,912,862.53	$5,250,431.06
2013	$5,570,389.98	$5,867,193.43
2014	$7,071,865.00	$7,329,765.42
2015	$7,127,020.00	$7.378.179.32
2016	$7,047,119.58	$7,204,571.51
2017	$10,718,649.22	
2018 Budget	$15,280,528.00	

Production and Cost

LG&E and KU provided ECI with cost data from 2010 through 2017. From this data, ECI calculated aerial spray cost per acre and unit costs. In addition, LG&E and KU provided ECI with weekly rates by crew type for calculating the estimated number crews need to manage the transmission system.

Vegetation Assessment

Vegetation conditions were sampled on 14 percent of the total transmission line miles to estimate the existing vegetation workload for each of the five voltages. The ECI survey team inventoried approximately 791 transmission miles. Field data gathered by the survey team focused on tree and brush quantities, conditions, and maintenance requirements. The results of the study are included in the following sections.

Specific Survey Criterion

ECI's survey team utilized the *FAC-003-4 Vegetation Program Document (Effective Date: October 1, 2016)* specifications for the basis in determining workload parameters. The survey team collected data on the current vegetation conditions on the LG&E and KU transmission system using the form found in Appendix C.

[10] CPI – Consumer Price Index.
[11] The actual vegetation expenses for each year were adjusted using the correct CPI for the base year of 2017. The adjustment was done to allow for a better comparison between years.

Vegetation Workload Survey Data

This section presents general findings of ECI's workload assessment. Total workload projections are based on the total line miles as provided by LG&E and KU.

Total Workload

Table 8 presents the estimated total vegetation workload summary for the LG&E and KU transmission system by voltage class based on the 2018 re-survey. The accuracy for determining the number line miles on the LG&E and KU transmission system has increased since 2014 and were updated for the 2018 re-assessment.

Table 8. Tree and Brush Workload by Voltage Category (Transmission).

Voltages (kV)	*System Miles*	*System Acres*	*Yard Trees*	*Edge Pruning - Mechanical (ft.)*	*Edge Pruning - Manual (ft.)*	*Re-clear (ft.)*	*Manageable Brush Acres*
69	2,738	33,191	11,100	6,280,400	1,690,700	128,700	11,560
138	1,298	23,592	4,100	4,914,400	372,600	15,500	10,720
161	657	11,938	400	1,515,400	698,200	66,900	6,450
345	677	14,370	600	2,578,000	334,800	90,700	5,140
500	57	1,206	---------	11,700	38,700	6,000	700
TOTAL	**5,427**	**84,297**	**16,200**	**15,299,900**	**3,135,000**	**307,800**	**34,570**

Total workload was projected for the LG&E and KU system based upon the conditions noted on the sampled miles and extrapolated for total system counts. Table 8 indicates that approximately 15,299,900 linear feet of ROW edge can be pruned using mechanical equipment (i.e. Jarraff or Skytrim crews), 3,135,000 feet consist of manual edge clearing and 307,800 feet of ROW edge to be re-cleared to re-establish ROW widths. The estimated linear footage of ROW needing to be re-cleared is larger than than the 2014 aerial survey due to better identification of actual ROW corridor widths as validated by the ROW Coordinators. The estimated re-clear footage for 500kV lines resulted from the need to achieve additional clearance where spans extend between ridgetops. LG&E and KU should consider leveraging LiDAR data to identify locations for ROW re-clearing.

The estimated hazard tree count is based upon a survey conducted by a third-party consulting group in 2017. Third-party surveyors covered 1,056 corridor miles (approximately 23 percent) and identified 2,108 hazards tree (86 percent were ash trees). An identified hazard tree was assigned to either P1, P2, or P3 categories based upon the tree condition and location. The density of hazard trees were equated for each voltage (Table 9). All ash trees regardless of condition that were within striking distance of transmission facilities were included in one of the three categories due to validated impact from the emarld ash borer bettle (EAB).

Table 9. Number of Hazard Trees Identified through Third-Party Surveyors.

Voltages (kV)	*Corridor Miles Surveyed*	*Ash Trees*	*P1 Trees*	*P2 Trees*	*P3 Trees*	*Hazard Trees Per Mile*[12]
69	295	1091	433	194	513	3.86
138	452	597	49	242	491	1.73
161	94	35	22	41	29	0.98
345	215	87	2	26	66	0.44
TOTAL	**1056**	**1810**	**506**	**503**	**1099**	**2.00**

The information from the survey was used to estimate the number of hazard trees over the entire transmission system. Surveyors did not visit any miles on 500 kV lines. However, ECI used the hazard tree density from 345 kV for 500 kV due to similar vegetation conditions on 345 kV. The estimated number of hazard tree over the entire LG&E and KU transmission system is presented in Table 10.

Table 10. Estimated Number of Hazard Trees on LG&E and KU Transmission System.

Voltages (kV)	*System Miles*	*Corridor Miles*	*Hazard Trees*
69	2,738	2,314	8,900
138	1,298	979	1,700
161	657	609	600
345	677	502	200
500	57	57	20
TOTAL	**5,427**	**4,461**	**11,420**

More than 83 percent of the total ROW edge workload was identified as non-NERC lines which is expected considering these three voltages comprise approximately 86 percent of the total transmission line miles. Figure 5 presents the distribution of the edge tree maintenance workload across the varying voltage classifications. Alternatively, Figure 6 presents the linear distance (in feet) of edge tree maintenance on a per mile basis, which shows 345 kV lines as having the highest concentration, followed by 138 kV and 161 kV lines.

[12] The ash tree category was used as description and not as a standalone tree count. The P1, P2, and P3 categories include ash trees identified during the survey. Hazard trees per mile are based upon the sum of P1, P2, and P3 categories.

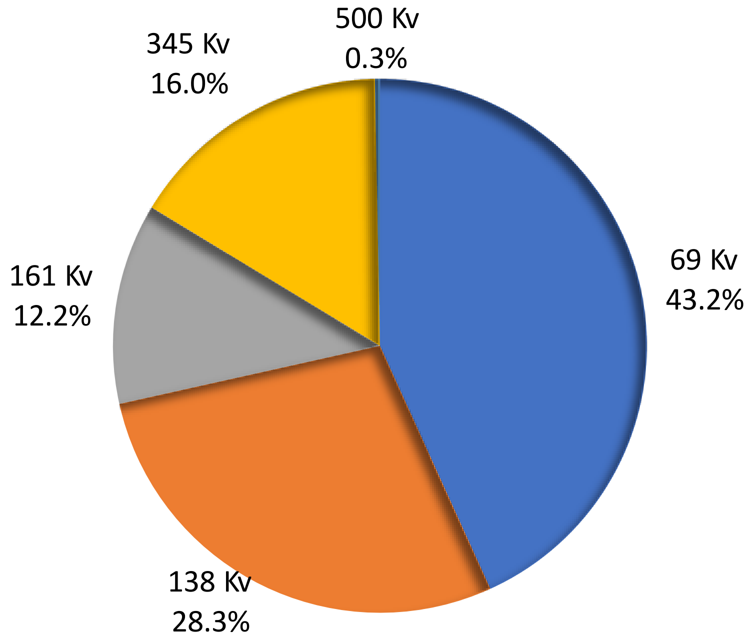


Figure 5. Percentage of Edge Tree Maintenance Workload by Voltage Classification.

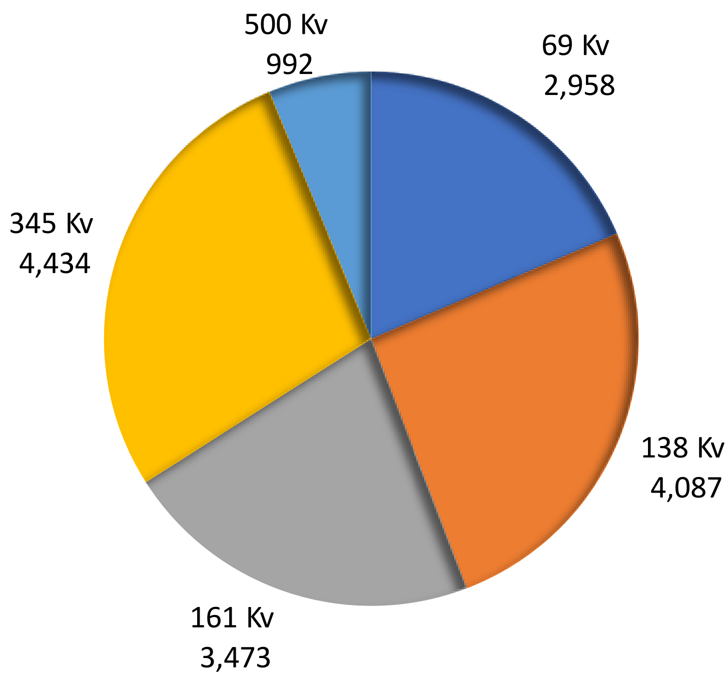


Figure 6. Linear Distance of Edge Tree Maintenance per Mile by Voltage Classification[13].

[13] Each side of the ROW was counted separately and then combined to provide actual footage to be pruned. Therefore, the liner footage per mile of workload can result in a number larger than a mile.

Yard trees account for approximately 16,200 total trees or 3.0 trees per mile at the system level. Approximately 41 percent of the LG&E and KU transmission system (or 34,570 acres) contain manageable brush acreage. Brush will be defined in greater detail later in the Brush Workload Characteristics section. The number of manageable brush acreas decreased from the previous 2014 survey due to the change in the ROW width for 69 kV. In 2014, 150 feet was noted for the ROW width but ECI was instructed to use 100 feet as the ROW width for 69 kV line segments in the 2018 re-assessment survey. In addition, the ROW width for NERC lines was increased in 175 feet but had little impact on brush acres since NERC lines account for approximately 14 percent of the total system miles. In addition to change in ROW width, total system miles decreased due to an increase in accuracy for determining actual corridor miles by voltage class due to LG&E and KU transitioning to a GIS based system to map out the transmission system.

Average Density and Statistical Error

Tree and brush density was quantified in terms of trees per mile, linear distance per mile and acres per mile. Table 11 shows the average trees per mile (Yard Trees), linear distance per mile of ROW edge trimming (Mechanical, Manual and Re-clear), and brush acres per mile by voltage class on the LG&E and KU transmission system. These are trees and acres of brush requiring maintenance according to *FAC-003-4 Vegetation Program Document (Effective Date: October 1, 2016)* specifications document. The tree counts and brush acres per mile data as expressed in Table 11 was used to estimate the total quantities at the system level (as shown in Table 8).

Table 11. Average per mile tree and brush densities per mile on the LG&E and KU transmission system observed during the 2018 aerial suvey.

Voltages (kV)	***Total System Miles***	***Surveyed Miles***	***Number of Yard Trees***	***Linear Distance for Mechanical Trimming (ft.)***	***Linear Distance for Manual Trimming (ft.)***	***Linear Distance for Re-clear of ROW (ft.)***	***Manageable Brush Acres***
69	2,738	254.4	2.8	2,293.6	617.4	47.0	4.2
138	1,298	181.3	2.7	3,787.5	287.2	11.9	6.8
161	657	116.7	0.6	2,308.0	1,063.4	101.9	9.7
345	677	212.7	1.0	3,805.5	494.2	133.9	7.5
500	57	26.6	0.0	204.9	681.1	105.6	11.8
SYSTEM AVERAGE	**5,427**	**791.7**	**1.9**	**2,973.6**	**576.6**	**72.4**	**6.7**

The statistical sampling error was calculated for the transmission survey samples by voltage class. Statistical sampling error calculations were based upon the mean linear distance of tree workload and brush acreage per span at the 90 percent level of confidence. Sampling error for linear distance of tree workload per span for each voltage category was: 69kV = ± 4.6 percent; 138kV = ± 4.6 percent; 161kV = ± 7.0 percent; 345kV = ± 4.4 percent; and 500kV = ± 37.1 percent. The sample error for 500kV was above the desired target error due to the high variability in edge maintenance required because of the effectiveness of the aerial herbicide spray applications. Sampling error for brush acres per span for each voltage category was: 69kV = ± 4.0 percent; 138kV = ± 4.9 percent; 161kV = ± 4.7 percent; 345kV = ± 4.6 percent; and 500kV = ± 8.6 percent.

The number of miles surveyed during 2018 was 791.7 miles, approximately 26 percent less than the miles surveyed in 2014 (Table 12). The decrease in the number of miles surveyed was the result of weather conditions which prevented safe aerial flights and a reduced time frame to perform the aerial flights. The largest difference in the number of miles surveyed occurred for the 69 and 138 kV line sections. Even with the decrease in miles surveyed, the majority of densities for the various maintenance categories were fairly similar due to similar site conditions and were not significantly different when using an analysis of variance (ANOVA) statistical test. The largest difference in work unit densities occurred with the number of yard trees for the 69 and 138 kV; mechanical and manual linear distance for 500 kV; and the amount of re-clear footage for all voltages. After reviewing the locations of scheduled flights that did not occur in 2018 and discussing the details of the site conditions with the ROW Coordinators, ECI determined that the reason for the decrease in yard trees per miles was the result of not surveying specific circuits where a large number of yard trees are located. ECI recommends using the yard tree density observed in 2014 for estimating the budget in 2018. The reduction in the amount of linear footage per mile for mechanical and manual trimming is due to the ROW edge maintained through aerial spray application. The third notable difference resulted from being able to capture scheduled re-clear work along each of the voltages. The challenge during 2014 was being able to identify the legal ROW boundary while performing the aerial survey. The re-clear footage in 2014 was based upon obvious signs of vegetation that had encroached and largely did not include scheduled re-clear work that was incorporated in the 2018 survey.

Table 12. Average per mile tree and brush densities per mile on the LG&E and KU transmission system observed during the 2014 aerial suvey.

Voltages (kV)	*Total System Miles*	*Survey Miles*	*Number of Yard Trees*	*Linear Distance for Mechanical Trimming (ft.)*	*Linear Distance for Manual Trimming (ft.)*	*Linear Distance for Re-clear of ROW (ft.)*	*Manageable Brush Acres*
69	2,738	432.0	4.0	2,569.4	710.7	10.5	6.6
138	1,298	231.7	3.2	3,287.8	201.4	4.0	6.9
161	657	156.0	0.6	3,955.6	1,331.3	15.7	10.1
345	677	233.2	1.3	2,701.7	363.0	0.0	6.5
500	57	23.1	0.0	946.9	4,298.6	23.0	12.5
SYSTEM AVERAGE	**5,427**	**1076.0**	**2.7**	**2,918.8**	**692.8**	**7.8**	**7.3**

Brush Workload Characteristics

Brush workload was collected and characterized by maintenance practice. Table 13 shows the total estimated brush acres on the LG&E and KU system by maintenance practice.

Table 13. Brush Workload by Voltage Category and Maintenance Practice.

Voltages (kV)	*Total System Miles*	*Total System Acres*	*Mow Acres*	*Hand Cut and Treat Acres*	*Low-Volume Foliar Acres*	*High-Volume Foliar Acres*	*Aerial Spray*	*Manageable Brush Acres*
69	2,738	33,191	300	1,100	8,000	50	2,110	11,560
138	1,298	23,592	1,600	700	6,500	100	1,820	10,720
161	657	11,938	30	300	3,800	10	2,310	6,450
345	677	14,370	400	400	3,900	30	410	5,140
500	57	1,206	-------	-------	100	-------	600	700
TOTAL	**5,427**	**84,297**	**2,330**	**2,500**	**22,300**	**190**	**7,250**	**34,570**

Approximately 41 percent (or 34,570 acres) of the total LG&E and KU transmission system currently contain brush species that require maintenance (Figure 7). When estimating brush acres, locations that had the potential to support brush were included in the low-volume foliar management practice. The remaining 61 percent (Figure 8) of the transmission system is currently void of brush due to land use (e.g., agricultural land, maintained lawns, waterways, etc.).

Approximately 63 percent (22,300 acres) of the total manageable transmission brush acres were classified as suitable for low-volume foliar treatment (i.e., backpack application of herbicide). For a location to be classified as low-volume foliar the stem heights were shorter than seven feet and stem density was approximately 1,500 or less stems per acre. Therefore, a large majority of the LG&E and KU transmission system is potentially manageable through low-volume herbicide maintenance work. Dependent upon the location and accessibility, brush acres that were classified as low-volume foliar may be suitable for aerial spray application. The next largest brush maintenance category which accounted for approximately 21 percent (7,250 acres) of the total brush acres is aerial spray. In addition to controlling brush, aerial spray applications are used to control edge trees through applying herbicide to tree limbs encroaching into the ROW. Since only tree limbs encroaching into the ROW are sprayed with herbicide, the trees remain viable and only shed the affected limbs. The ROW Coordinators assisted in identifying the location where only aerial spray application is used maintain both the ROW floor and edge.

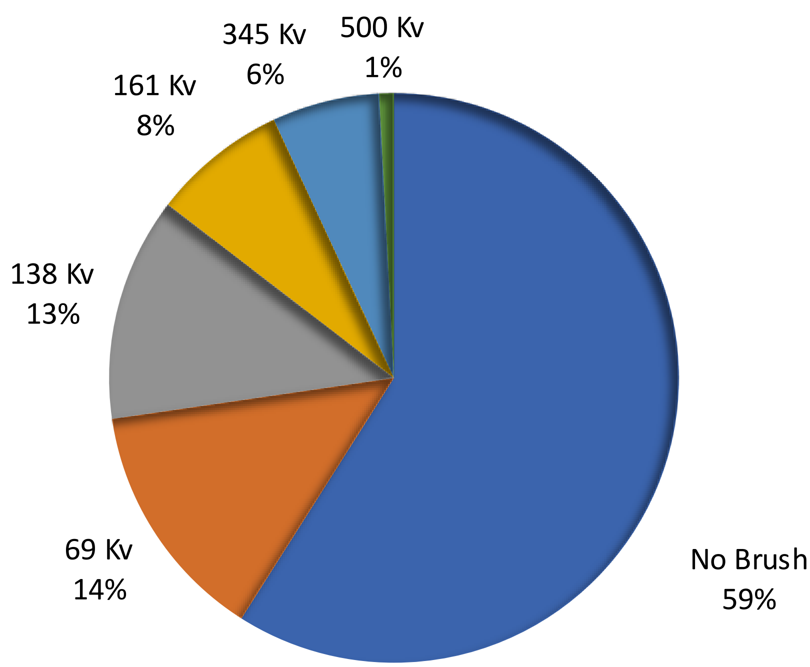


Figure 7. Percentage of Brush Acreage by Voltage Classification.

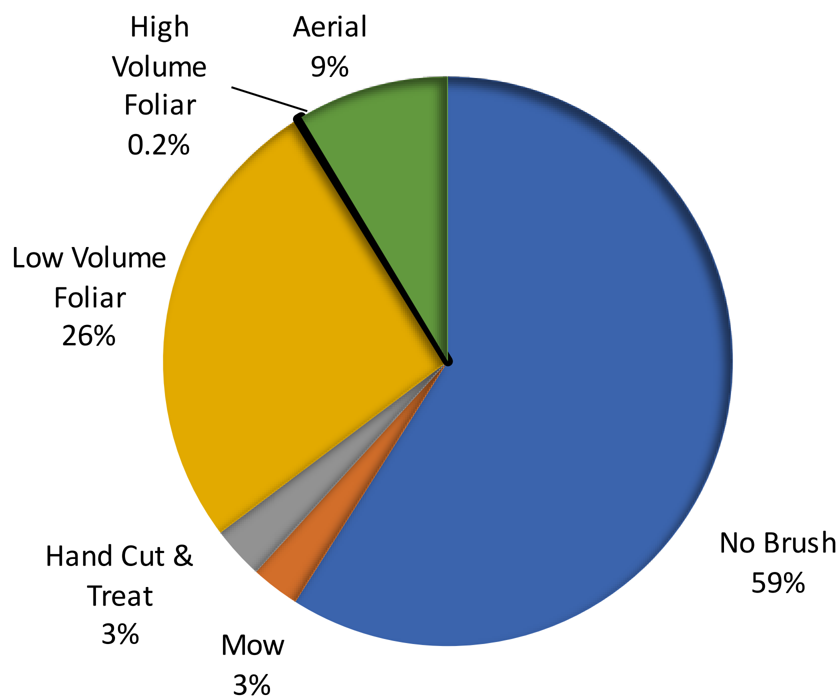


Figure 8. Percentage of Brush Acreage by Maintenance Practice.

ECI included aerial spray as a maintenance category for brush in the 2018 re-assessment. Historically, LG&E and KU has treated approximately 1,700 – 3,100 acres of brush using aearial spray each year. Since the manageable brush acres on the LG&E and KU transmission system is comprised of approximately 65 percent low and high-volume foliar treatment category, aerial treatments could be leveraged to treat these additional brush acres in an extremely cost effective manner (where practical).

ROW Edge Clearing Characteristics

ECI documented specific transmission spans where the established ROW width was less than desired. Table 8 above, presents the estimated linear feet of edge clearing required to reclaim existing rights-of-way edge to the targeted ROW width. The tree and immature tree categories were deemed important in understanding the nature of the widening or re-clearing requirements, particularly since each may yield different clearing costs. Immature trees that could be cleared with a bush hog or hydro-axe were classified as mow acres. When clearing large trees required equipment such as a bull dozer or feller buncher was classified as re-clear footage. Figure 9 shows examples of the specialized equipment commonly used for ROW clearing.

Bush Hog

Hydro-Axe

Bulldozer

Feller-Buncher

Figure 9. Specialized Equipment Commonly Used in Transmission ROW Clearing and Widening.

Maintenance Characteristics

As part of the field data collection, the ECI surveyors classified the workload within each span into eight maintenance categories. The categories used for classifying the workload are:

- MST – Mechanical side Trim (sky trim, Jarraff, etc)
- MT – manual trim
- RC – re-clear
- YT – yard tree
- HT – hazard tree
- MBH – mow: brush hog or hydro Ax (kershaw or similar)
- HC – hand cutting
- LVF – low-volume foliar herbicide treatment
- HVF – high-volume foliar herbicide treatment
- AS – aerial spray

Depending upon the terrain or geography of a span location workload was separated into different categories. For example, due to terrain a span may have a mixture of mechanical and manual side trimming work. It should also be noted that the total brush acres to be maintained over a five-year cycle would be higher than total brush acres observed on the system because some brush acres mechanically cut or hand cut should have a subsequent follow-up herbicide application scheduled in a future year.

Recommendations were assigned based on current field conditions with emphasis on minimizing maintenance costs. In most cases, herbicide was recommended in lieu of mowing unless specific site conditions warranted otherwise. However, specific herbicide restrictions may negate some herbicide recommendations. The data provided here has not been adjusted to balance the annual spend.

Note that these recommendations serve only as an estimate of the total workload by maintenance practice. Prior to beginning any work or budgeting for specific vegetation needs, it is recommended that the specific scheduled transmission lines be individually prescribed. This data serves only to characterize the existing workload over the entire transmission ROW system.

Budget and Man-Hour Estimates

Total vegetation management estimated costs and man-hours for the LG&E and KU transmission system are presented in Table 14. The estimated budget and man-hours to address hazard trees are presented in Table 15. The detail in Table 16 presents the system total cost to maintain the tree and brush workload by management category and voltage class on the LG&E and KU transmission system. Unit costs and weekly crew rates were used to calculate loaded labor and equipment rates (Table 17). The unit cost values were derived by ECI utilizing available industry data and historical LG&E and KU data.

Table 14. Total **First-Cycle** Transmission Budget and Man-Hour Estimate By Voltage.

Voltages (kV)	*Estimated Total Cost*	*Estimated Total Man Hours*
69	$23,660,000	630,300
138	$15,680,000	387,400
161	$7,980,000	202,900
345	$8,550,000	218,400
500	$434,000	6,300
Grand Total	**$56,304,000**	**1,445,300**

Table 15. Total **First-Cycle** Transmission Hazard Tree Budget and Man-Hour Estimate By Voltage.

Voltages (kV)	*Estimated Total Cost*	*Estimated Total Man Hours*
69	$1,914,600	58,000
138	$365,700	11,100
161	$129,100	3,900
345	$43,000	1,300
500	$4,300	100
Grand Total	**$2,456,700**	**74,400**

Table 16. Estimated **First-cycle** Budget by Tree and Brush Management Category and Voltage for the LG&E and KU Transmission System.

Voltages (kV)	*Yard Trees*	*Mechanical*	*Manual*	*Re-Clear*
69	$1,268,000	$9,735,000	$5,677,000	$743,000
138	$468,000	$7,620,000	$1,253,000	$89,000
161	$46,000	$2,350,500	$2,345,000	$386,000
345	$69,000	$3,999,000	$1,126,000	$523,000
500	------------	$18,000	$130,000	$35,000
Total	**$1,275,000**	**$23,722,000**	**$10,531,000**	**$1,776,000**

Voltages (kV)	*Mow*	*Hand Cut*	*Low-Volume Foliar*	*High-Volume Foliar*	*Aerial Spray*
69	$333,000	$2,193,000	$2,938,000	$22,000	$751,000
138	$1,775,000	$1,396,000	$2,387,000	$44,000	$684,000
161	$33,000	$598,000	$1,396,000	$4,000	$822,000
345	$444,000	$798,000	$1,432,000	$13,000	$146,000
500	------------	------------	$37,000	------------	$214,000
Total	**$2,585,000**	**$4,985,000**	**$8,190,000**	**$83,000**	**$2,581,000**

Table 17. Unit Cost and LLER

Management Category	*Unit Cost*	*Unit*	*LLER*
Yard Tree	$114.19	per tree	$33.04
Hazard Tree	$215.13	per tree	$33.04
Mechanical	$1.55	per foot	$43.08
Manual	$3.36	per foot	$30.92
Re-Clear	$5.77	per foot	$86.65
Mow	$1109.21	per acre	$60.05
Hand Cut and Treat	$1,993.84	per acre	$32.22
Low-Volume Foliar	$367.29	per acre	$29.49
High-Volume Foliar	$435.50	per acre	$50.61
Aerial Spray	$355.97	per acre	$7,133.25

Total budget to maintain the LG&E and KU transmission system for a targeted five-year cycle is estimated to be approximately $56.30 million (or approximately $11.26M annually) and requires approximately 1.45 million man-hours (or 289,060 man-hours annually). The average system cost per transmission mile based on the estimated budget is $10,375 per mile. The estimated annual cost is based only upon work performed as routine cycle maintenance (i.e. pre-identified circuit maintenance) and does not include just-in-time work, reactive work, hazard tree removals, or program oversite. Approximately 15 percent of the total budget dollars are allocated to low-volume herbicide work (LVF). Yard trees account for less than four percent. The three maintenance types (mechanical side trim, manual trim, and re-clear) for which industry unit cost values were used, account for approximately 64 percent of the total budget. Total budget to address the hazard trees on the transmission system is estimated to be approximately $2,456,700 (or approximately $491,340 annually) and requires approximately 74,400 man-hours (or 14,880 man-hours annually).

Crew Resource Allocations

Based on the existing vegetation workload and the production values provided to LG&E and KU, crew resource needs were estimated. Table 18 presents a summary of the estimated annual crew resource requirements based on a five-year cycle.

It should be noted that crew estimates are approximate and are based on the average crew sizes as indicated. Available annual work hours were estimated to be 1,800 hours.

Table 18. Annual Crew Resource Allocation Estimate by Crew Type (# of crews).

Voltages (kV)	3-Man Yard Tree Crew	3-Man Mechanical Trimmer	3-Man Climbing Crew	3-Man Excavator Re-Clear Crew	3-Man Mowing Crew	3-Man Hand Cut Brush Crew	3-Man Low-Volume Foliar Crew	2-Man High-Volume Foliar Crew
69	1.42	8.37	6.80	0.32	0.21	2.52	3.69	0.02
138	0.52	6.55	1.50	0.04	1.09	1.60	3.00	0.05
161	0.05	2.02	2.81	0.16	0.02	0.69	1.75	0.00
345	0.08	3.44	1.35	0.22	0.27	0.92	1.80	0.02
500	0.00	0.02	0.16	0.01	0.00	0.00	0.05	0.00
Total	**2.07**	**20.04**	**12.62**	**0.75**	**1.59**	**5.73**	**10.29**	**0.09**

Crew estimates are based on the work type and recommended maintenance practice as determined by the ECI field surveyor. Changes to the maintenance practice will affect crew make-ups and allocations.

Herbicide crews account for approximately 10.38 crews annually (exclude aerial spray) or 18 percent of the total crews and will utilize approximately 15 percent of the annual budget. The two and three-man herbicide crews will provide the required support to complete the low and high-volume herbicide workload. Aerial spray requires two helicopters to treat designated acres the last two weeks of June and the first two weeks of July. Three-man mechanical and climbing crews are the largest resource requirement at approximately 32.7 crews annually or 57 percent of the total crews and will utilize approximately 61 percent of the annual spend. The three-man mechanical and climbing crews will be responsible for all side trimming, incompatible ROW tree removals, and priority trees. Three-man hazard tree crews will account for an additional 5.2 crews annually.

Remaining First-cycle Estimated Cost

LG&E and KU began transitioning to the recommend five-year cycle in July 2017 for non-NERC transmission lines (i.e. <200 kV) and have completed approximately 631 miles or 13.4 percent as of March 2018. LG&E and KU started scheduled cycle on NERC lines in July 2014 and have completed approximately 464 miles or 63.2 percent as of March 2018. The estimated budget to complete the remaining miles is presented in Table 19.

Table 19. Progress of Completed Cycle Work and Estimated Cost to Complete First-Cycle.

Voltages (kV)	*Sytem Miles*	*Completed Miles*	*Percent Complete*	*Estimated Cost to Complete Cycle*[14]
69	2,738	220	8.0%	$21,757,600
138	1,298	307	23.6%	$11,972,000
161	657	104	15.8%	$6,721,200
345	677	421	62.2%	$3,233,600
500	57	43	76.2%	$103,300
Total	**5,427**	**1,095**	**20.2%**	**$43,787,700**

Second-cycle Cost

The estimated second-cycle budget is presented in Table 20 and Table 21. The second-cycle budget for routine maintenance is an estimated $52,443,000, a reduction of $3.86M from the first-cycle. The estimated annual cost is based only upon work performed as routine cycle maintenance (i.e. pre-identified circuit maintenance) and does not include just-in-time work, reactive work, hazard tree removals, or program oversite. The second-cycle budget for hazard trees is an estimated $1,228,400, a reduction of $1,228,300. Work unit adjustments were made to account for changes in vegetation workload characteristics. The number of hazards tree are not expected to be reduced to zero due to a continual input of trees transitioning from a healthly status to a hazardous condition resulting from various environmental and anthropologic factors. However, ECI expects a large reduction in the number of hazards trees if LG&E and KU pursues a dedicated program to indentify, track and remove these trees especially ash trees. The workload categorized as re-clear was proportionately moved into mechanical and manual categories as as LG&E and KU restablishes legal ROW. A reasonable amount of mow, hand cut (some locations maybe subject to stump treatment of herbicide), and high volume foliar acres are expected to transition into low-volume foliar acres. The amount of acres that remain in both mow and hand cut are estimated to account for areas where herbicides are not allowed and/or customer refusals. The adjustments to second-cycle budget estimates are standard practice for ECI and is reforced by industry observed adjustments that have been observed through ECI's work with other utilities.

[14] The estimated cost to complete the remain miles on the LG&E and KU transmission system does not include the hazard trees since this is separate program initiative.

Table 20. Estimated **Second-cycle** Budget by Maintenance Category and Voltage for the LG&E and KU Transmission System *(based upon 2018 dollars)*.

Voltages (kV)	Yard Trees	Mechanical	Manual	Re-Clear[15]
69	$1,268,000	$9,892,000	$5,769,000	------------
138	$468,000	$7,641,000	$1,256,000	------------
161	$46,000	$2,423,000	$2,417,000	------------
345	$69,000	$4,120,000	$1,159,000	------------
500	------------	$22,000	$147,000	------------
Total	**$1,851,000**	**$24,098,000**	**$10,748,000**	------------

Voltages (kV)	Mow	Hand Cut	Low-Volume Foliar	High-Volume Foliar	Aerial Spray
69	$133,000	$1,316,000	$3,184,000	------------	$751,000
138	$710,000	$837,000	$2,880,000	------------	$648,000
161	$13,000	$359,000	$1,450,000	------------	$822,000
345	$177,000	$479,000	$1,590,000	------------	$146,000
500	------------	------------	$37,000	------------	$214,000
Total	**$1,033,000**	**$2,991,000**	**$9,141,000**	------------	**$2,581,000**
Total Second-Cycle Costs					**$52,443,000**

Table 21. Estimated **Second-cycle** Hazard Tree Budget by Voltage for the LG&E and KU Transmission System *(based upon 2018 dollars)*.

Voltages (kV)	Hazard Trees
69	$957,300
138	$182,900
161	$64,500
345	$21,500
500	$2,200
Total	**$1,228,400**

[15] The workload categorized as re-clear was proportionately moved into mechanical and manual categories as as LG&E and KU restablishes legal ROW.

Recommendations

Utilizing the information gathered in the survey, ECI developed the estimated total transmission workload, budget, and man-hour requirements for the LG&E and KU transmission system.

Budget and workload assumptions:

- Recommended maintenance practices for the identified work units assume the utilization of Integrated Vegetation Management (IVM) principals and the maximization of herbicide use wherever possible to minimize future vegetation management expenditures. The continued use of herbicides will decrease future work (fewer stems per acre) thus requiring far less effort when IVM is fully implemented on the LG&E and KU system. With the implementation of IVM and continued herbicide use there should be minimal mowing required in future cycles.
- Brush acres maintained through mechanical brush clearing methods (i.e. mowers) were not incorporated into acre counts for high or low- volume herbicide treatment. Meaning the initial treatment of mowing acres requireing follow-up herbicide treatment within the same 5-year cycle are not included in the total cost.
- Per request from LG&E and KU, the ROW width used for calculating the amount of brush acres was 100 feet for 69 kV transmission circuits and 150 feet for other transmission voltages. Actual ROW width varies between and within each voltage category and it is recommended that prior to assigning work brush acres be re-calculated to represent actual ROW width for those schedule circuits.

A GAP Analysis documenting LG&E and KU progress with implementing recommendations from the 2014 assessment can be found in Appendix A. In addition, a second GAP Analysis (Appendix A) was conducted to document how LG&E and KU compares to current industry best management practices.

Best management practices and IVM are the focus of the ECI recommendations presented in this section. Refer to Appendix D for additional details on recommended industry best management practices.

Recommendations

ECI recommends the following program specific items based on the field data collection and observations of current vegetation practices on the LG&E and KU transmission system:

1. While LG&E and KU began transitioning to a five-year maintenance cycle in July of 2017 on non-NERC transmission lines, an annual budget of approximately $11.26M should be established for routine cycle maintenance only. The estimated annual cost is based only upon work performed as routine cycle maintenance (i.e. pre-identified circuit maintenance) and does not include just-in-time work, reactive work, hazard tree removals, or program oversite. Each one of these categories should be listed and budgeted as a separate line item for the system as a whole and each region individually.

2. Once the full transition to a cyclical maintenance strategy is complete (completion of just-in-time work), the focus should be on levelizing and maintaining a consistent annual budget based upon the number of miles to complete each year to achieve a 5-year maintenance cycle.

3. Continue to develop asset inventory to document ROW widths for each circuit.

4. Develop annual ground patrol inspection process specific to identifying hazard trees to supplement the aerial patrols particulary on NERC transmission lines (i.e., 345 and 500 kV).

5. Continue to collect hazard tree locations and develop prioritization metrics to determine which trees should be removed first.

6. Continue to work towards developing tree crew production reports and metrics to ensure that vegetation maintenance crews exhibit reasonable production levels.

7. Once sufficient unit and time data has been collected to develop accurate circuit cost history, consider moving towards a T&M with incentives contract (target pricing) to begin sharing the cost of production risk with contracted tree vendors.

8. Develop a formal QA/QC process to inspect completed work – specifically to document any inefficiency in herbicide applications and to validate the quality of the completed work.

9. Consider limiting the use of Tordon® for cut/stubble application to only those areas of high customer visibility due to potential liability for off-site woody vegetation kill.

10. Begin to utilize LiDAR data to assist with documenting yard trees to store in a database and the development of separate maintenance cycle.

11. Yard tree issues appear to be minimum and within reasonable expectations for a utility transmission system. LG&E and KU should develop a program to decrease the number of yard trees for the purpose of reducing public risk, maintaining reliability, and reducing long term cost.

Appendix A:
Gap Analysis

Gap Analysis From 2014 Report Recommendations		
Recommendation	**Current UTILITY Program**	**Gaps/Clarification**
13. Transition maintenance program to cyclical maintenance.	LG&E and KU began transitioning to a 5-year maintenance cycle in July of 2017 for non-NERC transmission line sections and July of 2014 for NERC transmission line sections.	ECI recommended an annual budget of $11.26M for routine cycle maintenance only and $491,340 for hazard trees. Of the $15.28M budgeted in 2018 and $10.582M actual in 2017, a large portion of these dollars were earmarked for just-in-time work to avoid losing the gains achieved on other parts of the system. LG&E and KU should continue focusing a majority of the resources on establishing the cycle and completing 1,085 miles per year.
14. Continue to remove incompatible trees within the ROW and particularly under the conductors (within the wire zone corridor).	The removal of incompatible species is evident throughout the system exemplified in the work completed to date.	☑ Good
15. LG&E and KU has legal easement documentation for transmission ROWs but the information is not readily available.	Currently in the process of working with the asset management group to update GIS information that clearly define the ROW edges for each circuit.	Continue to develop asset inventory to document ROW widths for each circuit.
16. Develop a hazard tree ground patrol to address potential risk from trees that may not be visible through normal routine aerial inspections.	LG&E and KU begun a 5-year hazard tree inspection program in 2017.	Consider developing an annual ground patrol inspection process specific to identifying hazard trees to supplement the two annual aerial patrols particularly on NERC lines to document compliance mandates.

Gap Analysis From 2014 Report Recommendations		
Recommendation	**Current UTILITY Program**	**Gaps/Clarification**
17. Establish a list or database of hazard tree locations and develop a priority program to determine which trees should be removed first. This database may include ash trees that could be affected by the emerald ash borer (EAB).	Began ground patrols in 2017 to identify hazard trees and ash trees.	Continue to collect the hazard tree location data and develop the mitigation strategy for addressing the removals.
18. Continue to enforce vegetation maintenance clearance specifications for transmission voltages and the policies and standards specific to LG&E and KU needs and conditions. Current specifications appear adequate to maintain vegetation on the transmission system.	ECI field inspection and survey results indicate clearances meet or exceed LG&E and KU specifications.	☑ Good
19. Ensure that vegetation maintenance crews exhibit reasonable production levels by implementing a work reporting/ measurement system and utilize the records to evaluate crews and compare contractor performance.	LG&E and KU has begun to capture additional work unit metrics from tree crew timesheets. These metrics are being compilded in a database that is being used to calculate unit costs.	Continue to build upon the breadth of data available to improve upon the accuracy of production reports and metrics. Consider developing a formal QA/QC process to evaluate crews and contractor performance.

Gap Analysis From 2014 Report Recommendations		
Recommendation	**Current UTILITY Program**	**Gaps/Clarification**
20. Implement Integrated Vegetation Management (IVM) as the guiding maintenance principle on the LG&E and KU transmission system.	LG&E and KU currently inspects and develops site specific recommendations for the maintenance of its ROW's including the proper selection and utilization of herbicides.	☑ Good
21. Re-establish the transmission corridor ROW edges wherever practical to bring the corridors back to specification by voltage.	ECI field review and survey results indicate that ROW corridors are being significantly widened in accordance with the established ROW widths.	☑ Good
22. Continue to maximize herbicide use where practical to minimize future vegetation management costs and better manage for compatible plant communities.	Aerial spray and high-volume foliar are used extensively and should result in significant brush density reductions in future cycles.	☑ Good
23. Once established, maintain consistent transmission vegetation maintenance program funding to maximize overall program effectiveness and ensure compliance with NERC Standards FAC-003.	Budgets increased from $7.1M in 2014 to $15.28M in 2018.	Once the transition is completed (completion of just-in-time work), the focus should be on levelizing and maintaining a consistent annual budget.

Gap Analysis From 2014 Report Recommendations		
Recommendation	**Current UTILITY Program**	**Gaps/Clarification**
24. Consider increasing vegetation management oversight to address the addition of approximately 46 crews to meet workload requirement for a 5-year cycle.	The Manager of Transmission Line Services is supported by the Team Leader of Transmission Line Assest Management and by three Transmission Right-Of-Way Coordinators with the plan to add an additional Coordinator in the West.	☑ Good

Best Management Practices Analysis		
Best Management Practice	**Current UTILITY Program**	**Gaps/Clarification**
COST		
Consistent and levelized funding. A consistent plan needs consistent funding. Budget changes causes workforce disruptions that increase future costs.	LG&E and KU has doubled their budget since 2014 but has not yet settled in on a consistent funding level to establish the 5-year annual cycle.	Complete the remaining identified just-in-time work and focus on the completion of approximately 1,085 miles per year at an annual cost of $11.26M and an additional $491,340 for hazard trees removal.
Workload and cycles drive budget requirements. Bottom up budgets maximize resources and production by retaining qualified and experienced crews.	Budgets are based on the workload analysis performed in 2014 which identified the amount of work to be performed and the estimated cost to perform the work.	☑ Good
Stump treatment of all removed deciduous trees (where applicable). The treatment of stumps with approved herbicides prevents re-sprouting and reduces future maintenance costs.	Stumps of removed deciduous trees are being sufficiently treated with approved herbicides to prevent re-sprouting.	☑ Good
Appropriate contract strategy. Contracts that put the burden of production on the contractor can help drive production improvements and reduce costs.	Vegetation maintenance is performed primarily through Time and Material (T&M) contracts.	Once crew production reports are developed, utilize the historical data to transition toward a T&M with incentives contract strategy (target pricing). This puts the burden of monitoring production and efficiency back on the tree contractor.

Best Management Practices Analysis		
Best Management Practice	**Current UTILITY Program**	**Gaps/Clarification**
Detailed budget level breakouts. Categorizing expenditures into appropriate work types is important to identify discretionary versus non-discretionary dollars. Budget dollars allocated to the completion of annual target miles should be considered non-discretionary.	Current budget and actuals lack a defined line item for each work type, primarily with identifying just-in-time work expenditures.	Clarify budget expenditures by adding line items for all work types.
EFFECTIVENESS		
Integrated Vegetation Management (IVM). Utilizing the principles of IVM to maximize herbicide use and reduce future costs.	LG&E and KU has adopted the principles of IVM and effectively utilize herbicides to control ROW brush conditions.	☑ Good
Hazard tree program. Seventy percent of tree related outages occur from off-ROW trees on well-maintained systems. Additional reliability improvements often result from focusing on hazard tree mitigation, particularly from outside of the ROW. Database of hazard trees can be used to prioritize work and document location of potential hazard trees (i.e., ash trees).	Began ground hazard tree patrols in 2017 to identify hazard tree locations.	Continue to collect hazard tree location data and develop mitigation strategy for their removals.
Tree-Caused Outages. Outages are formally investigated by trained personnel to document and determine root cause of tree-caused outages.	Tree outages are investigated by the Coordinators. Outage data is stored in an internal program called Transmission Reliability Outage Data System (TRODS).	Adopt a formal investigation process utilizing a form to collect failure characteristics such as species, tree height, distance from conductor, aspect, tree defects, etc. This data will be analyzed to determine root cause of the tree outage.

Best Management Practices Analysis		
Best Management Practice	**Current UTILITY Program**	**Gaps/Clarification**
EFFICIENCY / COMPLIANCE		
Centralized VM program. A centralized organization drives standardized processes and procedures to insure uniformity and compliance.	The vegetation program is centralized.	☑ Good
Supportive Management. Management is supportive of program improvements.	Upper management is supportive of the vegetation management program and has worked to transition the program to a 5-year cycle.	☑ Good
Clearly documented specification for vegetation work. The success of any vegetation management program is dependent upon a clear scope and defined expectations.	Clearance specifications are clearly documented.	☑ Good
Appropriate clearance standards. Clearance standard must be adequate to support the desired cycle length based on species regrowth. ROW width should be clearly established and documented. “Action Threshold Clearance” is used to ensure minimum acceptable clearances are not encroached upon.	Field review demonstrated clearance standards are appropriate and well identified.	☑ Good

Best Management Practices Analysis		
Best Management Practice	**Current UTILITY Program**	**Gaps/Clarification**
Record keeping. Best managed utilities have clear report processes and procedure along with appropriate data retention. This includes customer information, costs, production, and reliability.	Process and procedure documents and production reports do not currently exist. However, LG&E and KU is in the process of developing production reports.	Formal process and procedure documents should be developed for each transmission major process. Need to continue to develop crew production reports and metrics.
Annual and long-range maintenance planning. Best managed utilities possess annual and long-range management plans to ensure cycle target completion and appropriate funding and resource allocation to meet these goals.	Long-range and annual reports have been developed to identify the work scope for each year.	☑ Good
Appropriate supervision to tree crew ratio (utility staffing). T&M contract in particular, require a higher level of crew oversight to ensure cost effective management through production monitoring.	LG&E and KU have added support staff to manage the day-to-day functions. With the addition of a Coordinator to the West, crew staffing ratios should be in-line with the industry recommendations.	☑ Good
Right Tree Right Place Concept. Incompatible trees within the ROW should be removed, particularly trees located within the wire zone corridor.	ROW's are generally devoid of trees within the wire zone.	☑ Good
Customer notification process. An appropriate customer notification process is required to ensure customer satisfaction in regard to scheduled maintenance activities.	Customers are notified of impending routine maintenance work.	☑ Good

Best Management Practices Analysis		
Best Management Practice	**Current UTILITY Program**	**Gaps/Clarification**
QUALITY		
ANSI A300 compliance. Technically correct pruning in compliance with ANSI A300 pruning standards helps to reduce future workload by minimizing sucker growth. Improper pruning produces weak branch attachments which can lead to increased outages.	In general, trees are pruned in accordance with ANSI A300.	☑ Good
Formal QA/QC process. Documenting the inspection of planned and completed work. It is important to identify work that does not meet standards early so that corrections can be made before more deficient work is completed.	There is currently no formal QA/QC process for the inspection of completed work. Work is inspected informally.	Develop a formal QA/QC program to identify work quality on completed work. Particularly documenting herbicide effectiveness and efficacy.

Appendix B: Contracting Strategies

Introduction to Contracting Strategies

Three different approaches are commonly used by electric utilities to contract line clearance work. These include "time and material/equipment" (T&M), "unit price" and "firm price" or "lump sum" pricing strategies. Each has advantages and disadvantages that are important to understand, and there are multiple variations possible within each pricing family. Each carries a different risk profile for the contractor and the utility. Unit price and firm price contracts are inherently performance-based contracts. However, T&M with incentive pricing can also be a performance-based contracting strategy.

Performance-based contract strategies generally offer the lowest production risk for the utility by placing the burden to monitor crew productivity on the tree contractor and "incentivizing" the contractor to control costs. This applies to firm price, lump sum, unit price, and T&M with incentive type contracts. However, it should be understood that in order for these contract strategies to be effective, the utility and contractor should have a thorough understanding of the work scope, historical man-hours and costs for the work units to be maintained within the contract period. While it is possible to utilize these specific contract types for all work (i.e. ticket type work as well as preventative maintenance work), they are the most effective in situations where the scope of work is better defined such as on preventative maintenance. Ticket work such as Customer Trim Requests and Restoration are often too variable and can lead to higher "unit" prices due to the "contingency" contractors may build into their bid to account for this uncertainty.

Where historical data is not available, some utilities are successful in developing performance-based contracts by clearly defining the project scope prior to bidding through the development of detailed work plans. Pre-planning to define clearances, clearance exceptions, and removals has proven to be a very effective strategy in receiving least cost competitive bids. Contractors provide pricing on the defined work scope that the utility has pre-designated, thus eliminating guess work on the part of the contractor and eliminating the "contingency" cost that contractors build into bids. However, this does require additional effort on the part of the utility to employ knowledgeable personnel to perform the pre-work planning as well as post work acceptance. This strategy generally works well when the utility is developing firm price contracts in the form of a guaranteed cost per mile or a guaranteed cost per circuit.

Utilizing a T&M with incentives, such as Target Pricing, is a viable alternative for preventative maintenance work, but does require an extensive knowledge of historical man-hours in order to develop "should take times" in order to set contractor valid targets or thresholds for each work unit. In this contract type, the utility agrees to pay the contractor for their total actual man-hours incurred to complete the work unit. The contractor in turn, agrees to meet the established target and "share" with the utility any cost savings achieved by completing the work unit with less man-hours than allotted. Some contracts also include a shared "penalty" where the contractor agrees to also share the cost of any work units exceeding the threshold man-hours thus, this provides the contractor with an incentive to find cost savings while minimizing their perceived risk in relation to their skepticism to utility provided targets.

Another variation to this contract type includes a T&M not to exceed. In this contract type, the contractor and utility agree that any cost savings will be shared; however, the contractor bears the entire burden for any cost over-runs above the man-hour threshold set by the utility. The advantage to this contract strategy is that the utility can have 100 percent confidence in their maximum expenditure which they can then use to better plan and budget. The disadvantage is that the contractor may include higher pricing due to the “contingency” variable and therefore, it may not offer the same cost savings as could be expected through the shared incentive/penalty contract.

Utilizing multiple contract strategies for vegetation management is generally the most cost effective. Performance based contracts are preferred for preventative maintenance type work but should be utilized in combination with other contract strategies to ensure overall program cost effectiveness. Firm price or unit price contracts are most effective for brush maintenance or herbicide treatment programs where the contractor can easily inspect and quantify the work volume. Competitive bidding of these work types ensures the contractor will provide the lowest unit price based on their estimated cost to complete the defined work scope and their known material costs (i.e. herbicide costs). T&M contracts (without incentives) offer the greatest level of flexibility to the utility in terms of being able to easily add or remove work scope and therefore are recommended for ticket type work. For the contractor, T&M minimizes their risk where work scope is variable or undefined as in Customer Trim Requests and Restoration type work. This allows the contractor to provide better pricing but shifts the burden to the utility to ensure that crews remain productive. Even so, T&M is generally considered the preferred method for these work types. A combination of all the contract strategies tailored toward specific work types, will offer the greatest potential for cost savings to the utility while minimizing the resources required to monitor contractor performance.

Well-documented inspection of completed work and establishment of clear standards are critical to achieving value from firm price or unit price contracts. Where clearance requirements may be variable due to customer concerns or in situations where work scope is not clearly defined (as with ticket work), T&M normally can provide a better value.

In recent years, the impacts of fuel price fluctuations have become a major concern for contractors as well for the utilities they work for. Concerns arise when contract rates are set at a time when fuel prices are at the extremes and then change dramatically over the life of the contract. This either leaves the contractor with a windfall profit if fuel prices decrease (and the utility with higher costs) or can result in significant loss of profits for the contractor if fuel prices increase. Shorter contract periods (i.e. one-year) can minimize potential risk, but can be costly in terms of the cost to develop new contracts every year, and in terms of higher rates from contractors due to increased risk from shorter contract periods. Many utilities have elected to incorporate fuel escalators into their contracts to offset this concern.

The following are brief descriptions of the common contracting strategies:

Time and Materials (T&M)

T&M is normally the least risky for the contractor since most of the production-related risk is born by the utility. T&M contracts with performance measures and incentives tend to move some of the production risk back to the contractor. T&M often results in the highest work quality. Poor performance may subject a contractor to contract termination or result in assignment of "penalty points" as part of future bid evaluations. For work that is highly variable in nature, difficult to quantify in advance and where quality and customer relations are significant concerns, T&M may be the most desirable method.

Unit Price

Unit price work shifts production risk to the contractor but requires preplanning by the utility to designate which units the contractor should complete. Units are normally a tree trimmed, a square area of brush removed, footage cleared, or a tree removed by diameter classes. There is a natural incentive for the contractor to provide only the level of quality enforced by the utility. Consequently, quality control inspection by the utility is an important administrative requirement for this pricing strategy as well as work completion inspection. Administration of unit price contracts can become burdensome for utilities with high tree densities.

Firm Price

Firm price work also shifts production to the contractor but also shifts work unit selection to the contractor. The natural incentive in this pricing strategy is for the contractor to select the minimum acceptable units and provide the minimum acceptable quality. Post-work inspection by the utility is critical to assuring that all work was completed in compliance with the established specification. Tree removal is often an issue in a firm price contract since costs for tree removal can be highly variable. Consequently, trees to be removed are sometimes identified in advance as part of the bid package preparation. Alternatively, unit prices by size class for tree removal can be established or tree removal can be completed on a T&M basis for trees specifically authorized by the utility. Firm price is best suited to situations where the work can be clearly defined and understood by the bidders. It should also be limited to locations where there will be good competition by a number of bidders. Awarding of concurrent firm price contracts to multiple contractors is desirable. Small firm price contracts bid to companies that do not have a local presence frequently results in higher pricing to cover the cost of per diems or personnel relocations necessary to establish a labor force.

Turnkey and Incentive Based Contracts

Turnkey pricing shifts the maximum risk from the utility to the turnkey service provider. This pricing strategy normally is accomplished by establishing incentives tied to accomplishment of specific objectives such as cost control, tree-related reliability targets, and customer relations. Because most of the program management responsibility is that of the contractor, it is critical that the utility closely monitor the performance objects through periodic review of key performance indicators. A variation of turnkey pricing is a management services contract with a third party management firm that administers contracts on behalf of the utility. The contracts for craft labor and equipment may continue to be with the utility or through the management company. The management services company may utilize any or all of the other pricing methods. This pricing strategy should be utilized if the utility has limited management resources or desires to totally overhaul existing systems, methods and practices.

Target Pricing Strategy

Target Pricing involves an efficient and effective use of combined customer notification and tree selection work planning that becomes a basis for establishment of Target Price for individual circuits or circuit segments. Documented workload in terms of tree pruning, tree removal and brush control units, multiplied by realistic costs per unit worked (based on work history by district) allows creation of the target price that contractors can be incented to meet or beat.

Using this system the line clearance contractor is paid on the basis of T&M rates as work progresses. Reconciliation of actual production cost compared to the Target Pricing occurs quarterly.

This strategy requires designation of specific work units and agreement from the line clearance contractors to work the units designated by the Work Planner. Work Plan packets are prepared and distributed to crews from a Work Planning database and populated through Work Planning data acquisition software. Line clearance crew time and production must be monitored and recorded in a production database.

A simplified example of a Target Pricing work sheet is illustrated in Table 22. Table 23 is an example of a simplified quarterly reconciliation table.

Table 22. Target Pricing Circuit Summary.

Unit Description	Plan Quantity Circuit xyz	Standard $/Unit	Quantity x Unit Price
Bucket Trim 4"- 8"	300	$20	$6,000
Trim 8" - 12"	47	$30	$1,410
Removal 12.1" to 24“	3	$170	$510
Manual Trim 4"- 8"	655	$25	$16,375
Trim 12" - 24"	9	$140	$1,260
Brush removal	57	$240	$13,680
Total Standard Cost for Circuit xyz			$39,235

Table 23. Target Pricing Quarterly Reconciliation.

Unit Description	Quantity x Unit Price
Standard Cost	$96,268
Actual Cost	$83,040
Amount Actual Lower than Standard	$13,228
Percent Actual Below Standard Cost	13.7%
5 to 25% Qualified Bonus Tier Percentage	25%
Incentive Amount	$3,307

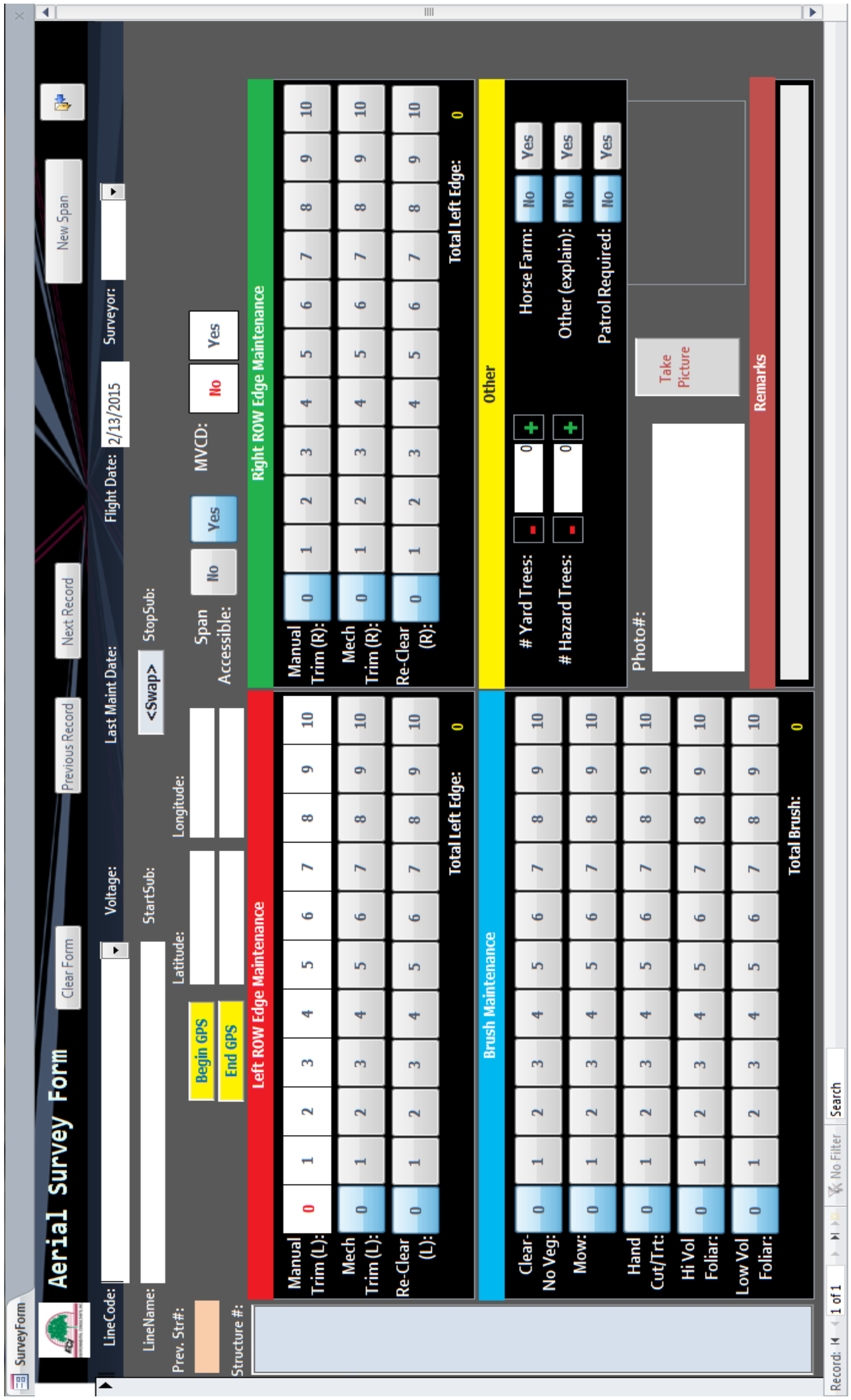
There are several requirements that must be in place for a Target Pricing strategy to be effective. They include:

1. Effective processes for work planning
2. A field data collection and work documentation system
3. Realistic production data by district or by characteristics such as maintained/unmaintained, accessible/inaccessible, overhang, etc.
4. Contracts with line clearance contractors that complement the Target Pricing strategy

Benefits of this strategy have included lower costs than firm priced or T&M bidding strategies. Because tree selection is closely aligned with utility goals, adequate reliability can be efficiently achieved.

Appendix C: Transmission System Vegetation Survey Form

TRANSMISSION RIGHT-OF-WAY VEGETATION SURVEY
LG&E and KU



Appendix D: Recommended Industry Best Management Practice Strategies

Recommended Industry Best Practices Strategies

Transmission owners need to develop practices that fulfill the requirements of the vegetation standard in a cost effective manner. These practices or strategies must be documented and consistently implemented. Over time, certain practices have been shown to be successful in preventing outages due to vegetation. Many of these practices were incorporated into the NERC Standard FAC-003 since the group that developed and approved the standard included experienced transmission vegetation managers. The American National Standards Institute (ANSI) has established standards for vegetation maintenance on transmission ROW[16]. In addition, the International Society of Arboriculture (ISA) has issued a companion publication to ANSI A300 Part 7, Best Management Practices, Integrated Vegetation Management.[17]

Work Management

ECI proposes the following best practice work management recommendations as part of any successful transmission vegetation management program. The utilization of some or all of these work management tools and methods may already be in use at LG&E and KU and therefore, these recommendations in no way imply the current lack of appropriate procedures. The original scope of this workload study did not include a review of the transmission program procedures or strategies. The recommendations presented here should be considered for implementation by LG&E and KU if not already integrated into the existing management program.

- **Develop and keep current a vegetation management plan.** Even though the current NERC standard FAC-003 does not explicitly require a vegetation management plan (TVMP), a TVMP is an extremely valuable tool to plan and implement both short-term and long-term vegetation management goals. A TVMP is the “road map” for vegetation management and provided direction and overview of system goals. It details how the work will be determined, planned and executed and provides a framework on how vegetation management will be implemented to ensure the reliability of the system. Annual plans are a subset of multi-year long-range plans. A plan will aid in developing budgets and tracking the work performed on individual lines.
- **Develop and keep a current work schedule.** The TVMP will detail system and procedures for documenting and tracking the planned work. Plans are in need of constant update as work progresses. Updating will track work in progress and allow notice for any necessary adjustments.
- **Implement a system of inspecting planned work.** Documenting the inspection of completed work is also necessary to properly approve payment and ensure work reported as complete by the contractor meets

[16] ANSI. 2006. The American National Standard for Tree Care Operations - *Tree, Shrub, and Other Woody Plant Maintenance- Standard practices (Integrated Vegetation Management a. Electric Utility Rights-of-way).* A 300 Part 7. American National Standards Institute, NY.

[17] Miller, R.H. 2007. Best Management Practices- Integrated Vegetation Management. International Society of Arboriculture, Champaign, Il.

LG&E's and KU's expectations. Spot checks of completed work are commonly used with inspections of additional completed work when deficiencies are found. It is important to identify work that does not meet the standard early so that corrections can be made before more deficient work is completed. This will save time for both the utility and the contractor performing the work. Formal documentation of the work inspection is recommended.

- **Provide for consistent budgeting.** A consistent plan needs consistent funding. Budget reductions mid-year can cause workforce disruptions that increase future costs. Any changes to the established annual plan require documentation.
- **Establish and enforce work specifications.** The personnel performing the work must know exactly what is expected of them. The work inspector must know the specifications to properly enforce them. If future contract strategies are being considered, a clear, concise specification is required to communicate LG&E and KU vegetation maintenance goals to perspective contractors. The clearer the contract specification, the better the pricing from a perspective new contractor.
- **Develop action thresholds.** Develop a "clearance at time of maintenance" (clearance 1) distance and establish a minimum clearance threshold (clearance 2) that vegetation should never exceed. This threshold clearance will provide an additional margin of error to allow for vegetation growth, line sag and variations in maintenance cycles. Best practice utilities have developed an action threshold clearance value between Clearance 1 and Clearance 2 in order have a intermediate point to take appropriate action to avoid violating the vegetation standard. Another type of action threshold relates to the maximum height that brush[18] is allowed to attain to provide efficient and cost effective foliar application of herbicides. Since herbicide application is frequently less costly than mechanical clearing, it is important that brush is not allowed to grow taller than the maximum height 8-12 feet for effective herbicide use.
- **Develop a mitigation plan for exceptions/non-standard maintenance.** Keeping a record of locations where exceptions to standard practices exist is important to prevent outages or violations of LG&E's and KU's minimum acceptable clearance (between vegetation and conductors). An example would be where pruning is the only vegetation maintenance option allowed by the easement. The record should be specific as to the nature of the situation and regular inspection should be scheduled. Use of an automatic reminder system is recommended. Renegotiating or acquiring easements to eliminate clearance restrictions, payment for tree removal or replacing tall

[18] Brush is normally defined as immature (less than 10.2 cm or 4 inches in diameter), tall-growing tree species that would grow tall enough to interfere with conductors

growing trees with compatible vegetation should be considered to eliminate the situation.

- **Develop standardized processes.** A uniform vegetation management plan for the entire LG&E and KU system that coincides with LG&E's and KU's current specification is key.
- **Implement an Integrated Vegetation Management program (IVM).** IVM is the art of controlling plant populations based on scientific principles from such fields as ecology, zoology and biology. Vegetation is managed to produce desired conditions (plant community density, structure and composition) and associated values consistent with stakeholder objectives on a sustainable basis. Stakeholders include both easement or fee holders, and all stakeholders and interested parties who may be influenced by IVM activities.
- **Manage the ROW by zones.** Managing the ROW in the zone immediately beneath the conductors differently from the rest of the ROW, known as the wire zone-border zone concept, is a successful approach to prevent outages in a cost effective manner (Figure 10), where sufficient ROW width is present. Different management techniques can be applied to these two zones and result in the many economic, operational and environmental benefits associated with the use of IVM techniques.

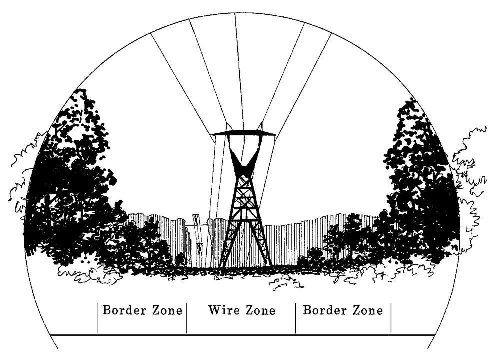


Figure 10. Wire Zone / Border Zone Vegetation Management.

- **Maintain the ROW edge**. Side pruning consists of pruning trees on the edge of the ROW. This work can be accomplished through the use of truck-mounted aerial lift equipment (bucket trucks), by manual climbing, or through the use of mechanical pruning equipment, such as a Jarraff, Aerial Saw, or similar tools.
- **Coordinate transmission work with related distribution work**. Occasionally distribution lines are found on the same ROW and even the same structures as a transmission line. Managing the vegetation simultaneously on both facilities can be cost effective. Problems can arise when different departments within the same company manage facilities with varying cycles, maintenance methods and budgets. The transmission maintenance organization should take the lead in

coordinating and ensuring that the work is completed because a transmission outage has greater consequences than a distribution outage.

Integrated Vegetation Management

In Integrated Vegetation Management (IVM), the selection of control options is based on effectiveness, site characteristics, environmental impacts, safety, and economics. Good vegetation management is based on an understanding of plants and their environment. A holistic approach considers the inter-relationship of plants, site, and species composition and growth rates.

IVM is recognized as an industry best practice, and it is therefore recommended that LG&E and KU adopt this strategy for the maintenance of undesirable brush on its transmission system. In general, this would be a combination of brushing, mechanical clearing (hydro-axe), and the use of herbicides to manage trees and bush on the LG&E and KU system.

Cutting deciduous brush without applying a follow-up herbicide application to the stump surface will permit the vegetation to re-sprout, thus requiring future maintenance. Trimming brush and/or allowing it to mature results in its becoming a more expensive and often permanent part of the workload. Trimming brush and the failure to use herbicides on cut stumps are not cost effective long term brush management techniques.

ECI recommends that LG&E and KU continue to remove trees with the ROW and ROW edge and treat the deciduous cut-stumps of trees and brush with appropriate herbicides whenever possible. LG&E and KU should continue to enforce the existing specifications for removal and stump treatment. This will prevent future expansion of the system vegetation workload and future line clearance cost increases.

On most of the LG&E and KU transmission system, there appears to be an opportunity to treat standing brush less than 8 - 12 feet tall with either foliar or basal herbicide applications, avoiding hand cutting. Taller standing dead brush can become a source of complaints, and taller brush can be difficult to control with foliar applications without risking exposure to off-target plants. This use of a basal bark-applied herbicide would be a particularly valuable tool in the removal of tall-growing tree species growing in sensitive areas or where there is concern for off-target damage.

Use of herbicides is essential if LG&E and KU is to maximize the benefits of mechanical clearing and brushing. Herbicide use is an important component of an IVM strategy. LG&E and KU should continue to enforce the specifications that require use of herbicides to treat stumps. The effectiveness of selective herbicide applications has been well documented through long-term studies on utility rights-of-way in the central and northeastern United States. Results from treatment simulation models developed through these studies project that sites dominated by deciduous species would nearly double in stem density by the end of two cycles if simply cut without a follow-up herbicide application (Figure 11). These same sites would be expected to exhibit about a 50 percent reduction in stem density over the same time period if treated with a selective herbicide application.

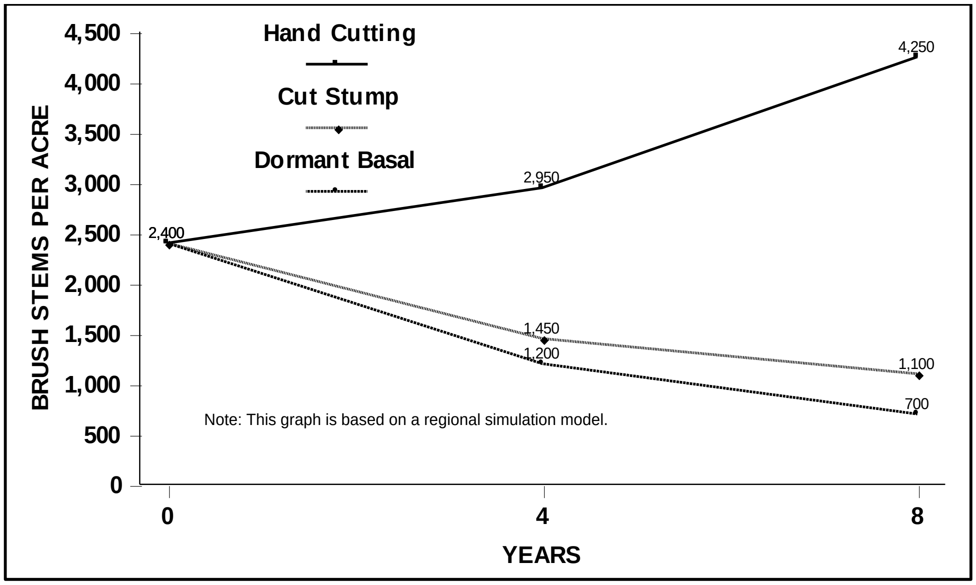


Figure 11. Effectiveness of Herbicides for Control of Brush Over Time. Results of long term study of brush management on utility rights-of-way in the northeast United States.

Currently, herbicides are effectively used in the control of ROW vegetation. This is an integral part of any IVM program. An important consideration is that a herbicide program must be environmentally safe and professionally supervised to maintain public acceptance. Line clearance crews performing herbicide applications should receive proper training in species identification and herbicide application methods that are approved and deemed acceptable by the public and land owners.

It is recommended that LG&E and KU continue to pursue the selective use of herbicides (e.g., foliar and basal) for the management of communities of deciduous brush species as a part of IVM program. Utilizing contractors trained and experienced in the use of herbicides will ensure the continued success of the LG&E and KU vegetation management program.

Herbicide Safety and Risk Assessments

Today's herbicides control tree/brush re-sprouting by blocking chemicals needed by plants to convert water, sunlight and nutrients into food for growth. Since these same chemicals are not present in animals and humans, the herbicides are very low in toxicity to people or animals. Without any food, the treated weed trees on the right-of-way wither and decompose. Treated stumps dry out and don't re-sprout.

Safety for humans and the environment includes not causing adverse effects that are unacceptable. In this context, risk assessment is the process by which the likelihood of unacceptable adverse effects from the use of various methods of vegetation management can be determined.

An extensive report prepared by ECI provided the technical basis for and a summary of the risk to human health, wildlife and the environment from the use of 10 herbicides by a utility owner in the US. These herbicide uses included broadcast foliar, selective foliar, basal bark and cut stump applications. This assessment concluded that the margins of safety for herbicide use by the utility that commissioned the assessment were "adequate to assure protection of human health of workers and the general public."

ECI also completed an environmental impact statement resulting in the authorization of herbicides to control right-of-way vegetation in the LG&E and KU National Forest in Pennsylvania (US). Subsequent evaluation of herbicide use in the National Forest confirmed safe and effective use of foliar herbicides to control brush on utility right-of-way.

The human health risk assessment methodology used in these reports was the one generally recognized by the scientific community as necessary to characterize the potential adverse human health effects of chemicals in the environment. It is the same process used in judging the human health risk from cosmetics, food additives, pharmaceuticals, various household chemicals, and many other materials.

Herbicide Acceptance by Wildlife Groups in the United States

In the US, stump control herbicides are used not only by electric utilities, but also by numerous private and governmental wildlife habitat improvement organizations. Examples include:

- The Nature Conservancy on projects designed to limit the spread of invasive and non-native trees and shrubs. This would be similar to the efforts in the UK to eradicate the invasive plants Japanese Knotweed and Himalayan Balsam.
- Under the banner of a former organization called Project Habitat®, groups such as the National Wild Turkey Federation, Buckmasters, Butterfly Lovers International and Quail Unlimited have joined together to encourage utilities to implement an "Integrated Vegetation Management" (IVM) approach to maintaining utility easements that appropriately utilizes herbicides as a component in the control of right-of-way vegetation. They have recognized that environmental benefits of herbicides, when properly used, outweigh any adverse risk and are far more desirable than the alternatives to herbicide use, such as frequent mowing or hand cutting of undesirable trees.

Significant research has been undertaken over the past 30 years in the United States to document the impact of right-of-way herbicide use on the environment, wildlife and management costs. Much of this research has been conducted by ECI and its university research associates. Stems per acre decrease over time through the use of herbicides, as does associated maintenance costs.

Brush control through the use of herbicides is an extremely cost effective maintenance tool. Figure 12 illustrates the successful use of herbicides and provides cost effective, environmentally acceptable and long-term brush control.

Figure 12. Example of good brush control through the use of herbicides.

Appendix E: Recommended Staffing to Contract Tree Crew Ratio

Need for Additional LG&E and KU Vegetation Maintenance Staffing

The vegetation maintenance program at LG&E and KU is moderately staffed for the administration of the current line clearance contracts and contractor staffing at the time of this review. The current vegetation management staff consist of three ROW Coordinators, one Patroller and two Inspectors. The Patroller is scheduled to retire and a new ROW Coordinator will be hired to manage the West region. The ROW Coordinators' job duties limit their ability for direct oversite or supervision of the current 33 contract tree crews. Direct supervision of the contract tree crews fall upon the Patroller and two Inspectors. As LG&E and KU continues adopting ECI's budget and other recommendations, additional contract crews will be added to the system to manage the increase workload to achieve the targeted five-year maintenance strategy. Additional staff (in house or contracted) will be required to effectively manage the increased work force.

Figure 13 shows data from two benchmarking studies that evaluated the average number of line clearance crews supervised by utility arborists. In the Pennsylvania Electric Association (PEA) and Edison Electric Institute (EEI) studies, the average ratio of line clearance crews to each utility arborist was respectively 8 and 11 (Figure 13). However, in both studies 75 percent of the reporting utilities average 10 crews or less per supervising arborist. Figure 13 also shows that in a recent benchmarking study of over 20 utilities, the two overall best-in-class utilities have a ratio of approximately one utility arborist (including the system arborist) for every 6 line clearance crews. Figure 13 also compares the current crews supervised by the Patroller and two Inspectors to the anticipated ratio should the recommend crew count for a five-year cycle be adopted at LG&E and KU.

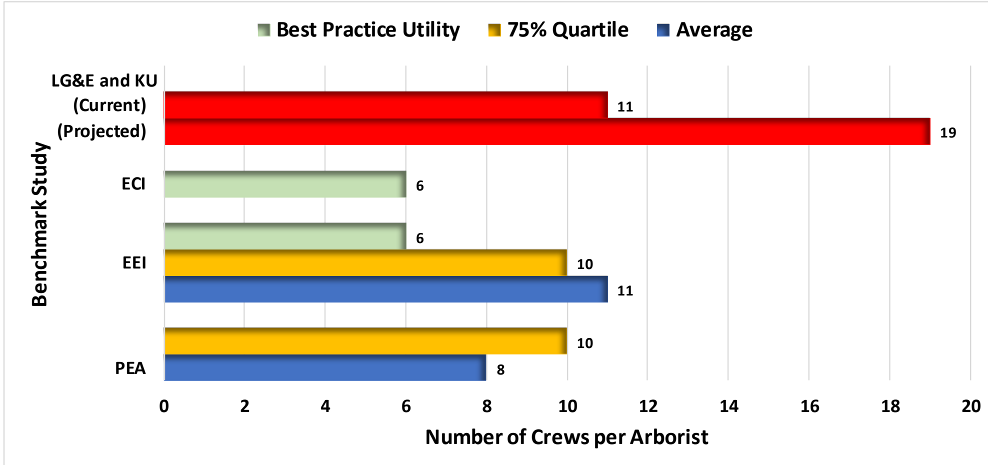


Figure 13. Comparative Data on the Average Number of Line Clearance Crews Overseen by Utility Foresters[19].

Based on the anticipated increase in contractor tree crew staffing on the transmission system, LG&E and KU may require additional positions (in-house or contract) to assist the ROW Coordinators in the day to day management of the program. If fully implemented, the LG&E and KU Transmission VM contractor tree crew work force will be approximately 56 crews for the first-cycle. This will provide a ratio of approximately 19 crews per the current LG&E and KU vegetation management staff that provides direct supervision. In order for the program recommendations to be implemented properly it has to be implemented correctly in the field. The addition of two to three supervising staff (i.e. Inspector or Utility Forester) would reduce the ratio to similar numbers reported in the EEI and PEA benchmarks. LG&E and KU will need to determine if the current vegetation management staff can efficiently plan work and audit tree crews. The current staff level may not be capable of assisting the ROW Coordinators with planning work and audit work for the increased number of tree crews, especially with the geographic dispersion of the maintenance work. For example inspecting customer requests, work associated with new construction, supervising tree crews, and handling of customer complaints or refusals. After the completion of the first-cycle, the number of tree crews is may decline, then staffing may be adjusted to meet the need. The use of contract foresters would be an option for staffing these positions as they are more easily flexed.

The additional two to three Utiltiy Foresters should primarily be responsible for field implementation of the line clearance program and the evaluation of the line clearance crews and contractors within their area of responsibility. These staff members should report directly to the ROW Coordinators. This will provide a measure of control over individual interpretation of company

[19] PEA = Data from a 7 utility survey conducted by the Pennsylvania Electric Association.
EEI = Data from the Edison Electric Institute benchmark study of 29 utilities.
ECI = Data from a 1998 benchmarking study of 22 North American utilities.
LG&E and KU: (Projected) = Based the project increase in tree crews with out changing the current number a staff members who provide direct supervision.

guidelines and will ensure consistent implementation of appropriate work practices and operating procedures across the system. These positions should assist in ensuring contractor compliance to ANSI A-300 standards and that crews are properly instructed on the correct and safe use of herbicides. The position will audit contractor work to ensure that clearance requirements are met.

The additional Utiltiy Foresters should assist in managing programs that provide ongoing information on field conditions, including tree crew production records (trees pruned removals, herbicide use, and brush treatment), electric service interruption data and conduct post-outage investigations.

If any additional positions are added to the vegetation management staff these Utility Foresters should be trained in all aspects of utility vegetation management, including proper pruning techniques and herbicide use. The Utility Foresters should have a minimum of 2 years of experience in utility vegetation management, ISA certification and, preferably, a Bachelor’s Degree in Forestry or a related field. This will help to ensure consistent implementation of program policies and will enable the ROW Coordinators to effectively evaluate the work being completed by the line clearance crews.

Appendix F: Regional Regrowth Rates for Trees

Table 24. Average Regrowth Rates of the Tree Species Collected During a 2004 Study on the Distribution System for LG&E.

		Feet of Growth by Age of Sprout					
Species	**Trim Type**	**1 Yr.**	**2 Yr.**	**3 Yr.**	**4 Yr.**	**5 Yr.**	**6 Yr**
Box-elder	Side	49.8	81.0	107.9	121.3		
	Std. Dev. ±	19.0	18.9	25.5	5.3		
	Top	85.3	118.4	151.1	157.3	199.0	
	Std. Dev. ±	18.2	19.5	28.8	18.2	18.2	
Maple, red	Side	38.5	69.2	99.7	106.3	125.7	158.0
	Std. Dev. ±	18.7	22.8	23.0	28.0	17.5	23.5
	Top	80.7	125.6	152.0	177.1	202.6	
	Std. Dev. ±	24.1	33.1	34.8	33.9	16.1	
Maple, silver	Side	54.1	90.1	117.3	126.2	142.0	144.0
	Std. Dev. ±	23.5	28.0	33.0	34.8	42.9	63.6
	Top	92.2	145.9	180.6	208.1	253.2	347.0
	Std. Dev. ±	25.7	32.1	35.9	45.1	47.6	47.6
Maple, sugar	Side	40.8	70.0	92.2	96.0	112.4	121.0
	Std. Dev. ±	25.3	35.2	37.8	22.2	22.6	33.0
	Top	68.1	105.0	131.6	150.4	162.2	
	Std. Dev. ±	32.6	38.5	43.0	52.3	57.0	
Ailanthus	Side	29.0	56.0	66.0			
(tree-of-heaven)	Std. Dev. ±	8.3	11.2	19.7			
	Top	98.4	137.5	190.0			
	Std. Dev. ±	12.6	14.3	21.8			
Hackberry, common	Side	41.1	69.8	96.7	112.3	139.0	
	Std. Dev. ±	18.8	22.6	22.1	35.3	38.2	
	Top	73.6	117.8	152.8	147.1	111.0	186.0
	Std. Dev. ±	27.2	32.2	45.2	19.6	27.9	31.0
Ash, green	Side	33.4	60.1	81.2	98.8	119.0	33.6
	Std. Dev. ±	16.8	21.2	24.4	29.2	40.2	14.2
	Top	47.4	78.6	107.9	127.0	152.0	
	Std. Dev. ±	20.6	23.9	27.4	32.8	39.7	
Honeylocust	Side	101.0	141.0	161.5	194.5	213.5	
	Std. Dev. ±	72.1	58.0	54.4	60.1	57.3	
	Top	31.8	64.3	94.3	116.0	167.0	
	Std. Dev. ±	15.3	16.8	15.5	22.6	24.1	
Walnut, black	Side	51.2	81.0	115.1	126.8	211.0	
	Std. Dev. ±	29.3	35.2	41.2	51.0	58.3	
	Top	88.4	144.3	191.2	207.3		
	Std. Dev. ±	35.8	36.5	43.8	30.1		

Species	Trim Type	Feet of Growth by Age of Sprout					
		1 Yr.	2 Yr.	3 Yr.	4 Yr.	5 Yr.	6 Yr
Sweetgum	Side	26.2	46.4	66.7	83.0	91.0	
	Std. Dev. ±	10.1	15.9	20.8	20.7	22.1	
	Top	45.0	94.3	130.7	155.0		
	Std. Dev. ±	14.2	31.0	38.7	77.8		
Yellow-poplar	Side	40.7	67.0	83.7	98.3	95.0	122.0
	Std. Dev. ±	27.5	28.7	30.8	31.3	37.6	38.1
	Top	80.9	127.9	151.1	170.0	190.0	
	Std. Dev. ±	26.3	35.0	36.2	38.5	41.5	
Mulberry, red	Side	31.7	63.3	88.3	85.0		
	Std. Dev. ±	12.5	19.3	21.8	26.1		
	Top	84.9	136.0	143.3	161.5	163.0	197.0
	Std. Dev. ±	36.2	39.4	44.9	51.9	55.1	63.2
Sycamore	Side	59.8	99.5	117.8	119.8		
	Std. Dev. ±	13.2	18.7	25.2	27.2		
	Top	82.0	122.4	156.5	152.5		
	Std. Dev. ±	13.0	22.6	38.2	21.9		
Cherry, black	Side	52.9	81.6	106.4	125.0	156.5	
	Std. Dev. ±	21.7	22.9	19.8	25.8	33.9	
	Top	55.4	95.5	132.8	155.1	111.0	130.0
	Std. Dev. ±	23.3	25.9	29.7	45.5	48.2	49.3
Pear, Bradford	Top	46.0	76.7	106.9	118.0	119.5	
	Std. Dev. ±	22.5	24.4	23.6	20.6	4.9	
Oak, white	Side	28.9	50.0	76.9	101.5	118.0	
	Std. Dev. ±	11.7	18.0	17.4	19.5	19.9	
	Top	33.0	56.0	94.0			
	Std. Dev. ±	10.1	17.5	18.9			
Oak, southern red	Side	37.1	67.0	93.8	117.0	146.0	162.0
	Std. Dev. ±	9.7	13.3	23.8	28.4	33.5	42.5
	Top	68.0	113.0	157.0			
	Std. Dev. ±	12.4	17.8	23.5			
Oak, swamp chestnut	Side	55.0	92.0	115.0	172.0		
	Std. Dev. ±	18.4	48.1	55.2	63.4		
	Top	73.0	97.0	115.0			
	Std. Dev. ±	21.2	25.7	30.1			
Oak, pin	Side	36.2	64.0	83.9	96.2	113.2	124.0
	Std. Dev. ±	11.4	18.1	25.6	19.4	25.6	27.5
	Top	57.7	86.3	111.8	144.5	150.0	
	Std. Dev. ±	20.6	31.7	51.0	57.8	58.7	

Species	Trim Type	Feet of Growth by Age of Sprout 1 Yr.	2 Yr.	3 Yr.	4 Yr.	5 Yr.	6 Yr
Oak, black	Side	29.0	63.0	85.0	98.0	121.0	
	Std. Dev. ±	11.7	14.3	18.0	25.7	31.7	
	Top	52.0	80.0	112.0	137.0	158.0	
	Std. Dev. ±	8.7	16.9	18.0	26.2	30.1	
Locust, black	Side	55.2	86.6	106.7	126.3	160.5	173.0
	Std. Dev. ±	21.4	22.6	15.9	16.9	22.1	26.4
	Top	87.9	142.1	165.9	117.0		
	Std. Dev. ±	37.2	44.1	46.3	48.1		
Sassafras	Side	30.0	41.0	57.0			
	Std. Dev. ±	7.8	9.0	14.1			
Elm, winged	Side	19.5	53.0	72.0	81.0		
	Std. Dev. ±	10.6	13.1	15.3	21.7		
Elm, American	Side	45.6	86.9	128.0	140.3		
	Std. Dev. ±	16.4	31.0	38.6	41.0		
	Top	79.4	123.2	149.9	161.3	170.7	
	Std. Dev. ±	28.5	41.1	38.7	33.6	34.2	
Elm	Side	51.0	81.9	111.1	128.0	169.3	272.0
	Std. Dev. ±	22.4	28.0	39.9	68.8	70.7	71.4
	Top	51.7	118.3	152.5	147.0		
	Std. Dev. ±	6.1	20.8	43.1	43.8		

Table 25. Regional Re-Growth Rates for Common Trees Found on Utility Systems in Indiana, Kentucky, Ohio, Tennessee, and Virginia.

		Feet of Re-Growth by Age of Sprout					
Species	**TrimType**	**1 Yr.**	**2 Yr.**	**3 Yr.**	**4 Yr.**	**5 Yr.**	**6 Yr.**
Ailanthus	Side	55.8	93.3	112.3	156.7	174.0	192.3
(tree-of-heaven)	Std. Dev. ±	35.2	46.6	48.2	44.1	51.4	49.4
	Top	74.4	113.4	136.0	144.2	156.8	166.2
	Std. Dev. ±	27.6	29.1	36.6	30.8	28.9	27.3
Ash	Side	39.6	73.5	96.8	120.1	138.4	158.5
	Std. Dev. ±	14.3	21.3	21.8	21.5	26.2	33.0
	Top	52.7	94.5	128.5	152.3	177.6	203.3
	Std. Dev. ±	17.6	26.6	33.3	34.0	39.2	45.6
Ash, green	Side	37.9	66.5	91.1	112.0	136.1	152.1
	Std. Dev. ±	17.5	21.1	26.4	30.9	34.3	34.5
	Top	46.6	80.2	110.0	131.1	153.1	166.8
	Std. Dev. ±	19.5	22.9	25.7	29.2	27.2	13.0
Box-elder	Side	46.5	78.1	105.4	124.5	141.7	156.3
	Std. Dev. ±	16.9	18.6	24.6	26.6	27.2	25.9
	Top	61.6	98.2	131.8	152.0	174.9	193.9
	Std. Dev. ±	23.6	24.5	30.1	29.8	35.7	36.5
Cherry, black	Side	49.0	79.9	107.1	128.7	150.9	170.0
	Std. Dev. ±	19.7	24.6	27.3	32.1	36.9	43.6
	Top	58.8	101.9	142.4	178.9	212.5	234.2
	Std. Dev. ±	22.5	27.5	32.0	44.9	50.0	51.2
Cottonwood, eastern	Side	49.7	88.2	121.8	151.9	161.8	201.2
	Std. Dev. ±	17.6	29.5	33.3	41.6	23.2	21.7
	Top	42.0	80.2	155.4	144.6	174.7	201.5
	Std. Dev. ±	17.0	27.3	98.7	26.9	21.5	25.7
Elm	Side	43.3	73.8	99.8	118.9	143.8	164.3
	Std. Dev. ±	19.4	30.0	37.0	46.5	48.7	55.9
	Top	55.7	111.5	143.8	150.8	166.3	182.3
	Std. Dev. ±	22.3	36.9	63.1	69.9	88.6	88.6
Elm, American	Side	46.4	87.3	127.7	144.4	190.0	211.0
	Std. Dev. ±	16.2	29.6	36.1	36.7	41.2	43.5
	Top	73.4	114.6	138.3	139.2	144.4	113.5
	Std. Dev. ±	29.8	43.2	44.5	43.2	43.9	16.3
Elm, Siberian	Side	41.8	75.0	104.1	131.5	155.1	176.3
	Std. Dev. ±	22.5	34.0	43.3	44.8	46.0	51.9
	Top	58.0	99.8	138.3	154.8	172.8	188.5
	Std. Dev. ±	5.4	11.6	10.5	10.9	13.5	12.2

		Feet of Re-Growth by Age of Sprout					
Species	**TrimType**	**1 Yr.**	**2 Yr.**	**3 Yr.**	**4 Yr.**	**5 Yr.**	**6 Yr.**
Hackberry, common	Side	40.7	70.1	97.4	121.5	142.4	164.2
	Std. Dev. ±	15.9	20.2	24.0	29.0	28.8	30.6
	Top	56.4	95.7	128.6	147.8	168.3	190.5
	Std. Dev. ±	24.7	31.0	38.1	35.5	43.9	42.5
Hickory	Side	44.6	78.2	105.5	128.5	140.9	151.5
	Std. Dev. ±	17.9	28.1	36.3	41.2	42.8	46.2
	Top	60.5	90.5	116.3	140.3	153.8	162.0
	Std. Dev. ±	21.8	12.6	21.1	25.7	19.6	15.1
Honeylocust	Side	71.8	104.4	131.4	153.2	169.6	170.0
	Std. Dev. ±	46.4	50.1	49.2	56.9	59.6	53.1
	Top	31.8	64.3	94.3	116.0	167.0	
	Std. Dev. ±	15.3	16.8	15.5	22.6	26.8	
Locust, black	Side	53.6	85.4	111.2	135.8	157.6	180.8
	Std. Dev. ±	21.9	24.3	26.0	33.0	36.7	38.9
	Top	73.5	122.9	149.1	174.4	215.8	233.8
	Std. Dev. ±	35.1	43.0	43.4	51.0	59.7	55.7
Maple, Norway	Side	10.0	29.0	46.0	59.0	70.0	72.0
	Std. Dev. ±	2.1	7.3	15.6	18.7	23.4	25.1
	Top	46.0	68.5	88.0	103.5	117.0	121.5
	Std. Dev. ±	1.2	7.5	5.8	11.0	15.0	17.9
Maple, red	Side	41.5	72.6	104.5	128.0	152.4	180.4
	Std. Dev. ±	17.2	22.8	27.2	34.5	35.0	33.5
	Top	76.7	119.7	148.5	172.4	191.0	199.1
	Std. Dev. ±	23.5	33.2	38.8	47.9	56.4	62.6
Maple, silver	Side	55.2	92.8	123.3	147.1	169.9	190.4
	Std. Dev. ±	22.4	30.5	33.8	37.1	39.8	42.2
	Top	75.4	126.8	156.2	179.8	205.2	223.8
	Std. Dev. ±	33.6	49.2	42.2	45.8	52.0	57.0
Maple, sugar	Side	38.1	67.1	91.1	110.4	130.2	147.6
	Std. Dev. ±	18.2	25.6	27.2	24.9	26.3	27.7
	Top	48.2	82.6	113.2	137.1	156.0	176.7
	Std. Dev. ±	24.7	29.3	31.2	32.3	34.9	32.6
Mulberry	Side	52.2	85.5	116.5	151.3	170.7	187.2
	Std. Dev. ±	20.7	30.9	43.8	57.9	56.7	54.7
	Top	60.2	95.2	128.6	164.1	183.3	198.4
	Std. Dev. ±	20.5	24.6	34.0	45.8	49.7	49.2
Mulberry, red	Side	31.7	63.3	88.3	95.0		
	Std. Dev. ±	12.5	19.3	21.8	24.1		

		Feet of Re-Growth by Age of Sprout					
Species	**TrimType**	**1 Yr.**	**2 Yr.**	**3 Yr.**	**4 Yr.**	**5 Yr.**	**6 Yr.**
	Top	84.9	136.0	143.3	161.5	163.0	197.0
	Std. Dev. ±	36.2	39.4	64.9	21.9	23.1	25.3
Oak, black	Side	30.5	65.5	100.0	110.0	125.5	138.0
	Std. Dev. ±	2.1	3.5	21.2	27.0	31.2	35.7
	Top	52.0	80.0	112.0	137.0	158.0	
	Std. Dev. ±	20.7	26.7	33.5	36.7	41.8	
Oak, northern red	Side	42.8	69.7	92.2	116.1	132.4	145.4
	Std. Dev. ±	18.0	24.6	31.3	38.9	40.2	40.0
	Top	66.0	109.6	137.4	161.0	179.2	204.0
	Std. Dev. ±	19.0	31.4	29.8	22.5	24.7	24.0
Oak, pin	Side	36.3	64.5	87.0	108.0	129.4	152.5
	Std. Dev. ±	12.8	19.0	25.1	26.7	30.2	32.9
	Top	48.3	78.1	98.4	126.1	145.1	170.1
	Std. Dev. ±	19.7	28.3	45.5	31.1	31.7	41.8
Oak, southern red	Side	37.1	67.0	93.8	117.0	146.0	162.0
	Std. Dev. ±	9.7	13.3	23.8	18.4	24.5	33.0
Oak, white	Side	28.9	50.9	74.7	95.7	113.6	131.8
	Std. Dev. ±	11.5	17.0	19.4	23.7	27.6	31.8
	Top	29.2	56.2	79.0	101.2	121.2	133.0
	Std. Dev. ±	9.1	16.7	17.6	24.3	26.4	41.6
Pear, Bradford	Side	31.8	56.2	81.2	102.5	119.8	127.9
	Std. Dev. ±	9.7	16.1	19.1	19.8	25.0	26.8
	Top	38.3	64.6	93.0	108.5	123.1	141.3
	Std. Dev. ±	15.5	19.3	23.1	22.0	24.1	28.6
Pine, eastern white	Side	20.2	36.0	51.0	63.9	78.3	91.1
	Std. Dev. ±	8.2	13.1	16.3	18.9	21.4	24.9
	Top	22.8	44.5	62.9	82.6	98.8	111.8
	Std. Dev. ±	9.2	15.4	22.0	27.2	30.8	32.9
Redbud, eastern	Side	50.0	79.0	102.0	119.0	140.0	148.0
	Std. Dev. ±	11.3	14.5	22.0	26.7	31.1	36.4
	Top	54.5	95.0	123.5	148.0	174.5	190.0
	Std. Dev. ±	9.2	33.9	30.4	14.1	36.1	43.8
Redcedar, eastern	Side	10.2	17.2	27.0	33.9	40.2	47.1
	Std. Dev. ±	7.4	10.4	17.9	20.4	21.8	21.9
	Top	12.8	26.8	37.7	48.3	58.6	69.0
	Std. Dev. ±	5.6	9.5	11.5	12.5	14.0	15.3
Sassafras	Side	43.3	74.8	100.0	131.3	148.7	165.0
	Std. Dev. ±	12.6	23.7	32.2	11.2	7.4	9.8

Species	TrimType	Feet of Re-Growth by Age of Sprout 1 Yr.	2 Yr.	3 Yr.	4 Yr.	5 Yr.	6 Yr.
	Top	93.9	132.5	169.4	198.8	223.5	255.8
	Std. Dev. ±	17.0	22.2	27.2	30.7	34.6	35.1
Spruce, Norway	Side	9.8	17.8	26.8	35.5	43.2	49.8
	Std. Dev. ±	3.2	4.6	7.4	10.7	13.4	15.3
	Top	22.4	34.9	47.9	61.3	77.1	93.7
	Std. Dev. ±	16.0	17.4	19.6	21.7	22.4	25.2
Sweetgum	Side	30.3	52.4	73.3	101.2	135.0	191.0
	Std. Dev. ±	18.7	27.1	31.1	44.5	62.2	55.7
	Top	45.0	94.3	130.7	155.0		
	Std. Dev. ±	14.2	31.0	38.7	77.8		
Sycamore	Side	48.7	87.8	122.1	142.9	175.1	198.9
	Std. Dev. ±	17.8	24.0	33.6	32.9	38.2	38.9
	Top	60.1	106.7	151.2	180.2	203.1	230.0
	Std. Dev. ±	18.1	23.8	31.8	38.3	33.5	36.2
Walnut, black	Side	49.9	84.8	114.9	139.4	161.8	178.8
	Std. Dev. ±	25.0	32.1	38.3	46.0	48.5	50.4
	Top	68.3	112.9	152.5	173.2	193.9	211.5
	Std. Dev. ±	30.6	38.3	44.9	45.1	52.5	51.0
Willow	Side	43.6	76.3	111.9	134.0	158.4	197.5
	Std. Dev. ±	15.2	12.1	16.8	19.0	23.6	34.6
	Top	41.0	82.9	119.4	145.9	167.0	199.7
	Std. Dev. ±	11.2	14.4	20.6	22.2	19.4	33.5
Yellow-poplar	Side	42.2	69.0	88.8	108.2	120.0	138.5
	Std. Dev. ±	23.0	24.0	26.5	23.9	23.1	20.5
	Top	82.6	129.7	156.2	202.0	219.5	270.0
	Std. Dev. ±	25.4	33.4	37.1	45.3	41.7	47.9

Appendix G:
LG&E and KU Transmission System Benchmark Comparison

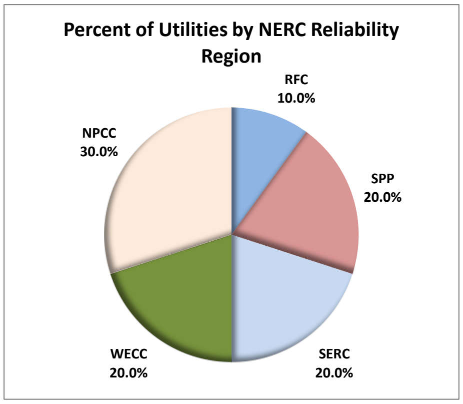


Figure 14

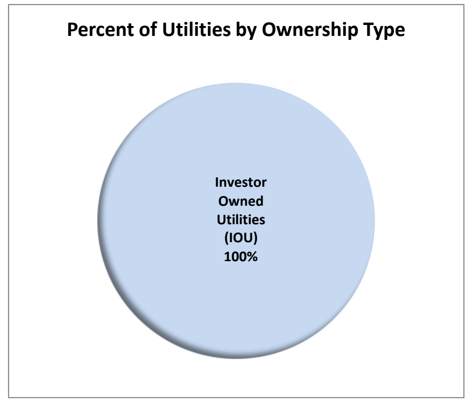


Figure 17

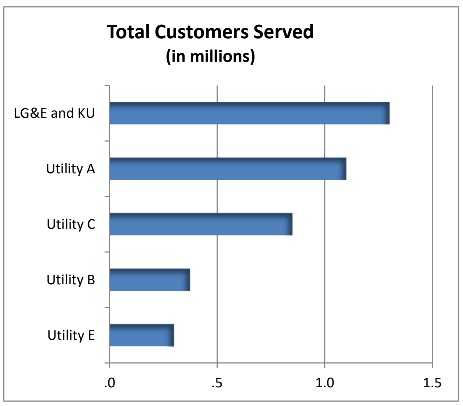


Figure 15

Transmission Program Attributes

Utilities Regulated by a Public Utility or Service Commission(s) or other Agency(s):	............................100%
Centralized VM Program:	............................100%
VM Managed by Professional Forester or Arborist:	.... 80%

Figure 18

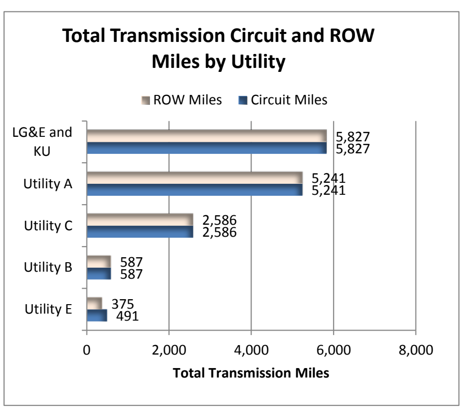


Figure 16

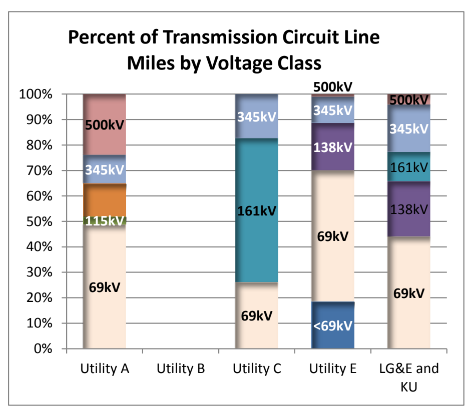


Figure 19

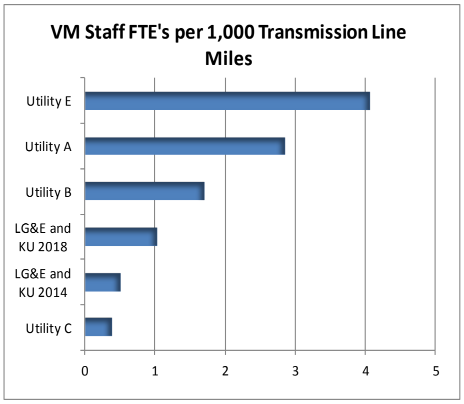


Figure 20

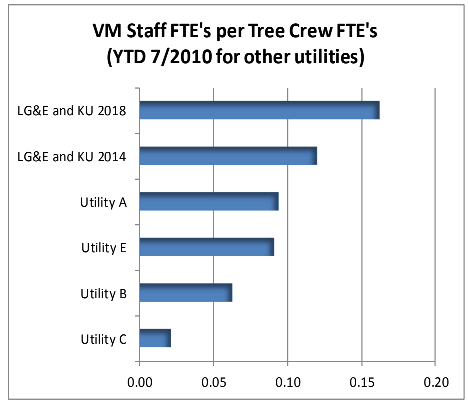


Figure 23

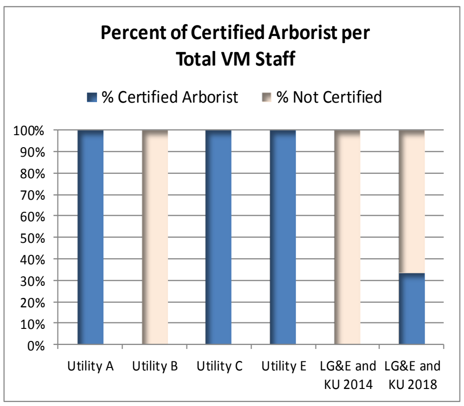


Figure 21

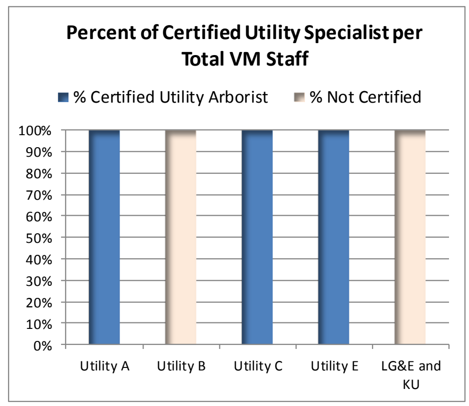


Figure 24

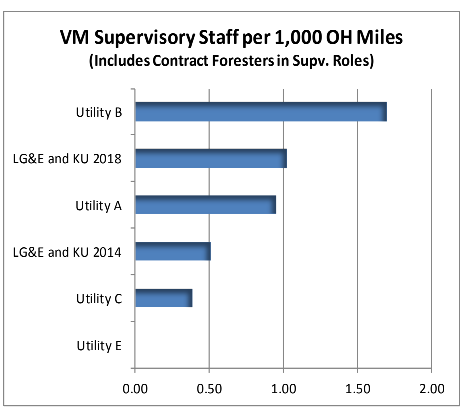
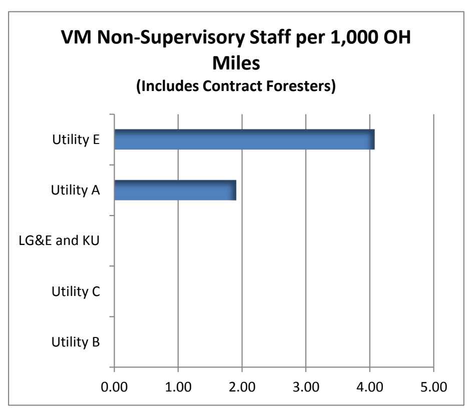


Figure 22



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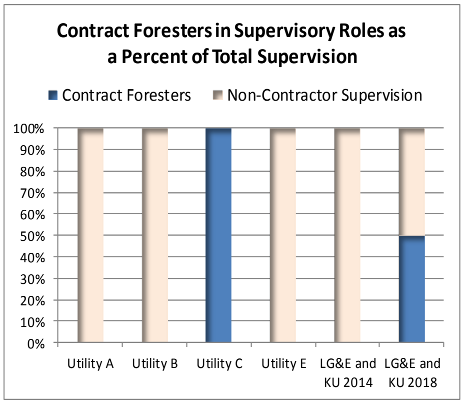

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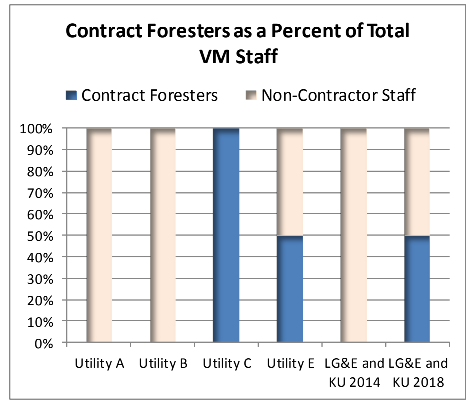

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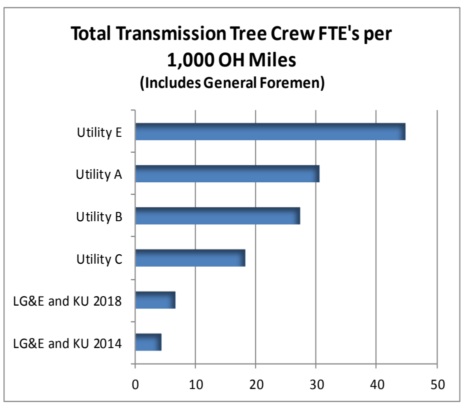

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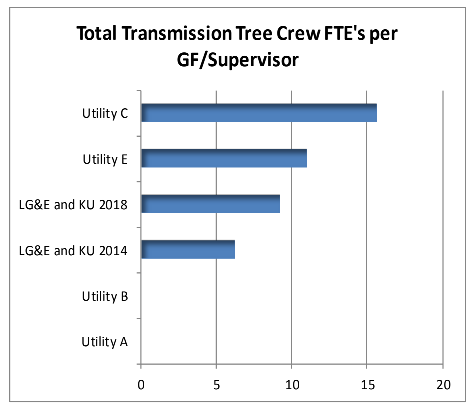

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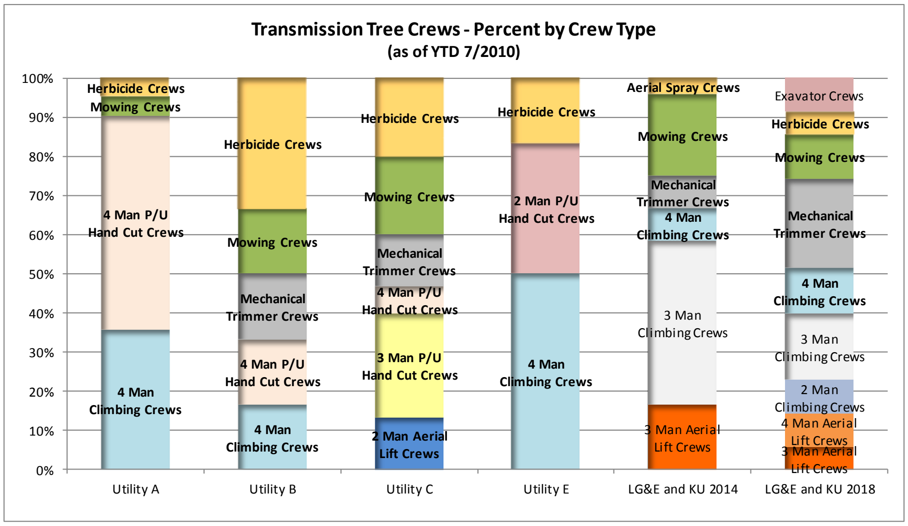

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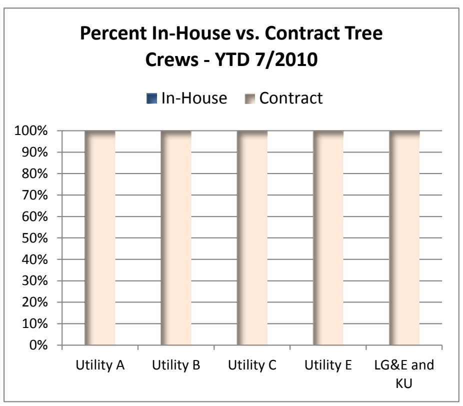

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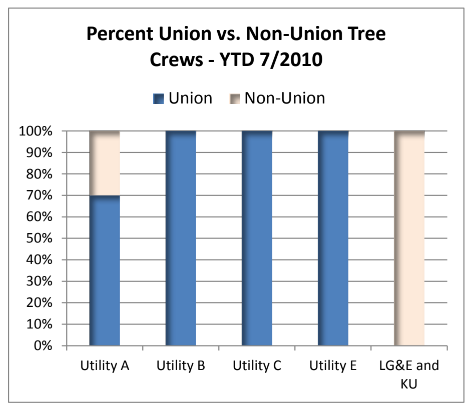

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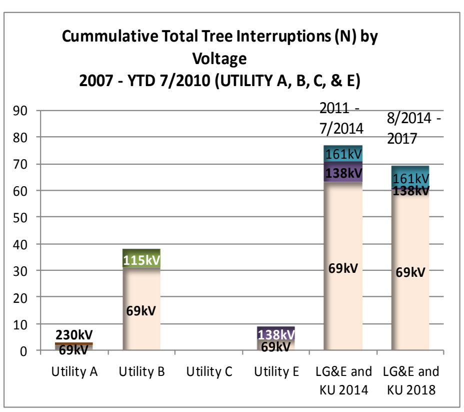

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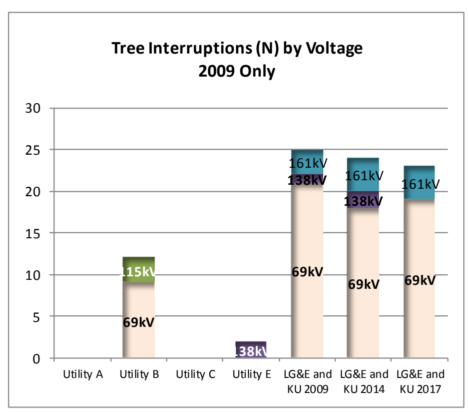

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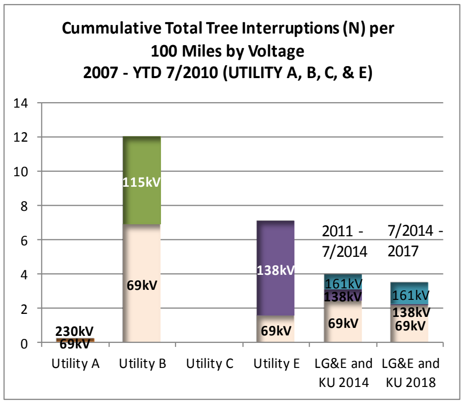

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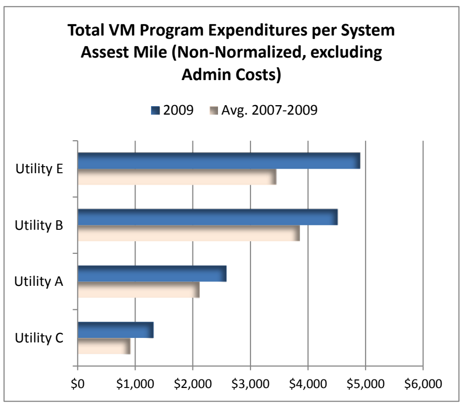

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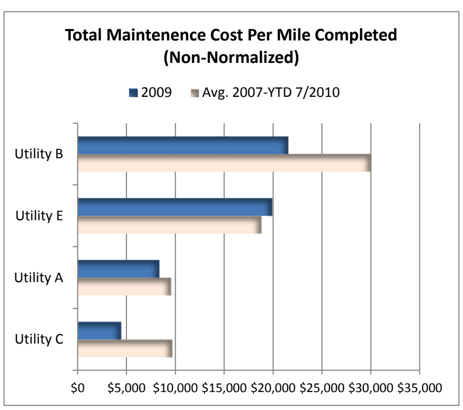

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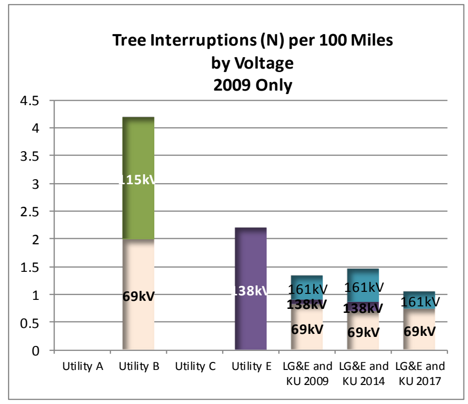

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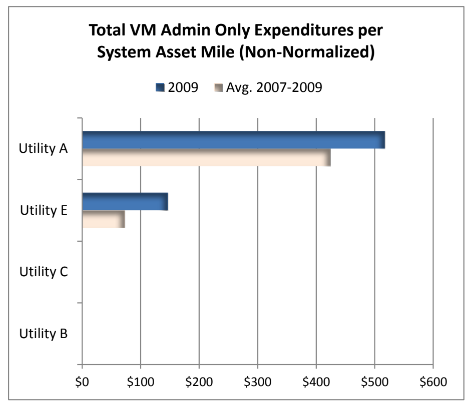

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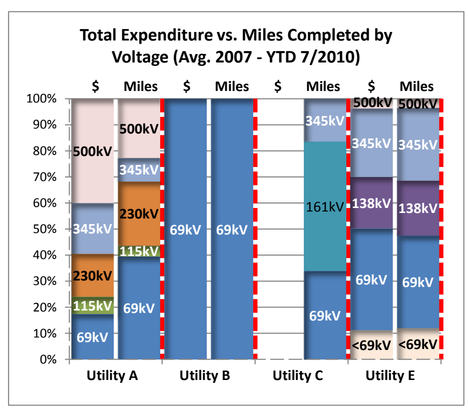

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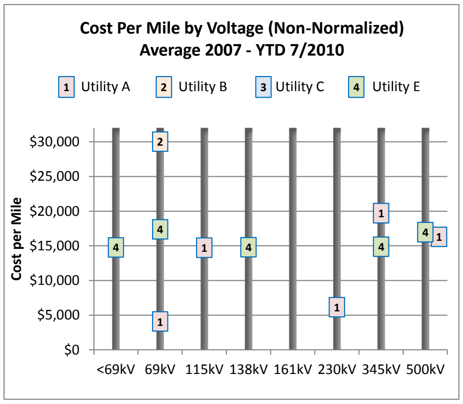

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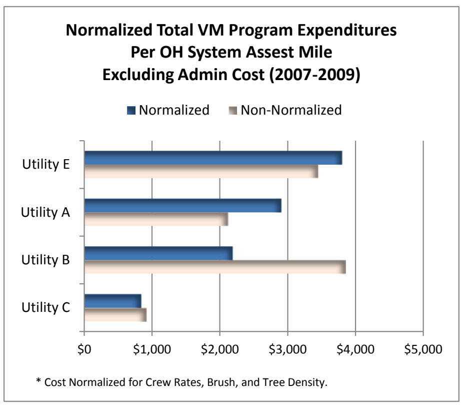

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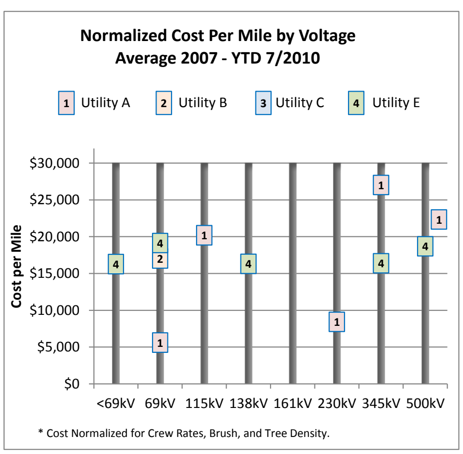

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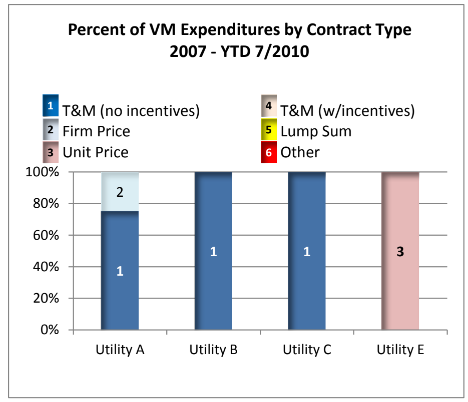

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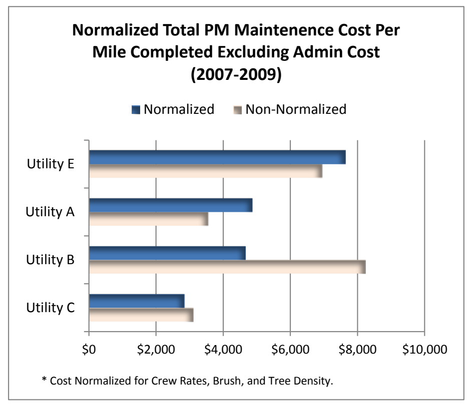

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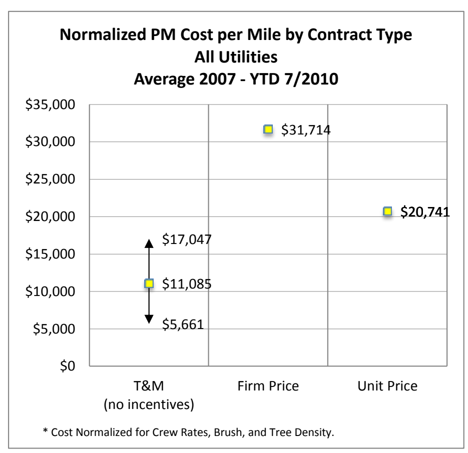

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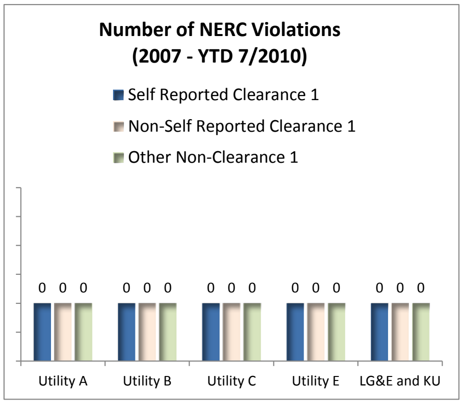

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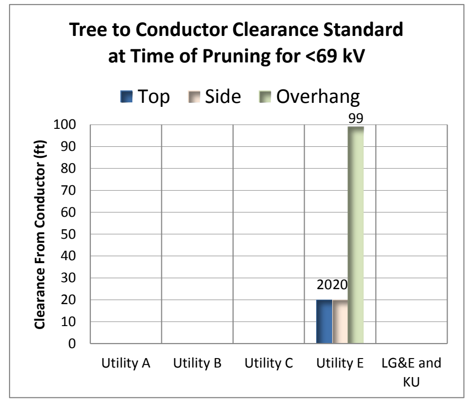

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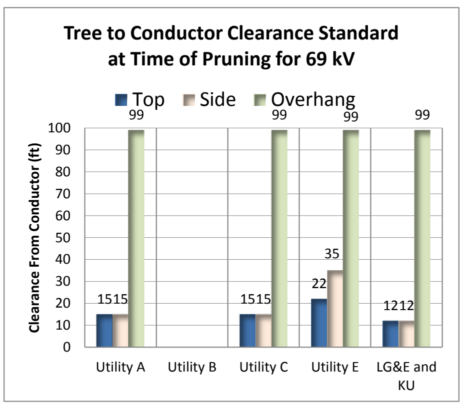

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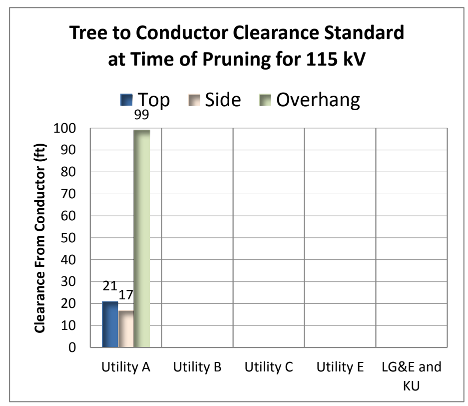

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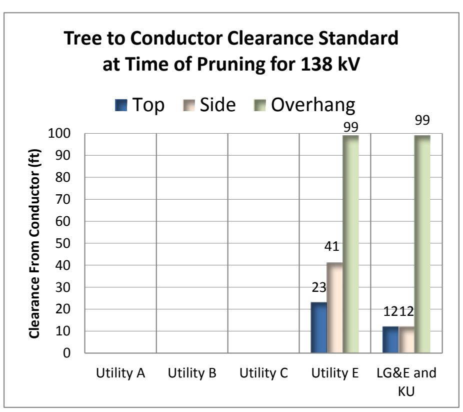

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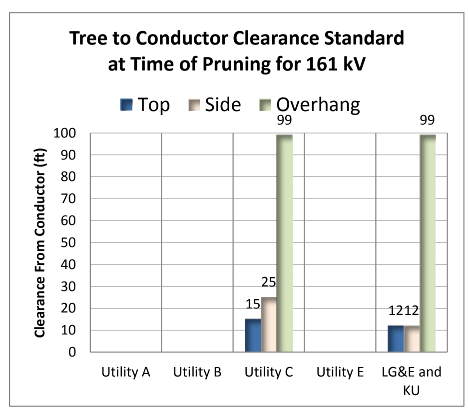

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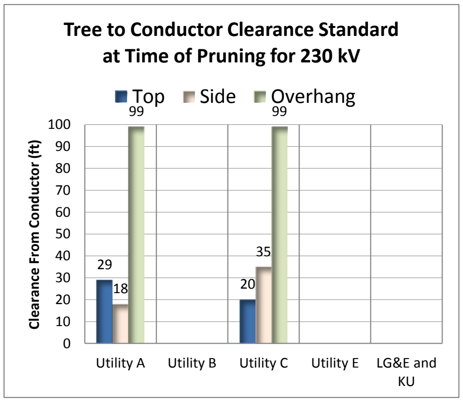

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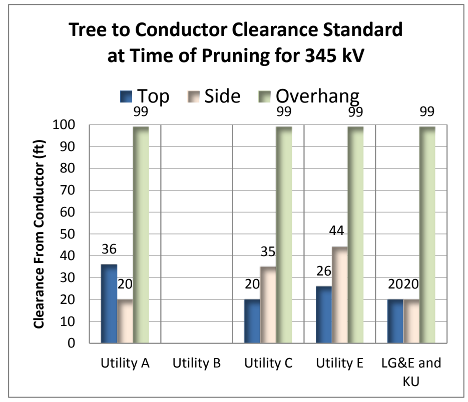

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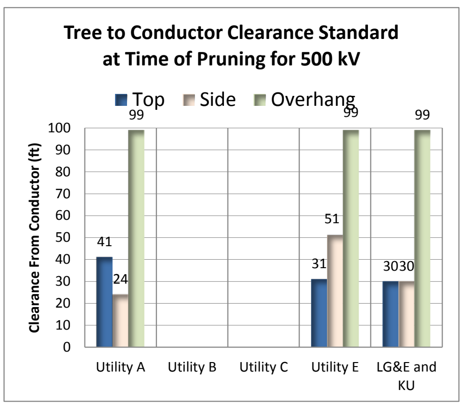

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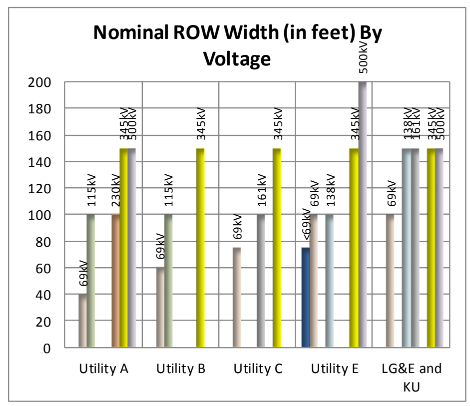

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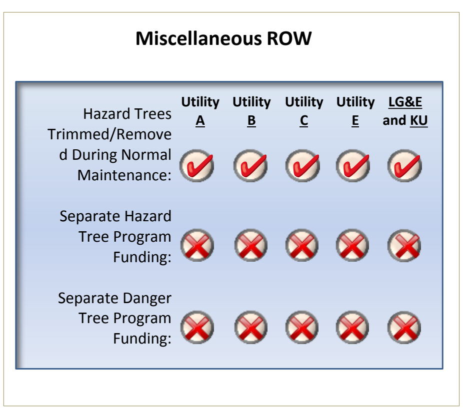

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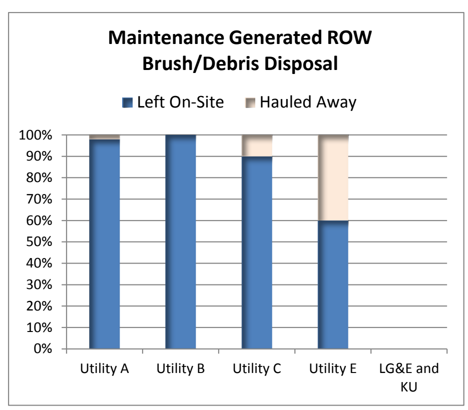
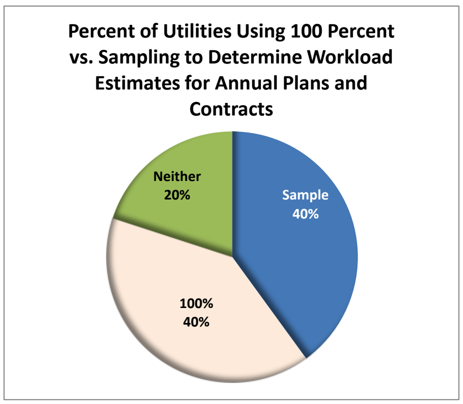


Figure 58

Tree Inventory System Capabilities	Utility A	Utility B	Utility C	Utility E
Work Prescription and Estimating (Work Planning)	X			
Map, Manifest and Work Package Generation	X			
GIS Tree Location Information	X			
Electronic Facility Asset Maps with Tree Inventory Overlay	X			
Cost Generation and Budgeting				
QA/QC Audit and Inspection Tracking	X			
Payment Processing				
Electronic Billing and Payment Processing				
Productivity Tracking and Analysis				
Work Status and Completion Tracking (Work Management)	X			
Reliability Tracking and Follow-Up Investigations	X			
Emergency Work and Restoration Management Coordination				

Figure 59



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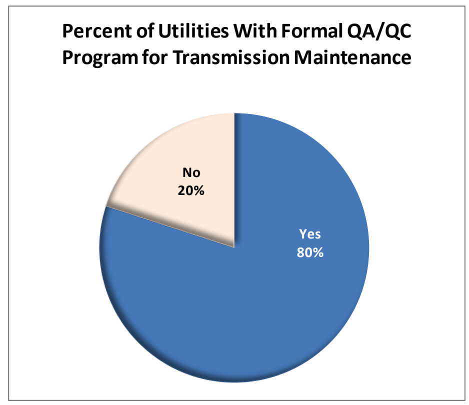

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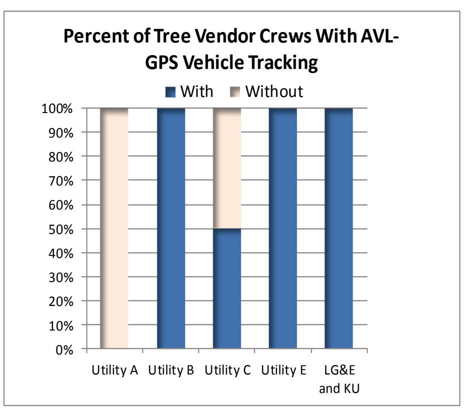

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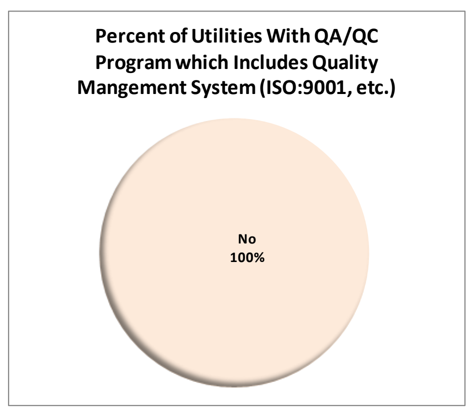

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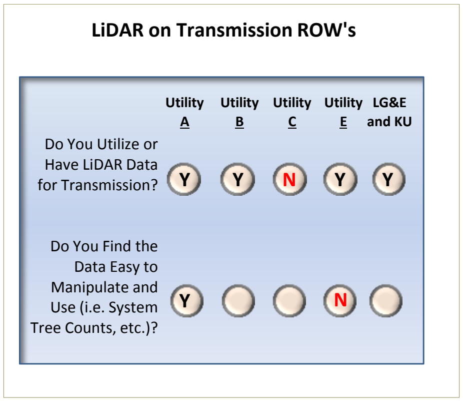

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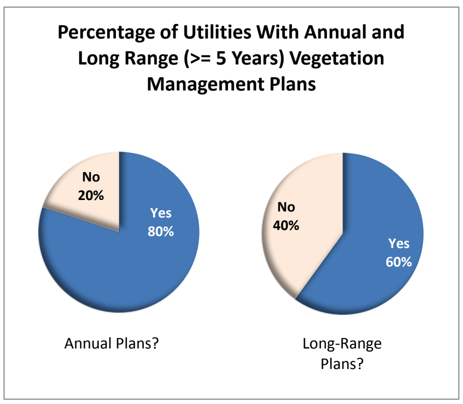

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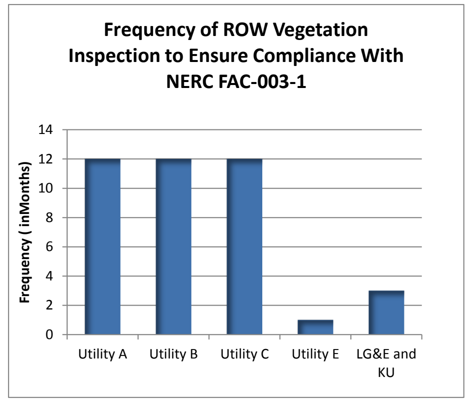

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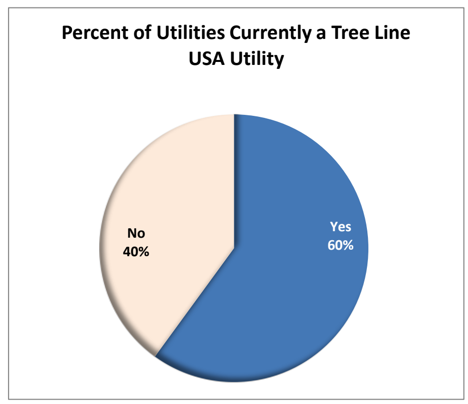

Figure 67

Exhibit LEB-5

Distribution Reliability and Resilience
Improvement Program

Electric Distribution Operations

Distribution Reliability & Resiliency Improvement Program

LG&E KU
PPL companies

August 2018

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Executive Summary

As stewards of the LG&E and KU electric distribution system, Electric Distribution Operations (EDO) is responsible for providing safe, reliable, resilient, high quality and valuable electric service to customers. Acting upon this responsibility and consistent with industry trends, EDO has focused on improving distribution system reliability and resiliency by increasing capital investments in circuit hardening, critical asset contingency, aging infrastructure replacement, and grid intelligence technologies. These initiatives have produced significant improvements in LG&E and KU SAIDI (22%) and SAIFI (26%) between 2010 and 2017 as well as LG&E and KU's customer satisfaction ratings which have improved by 35 percent and 9 percent, respectively.

To continue these improving trends, this Distribution Reliability and Resiliency Improvement Program (DRRIP) provides nearly $465 million total capital investment and $30 million in total expenses during 2019 through 2023 focused on the strategies shown below.

- System reliability and contingency investments to meet increasing customer expectations respective to service availability
- Investments in aging infrastructure to continue long term service reliability
- Advanced grid intelligence to meet evolving customer expectations and align with industry trends
- Respond to outage events in an efficient and effective manner, and continue to improve on the accuracy, timeliness, and provision of estimated restoration times
- Technology which enhances business processes, reduces cycle times, and expands communications with customers.

Specific investment and operating initiatives evaluated and prioritized through EDO's investment selection methodology are provided in the DRRIP and in EDO's 2019 Business Plan (BP). These initiatives include the following:

- Continued development and enhancement of a centralized grid operation strategy
- Continuation and extension of automation on the distribution system;
- Continued funding for the distribution substation transformer contingency program;
- Continuation of existing reliability improvement programs; and
- Continued expansion of existing aging infrastructure replacement programs.

In summary, this DRRIP delivers prudent investment and operating strategies to ensure continued improvement in LG&E and KU's reliability and customer satisfaction performance by advancing grid intelligence, providing for increased operational control and flexibility, prudently replacing aging assets, and building additional contingency into critical assets.

1.0 Background

1.1 LG&E and KU Performance and Investments

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 411,000 electric customers in Louisville and 9 surrounding counties, and KU serves 553,000 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 administered by J.D. Power, which evaluates several key indices. The 2017 J.D. Power Electric Utility Residential Customer Satisfaction Study placed KU first and LG&E second in residential customer satisfaction among Midwest midsize utilities. Both utilities achieved first quartile rankings in categories such as Power Quality and Reliability, Billing and Payment, Price, Corporate Citizenship, Communication, and Customer Service. While each category drives customer satisfaction to some degree, satisfaction with a utility's Power Quality and Reliability was the most significant factor in determining overall customer satisfaction. LG&E and KU results are shown in Figure 1 below. Areas of significant improvement compared to the 2016 survey are circled.

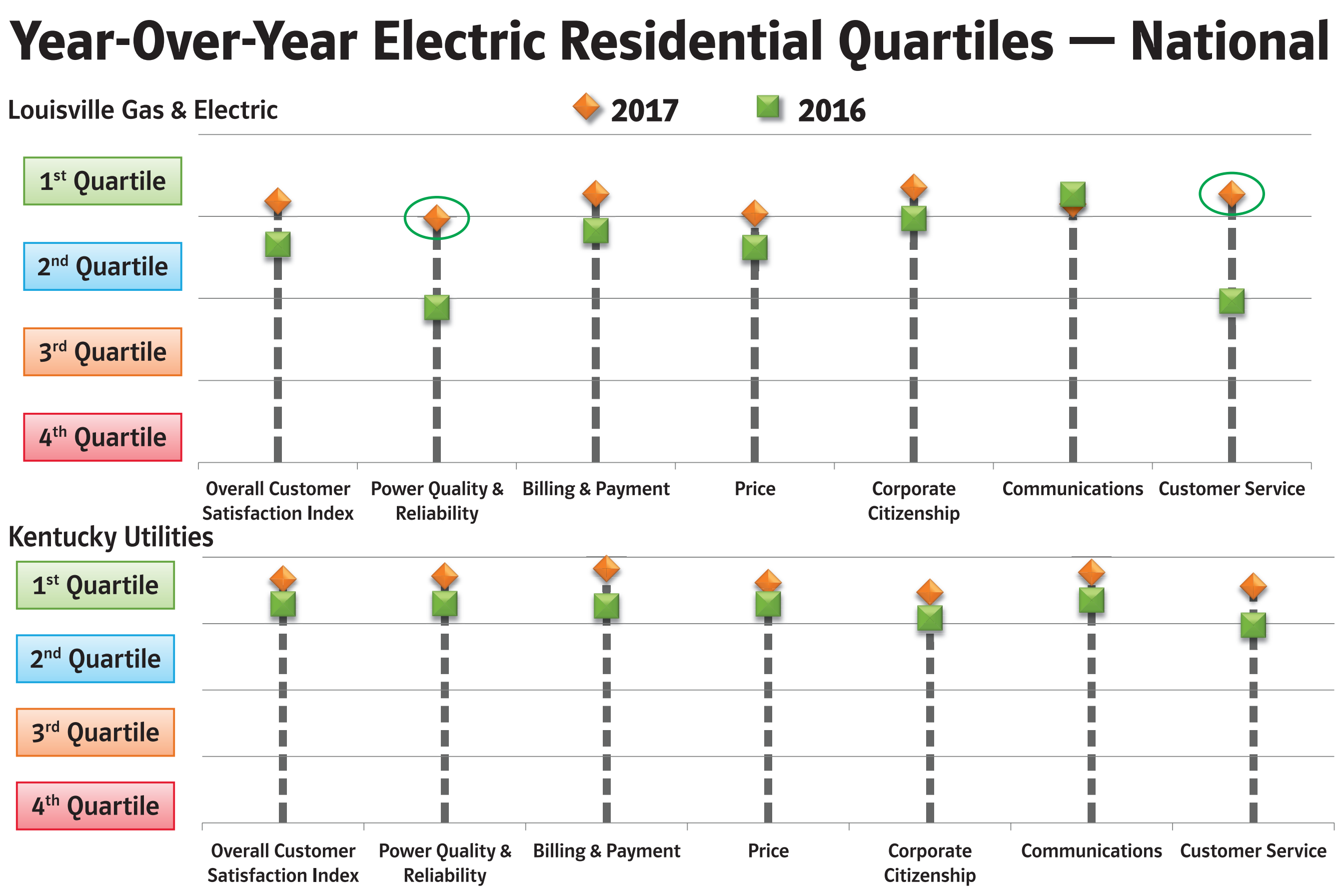


Figure 1: J.D. Power 2017 Electric Utility Residential Customer Satisfaction Study

Electric Distribution Operation's (EDO) primary benchmarking surveys for reliability performance[1] within the electric industry are REDACTED - Third Party Confidentiality Agreement Figures 2-5 display LG&E and KU SAIDI and SAIFI performance against REDACTED - Third Party Confidentiality Agreement performance thresholds since 2006.

1. Since 2010, and consistent with the utility industry, LG&E and KU has tracked and reported electric reliability indices as defined by the Institute of Electrical and Electronics Engineers (IEEE) standard P1366, "Guide for Electric Distribution Reliability Indices." The general acceptance of these metrics by the industry makes them useful as benchmarks and as long-term average system performance measures. They are also useful tools to help guide decision making respective to sustaining or enhancing reliability performance.
   The primary IEEE 1366 performance metrics tracked and benchmarked by LG&E and KU are:
   - System Average Interruption Frequency Index (SAIFI) — calculated by dividing the total number of customers interrupted in a time period by the average number of customers served. The resulting unit is interruptions per customer.
   - System Average Interruption Duration Index (SAIDI) — calculated by summing the customer-minutes off for each interruption during a specified time period and dividing the sum by the average number of customers served during that period. The resulting unit is minutes.

REDACTED - Third Party Confidentiality Agreement

[redacted]

Figure 2: LG&E and KU Distribution SAIDI performance against REDACTED - Third Party Confidentiality Agreement[2]

REDACTED - Third Party Confidentiality Agreement

[redacted]

Figure 3: LG&E and KU Distribution SAIFI performance against REDACTED - Third Party Confidentiality Agreement

[redacted]

REDACTED - Third Party Confidentiality Agreement

Figure 4: LG&E and KU Distribution SAIDI performance against REDACTED - Third Party Confidentiality Agreement[4]

REDACTED - Third Party Confidentiality Agreement

Figure 5: LG&E and KU Distribution SAIFI performance against REDACTED - Third Party Confidentiality Agreement[5]

4. Includes distribution lines and substations SAIDI, and excludes Major Event Days.
5. Includes distribution lines and substation SAIFI, and excludes Major Event Days.

LG&E and KU's SAIDI and SAIFI performance ranked in first quartile REDACTED - Third Party Confidentia, and upper second quartile REDACTED - Third Party Confident, 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,[6] LG&E and KU's actual and comparative reliability performance (Figures 2-5) and customer satisfaction levels 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[7] 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 Circuits Identified for Improvement (CIFI) program. In subsequent years, EDO allocated incremental funding for Aging Infrastructure Replacement (AIR) and Distribution Substation Transformer Contingency (N1DT) programs.

EDO's increased investments in reliability and resiliency produced significant improvements in LG&E and KU SAIDI (22%) and SAIFI (26%) between 2010 and 2017. Additionally, LG&E and KU's customer satisfaction ratings improved by 35 percent and 9 percent, respectively. EDO attributes much of its realized reliability improvements to its CIFI program. Between 2010 and 2017, EDO completed circuit hardening on 234 LG&E and KU circuits which were targeted for the CIFI program based on historical Customers Interrupted (CI).

When the CIFI program was initiated, EDO understood that eventually, the same investment would yield progressively smaller reliability benefit per dollar invested. As the CIFI program progressed, the average annual SAIFI contribution of circuits targeted for the program 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. As a result of EDO's assessment, and upon receiving CPCN approval in 2017, LG&E and KU began its Distribution Automation (DA) program.

Figure 6 displays EDO's electric distribution system reliability and resiliency capital investment allocations between 2005 and 2017.

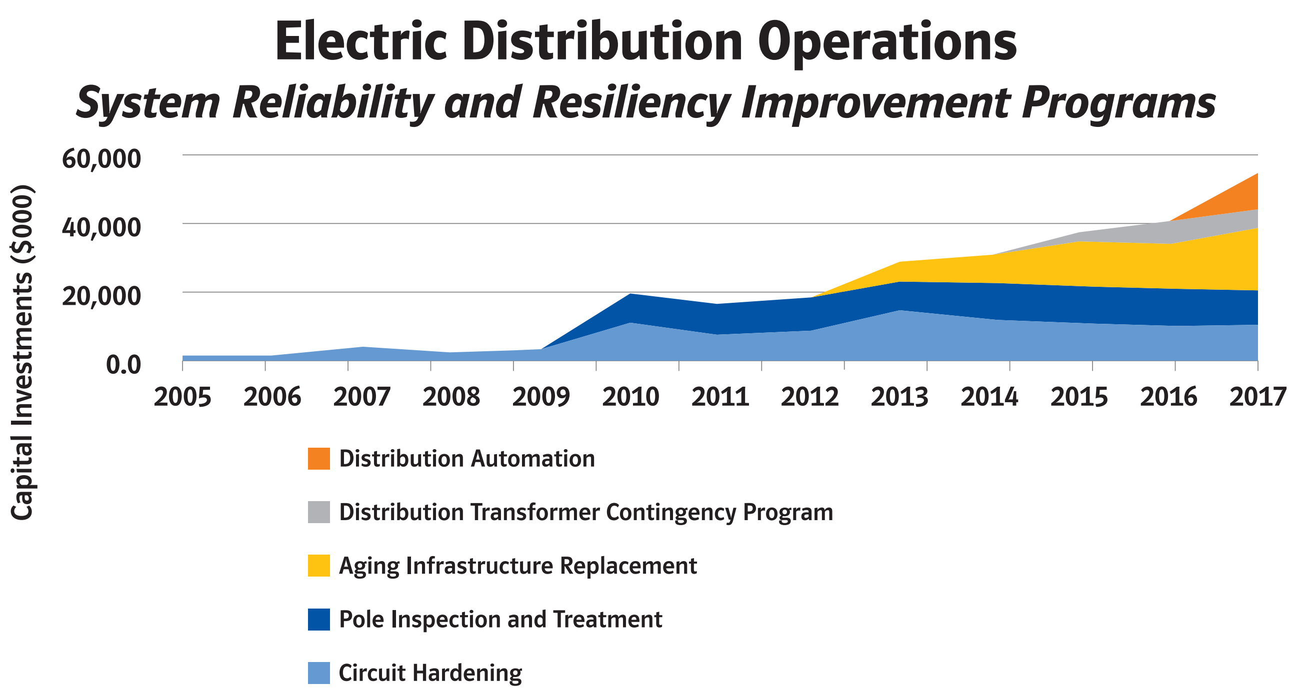


Figure 6: LG&E and KU electric distribution service reliability and system resiliency capital investment programs (2005-2017).

6. 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.

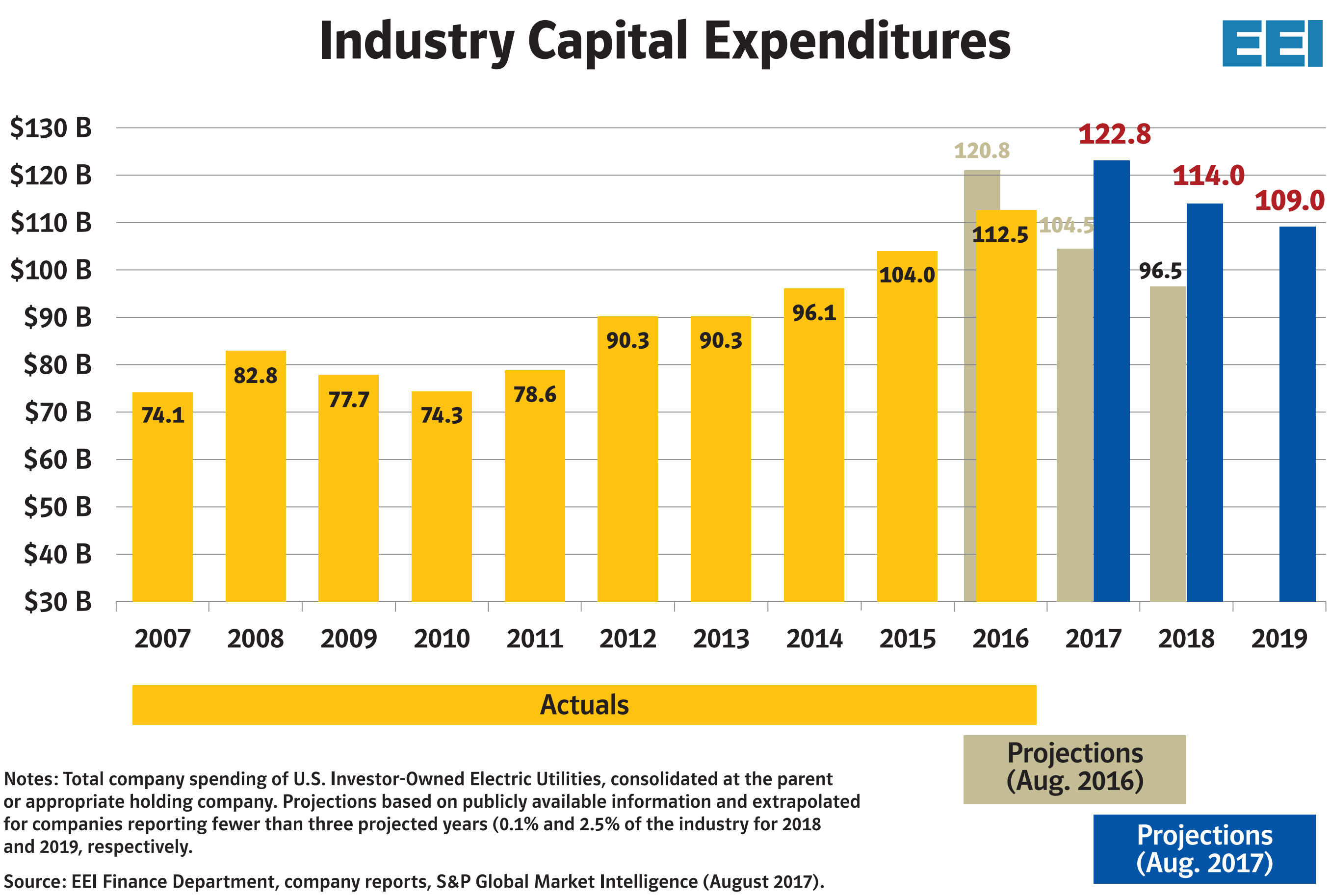
7. Definition: ***Resilience*** is defined as "robustness and recovery characteristics of utility infrastructure and operations, which avoid or minimize interruptions of service during an extraordinary and hazardous event."
Source: National Association of Regulatory Utility Commissioners, Resilience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

1.2 Industry Perspective

Results from REDACTED - Third Party Confidentiality Agreement benchmarking studies demonstrate continuous improvement and a compression of quartile reliability performance levels. REDACTED - Third Party Confidentiality Agreement [redacted] 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).

During EEI's February 7, 2018 Wall Street Briefing, Richard McMahon, Vice President, Energy Supply and Finance discussed Industry Investment and Financial Overview. The Industry Capital Expenditure and Projected Functional Capital Expenditure information he shared is shown in Figures 7 and 8 below. Based on EEI's analysis, annual capital investments in U.S. investor owned electric utilities have increased by 52% over the last ten years, and are projected to remain above $100 billion through 2019 (Figure 7).



Notes: Total company spending of U.S. Investor-Owned Electric Utilities, consolidated at the parent or appropriate holding company. Projections based on publicly available information and extrapolated for companies reporting fewer than three projected years (0.1% and 2.5% of the industry for 2018 and 2019, respectively.

Source: EEI Finance Department, company reports, S&P Global Market Intelligence (August 2017).

Figure 7: Annual Capital Expenditures of U.S. Investor Owned Utilities.[8]

8. Edison Electric Institute (EEI) — Delivering America's Energy Future; Electric Power Industry Outlook; Edison Electric Institute Wall Street Briefing; February 2018; New York, NY; http://eei.org/issuesandpolicy/finance/wsb/Documents/EEI_WSB_Presentation.pdf.

Further, 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 2017, the percent of investor owned utility capital investments in distribution increased to 29% from 27% of total investment, when compared to 2016 capital allocations (Figure 8).

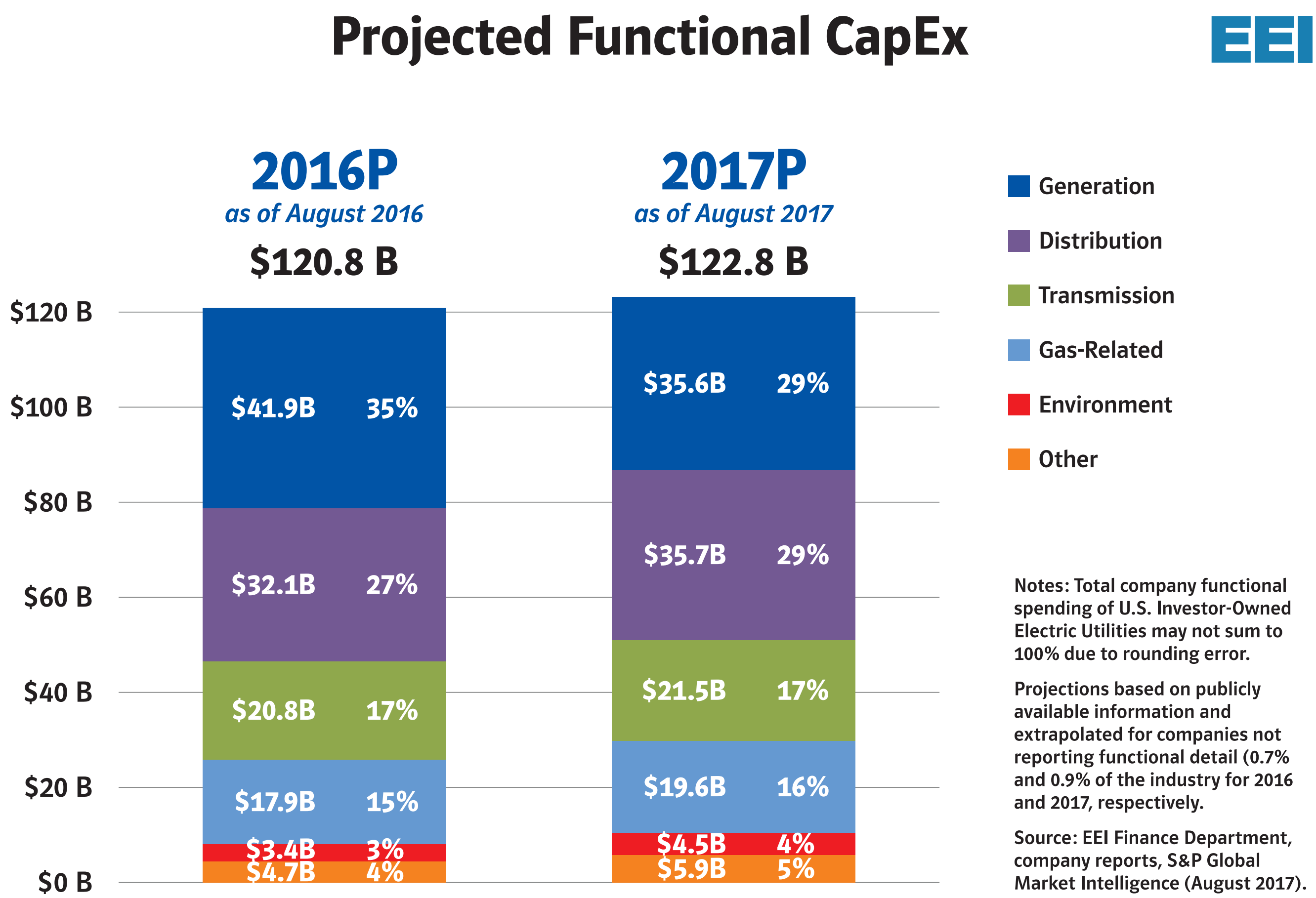


Figure 8: Projected Functional CapEx.[9]

The American Recovery and Reinvestment Act (ARRA) has been 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 the Department of Energy (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 for DOE approved smart grid projects. The DOE Office of Electricity Delivery and Energy Reliability managed each SGIG project to ensure performance remained on schedule and on budget. In December, 2016, the DOE released its final SGIG report. Figure 9 displays the final SGIG program overview.

9. Edison Electric Institute (EEI) — Delivering America's Energy Future; Electric Power Industry Outlook; Edison Electric Institute Wall Street Briefing; February 2018; New York, NY; http://eei.org/issuesandpolicy/finance/wsb/Documents/EEI_WSB_Presentation.pdf.

Smart Grid Investment Grant (SGIG)

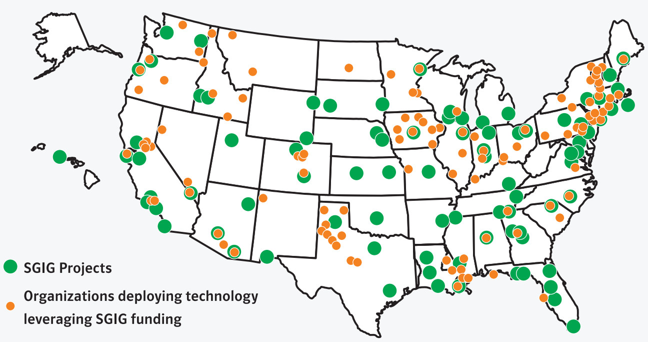
Program Overview

SGIG Programs and Funding

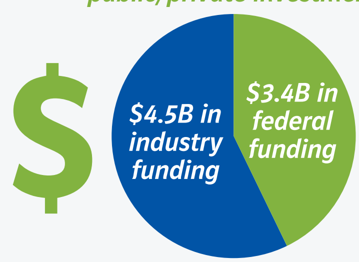
99 *competitively selected projects*

228 *participating utilities and organizations*

6 *years (2010–2015)*



$7.9B
public/private investment



ARRA funding was matched or exceeded dollar for dollar by recipients.

SGIG Project Technology Areas

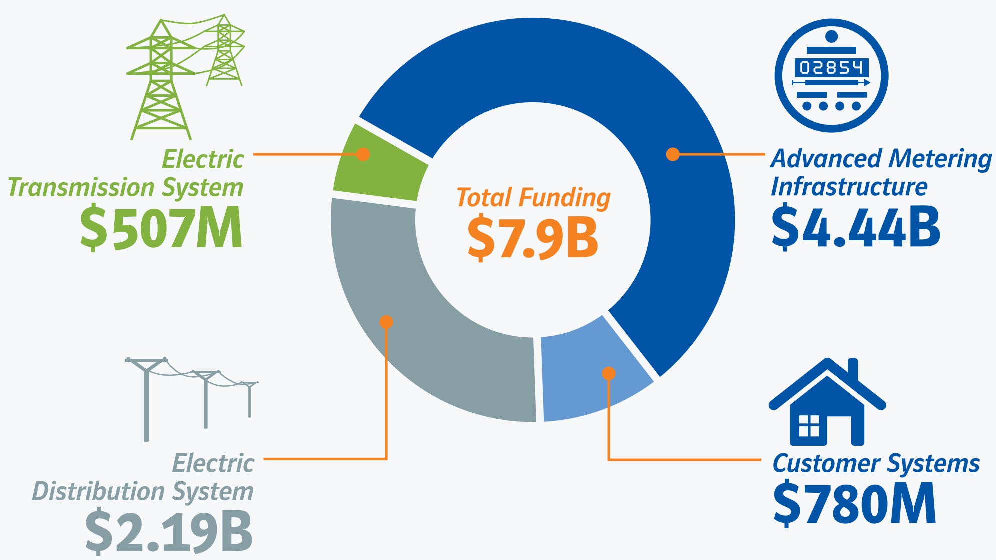


Figure 9: SGIG Program Overview.[10]

10. Smart Grid Investment Grant Program Final Report December 2016; U.S. Department of Energy, Office of Electricity Delivery & Energy Reliability; p6; https://www.smartgrid.gov/files/Final_SGIG_Report_20161220.pdf.

Demonstrated smart grid technology benefits cited in the final report include:

- Fewer and shorter outages that result in less inconvenience and lower outage costs for customers.
- Improved grid resilience to extreme weather events by automatically limiting the extent of major outages and improving operator ability to diagnose and repair damaged equipment.
- Faster and more accurate outage location identification for improved repair crew dispatching and service restoration, reducing operating costs, truck rolls, and environmental emissions.
- More effective equipment monitoring and preventative maintenance that reduce operating costs and the likelihood of equipment failures, make more efficient use of capital assets, and result in fewer outages.[11]

Finally, the DOE's final SGIG report referenced smart grid investments in the U.S. as a whole. "In all, the U.S. electricity industry as a whole spent an estimated $24.97 billion for smart grid technology deployed from 2010 through 2015 (excluding transmission system technologies).[12] Smart grid investments under the ARRA accounted for nearly a third of spending during this period. The rate of expenditures was highest in 2010–2012, following the spirit of ARRA to stimulate the economy. This infusion of technologies is catalyzing continued industry investment over the next several years as smart grid technologies continue to mature."[13] Total U.S. smart grid investments are shown graphically in Figure 10 below.

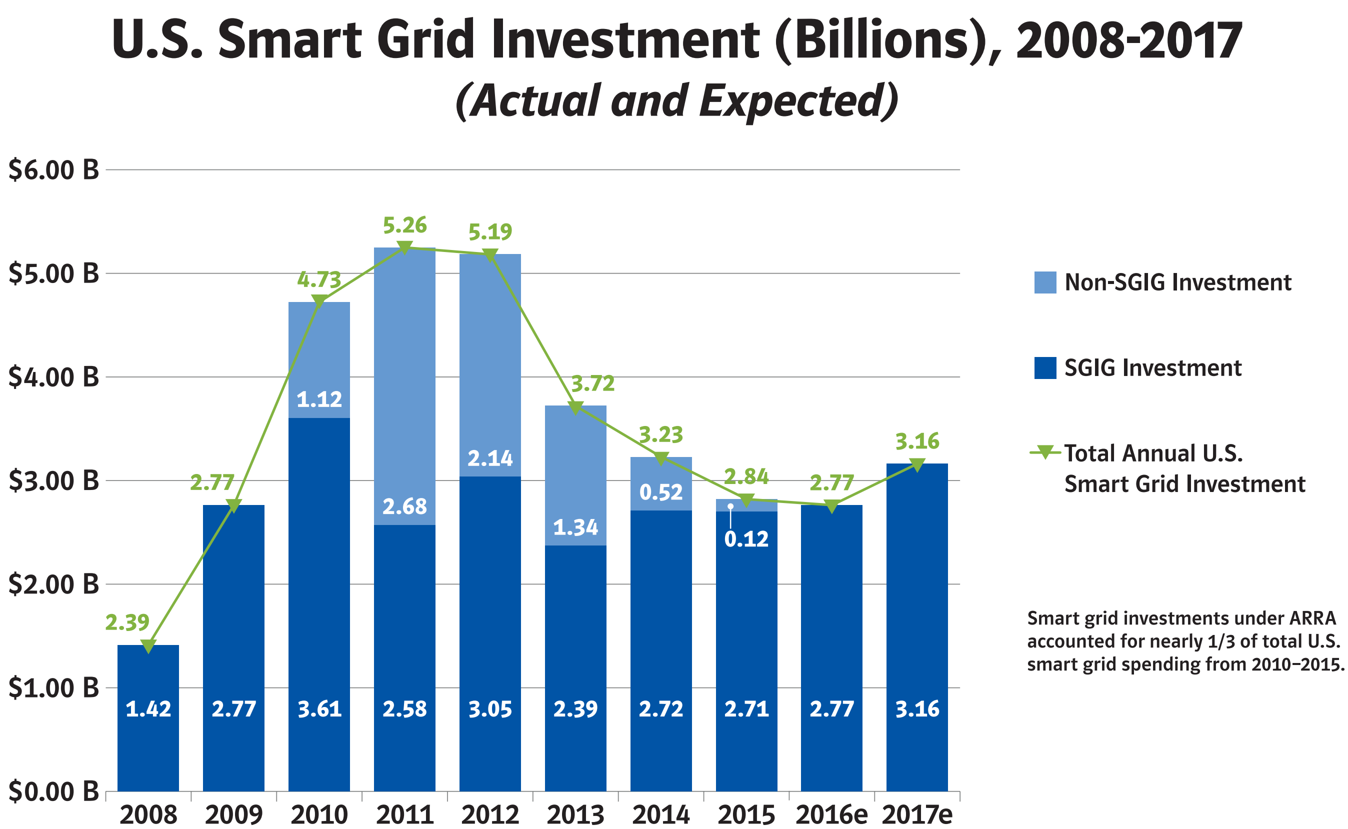


Figure 10: U.S. Smart Grid Investment.[14]

11. Smart Grid Investment Grant Program Final Report December 2016; U.S. Department of Energy, Office of Electricity Delivery & Energy Reliability;p7; https://www.smartgrid.gov/files/Final_SGIG_Report_20161220.pdf.

12. Bloomberg New Energy Finance, U.S. Smart Grid and Smart Metering Forecasts, prepared for the U.S. Department of Energy (February 17, 2016).

13. Smart Grid Investment Grant Program Final Report December 2016; U.S. Department of Energy, Office of Electricity Delivery & Energy Reliability;p34; https://www.smartgrid.gov/files/Final_SGIG_Report_20161220.pdf.

14. Smart Grid Investment Grant Program Final Report December 2016; U.S. Department of Energy, Office of Electricity Delivery & Energy Reliability;p34; https://www.smartgrid.gov/files/Final_SGIG_Report_20161220.pdf.

1.3 Recent Investments into System Improvement

As referenced previously, 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 2018.

Table 1: EDO Primary Incremental System Reliability and Resiliency Improvement Programs

(Dollars in Thousands)

	Program Description	2010	2011	2012	2013	2014	2015	2016	2017	2018 (Forecast)
Capital	Distribution Automation								$ 10,715	$ 28,330
	Circuit Hardening/Reliability	$ 10,856	$ 7,273	$ 8,486	$ 14,484	$ 11,826	$ 10,692	$ 10,086	$ 10,318	$ 14,505
	Pole Inspection & Treatment Program	$ 8,568	$ 8,965	$ 9,680	$ 8,436	$ 10,723	$ 11,000	$ 10,758	$ 10,134	$ 11,901
	Aging Infrastructure Replacement				$ 5,838	$ 8,167	$ 13,063	$ 13,105	$ 18,137	$ 22,202
	N1DT Contingency Program						$ 2,632	$ 6,635	$ 5,628	$ 10,714
	DSCADA Expansion									$ 1,957
	Total Capital	**$ 19,424**	**$ 16,238**	**$ 18,166**	**$ 28,758**	**$ 30,716**	**$ 37,387**	**$ 40,584**	**$ 54,932**	**$ 89,609**
Expense	Hazard Tree Mitigation	$ 1,088	$ 5,852	$ 5,392	$ 5,020	$ 5,110	$ 5,458	$ 4,655	$ 2,896	$ 4,195
	Pole Inspection and Treatment	$ 328	$ 301	$ 472	$ 515	$ 631	$ 542	$ 277	$ 375	$ 490
	Total Expenses	**$ 1,416**	**$ 6,153**	**$ 5,864**	**$ 5,535**	**$ 5,741**	**$ 6,000**	**$ 4,932**	**$ 3,271**	**$ 4,685**

Table 1: EDO incremental system reliability and resiliency program funding — 2010–2018

- ***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 $15M in 2018.
- ***Pole Inspection and Treatment (PITP)*** — program provides for annual inspection, treatment, reinforcement, and replacement, where necessary, of approximately 7% 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-covered 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.
- ***Distribution Automation (DA)*** — program initiated in 2017 to 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.
- ***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 four to six million dollars annually since 2011.

2.0 2019 EDO Business Plan Reliability and Resiliency Strategy

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. The EDO 2019 Business Plan delivers a prudent system reliability and resiliency strategy which sustains this responsibility. The following assumptions adopted in the plan are founded on customer satisfaction surveys and industry intelligence.

- Customer reliance on electricity will continue to increase, with advancement of end use technologies and electrification of nearly everything. Accordingly, customer expectations respective to electric service safety, reliability, and quality will continue to evolve.
- Expectations for system resiliency and outage responsiveness will continue to grow in the face of increased grid vulnerabilities linked to severe and extreme weather, threats of cyber and physical attacks, and interference from wildlife and vegetation.
- Across the industry, customers, regulators, and community leaders will continue to push for modernization of the electric grid, effective interconnection of distributed energy resources, increased operational flexibility, and enhanced customer communications

In accordance with its Business Plan, EDO will address these ongoing issues and continue to deliver increasing value to its customers via the following initiatives:

- Invest in system reliability and contingency to meet increasing customer expectations respective to service availability
- Investment in aging infrastructure to continue long term service reliability
- Advance grid intelligence to meet evolving customer expectations and align with industry trends
- Respond to outage events in an efficient and effective manner, and continue to improve on the accuracy, timeliness, and provision of estimated restoration times
- Invest in and deploy technology which enhances business processes, reduces cycle times, and expands communications with customers.

Strategies and programs developed to enhance and sustain these initiatives are detailed in the remainder of this paper.

3.0 Centralized Grid Operations Strategy

EDO must continuously evaluate its operating strategies to increase efficiencies in day to day operations and in outage response. The recently approved Distribution Automation (DA) program provides enabling technology for development of an enhanced grid operations model. EDO is standardizing distribution grid operations with the current Oracle Network Management System (NMS) for integrating outage management and distribution management. Connectivity to field devices will utilize the OSI Systems, Incorporated (OSI) Monarch Supervisory Control and Data Acquisition (SCADA) platform, leveraging OSI's built-in interfaces with the Oracle NMS. SCADA functionality will include access to existing substation telemetry currently available in the transmission system's OSI Energy Management System (EMS), addition of SCADA capability at existing substations currently without SCADA, Distribution Automation (DA) reclosers, and capacitor controllers.

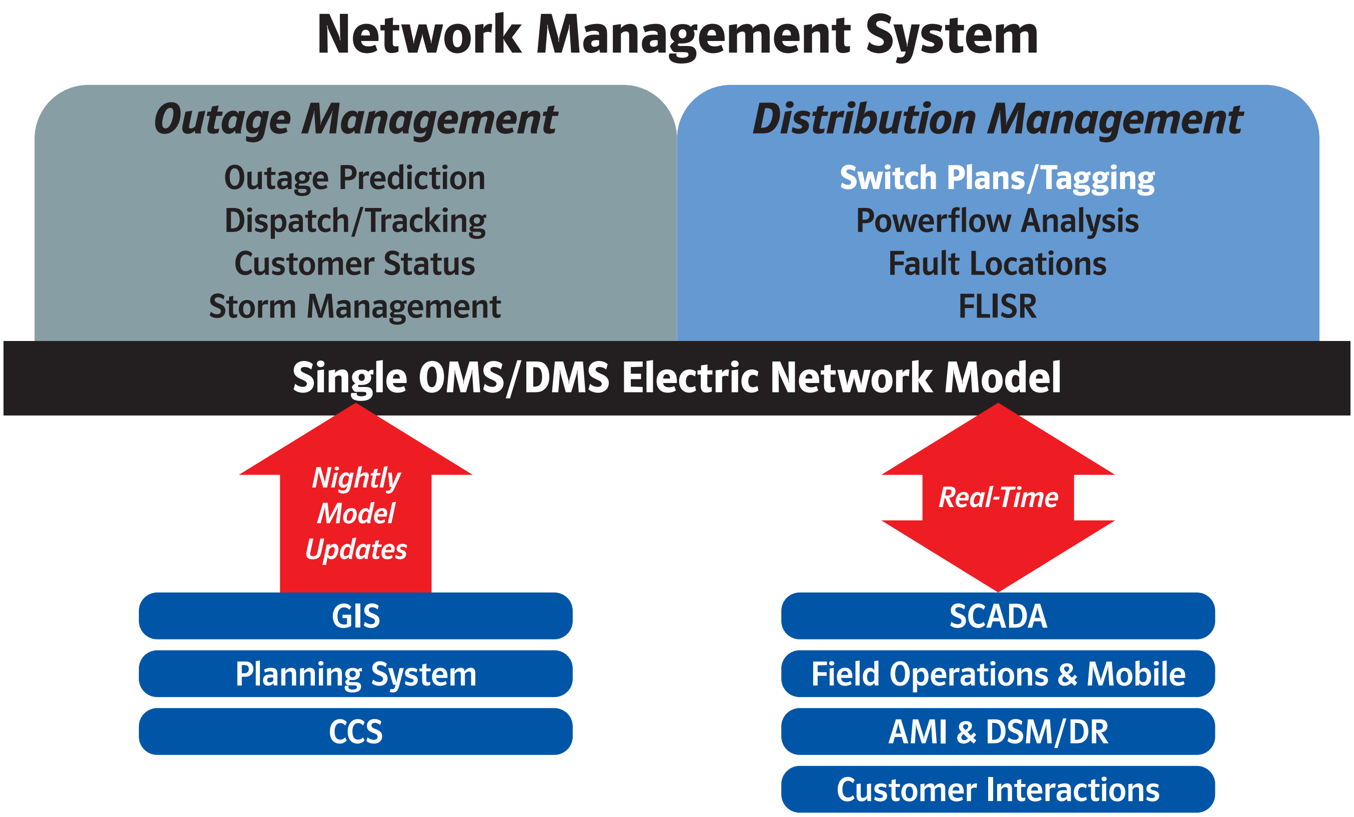


Figure 11: Centralized Grid Operation Systems.

In conjunction with the DA program, consolidation of two Distribution Control Centers (DCC) into one location presents the Company with a unique opportunity to standardize business processes and develop a centralized approach that will allow for 24x7 monitoring and control of the grid across LG&E and KU. This Centralized Grid Operations approach will enable the Company to proactively meet customers' expectations while positioning EDO to support future technologies such as Advanced Meter Systems (AMS) and Distributed Energy Resources (DER).

Today's customers are becoming less accepting of service interruptions or even momentary interruptions of less than five minutes. In order to manage these customer expectations, EDO is increasing the number of intelligent devices that can remotely communicate with the centralized grid operations group, DCC, allowing them to proactively monitor, control, and dispatch trouble crews even before customers may be aware of the problem. Key to the success of a centralized grid operating strategy is the implementation of a Distribution Management System (DMS), whereby advanced applications provide map based situational awareness capability, outage information, real-time power flow calculations, alarming, and fault identification and location. EDO's advanced DMS will provide FLISR (fault location, isolation, and service restoration) capability, the ability for the system to automatically isolate faulted distribution facilities and reroute power to minimize customer outage durations.

Future initiatives will focus around Centralized Grid Operations which will leverage a Distribution Management System as the focal point of LG&E and KU's overall capital model. Resiliency programs, circuit hardening, N1DT, and advancement of DA will be part of this overall EDO strategy.

4.0 Investment Strategy

Prudent investment strategies are fundamental to advancement of EDO's business plan initiatives. Results of analysis completed during EDO's 2018 planning process for the 2019 business plan indicated priority should be placed in the following areas:

- Continued development and enhancement of a centralized grid operation strategy
- Continuation, acceleration and extension of automation on the distribution system;
- Continued funding for the distribution substation transformer contingency program;
- Continuation of existing reliability improvement programs; and
- Continued expansion and in some cases, acceleration, of existing aging infrastructure replacement programs.

These investment strategies will continue to 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.

4.1 Investment Selection Methodology

In 2011, EDO began 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 capital 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 provided 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. The 2018 business planning process continued to support this conclusion.

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.

In addition to these programs, 2018 AIS analysis indicated priority should be given to Distribution SCADA expansion and accelerated or expanded aged asset replacement.

4.2 Reliability and Resiliency Programs

Table 2 provides a summary of EDO's strategic 2019-2023 reliability and resiliency capital and expense programs.

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

		(Dollars in Thousands)				
	Program Description	2019	2020	2021	2022	2023
Capital	Distribution Automation	$ 28,243	$ 23,974	$ 20,974		
	Circuit Hardening/Reliability	$ 17,963	$ 16,727	$ 22,088	$ 18,292	$ 18,954
	Pole Inspection & Treatment Program	$ 12,278	$ 12,646	$ 13,026	$ 13,417	$ 13,820
	Aging Infrastructure Replacement	$ 35,303	$ 33,594	$ 33,611	$ 16,179	$ 15,743
	N1DT Contingency Program	$ 14,997	$ 6,931	$ 17,691	$ 14,370	$ 9,000
	Distribution Automation Expansion				$ 4,250	$ 5,750
	DSCADA Expansion	$ 4,936	$ 4,998	$ 5,085	$ 5,000	$ 5,000
	Total Capital	**$ 113,720**	**$ 98,870**	**$ 112,475**	**$ 71,508**	**$ 68,266**
Expense	Hazard Tree Mitigation	$ 5,609	$ 5,026	$ 5,873	$ 5,265	$ 5,265
	Pole Inspection and Treatment	$ 506	$ 520	$ 535	$ 542	$ 558
	Total Expenses	**$ 6,115**	**$ 5,546**	**$ 6,408**	**$ 5,807**	**$ 5,823**

Table 2: EDO 2019-2023 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 234 of LG&E and KU's 1800 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 394,028 of 672,596 (58.5%) LG&E and KU distribution poles. More than 16,000 poles have been replaced under this program, and the contribution of pole related outages to SAIDI has dropped by approximately 32% 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.

4.2.1 Distribution Substation Transformer Contingency Program

The N1DT Contingency Program is a 15-year program that began in 2015 and will continue to be implemented through 2029. The purpose of the program is to enhance the LG&E and KU customer experience through improved reliability and reduced exposure to low probability, high consequence, and long duration service interruptions due to failure of a substation power transformer. Since the inception of the N1DT program in 2015, the number of transformers considered "at risk" has been reduced from 484 to 462 across KU and LG&E. This reduction of 24 transformers is a 5% improvement in the substation transformer related long term outage exposure to the electric distribution system.

4.2.2 Distribution Automation Expansion

Phase one of DA began in July 2017 and consists of a $112 million capital investment that will install 1,400 electronic SCADA connected reclosers and target approximately 360 (20%) distribution circuits and 50% of LG&E and KU customers. Phase one was initially planned to complete in 2022, but current acceleration efforts will likely see completion sometime in 2021. Through July 2018, EDO installed nearly 360 electronic reclosers which resulted in 6,281,428 avoided outage minutes including more than 16,763 avoided interruptions.

DA will continue expansion during 2022–2023 in order to provide centralized control capabilities along with DA's reliability benefits to all distribution circuits having a total of at least 500 customers and a serviceable circuit tie for switching (40% of all circuits, 70% of customers). Total DA investment will amount to approximately $144 million and the total number of reclosers installed will increase from 1,400 to about 1,900.

4.2.3 Substation SCADA Expansion

EDO has identified an opportunity to expand SCADA capabilities to KU substations across the state. Currently, approximately 20% of circuits in the KU service territory are equipped with SCADA connectivity - accounting for approximately 30% of KU customers (including ODP). Lack of SCADA capabilities to monitor and control these facilities is an operational hindrance to daily duties and delays circuit restoration following an outage event.

The expansion of SCADA capabilities will allow the Distribution Control Center, the centralized grid operator, to have the necessary information to identify outages and take remedial measures in real-time. Under this program, approximately 570 additional circuits will be upgraded and connected to SCADA by 2024. To accomplish this, over 150 legacy breakers and 300 electromechanical relays will be upgraded to modern technology — serving as an enabler for EDO's overall centralized grid operator strategy. Under this program, approximately 85% - 90% of all KU and ODP customers will be served from a SCADA connected circuit by 2024.

There are many overall benefits to substation SCADA capabilities. These benefits can be grouped into four categories: Operational Efficiencies, Emergency Response, Enhanced Worker Safety, and Improved System Data. Detailed below are each of these categories, along with the benefits they bring to the distribution system:

- ***Operational Efficiencies:*** Expanded SCADA functionality in KU and ODP substations provides DCC and field resources with the ability to know the status of station breakers quickly during an emergency, after an interruption, and during normal operations. The microprocessor relays that will be installed in substations will allow control center system operators to identify possible fault locations through the use of the DMS. Field personnel will then be directly dispatched to the trouble area identified, leading to faster restoration times and more efficient use of field resources. These efficiencies are estimated to reduce targeted circuit outages by 30 minutes on average. System operators will also be able to control breakers and components such as reclosers from the DCC, reducing the need for crews to visit the substation before and after performing live line work. Additionally, the feature rich microprocessor relaying will provide alarming and diagnostics data to system operations. Of significance is battery monitoring and alarming, which today is unavailable and places stations at significant risk for breaker failure operation and total loss of a station.
- ***Emergency Response:*** With the ability to remotely control substation assets, system operators will be able to quickly respond in times of emergency (e.g. 911 calls) and coordination during the restoration of a Transmission outage — providing for improved public safety and equipment protection. This is a valuable benefit, as response to such events can be time consuming and requires dispatching a person physically to the substation(s) to de-energize equipment.
- ***Enhanced Worker Safety:*** The upgraded relays bring a unique feature that enhances the safety for Company and contract crews performing live line maintenance. These advanced relays offer a "Hot Line Tag" (HLT) feature that goes above and beyond current practices for protecting line crews at the circuit breaker. The HLT option, when enabled, makes the device more sensitive to faults

resulting in faster clearing times and potentially reducing impacts of arc flash situations.

- ***Improved System Data:*** Capturing data will enhance Distribution's and Transmission's abilities to analyze real-time situations and have the best information to make decisions. For Distribution, circuit loading data will provide the operator information to know if an overload is occurring and/or other circuits' conditions in the area if action is required. Transmission Operations will benefit from additional system data to further improve State Estimator and Power Flow results — two analyses that drive operator action on the transmission system. System data will also be extremely beneficial for Distribution Planning to compare and optimize planning models with the actual, coincidental circuit data, aiding in capital project prioritization.

4.2.4 Aged Asset Replacement

LG&E and KU will continue investments targeted toward aged asset replacement. The LG&E and KU Distribution system is comprised of a mix of old and new equipment. On the system, old equipment that is well beyond its designed operating life is being relied on to reliably and effectively serve customers. While this equipment has performed well over the years, the Companies believe proactive replacement is the prudent alternative to maintain reliable service, advance distribution system operations, and effectively manage costs. As such equipment on the system ages, risk of failure rises. For the company to effectively manage operational costs, these devices must be replaced proactively rather than upon failure. Failures of these types of equipment typically result in long duration outages, additional associated equipment damage, and more expensive installation costs. Additionally, equipment such as this requires extensive periodic and preventative maintenance practices compared to its modern day equivalent technology. Proactively replacing these aged assets allows the company to more effectively manage capital and operational costs.

During 2018, EDO's Asset Management department performed a study to evaluate all asset classes pertaining to electric distribution equipment and determine if the current asset replacement strategies adequately mitigate potential asset failures. This evaluation took into account overall condition and reliability of each asset class to estimate the likelihood of failure. Further, consideration was given to distribution system criticality and potential customer impact of each asset class to infer consequences associated with asset failure. Asset condition was evaluated via technologies such as infrared scans, dissolved gas analysis, power factor testing and internal inspection results. Asset reliability and performance was reflected through review of maintenance history and failure rates. Assessment of asset class probabilities of failure and associated consequences enabled development of an overall risk profile identifying asset classes at greatest risk for failure and in most need of replacement. The resulting replacement priority was compared to existing asset replacement programs to identify potential need for acceleration of current programs and to establish new programs if needed.

Oil filled substation breakers, electromechanical relays, and copper and copper-clad overhead conductor were found to have a need for prudent, proactive replacement. The current replacement program addressing oil filled substation breakers will be accelerated based on the study results. The LG&E and KU systems contain over 180 substation oil filled circuit breakers. These breakers are 50+ years old and beyond their designed in-service life.

The LG&E and KU systems contain more than 5,900 electromechanical relays. In addition to the risk associated with failure, electromechanical relays are simple in design and limit the companies' ability to advance distribution system operations. As part of a strategy to move to a more centralized, smarter distribution system, the replacement of these relays with more advanced microprocessor relays is needed. These relays will provide the additional information needed to better leverage existing IT systems - allowing operators and field technicians to more quickly locate faults and restore service following an outage.

In addition to aging substation assets, distribution lines contain assets near end of life as well. Equipment such as copper and copper-weld conductor is a legacy construction method that requires preventative attention. These conductors become brittle over time and are subject to break when contacted by vegetation. Detailed design and engineering is required to cost effectively replace this equipment. It is not feasible to replace upon failure, as a typical installation may be hundreds of feet long.

5.0 Summary

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. 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 and are consistent with industry best practice. To meet evolving customer expectations respective to electric service safety, reliability, and quality, EDO's 2018 DRRIP and 2019-2023 Business Plan provide for the following high-level investment strategies.

- Continued development and enhancement of a centralized grid operation strategy
- Continuation and extension of automation on the distribution system;
- Continued funding for the distribution substation transformer contingency program;
- Continuation of existing reliability improvement programs; and
- Continued expansion of existing aging infrastructure replacement programs.

These investment strategies will continue to 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.

Exhibit LEB-6

Smart Grid Investments

Smart Grid Investments
2019 BP
$000

Project	2019	2020	2021	2022	2023	Total	January 1, 2018 to October 31, 2019
LG&E							
Distribution and Customer Services:							
Advanced Metering Systems (AMS) Opt In DSM	250	30	32	33	34	378	312
Distribution Automation	16,557	14,384	14,384	2,550	3,450	51,325	28,457
Electro-Mechanical Relay Replacement	3,000	2,500	2,500	2,500	2,500	13,000	2,673
Fuse Savings Pilot	350	350	490			1,190	302
Transmission:							
Control Houses	-	-	2,062	2,065	1,875	6,002	29
Fiber/Telecom	-	-	-	-	-	-	-
Relay Panels	3,959	2,542	2,178	2,171	2,873	13,722	6,801
RTU's	610	874	1,120	1,125	1,302	5,031	900
Switch - Auto	371	-	-	-	-	371	2,348
Switch - Motor Operated	156	507	-	-	-	663	391
Total LG&E	25,253	21,187	22,766	10,443	12,033	91,682	42,213
KU							
Distribution and Customer Services:							
Advanced Metering System (AMS) Opt In DSM	250	31	32	33	34	378	554
Distribution Automation	11,686	9,590	6,590	1,700	2,300	31,866	23,808
Electro-Mechanical Relay Replacement	3,000	2,500	2,500	2,500	2,500	13,000	2,776
Fuse Savings Pilot	150	150	210			510	130
KU SCADA Expansion	4,936	4,998	5,085	5,000	5,000	25,019	6,525
Transmission:							
Control Houses	3,687	5,242	4,464	3,994	3,520	20,906	5,845
Fiber/Telecom	-	345	349	-	-	694	-
Relay Panels	2,535	4,999	4,517	4,386	5,722	22,159	4,737
RTU's	2,573	2,843	2,133	2,119	2,359	12,027	3,804
Switch - Auto	953	683	-	-	-	1,636	4,013
Switch - Motor Operated	3,079	1,737	1,795	2,238	-	8,849	3,644
Total KU	32,850	33,118	27,675	21,969	21,434	137,046	55,837

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

ELECTRONIC APPLICATION OF KENTUCKY UTILITIES COMPANY FOR AN ADJUSTMENT OF ITS ELECTRIC RATES	**)**	**CASE NO. 2018-00294**

In the Matter of:

ELECTRONIC APPLICATION OF LOUISVILLE GAS AND ELECTRIC COMPANY FOR AN ADJUSTMENT OF ITS ELECTRIC AND GAS RATES	**)**	**CASE NO. 2018-00295**

TESTIMONY OF
DAVID S. SINCLAIR
VICE PRESIDENT, ENERGY SUPPLY AND ANALYSIS
KENTUCKY UTILITIES COMPANY AND
LOUISVILLE GAS AND ELECTRIC COMPANY

Filed: September 28, 2018

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 Kentucky Utilities Company ("KU") and Louisville Gas and Electric Company ("LG&E") (collectively "Companies"), and an employee of LG&E and KU Services Company, which provides services to KU and LG&E. My business address is 220 West Main Street, Louisville, Kentucky 40202.

Q. Have you previously testified before the Kentucky Public Service Commission ("Commission")?

A. Yes, I have testified before the Commission numerous times in a variety of cases.[1] I testified most recently in Case No. 2016-00370, *Application of Kentucky Utilities Company for an Adjustment of Its Electric Rates and for Certificates of Public Convenience and Necessity*, and Case No. 2016-00371, *Application of Louisville Gas and Electric Company for an Adjustment of Its Electric and Gas Rates and for Certificates of Public Convenience and Necessity*.

[1] Among other cases, I testified before the Commission in the following cases: Case No. 2015-00194, *In the Matter 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;* 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*. 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*.

Q. Please describe your job responsibilities.

A. I have four primary areas of responsibility: (i) fuel procurement (coal and natural gas) for the Companies' generating stations, (ii) real-time dispatch optimization of the generating stations to meet the Companies' native load obligations, (iii) wholesale market activities, and (iv) sales and market analysis and generation planning. As 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. 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 including the impact of the April 30, 2019 wholesale municipal contract termination; (3) explain the process for developing class load profiles, which are an input to the Cost of Service Study; (4) explain the Companies' forecast of generation and future resource mix; and (5) explain changes from the base period to the forecasted test period for operating revenues, sales for resale, and purchased power.

Q. Are you supporting any exhibits and schedules that are required by Commission regulation 807 KAR 5:001?

A. Yes, I am sponsoring (or co-sponsoring) the following exhibits and schedules for the corresponding filing requirements for both Companies:

- 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 you are sponsoring attached at Tab 16 of the Companies' Applications.

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) Electric Sales & Demand Forecast Process; (2) 2019 Business Plan Electric Sales Forecast; (3) Annual Natural Gas Volume Forecast Process; (4) 2019 Business Plan Gas Volume Forecast; (5) Class Load Profile Forecast Process; (6) Annual Generation Forecast Process; and (7) 2019 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 KU Electric Customers, Billing Demand, and Energy: Base Period vs. Forecasted Test Period
Exhibit DSS-2	Comparison of LG&E 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 "2019 Load Forecast." The electric load forecast process is essentially the same for both KU and LG&E and is described in the document at Tab 16 to the Companies' Applications entitled "Electric Sales & Demand Forecast Process." Basically 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, appliance efficiencies and adaptation, 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.

Q. Have the Companies materially changed their approach to electric load forecasting since their 2016 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 2019 Load Forecast reflects information that has become available since the 2016 rate cases such as updated actual load and customer data, updated national and regional economic forecasts, and updated model parameters.

Q. Have the Companies filed an integrated resource plan with the Commission since the 2016 rate cases?

A. No. The 2018 Integrated Resource Plan ("2018 IRP") will be filed no later than November 1, 2018, but I am hopeful that it will be filed before then. Regardless, the methods used to forecast load in the 2018 IRP and the 2019 Load Forecast are not materially different from those discussed in Section 7 of the prior 2014 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 …."[2] 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.[3]

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 economic conditions 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

[2] *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).
[3] *Id.* at 59.

or declining sales and customers, primarily driven by ongoing challenges facing the coal industry and limited success at attracting new businesses.

Q. Does the Companies' load forecast reflect the impact of the Companies' demand side management and energy efficiency ("DSM-EE") programs?

A. Yes. The load forecast reflects the demand and energy impacts of the Companies' past and future demand side management programs. The 2019 Load Forecast assumes the Commission will approve the Companies' most recent DSM-EE application.

Q. In addition to the Companies' DSM-EE programs, does the electric load forecast reflect other changes in end-use energy efficiency?

A. Yes. For example, 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 forecasts of both consumer adaptation and technology efficiency that are impacted by legislation and regulations of the energy efficiency of specific technologies. Recent years have seen rapid adoption of new LED lighting that is having a significant impact on energy utilization across all customer classes. The 2019 Load Forecast projects LED lighting adoption increasing at a faster rate than the forecast used in the 2016 rate cases. Figure 1 highlights the growth of LED lighting since 2014 and the potential for further energy reductions as LED's replace halogen lights, which use three to four times as much energy as an LED.

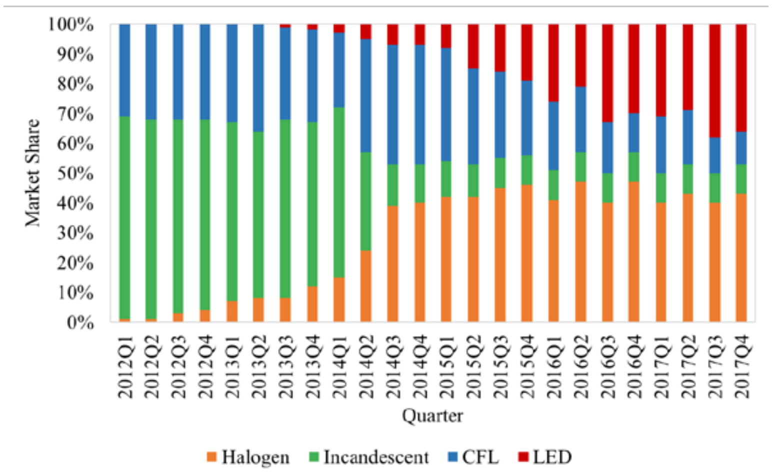


Figure 1 – U.S. Market Penetration by Lighting Type (%)

Q. Does the electric forecast reflect the impact of distributed solar generation and electric vehicles?

A. Yes, but the impact is negligible in the near term. The actual numbers of distributed generation resources and electric vehicles are both very small, and there is a great deal of uncertainty about how these technologies might grow, or not grow, in the future. According to the Electric Power Research Institute ("EPRI"), as of March 2018 there were 1,537 plug-in electric vehicles ("EVs") in the Companies' service territories. Assuming the average EV is driven 10,000 miles a year and that it requires 30 kWh per 100 miles of charge, this amounts to 2.1 GWh and 2.5 GWh of sales in the Forecasted Test Period for KU and LG&E, respectively, or less than 0.03 percent. Similarly, existing distributed generation resources are estimated to be around 1.7 MW at KU and 1.9 MW at LG&E of summer capacity as of March 2018, almost all of it in the form of solar generation. Assuming an annual capacity factor of 16 percent results in a reduction of energy sales in the Forecasted Test Period of 2.4

GWh and 2.6 GWh for KU and LG&E, respectively. Again, these volumes represent less the 0.03 percent of Forecasted Test Year energy.

Q. Please explain how weather is reflected in the electric load forecast.

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 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.[4] 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 2019 business plan?

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[4] *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.").

A. The 2019 Load Forecast that was used in preparing the 2019 business plan was completed in the spring of 2018. The electric load forecasts for KU and LG&E that were used in the 2019 business plan are attached at Tab 26 to the Applications.

Q. How was the 2019 Load Forecast used to develop class load shapes for the cost of service study?

A. The Companies utilize historical hourly load data by customer class to develop forecasted energy sales by class on an hourly basis. This process is essentially the same for both KU and LG&E and is described in detail in the document at Tab 16 to the Companies' Applications entitled "Class Load Profile Forecast Process." Part of this process includes various quality control and data integrity checks to ensure that the resulting forecasts of class profiles are reasonable.

<u>Section 3 – KU Electric Load Forecast</u>

Q. How are KU's customer count and electricity sales expected to change in the Forecasted Test Period as compared to the Base Period?

A. As shown in Exhibit DSS-1, from the Base Period (January 2018 through December 2018) to the Forecasted Test Period (May 2019 through April 2020), total retail KU calendar-adjusted electric sales decrease by 283 GWh (1.6 percent) and total customers increase by 3,278 (0.6 percent). The customer growth is consistent with what one would expect given the economic and other assumptions underlying the forecast.[5] 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.

[5] See Exhibit DSS-4 for detailed assumptions for the Forecasted Test Period.

Q. What is the impact of the departure of certain wholesale municipal customers on KU's electricity sales?

A. The departure of eight wholesale municipal customers on May 1, 2019 results in a sales reduction of 1,416 GWh from the Base Period to the Forecasted Test Period.

Q. Excluding the departing municipal customers, what accounts for the difference between the Base Period and the Forecasted Test Period?

A. As can be seen in Exhibit DSS-1, the RS, GS and PS-Secondary rate classes are the biggest drivers of the sales decline between the Base Period and the Forecasted Test Period. Including the Total KU unbilled adjustment, these classes explain 287 GWh of the total negative retail variance of 283 GWh between the two periods. 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 37 GWh annually to residential sales. However, 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 decreasing by 156 GWh (-265 GWh RS Energy variance offset by 108 GWh Residential Unbilled).

Q. What is driving the reductions in the GS and PS-Secondary forecasts compared to the Base Period?

A. At KU, PS-Secondary sales are declining as a result of decreased customers. The customer decline comes from both closings and movements to other rates such as GS. For both GS and PS-Secondary, commercial efficiencies continue to drive down the use-per-customer particularly in refrigeration and cooling.

Q. What is the impact of the unbilled sales adjustment on other customer classes?

A. The total unbilled sales adjustment is 122 GWh. The majority of the residential (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 (108 GWh) to the Base Period energy total for the RS rate class decreases the difference in energy from the Base Period to the Forecasted Test Period from 265 GWh to 156 GWh. The positive adjustment to align the Base Period with the Forecasted Test Period is reflective of high electric heating penetration and extremely cold weather from late December that is embedded in January billed data.

Q. Does weather explain any of the difference between the sales in the Base Period and the Forecasted Test Period?

A. Yes. The Base Period consists of actual billed data for the first six months and, therefore, reflects the actual weather during that time. On the other hand, sales in the last six months of the Base Period and the entire Forecasted Test Period are based on 20-year normal weather for the KU service area as described in Annual Electric Sales & Demand Forecast Process at Tab 16. Table 1 compares the actual monthly heating degree days ("HDDs") and cooling degree days ("CDDs") to their 20-year normal values. Temperature sensitive load would be higher than average in every month except February. The net result is that weather sensitive load should be higher in the Base Period as compared to the Forecasted Test Period for the months of January, and March through June. The Residential and Small Commercial classes are the most weather sensitive and this contributes to the decline in the RS, GS and PS-Secondary energy volumes.

	Actual	Average	Difference
January (HDD)	1,045	973	72
February (HDD)	563	805	(242)
March (HDD)	676	597	79
April (HDD)	423	273	150
May (CDD)	259	100	159
June (CDD)	329	254	75

Table 1 - Comparison of Actual and 20-year Average Weather for KU

Q. Please describe the primary differences in billing demands between the Base Period and the Forecasted Test Period.

A. As shown on Schedule DSS-1, billing demand is decreasing on the PS-Secondary, TOD-Primary, OSL, RTS, and FLS rates. At KU, PS-Secondary and RTS demand are decreasing in large part due to the decrease in energy. FLS and PS-Primary rates remain consistent with the small changes in the energy forecast and no customer count changes. The TOD-Primary and TOD-Secondary rates both have Base demand within 0.5 percent of the Base Period and reductions of less than 3 percent in the Intermediate and Peak periods.

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' 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 – LG&E Electric Load Forecast

Q. How are LG&E's customer count and electricity sales expected to change in the Forecasted Test Period as compared to the Base Period?

A. As can be seen in Exhibit DSS-2, from the Base Period (January 2018 through December 2018) to the Forecasted Test Period (May 2019 through April 2020), total LG&E calendar-adjusted electric sales decrease by 200 GWh (1.7 percent) and total customers increase by an average of 3,063 (0.7 percent). The customer growth forecast is 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.

Q. Why are sales decreasing between the Base Period and the Forecasted Test Period despite customer growth?

A. The major difference between Base Period and the Forecasted Test Period is a decline of 204 GWh including the unbilled adjustment in Residential Sales. Small gains in TOD-Primary and TOD-Secondary were generally offset by small declines in PS-Secondary and GS. Exhibit DSS-2 shows that the majority of LG&E's customer growth is coming from the residential (RS) rate class. Assuming each new customer is using about the same amount of energy as the average customer, new customers would add about 33 GWh annually to residential sales. However, some of this potential growth is being offset by energy efficiency impacts related to lighting and replacement of older appliances with more efficient models. Also, newer customers typically use less energy than older customers due to better insulated housing stock and more efficient appliances. Figure 2 shows the average monthly usage in 2017 of new premises in 2012, 2014, and 2016. There is a clear trend over just these four years as efficiencies drive down the energy for end-uses such as heating, cooling, and lighting as well as showing that they use more energy in the winter months as compared to the summer months due to an increasing share of all-electric homes.

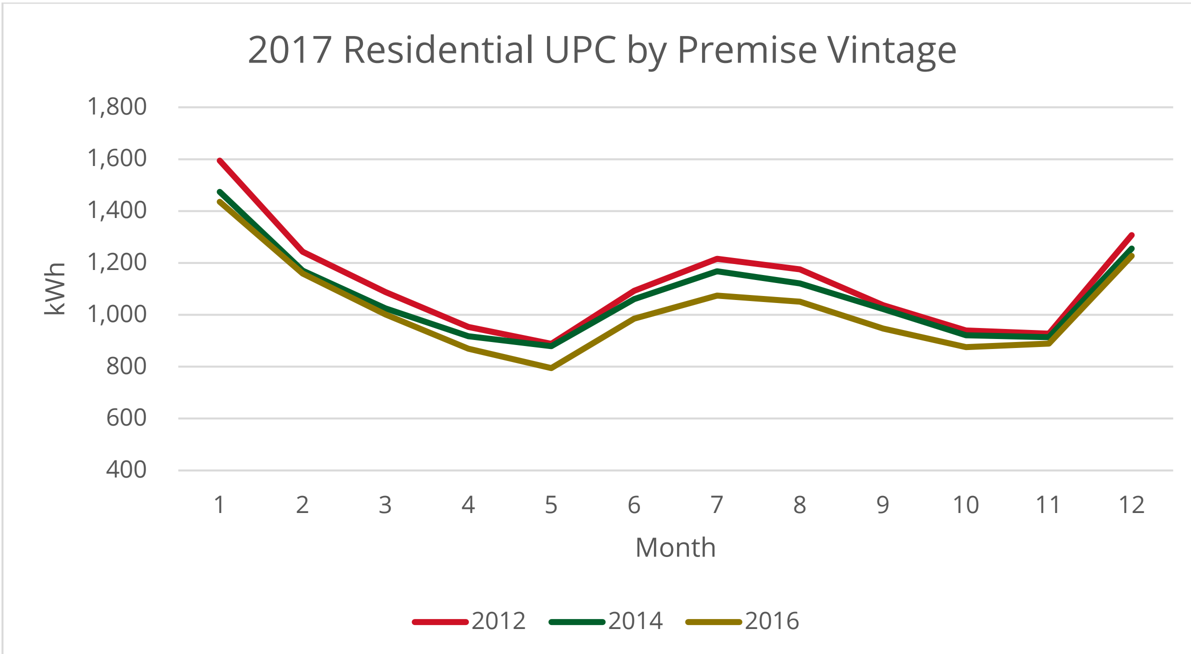

Figure 2 – LG&E Residential Use-Per-Customer by Premise Vintage

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 (45 GWh) to the Base Period energy of the RS rate class increases the change in energy from the Base Period to the Forecasted Test Period increases to 204 GWh. The unbilled adjustment for all other classes was zero and therefore has no impact on the comparison of the Base Period and Forecasted Test Period.

Q. Does weather explain any of the difference between the sales in the Base Period and the Forecasted Test Period?

A. Yes. The Base Period consists of actual billed data for the first six months and, therefore, reflects the actual weather during that time. On the other hand, sales in the last six months of the Base Period and the entire Forecasted Test Period are based on 20-year normal weather for the LG&E service territory 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 used in the forecast period. Based on the departure from "normal," temperature sensitive load would be higher than average in every month except February, which was milder. The high market share of gas heating in the LG&E service territory means that the colder winter temperatures in January, March, and April had less of an impact on electricity sales than did the warmer than normal temperatures in May and June. The net result is that weather sensitive load should be higher in the Base Period as compared to the Forecasted Test Period for the months of January, and March through June.

	Actual	Average	Difference
January (HDD)	1,019	922	97
February (HDD)	588	754	(166)
March (HDD)	637	543	94
April (HDD)	395	224	171
May (CDD)	306	135	171
June (CDD)	395	319	76

Table 2 - Comparison of Actual and 20-year Average Weather for LG&E

Q. Please describe the primary differences in billing demands between the Base Period and the Forecasted Test Period.

A. As can be seen on Exhibit DSS-2, billing demand volumes are decreasing in the PS-Primary, PS-Secondary, TOD-Secondary, and RTS classes. This is consistent with recent trends in these particular rate classes. Figure 3 shows an example of recent history with LG&E PS-Secondary demand including the Base Period and Forecasted Test Period volumes shown in Exhibit DSS-2. The consistent decline despite a distinctly seasonal pattern with summer cooling load highlights the efficiency improvements across all end-uses in Commercial customers. The decline in LG&E RTS Base demand is the result of a particular customer's billing demand returning to normal in the Forecasted Test Period following unusually high billing demand in the Base Period. Their high demand was the result of abnormally high utilization due to high river levels in Louisville in February 2018. This impacts Base, Intermediate, and Peak demands but the variance is greater in the Base demand period with a 100% ratchet and this event occurring in the second month of the Base Period.

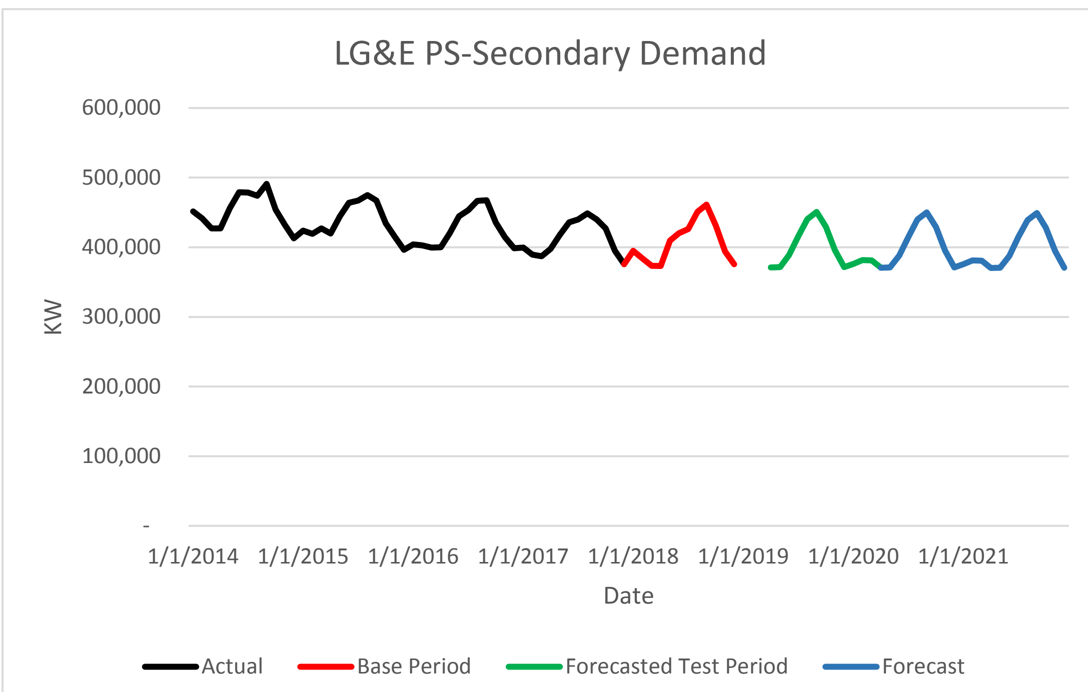

Figure 3 – LG&E PS-Secondary Demand

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' 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 2019 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. As shown in Exhibit DSS-3, from the Base Period (January 2018 through December 2018) to the Forecasted Test Period (May 2019 through April 2020), natural gas sales increase by 492,919 Mcf (1.6 percent) and total customers increase by 985 (0.3 percent). Comparing the same time periods, volumes for transportation customers decrease by 1,040,735 Mcf (7.1 percent).

Q. What explains the 1.6% increase in gas sales from the Base Period to the Forecasted Test Period?

A. Mild weather in February 2018 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 February 2018 were almost 25 percent lower than the 30-year normal values used in developing the forecast volumes for the same months in the Forecasted Test Period.[6] This milder weather in February 2018 caused gas sales to consumers in the Base Period to be 1,566,632 Mcf lower than February 2020 sales in the Forecasted Test Period. Ninety-eight percent of this variance is from the Residential and Commercial customer classes, which are the most weather-sensitive with usage driven by space heating. While April experienced colder than normal weather, the absolute number of HDDs are significantly less than other winter months so it did not have a large impact on gas utilization.

	Actual	Average	Difference
January (HDD)	993	916	77
February (HDD)	566	750	-184
March (HDD)	601	539	62
April (HDD)	371	232	139

Table 3 - Comparison of Actual and 30-year Average Weather for LG&E

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, but the rate also includes other customers who are not forecasted individually. As shown in Exhibit DSS-3, the "Gas Transport Service, FT Industrial" rate class decreased by 794,751 Mcf (5.9 percent) in the Forecasted Test Period.

[6] 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.

Strong sales at two individually forecasted customers in the Actual portion of the Base Period account for 201,155 Mcf of this variance as shown in Table 4. They are not forecasting similar volumes in the Forecasted Test Period.

	Base Period				
(Volumes in Mcf)	**Actual Jan 18–Jun 18**	**Forecasted Jul 18-Dec 18**	**Total Jan 18-Dec 18**	**Forecasted Test Period May 19-Apr 20**	**Variance**
Customer 1	222,712	111,005	333,717	213,040	(120,678)
Customer 2	211,031	191,456	402,488	322,010	(80,477)
Other Individually Forecasted	5,275,679	4,333,098	9,608,777	9,602,044	(6,733)
Total	5,709,422	4,635,560	10,344,981	10,137,093	(207,888)

Table 4 – Individually Forecasted Gas Major Accounts

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 gas base-rate cases.

<u>Section 6 – Electric and Gas Forecast Summary</u>

Q. Please summarize your opinions on the 2019 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 2019 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 2019 Load Forecast a reasonable forecast that can be relied upon in the development of the 2019 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 2019 Load Forecast fully meets the criteria I just discussed and is a reasonable forecast upon which to base the business plan.

Section 7 – Generation Forecast

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 KU and LG&E 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 "Generation Forecast Process" attached at Tab 16 of the Companies' Applications.

Q. Why is the Companies' generation system jointly planned and dispatched?

A. Generation units are jointly dispatched by KU and LG&E to achieve operational efficiencies associated with serving their combined loads. Pursuant to the Companies' *Power Supply System Agreement* filed with the Federal Energy Regulatory Commission ("FERC"), the joint planning objectives of the Companies are to maximize the economy, efficiency, and reliability of their combined systems as a whole. Dispatch of generation, whether from the Companies' own generating resources or from purchased power, is determined by lowest variable operating cost regardless of ownership that is required to maintain system reliability. Therefore it is reasonable to view the Companies' generation systems from the perspective of the combined KU and LG&E system.

Q. What are the primary reasons for differences in the generation volumes in the Forecasted Test Period compared to the Base Period?

A. The primary reason for differences in generation volumes in the Forecasted Test Period compared to the Base Period is the decreased load forecast due to the departure of the eight municipal customers on May 1, 2019. Coal generation decreases by 8 percent, most notably at Brown Units 1 and 2 with their retirement in February 2019. The only coal units with increased generation in the Forecasted Test Period are Mill Creek Units 2 and 4 and Trimble County Unit 2, which have reduced generation during the Base Period due to their planned outages. Cane Run Unit 7 generation decreases by 5 percent, partly due to its planned outage in spring of 2020. Generation from simple-cycle combustion turbines increases by 10 percent due to increased coal unit planned outages during fall of 2019. Other unit-by-unit differences are primarily attributable to the timing and duration of outages.

Q. You mentioned the decline in forecasted generation due in part to the departure of the eight municipal customers on May 1, 2019. Please provide an overview of the actions the Companies have taken to address this loss of load.

A. When the Companies received the nine municipal customers' termination notices in April 2014, they took action to mitigate the impact of the municipals' departure, which at that time was forecasted to reduce summer peak by approximately 285 MW and annual energy by approximately 1,700 GWh. First, in August 2014 the Companies withdrew their then-pending application seeking Commission approval to build Green River Unit 5, a 670 MW natural gas combined cycle generating unit that would have been similar to Cane Run Unit 7.[7] Second, to address a need for short-term capacity, the Companies secured 165 MW via a Commission-approved purchased power agreement from Bluegrass Unit 3 through April 2019 to ensure adequate energy supply for customers prior to the departure of the municipal load.[8] Based on the Companies' then-current load projections, these actions were sufficient to address the municipal load departure while maintaining an adequate level of generation reliability.

Q. In addition to these actions, have there been or will there be other changes to the Companies' generation fleet since 2014?

A. Yes. In November 2017, KU announced plans to retire the 106 MW Unit 1 and the 166 MW Unit 2 at the E.W. Brown Generating Station in February 2019, which came on-line in 1957 and 1963, respectively. In addition, LG&E plans to retire the 50+ year old 14 MW Zorn simple-cycle combustion turbine within the next three years. Both of these decisions will reduce costs for customers while maintaining an adequate level of generation reliability.

Q. Was the decision to retire Brown 1 and Brown 2 related to the municipal contract termination?

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[7] *In the Matter of: Joint Application of Louisville Gas and Electric Company and Kentucky Utilities Company for a Certificate of Public Convenience and Necessity 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, LG&E and KU Notice of Withdrawal of Their Application for a Certificate of Public Convenience and Necessity for the Construction of Green River NGCC and Motion for Resumption of this Proceeding for Brown Solar Facility (Ky. PSC Aug. 22, 2014).

[8] *In the Matter of: Application of Louisville Gas and Electric Company and Kentucky Utilities Company for a Declaratory Order and Approval Pursuant to KRS 278.300 for a Capacity Purchase and Tolling Agreement*, Case No. 2014-00321 (Ky. PSC Nov. 24, 2014).

A. No. As I just mentioned, the Companies addressed the municipal contract termination in 2014 by withdrawing their application to build Green River 5. The ability to retire Brown 1 and Brown 2 without replacement is the result of a nearly 500 MW decrease in forecasted retail load since 2014. If the municipals had not terminated, Green River 5 would have come online in 2018 and the decline in forecasted retail load would have still enabled the Companies' to lower environmental compliance costs by retiring Brown 1 and Brown 2 without replacement.

Q. What is the Companies' forecasted summer reserve margin after the municipal termination and after the retirement of Brown 1 and Brown 2?

A. Based on the 2019 Load Forecast, the Companies' forecasted reserve margin for the summer of 2019 is 23.5 percent.

Q. What do you anticipate the Companies' target summer reserve margin will be in the upcoming 2018 IRP?

A. Based on the long-run marginal cost of the Companies' existing resources, I anticipate the target summer reserve margin range will be 17 to 25 percent. Because winter peak demands are more volatile than summer peak demands, the Companies require more reserves (relative to the forecasted summer and winter peak demand) in the winter months than in the summer months. The equivalent reserve margin range in the winter is 28 to 38 percent.

Q. Is having an adequate summer and winter reserve margin the only determinant of generation reliability?

A. Absolutely not. Reserve generation, both online spinning generation reserves and offline supplemental generation reserves, are required to ensure reliable operation of the electric system in accordance with Good Utility Practice. The Open Access Transmission Tariff ("OATT") requires the Transmission Owner to provide certain services that require having reserve generation, namely OATT *Schedule 3 – Regulation and Frequency Response Service, Schedule 4 – Energy Imbalance Service, Schedule 5 – Operating Reserve – Spinning Reserve Service, Schedule 6 – Operating Reserve – Supplemental Reserve Service, and Schedule 9 – Generator Imbalance Service*. These Ancillary Services are essential to the reliable operation of the electric system because they (1) provide balancing of resources (generation and interchange) with load and for maintaining scheduled interconnection frequency at sixty cycles per second (60 Hz), (2) ensure instantaneous and scheduled load levels greater those anticipated by load serving entities can be served, (3) serve load immediately in the event of a system contingency, and (4) supplement generator forced outages until backup supply or schedules can be implemented. These Ancillary Services are part and parcel to compliance with the NERC families of Reliability Standards entitled *Resource and Demand Balancing* (BAL), *Emergency Preparedness and Operations* (EOP), and *Transmission Operations* (TOP).

Q. Does each of the Companies' supply-side and demand-side resources have the capability to provide all of these grid reliability services?

A. No. The Companies' coal units, natural gas combined cycle ("NGCC") unit, and large-frame simple-cycle combustion turbines ("SCCTs") are critically important for grid reliability, but the grid reliability services provided by the other resources are limited. All of the Companies' coal units have load-following capabilities and can be dispatched with less than a day's notice to serve load. With high ramp rates, the Companies' NGCC unit and large-frame SCCTs can respond to significant load swings and can be dispatched with little notice in response to forced outages. The Companies' small-frame SCCTs and demand-side resources have no load-following capabilities. While they could be dispatched in response to forced outages, they require more notice than large-frame SCCTs or NGCC units and their availability is significantly lower. In addition, because of their small size, their impact in responding to the forced outage of a larger unit is limited. Finally, the Companies' renewable resources provide no grid reliability services.

Q. Do all of the Companies' supply-side and demand-side resources have the same availability and long-term reliability characteristics?

A. No. Considering the need for maintenance, the Companies' coal, NGCC, and large-frame SCCTs can be available to be utilized up to 90 percent of the hours in a year. However, the Companies' small-frame SCCTs are close to 50 years old and are therefore far less reliable than the large-frame SCCTs. The Demand Conservation Program ("DCP") that is part of the Companies' DSM-EE program portfolio can be called upon up to twenty times in the summer months, but the variable cost of this program limits the Companies' use of it to extreme circumstances, and the magnitude of the program's load reductions is weather-dependent. Finally, the Curtailable Service Rider ("CSR") limits the Companies' ability to curtail participating customers to hours when all available units have been dispatched or are being dispatched. As a result, the ability to utilize this program is limited to at most a handful of hours each year, and then the magnitude of load reductions depends on participating customers' load during the hours when they are called upon.

The long-term reliability of the small-frame SCCTs, CSR, and DCP is also limited. Because of their age, the Companies plan to limit spending on the small-frame SCCTs and retire the units when significant investment is needed for their continued operation. As evidenced by the 2013 retirement of Haefling 3 and plans to retire Zorn 1 within the next three years, the remaining useful lives of the small-frame SCCTs are limited. The long-term reliability of the CSR and the DCP is also limited because customers that participate in these programs can opt out of these programs with little to no notice (6 months' notice for CSR customers and no notice for DCP customers).

Q. What is the Companies' summer reserve margin excluding the small-frame SCCTs, CSR, and DCP?

A. Excluding these resources, the Companies' forecasted reserve margin for the summer of 2019 is 18.1 percent. Notably, decreasing the Companies' forecasted reserve margin to this level would result in having a reserve margin at the low end of the target summer reserve margin range I anticipate the 2018 IRP will recommend (i.e., 17 to 25 percent). In addition, retiring the small-frame SCCTs and terminating the CSR and DCP programs would have little to no impact on system revenue requirements but would reduce summer peak-hour reliability.

Q. In your professional opinion, is the 2019 generation forecast reasonable and can it be relied upon in the development of the 2019 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 processes and software were also reviewed in the Companies' 2016 base-rate cases. Using sound models and assumptions produces reasonable forecasts.

Section 8 – Schedule D-1 Support

Q. Does your testimony support the Jurisdictional Adjustments to Base Period for Operating Revenues from Sales of Electricity in Schedule D-1?

A. Yes. For the reasons I have stated, the volumetric changes to both KU's and LG&E's electric and gas load forecasts serve as a driver for the differences in Operating Revenues from Sales of Electricity (Account Nos. 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. Purchased Power contains intercompany purchased power expense, market economy purchased power expense, Ohio Valley Electric Corporation ("OVEC") purchase power expense, and (for LG&E) non-fuel expenses associated with the Bluegrass tolling agreement, which terminates in April 2019. Intercompany sales revenue for one company in Account No. 447 equals the intercompany purchased power expense for the other company in Account No. 555. Off-System Sales ("OSS") revenues recorded to Account No. 447 and OSS-related purchased power expenses recorded to Account No. 555 have been removed with a pro forma adjustment.

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, KU's Sales for Resale are expected to increase by $2 million, from $4.9 million to $6.9 million; LG&E's Sales for Resale in the Forecasted Test Period are expected to increase by $4.9 million, from $32.7 million to $37.6 million. The primary drivers of LG&E's $4.9 million increase are the increase in intercompany sales from LG&E to KU due to the retirement of KU's Brown Units 1 and 2 and during the planned maintenance periods of Ghent Units 1 and 4 (owned by KU) and Cane Run Unit 7 (78 percent owned by KU).

Compared to the Base Period, KU's Purchased Power is expected to be higher by $11 million; LG&E's Purchased Power in the Forecasted Test Period is expected to be lower by $3 million. KU's change is explained by higher demand charges projected for purchased power from OVEC due to expectations for OVEC to collect in advance for repayments of a portion of its debt due in 2019, as well as the increase in intercompany purchased power expense associated with the aforementioned retirement of Brown Units 1 and 2 and the planned maintenance of Ghent Units 1 and 4 and Cane Run Unit 7. LG&E's change is explained primarily by the savings realized by the termination of the Bluegrass tolling agreement at the end of April 2019, which is partially offset by higher demand charges projected for purchased power from OVEC.

Q. Does this conclude your testimony?

A. Yes, it does.

VERIFICATION

COMMONWEALTH OF KENTUCKY)
)
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

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 19th day of September 2018.

Judy Schooler
Notary Public

My Commission Expires:
Judy Schooler
Notary Public, ID No. 603967
State at Large, Kentucky
Commission Expires 7/11/2022

APPENDIX A

David S. Sinclair

Vice President, Energy Supply and Analysis
Kentucky Utilities Company
Louisville Gas and Electric Company
220 West Main Street
Louisville, Kentucky 40202
(502) 627-4653

Education

Arizona State University, M.B.A. -1991
Arizona State University, M.S. in Economics – 1984
University of Missouri, Kansas City, B.A. in Economics - 1982

Professional Experience

LG&E and KU Energy, LLC
2008-present – Vice President, Energy Supply and Analysis
2000-2008 – Director, Energy Planning, Analysis and Forecasting

LG&E Energy Marketing, Louisville, Kentucky
1997-1999 – Director, Product Management
1997-1997 (4th Quarter) – Product Development Manager
1996-1996 – Risk Manager

LG&E Power Development, Fairfax Virginia
1994-1995 – Business Developer

Salt River Project, Tempe, Arizona
1992-1994 – Analyst, Corporate Planning Department

Arizona Public Service, Phoenix, Arizona
1989-1992 – Analyst, Financial Planning Department
1986-1989 – Analyst, Forecasts Department

State of Arizona, Phoenix, Arizona
1983-1986 – Economist, Arizona Department of Economic Security

Affiliations

Consensus Forecasting Group (2013-present) - nonpartisan group of economists that monitor Kentucky's revenues and the economy on behalf of the governor and legislature.

Civic Activities

Serve on the Board of Junior Achievement of Kentuckiana

Graduate of Leadership Louisville (2008) and Bingham Fellows (2011)

Exhibit DSS-1

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 (Jan '18 - Jun '18)*	Base Period: Calendar Forecasted (Jul '18 - Dec '18)	Base Period: Total (Jan '18 - Dec '18)	Forecasted Test Period (May '19 - Apr '20)	Difference	% Difference
KU RETAIL										
AES	Customers	Avg Number of Customers			510	561	535	558	23	4.3%
	Energy	Sum of Volume	GWh		75	66	140	132	(8)	-5.9%
EV_Charge	Customers	Avg Number of Customers			3	8	5	10	5	93.5%
	Energy	Sum of Volume	GWh		0	0	0	0	0	89.9%
FLS	Customers	Avg Number of Customers			1	1	1	1	-	0.0%
	Demand	Sum of Volume	MVA	Base	1,220	1,212	2,432	2,388	(44)	-1.8%
	Demand	Sum of Volume	MVA	Intermediate	1,213	1,191	2,404	2,381	(23)	-0.9%
	Demand	Sum of Volume	MVA	Peak	834	823	1,657	1,646	(11)	-0.7%
	Energy	Sum of Volume			326	309	635	622	(12)	-2.0%
GS	Customers	Avg Number of Customers			83,363	83,956	83,659	84,439	780	0.9%
	Energy	Sum of Volume	GWh		914	901	1,815	1,740	(75)	-4.1%
OSL	Customers	Avg Number of Customers			6	6	6	6	(0)	-2.7%
	Demand	Sum of Volume	MW	Base	5	2	7	5	(2)	-24.7%
	Demand	Sum of Volume	MW	Peak	2	1	2	1	(1)	-33.3%
	Energy	Sum of Volume	GWh		0	0	0	0	(0)	-11.8%
PS-Pri	Customers	Avg Number of Customers			207	206	206	206	(0)	-0.2%
	Demand	Sum of Volume	MW	Base	203	217	420	422	2	0.6%
	Energy	Sum of Volume	GWh		69	74	143	144	1	0.6%
PS-Sec	Customers	Avg Number of Customers			4,561	4,511	4,536	4,470	(66)	-1.5%
	Demand	Sum of Volume	MW	Base	2,800	2,851	5,651	5,474	(177)	-3.1%
	Energy	Sum of Volume	GWh		920	959	1,879	1,809	(70)	-3.7%
RS	Customers	Avg Number of Customers			433,737	433,855	433,796	436,362	2,566	0.6%
	Energy	Sum of Volume	GWh		3,351	2,879	6,229	5,965	(265)	-4.3%
RTOD	Customers	Avg Number of Customers			41	49	45	62	17	36.9%
	Demand	Sum of Volume	MW	Base	-	-	-	-	-	0.0%
	Demand	Sum of Volume	MW	Peak	-	-	-	-	-	0.0%
	Energy	Sum of Volume	GWh		0	0	1	1	0	27.5%
RTS	Customers	Avg Number of Customers			25	25	25	25	-	0.0%
	Demand	Sum of Volume	MVA	Base	1,712	1,675	3,387	3,357	(30)	-0.9%
	Demand	Sum of Volume	MVA	Intermediate	1,557	1,494	3,051	2,986	(65)	-2.1%
	Demand	Sum of Volume	MVA	Peak	1,540	1,492	3,032	2,989	(43)	-1.4%
	Energy	Sum of Volume	GWh		749	732	1,481	1,473	(9)	-0.6%
TOD-Pri	Customers	Avg Number of Customers			256	258	257	259	2	0.8%
	Demand	Sum of Volume	MVA	Base	5,219	5,148	10,367	10,332	(35)	-0.3%
	Demand	Sum of Volume	MVA	Intermediate	4,268	4,481	8,749	8,644	(105)	-1.2%
	Demand	Sum of Volume	MVA	Peak	4,213	4,417	8,630	8,525	(105)	-1.2%
	Energy	Sum of Volume			1,960	2,069	4,029	4,030	1	0.0%
TOD-Sec	Customers	Avg Number of Customers			702	725	714	736	22	3.1%
	Demand	Sum of Volume	MW	Base	2,826	2,763	5,589	5,598	9	0.2%
	Demand	Sum of Volume	MW	Intermediate	2,123	2,164	4,287	4,174	(113)	-2.6%
	Demand	Sum of Volume	MW	Peak	2,070	2,110	4,180	4,068	(112)	-2.7%
	Energy	Sum of Volume	GWh		875	932	1,807	1,838	31	1.7%
Lighting	Customers	Avg Number of Customers			936	796	866	796	(70)	-8.1%
	Energy	Sum of Volume	GWh		64	62	126	126	(0)	-0.2%
KU Unbilled Adjustment**										
Residential	Energy	Sum of Volume	GWh		(108)		(108)		108	-100.0%
Other	Energy	Sum of Volume	GWh		(14)		(14)		14	-100.0%
Total KU Unbilled	Energy	Sum of Volume	GWh				(122)		122	-100.0%
KU WHOLESALE										
Municipal - Departing	Customers	Avg Number of Customers			8	8	8	-	(8)	-100.0%
	Demand	Sum of Volume	MW	Base	1,387	1,412	2,799	-	(2,799)	-100.0%
	Energy	Sum of Volume	GWh		681	736	1,416	-	(1,416)	-100.0%
Municipal - Remaining	Customers	Avg Number of Customers			2	2	2	2	-	0.0%
	Demand	Sum of Volume	MW	Base	400	404	804	814	9	1.2%
	Energy	Sum of Volume	GWh		205	213	418	422	4	1.0%

Total KU KY Retail Energy - Calendar Adjusted	Energy	Sum of Volume	GWh		9,182	8,982	18,164	17,881	(283)	-1.6%
Total KU KY Energy - Calendar Adjusted	Energy	Sum of Volume	GWh		10,067	9,931	19,998	18,303	(1,696)	-8.5%
Total KU Customers	Customers	Avg Number of Customers			524,347	524,956	524,652	527,929	3,278	0.6%

*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 January include a portion of the energy consumed in January and a portion of the energy consumed in December. Likewise, billed sales for June include a portion of the energy consumed in June and a portion of the energy consumed in May. The portion of the energy consumed in June but not included in June billed sales is the "unbilled" portion of calendar-month ("calendar") sales for June. To properly compare the Base Period to the Forecasted Test Period (which includes twelve months of calendar sales), unbilled sales for June must be added to the Base Period and unbilled sales for December (which are included in January billed sales) must be subtracted from the Base Period. Because June unbilled sales are less than December unbilled sales, the total unbilled sales adjustment is negative.

Exhibit DSS-2

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 (Jan '18 - Jun '18)*	Base Period: Calendar Forecasted (Jul '18 - Dec '18)	Base Period: Total (Jan '18 - Dec '18)	Forecasted Test Period (May '19 - Apr '20)	Difference	% Difference
PS-Pri	Customers	Avg Number of Customers			64	63	63	63	(0)	-0.5%
	Demand	Sum of Volume	MW	Base	183	212	395	283	(112)	-28.3%
	Energy	Sum of Volume	GWh		46	54	100	107	7	6.9%
PS-Sec	Customers	Avg Number of Customers			2,854	2,878	2,866	2,894	28	1.0%
	Demand	Sum of Volume	MW	Base	2,361	2,540	4,901	4,775	(126)	-2.6%
	Energy	Sum of Volume	GWh		853	899	1,753	1,739	(14)	-0.8%
TOD-Pri	Customers	Avg Number of Customers			128	126	127	128	1	1.1%
	Demand	Sum of Volume	MVA	Base	2,638	2,701	5,339	5,383	43	0.8%
	Demand	Sum of Volume	MVA	Intermediate	2,179	2,266	4,445	4,438	(7)	-0.1%
	Demand	Sum of Volume	MVA	Peak	2,117	2,237	4,354	4,358	3	0.1%
	Energy	Sum of Volume	GWh		989	1,035	2,024	2,040	16	0.8%
TOD-Sec	Customers	Avg Number of Customers			424	423	423	434	11	2.6%
	Demand	Sum of Volume	MW	Base	1,750	1,684	3,434	3,404	(30)	-0.9%
	Demand	Sum of Volume	MW	Intermediate	1,332	1,302	2,633	2,589	(44)	-1.7%
	Demand	Sum of Volume	MW	Peak	1,294	1,284	2,578	2,525	(53)	-2.1%
	Energy	Sum of Volume	GWh		576	599	1,175	1,189	13	1.1%
Special Contract #1	Customers	Avg Number of Customers			2	2	2	2	-	0.0%
	Demand	Sum of Volume	MW	Base	59	56	116	112	(3)	-2.7%
	Energy	Sum of Volume	GWh		28	29	56	57	1	1.0%
GS	Customers	Avg Number of Customers			45,835	45,714	45,774	45,931	156	0.3%
	Energy	Sum of Volume	GWh		630	673	1,303	1,280	(23)	-1.8%
EV Charge	Customers	Avg Number of Customers			4	8	6	10	4	66.7%
	Energy	Sum of Volume	GWh		0	0	0	0	0	50.7%
OSL	Customers	Avg Number of Customers			1	1	1	1	-	0.0%
	Demand	Sum of Volume	MW	Base	1	1	2	2	(0)	-0.6%
	Demand	Sum of Volume	MW	Peak	0	0	0	0	(0)	-56.6%
	Energy	Sum of Volume	GWh		0	0	0	0	(0)	-28.7%
RS	Customers	Avg Number of Customers			367,450	367,870	367,660	370,507	2,847	0.8%
	Energy	Sum of Volume	GWh		2,043	2,193	4,236	4,077	(159)	-3.8%
RTOD	Customers	Avg Number of Customers			54	61	57	74	16	28.4%
	Demand	Sum of Volume	MW	Base	0	0	0	0	0	1.8%
	Demand	Sum of Volume	MW	Peak	0	0	0	0	0	7.2%
	Energy	Sum of Volume	GWh		0	0	1	1	0	6.5%
RTS	Customers	Avg Number of Customers			13	13	13	13	-	0.0%
	Demand	Sum of Volume	MVA	Base	1,259	1,310	2,570	2,362	(207)	-8.1%
	Demand	Sum of Volume	MVA	Intermediate	1,108	1,064	2,172	2,089	(83)	-3.8%
	Demand	Sum of Volume	MVA	Peak	1,087	1,045	2,132	2,063	(69)	-3.2%
	Energy	Sum of Volume	GWh		527	525	1,052	1,056	4	0.4%
Lighting	Customers	Avg Number of Customers			1,121	1,119	1,120	1,119	(1)	-0.1%
	Energy	Sum of Volume	GWh		55	54	109	109	(0)	0.0%
LG&E Unbilled Adjustment**										
Residential	Energy	Sum of Volume	GWh		45		45		(45)	-100.0%
Other	Energy	Sum of Volume	GWh		0		0		(0)	-100.0%
Total LG&E Unbilled	Energy	Sum of Volume	GWh		45		45		(45)	-100.0%
Total LG&E Energy - Calendar Adjusted	Energy	Sum of Volume	GWh		5,792	6,062	11,854	11,654	(200)	-1.7%
Total LGE Customers	Customers	Avg Number of Customers			417,949	418,277	418,113	421,175	3,063	0.7%

*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 January include a portion of the energy consumed in January and a portion of the energy consumed in December. Likewise, billed sales for June include a portion of the energy consumed in June and a portion of the energy consumed in May. The portion of the energy consumed in June but not included in June billed sales is the "unbilled" portion of calendar-month ("calendar") sales for June. To properly compare the Base Period to the Forecasted Test Period (which includes twelve months of calendar sales), unbilled sales for June must be added to the Base Period and unbilled sales for December (which are included in January billed sales) must be subtracted from the Base Period. Because June unbilled sales are greater than December 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

Rate	Category	Volume Type	Values	Base Period Billed Actual (Jan '18 - Jun '18)*	Base Period Calendar Forecasted (Jul '18 - Dec '18)	Base Period Total (Jan '18 - Dec '18)	Forecasted Test Period (May '19 - Apr '20)	Difference	% Difference
As-Available Gas Service, Commercial	Gas Volumes	Sales	Volume (Mcf)	51,273	32,566	83,839	73,678	(10,161)	-12.1%
	Customers	Sales	Average Number of Customers	2	2	2	2	-	0.0%
As-Available Gas Service, Industrial	Gas Volumes	Sales	Volume (Mcf)	29,278	49,382	78,660	72,373	(6,287)	-8.0%
	Customers	Sales	Average Number of Customers	2	2	2	2	-	0.0%
Distributed Generation Gas Service	Gas Volumes	Sales	Volume (Mcf)	11	5	16	8	(7)	-46.0%
	Customers	Sales	Average Number of Customers	1	2	2	2	0	26.3%
Firm Commercial Gas Service	Gas Volumes	Sales	Volume (Mcf)	7,342,260	3,745,489	11,087,748	9,951,330	(1,136,418)	-10.2%
	Customers	Sales	Average Number of Customers	25,438	24,890	25,164	25,078	(86)	-0.3%
Firm Industrial Gas Service	Gas Volumes	Sales	Volume (Mcf)	808,682	689,964	1,498,646	1,443,313	(55,333)	-3.7%
	Customers	Sales	Average Number of Customers	244	244	244	246	2	0.7%
Gas Special Contracts - LG&E Generation	Gas Volumes	Generation	Volume (Mcf)	171,950	195,390	367,340	404,400	37,061	10.1%
	Customers	Generation	Average Number of Customers	1	1	1	1	-	0.0%
Gas Transport Service, FT Commercial	Gas Volumes	Transport	Volume (Mcf)	323,051	292,161	615,212	571,880	(43,332)	-7.0%
	Customers	Transport	Average Number of Customers	9	9	9	9	-	0.0%
Gas Transport Service, FT Industrial	Gas Volumes	Transport	Volume (Mcf)	6,980,846	6,533,753	13,514,598	12,719,847	(794,751)	-5.9%
	Customers	Transport	Average Number of Customers	65	67	66	68	2	3.4%
Residential Gas Service	Gas Volumes	Sales	Volume (Mcf)	14,113,518	6,768,925	20,882,443	19,344,465	(1,537,979)	-7.4%
	Customers	Sales	Average Number of Customers	298,448	297,376	297,912	298,980	1,068	0.4%
Substitute Gas Sales Service	Gas Volumes	Sales	Volume (Mcf)	12,226	683	12,909	1,498	(11,411)	-88.4%
	Customers	Sales	Average Number of Customers	1	1	1	1	-	0.0%
TS-2: Gas Trans/Firm Balancing (AAGS In)	Gas Volumes	Transport	Volume (Mcf)	95,929	77,447	173,376	69,851	(103,525)	-59.7%
	Customers	Transport	Average Number of Customers	2	2	2	1	(1)	-45.5%
TS-2: Gas Transport/Firm Balancing (IGS)	Gas Volumes	Transport	Volume (Mcf)	184,322	265,157	449,479	350,352	(99,127)	-22.1%
	Customers	Transport	Average Number of Customers	6	6	6	5	(1)	-13.0%
LG&E Gas Unbilled Adjustment**									
Residential	Gas Volumes	Sales	Volume (Mcf)	(2,198,491)		(2,198,491)		2,198,491	-100.0%
Other	Gas Volumes	Sales	Volume (Mcf)	(1,052,024)		(1,052,024)		1,052,024	-100.0%
Total LGE Gas Unbilled	Gas Volumes	Sales	Volume (Mcf)	(3,250,515)		(3,250,515)		3,250,515	-100.0%

Total Volumes - Calendar Adjusted	Gas Volumes	Total	Volume (Mcf)	26,862,830	18,650,921	45,513,751	45,002,996	(510,755)	-1.1%
Total Customers	Customers	Total	Average Number of Customers	324,218	322,601	323,409	324,395	985	0.3%
Total Sales Volumes - Calendar Adjusted	Gas Volumes	Sales	Volume (Mcf)	19,106,732	11,287,015	30,393,747	30,886,666	492,919	1.6%
Total Customers	Customers	Sales	Average Number of Customers	324,135	322,517	323,326	324,311	985	0.3%
Total Transport Volumes	Gas Volumes	Transport	Volume (Mcf)	7,584,148	7,168,516	14,752,665	13,711,930	(1,040,735)	-7.1%
Total Customers	Customers	Transport	Average Number of Customers	82	83	82	83	1	0.8%
Total Generation Volumes	Gas Volumes	Generation	Volume (Mcf)	171,950	195,390	367,340	404,400	37,061	10.1%
Total Customers	Customers	Generation	Average Number of Customers	1	1	1	1	-	0.0%

*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 January include a portion of the energy consumed in January and a portion of the energy consumed in December. Likewise, billed sales for June include a portion of the energy consumed in June and a portion of the energy consumed in May. The portion of the energy consumed in June but not included in June billed sales is the "unbilled" portion of calendar-month ("calendar") sales for June. To properly compare the Base Period to the Forecasted Test Period (which includes twelve months of calendar sales), unbilled sales for June must be added to the Base Period and unbilled sales for December (which are included in January billed sales) must be subtracted from the Base Period. Because June unbilled sales are less than December unbilled sales, the total unbilled sales adjustment is negative.

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)
2007 Q1	14,873.73	161,458.00	214.03	77.13	103.55
2007 Q2	14,830.36	162,254.00	214.27	77.27	105.20
2007 Q3	14,418.74	162,175.00	213.00	77.00	104.66
2007 Q4	14,783.81	163,832.00	212.97	76.63	104.37
2008 Q1	15,020.57	164,088.00	212.93	76.93	104.52
2008 Q2	15,354.63	165,252.00	211.63	76.57	103.32
2008 Q3	15,612.18	162,150.00	210.50	76.20	99.22
2008 Q4	16,013.28	158,432.00	207.47	75.50	94.98
2009 Q1	16,471.52	155,943.00	203.27	73.50	88.91
2009 Q2	16,716.16	154,402.00	202.07	72.40	86.75
2009 Q3	17,092.67	155,945.00	201.30	71.73	87.97
2009 Q4	17,558.89	158,985.00	200.40	71.80	89.11
2010 Q1	18,037.77	158,978.00	200.10	71.67	90.45
2010 Q2	18,417.22	163,316.00	200.40	71.60	92.86
2010 Q3	18,762.38	165,616.00	200.60	71.80	94.47
2010 Q4	19,120.16	165,761.00	201.13	71.77	94.94
2011 Q1	19,486.41	163,540.00	201.03	71.77	94.64
2011 Q2	14,726.02	164,531.00	201.03	71.70	94.69
2011 Q3	14,838.66	165,790.00	201.00	72.47	96.15
2011 Q4	14,938.47	168,986.00	201.70	72.33	97.49
2012 Q1	14,991.78	167,776.00	202.53	72.43	98.60
2012 Q2	14,889.45	168,346.00	203.07	72.67	99.69
2012 Q3	14,963.36	166,812.00	202.67	72.80	100.56
2012 Q4	14,891.64	164,474.00	202.73	73.17	101.15
2013 Q1	14,576.99	168,802.00	202.67	73.73	101.62
2013 Q2	14,375.02	167,574.00	202.57	73.77	101.96
2013 Q3	14,355.56	168,201.00	203.43	73.90	102.08
2013 Q4	14,402.48	168,647.00	204.43	73.87	103.07
2014 Q1	14,541.90	167,639.00	203.80	74.17	104.04
2014 Q2	14,604.85	169,346.00	204.80	74.20	105.90
2014 Q3	14,745.93	169,786.00	205.40	73.97	106.92
2014 Q4	14,845.46	169,915.00	207.03	74.13	107.23
2015 Q1	14,939.00	168,919.00	208.53	74.20	106.69
2015 Q2	14,881.30	170,523.00	209.23	74.33	105.60
2015 Q3	14,989.56	171,038.00	210.13	74.87	106.46
2015 Q4	15,021.15	172,849.00	210.53	75.13	105.94
2016 Q1	15,190.26	169,452.00	213.47	75.53	106.36
2016 Q2	15,291.04	172,344.00	213.53	76.07	107.06
2016 Q3	15,362.42	174,809.00	215.37	76.03	108.07
2016 Q4	15,380.80	174,678.00	215.77	76.67	108.14
2017 Q1	15,384.25	174,162.00	214.67	77.67	109.45
2017 Q2	15,491.88	175,749.00	212.13	78.30	109.68
2017 Q3	15,521.56	176,710.00	214.83	77.40	108.17
2017 Q4	15,641.34	177,667.69	215.17	76.63	110.33
2018 Q1	15,793.93	178,470.91	215.23	76.99	111.50
2018 Q2	15,757.57	179,432.47	214.97	77.32	111.82
2018 Q3	15,935.83	180,432.45	214.76	77.65	112.49
2018 Q4	16,139.51	181,369.24	214.85	78.02	113.35
2019 Q1	16,220.22	182,593.98	215.20	78.23	114.33
2019 Q2	16,349.97	183,704.54	215.09	78.45	115.40
2019 Q3	16,460.89	184,782.95	215.16	78.74	116.40
2019 Q4	16,527.59	185,622.88	215.05	78.99	117.15
2020 Q1	16,547.62	186,168.84	215.07	79.05	117.98
2020 Q2	16,571.57	186,833.09	215.05	79.14	118.43
2020 Q3	16,663.52	187,382.80	215.23	79.27	118.82
2020 Q4	16,778.15	187,978.54	214.88	79.37	119.20
2021 Q1	16,851.42	188,730.97	214.25	79.54	119.83
2021 Q2	16,903.24	189,440.82	213.75	79.57	120.33
2021 Q3	17,031.09	190,137.77	213.22	79.60	120.83
2021 Q4	17,163.89	190,721.69	212.76	79.60	121.21
2022 Q1	17,272.47	191,491.69	211.91	79.63	121.69
2022 Q2	17,373.11	192,116.84	211.29	79.63	122.10
2022 Q3	17,499.82	192,817.46	210.62	79.66	122.44
2022 Q4	17,619.62	193,435.43	209.98	79.68	122.80
2023 Q1	17,743.01	194,142.22	209.14	79.75	123.35
2023 Q2	17,868.27	194,643.24	208.59	79.77	123.85
2023 Q3	17,988.43	195,350.24	208.01	79.81	124.33
2023 Q4	18,097.75	195,945.43	207.44	79.85	124.66

	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
2007 Q1	112.50	155,617.12	4,247.31	1,660.22	2.56
2007 Q2	114.07	156,162.02	4,256.67	1,661.38	2.56
2007 Q3	117.24	156,090.84	4,264.97	1,669.17	2.56
2007 Q4	117.44	156,478.83	4,273.28	1,677.01	2.55
2008 Q1	117.97	158,371.50	4,281.58	1,684.88	2.54
2008 Q2	115.00	163,012.63	4,289.88	1,692.78	2.53
2008 Q3	109.53	157,537.78	4,296.68	1,694.96	2.53
2008 Q4	102.22	158,835.52	4,303.48	1,697.15	2.54
2009 Q1	88.52	157,406.84	4,310.28	1,699.33	2.54
2009 Q2	80.82	158,522.81	4,317.07	1,701.52	2.54
2009 Q3	80.31	157,360.16	4,324.50	1,707.50	2.53
2009 Q4	81.32	157,745.85	4,331.92	1,713.64	2.53
2010 Q1	83.40	157,410.19	4,339.34	1,719.97	2.52
2010 Q2	87.30	159,626.73	4,347.95	1,722.13	2.52
2010 Q3	91.03	160,853.73	4,353.09	1,719.08	2.53
2010 Q4	93.03	161,104.53	4,358.23	1,716.02	2.54
2011 Q1	93.84	163,015.49	4,363.37	1,712.97	2.55
2011 Q2	95.62	163,070.10	4,368.51	1,709.92	2.55
2011 Q3	97.03	164,241.62	4,372.30	1,718.64	2.54
2011 Q4	97.76	164,738.37	4,376.09	1,727.36	2.53
2012 Q1	98.28	165,344.71	4,379.88	1,736.07	2.52
2012 Q2	99.90	166,089.61	4,383.67	1,744.79	2.51
2012 Q3	100.94	165,039.59	4,387.54	1,744.44	2.52
2012 Q4	100.86	166,628.41	4,391.40	1,744.09	2.52
2013 Q1	102.90	162,987.83	4,395.26	1,743.74	2.52
2013 Q2	101.59	163,144.83	4,399.12	1,743.39	2.52
2013 Q3	101.48	163,777.01	4,401.94	1,745.01	2.52
2013 Q4	104.29	163,904.81	4,404.77	1,746.63	2.52
2014 Q1	105.89	166,696.60	4,407.59	1,748.24	2.52
2014 Q2	106.89	168,769.05	4,410.42	1,749.86	2.52
2014 Q3	106.82	170,036.42	4,413.33	1,750.88	2.52
2014 Q4	106.35	172,696.30	4,416.24	1,751.90	2.52
2015 Q1	105.43	173,720.12	4,419.15	1,752.92	2.52
2015 Q2	105.75	175,329.66	4,422.06	1,753.94	2.52
2015 Q3	106.12	175,739.93	4,425.57	1,754.32	2.52
2015 Q4	104.94	178,042.17	4,429.09	1,754.70	2.52
2016 Q1	105.20	175,207.05	4,432.60	1,755.09	2.53
2016 Q2	105.55	176,073.04	4,436.11	1,755.47	2.53
2016 Q3	105.74	177,032.56	4,440.63	1,758.28	2.53
2016 Q4	106.37	175,336.49	4,445.15	1,760.65	2.52
2017 Q1	107.00	175,291.80	4,449.67	1,763.46	2.52
2017 Q2	106.34	175,744.58	4,454.19	1,765.11	2.52
2017 Q3	105.24	176,178.39	4,458.78	1,767.95	2.52
2017 Q4	106.58	177,188.05	4,463.45	1,771.43	2.52
2018 Q1	107.67	178,013.57	4,468.20	1,775.34	2.52
2018 Q2	108.97	179,280.98	4,473.02	1,779.58	2.51
2018 Q3	109.99	180,271.12	4,477.91	1,783.10	2.51
2018 Q4	111.20	181,634.79	4,482.87	1,786.84	2.51
2019 Q1	112.14	183,654.83	4,487.89	1,791.25	2.51
2019 Q2	113.13	185,049.23	4,493.09	1,795.68	2.50
2019 Q3	113.86	186,343.50	4,498.44	1,800.42	2.50
2019 Q4	114.41	187,486.36	4,503.85	1,804.76	2.50
2020 Q1	114.79	188,793.14	4,509.28	1,808.93	2.49
2020 Q2	114.95	189,944.27	4,514.73	1,812.99	2.49
2020 Q3	115.15	190,858.84	4,520.19	1,816.97	2.49
2020 Q4	115.20	191,730.88	4,525.65	1,820.69	2.49
2021 Q1	115.28	193,077.25	4,531.10	1,824.72	2.48
2021 Q2	115.33	193,917.08	4,536.54	1,828.59	2.48
2021 Q3	115.45	194,777.79	4,541.97	1,832.73	2.48
2021 Q4	115.57	195,677.14	4,547.38	1,836.81	2.48
2022 Q1	115.80	196,814.51	4,552.78	1,840.18	2.47
2022 Q2	116.05	197,662.61	4,558.17	1,843.84	2.47
2022 Q3	116.35	198,488.59	4,563.54	1,847.40	2.47
2022 Q4	116.72	199,358.21	4,568.89	1,850.76	2.47
2023 Q1	117.13	200,729.31	4,574.22	1,854.25	2.47
2023 Q2	117.58	201,524.56	4,579.53	1,857.65	2.47
2023 Q3	118.08	202,313.01	4,584.82	1,860.93	2.46
2023 Q4	118.62	203,096.23	4,590.09	1,864.38	2.46

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	320	0	(320)	-100%
Brown 2	661	0	(661)	-100%
Brown 3	1,260	670	(590)	-47%
Ghent 1	2,898	2,662	(236)	-8%
Ghent 2	3,241	2,866	(375)	-12%
Ghent 3	2,276	2,256	(20)	-1%
Ghent 4	2,714	2,432	(282)	-10%
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	243	236	(6)	-3%
Trimble County 1	N/A	N/A		
Trimble County 2	2,385	2,791	406	17%
SCCT				
Bluegrass/EKPC[2]	N/A	N/A		
Brown 5	48	76	28	57%
Brown 6	87	99	12	14%
Brown 7	81	42	(38)	-47%
Brown 8	28	23	(6)	-21%
Brown 9	20	25	5	24%
Brown 10	28	36	8	30%
Brown 11	10	17	6	60%
Cane Run 11	N/A	N/A		
Haefling	0	1	1	0%
Paddy's Run 11	N/A	N/A		
Paddy's Run 12	N/A	N/A		
Paddy's Run 13	52	70	19	36%
Trimble County 05	135	283	149	110%
Trimble County 06	123	217	94	76%
Trimble County 07	142	138	(4)	-3%
Trimble County 08	117	63	(54)	-46%
Trimble County 09	99	38	(61)	-61%
Trimble County 10	26	18	(8)	-30%
Zorn 1	N/A	N/A		
NGCC				
Cane Run 7	3,901	3,697	(204)	-5%
Hydro				
Dix Dam	113	82	(31)	-28%
Ohio Falls	N/A	N/A		
Solar				
Brown Solar	11	11	0	1%
Total Coal	15,997	13,912	(2,086)	-13%
Total SCCT	996	1,147	151	15%
Total NGCC	3,901	3,697	(204)	-5%
Total Hydro	113	82	(31)	-28%
Total Solar	11	11	0	1%
Grand Total	21,018	18,849	(2,170)	-10%

[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	1,990	1,814	(176)	-9%
Mill Creek 2	1,490	1,653	162	11%
Mill Creek 3	2,476	2,023	(453)	-18%
Mill Creek 4	2,641	3,020	380	14%
OVEC	558	544	(13)	-2%
Trimble County 1	2,518	2,318	(199)	-8%
Trimble County 2	559	655	95	17%
SCCT				
Bluegrass/EKPC[4]	58	0	(58)	-100%
Brown 5	55	86	31	57%
Brown 6	53	61	7	14%
Brown 7	49	26	(23)	-47%
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	1	1	0%
Haefling	N/A	N/A		
Paddy's Run 11	0	0	0	0%
Paddy's Run 12	0	1	1	0%
Paddy's Run 13	58	79	21	36%
Trimble County 05	55	116	61	110%
Trimble County 06	50	89	38	76%
Trimble County 07	83	81	(2)	-3%
Trimble County 08	68	37	(32)	-46%
Trimble County 09	58	23	(36)	-61%
Trimble County 10	15	11	(5)	-30%
Zorn 1	0	1	1	0%
NGCC				
Cane Run 7	1,100	1,043	(57)	-5%
Hydro				
Dix Dam	N/A	N/A		
Ohio Falls	247	300	53	22%
Solar				
Brown Solar	7	7	0	1%
Total Coal	12,231	12,028	(204)	-2%
Total SCCT	605	609	5	1%
Total NGCC	1,100	1,043	(57)	-5%
Total Hydro	247	300	53	22%
Total Solar	7	7	0	1%
Grand Total	14,190	13,987	(203)	-1%

[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	320	0	(320)	-100%
Brown 2	661	0	(661)	-100%
Brown 3	1,260	670	(590)	-47%
Ghent 1	2,898	2,662	(236)	-8%
Ghent 2	3,241	2,866	(375)	-12%
Ghent 3	2,276	2,256	(20)	-1%
Ghent 4	2,714	2,432	(282)	-10%
Mill Creek 1	1,990	1,814	(176)	-9%
Mill Creek 2	1,490	1,653	162	11%
Mill Creek 3	2,476	2,023	(453)	-18%
Mill Creek 4	2,641	3,020	380	14%
OVEC	800	781	(20)	-2%
Trimble County 1	2,518	2,318	(199)	-8%
Trimble County 2	2,944	3,445	501	17%
SCCT				
Bluegrass/EKPC[6]	58	0	(58)	-100%
Brown 5	103	162	59	57%
Brown 6	140	160	19	14%
Brown 7	130	68	(62)	-47%
Brown 8	28	23	(6)	-21%
Brown 9	20	25	5	24%
Brown 10	28	36	8	30%
Brown 11	10	17	6	60%
Cane Run 11	0	1	1	0%
Haefling	0	1	1	0%
Paddy’s Run 11	0	0	0	0%
Paddy’s Run 12	0	1	1	0%
Paddy’s Run 13	110	149	39	36%
Trimble County 05	190	399	209	110%
Trimble County 06	174	306	133	76%
Trimble County 07	225	219	(6)	-3%
Trimble County 08	185	99	(86)	-46%
Trimble County 09	157	61	(96)	-61%
Trimble County 10	41	29	(12)	-30%
Zorn 1	0	1	1	0%
NGCC				
Cane Run 7	5,001	4,740	(261)	-5%
Hydro				
Dix Dam	113	82	(31)	-28%
Ohio Falls	247	300	53	22%
Solar				
Brown Solar	18	18	0	1%
Total Coal	28,229	25,939	(2,289)	-8%
Total SCCT	1,601	1,756	155	10%
Total NGCC	5,001	4,740	(261)	-5%
Total Hydro	360	382	22	6%
Total Solar	18	18	0	1%
Grand Total	35,209	32,836	(2,373)	-7%

[5] Generation volumes reflect the Companies’ ownership share of the unit.
[6] Capacity Purchase and Tolling Agreement with Bluegrass Generation/EKPC

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

ELECTRONIC APPLICATION OF KENTUCKY UTILITIES COMPANY FOR AN ADJUSTMENT OF ITS ELECTRIC RATES	**)))**	**CASE NO. 2018-00294**

In the Matter of:

ELECTRONIC APPLICATION OF LOUISVILLE GAS AND ELECTRIC COMPANY FOR AN ADJUSTMENT OF ITS ELECTRIC AND GAS RATES	**))))**	**CASE NO. 2018-00295**

TESTIMONY OF
GREGORY J. MEIMAN
VICE PRESIDENT, HUMAN RESOURCES
KENTUCKY UTILITIES COMPANY AND
LOUISVILLE GAS AND ELECTRIC COMPANY

Filed: September 28, 2018

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

A. My name is Gregory J. Meiman. I am Vice President, Human Resources for 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 ("Service Company"). My business address is 220 West Main Street, Louisville, Kentucky 40202.

Q. Please describe your educational and professional background.

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

Q. Have you previously testified before this Commission?

A. Yes. I submitted written direct testimony in Case No. 2014-00002,[1] while serving in my prior position as Director of Corporate Tax and Benefit Plan Compliance for the Companies. In the Companies' 2016 rate cases,[2] I appeared at the evidentiary hearing and answered questions in my then and still current capacity as Vice President, Human Resources for the Companies.

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

A. The purpose of my testimony is to inform the Commission of the overall reasonableness of the compensation and benefits structure we offer to current and prospective employees. More specifically, I will: (1) explain the Companies'

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[1] *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.

[2] *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.

compensation and employee benefit expenses and sponsor a schedule required by 807 KAR 5:001, Section 16, as set forth at Tab 60 of the filing requirements attached to the Applications; (2) describe the results of Willis Towers Watson's ("WTW") *Target Total Cash Compensation Study* which examines the Companies' mix of base and incentive pay compared to market; and (3) describe the results of the study prepared by Mercer (a national employee benefits consulting firm) which examines the Companies' retirement and welfare benefits offerings compared to market. My testimony shows that the Companies diligently manage compensation and benefit offerings so that they are reasonable, prudent, market competitive, and, therefore, should be fully recovered in rates.

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

A. Yes. I am sponsoring Section 16(8)(g), analyses of payroll costs including schedules for wages and salaries, employee benefits, payroll taxes, straight time and overtime hours, and executive compensation by title.

I. WORKFORCE AND TOTAL CASH COMPENSATION

Q. Please describe the general composition of the Companies' workforce.

A As of July 31, 2018, a total of 3,617 employees (including a small number of temporary employees) perform work for the Companies through employment by KU, LG&E, or the Service Company. More specifically, KU has 909 employees, LG&E has 1,031 employees, and the Service Company has 1,677 employees. Of the total amount, 797 are union employees.

Q. What sort of expertise and knowledge are required by the Companies' employees?

A. A large segment of our employment force requires specialized and technical skills for their work involving electric generating plants, gas facilities, transmission substations, and electric and gas transmission and distribution equipment. Our employees must have the requisite knowledge and technical skills to plan, design, operate, and maintain electric generating plants, high voltage equipment, gas storage fields, and gas lines in a manner that provides safe and reliable service. They must also have an aptitude for continuous learning and training on computer software systems.

The operation and maintenance of a field office and a customer call center requires detailed knowledge of all aspects of customer service. Field office and call center employees must understand the characteristics of electric generating and delivery service, metering, billing and collection processes, and various other customer service matters. At the corporate level, highly skilled managers, attorneys, engineers, accountants, computer hardware and software professionals, cyber security experts, and other highly trained professionals are needed to support the employees who are directly responsible for generating and delivering utility service to the Companies' customers. Competition for such employees has always been and will continue to be fierce. This is especially so in the current economy.

Q. Can you elaborate on the skills required of employees, the training they must complete to develop those skills, and the cost of that training?

A. Yes. When recruiting for talent, the Companies look for the required skills or the ability to acquire these skills (evaluated via pre-employment testing) in order to provide safe and reliable service to our customers. Understanding it takes a minimum of three and in some areas as many as five years of training before most of our field employees can work independently, it is critically important to hire the right candidate.

Employee training is an investment. If the right hiring decision is not made, the Companies' overall turnover costs are increased, leading to inefficiencies and a lack of productivity. Therefore, the hiring decision is not taken lightly. Being market competitive and providing a culture of engagement and growth are critical for retention. For example, the Companies, other utilities, municipals, and co-ops recruit for line technicians at the Georgia Line School as well as Somerset Community and Technical College. We are considered an employer of choice at the Georgia Line School due to our outstanding safety record as well as competitive pay and benefits.

Q. Please explain the overarching goal of the Companies in determining the level of compensation and benefits offered to employees.

A. It is imperative that the Companies offer a *total* compensation and benefits package to existing and prospective employees that is competitive within the utility sector. When we set compensation and benefit levels, we do not look at any one part of compensation or a single benefit offering in isolation. Instead, by any objective measure, the entire compensation and benefits package should be evaluated on an *aggregated* basis to determine whether the total package is aligned with utility market medians. That is exactly how we strive to insure compensation and benefit levels are set at a reasonable level. Likewise, when existing and potential employees consider employment with the Companies, they do not look solely at base compensation, retirement benefits, healthcare coverage, or any other single element of compensation or benefits. Instead, they act rationally by considering all aspects of compensation and benefits in making their employment decisions. The Companies set compensation and benefit levels in exactly the same way.

While one element of our compensation and benefits package may be slightly above market median, another element may be slightly below. Those variances to market are unimportant and irrelevant as long as the overall package offered to employees is in line with market median levels. In our experience, offering a competitive package of compensation and benefits is precisely how the Companies have maintained the excellent, dedicated, and productive workforce they have, which, of course, leads directly to providing value to customers. The excellent operational results described in Mr. Bellar's testimony could not be achieved without such a workforce.

Just as the Companies and employees do not overly emphasize any one element of compensation and benefits in making rational decisions, any objective analysis should not cherry pick any compensation or benefit levels that are above market as long as the entire package of compensation and benefits is reasonable. As set forth below and in the WTW and Mercer independent studies, it is clear that the entire package is competitive in the utility market, which is the appropriate comparator and is therefore reasonable. At bottom, a competitive compensation and benefits package is essential to meet the Companies' obligation to provide safe, reliable, and adequate service and to do so efficiently and productively.

Q. Would customers suffer if the Companies' employees are not provided competitive compensation and benefits?

A. Yes, definitely. If compensation and benefits are not at market levels in the utility sector, customers would suffer substantial negative consequences through unreliable service and higher costs of service. Many of our employment positions require lengthy apprenticeships and training to learn the skills needed to perform work independently and safely. As Mr. Bellar describes in his testimony, the delivery of electricity and gas is inherently dangerous and our society demands that those entrusted with this critical public function exercise the highest standard of care. The expense incurred to hire and train new employees and the loss of productivity realized through high turnover rates would negatively affect the ability of the Companies to serve customers at expected levels.

To maintain our current high levels of service, we must avoid high turnover by attracting and retaining highly skilled employees. For example, earlier this year, a turnover study was conducted for our call center employees given the number of departures we were experiencing. The three-year average turnover rate in the call center was 13.4% (excluding retirements). We determined that it costs the Companies approximately $16,000 for every call center representative who departed. We also determined that compensation paid to those individuals was below market. Therefore, an adjustment to base wages is being implemented to become market competitive. This will reduce turnover costs and allow for uninterrupted service for our customers. Our existing compensation and benefits package allows us to avoid high turnover. This means that we can serve customers while keeping our costs, and therefore our rates, as low as reasonably possible. In fact, as described by Mr. Blake, the Companies' cost of producing electricity is among the lowest in the country. He explains that the Companies are a top quartile performer with respect to O&M cost per megawatt hour sold. And for 2017, the Companies ranked 6th among 41 vertically-integrated utility holding companies for O&M cost per megawatt hour.

Q. Please explain the Companies' compensation philosophy.

A. The Companies' compensation philosophy and practices are grounded in the goal of producing sustainable operating results by attracting and retaining talented and experienced individuals. Compensation reflects the long established commitment to a "pay-for-performance" model while targeting the market median. We want our compensation to be market-based and competitive while also driving performance. We set high expectations for employees and pay them appropriately.

The Companies have a written compensation policy that has been in effect since 1997 which is reviewed on a regular basis by Human Resources. Compensation decisions made under this policy are supported by various levels of approval. Individual salary recommendations made under the Companies' written compensation policy are reviewed and approved by the manager, next level manager, and Human Resources, thus ensuring base salaries are competitive based on the nature and responsibilities of the employee's position and are fair relative to the pay for other similarly-situated positions within the organization. In addition, the annual salary increase budget is included in the Companies' budgeting process which is reviewed and approved by the LG&E and KU Boards.

Using external market compensation data at the 50th percentile of the national general or utility industry, job pay midpoints are established. Salary range minimums and maximums are based on 70% and 130% of the 50th percentile midpoint, respectively. Individual employee compensation is then managed within this competitive range. As detailed in the WTW *Target Total Cash Compensation Study*, compensation is considered competitive if it is within +/- 10% of the midpoint when considering factors that include performance, time in position, tenure, education, and experience.

Q. Describe how the Companies undertake the process of setting the compensation and benefit levels for their employees as that information is proposed at Tab 60 of the filing requirements.

A. Certainly. Although Mr. Arbough explains the process by which labor costs are budgeted and then used in the forecasted test period, I can provide information on how the Companies set their compensation and benefit levels. On an annual basis, the Companies rely on benchmark information in calibrating the level of certain components of compensation and benefits arrangements.

With regard to compensation, total compensation paid to employees is comprised of base compensation and incentive compensation. Base pay adjustments are awarded, if any, based on a combination of factors, including the employee's individual performance, performance relative to their peers, and the position of their salary within the salary range and as compared to their peer group. Incentive compensation is provided via the Companies' Team Incentive Award ("TIA") Plan which is attached as Exhibit GJM-1. As described above, the Companies strive to ensure that total compensation paid is consistent with the market and rely on various third-party benchmarking and salary planning surveys from the energy services and general industries to do so.

Q. Although the Companies routinely rely on such benchmarking and salary planning surveys in setting total compensation, have they commissioned a study to look specifically at their total compensation relative to market?

A. Yes. The Companies commissioned WTW to provide a separate and independent study that specifically examines the Companies' compensation levels. They did so to provide the Commission with the most current and specific information possible on those compensation levels. The study is attached to the Applications at Tab 60. It is entitled "*Target Total Cash Compensation*" because it studied all cash compensation paid to the Companies' employees and measures that total cash compensation relative to market.

Q. Who is WTW?

A. WTW, which traces its roots back to 1934, is a global consulting company that provides an array of services to businesses. WTW advises organizations on all aspects of their compensation programs with the goal of paying employees appropriately and enabling organizations to attract, retain, and motivate employees efficiently and cost-effectively. Typical areas of compensation consulting assistance include pay philosophy development, variable or incentive compensation plan design, total compensation benchmarking, and compensation structure development.

Q. Please describe the results of the WTW study.

A. The WTW *Target Total Cash Compensation Study* found the following:

- When compared to available published survey data, the Companies' projected and actual base salary budgets are closely aligned with market median levels;

- The Companies' use of base salary and target incentive compensation as its primary pay vehicles for employees is consistent and aligned with market pay vehicles used by utility and general industry peers. Likewise, when compared to available published survey data, the Companies' compensation levels fall within the competitive range of the market 50th percentile for base salary and target total cash compensation, and, in fact, is actually 6.4% below market median; and
- When compared to available published survey data, LG&E's and KU's pay mix (base salary and target incentive compensation) generally places less emphasis on short-term at-risk compensation than peers, but approximates market practice overall.

The WTW report confirms that our compensation-setting philosophy and process has resulted in exactly what we strive to achieve -- that with the inclusion of incentive compensation, our total compensation levels are very closely aligned with market medians. And the converse is also true in that without incentive compensation as part of the total compensation, the Companies' compensation levels would fall well below market and therefore jeopardize our ability to attract and retain an adequate workforce.

Q. Please describe the Companies' TIA Plan.

A. The TIA Plan is a long-standing "at risk" component of pay in which a part of an employee's annual cash compensation is considered "at risk" and earned only if certain objectives are met. In other words, if certain performance results are achieved, a cash incentive award will be earned. The actual amount of the award depends upon the achieved results. The TIA Plan, which has been in place since the 1990s, was developed to motivate, focus, and direct employees toward the achievement of strategic goals and is part of an overall corporate strategy to attract and retain skilled employees by providing competitive financial awards that are commensurate with the employees' talents, teamwork, and contribution. It is intended to set high expectations and motivate participants to achieve higher levels of performance, communicate and focus on critical success measures, reinforce desired behaviors including increased focus on the customer by motivating employees to lower costs and achieve higher reliability and customer satisfaction results, and bolster an employee ownership culture and reward results if achieved.

Q. Do you believe incentive compensation pay should be recovered in rates?

A. Absolutely. The Companies' incentive compensation expense is reasonable and it should be recovered in full for several reasons. First, I believe that incentive compensation aligns the interests of our employees with those of our customers. Through the measures used in the plan (customer satisfaction, customer reliability, cost control, and safety) employees' compensation depends upon an unwavering focus on the customer. Customers benefit from this focus. Second, the WTW study shows that the total compensation paid to employees, which includes both base salary and incentive compensation, is reasonable and consistent in the competitive marketplace. Without incentive compensation, the compensation paid would fall below market rates and hinder the Companies' ability to attract and retain a qualified workforce. Third, the WTW study shows that the relative mix of base salaries and incentive compensation in determining overall cash compensation is reasonable and at a competitive level when compared to the competitive marketplace. In other words, the amount of incentive compensation offered is consistent with the marketplace levels. Finally, in the competitive market for talent, employees consider all aspects of compensation and benefits – including incentive compensation – in making employment decisions.

As described below, the Companies modified the TIA Plan in recent years to eliminate any connection between the Companies' financial performance and the availability of incentive compensation. Thus, to the extent the Commission has disallowed incentive compensation expense for utilities in the past because it has been tied to a utility's financial performance (such as earnings per share or net income), those past decisions have no bearing on the Companies' current TIA Plan because, while the TIA Plan once had those financial connections, it no longer does.

Q. How are TIA payments determined?

A. All eligible employees have a TIA target award. The criteria for and calculation of those awards for 2018 are set forth in the TIA Plan. As set forth in that document, the target awards are:

Employee Status	**Target Award**
Non-Exempt and Hourly/Bargaining Unit	6% of Annual Earnings
Exempt Individual Contributors	9% of Base Salary
Managers	14% of Base Salary
Senior Managers	25% of Base Salary

For an individual employee in 2018, the calculation of incentive compensation is determined using the following objectives and percentages: (1) customer satisfaction (15%); (2) customer reliability (15%); (3) cost control (15%); (4) corporate safety (15%); and (5) individual and team effectiveness (40%).[3]

Q. Please describe the performance objectives of customer satisfaction, customer reliability, cost control, corporate safety, and individual and team effectiveness.

A. Certainly. Those descriptions are:

- Customer Satisfaction is measured by the Companies' performance ranking within its peer group. The Companies' market research vendor contacts randomly selected customers and customers from peer group companies and asks them about overall satisfaction with their respective utilities.
- Customer Reliability is measured by the System Average Interruption Duration Index ("SAIDI") which is a well-known industry metric for service reliability.
- Cost Control is measured by non-fuel operation and maintenance expenses in accordance with generally accepted accounting principles as published in the Companies' annual Form 10-K filings with the Securities and Exchange Commission.
- Corporate Safety is measured by using recordable injury rates, illness rates, and "days away, restricted and transfer" rates, commonly referred to as "DART" rates.
- Individual and Team Effectiveness measures ensure that employees are collectively working to achieve strategic business goals. Individual goals will

[3] See TIA Plan, p. 4.

vary by the individual employee and by department. They support respective department and line of business objectives and are overall customer focused.

As one can see, like many incentive compensation plans offered by employers, the TIA plan seeks to reward high-performing employees for successful efforts in the areas of customer service, cost control, and individual and team effectiveness. The TIA Plan "provides an opportunity for eligible employees to share in the added value they create through superior performance."[4] Without question, it also aligns our employees with our customers, while helping to attract and retain quality employees by ensuring their total compensation is consistent with the market.

Q. How is the Companies' TIA Plan different than other incentive plans provided by some other utilities under the Commission's jurisdiction?

A. It is different in at least one material respect. As mentioned above, incentive pay provided under the TIA Plan is *not* tied to or predicated upon the Companies' financial performance. In calculating an individual's amount of incentive compensation, the Companies' financial performance (such as their earnings per share) is not considered. Likewise, there is no baseline financial threshold the Companies must meet in order for incentive compensation to be available. While those requirements were, at one time, a feature of the TIA Plan, they no longer are.

The Companies understand that the Commission has historically disallowed rate recovery of incentive pay to the extent it has been tied to or predicated upon the utility's financial performance because such pay would benefit shareholders rather than customers. But the Companies' TIA Plan is simply not tied to the Companies'

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[4] TIA Plan, p. 1.

financial performance. Instead, the TIA Plan rewards superior performance in a way that benefits customers by its focus on customer satisfaction, customer reliability, cost control, and corporate safety. At the same time, it provides employees with an opportunity to earn competitive compensation without regard to the Companies' bottom line.

II. RETIREMENT AND WELFARE BENEFITS

Q. Please describe the Companies' philosophy with respect to retirement and welfare benefits.

A. As discussed above, the Companies' overarching goal is to offer a *total* package of compensation and benefits that is competitive to market. Because benefits are essential to attracting and retaining an adequate workforce, it is imperative that the overall benefits package be market competitive. Therefore, when we set retirement and welfare benefit levels, we do not look at each individual benefit or segment of the employee population in isolation and neither should any objective analysis. Instead, we strive to ensure that the aggregated package of benefits, including both retirement and welfare benefits, is aligned with market for the aggregate workforce.

Q. Please describe the retirement benefits the Companies offer to employees.

A. In addition to providing a compensation package that is consistent with the market, the Companies also offer certain retirement and welfare benefits to their employees at levels that ensure the entire benefits "package" is consistent with the market. We believe that offering a competitive benefits package is just as important as compensation to attract and retain an adequate workforce. The Companies' retirement benefits include:

(1) A traditional defined benefit pension plan ("DB Plan") available to those who were hired prior to 1/1/06 which was closed to all those hired after that date. Under the DB Plan, pension payments are made by the Companies to eligible retirees based on a mathematical formula and actuarial calculations.

(2) A Retirement Income Account which is a defined contribution plan ("DC Plan") available to those who were hired or rehired on or after 1/1/06. Under the DC Plan, the Companies make annual contributions to an employee' Retirement Income Account. The amount of those payments is calculated using a percentage of compensation which percentage can range from three to seven percent depending on the employee's years of service.

(3) A Company match by which the Companies will match 70% of an employee's voluntary deferred compensation amount up to a maximum of 6 percent (and subject to IRS limits) within the employee's 401(k) account. The Company match is available to all employees that invest in their retirement by making voluntary contributions to the plan.

To be clear, each employee may participate in the Companies' Savings Plan. For employees hired on or after January 1, 2006, the Savings Plan is comprised of item number (2) above, and, if the employee makes voluntary deferred compensation contributions, then item number (3) above as well. For employees hired before January 1, 2006, the Savings Plan is comprised of item number (3) above, if the employee makes voluntary deferred compensation contributions.

Q. What have the Companies done to control the cost of providing these retirement benefits?

A. While it is critical for all employees to have a retirement benefit available to them, it is equally important for the cost of that benefit to be reasonable. Thus, in 2005, the Companies took a difficult but necessary step to control pension costs that continues to drive customer value today. As set forth above, the Companies closed their DB Plan to new entrants for anyone hired (or rehired) after December 31, 2005. While it is true that many employers have since taken similar steps, the Mercer *Benefits Study* attached at Tab 60 to the Applications shows that the Companies were among the first half of utilities to do so when they decided to close the DB Plan to new entrants in 2005. That decision will continue to keep the cost of retirement benefits down as employees who participate in the DB Plan transition into retirement and they are replaced by employees participating in the DC Plan. In other words, the Companies recognized DB Plans were not sustainable over time for a number of reasons and took effective steps long ago to resolve that issue.

Although the 2005 decision to close the DB Plan is the most impactful step taken to control costs and reduce risks of retirement benefits, the Companies have taken numerous other steps for that purpose. For example, in 2000, the KU retirement plan was merged with the LG&E retirement plan as a way to save administrative costs. In 2013 and again in 2014, the Companies offered voluntary limited-time windows in which former employees who had not started taking a monthly benefit could elect a lump-sum benefit instead. This decision allowed the Companies to reduce the risks associated with investments, longevity and it eliminated the liability associated with Pension Benefit Guaranty Association premiums for those individuals. Approximately 60% of eligible participants made that election. In 2016, the Companies amended the DB Plan to offer a permanent lump sum payment option instead of only a monthly payment which further reduced the risks associated with investments and longevity.

Due to the nature of retirement benefits and the fact that employees base important life decisions on the levels of those benefits during the span of their career, changing the retirement benefits for existing participants should only be done with great caution and after consideration of potential disruptions of the workforce. However, the steps described above show that the Companies have in fact taken prudent actions to manage the overall costs of benefits while still fulfilling commitments made to employees.

Q. Who is Mercer?

A. Mercer is a nationally and globally known entity offering a wide array of services to employers including providing advice, technology, and benchmarking analyses to help organizations meet the health, welfare, and career needs of their workforces. The Companies commissioned Mercer to assess their retirement and welfare benefits offerings relative to market so that the Commission will have current, accurate, and robust data concerning the Companies' overall benefits offerings.

Q. Did Mercer look at just a single element of benefits in reaching their conclusions?

A. No, not at all. As I stated above, from an employment and ratemaking perspective, any objective analysis must examine the aggregate package of retirement and welfare benefits to determine whether that package is aligned with market. Mercer did what the Companies, current employees, and prospective employees do; they examined the *aggregate* package of retirement and welfare benefits to determine whether that package is aligned with market.

Q. What did Mercer conclude?

A. The Mercer *Benefits Study* shows that the combined (retirement and welfare) package of benefits is within the range of market competitiveness of plus or minus five percent of median within the utility sector. It proves that the Companies' 2005 decision to close the DB Plan has and continues to result in the intended effect of controlling retirement benefit costs. Thus, over time, because of the proactive steps the Companies took in 2005, the number of DB Plan participants will decline and then cease. It also proves that the Companies' efforts to ensure that welfare benefits are aligned with the utility market have been successful. Thus, when analyzing the overall positioning of the entire retirement and welfare benefit package, Mercer concludes that the Companies' benefits are competitive in the utility market.

Q. What else does the Mercer *Benefits Study* show?

A. The Mercer *Benefits Study* indicates:

- When evaluating benefits programs, it is important to look at the positioning of all benefits in aggregate as benefit plans are designed holistically and not in finite parts;
- It is important to examine benefit levels in the context of total remuneration (compensation and benefits) as compensation and benefits are designed and assessed in tandem;

- The Companies total package of benefits is aligned with utility market median with an Index 104 score (consistency with market being defined as anything between an Index score of 95-105); and
- All organizations that sponsor an ongoing DB Plan provide 401(k) matching contributions to DB Plan participants.

Q. Have the Companies completed collective bargaining efforts since their last rate cases?

A. Yes. Since the Companies' 2016 rate cases were decided, LG&E completed collective bargaining efforts with the International Brotherhood of Electrical Workers ("IBEW") Local 2100. Those efforts resulted in a new Collective Bargaining Agreement for 2017-2020. That new agreement specifically provides that all IBEW employees will participate in the Savings Plan on the same basis as all other regular full-time employees of LG&E. The existing KU-IBEW agreement and the recently executed KU-United Steel Workers agreement have similar language. Likewise, the revised union contracts updated the medical coverage provisions to remove the formulaic approach to premium increase determinations.

Q. Do you agree with the Commission's decision in the Companies' 2016 rate cases in which the Commission modified the proposed settlement agreement by excluding from rate recovery the employer-provided 401(k) match amount made to non-union employees who participate in the DB Plan?

A. No. The Companies' 2005 decision to close its DB Plan to new entrants is the same kind of cost-control measure the Commission emphasized in its recent decision in a

Duke Energy case[5] in which it *allowed* rate recovery for "matches" paid to DB Plan participants. The Companies have effectively managed costs related to their retirement plans by closing their DB Plan and offering employees hired on or after January 1, 2006 participation in their DC Plan. Some of those savings are now being used to make the matching payments the Commission disallowed in the 2016 rate cases. To eliminate that match just because an ever-decreasing number of employees receive a benefit from both plans would penalize the Companies for their cost control efforts.

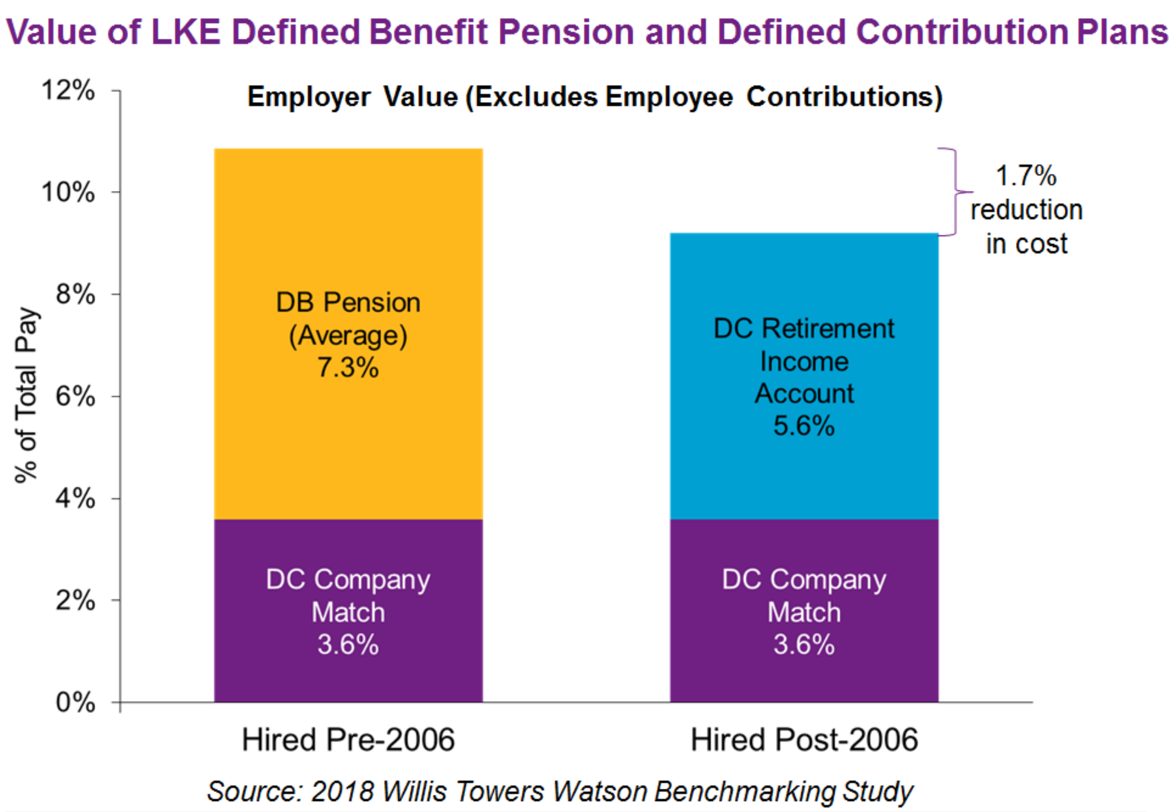
Eliminating matching payments would deprive employees of benefits they were promised and have relied upon for years when making important life decisions. The Companies have encouraged all employees to take ownership of their retirement planning by directing them to use modeling tools that show the effects of their investment by making voluntary contributions to the Savings Plan. Matching payments encourage voluntary deferral of compensation and are also a part of the retirement modeling tools employees have used. Elimination of matching payments will also cause employee morale issues, inefficiencies, and a loss of productivity, all of which can cause a negative impact on customer service and an increase in the cost of providing service. Finally, an employee's ability to retire at the right time increases opportunities for the workforce as a whole and helps manage costs.

Mercer found that all of the organizations in its study that sponsor an ongoing DB Plan also provide a 401(k) matching contribution for DB Plan participants. Thus,

[5] *In the Matter of: Application of Duke Energy Kentucky, Inc. for: (1) An Adjustment of the Electric Rates; (2) Approval of an Environmental Compliance Plan and Surcharge Mechanism; (3) Approval of New Tariffs; (4) Approval of Accounting Practices to Establish Regulatory Assets and Liabilities; and (5) All Other Required Approvals and Relief*, Case No. 2017-00321, April 13, 2018 Order, p. 23.

by providing matching payments, the Companies are aligned with 100% of Mercer's comparator group.

In addition to the Mercer Benefits study, the Companies also engaged WTW to review the levels of the Companies' retirement benefits as a percentage of pay using the 2018 WTW benchmarking data and their standard assumptions for that type of review. As illustrated below, the cost savings between the pre-2006 and the post-2006 employee populations is 1.7%.



Accordingly, the study confirms the Companies' position that it took appropriate steps many years ago to manage the overall cost of its retirement plans. As such, the Companies' cost of providing these benefits should be a recoverable expense.

Q. Please describe the welfare benefits the Companies offer to employees.

A. The Companies offer a package of welfare benefits that employers commonly provide to employees. The primary welfare benefits include the opportunity for employees and their families to participate in plans for medical care coverage, dental and vision coverage, life insurance coverage, and disability coverage.

Q. What principles do the Companies follow in offering and managing health benefits?

A. Our ultimate goal is healthy employees who strive to meet their best achievable health status. We try to partner with employees in establishing a culture of health by emphasizing health status knowledge, preventive care, and healthy lifestyles. It is critical to offer welfare benefits at market levels so that we can attract and retain a skilled and reliable workforce. At the same time, prudent cost control is a necessity which is why the Companies require cost increases to be shared between the Companies *and* employees and why the Companies take advantage of cost savings measures whenever possible.

Q. What steps have the Companies taken to control costs of the health benefits they offer?

A. The Companies continually look for more efficient ways to deliver service. As part of that effort, the Companies have a long and successful history of controlling the costs of welfare benefits that are included in the rates customers pay. In recent cases before the Commission, the Commission has indicated its belief that employees should share the costs of welfare benefits. The Companies agree with that policy which is why, over 22 years ago in 1996, employees began paying a share of medical and dental premiums.

The Companies' study and focus on rising healthcare costs have led to other cost control efforts beyond premium sharing. The Companies took a major step in this regard when they decided to "self-insure" all options in their healthcare plan in 2002. The Companies manage the risks of self-insuring by purchasing stop-loss coverage for particularly high claim events, but being self-insured has allowed costs savings that could not have occurred in a fully-insured environment.

As I discussed above, making adjustments to retirement benefit levels and offerings is a particularly difficult endeavor given the importance of those benefits to employee's life decisions. And although adjusting welfare benefits must be done with great care, notice, and fairness, the nature of those benefits allows them to be adjusted on a more regular basis. Therefore, over the years, various cost control steps have included: increases in amounts paid by employees for spousal coverage (2008); additional premium amounts for spousal coverage if that spouse works and is eligible to participate in his/her employer's medical plan (2012); and, implementation of a tobacco user surcharge (2014).

We have also taken steps to control prescription costs by participating in a Pharmacy Benefit Collective for the last several years. That effort ensures we are receiving the best possible terms and pricing for prescriptions. In 2014, we removed vision coverage from the medical plan and now require employees to pay 100% of the cost of vision premiums. We are proud of the success of one of our more recent and innovative initiatives called LiveHealth Online in which employees may consult with board-certified physicians via computer, tablet, or mobile device for an average cost of $49 which is much lower than the average $105 cost of a doctor's office visit, the

$147 cost of an urgent care center visit, or the $1,636 cost of an emergency room visit. We also made significant medical design plan changes in 2017 discussed in more detail below.

Finally, the Companies work together with union and non-union employees in a continuous effort to stay abreast of health care issues. This occurs through the Health Care Task Force which is a broad-based employee group of union and non-union employees that meets regularly with the goal of maximizing healthcare coverage value while controlling costs. That group then provides suggestions to the Companies. One of the benefits of this practice is that it simplifies negotiations with unions over healthcare issues and provides the Companies with healthcare advocates across its workforce.

Q. What have the Companies done to encourage a healthier workforce and have those efforts been successful?

A. The Companies have taken many significant steps over the years in furtherance of their belief that a healthy workforce is safer and more productive. This "wellness" goal led to the adoptions of a "Healthy for Life" premium structure that allows employees and covered spouses a reduction of $125 per month in their premiums if they complete four steps: (1) obtain and submit a biometric screening; (2) complete a "well-being assessment" survey; (3) represent they are tobacco-free or complete a "Quit for Life" tobacco cessation program; and (4) complete an acknowledgment of preventative health measures they should consider.

Our wellness initiatives are both successful and award-winning. Most recently and perhaps most significantly, we were one of only three entities receiving

Honorable Mention for the 2018 C. Everett Koop National Health Award. This is a prestigious and hard-earned recognition of which we are very proud. It was awarded based on our demonstrated commitment to wellness through a wide array of wellness initiatives. In recent years, the Companies have also received the following awards for their wellness initiatives:

- In 2016, 2017, and 2018, we were ranked as a Top 100 Healthiest Employer in the country;
- In 2015, 2016, 2017, and 2018, we either won or were a finalist in the Louisville *Business First* Healthiest Employer competition; and
- Gold Level recognition by the American Heart Association for 2015-2017.

The end result of these wellness initiatives and awards is that, despite an environment in which others have seen healthcare costs increase significantly, the Companies total medical costs have only increased an average of 3.1% over the past five years which is better than the national trend which for this same period was 3.4%.

Q. Describe how the Companies ensure that their healthcare benefit offerings are consistent with market levels.

A. Since 2001, the Companies have participated in regional healthcare benchmarking surveys to ensure our medical benefits are in alignment with market. Our more recent survey comparisons now include national and local employers as well as utilities. Adjustments are made based upon Mercer's analysis of plan costs and their recommendation and plan design structure changes are made in order to keep benefits in line with benchmarks. Benchmark data, medical claim information, and medical trend data are utilized in structuring plan offerings and medical premiums. This effort occurs annually. In 2017, the Companies made significant plan design changes to align with benchmarking. Those changes included:

- Increases to employee out-of-pocket costs comprised of deductibles, out-of-pocket maximums, copays, and coinsurance;
- Additional utilization management rules for prescription coverages; and
- Recalibration of spouse premiums by which those employees who elect coverage for their spouses pay higher premiums than they did previously.

Of course, the decision to require employees to pay an increase in their out-of-pocket costs was not taken lightly. However, it is one of the most direct and effective ways to control these costs. The Companies do not look only at the premium, as it does not provide the total picture of employee cost sharing. Cost sharing is designed to encourage good consumer health care choices by providing opportunities for lower employee premiums and higher "out-of-pocket" costs at the point of service so that the consumers of health care services are paying for it.

For these "out-of-pocket" costs (which include premium sharing amounts, deductibles, co-insurance, and co-payments) for medical, dental, and vision employees are required to shoulder a significant portion of the total cost. For 2017, our employees' total out-of-pocket costs were 33% of the total medical and prescription costs. Employees are required to pay 100% of the premium for vision, supplemental life, and dependent life insurance coverage.

Q. Did the Companies also commission Mercer to review the Companies' welfare benefit offerings as they relate market levels?

A. Yes. As stated, the Mercer *Benefits Study* assesses the Companies' total employee benefits offerings, including both retirement and welfare benefits, in determining how those benefits compare to market in the utility sector in which the Companies compete for employees. Again, Mercer concluded that the Companies' total benefits package is consistent with utility market median with an Index score of 104.

Q. Do you have a conclusion and recommendation for the Commission?

A. Yes, as described in more detail above, the Companies' compensation, including base pay and incentive compensation, and its various retirement and welfare benefit offerings are critical to the Companies' ability to provide the service our customers expect and deserve. We take great care to ensure that compensation and benefits are reasonable and we have offered proof in this case that we have met our goal of providing a total compensation and benefits package that is aligned with market. I believe the Companies benefit and compensation programs are competitive with the market, reasonable, and necessary to attract, retain, and motivate the qualified employees that the Companies need to provide safe, reliable and efficient services to LG&E and KU customers. Accordingly, I recommend that the Commission allow full rate recovery for these crucial components of operating our business.

Q. Does this conclude your testimony?

A. Yes, it does.

VERIFICATION

COMMONWEALTH OF KENTUCKY)
)
COUNTY OF JEFFERSON)

The undersigned, **Gregory J. Meiman**, being duly sworn, deposes and says that he is Vice President, Human Resources 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.

Gregory J. Meiman

Gregory J. Meiman

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 19th day of September 2018.

Judy Schooler

Notary Public

My Commission Expires:

Judy Schooler
Notary Public, ID No. 603967
State at Large, Kentucky
Commission Expires 7/11/2022

APPENDIX A

Gregory J. Meiman
Vice President, Human Resources
Kentucky Utilities Company
Louisville Gas and Electric Company
220 West Main Street
Louisville, Kentucky 40202
Telephone: (502) 627-2562

Education

University of Louisville, Louis D. Brandeis School of Law, Juris Doctor,
Louisville, Kentucky 1986
University of Louisville, Bachelor of Science in Business Administration,
Louisville, Kentucky 1983

Professional Experience

LG&E and KU Energy LLC, Louisville, Kentucky

Vice President, Human Resources	2016 – present
Director, Corporate Tax and Benefit Plan Compliance	2013 – 2016
Senior Counsel and Executive Plans Specialist	2002 – 2012
Asst. General Counsel and Executive Plan Manager	2000 – 2001
Senior Counsel and Executive Plan Manager	1999 – 2000
Senior Corporate Attorney	1996 – 1999

Greenebaum Doll & McDonald PLLC, Louisville, Kentucky

Of Counsel	2001-2002

Providian Corporation, Louisville, Kentucky

Tax and Benefits Counsel	1988 – 1996

Welenken, Himmelfarb & Company, Louisville, Kentucky

Staff Accountant	1986 – 1988

Professional Memberships

Kentucky Bar Association
Louisville Bar Association
Kentucky Society of Certified Public Accountants
Certified Employee Benefits Specialist

Civic Activities

Louisville Ballet Board (2012-2018)
University of Louisville College of Business Board of Advisors

Exhibit GJM-1

Team Incentive Award (TIA) Plan

TEAM INCENTIVE AWARD (TIA) PLAN

- Corporate Safety
- Customer Satisfaction
- Cost Control
- Customer Reliability
- Individual and Team Effectiveness

TIA

Eligible employees participate in the LG&E and KU Team Incentive Award ("TIA"). The TIA focuses employee efforts on customer and business goals and rewards employees for achieving those goals. The TIA provides an opportunity for eligible employees to share in the added value they create through superior performance.

TIA AND BUSINESS STRATEGY

The company realizes the wealth that exists in the abilities of its people. The challenge is to become the best in our competitive market through each individual using his or her talents combined with other team members to make it happen. The TIA Plan plays a key role in assisting the company in focusing employees on customer and business goals as well as providing employees with a program that can increase their individual compensation.

The TIA was developed to motivate and direct employees toward the achievement of strategic goals. It also assists with attracting and retaining skilled personnel by providing competitive compensation commensurate with their talents, cooperation and contribution.

There are several basic TIA concepts:

- There is a focus on the cooperative spirit of all employees working together as a team.
- Risk-taking, embodied in initiative, fresh perspectives and innovative solutions, is encouraged and rewarded.
- The plan is designed to motivate and improve the individual performance of all employees.
- Incentive award levels vary depending on the employee's base salary, position and performance. The TIA represents "pay at risk." The relationship of the target awards to salary reflects that employees who have increasing responsibility for customer and business performance, as reflected in higher salaries, generally have higher amounts of individual compensation tied to that performance.

With these concepts in mind, the TIA was designed:

- To promote the achievement of the company's objectives.
- To attract, motivate and retain employees.

TIA PLAN

Key elements of the TIA are as follows:

1. Participants include all active full-time and regular, part-time salaried employees, IBEW 2100 employees and KU hourly and bargaining unit employees.
2. All TIA participants have Target Awards based on the following:

<u>Target Award Participation</u>

Non-Exempt & Hourly	6% of annual earnings
Exempt Individual Contributors	9% of base salary
Managers	14% of base salary
Senior Managers	25% of base salary

3. Performance objectives are established annually to support the customer and business strategies. The size of the awards depend upon the degree to which these objectives are achieved.
4. Exempt employees with salary changes during the year will have their awards calculated in accordance with the amount of time they work under each respective base salary.
5. Total annual earnings, including overtime, are used in calculating the earned awards for all regular non-exempt and hourly full- and part-time employees. Prior TIA awards are excluded from total annual earnings to calculate earned awards.
6. Earned TIA Awards will be paid in cash within 90 days of the completion of the calendar-based annual performance period.
7. Compensation from the TIA is included in calculating benefits under the Company's Retirement (except for the KU Retirement Plan) and 401(k) Savings Plan.
8. This plan in no way creates a contract of employment for any duration. The company has full and final discretion with respect to the interpretation and application of this plan. The Company reserves the right to modify or terminate this plan in its sole discretion. This plan document supersedes any prior plan document relating to the TIA.

ELIGIBILITY

All active, regular full- and part-time salaried employees, IBEW 2100 employees and KU hourly and bargaining unit employees, who have at least one month continuous service and are on the payroll on December 31 of the performance year, are eligible for a TIA.

Employees who become disabled, die or retire during the performance year will be eligible for a prorated award.

Disability, for purpose of this plan, means that the employee is eligible for the receipt of benefits under the Long Term Disability Plan.

Upon an employee’s death any prorated award shall be paid at the time such awards are payable under this plan to the employee’s estate, or if the estate is closed at the time the award is payable to the person or persons in the first of the following classes of successive preference beneficiaries then surviving: the employee’s surviving spouse, children, parents, brothers and sisters, executors and administrators.

Retire means that the employee is eligible to retire under the terms of a company sponsored retirement plan.

Employees who join the company during the performance year, who have at least one month continuous service, and are on the payroll on December 31 will also be eligible for a prorated award. Employees incurring unpaid work days during the performance year may experience a proportionate reduction in their TIA.

INDIVIDUAL PERFORMANCE OBJECTIVES

The individual performance objective links individual performance to the TIA award. The individual performance objective can be combined with performance objectives for small teams as well as with key objectives from the Performance Excellence Process. Individual performance objectives should align with, and support, strategic customer and business goals to drive performance.

TIA COMMUNICATION

TIA performance results for customer, business and operational performance measures are communicated through the Company’s internal communications to provide information concerning performance. Final TIA performance results are approved following the completion of the performance period and are communicated through the Company’s internal communications.

CONCLUSION

The Team Incentive Award Plan is designed to strengthen the connection between pay and performance. It will direct a portion of total pay to awards based on customer, business, operational and individual achievements. The TIA focuses eligible salaried and hourly employees’ attention on the company’s business goals.

TIA FORMULA

The TIA calculation formula is shown below, along with an example of a potential award. In this example, note the participant's salary is $40,000 and the target award is 9%.

TIA CALCULATION

Step 1: Target Award % x Annual Base Pay Earnings = Target Award

Step 2: Target Award x Corporate Safety Weighting x Performance % = Corporate Safety Award

Step 3: Target Award x Customer Satisfaction Weighting x Performance % = Customer Satisfaction Award

Step 4: Target Award x Cost Control Weighting x Performance % = Cost Control Award

Step 5: Target Award x Customer Reliability Weighting x Performance % = Customer Reliability Award

Step 6: Target Award x Individual or Team Weighting x Performance % = Individual or Team Award

Step 7: Corporate Safety Award + Customer Satisfaction Award + Cost Control Award
+ Customer Reliability Award + Individual or Team Award = Total TIA Award

TIA CALCULATION EXAMPLE

Annual Base Pay Earnings = $40,000
Target Award Percent = 9%
Corporate Safety Performance % = 105%
Customer Satisfaction Performance % = 110%
Cost Control Performance % = 100%
Customer Reliability Performance = 110%
Individual or Team Performance % = 105%

Step 1: 9% x $40,000 = $3,600 Total Award

Step 2: $3,600 x 15% x 105% = $567 Corporate Safety Award

Step 3: $3,600 x 15% x 110% = $594 Customer Satisfaction Award

Step 4: $3,600 x 15% x 100% = $540 Cost Control Award

Step 5: $3,600 x 15% x 110% = $594 Customer Reliability Award

Step 6: $3,600 x 40% x 105% = $1,512 Individual or Team Award

Step 7: $567 + $594 + $540 + $594 + 1,512 = $3,807 Total TIA Award

EMPLOYEE BULLETIN

March 23, 2018

2018 Team Incentive Award measures, weightings announced
TIA measures remain the same as in 2017.

LG&E and KU's Team Incentive Award (TIA) is a core component of the company's compensation. Last year, the TIA included measures for Corporate Safety, Customer Satisfaction, Cost Control (O&M), Customer Reliability (SAIDI), and Individual or Team Effectiveness. In 2018, core TIA measures will remain the same.

2018 TIA Measures and Weightings
15% – Corporate Safety **15%** – Customer Satisfaction **15%** – Cost Control **15%** – Customer Reliability **40%** – Individual/Team Effectiveness

Provided below are some questions and answers about the operational and performance targets as well as the other TIA measures.

If you have specific questions about your TIA, please contact your manager or the appropriate **Human Resources representative**.

Are LG&E and KU's TIA measures and weightings changing in 2018?
No. Corporate Safety, Customer Satisfaction, Cost Control, Customer Reliability, and Individual/Team Effectiveness weightings have not changed.

TIA Measure	2017 Weighting	2018 Weighting
Corporate Safety	15%	15%
Customer Satisfaction	15%	15%
Cost Control	15%	15%
Customer Reliability	15%	15%
Individual/Team Effectiveness	40%	40%

Why are Cost Control and Customer Reliability measures?
Our strong focus on providing reliable and cost-effective service to our customers is enhanced through effective cost management and ensuring reliability. Employees have significant control over operating costs and contribute directly and indirectly to customer reliability.

How will Cost Control be measured?
Cost Control will be measured by O&M, which includes all labor and non-labor operation and maintenance costs. These costs include those that are recovered through the Environmental Cost Recovery (ECR), Demand Side Management (DSM) and Gas Line Tracker (GLT) mechanisms, but exclude those items that are classified as Other Income and Expense. Expenses related to fuel for generation, power purchases and gas supply to serve customers are excluded. Through the measure, employees are encouraged to seek sustainable savings to benefit our customers.

How will Customer Reliability be measured?
Customer Reliability will be measured by our System Average Interruption Duration Index (SAIDI). SAIDI

is an industry-recognized metric which has been used by the company for many years to measure reliability. By planning and executing restoration activities efficiently to reduce the duration of an outage, our customers are positively impacted.

Why is Corporate Safety an incentive measure?
LG&E and KU have established and continue to maintain a robust safety culture with employees and business partners. Since 2000, the safety performance of the company's employees and contractors has been progressively positive. Recordable Injury and Illness Rates (RIIR) have decreased consistently, enabling the company to rank highly among the industry's top safety performers. As we work toward our goal of zero incidents, LG&E and KU will continue to track injuries through the RIIR. The Days Away Restricted and Transferred (DART) safety measure tracks days away from work or a job restriction or a transfer to another position due to a recordable work injury. RIIR and DART each have a 50 percent weighting in the total Corporate Safety measure. The RIIR and DART calculation formulas are measured in accordance with federal Occupational Safety and Health Administration (OSHA) standards.

How is Customer Satisfaction measured?
The company's market research vendor contacts randomly selected LG&E and KU customers and customers from peer group companies and asks them about satisfaction with their respective utilities. The scores are compiled quarterly, and those results are used to rank the utility companies. Our performance ranking determines achievement of the measure.

What are Individual and Team Effectiveness measures?
Individual and Team Effectiveness measures are established each year to ensure we are collectively working to achieve strategic business goals. Goals vary by individual and by department and support respective department business objectives. Team Effectiveness measures may include safety, reliability and budget goals. Aligning team measures with performance and operational indicators demonstrates our focus on providing reliable, safe energy at a reasonable cost to our customers.

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

ELECTRONIC APPLICATION OF KENTUCKY UTILITIES COMPANY FOR AN ADJUSTMENT OF ITS ELECTRIC RATES	**)))**	**CASE NO. 2018-00294**

In the Matter of:

ELECTRONIC APPLICATION OF LOUISVILLE GAS AND ELECTRIC COMPANY FOR AN ADJUSTMENT OF ITS ELECTRIC AND GAS RATES	**))))**	**CASE NO. 2018-00295**

TESTIMONY OF
DANIEL K. ARBOUGH
TREASURER
KENTUCKY UTILITIES COMPANY AND
LOUISVILLE GAS AND ELECTRIC COMPANY

Filed: September 28, 2018

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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") 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 KU and LG&E. My business address is 220 West Main Street, Louisville, Kentucky. A statement of my education and work experience is attached to this testimony as Appendix A.

Q. Have you previously testified before the Commission?

A. Yes. I testified in KU's and LG&E's last base rate cases.[1] Since 2000, I have also attested to the factual representations in each of KU's and LG&E's financing applications filed with the Kentucky Public Service Commission ("Commission") and have regularly appeared before Commission Staff on behalf of the Companies 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 forecasted test periods; (2) present KU's and LG&E's capital structures; (3) describe KU's and LG&E's cost of debt, debt issuances since the last rate case and forecasted debt issuances; and (4) support several filing requirements.

Q. Have your duties as Treasurer changed since the Companies' last rate cases?

[1] *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.

A. No, they have not. I continue to have responsibility for cash management, corporate finance, credit risk management, insurance, pension fund management oversight, and overseeing the Companies' forecasting and business planning processes, which is central to the development of the forecasted test period in these cases.

I. BUSINESS PLANNING PROCESS RESULTING IN THE FORECASTED TEST PERIOD

Q. What is the forecasted test period the Companies have used to support their requested increase in revenues in these cases?

A. The forecasted test period begins May 1, 2019, and ends April 30, 2020. The information and projections in the forecasted test period are the result of the Companies' annual business planning process.

Q. Please describe the business planning processes the Companies utilized in preparing the forecasted test period in these cases.

A. KU's and LG&E's business planning processes remain very similar to those I explained in my direct testimony in Case Nos. 2016-00370 and 2016-00371, which were the Companies' most recent rate cases. Consistent with their well-established practice, the Companies prepare a five-year business plan each year that contains projected income statements, cash flow statements, and balance sheets. KU's and LG&E's budget is described in the first year of the five-year plan.[2] Preparing the five-year plan involves significant effort, which includes the use of econometric models, variables, assumptions, and changes in activity levels. All segments of the Companies participate, with many personnel contributing to the effort. In addition to

[2] Certain filing requirements that support the Company's application reflect the full increase in rates and contain no assumptions regarding the possible results of this case.

my testimony, a detailed description of these tools and how they are used are set forth in Filing Requirement Schedule 807 KAR 5:001 Section 16(7)(c) at Tab 16 of each application, as well as in the testimony of Mr. David Sinclair. Mr. Bellar and Mr. Blake also discuss assumptions in their testimony.

Attached as Exhibit DKA-1 is a visual depiction of the planning process, and Exhibit DKA-2 contains a list of components from KU's and LG&E'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 KU and LG&E each 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 their Applications as required by 807 KAR 5:001 Section 16(7)(t)?

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

Q. What are the two computer programs the Companies primarily utilize in their business planning process?

A. The two programs are UIPlanner and PowerPlan. The Companies are able to extract and import data from the two programs, which aids in the efficiency and continuity of business planning and forecasting. The Companies utilize UIPlanner's financial planning software, which is used by 21 of the largest 25 investor owned utilities in the United States, to consolidate data from several systems and generate projected financial statements for planning purposes. The Companies utilized UIPlanner in their 2014 and 2016 rate cases, as well.

Similarly, PowerPlan is a leading utility software that allows the Companies to robustly manage their assets. KU and LG&E use the software to budget and track actuals for O&M, capital expenditures, taxes, and lease costs.

Q. Please explain the steps involved in KU's and LG&E's business planning process that led to the forecast in these cases.

A. In March of this year, KU and LG&E finalized their workforce plans and loaded the labor forecast into PowerPlan. Once complete, the corporate burdens (i.e., payroll taxes, worker's compensation, off duty costs, health insurance, and pensions) for employee benefits were calculated and entered into PowerPlan. Next, the electric and gas sales and commodity price forecasts were completed and loaded into UIPlanner. At this point, the capital plan was prepared, reviewed, and entered into PowerPlan.

Then the Generation forecast was completed, reviewed, extracted and uploaded into UIPlanner. Next, Operations and Maintenance, Costs of Sales, and Other expense budgets were completed, reviewed, and loaded into PowerPlan. The PowerPlan data was then extracted and imported into UIPlanner. Once complete, Business Plan presentations were conducted for each line of business, reviews were performed, and necessary changes made. At this point, other revenue calculations, depreciation, financing and tax calculations were made in UIPlanner.

Next, the comprehensive Business Plan was reviewed with KU and LG&E senior officers and changes were made to the plan based on their review.

Q. Can you please explain how the labor forecasts that you mentioned are developed?

A. Certainly. KU's and LG&E's Human Resources Department works closely with each business segment to determine future personnel needs, and determine planning assumptions for existing employees' development, retention, and anticipated staffing changes, including retirements. During this process, open positions and anticipated needs are analyzed. As discussed in Mr. Meiman's testimony, the Companies utilize annual benchmarking studies to determine salaries for new hires.

Information and data regarding KU's and LG&E's current workforce is housed in PeopleSoft, which is a computer software program the Companies use for many of their human resources functions. Information regarding wages, vacation hours, personal days, and sick time is extracted from PeopleSoft and imported into PowerPlan. KU and LG&E adjust the data based on expected changes in the workforce, union contracts, retirements and pay adjustments based on the benchmarking surveys discussed above. Estimates are calculated for the amount of time each business segment will spend working each month on capital projects. Labor costs are split between capital and operating and maintenance expense based on these estimates.

Q. How do the Companies determine the capital projects that are included in the business plan and in the forecasted test period in these cases?

A. Each line of business prepares a comprehensive list of capital projects that includes the expected investment over time, when construction would begin, and the expected in-service date. The Resource Allocation Committee ("RAC") is comprised of leaders from across the Companies and ensures that the capital budgets are prepared based on the needs of the business and our customers. 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. The Companies develop their electric sales, generation, and off-system sales forecasts through the business processes described in the Companies' integrated resource plans and certificate of public convenience and necessity cases 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 these cases.

A. For many years, KU and LG&E have budgeted their operation and maintenance expenses through a "bottom-up" approach that begins with each line of business. The Companies 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 Companies' senior officers. A copy of the current year's budget presentations is included at Tab 16 of KU's and LG&E's applications.

Q. Was this business planning process used to develop the fully forecasted test period ending April 30, 2020, for KU's and LG&E's applications?

A. Yes. The fully forecasted test period supporting these rate applications was developed through the Companies' 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 these cases, which includes KU's and LG&E's requested annual increase in revenues.

Q. Did KU and LG&E fully reflect the impact of the Tax Cuts and Jobs Act ("TCJA") in their forecasted test period?

A. Yes, they did. The forecasted test period for KU and LG&E also includes the effects of the recent reduction in the Commonwealth of Kentucky's corporate income tax rate. Because these tax impacts are fully reflected in the forecasted test period and the Companies' budgets, as discussed in the testimony of Mr. Conroy, the Companies have requested the termination of the TCJA surcredits when base rates are reset effective with service rendered on May 1, 2019.

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

A. Yes, KU and LG&E included assumptions concerning their capital structures, cost of equity, and cost of debt in developing the forecasted test period supporting the rate applications in this case. Assumptions that are based on the forecasted cost of equity are set forth in Mr. McKenzie's direct testimony.

II. CAPITAL STRUCTURE

Q. Please explain the Companies' capital structures.

A. A significant indicator of any company's financial strength is its level of debt as compared to total capitalization. A utility is no exception. 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 needed. Cumulatively, this leads to higher credit ratings and lower interest costs.

The Companies maintain their capital structures in adherence with these bedrock principles. For the forecasted test period, KU has projected a debt-to-capitalization ratio of 47.16 percent. This is consistent with KU's year-end ratios since 2008, which have stayed within 45.9 to 47.6 percent.[3]

Likewise, for the forecasted test period, LG&E has projected a debt-to-capitalization ratio of 47.16 percent. This is consistent with LG&E's year-end ratios since 2008, which have stayed within 43.8 to 47.6 percent.[4] Maintaining these ratios is consistent with KU's and LG&E'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 explained in its *Rating Methodology, Regulated Electric and Gas Utilities*, dated June 23, 2017, a copy of which is attached to my testimony as Exhibit DKA-3. Moody's considers four factors: (1) regulatory framework; (2) ability to recover costs and earn returns; (3) diversification; and (4) financial strength.

[3] These quarter-end ratios exclude purchase accounting adjustments reflected in federal GAAP filings.
[4] These quarter-end ratios exclude purchase accounting adjustments reflected in federal GAAP filings.

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 ability of a utility to raise additional financing if needed, and can lead to leverage covenant violations in credit facilities or other financing agreements."[5]

KU and LG&E aim for an "A" rating from Moody's. An "A" 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 several adjustments in computing a company's debt and capitalization. For example, long-term obligations under pensions and leases are considered "debt" obligations, and deferred taxes are included as part of capitalization. Taking into account Moody's adjustments, KU's debt-to-capitalization ratio for the base period is 37.66 percent; for the forecasted test period it is 37.81 percent, both within Moody's range for an "A" rating. LG&E's debt-to-capitalization ratio for the base period is also within the "A" range, as it is 38.80 percent for the base period and 38.29 percent for the forecasted test period.

Moody's includes deferred taxes in its definition of capitalization, and the passage of bonus depreciation has caused a significant increase in the Companies' deferred tax balances. KU's deferred tax balance is approximately $690 million, and LG&E's is approximately $581 million as of June 30, 2018. The magnitude of the deferred taxes is the cause for the debt/total capitalization ratio being slightly below the mid-point of the range. The Companies cannot simply incorporate deferred taxes

[5]Moody's *Rating Methodology, Regulated Electric and Gas Utilities*, June 23, 2017 at 21.

into its target ratios because other agencies do not include deferred taxes in their ratios, which is 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 methodology assigns values to the following: Country Risk, Industry Risk, and Competitive Position, each of which is 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 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, KU's debt/(debt + equity) ratio is 44.74 percent for the base period and 44.88 percent for the forecasted test period. LG&E's is 46.33 percent for the base period and 46.25 percent for the forecasted test period. Both KU's and LG&E's current capital structures retain 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 the Companies' target "A" rating.

III. CREDIT RATINGS

Q. What are the Companies' current credit ratings?

A. Filing requirement 807 KAR 5:001 Section 16(8)(k) at Tab 64 in KU's and LG&E's applications show the current credit ratings for KU and LG&E. 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 KU and LG&E to continue to raise debt capital at very reasonable costs.

Q. Have there been any changes to the Companies' credit ratings since Case Nos. 2016-00370 and 2016-00371, which were their last rate cases?

A. No, there has not.

Q. Although there has been no change to the Companies' credit ratings, did Moody's recently release an article that shifts the outlook for utilities to negative?

A. Yes, it did. On June 18, 2018, Moody's released an article, a copy of which is attached as Exhibit DKA-5, shifting the utility sector outlook from stable to negative. Moody's Outlook was based in part on its assessment that the TCJA will likely have a negative impact on utilities' cash flows, thus increasing the need for and cost of additional financings.

With regard to the Companies, although KU and LG&E have maintained capital structures consistent with their structures prior to the passage of the Tax Cuts and Jobs Act, the Companies' metrics will be lower for Moody's and S&P simply because of the impact on cash flows. As an example, the most heavily weighted financial metric used by Moody's is Cash from Operations Pre-Working Capital to Debt ratio. Moody's published range for this metric supporting the Companies' current credit rating is 22% to 30%. At current rates with the Commission approved TCJA Surcredit amount, KU's and LG&E's ratios fall below the low end of Moody's range.

Q. Do KU and LG&E have sufficient access to short term capital?

A. Yes. KU has authority from the FERC to issue up to $500 million in short-term debt,[6] and maintains a $400 million line of credit. The primary source used by KU for short-term liquidity needs is its $350 million commercial paper program. LG&E also has authority from the FERC to issue up to $500 million in short-term debt,[7] and maintains a $500 million line of credit. LG&E likewise maintains a commercial paper program of $350 million.

IV. RETURN ON COMMON EQUITY

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?

[6] FERC Docket No. ES17-55-000 dated November 17, 2017.
[7] FERC Docket No. ES17-41-000, September 18, 2017.

A. Yes, I do. I have reviewed his analyses that support his recommendation and find Mr. McKenzie's proposed return on common equity of 10.42% percent to be fair and reasonable.

V. COST OF DEBT AND DEBT ISSUANCE

Q. Do the Companies' cost of debt compare favorably to other utility companies?

A. Yes, it does. Since 2007, the Companies have closely monitored their cost of debt in comparison to a peer group of other utility companies on a quarterly basis. KU and LG&E have consistently been in the top five for the lowest cost of debt during this almost eleven-year period. As shown on Exhibit DKA-6, KU's cost of debt (combined taxable and tax-exempt debt) is fifth lowest of the twenty-five member group for the twelve months ending June 30, 2018. LG&E has the second lowest debt costs of the group. This comparison further demonstrates that the Companies' cost of debt is reasonable.

Q. What debt issuance activities have occurred since the filing of the last rate case in November 2016?

A. In January of 2017 and 2018, KU extended the term of its revolving credit facility pursuant to the authority granted by the Commission in Case No. 2016-00360. In August 2017, KU also extended its letter of credit facility. In July 2018, KU redeemed its $8,927,000 Trimble Co. 2007 Series A bond. In September 2018, KU also refinanced at a lower rate its $17,875,000 Carroll No. 2007 Series A bond.

In November 2016, LG&E redeemed a $25 million Jefferson Co. 2000 Series A bond. In June 2017, LG&E refinanced at a lower rate its $60 million Trimble County 2007 Series A bond. In October 2017, LG&E entered into a $200,000,000 term loan with US Bank. Because the term was for less than two years, LG&E was only required to obtain FERC approval and did so. In November of 2017, the Company redeemed its $10.1 million Trimble County 2001 Series A bond. In January 2017 and 2018, LG&E extended the term of its revolving credit facility pursuant to the authority granted by the Commission in Case No. 2016-00361.

Q. What debt issuance activities do KU and LG&E expect during the forecasted test period?

A. KU and LG&E expect to issue First Mortgage bonds in May 2019 of $300 million and $500 million, respectively.

VI. 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 for both KU's and LG&E's applications:

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 written testimony form, of all factor uses 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)	Utility's annual and monthly budget for twelve (12) months preceding filing date, base period, and forecasted period
Section 16(7)(f)	For each major construction project which constitutes five (5) percent or more of the annual construction budget within the three (3) year forecast the following information shall be filed: 1. The date the project was started or estimated starting date; 2. The estimated completion date; 3. The 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. The most recent available total costs incurred exclusive

	and inclusive of AFUDC or interest during construction credit
Section 16(7)(g)	For all construction projects which constitute less than five (5) percent of the annual construction budget within the three (3) year forecast, the utility shall file an aggregate of the information requested in paragraph (f)3 and 4 of this subsection
Section 16(7)(h)(1-4), (9)-(12)	A financial forecast corresponding to each of the three (3) forecasted years included in the capital construction budget. The financial forecast shall be supported by the underlying assumptions made in projecting the results of operations and shall include 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; 11. Capital structure requirements; 12. Rate base;
Section 16(7)(j)	The prospectuses of the most recent stock or bond offerings
Section 16(7)(n)	The latest twelve (12) months of the monthly managerial reports providing financial results of operations in comparison to the forecast
Section 16(7)(o)	Complete monthly budget variance reports, with narrative explanations, for the twelve (12) months immediately prior to the base period, each month of the base period, and any subsequent months, as they become available
Section 16(7)(t)	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 utility's application. This list shall include each software, program, or model; what the software, program, or model was used for; identify the supplier of each software, program, or model; a brief description of the software, program, or model; the specifications for the computer hardware and the operating system required to run the program
Section 16(8)(g)	Analyses of payroll costs including schedules for wages and salaries, employee 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)(j)	A cost of capital summary for both the base period and forecasted period with supporting schedules providing details on each component of the capital structure
Section 16(8)(k)	Comparative financial data and earnings measures for the ten (10) most recent calendar years, the base period, and the forecast period

A. Cost of Capital Summary

Q. Has KU and LG&E each 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 applications. 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. I sponsor each of the schedules, except for B-1.1, which is sponsored by Mr. Garrett.

Q. Please describe Schedule J-1.

A. In KU's application, Schedule J-1 shows the calculation of its adjusted capitalization, as well as the weighted average cost of capital, as of the end of the base and forecasted test periods.

For LG&E, Schedule J-1 shows the calculation of its adjusted capitalization for electric and gas operations, as well as the weighted average cost of capital, as of the end of the base and forecasted test periods for its electric and gas operations.

Q. Please describe Schedule J-1.1/J-1.2 filed to support KU's application.

A. As 807 KAR 5:001 Section 16(6)(c) requires, Schedule J-1.1/J-1.2 shows the calculation of KU's 13-month-average adjusted capitalization, as well as the weighted average cost of capital, KU 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 7.56 percent, based on the proposed 10.42% percent return on common equity proposed by KU, 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. 2016-00370, 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 KU'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 KU's capitalization is necessary because KU 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 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, 7.56 percent, appears in Line 4 of Schedule A.

Q. Please describe Schedule J-1.1/J-1.2 filed to support LG&E's application.

A. Schedule J-1.1/J-1.2 shows the calculation of LG&E's 13-month-average adjusted capitalization for electric and gas operations, as well as the weighted average cost of capital, LG&E 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 electric and gas capitalization is 7.62 percent, based on the proposed 10.42% percent return on common equity proposed by LG&E, which is the return on common equity recommended by Mr. McKenzie. Pages 1 and 2 provide this calculation for the electric and gas operations, respectively. Pages 3 and 4 detail the “Adjustment Amount” reflected in Column F of Pages 1 and 2.

The adjustments on pages 3 and 4 of this Schedule at Column E remove the ECR rate base from the electric operations’ capitalization and the GLT rate base from the gas operations’ capitalization. The adjustments on pages 3 and 4 of this Schedule at Column F remove the DSM rate base amounts from both the electric and gas operations’ capitalization to be considered in this proceeding. Removing ECR, GLT, and DSM rate base from the electric and gas operations’ capitalization is necessary because LG&E recovers its ECR, GLT, and DSM capital investments and a return on those investments through the ECR, GLT and DSM cost-recovery mechanisms.

The adjustments on Pages 3 and 4 of this Schedule at Columns G through J remove from LG&E’s capitalization the 25 percent portion of Trimble County Unit No. 1 inventories that represent IMEA’s and IMPA’s portions of these assets, LG&E’s equity investment in Ohio Valley Electric Corporation and other investments, and add the Job Development Investment Tax Credit, the Qualifying Advanced Coal Project Program Investment Tax Credit, and the Solar Investment Tax Credit, consistent with the adjustments the Commission approved in Case Nos. 2009-00549 and 2003-00433, and as proposed by LG&E in Case Nos. 2016-00371, 2014-00372, 2012-00222 and 2008-00252, which was resolved by a settlement approved by the Commission. The Job Development Investment Tax Credit is the only adjustment in Columns G through J that applies to gas operations’ capitalization and is included in Column H on page 4.

Column D on pages 1 and 2 of this schedule reflect the rate base allocation factor to allocate the 13-month average between electric and gas operations. Column H shows each capital component's percentage of total capitalization, which is calculated by dividing the individual capital component's amount shown in Column G by the "Total Capital" shown at the bottom of Column G. Column I 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 I discussed above. Finally, Column J multiplies capitalization percentages in Column H by the cost rates in Column I to obtain the 13-month-average weighted cost of each capital component. This weighted capital cost, 7.62 percent, is shown in Column J and is used on Line 4 of Schedule A to calculate the Company's Required Operating Income for the forecasted period.

Q. Please describe Schedule J-2 in KU's and LG&E's applications.

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, December 31, 2018. The second page provides the short-term debt information as of the end of the forecasted test period, April 30, 2020. The third page provides the 13-month-average short-term debt information for the forecasted test period.

Q. Please explain how KU's and LG&E'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, KU's rate is projected to be 2.59 percent, and for the forecasted period the 13-month average rate is calculated to be 3.23 percent. LG&E's rates at the end of the base period and the forecasted 13-month average rate are 2.59 percent and 3.25 percent, respectively. 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 and LG&E expect to provide updates on the cost of short-term debt as the cases develop.

Q. Please describe Schedule J-3 in KU's and LG&E's applications.

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, December 31, 2018. The second page provides the long-term debt information as of the end of the forecasted test period, April 30, 2020. 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. KU's weighted-average cost of long-term debt at the end of the base period is projected to be 4.23 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 4.38 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 how LG&E's cost of long-term debt was calculated on Schedule J-3.

A. LG&E's weighted-average cost of long-term debt at the end of the base period is projected to be 4.13 percent. Consistent with prior rate cases, this includes all components of interest expense for each bond, including the interest paid to bondholders or bank (in the case of the LG&E $200 million term loan), amortization of the debt 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 and letters of credit where applicable, interest paid on outstanding interest rate swap agreements, and amortization of pre-issuance hedging gains or losses. A regulatory asset has been recorded for the mark-to-market value of the outstanding interest rate swaps. This regulatory asset is amortized to interest expense as shown on Schedule J-3 in the amount of the monthly cash settlements and monthly fluctuations in the mark-to-market value are recorded to the regulatory asset balance. Additionally, 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.

LG&E's weighted-average cost of long-term debt for the forecasted test period is calculated as 4.53 percent. The calculation of LG&E's cost of long-term debt is detailed on Filing schedule J-3 as required by 807 KAR 5:001, Section 16(8)(j).

Q. Do you have a recommendation to the Commission?

A. Yes, my recommendation is the Commission approve the Companies' applications and requested increases in rates therein.

Q. Does this conclude your testimony?

A. Yes, it does.

VERIFICATION

COMMONWEALTH OF KENTUCKY)
)
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 21st day of September 2018.

Judy Schooler

Notary Public

My Commission Expires:

Judy Schooler
Notary Public, ID No. 603967
State at Large, Kentucky
Commission Expires 7/11/2022

APPENDIX A

Daniel K. Arbough

Treasurer
Kentucky Utilities Company
Louisville Gas and Electric Company

220 West Main Street
Louisville, Kentucky 40202
(502) 627-4956

<u>Previous Positions</u>

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

<u>Professional/Trade Memberships</u>

National Association of Corporate Treasurers
Association for Financial Professionals
Financial Executives International

<u>Education</u>

Master of Business Administration – Finance - May 1988 – University of Denver
Bachelor of Science Business Administration – General Business – June 1983
University of Denver

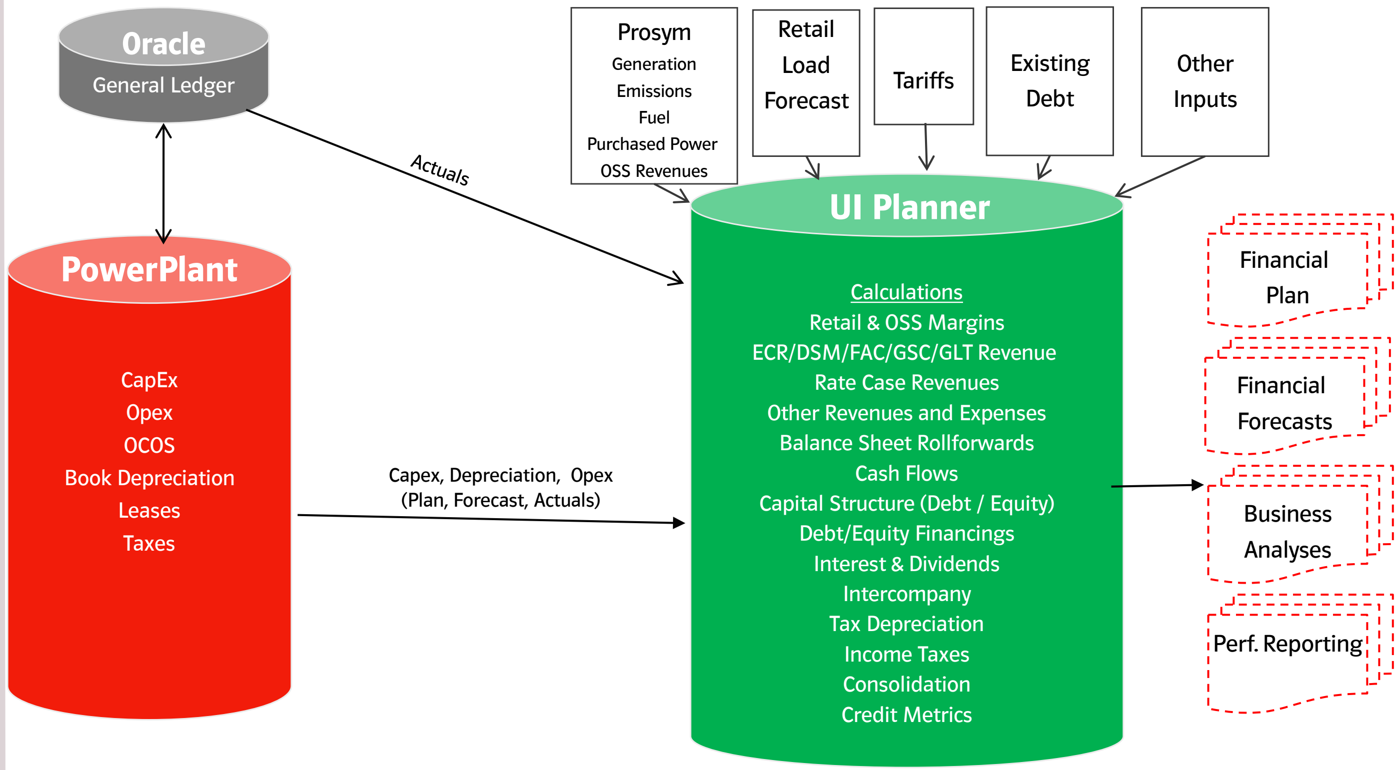
<u>Civic Activities</u>

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 depiction of the planning process

Financial Planning Software



LG&E KU
PPL companies

Exhibit DKA-1
Page 1 of 1

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 Intercompany costs brought in via PowerPlan	Excel PowerPlan
Other Operating Revenue	Projected based on historical trends or current contracts (if any) as well as incorporating any tariff changes.	Excel
Fuel	Based on generation forecast and heat rates by plant x price curves which are a blend of contracted rates and market prices for unhedged positions	Prosym
Gas Supply	Gas load forecast priced out at contracted rates and market prices for open/indexed positions	Excel

Income Statement

Line Item	*Basis to Derive*	*System Employed*
Purchased Power	Projected in generation forecast model run using contracted capacity terms and market prices	Prosym
Other Cost of Sales	Existing contract/market prices for consumables applied to generation forecast by plant and usage rates for each plant	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 (Filed rates based on most recent depreciation study to be approved by the KPSC)	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 for current year, projected balances are set a$5 million per utility.	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

Balance Sheet

Line Item	*Basis to Derive*	*System Employed*
Leases	Monthly balance sheet amounts are obtained via Excel from the PowerPlan Lease module and uploaded to UI.	Excel PowerPlan
Other Assets	Current levels only adjusted for known changes	
Accounts Payable	Function of capital and O&M spend, adjusted for some payment lag	UIPlanner
Accrued Interest	Calculated based on debt schedules	UIPlanner
Accrued Taxes	Calculated based on income tax expense calculations and payment schedules	UIPlanner
Deferred Income Taxes	Rollforward maintained based on book and tax depreciation using capital plan, current tax rates and book depreciation rates	UIPlanner 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 Utility Rating Methodology

MOODY'S
INVESTORS SERVICE

RATING METHODOLOGY

Regulated Electric and Gas Utilities

Table of Contents:

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This rating methodology replaces "Regulated Electric and Gas Utilities" last revised on December 23, 2013. We have updated some outdated links and removed certain issuer-specific information.

Summary

This rating methodology explains our approach to assessing credit risk for regulated electric and gas utilities globally. This document does not include an exhaustive treatment of all factors that are reflected in our 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. [1]

This report includes a detailed rating grid which 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 grid in this document uses 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.

THIS RATING METHODOLOGY WAS UPDATED ON FEBRUARY 15, 2018. WE HAVE CORRECTED THE FORMATTING OF THE FACTOR 4: FINANCIAL STRENGTH TABLE ON PAGE 34.

THIS RATING METHODOLOGY WAS UPDATED ON SEPTEMBER 27, 2017. WE REMOVED A DUPLICATE FOOTNOTE THAT WAS PLACED IN THE MIDDLE OF THE TEXT ON PAGE 7

[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:

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

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 might 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), our approach to ratings within a utility family (Appendix B), a description of the various types of companies rated under this methodology (Appendix C), key industry issues over the intermediate term (Appendix D), regional and other considerations (Appendix E), and treatment of power purchase agreements (Appendix F).

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. A link to documents that describe our approach to such cross-sector credit rating methodological considerations can be found in the Related Research section of this report.

About the Rated Universe

The Regulated Electric and Gas Utilities rating methodology applies to rate-regulated[2] electric and gas utilities that are not Networks[3]. Regulated Electric and Gas Utilities are companies whose predominant[45] 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 C, 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.[5]

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

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.

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.

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.

A link to credit rating methodologies covering these and other sectors can be found in the Related Research section of this report.

vary significantly from jurisdiction to jurisdiction. Most issuers at the lower end of the ratings spectrum operate in challenging regulatory environments.

About this Rating Methodology

This report explains the rating methodology for regulated electric and gas utilities in sixsections, 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 comprisedof 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 thegrid. We also provide a rationale for why each of these grid components is meaningful as a creditindicator. The information used in assessing the sub-factors is generally found in or calculated frominformation in company financial statements, derived from other observations or estimated by our analysts.[6] All of the quantitative credit metrics incorporate Moody's standard adjustments toincome 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.[7]

For definitions of our most common ratio terms, please see "Moody's Basic Definitions for Credit Statistics, User's Guide," a link to which may be found in the Related Research section of this report.

Our standard adjustments are described in "Financial Statement Adjustments in the Analysis of Non-Financial Corporations". A link to this and other sector and cross-sector credit rating methodologies can be found in the Related Research section of this report.

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 the rating grid. 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. 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.

5. Determining the Overall Grid-Indicated Rating[8]

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	$1.5 \leq x < 2.5$
Aa2	$2.5 \leq x < 3.5$
Aa3	$3.5 \leq x < 4.5$
A1	$4.5 \leq x < 5.5$
A2	$5.5 \leq x < 6.5$
A3	$6.5 \leq x < 7.5$
Baa1	$7.5 \leq x < 8.5$
Baa2	$8.5 \leq x < 9.5$
Baa3	$9.5 \leq x < 10.5$

In general, the grid-indicated rating is oriented to the Corporate Family Rating (CFR) for speculative-grade issuers and the senior unsecured rating for investment-grade issuers. For issuers that benefit from ratings uplift due to parental support, government ownership or other institutional support, the grid-indicated rating is oriented to the baseline credit assessment. For an explanation of baseline credit assessment, please refer to our rating methodology on government-related issuers. Individual debt instrument ratings also factor in decisions on notching for seniority level and collateral. The documents that provide broad guidance for these notching decisions are our rating methodologies on loss given default for speculative grade non-financial companies and for aligning corporate instrument ratings based on differences in security and priority of claim. The link to these and other sector and cross-sector credit rating methodologies can be found in the Related Research section of this report.

Grid-Indicated Rating

Grid-Indicated Rating	Aggregate Weighted Total Factor Score
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.

6. Appendices

The Appendices present a full grid and provide additional commentary and insights on our view of credit risks in this industry.

Discussion of the Grid Factors

Our 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[9] 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 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.

9 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.

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 economically to 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 more highly in this sub-factor. Issuers that have concentration in one or two sources of generation, especially if they are threatened or challenged sources, will incur lower scores.

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	5.00% *	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	5.00% **	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	Definiitons
Market Position	5.00% *	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	5.00% **	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. 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 our standard adjustments[10], 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[11]. 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.

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

In certain circumstances, analysts may also apply specific adjustments.

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

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	7.50%		≥ 8.0x	6.0x - 8.0x	4.5x - 6.0x	3.0x - 4.5x	2.0x - 3.0x	1.0x - 2.0x	< 1.0x
CFO pre-WC / Debt	15.00%	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	10.00%	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	7.50%	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 upstreamed by the OpCos[12]. 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[1310] 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[14]

» Significant dividend limitations or potential limitations at an important OpCo

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

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:

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

13 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.

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

- 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 B has additional insights on ratings within a utility family.

Rating Methodology Assumptions, 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 might 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 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 lack of 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 precisely to 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

We consider 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 typically only rarely will 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 generally has 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 us 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.[15]

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.

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

15 See also the cross-sector methodology "How Sovereign Credit Quality May Affect Other Ratings." A link to this and other sector and cross-sector credit rating methodologies can be found in the Related Research section of this report.

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.

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.

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

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	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

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	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: 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[16][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

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

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

» 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 C) 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. Typically, most entities in US utility families (including HoldCos and OpCos) are rated within 3 notches of each other. However, it is possible for the HoldCo and OpCos in a family to 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 C: 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.

Utility Holding Company (Utility HoldCo): As detailed in Appendix B, 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 D: 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, largerwaves 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 longperiod of globally low interest rates, held down by monetary stimulus policies, has generally benefittedutilities, 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 topredict is how regulators will respond when monetary stimulus reverses, and how well utilities will farewhen fixed income investors require higher interest rates and equity investors require higher total returnsand 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 compressionof returns has been relatively steep in recent years. In Japan, the regulatory authorities are working throughthe challenges presented by the decision to shut down virtually all of the country's nuclear generationcapacity, 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 frameworkhas continued to evolve, with fairly low transparency and some time-to-time shifts in favored versus less-favoredgeneration 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 developedand supportive regulatory frameworks despite a trend towards lower returns, whereas Malaysia, Korea andThailand have been moving towards a more transparent regulatory framework. The Philippines is in theprocess of deregulating its power market, while Indian power utilities continue to grapple with structuralchallenges. 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 tounsettled economic and financial market conditions for several reasons. Unlike many companies that facedirect market-based competition, their rates do not decrease when demand decreases. The elasticityof demand for electricity and gas is much lower than for most products in the consumereconomy.

When financial markets are volatile, utilities often have greater capital market access thanindustrial 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 severerecession.

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 copperwire 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 disrupt materially 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, 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.

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. 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. decided to shut permanently 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 closed permanently 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 and its parent, Korea Electric Power Corporation, faced 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 shut down temporarily.

Appendix E: 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," including a one notch differential between senior secured and senior unsecured debt.[17] 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 Companies."[18]

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

17 A link to this and other sector and cross-sector credit rating methodologies can be found in the Related Research section of this report.
18 A link to this and other sector and cross-sector credit rating methodologies can be found in the Related Research section of this report.

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, we make our 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 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.[19]

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

Our 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. 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.

A link to this and other sector and cross-sector credit rating methodologies can be found in the Related Research section of this report.

Appendix F: 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 we regard 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 we analyze them 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 we treat 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 we recognize that this is the fundamental reason for their existence. Thus, we 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 we regard 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, our 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. We will focus particularly 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 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. We 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 our 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, we 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, we 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, we 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 we believe 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

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

Please refer to Moody's Rating Symbols & Definitions, which is available here, for further information. Definitions of Moody's most common ratio terms can be found in "Moody's Basic Definitions for Credit Statistics, User's Guide", accessible via this link.

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Exhibit DKA-4

Standard and Poor's Utility Rating Methodology

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Key Credit Factors For The Regulated Utilities Industry

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Key Credit Factors For The Regulated Utilities Industry

*(**Editor's Note:** This criteria article supersedes "Key Credit Factors: Business And Financial Risks In The Investor-Owned Utilities Industry," published Nov. 26, 2008, "Assessing U.S. Utility Regulatory Environments," Nov. 7, 2007, and "Revised Methodology For Adjusting Amounts Reported By U.K. GAAP Water Companies For Infrastructure Renewals Accounting," Jan. 27, 2010.)*

1. Standard & Poor's Ratings Services is refining and adapting its methodology and assumptions for its Key Credit Factors: Criteria For Regulated Utilities. We are publishing these criteria in conjunction with our corporate criteria (see "Corporate Methodology, published Nov. 19, 2013). This article relates to our criteria article, "Principles Of Credit Ratings," Feb. 16, 2011.

2. This criteria article supersedes "Key Credit Factors: Business And Financial Risks In The Investor-Owned Utilities Industry," Nov. 26, 2008, "Criteria: Assessing U.S. Utility Regulatory Environments," Nov. 7, 2007, and "Revised Methodology For Adjusting Amounts Reported By U.K. GAAP Water Companies For Infrastructure Renewals Accounting," Jan. 27, 2010.

SCOPE OF THE CRITERIA

3. These criteria apply to entities where regulated utilities represent a material part of their business, other than U.S. public power, water, sewer, gas, and electric cooperative utilities that are owned by federal, state, or local governmental bodies or by ratepayers. A regulated utility is defined as a corporation that offers an essential or near-essential infrastructure product, commodity, or service with little or no practical substitute (mainly electricity, water, and gas), a business model that is shielded from competition (naturally, by law, shadow regulation, or by government policies and oversight), and is subject to comprehensive regulation by a regulatory body or implicit oversight of its rates (sometimes referred to as tariffs), service quality, and terms of service. The regulators base the rates that they set on some form of cost recovery, including an economic return on assets, rather than relying on a market price. The regulated operations can range from individual parts of the utility value chain (water, gas, and electricity networks or "grids," electricity generation, retail operations, etc.) to the entire integrated chain, from procurement to sales to the end customer. In some jurisdictions, our view of government support can also affect the final rating outcome, as per our government-related entity criteria (see "General Criteria: Rating Government-Related Entities: Methodology and Assumptions," Dec. 9, 2010).

SUMMARY OF THE CRITERIA

4. Standard & Poor's is updating its criteria for analyzing regulated utilities, applying its corporate criteria. The criteria for evaluating the competitive position of regulated utilities amend and partially supersede the "Competitive Position" section of the corporate criteria when evaluating these entities. The criteria for determining the cash flow leverage

assessment partially supersede the "Cash Flow/Leverage" section of the corporate criteria for the purpose of evaluating regulated utilities. The section on liquidity for regulated utilities partially amends existing criteria. All other sections of the corporate criteria apply to the analysis of regulated utilities.

IMPACT ON OUTSTANDING RATINGS

5. These criteria could affect the issuer credit ratings of about 5% of regulated utilities globally due primarily to the introduction of new financial benchmarks in the corporate criteria. Almost all ratings changes are expected to be no more than one notch, and most are expected to be in an upward direction.

EFFECTIVE DATE AND TRANSITION

6. These criteria are effective immediately on the date of publication.

METHODOLOGY

Part I--Business Risk Analysis

Industry risk

7. Within the framework of Standard & Poor's general criteria for assessing industry risk, we view regulated utilities as a "very low risk" industry (category '1'). We derive this assessment from our view of the segment's low risk ('2') cyclicality and very low risk ('1') competitive risk and growth assessment.

8. In our view, demand for regulated utility services typically exhibits low cyclicality, being a function of such key drivers as employment growth, household formation, and general economic trends. Pricing is non-cyclical, since it is usually based in some form on the cost of providing service.

Cyclicality

9. We assess cyclicality for regulated utilities as low risk ('2'). Utilities typically offer products and services that are essential and not easily replaceable. Based on our analysis of global Compustat data, utilities had an average peak-to-trough (PTT) decline in revenues of about 6% during recessionary periods since 1952. Over the same period, utilities had an average PTT decline in EBITDA margin of about 5% during recessionary periods, with PTT EBITDA margin declines less severe in more recent periods. The PTT drop in profitability that occurred in the most recent recession (2007-2009) was less than the long-term average.

10. With an average drop in revenues of 6% and an average profitability decline of 5%, utilities' cyclicality assessment calibrates to low risk ('2'). We generally consider that the higher the level of profitability cyclicality in an industry, the higher the credit risk of entities operating in that industry. However, the overall effect of cyclicality on an industry's risk profile may be mitigated or exacerbated by an industry's competitive and growth environment.

Competitive risk and growth

11 We view regulated utilities as warranting a very low risk ('1') competitive risk and growth assessment. For competitive risk and growth, we assess four sub-factors as low, medium, or high risk. These sub-factors are:

- Effectiveness of industry barriers to entry;
- Level and trend of industry profit margins;
- Risk of secular change and substitution by products, services, and technologies; and
- Risk in growth trends.

Effectiveness of barriers to entry--low risk

12. Barriers to entry are high. Utilities are normally shielded from direct competition. Utility services are commonly naturally monopolistic (they are not efficiently delivered through competitive channels and often require access to public thoroughfares for distribution), and so regulated utilities are granted an exclusive franchise, license, or concession to serve a specified territory in exchange for accepting an obligation to serve all customers in that area and the regulation of its rates and operations.

Level and trend of industry profit margins--low risk

13. Demand is sometimes and in some places subject to a moderate degree of seasonality, and weather conditions can significantly affect sales levels at times over the short term. However, those factors even out over time, and there is little pressure on margins if a utility can pass higher costs along to customers via higher rates.

Risk of secular change and substitution of products, services, and technologies--low risk

14. Utility products and services are not overly subject to substitution. Where substitution is possible, as in the case of natural gas, consumer behavior is usually stable and there is not a lot of switching to other fuels. Where switching does occur, cost allocation and rate design practices in the regulatory process can often mitigate this risk so that utility profitability is relatively indifferent to the substitutions.

Risk in industry growth trends--low risk

15 As noted above, regulated utilities are not highly cyclical. However, the industry is often well established and, in our view, long-range demographic trends support steady demand for essential utility services over the long term. As a result, we would expect revenue growth to generally match GDP when economic growth is positive.

B. Country risk

16. In assessing "country risk" for a regulated utility, our analysis uses the same methodology as with other corporate issuers (see "Corporate Methodology").

C. Competitive position

17. In the corporate criteria, competitive position is assessed as ('1') excellent, ('2') strong, ('3') satisfactory, ('4') fair, ('5') weak, or ('6') vulnerable.

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

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

19 In the corporate criteria we assess the strength of each of the first three components. Each component is assessed as either: (1) strong, (2) strong/adequate, (3) adequate, (4) adequate/weak, or (5) weak. After assessing these components, we determine the preliminary competitive position assessment by ascribing a specific weight to each component. The applicable weightings will depend on the company's Competitive Position Group Profile. The group profile for regulated utilities is "National Industries & Utilities," with a weighting of the three components as follows: competitive advantage (60%), scale, scope, and diversity (20%), and operating efficiency (20%). Profitability is assessed by combining two sub-components: level of profitability and the volatility of profitability.

20. "Competitive advantage" cannot be measured with the same sub-factors as competitive firms because utilities are not primarily subject to influence of market forces. Therefore, these criteria supersede the "competitive advantage" section of the corporate criteria. We analyze instead a utility's "regulatory advantage" (section 1 below).

Assessing regulatory advantage

21. The regulatory framework/regime's influence is of critical importance when assessing regulated utilities' credit risk because it defines the environment in which a utility operates and has a significant bearing on a utility's financial performance.

22. We base our assessment of the regulatory framework's relative credit supportiveness on our view of how regulatory stability, efficiency of tariff setting procedures, financial stability, and regulatory independence protect a utility's credit quality and its ability to recover its costs and earn a timely return. Our view of these four pillars is the foundation of a utility's regulatory support. We then assess the utility's business strategy, in particular its regulatory strategy and its ability to manage the tariff-setting process, to arrive at a final regulatory advantage assessment.

23. When assessing regulatory advantage, we first consider four pillars and sub-factors that we believe are key for a utility to recover all its costs, on time and in full, and earn a return on its capital employed:

24. Regulatory stability:

- Transparency of the key components of the rate setting and how these are assessed
- Predictability that lowers uncertainty for the utility and its stakeholders
- Consistency in the regulatory framework over time

25 Tariff-setting procedures and design:

- Recoverability of all operating and capital costs in full
- Balance of the interests and concerns of all stakeholders affected
- Incentives that are achievable and contained

26. Financial stability:

- Timeliness of cost recovery to avoid cash flow volatility
- Flexibility to allow for recovery of unexpected costs if they arise
- Attractiveness of the framework to attract long-term capital
- Capital support during construction to alleviate funding and cash flow pressure during periods of heavy investments

27 Regulatory independence and insulation:

- Market framework and energy policies that support long-term financeability of the utilities and that is clearly enshrined in law and separates the regulator's powers
- Risks of political intervention is absent so that the regulator can efficiently protect the utility's credit profile even during a stressful event

28. We have summarized the key characteristics of the assessments for regulatory advantage in table 1.

Table 1

Preliminary Regulatory Advantage Assessment

Qualifier	What it means	Guidance
Strong	The utility has a major regulatory advantage due to one or a combination of factors that support cost recovery and a return on capital combined with lower than average volatility of earnings and cash flows.	The utility operates in a regulatory climate that is transparent, predictable, and consistent from a credit perspective.
	There are strong prospects that the utility can sustain this advantage over the long term.	The utility can fully and timely recover all its fixed and variable operating costs, investments and capital costs (depreciation and a reasonable return on the asset base).
	This should enable the utility to withstand economic downturns and political risks better than other utilities.	The tariff set may include a pass-through mechanism for major expenses such as commodity costs, or a higher return on new assets, effectively shielding the utility from volume and input cost risks.
		Any incentives in the regulatory scheme are contained and symmetrical.
		The tariff set includes mechanisms allowing for a tariff adjustment for the timely recovery of volatile or unexpected operating and capital costs.
		There is a track record of earning a stable, compensatory rate of return in cash through various economic and political cycles and a projected ability to maintain that record.
		There is support of cash flows during construction of large projects, and pre-approval of capital investment programs and large projects lowers the risk of subsequent disallowances of capital costs.
		The utility operates under a regulatory system that is sufficiently insulated from political intervention to efficiently protect the utility's credit risk profile even during stressful events.
Adequate	The utility has some regulatory advantages and protection, but not to the extent that it leads to a superior business model or durable benefit.	It operates in a regulatory environment that is less transparent, less predictable, and less consistent from a credit perspective.
	The utility has some but not all drivers of well-managed regulatory risk. Certain regulatory factors support the business's long-term stability and viability but could result in periods of below-average levels of profitability and greater profit volatility. However, overall these regulatory drivers are partially offset by the utility's disadvantages or lack of sustainability of other factors.	The utility is exposed to delays or is not, with sufficient certainty, able to recover all of its fixed and variable operating costs, investments, and capital costs (depreciation and a reasonable return on the asset base) within a reasonable time.
		Incentive ratemaking practices are asymmetrical and material, and could detract from credit quality.
		The utility is exposed to the risk that it doesn't recover unexpected or volatile costs in a full or less than timely manner due to lack of flexible reopeners or annual revenue adjustments.
		There is an uneven track record of earning a compensatory rate of return in cash through various economic and political cycles and a projected ability to maintain that record.

Table 1

Preliminary Regulatory Advantage Assessment (cont.)		
		There is little or no support of cash flows during construction, and investment decisions on large projects (and therefore the risk of subsequent disallowances of capital costs) rest mostly with the utility.
		The utility operates under a regulatory system that is not sufficiently insulated from political intervention and is sometimes subject to overt political influence.
Weak	The utility suffers from a complete breakdown of regulatory protection that places the utility at a significant disadvantage.	The utility operates in an opaque regulatory climate that lacks transparency, predictability, and consistency.
	The utility's regulatory risk is such that the long-term cost recovery and investment return is highly uncertain and materially delayed, leading to volatile or weak cash flows. There is the potential for material stranded assets with no prospect of recovery.	The utility cannot fully and/or timely recover its fixed and variable operating costs, investments, and capital costs (depreciation and a reasonable return on the asset base).
		There is a track record of earning minimal or negative rates of return in cash through various economic and political cycles and a projected inability to improve that record sustainably.
		The utility must make significant capital commitments with no solid legal basis for the full recovery of capital costs.
		Ratemaking practices actively harm credit quality.
		The utility is regularly subject to overt political influence.

29. After determining the preliminary regulatory advantage assessment, we then assess the utility's business strategy. Most importantly, this factor addresses the effectiveness of a utility's management of the regulatory risk in the jurisdiction(s) where it operates. In certain jurisdictions, a utility's regulatory strategy and its ability to manage the tariff-setting process effectively so that revenues change with costs can be a compelling regulatory risk factor. A utility's approach and strategies surrounding regulatory matters can create a durable "competitive advantage" that differentiates it from peers, especially if the risk of political intervention is high. The assessment of a utility's business strategy is informed by historical performance and its forward-looking business objectives. We evaluate these objectives in the context of industry dynamics and the regulatory climate in which the utility operates, as evaluated through the factors cited in paragraphs 24-27.

30. We modify the preliminary regulatory advantage assessment to reflect this influence positively or negatively. Where business strategy has limited effect relative to peers, we view the implications as neutral and make no adjustment. A positive assessment improves the preliminary regulatory advantage assessment by one category and indicates that management's business strategy is expected to bolster its regulatory advantage through favorable commission rulings beyond what is typical for a utility in that jurisdiction. Conversely, where management's strategy or businesses decisions result in adverse regulatory outcomes relative to peers, such as failure to achieve typical cost recovery or allowed returns, we adjust the preliminary regulatory advantage assessment one category worse. In extreme cases of poor strategic execution, the preliminary regulatory advantage assessment is adjusted by two categories worse (when possible; see table 2) to reflect management decisions that are likely to result in a significantly adverse regulatory outcome relative to peers.

Table 2

Determining The Final Regulatory Advantage Assessment

	--Strategy modifier--			
Preliminary regulatory advantage score	**Positive**	**Neutral**	**Negative**	**Very negative**
Strong	Strong	Strong	Strong/Adequate	Adequate
Strong/Adequate	Strong	Strong/Adequate	Adequate	Adequate/Weak
Adequate	Strong/Adequate	Adequate	Adequate/Weak	Weak
Adequate/Weak	Adequate	Adequate/Weak	Weak	Weak
Weak	Adequate/Weak	Weak	Weak	Weak

Scale, scope, and diversity

31. We consider the key factors for this component of competitive position to be primarily operational scale and diversity of the geographic, economic, and regulatory foot prints. We focus on a utility's markets, service territories, and diversity and the extent that these attributes can contribute to cash flow stability while dampening the effect of economic and market threats.

32. A utility that warrants a Strong or Strong/Adequate assessment has scale, scope, and diversity that support the stability of its revenues and profits by limiting its vulnerability to most combinations of adverse factors, events, or trends. The utility's significant advantages enable it to withstand economic, regional, competitive, and technological threats better than its peers. It typically is characterized by a combination of the following factors:

- A large and diverse customer base with no meaningful customer concentration risk, where residential and small to medium commercial customers typically provide most operating income.
- The utility's range of service territories and regulatory jurisdictions is better than others in the sector.
- Exposure to multiple regulatory authorities where we assess preliminary regulatory advantage to be at least Adequate. In the case of exposure to a single regulatory regime, the regulatory advantage assessment is either Strong or Strong/Adequate.
- No meaningful exposure to a single or few assets or suppliers that could hurt operations or could not easily be replaced.

33. A utility that warrants a Weak or Weak/Adequate assessment lacks scale, scope, and diversity such that it compromises the stability and sustainability of its revenues and profits. The utility's vulnerability to, or reliance on, various elements of this sub-factor is such that it is less likely than its peers to withstand economic, competitive, or technological threats. It typically is characterized by a combination of the following factors:

- A small customer base, especially if burdened by customer and/or industry concentration combined with little economic diversity and average to below-average economic prospects;
- Exposure to a single service territory and a regulatory authority with a preliminary regulatory advantage assessment of Adequate or Adequate/Weak; or
- Dependence on a single supplier or asset that cannot easily be replaced and which hurts the utility's operations.

34. We generally believe a larger service territory with a diverse customer base and average to above-average economic growth prospects provides a utility with cushion and flexibility in the recovery of operating costs and ongoing investment (including replacement and growth capital spending), as well as lessening the effect of external shocks (i.e.,

extreme local weather) since the incremental effect on each customer declines as the scale increases.

35. We consider residential and small commercial customers as having more stable usage patterns and being less exposed to periodic economic weakness, even after accounting for some weather-driven usage variability. Significant industrial exposure along with a local economy that largely depends on one or few cyclical industries potentially contributes to the cyclicality of a utility's load and financial performance, magnifying the effect of an economic downturn.

36. A utility's cash flow generation and stability can benefit from operating in multiple geographic regions that exhibit average to better than average levels of wealth, employment, and growth that underpin the local economy and support long-term growth. Where operations are in a single geographic region, the risk can be ameliorated if the region is sufficiently large, demonstrates economic diversity, and has at least average demographic characteristics.

37 The detriment of operating in a single large geographic area is subject to the strength of regulatory assessment. Where a utility operates in a single large geographic area and has a strong regulatory assessment, the benefit of diversity can be incremental.

Operating efficiency

38. We consider the key factors for this component of competitive position to be:

- Compliance with the terms of its operating license, including safety, reliability, and environmental standards;
- Cost management; and
- Capital spending: scale, scope, and management.

39. Relative to peers, we analyze how successful a utility management achieves the above factors within the levels allowed by the regulator in a manner that promotes cash flow stability. We consider how management of these factors reduces the prospect of penalties for noncompliance, operating costs being greater than allowed, and capital projects running over budget and time, which could hurt full cost recovery.

40. The relative importance of the above three factors, particularly cost and capital spending management, is determined by the type of regulation under which the utility operates. Utilities operating under robust "cost plus" regimes tend to be more insulated given the high degree of confidence costs will invariably be passed through to customers. Utilities operating under incentive-based regimes are likely to be more sensitive to achieving regulatory standards. This is particularly so in the regulatory regimes that involve active consultation between regulator and utility and market testing as opposed to just handing down an outcome on a more arbitrary basis.

41 In some jurisdictions, the absolute performance standards are less relevant than how the utility performs against the regulator's performance benchmarks. It is this performance that will drive any penalties or incentive payments and can be a determinant of the utilities' credibility on operating and asset-management plans with its regulator.

42. Therefore, we consider that utilities that perform these functions well are more likely to consistently achieve determinations that maximize the likelihood of cost recovery and full inclusion of capital spending in their asset bases. Where regulatory resets are more at the discretion of the utility, effective cost management, including of labor, may allow for more control over the timing and magnitude of rate filings to maximize the chances of a constructive outcome such as full operational and capital cost recovery while protecting against reputational risks.

43. A regulated utility that warrants a Strong or Strong/Adequate assessment for operating efficiency relative to peers generates revenues and profits through minimizing costs, increasing efficiencies, and asset utilization. It typically is characterized by a combination of the following:

- High safety record;
- Service reliability is strong, with a track record of meeting operating performance requirements of stakeholders, including those of regulators. Moreover, the utility's asset profile (including age and technology) is such that we have confidence that it could sustain favorable performance against targets;
- Where applicable, the utility is well-placed to meet current and potential future environmental standards;
- Management maintains very good cost control. Utilities with the highest assessment for operating efficiency have shown an ability to manage both their fixed and variable costs in line with regulatory expectations (including labor and working capital management being in line with regulator's allowed collection cycles); or
- There is a history of a high level of project management execution in capital spending programs, including large one-time projects, almost invariably within regulatory allowances for timing and budget.

44. A regulated utility that warrants an Adequate assessment for operating efficiency relative to peers has a combination of cost position and efficiency factors that support profit sustainability combined with average volatility. Its cost structure is similar to its peers. It typically is characterized by a combination of the following factors:

- High safety performance;
- Service reliability is satisfactory with a track record of mostly meeting operating performance requirements of stakeholders, including those of regulators. We have confidence that a favorable performance against targets can be mostly sustained;
- Where applicable, the utility may be challenged to comply with current and future environmental standards that could increase in the medium term;
- Management maintains adequate cost control. Utilities that we assess as having adequate operating efficiency mostly manage their fixed and variable costs in line with regulatory expectations (including labor and working capital management being mostly in line with regulator's allowed collection cycles); or
- There is a history of adequate project management skills in capital spending programs within regulatory allowances for timing and budget.

45. A regulated utility that warrants a weak or weak/adequate assessment for operating efficiency relative to peers has a combination of cost position and efficiency factors that fail to support profit sustainability combined with below-average volatility. Its cost structure is worse than its peers. It typically is characterized by a combination of the following:

- Poor safety performance;
- Service reliability has been sporadic or non-existent with a track record of not meeting operating performance requirements of stakeholders, including those of regulators. We do not believe the utility can consistently meet performance targets without additional capital spending;
- Where applicable, the utility is challenged to comply with current environmental standards and is highly vulnerable to more onerous standards;
- Management typically exceeds operating costs authorized by regulators;
- Inconsistent project management skills as evidenced by cost overruns and delays including for maintenance capital spending; or
- The capital spending program is large and complex and falls into the weak or weak/adequate assessment, even if

operating efficiency is generally otherwise considered adequate.

Profitability

46. A utility with above-average profitability would, relative to its peers, generally earn a rate of return at or above what regulators authorize and have minimal exposure to earnings volatility from affiliated unregulated business activities or market-sensitive regulated operations. Conversely, a utility with below-average profitability would generally earn rates of return well below the authorized return relative to its peers or have significant exposure to earnings volatility from affiliated unregulated business activities or market-sensitive regulated operations.

47. The profitability assessment consists of "level of profitability" and "volatility of profitability."

Level of profitability

48. Key measures of general profitability for regulated utilities commonly include ratios, which we compare both with those of peers and those of companies in other industries to reflect different countries' regulatory frameworks and business environments:

- EBITDA margin,
- Return on capital (ROC), and
- Return on equity (ROE).

49. In many cases, EBITDA as a percentage of sales (i.e., EBITDA margin) is a key indicator of profitability. This is because the book value of capital does not always reflect true earning potential, for example when governments privatize or restructure incumbent state-owned utilities. Regulatory capital values can vary with those of reported capital because regulatory capital values are not inflation-indexed and could be subject to different assumptions concerning depreciation. In general, a country's inflation rate or required rate of return on equity investment is closely linked to a utility company's profitability. We do not adjust our analysis for these factors, because we can make our assessment through a peer comparison.

50. For regulated utilities subject to full cost-of-service regulation and return-on-investment requirements, we normally measure profitability using ROE, the ratio of net income available for common stockholders to average common equity. When setting rates, the regulator ultimately bases its decision on an authorized ROE. However, different factors such as variances in costs and usage may influence the return a utility is actually able to earn, and consequently our analysis of profitability for cost-of-service-based utilities centers on the utility's ability to consistently earn the authorized ROE.

51. We will use return on capital when pass-through costs distort profit margins--for instance congestion revenues or collection of third-party revenues. This is also the case when the utility uses accelerated depreciation of assets, which in our view might not be sustainable in the long run.

Volatility of profitability

52. We may observe a clear difference between the volatility of actual profitability and the volatility of underlying regulatory profitability. In these cases, we could use the regulatory accounts as a proxy to judge the stability of earnings.

53 We use actual returns to calculate the standard error of regression for regulated utility issuers (only if there are at least

seven years of historical annual data to ensure meaningful results). If we believe recurring mergers and acquisitions or currency fluctuations affect the results, we may make adjustments.

Part II--Financial Risk Analysis

D. Accounting

54. Our analysis of a company's financial statements begins with a review of the accounting to determine whether the statements accurately measure a company's performance and position relative to its peers and the larger universe of corporate entities. To allow for globally consistent and comparable financial analyses, our rating analysis may include quantitative adjustments to a company's reported results. These adjustments also align a company's reported figures with our view of underlying economic conditions and give us a more accurate portrayal of a company's ongoing business. We discuss adjustments that pertain broadly to all corporate sectors, including this sector, in "Corporate Methodology: Ratios And Adjustments." Accounting characteristics and analytical adjustments unique to this sector are discussed below.

Accounting characteristics

55. Some important accounting practices for utilities include:

- For integrated electric utilities that meet native load obligations in part with third-party power contracts, we use our purchased power methodology to adjust measures for the debt-like obligation such contracts represent (see below).
- Due to distortions in leverage measures from the substantial seasonal working-capital requirements of natural gas distribution utilities, we adjust inventory and debt balances by netting the value of inventory against outstanding short-term borrowings. This adjustment provides an accurate view of the company's balance sheet by reducing seasonal debt balances when we see a very high certainty of near-term cost recovery (see below).
- We deconsolidate securitized debt (and associated revenues and expenses) that has been accorded specialized recovery provisions (see below).
- For water utilities that report under U.K. GAAP, we adjust ratios for infrastructure renewals accounting, which permits water companies to capitalize the maintenance spending on their infrastructure assets (see below). The adjustments aim to make those water companies that report under U.K. GAAP more comparable to those that report under accounting regimes that do not permit infrastructure renewals accounting.

56. In the U.S. and selectively in other regions, utilities employ "regulatory accounting," which permits a rate-regulated company to defer some revenues and expenses to match the timing of the recognition of those items in rates as determined by regulators. A utility subject to regulatory accounting will therefore have assets and liabilities on its books that an unregulated corporation, or even regulated utilities in many other global regions, cannot record. We do not adjust GAAP earnings or balance-sheet figures to remove the effects of regulatory accounting. However, as more countries adopt International Financial Reporting Standards (IFRS), the use of regulatory accounting will become more scarce. IFRS does not currently provide for any recognition of the effects of rate regulation for financial reporting purposes, but it is considering the use of regulatory accounting. We do not anticipate altering our fundamental financial analysis of utilities because of the use or non-use of regulatory accounting. We will continue to analyze the effects of regulatory actions on a utility's financial health.

Purchased power adjustment

57 We view long-term purchased power agreements (PPA) as creating fixed, debt-like financial obligations that represent substitutes for debt-financed capital investments in generation capacity. By adjusting financial measures to incorporate PPA fixed obligations, we achieve greater comparability of utilities that finance and build generation capacity and those that purchase capacity to satisfy new load. PPAs do benefit utilities by shifting various risks to the electricity generators, such as construction risk and most of the operating risk. The principal risk borne by a utility that relies on PPAs is recovering the costs of the financial obligation in rates. (See "Standard & Poor's Methodology For Imputing Debt for U.S. Utilities' Power Purchase Agreements," May 7, 2007, for more background and information on the adjustment.)

58. We calculate the present value (PV) of the future stream of capacity payments under the contracts as reported in the financial statement footnotes or as supplied directly by the company. The discount rate used is the same as the one used in the operating lease adjustment, i.e., 7%. For U.S. companies, notes to the financial statements enumerate capacity payments for the coming five years, and a thereafter period. Company forecasts show the detail underlying the thereafter amount, or we divide the amount reported as thereafter by the average of the capacity payments in the preceding five years to get an approximation of annual payments after year five.

59. We also consider new contracts that will start during the forecast period. The company provides us the information regarding these contracts. If these contracts represent extensions of existing PPAs, they are immediately included in the PV calculation. However, a contract sometimes is executed in anticipation of incremental future needs, so the energy will not flow until some later period and there are no interim payments. In these instances, we incorporate that contract in our projections, starting in the year that energy deliveries begin under the contract. The projected PPA debt is included in projected ratios as a current rating factor, even though it is not included in the current-year ratio calculations.

60. The PV is adjusted to reflect regulatory or legislative cost-recovery mechanisms when present. Where there is no explicit regulatory or legislative recovery of PPA costs, as in most European countries, the PV may be adjusted for other mitigating factors that reduce the risk of the PPAs to the utility, such as a limited economic importance of the PPAs to the utility's overall portfolio.The adjustment reduces the debt-equivalent amount by multiplying the PV by a specific risk factor.

61 Risk factors based on regulatory or legislative cost recovery typically range between 0% and 50%, but can be as high as 100%. A 100% risk factor would signify that substantially all risk related to contractual obligations rests on the company, with no regulatory or legislative support. A 0% risk factor indicates that the burden of the contractual payments rests solely with ratepayers, as when the utility merely acts as a conduit for the delivery of a third party's electricity. These utilities are barred from developing new generation assets, and the power supplied to their customers is sourced through a state auction or third parties that act as intermediaries between retail customers and electricity suppliers. We employ a 50% risk factor in cases where regulators use base rates for the recovery of the fixed PPA costs. If a regulator has established a separate adjustment mechanism for recovery of all prudent PPA costs, a risk factor of 25% is employed. In certain jurisdictions, true-up mechanisms are more favorable and frequent than the review of base rates, but still do not amount to pure fuel adjustment clauses. Such mechanisms may be triggered by financial thresholds or passage of prescribed periods of time. In these instances, a risk factor between 25% and 50% is

employed. Specialized, legislatively created cost-recovery mechanisms may lead to risk factors between 0% and 15%, depending on the legislative provisions for cost recovery and the supply function borne by the utility. Legislative guarantees of complete and timely recovery of costs are particularly important to achieving the lowest risk factors. We also exclude short-term PPAs where they serve merely as gap fillers, pending either the construction of new capacity or the execution of long-term PPAs.

62. Where there is no explicit regulatory or legislative recovery of PPA costs, the risk factor is generally 100%. We may use a lower risk factor if mitigating factors reduce the risk of the PPAs on the utility. Mitigating factors include a long position in owned generation capacity relative to the utility's customer supply needs that limits the importance of the PPAs to the utility or the ability to resell power in a highly liquid market at minimal loss. A utility with surplus owned generation capacity would be assigned a risk factor of less than 100%, generally 50% or lower, because we would assess its reliance on PPAs as limited. For fixed capacity payments under PPAs related to renewable power, we use a risk factor of less than 100% if the utility benefits from government subsidies. The risk factor reflects the degree of regulatory recovery through the government subsidy.

63. Given the long-term mandate of electric utilities to meet their customers' demand for electricity, and also to enable comparison of companies with different contract lengths, we may use an evergreening methodology. Evergreen treatment extends the duration of short- and intermediate-term contracts to a common length of about 12 years. To quantify the cost of the extended capacity, we use empirical data regarding the cost of developing new peaking capacity, incorporating regional differences. The cost of new capacity is translated into a dollars-per-kilowatt-year figure using a proxy weighted-average cost of capital and a proxy capital recovery period.

64. Some PPAs are treated as operating leases for accounting purposes--based on the tenor of the PPA or the residual value of the asset on the PPA's expiration. We accord PPA treatment to those obligations, in lieu of lease treatment; rather, the PV of the stream of capacity payments associated with these PPAs is reduced to reflect the applicable risk factor.

65. Long-term transmission contracts can also substitute for new generation, and, accordingly, may fall under our PPA methodology. We sometimes view these types of transmission arrangements as extensions of the power plants to which they are connected or the markets that they serve. Accordingly, we impute debt for the fixed costs associated with such transmission contracts.

66. Adjustment procedures:

- Data requirements:
- Future capacity payments obtained from the financial statement footnotes or from management.
- Discount rate: 7%.
- Analytically determined risk factor.

- Calculations:
- Balance sheet debt is increased by the PV of the stream of capacity payments multiplied by the risk factor.
- Equity is not adjusted because the recharacterization of the PPA implies the creation of an asset, which offsets the debt.
- Property, plant, and equipment and total assets are increased for the implied creation of an asset equivalent to the

debt.

- An implied interest expense for the imputed debt is determined by multiplying the discount rate by the amount of imputed debt (or average PPA imputed debt, if there is fluctuation of the level), and is added to interest expense.
- We impute a depreciation component to PPAs. The depreciation component is determined by multiplying the relevant year's capacity payment by the risk factor and then subtracting the implied PPA-related interest for that year. Accordingly, the impact of PPAs on cash flow measures is tempered.
- The cost amount attributed to depreciation is reclassified as capital spending, thereby increasing operating cash flow and funds from operations (FFO).
- Some PPA contracts refer only to a single, all-in energy price. We identify an implied capacity price within such an all-in energy price, to determine an implied capacity payment associated with the PPA. This implied capacity payment is expressed in dollars per kilowatt-year, multiplied by the number of kilowatts under contract. (In cases that exhibit markedly different capacity factors, such as wind power, the relation of capacity payment to the all-in charge is adjusted accordingly.)
- Operating income before depreciation and amortization (D&A) and EBITDA are increased for the imputed interest expense and imputed depreciation component, the total of which equals the entire amount paid for PPA (subject to the risk factor).
- Operating income after D&A and EBIT are increased for interest expense.

Natural gas inventory adjustment

67. In jurisdictions where a pass-through mechanism is used to recover purchased natural gas costs of gas distribution utilities within one year, we adjust for seasonal changes in short-debt tied to building inventories of natural gas in non-peak periods for later use to meet peak loads in peak months. Such short-term debt is not considered to be part of the utility's permanent capital. Any history of non-trivial disallowances of purchased gas costs would preclude the use of this adjustment. The accounting of natural gas inventories and associated short-term debt used to finance the purchases must be segregated from other trading activities.

68. Adjustment procedures:

- Data requirements:
- Short-term debt amount associated with seasonal purchases of natural gas devoted to meeting peak-load needs of captive utility customers (obtained from the company).

- Calculations:
- Adjustment to debt--we subtract the identified short-term debt from total debt.

Securitized debt adjustment

69 For regulated utilities, we deconsolidate debt (and associated revenues and expenses) that the utility issues as part of a securitization of costs that have been segregated for specialized recovery by the government entity constitutionally authorized to mandate such recovery if the securitization structure contains a number of protective features:

- An irrevocable, non-bypassable charge and an absolute transfer and first-priority security interest in transition property;
- Periodic adjustments ("true-up") of the charge to remediate over- or under-collections compared with the debt service obligation. The true-up ensures collections match debt service over time and do not diverge significantly in the short run; and,
- Reserve accounts to cover any temporary short-term shortfall in collections.

70. Full cost recovery is in most instances mandated by statute. Examples of securitized costs include "stranded costs" (above-market utility costs that are deemed unrecoverable when a transition from regulation to competition occurs) and unusually large restoration costs following a major weather event such as a hurricane. If the defined features are present, the securitization effectively makes all consumers responsible for principal and interest payments, and the utility is simply a pass-through entity for servicing the debt. We therefore remove the debt and related revenues and expenses from our measures. (See "Securitizing Stranded Costs," Jan. 18, 2001, for background information.)

71 Adjustment procedures:

- Data requirements:
- Amount of securitized debt on the utility's balance sheet at period end;
- Interest expense related to securitized debt for the period; and
- Principal payments on securitized debt during the period.

- Calculations:
- Adjustment to debt: We subtract the securitized debt from total debt.
- Adjustment to revenues: We reduce revenue allocated to securitized debt principal and interest. The adjustment is the sum of interest and principal payments made during the year.
- Adjustment to operating income after depreciation and amortization (D&A) and EBIT: We reduce D&A related to the securitized debt, which is assumed to equal the principal payments during the period. As a result, the reduction to operating income after D&A is only for the interest portion.
- Adjustment to interest expense: We remove the interest expense of the securitized debt from total interest expense.

- Operating cash flows:
- We reduce operating cash flows for revenues and increase for the assumed interest amount related to the securitized debt. This results in a net decrease to operating cash flows equal to the principal repayment amount.

Infrastructure renewals expenditure

72. In England and Wales, water utilities can report under either IFRS or U.K. GAAP. Those that report under U.K. GAAP are allowed to adopt infrastructure renewals accounting, which enables the companies to capitalize the maintenance spending on their underground assets, called infrastructure renewals expenditure (IRE). Under IFRS, infrastructure renewals accounting is not permitted and maintenance expenditure is charged to earnings in the year incurred. This difference typically results in lower adjusted operating cash flows for those companies that report maintenance expenditure as an operating cash flow under IFRS, than for those that report it as capital expenditure under U.K. GAAP. We therefore make financial adjustments to amounts reported by water issuers that apply U.K. GAAP, with the aim of making ratios more comparable with those issuers that report under IFRS and U.S. GAAP. For example, we deduct IRE from EBITDA and FFO.

73. IRE does not always consist entirely of maintenance expenditure that would be expensed under IFRS. A portion of IRE can relate to costs that would be eligible for capitalization as they meet the recognition criteria for a new fixed asset set out in International Accounting Standard 16 that addresses property, plant, and equipment. In such cases, we may refine our adjustment to U.K. GAAP companies so that we only deduct from FFO the portion of IRE that would not be capitalized under IFRS. However, the information to make such a refinement would need to be of high quality, reliable, and ideally independently verified by a third party, such as the company's auditor. In the absence of this, we assume

that the entire amount of IRE would have been expensed under IFRS and we accordingly deduct the full expenditure from FFO.

74. Adjustment procedures:

- Data requirements:
- U.K. GAAP accounts typically provide little information on the portion of capital spending that relates to renewals accounting, or the related depreciation, which is referred to as the infrastructure renewals charge. The information we use for our adjustments is, however, found in the regulatory cost accounts submitted annually by the water companies to the Water Services Regulation Authority, which regulates all water companies in England and Wales.
- Calculations:
- EBITDA: Reduced by the value of IRE that was capitalized in the period.
- EBIT: Adjusted for the difference between the adjustment to EBITDA and the reduction in the depreciation expense, depending on the degree to which the actual cash spending in the current year matches the planned spending over the five-year regulatory review period.
- Cash flow from operations and FFO: Reduced by the value of IRE that was capitalized in the period.
- Capital spending: Reduced by the value of infrastructure renewals spending that we reclassify to cash flow from operations.
- Free operating cash flow: No impact, as the reduction in operating cash flows is exactly offset by the reduction in capital spending.

E. Cash flow/leverage analysis

75. In assessing the cash flow adequacy of a regulated utility, our analysis uses the same methodology as with other corporate issuers (see "Corporate Methodology"). We assess cash flow/leverage on a six-point scale ranging from ('1') minimal to ('6') highly leveraged. These scores are determined by aggregating the assessments of a range of credit ratios, predominantly cash flow-based, which complement each other by focusing attention on the different levels of a company's cash flow waterfall in relation to its obligations.

76. The corporate methodology provides benchmark ranges for various cash flow ratios we associate with different cash flow leverage assessments for standard volatility, medial volatility, and low volatility industries. The tables of benchmark ratios differ for a given ratio and cash flow leverage assessment along two dimensions: the starting point for the ratio range and the width of the ratio range.

77 If an industry's volatility levels are low, the threshold levels for the applicable ratios to achieve a given cash flow leverage assessment are less stringent, although the width of the ratio range is narrower. Conversely, if an industry has standard levels of volatility, the threshold levels for the applicable ratios to achieve a given cash flow leverage assessment may be elevated, but with a wider range of values.

78. We apply the "low-volatility" table to regulated utilities that qualify under the corporate criteria and with all of the following characteristics:

- A vast majority of operating cash flows come from regulated operations that are predominantly at the low end of the utility risk spectrum (e.g., a "network," or distribution/transmission business unexposed to commodity risk and with very low operating risk);
- A "strong" regulatory advantage assessment;

- An established track record of normally stable credit measures that is expected to continue;
- A demonstrated long-term track record of low funding costs (credit spread) for long-term debt that is expected to continue; and
- Non-utility activities that are in a separate part of the group (as defined in our group rating methodology) that we consider to have "nonstrategic" group status and are not deemed high risk and/or volatile.

79. We apply the "medial volatility" table to companies that do not qualify under paragraph 78 with:

- A majority of operating cash flows from regulated activities with an "adequate" or better regulatory advantage assessment; or
- About one-third or more of consolidated operating cash flow comes from regulated utility activities with a "strong" regulatory advantage and where the average of its remaining activities have a competitive position assessment of '3' or better.

80. We apply the "standard-volatility" table to companies that do not qualify under paragraph 79 and with either:

- About one-third or less of its operating cash flow comes from regulated utility activities, regardless of its regulatory advantage assessment; or
- A regulatory advantage assessment of "adequate/weak" or "weak."

Part III--Rating Modifiers

F. Diversification/portfolio effect

81. In assessing the diversification/portfolio effect on a regulated utility, our analysis uses the same methodology as with other corporate issuers (see "Corporate Methodology").

G. Capital structure

82. In assessing the quality of the capital structure of a regulated utility, we use the same methodology as with other corporate issuers (see "Corporate Methodology").

H. Liquidity

83. In assessing a utility's liquidity/short-term factors, our analysis is consistent with the methodology that applies to corporate issuers (See "Methodology And Assumptions: Liquidity Descriptors For Global Corporate Issuers," Nov. 19, 2013) except for the standards for "adequate" liquidity set out in paragraph 84 below.

84. The relative certainty of financial performance by utilities operating under relatively predictable regulatory monopoly frameworks make these utilities attractive to investors even in times of economic stress and market turbulence compared to conventional industrials. For this reason, utilities with business risk profiles of at least "satisfactory" meet our definition of "adequate" liquidity based on a slightly lower ratio of sources to uses of funds of 1.1x compared with the standard 1.2x. Also, recognizing the cash flow stability of regulated utilities we allow more discretion when calculating covenant headroom. We consider that utilities have adequate liquidity if they generate positive sources over uses, even if forecast EBITDA declines by 10% (compared with the 15% benchmark for corporate issuers) before covenants are breached.

I. Financial policy

85. In assessing financial policy on a regulated utility, our analysis uses the same methodology as with other corporate issuers (see "Corporate Methodology").

J. Management and governance

86. In assessing management and governance on a regulated utility, our analysis uses the same methodology as with other corporate issuers (see "Corporate Methodology").

K. Comparable ratings analysis

87. In assessing the comparable ratings analysis on a regulated utility, our analysis uses the same methodology as with other corporate issuers (see "Corporate Methodology").

Appendix--Frequently Asked Questions

Does Standard & Poor's expect that the business strategy modifier to the preliminary regulatory advantage will be used extensively?

88. Globally, we expect management's influence will be neutral in most jurisdictions. Where the regulatory assessment is "strong," it is less likely that a negative business strategy modifier would be used due to the nature of the regulatory regime that led to the "strong" assessment in the first place. Utilities in "adequate/weak" and "weak" regulatory regimes are challenged to outperform due to the uncertainty of such regulatory regimes. For a positive use of the business strategy modifier, there would need to be a track record of the utility consistently outperforming the parameters laid down under a regulatory regime, and we would need to believe this could be sustained. The business strategy modifier is most likely to be used when the preliminary regulatory advantage assessment is "strong/adequate" because the starting point in the assessment is reasonably supportive, and a utility has shown it manages regulatory risk better or worse than its peers in that regulatory environment and we expect that advantage or disadvantage will persist. An example would be a utility that can consistently earn or exceed its authorized return in a jurisdiction where most other utilities struggle to do so. If a utility is treated differently by a regulator due to perceptions of poor customer service or reliability and the "operating efficiency" component of the competitive position assessment does not fully capture the effect on the business risk profile, a negative business strategy modifier could be used to accurately incorporate it into our analysis. We expect very few utilities will be assigned a "very negative" business strategy modifier.

Does a relatively strong or poor relationship between the utility and its regulator compared with its peers in the same jurisdiction necessarily result in a positive or negative adjustment to the preliminary regulatory advantage assessment?

89. No. The business strategy modifier is used to differentiate a company's regulatory advantage within a jurisdiction where we believe management's business strategy has and will positively or negatively affect regulatory outcomes beyond what is typical for other utilities in that jurisdiction. For instance, in a regulatory jurisdiction where allowed returns are negotiated rather than set by formula, a utility that is consistently authorized higher returns (and is able to earn that return) could warrant a positive adjustment. A management team that cannot negotiate an approved capital spending program to improve its operating performance could be assessed negatively if its performance lags behind peers in the same regulatory jurisdiction.

What is your definition of regulatory jurisdiction?

90. A regulatory jurisdiction is defined as the area over which the regulator has oversight and could include single or multiple subsectors (water, gas, and power). A geographic region may have several regulatory jurisdictions. For example, the Office of Gas and Electricity Markets and the Water Services Regulation Authority in the U.K. are considered separate regulatory jurisdictions. In Ontario, Canada, the Ontario Energy Board represents a single jurisdiction with regulatory oversight for power and gas. Also, in Australia, the Australian Energy Regulator would be considered a single jurisdiction given that it is responsible for both electricity and gas transmission and distribution networks in the entire country, with the exception of Western Australia.

Are there examples of different preliminary regulatory advantage assessments in the same country or jurisdiction?

91. Yes. In Israel we rate a regulated integrated power utility and a regulated gas transmission system operator (TSO). The power utility's relationship with its regulator is extremely poor in our view, which led to significant cash flow volatility in a stress scenario (when terrorists blew up the gas pipeline that was then Israel's main source of natural gas, the utility was unable to negotiate compensation for expensive alternatives in its regulated tariffs). We view the gas TSO's relationship with its regulator as very supportive and stable. Because we already reflected this in very different preliminary regulatory advantage assessments, we did not modify the preliminary assessments because the two regulatory environments in Israel differ and were not the result of the companies' respective business strategies.

How is regulatory advantage assessed for utilities that are a natural monopoly but are not regulated by a regulator or a specific regulatory framework, and do you use the regulatory modifier if they achieve favorable treatment from the government as an owner?

92. The four regulatory pillars remain the same. On regulatory stability we look at the stability of the setup, with more emphasis on the historical track record and our expectations regarding future changes. In tariff-setting procedures and design we look at the utility's ability to fully recover operating costs, investments requirements, and debt-service obligations. In financial stability we look at the degree of flexibility in tariffs to counter volume risk or commodity risk. The flexibility can also relate to the level of indirect competition the utility faces. For example, while Nordic district heating companies operate under a natural monopoly, their tariff flexibility is partly restricted by customers' option to change to a different heating source if tariffs are significantly increased. Regulatory independence and insulation is mainly based on the perceived risk of political intervention to change the setup that could affect the utility's credit profile. Although political intervention tends to be mostly negative, in certain cases political ties due to state ownership might positively influence tariff determination. We believe that the four pillars effectively capture the benefits from the close relationship between the utility and the state as an owner; therefore, we do not foresee the use of the regulatory modifier.

In table 1, when describing a "strong" regulatory advantage assessment, you mention that there is support of cash flows during construction of large projects, and preapproval of capital investment programs and large projects lowers the risk of subsequent disallowances of capital costs. Would this preclude a "strong" regulatory advantage assessment in jurisdictions where those practices are absent?

93. No. The table is guidance as to what we would typically expect from a regulatory framework that we would assess as "strong." We would expect some frameworks with no capital support during construction to receive a "strong" regulatory advantage assessment if in aggregate the other factors we analyze support that conclusion.

RELATED CRITERIA AND RESEARCH

- Corporate Methodology, Nov. 19, 2013
- Group Rating Methodology, Nov. 19, 2013
- Methodology: Industry Risk, Nov. 19, 2013
- Corporate Methodology: Ratios And Adjustments, Nov. 19, 2013
- Ratings Above The Sovereign--Corporate And Government Ratings: Methodology And Assumptions, Nov. 19, 2013
- Methodology And Assumptions: Liquidity Descriptors For Global Corporate Issuers, Nov. 19, 2013
- Collateral Coverage And Issue Notching Rules For '1+' And '1' Recovery Ratings On Senior Bonds Secured By Utility Real Property, Feb. 14, 2013
- Methodology: Management And Governance Credit Factors For Corporate Entities and Insurers, Nov. 13, 2012
- General Criteria: Principles Of Credit Ratings, Feb. 16, 2011
- General Criteria: Rating Government-Related Entities: Methodology And Assumptions, Dec. 9, 2010

These criteria represent the specific application of fundamental principles that define credit risk and ratings opinions. Their use is determined by issuer- or issue-specific attributes as well as Standard & Poor's Ratings Services' assessment of the credit and, if applicable, structural risks for a given issuer or issue rating. Methodology and assumptions may change from time to time as a result of market and economic conditions, issuer- or issue-specific factors, or new empirical evidence that would affect our credit judgment.

(And watch the related CreditMatters TV segment titled, "Standard & Poor's Highlights The Key Credit Factors For Rating Regulated Utilities," dated Nov. 21, 2013.)

Exhibit DKA-5
Moody's Outlook on Utility Industry

MOODY'S
INVESTORS SERVICE

OUTLOOK
18 June 2018

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Regulated utilities - US

2019 outlook shifts to negative due to weaker cash flows, continued high leverage

Our negative outlook indicates our expectations for the fundamental business conditions driving the US regulated utility industry over the next 12-18 months.

The outlook for the US regulated utility sector has changed to negative from stable, reflecting increased financial risk due to lower cash flow and holding company leverage at its highest level since 2008. These factors will reduce the ratio of funds from operations (FFO) to debt by up to 200 basis points over the next 12-18 months.

» **Cash flow will decline due to a lower contribution from deferred taxes.** The combination of the loss of bonus depreciation and a lower tax rate as a result of the Tax Cuts & Jobs Act (TCJA) means that utilities and their holding companies will lose some of the cash flow contribution from deferred taxes. Since 2010, deferred taxes have contributed around 14% of consolidated FFO, but we see this falling to around 8% through 2019. This will drive down the consolidated ratio of FFO to debt, for a peer group of 42 utility holding companies, from 17% toward 15% over the outlook period.

» **Regulatory and management responses may not improve financials until 2020.** Some state regulatory commissions have issued credit-supportive rate orders to offset reduced cash flow because of tax reform, and several holding companies are executing plans to strengthen their balance sheets. But it could take longer than 12-18 months before sector-wide financial metrics improve.

» **High leverage will persist due to growing capital spending and rising dividends.** For our peer group, consolidated debt to EBITDA of 5.1x in 2017 was at a 10-year high, and a consolidated debt to equity ratio of 1.5x was at its highest level since 2008. These leverage metrics will remain elevated given higher capital spending in 2018 and 2019, rising dividends and a continued heavy reliance on debt financing.

» **What could change our outlook** The outlook could return to stable if we expect the sector's financial profile to stabilize, even if that is at today's lower levels. A positive outlook could be considered if we expect a recovery in key cash flow metrics where consolidated cash flow starts to improve by roughly 15%-20% or the ratio of consolidated FFO to debt indicates a return to the 17%-19% range. Underpinning each of these scenarios is a supportive regulatory environment across most US jurisdictions.

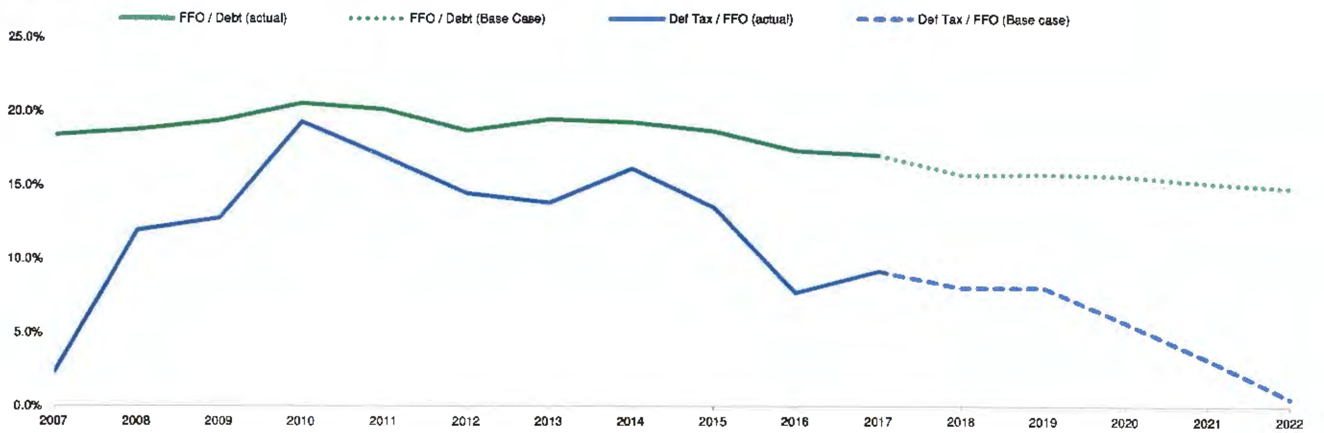
Cash flow will decline due to a lower contribution from deferred taxes

The combination of a lower tax rate and the loss of bonus depreciation as a result of the federal Tax Cuts & Jobs Act (TCJA) in December 2017 means that utilities and their holding companies will lose some of the cash flow contribution from deferred taxes on an ongoing basis, as shown in Exhibit 1.

For nearly a decade, bonus depreciation has created large timing differences between the book and tax amounts that utility holding companies report and pay as tax expense, and has resulted in a very low cash tax payment rate for the sector. Consequently, virtually all of the revenue that utilities have collected from customers to cover tax expense has been retained by the company as deferred tax liabilities, rather than paid to the Internal Revenue Service in any given year. These deferred taxes have boosted cash flow measures[1] significantly, accounting for roughly 14% of consolidated FFO, on average, since 2010.

Now, with the reduction in the corporate tax rate to 21% from 35%, utilities will collect less revenue from customers (since their federal tax expense is lower) and retain less cash via deferred taxes. As a result, the deferred-tax contribution to consolidated FFO will fall to around 8% through 2019, from an average of 14% since 2010, based on our financial forecast using a peer group of 42 regulated utility holding companies with 10 years of historical data (see Appendix A for a listing of holding company peers and Appendix D for a description of our key forecast assumptions). We also see the same trend for a peer group of 102 utility operating companies with 10 years of historical data. This decline will drive consolidated FFO to debt metrics down toward 15% from 17% and operating company FFO to debt to 20% from 24% over the next 12-18 months. See Appendix B for a list of the 102 operating companies.

Exhibit 1
Consolidated FFO to debt will decline as a result of lower deferred taxes



Key assumption: Cash tax rates of 0% in 2018 and 2019, 5% in 2020, 10% in 2021 and 15% in 2022
Source: Moody's Investors Service

Because outlooks represent our forward-looking view on business conditions that factor into our ratings, a negative (positive) outlook suggests that negative (positive) rating actions are more likely on average. However, the industry outlook does not represent a sum of upgrades, downgrades or ratings under review, or an average of the rating outlooks of issuers in the industry, but rather our assessment of the main direction of business fundamentals within the overall industry.

The loss of bonus depreciation means that most companies will start paying cash tax earlier than under the previous law. Under the TCJA, utilities can claim less in depreciation expense for tax purposes and will have higher taxable income. Notwithstanding the change in law, we still expect holding companies to pay little or no cash tax in 2018 and 2019 because most have significant accumulated net operating losses driven by past claims of bonus depreciation, production tax credits from renewable generation or other tax offsets.

Lowering the tax rate also means that utilities will have over-collected for tax expenses in the past because they charged for future tax expense assuming a 35% tax rate. As utilities refund the excess collection to customers, cash flow will be reduced, with the decline likely spread over 20 years or more.

Regulatory and management responses may not improve financials until 2020

Regulatory commissions and utility management teams are taking important first steps in addressing increased financial risk, but we believe that it will take longer than 12-18 months for the majority of the sector to show any material financial improvement from such efforts.

There are two principal approaches for a utility seeking to take mitigating action against rising financial risk. The first option is to pursue financial relief from regulators, which we see most companies doing across the industry in response to tax reform. The second is "self-help," where management teams alter financial policies to improve cash flow or their balance sheet. These efforts could include cutting operating or capital costs, issuing equity, reducing debt, selling non-core assets or slowing dividend growth. Such strategies were popular during the early 2000s period known as "back to basics," when many companies shed unregulated and international assets, reduced debt and focused on strengthening core regulatory relationships.

Regulation addressing tax reform

So far, we have seen credit positive developments in some states in response to tax reform, described in the box below. Most of these measures are positive because they provide incremental cash flow that will be used to replace some of the cash lost due to tax reform.

Some regulatory commissions have allowed early tax reform relief

In Florida, the Florida Public Service Commission allowed several of the state's utilities including Florida Power & Light Company (A1 stable), Duke Energy Florida, LLC (A3 stable) and Tampa Electric Company (A3 stable) to use the bulk of customer refunds resulting from tax reform changes to offset rate increases for power restoration costs associated with the utilities' response to Hurricane Irma. Duke Energy Florida was also permitted to use a portion of the savings to accelerate the depreciation of existing coal plants.

In April, the Georgia Public Service Commission (GPSC) approved a tax reform settlement agreement allowing Georgia Power Company (A3 negative) to increase its authorized retail equity ratio, currently around 51%, to the utility's actual equity capitalization percentage or 55% (whichever is lower) until its next rate case filing, scheduled to be filed 1 July 2019.

In May, the Alabama Public Service Commission approved two supportive rate proposal requests by Alabama Power Company (A1 negative), including 1) a plan designed to improve the company's balance sheet and credit quality over time by gradually increasing its equity ratio to 55% by 2025 and 2) allowing up to $30 million of excess deferred tax liability deferrals to offset under-recovered fuel costs.

In Indiana, Northern Indiana Public Service Company (Baa1 stable) has reached a gas rate settlement that, if approved by the Indiana Utility Regulatory Commission, would defer the cash outflows associated with unprotected deferred tax liabilities until 2020.

While we expect very supportive regulatory outcomes in states such as Florida, Georgia and Alabama—three of the most credit-supportive regulatory environments in the US—other states will likely have more moderate allowances for increased rates and cash flow recovery in regard to tax reform. So far, many state commissions have provided for the 21% tax rate to be implemented into rates in 2018, but have said they will address the return of excess deferred tax liabilities to customers at a later date—under a separate proceeding or at the time of a utility's next general rate case. This adds a degree of uncertainty to the ultimate timing of any cash flow impact on the sector.

Management efforts to address financial risk

Many companies are executing plans to strengthen their balance sheets in the face of increased financial risk, including incremental equity issuances beyond their pre-tax reform plans, selling assets or modest capex reductions. Some of these actions are defensive measures brought about by tax reform, while others are reactions to developments such as funding acquisitions, regulatory and political uncertainties, large capital programs or natural disasters. Other companies, although faced with negative credit trends, are making no material changes to financial policies.

Exhibit 2 shows a list of selected holding companies with a negative outlook or ratings under review for downgrade, as well as their planned responses to deal with heightened financial risks or other negative credit conditions.

Exhibit 2

Management teams are pursuing different avenues to relieve financial and credit risk

Holding companies with a negative outlook and under review for downgrade (RUR-D) as of 18 June 2018

Company	Rating	Outlook	Pursuing Regulatory Relief for Tax Reform	Incremental Equity Issuance	Selling Assets	Incremental Capex Reduction	% of Annual Capex Reduced	Dividend Reduction
ALLETE, Inc.	A3	Negative	Yes	No	No	No	NA	No
Consolidated Edison, Inc.	A3	Negative	Yes	No	No	No	NA	No
Edison International	A3	Negative	Yes	No	No	No	NA	No
Integrys Holding, Inc.	A3	RUR-D	Yes	No	No	No	NA	No
OGE Energy Corp.	A3	Negative	Yes	No	No	No	NA	No
WEC energy Group, Inc.	A3	RUR-D	Yes	No	No	No	NA	No
WGL Holdings, Inc.	A3	Negative	Yes	No	No	No	NA	No
Alliant Energy Corporation	Baa1	Negative	Yes	No	No	No	NA	No
CenterPoint Energy, Inc.	Baa1	Negative	Yes	Yes	No	No	NA	No
Duke Energy Corporation	Baa1	Negative	Yes	Yes	No	Yes	2%	No
PG&E Corporation	Baa1	Negative	Yes	No	No	No	NA	Yes
Sempra Energy	Baa1	Negative	Yes	Yes	Yes	No	NA	No
Dominion Energy, Inc.	Baa2	Negative	Yes	Yes	Yes	Yes	11%	No
Entergy Corporation	Baa2	Negative	Yes	Yes	No	No	NA	No
Southern Company (The)	Baa2	Negative	Yes	Yes	Yes	No	NA	No
Cleco Corporate Holdings LLC	Baa3	RUR-D	Yes	No	No	No	NA	No
Emera Inc.	Baa3	Negative	Yes	Yes	No	No	NA	No
SCANA Corporation	Ba1	RUR-D	Yes	No	No	No	NA	No

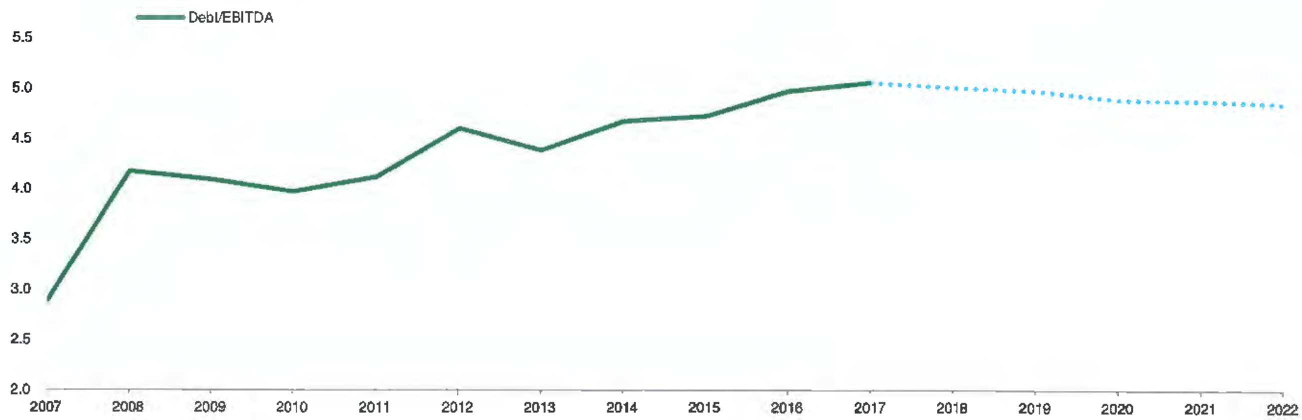
Source: Company announcements and Moody's Investors Service

High leverage will persist because of significant capital spending and rising dividends

With roughly $600 billion of adjusted debt at year-end 2017, our peer group of 42 utility holding companies are exhibiting a 10-year high consolidated ratio of debt to EBITDA (5.1x in 2017) and the highest consolidated debt to equity ratio (1.5x in 2017) since 2008, the height of the financial crisis. As shown in Exhibit 3, these leverage ratios will remain elevated amid higher capital spending in 2018 and in 2019, rising dividends, and a continued heavy reliance on debt financing for negative free cash flow.

Exhibit 3

The ratio of debt to EBITDA for utility holding companies will likely remain at 10-year highs



Source: Moody's Investors Service

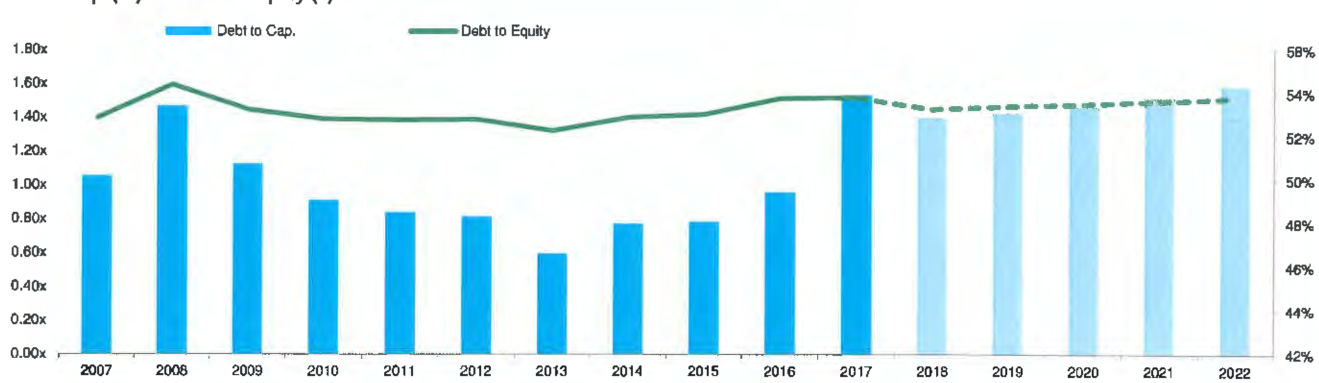
Because of the lower tax rate, deferred tax liabilities were reduced, which negatively impacts our adjusted capitalization ratios. The deferred tax revaluation has increased the adjusted debt to capitalization ratio to 54% in 2017, from 49% in 2016, since it reduces the amount of total capitalization (debt + equity + deferred taxes) and reclassifies the excess deferred tax liabilities as a long-term regulatory liability owed to customers.

As Exhibit 4 shows, leverage is expected to remain high compared with historical levels, despite a significant amount of equity being issued in 2018. In 2018 we made a simplifying assumption that $20 billion of equity would be issued, offsetting a similar amount of debt that would otherwise have been used to fund negative free cash flow. That assumption acknowledges that several companies have announced equity issuances in 2018, including Duke Energy Corporation (Baa1 negative), Dominion Energy, Inc. (Baa2 negative) and Entergy Corporation (Baa2 negative). Without this equity, the ratio of debt to capitalization would have been 55% through 2022 and debt to equity would have been 1.5x, trending to 1.6x in 2022.

Exhibit 4

Despite equity issuance in 2018, leverage metrics will remain much higher than historical levels

Debt to Cap. (%) and Debt to Equity (x)



Source: Moody's Investors Service

Holding company leverage has been increasing in recent years due to factors such as highly levered mergers and acquisitions, investments in non-regulated activities including renewable energy portfolios and midstream ventures, and using holding company debt as a source for equity infusions into operating subsidiaries. We do not incorporate unregulated investment into our forecast scenarios, but we still see increasing debt levels because of high capital investments and rising dividends.

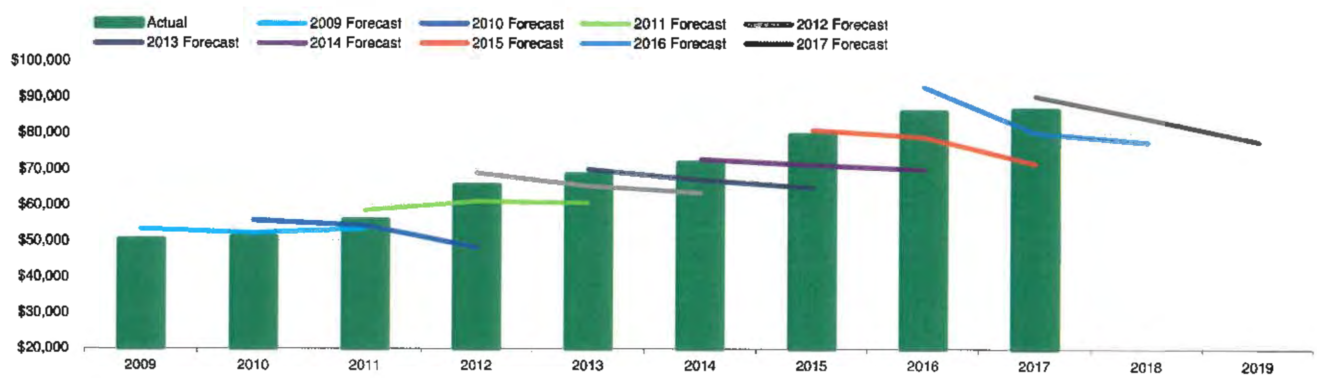
Capital spending is likely to increase

Utility companies continue to spend significant capital on their rate base through smart-grid investments, system resilience measures and carbon transition efforts, including renewable generation assets. This is likely to keep spending levels high for the next several years. A trend of higher capital spending could also ensue if companies see the revenue reduction from tax reform, and the consequent reduction in customer bills, as an opportunity to make additional capital investments that could be recovered in rates without increasing customer bills above their pre-tax reform levels.

While many companies are estimating a steady decline in capital spending after 2018, our base-case projections assume that their capital spending will continue to increase, at about 5.0% each year, compared with a 2012-2017 compound annual growth rate (CAGR) of 5.7%.

As Exhibit 5 shows, while companies often project a downward trajectory in capital spending, the level of capital actually deployed frequently exceeds projections by a wide margin. In fact, for 25 holding companies that have reported 3-year capex projections since 2009 (see Appendix C for a list of companies), aggregate capital spending has always increased despite projections that usually predict a declining trend.

Exhibit 5
Utility capital spending is often projected to decline, but has actually grown annually since 2009
Annual 3-year capex projections for 25 regulated utility holding companies



Source: SPGMI

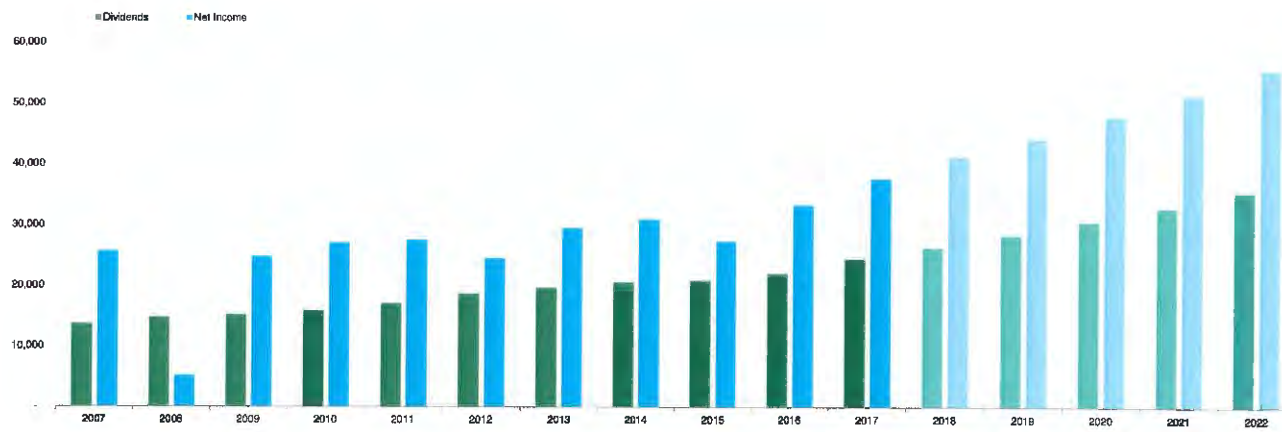
Dividends will continue to rise

As shown in Exhibit 6, we also expect that dividends will continue to increase, consistent with 2018 earnings call guidance indicating that payout policies are either unchanged or growing. In our base case forecast, we assume dividends increase at 8% year-over-year, which is the same growth rate as shown by net income.

Exhibit 6

The 10-year trend of increasing overall dividends is likely to continue through 2022

Actual dividends/net income (dark green/blue) and projected dividends/net income (light green/blue)



Source: Moody's Investors Service

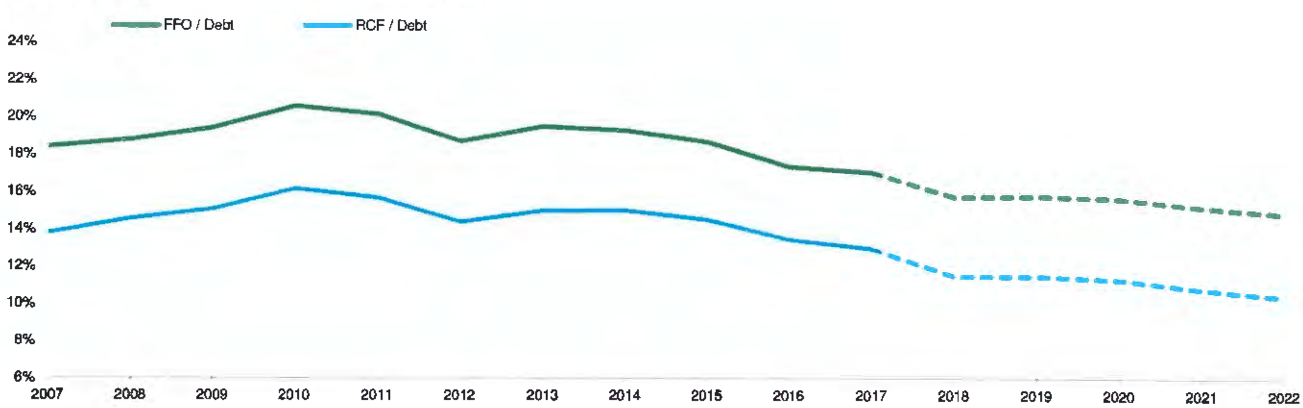
What could change our outlook

Stable outlook

The outlook could return to stable if we expect that the sector's financial profile will stabilize at today's lower levels, with consolidated FFO to debt metrics remaining steady. Exhibit 7 shows such stability could happen as early as 2019, with both FFO to debt and retained cash flow (RCF) to debt remaining between 15%-16% and 11%-12%, respectively, through year-end 2020.

Exhibit 7

A stable financial trend could emerge in 2019-2020 if cash flow growth keeps pace with debt



Key assumption: Cash tax rates of 0% in 2018 and 2019, 5% in 2020, 10% in 2021 and 15% in 2022

Source: Moody's Investors Service

We ran alternative scenarios to our base case forecast, including an upside case that assumes an improved financial performance by utilities and a downside case that assumes additional financial challenges.

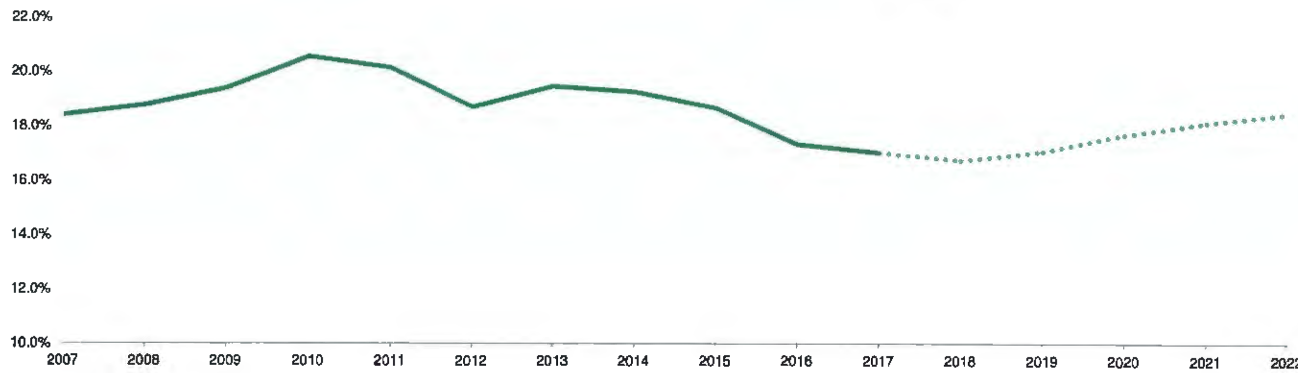
Positive outlook

A positive outlook would be possible if we expect a recovery in key cash flow metrics, such as consolidated FFO to debt returning to the 17%-19% range. This is the case in our upside projection scenario, which reflects a greater use of equity funding of negative free cash flow and very strong recovery provisions allowed by regulators. In Exhibit 8, we assumed a 5% annual decline in capital spending after 2019, simulating the downward trend in industry-reported projections.

Exhibit 8

The sector outlook could change to positive if FFO to debt rebounds as projected in our upside case

Actual historical FFO to debt (solid line) and as-projected in our upside case (dotted line)



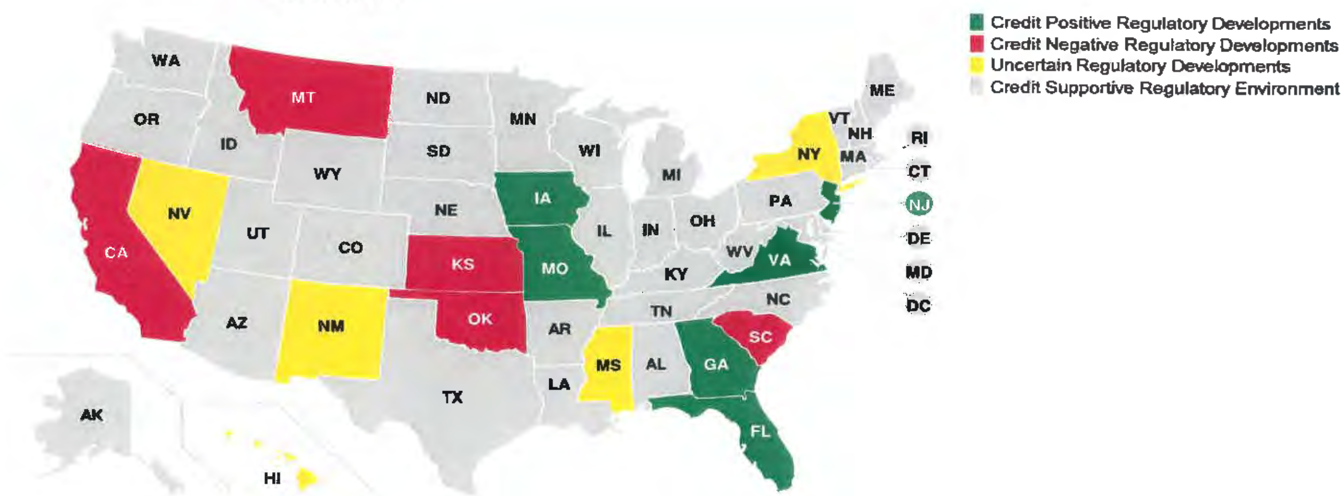
Source: Moody's Investors Service

Most state regulatory environments remain steadily supportive of credit

The underpinning of the sector outlook potentially returning to stable or changing to positive is a supportive regulatory environment. Exhibit 9 shows that, even today, most state jurisdictions remain predictably supportive of utility credit (grey), while some states have regulatory or legislative developments that could have positive (green), negative (red) or uncertain (yellow) impacts on utility credit.

Exhibit 9

Regulatory developments in most states continue to be stable and supportive of credit



Source: Moody's Investors Service

Appendix A - Holding company peer group

Exhibits 10 and 11 list the 42 regulated utility holding companies from which financial figures were derived by aggregating the annual data from 2007-2017 and applying key assumptions (see Appendix D) to drive our forecast scenarios. These companies were selected based on having ten years of historical data.

Exhibit 10

Companies 1-22 of 42 holding companies, sorted by highest to lowest consolidated CFO / Debt
$ in millions, as of the last twelve months available

Issuer	Rating and Outlook	CFO	Total Debt	CFO / Debt	Equity	Capex	Dividends
PG&E Corporation	Baa1 Negative	$ 5,908	$ 21,352	28%	$ 19,576	$ 5,900	$ 766
ALLETE, Inc.	A3 Negative	$ 465	$ 1,747	27%	$ 2,088	$ 275	$ 111
OGE Energy Corp.	A3 Negative	$ 851	$ 3,346	25%	$ 3,800	$ 728	$ 254
Edison International	A3 Negative	$ 3,749	$ 15,920	24%	$ 12,692	$ 4,072	$ 790
Vectren Utility Holdings, Inc.	A2 Stable	$ 419	$ 1,816	23%	$ 1,766	$ 569	$ 125
Ameren Corporation	Baa1 Stable	$ 2,040	$ 9,477	22%	$ 7,230	$ 2,264	$ 441
Pinnacle West Capital Corporation	A3 Stable	$ 1,205	$ 5,661	21%	$ 5,005	$ 1,439	$ 295
WEC Energy Group, Inc.	A3 Rating(s) Under Review	$ 2,292	$ 10,809	21%	$ 10,067	$ 2,080	$ 679
Public Service Enterprise Group Incorporated	Baa1 Stable	$ 3,053	$ 14,503	21%	$ 14,006	$ 4,049	$ 879
NextEra Energy, Inc.	Baa1 Stable	$ 6,437	$ 31,715	20%	$ 33,116	$ 9,035	$ 2,040
IDACORP, Inc.	Baa1 Stable	$ 440	$ 2,178	20%	$ 2,267	$ 281	$ 113
Exelon Corporation	Baa2 Stable	$ 8,073	$ 40,215	20%	$ 30,241	$ 7,612	$ 1,274
WGL Holdings, Inc.	A3 Negative	$ 505	$ 2,683	19%	$ 1,733	$ 466	$ 105
CMS Energy Corporation	Baa1 Stable	$ 1,782	$ 9,930	18%	$ 4,535	$ 1,739	$ 382
CenterPoint Energy, Inc.	Baa1 Negative	$ 1,635	$ 9,253	18%	$ 4,657	$ 1,485	$ 466
Evergy, Inc.	Baa2 Stable	$ 879	$ 4,980	18%	$ 4,920	$ 595	$ 257
DTE Energy Company	Baa1 Stable	$ 2,414	$ 13,894	17%	$ 10,064	$ 2,266	$ 659
American Electric Power Company, Inc.	Baa1 Stable	$ 4,413	$ 25,446	17%	$ 18,391	$ 6,505	$ 1,207
Consolidated Edison, Inc.	A3 Negative	$ 3,261	$ 18,992	17%	$ 15,514	$ 3,701	$ 814
Pepco Holdings, LLC	Baa2 Stable	$ 1,068	$ 6,267	17%	$ 9,488	$ 1,367	$ 313
PNM Resources, Inc.	Baa3 Positive	$ 493	$ 3,048	16%	$ 1,689	$ 524	$ 80
Puget Energy, Inc.	Baa3 Stable	$ 974	$ 6,066	16%	$ 3,649	$ 1,067	$ 153

Source: Moody's Investors Service

Appendix A (continued) - Holding company peer group

Exhibit 11

Companies 23-42 of 42 holding companies, sorted by highest to lowest consolidated CFO / Debt
$ in millions, as of the last twelve months available

Issuer	Rating and Outlook	CFO	Total Debt	CFO / Debt	Equity	Capex	Dividends
Hawaiian Electric Industries, Inc.	WR Stable	$ 418	$ 2,614	16%	$ 2,117	$ 546	$ 137
Berkshire Hathaway Energy Company	A3 Stable	$ 6,287	$ 42,392	15%	$ 28,667	$ 4,886	$ -
TECO Energy, Inc.	Baa2 Stable	$ 624	$ 4,276	15%	$ 2,879	$ 709	$ -
Black Hills Corporation	Baa2 Stable	$ 483	$ 3,331	15%	$ 1,871	$ 338	$ 101
Alliant Energy Corporation	Baa1 Negative	$ 873	$ 6,036	14%	$ 4,217	$ 1,520	$ 284
Entergy Corporation	Baa2 Negative	$ 2,909	$ 20,475	14%	$ 7,806	$ 3,940	$ 634
Spire Inc.	Baa2 Stable	$ 400	$ 2,872	14%	$ 2,138	$ 474	$ 102
Southern Company (The)	Baa2 Negative	$ 7,220	$ 52,269	14%	$ 26,339	$ 9,251	$ 2,505
SCANA Corporation	Ba1 Rating(s) Under Review	$ 956	$ 7,189	13%	$ 5,305	$ 1,114	$ 349
PPL Corporation	Baa2 Stable	$ 2,990	$ 22,682	13%	$ 11,409	$ 3,287	$ 1,098
Sempra Energy	Baa1 Negative	$ 3,627	$ 28,450	13%	$ 15,532	$ 3,994	$ 904
Duke Energy Corporation	Baa1 Negative	$ 6,849	$ 55,877	12%	$ 41,554	$ 8,043	$ 2,455
Eversource Energy	Baa1 Stable	$ 1,906	$ 15,542	12%	$ 11,219	$ 2,440	$ 615
Duquesne Light Holdings, Inc.	Baa3 Stable	$ 318	$ 2,596	12%	$ 1,076	$ 300	$ 103
Dominion Energy, Inc.	Baa2 Negative	$ 4,329	$ 38,692	11%	$ 18,857	$ 5,436	$ 2,050
NiSource Inc.	Baa2 Stable	$ 1,006	$ 9,429	11%	$ 4,435	$ 1,791	$ 238
FirstEnergy Corp.	Baa3 Stable	$ 2,247	$ 22,639	10%	$ 8,470	$ 3,002	$ 672
Cleco Corporate Holdings LLC	Baa3 Rating(s) Under Review	$ 287	$ 2,929	10%	$ 2,070	$ 252	$ 75
DPL Inc.	Ba2 Positive	$ 157	$ 1,692	9%	$ (536)	$ 107	$ -
IPALCO Enterprises, Inc.	Baa3 Stable	$ 253	$ 2,747	9%	$ 564	$ 179	$ 107

Source: Moody's Investors Service

Appendix B - Operating company peer group

Exhibits 12-15 list 102 operating companies that were analyzed as part of our financial comparisons. These companies were selected based on having ten years of historical data. Our base case scenario shows the aggregate cash flow to debt ratios of these companies dropping by 400 basis points over the next 12-18 months.

Exhibit 12

Companies 1-30 of 102 operating companies, sorted by highest to lowest CFO / Debt

$ in millions, as of the last twelve months available

Issuer	Rating and Outlook	CFO	Total Debt	CFO / Debt	Capex	Dividends
Metropolitan Edison Company	A3 Stable	$ 458	$ 1,060	43%	$ 152	$ 80
Atmos Energy Corporation	A2 Stable	$ 1,095	$ 3,371	32%	$ 1,300	$ 203
Southern California Gas Company	A1 Stable	$ 1,299	$ 4,111	32%	$ 1,433	$ 1
Baltimore Gas and Electric Company	A3 Stable	$ 945	$ 3,029	31%	$ 921	$ 199
Pennsylvania Power Company	Baa1 Stable	$ 64	$ 217	30%	$ 51	$ 20
Gulf Power Company	A2 Stable	$ 420	$ 1,420	30%	$ 235	$ 175
Tampa Electric Company	A3 Stable	$ 744	$ 2,530	29%	$ 660	$ 324
Duquesne Light Company	A3 Stable	$ 387	$ 1,321	29%	$ 282	$ 90
Madison Gas and Electric Company	A1 Stable	$ 136	$ 473	29%	$ 131	$ 32
Spire Alabama Inc.	A2 Stable	$ 136	$ 476	29%	$ 121	$ 32
Wisconsin Public Service Corporation	A2 Stable	$ 414	$ 1,465	28%	$ 363	$ 120
Kentucky Utilities Co.	A3 Stable	$ 690	$ 2,460	28%	$ 496	$ 235
Pacific Gas & Electric Company	A3 Negative	$ 5,860	$ 21,051	28%	$ 5,931	$ 542
Florida Power & Light Company	A1 Stable	$ 3,764	$ 13,562	28%	$ 4,728	$ 1,050
Consumers Energy Company	(P)A2 Stable	$ 1,865	$ 6,734	28%	$ 1,702	$ 494
Indiana Gas Company, Inc.	A2 Stable	$ 159	$ 574	28%	$ 209	$ -
Tucson Electric Power Company	A3 Stable	$ 435	$ 1,596	27%	$ 401	$ 70
Southern California Edison Company	A2 Negative	$ 3,777	$ 13,937	27%	$ 3,981	$ 657
Puget Sound Energy, Inc.	Baa1 Stable	$ 1,120	$ 4,136	27%	$ 1,036	$ 262
Northern States Power Company (Minnesota)	A2 Stable	$ 1,425	$ 5,296	27%	$ 920	$ 516
New Jersey Natural Gas Company	Aa2 Negative	$ 205	$ 764	27%	$ 185	$ 68
Louisville Gas & Electric Company	A3 Stable	$ 529	$ 2,021	26%	$ 527	$ 139
PPL Electric Utilities Corporation	A3 Stable	$ 937	$ 3,583	26%	$ 1,224	$ 332
Entergy New Orleans, Inc.	Ba1 Stable	$ 139	$ 533	26%	$ 130	$ 69
Ohio Power Company	A2 Stable	$ 655	$ 2,539	26%	$ 634	$ 178
MidAmerican Energy Company	A1 Stable	$ 1,391	$ 5,529	25%	$ 1,887	$ -
San Diego Gas & Electric Company	A1 Negative	$ 1,566	$ 6,246	25%	$ 1,613	$ 275
Oklahoma Gas & Electric Company	A1 Negative	$ 783	$ 3,121	25%	$ 727	$ 105
Southwestern Public Service Company	Baa1 Negative	$ 495	$ 1,988	25%	$ 555	$ 105
Central Hudson Gas & Electric Corporation	A2 Stable	$ 156	$ 636	24%	$ 171	$ 9

Source: Moody's Investors Service

Exhibit 13

Companies 31-60 of 102 operating companies, sorted by highest to lowest CFO / Debt
$ in millions, as of the last twelve months available

Issuer	Rating and Outlook	CFO	Total Debt	CFO / Debt	Capex	Dividends
Northern Illinois Gas Company	A2 Stable	$ 284	$ 1,205	24%	$ 601	$ 70
Questar Gas Company	A2 Negative	$ 192	$ 819	23%	$ 231	$ -
Arizona Public Service Company	A2 Stable	$ 1,229	$ 5,280	23%	$ 1,410	$ 324
Black Hills Power, Inc.	A3 Stable	$ 81	$ 351	23%	$ 75	$ -
Public Service Company of Colorado	A3 Stable	$ 1,166	$ 5,075	23%	$ 1,593	$ 336
Alabama Power Company	A1 Negative	$ 1,883	$ 8,204	23%	$ 2,192	$ 734
Duke Energy Carolinas, LLC	A1 Stable	$ 2,510	$ 10,995	23%	$ 2,575	$ 700
Sierra Pacific Power Company	Baa1 Stable	$ 272	$ 1,194	23%	$ 193	$ 43
Connecticut Natural Gas Corporation	A3 Stable	$ 55	$ 245	23%	$ 64	$ 7
Avista Corp.	Baa1 Negative	$ 447	$ 1,993	22%	$ 407	$ 94
UGI Utilities, Inc.	A2 Stable	$ 256	$ 1,144	22%	$ 328	$ 63
Piedmont Natural Gas Company, Inc.	A2 Negative	$ 500	$ 2,254	22%	$ 559	$ -
Union Electric Company	Baa1 Stable	$ 1,008	$ 4,554	22%	$ 883	$ 355
Rochester Gas & Electric Corporation	A3 Stable	$ 237	$ 1,077	22%	$ 279	$ -
Orange and Rockland Utilities, Inc.	A3 Negative	$ 224	$ 1,019	22%	$ 198	$ 45
Nevada Power Company	Baa1 Stable	$ 694	$ 3,178	22%	$ 283	$ 473
DTE Electric Company	A2 Stable	$ 1,639	$ 7,513	22%	$ 1,560	$ 439
Portland General Electric Company	A3 Stable	$ 603	$ 2,766	22%	$ 520	$ 118
Wisconsin Power and Light Company	A2 Negative	$ 456	$ 2,098	22%	$ 607	$ 129
Duke Energy Indiana, LLC.	A2 Stable	$ 926	$ 4,279	22%	$ 902	$ 300
PacifiCorp	A3 Stable	$ 1,586	$ 7,337	22%	$ 839	$ 750
PECO Energy Company	A2 Stable	$ 680	$ 3,192	21%	$ 756	$ 507
Duke Energy Kentucky, Inc.	Baa1 Stable	$ 103	$ 487	21%	$ 222	$ -
Mississippi Power Company	Ba1 Positive	$ 453	$ 2,153	21%	$ 249	$ (1)
Northern States Power Company (Wisconsin)	A2 Stable	$ 172	$ 825	21%	$ 220	$ 69
Westar Energy, Inc.	Baa1 Stable	$ 957	$ 4,602	21%	$ 778	$ 228
Otter Tail Power Company	A3 Stable	$ 125	$ 603	21%	$ 121	$ 40
Public Service Company of New Hampshire	A3 Stable	$ 287	$ 1,393	21%	$ 313	$ 155
Public Service Electric and Gas Company	A2 Stable	$ 1,829	$ 8,914	21%	$ 2,848	$ -
United Illuminating Company	Baa1 Stable	$ 234	$ 1,154	20%	$ 167	$ 125

Source: Moody's Investors Service

Appendix B (continued) - Operating company peer group

Exhibit 14

Companies 61-90 of 102 operating companies, sorted by highest to lowest CFO / Debt
$ in millions, as of the last twelve months available

Issuer	Rating and Outlook	CFO	Total Debt	CFO / Debt	Capex	Dividends
Spire Missouri Inc.	A1 Stable	$ 267	$ 1,329	20%	$ 294	$ 14
NSTAR Electric Company	A2 Stable	$ 696	$ 3,489	20%	$ 757	$ 378
Delmarva Power & Light Company	Baa1 Stable	$ 324	$ 1,624	20%	$ 421	$ 118
Cleco Power LLC	A3 Stable	$ 305	$ 1,574	19%	$ 242	$ 128
CenterPoint Energy Houston Electric, LLC	A3 Stable	$ 985	$ 5,102	19%	$ 895	$ 180
Dayton Power & Light Company	Baa3 Positive	$ 134	$ 697	19%	$ 91	$ (96)
Virginia Electric and Power Company	A2 Stable	$ 2,562	$ 13,409	19%	$ 2,607	$ 908
Public Service Company of New Mexico	Baa2 Positive	$ 365	$ 1,937	19%	$ 324	$ 61
Washington Gas Light Company	A1 Negative	$ 279	$ 1,487	19%	$ 349	$ 87
Kansas City Power & Light Company	Baa1 Stable	$ 674	$ 3,592	19%	$ 463	$ 215
Oncor Electric Delivery Company LLC	A2 Stable	$ 1,541	$ 8,234	19%	$ 1,678	$ 151
El Paso Electric Company	Baa1 Negative	$ 284	$ 1,525	19%	$ 242	$ 54
Southern Indiana Gas & Electric Company	A2 Stable	$ 157	$ 849	19%	$ 154	$ 55
Appalachian Power Company	Baa1 Stable	$ 828	$ 4,486	18%	$ 828	$ 130
Georgia Power Company	A3 Negative	$ 2,180	$ 11,808	18%	$ 2,942	$ 1,302
Potomac Electric Power Company	Baa1 Stable	$ 502	$ 2,717	18%	$ 614	$ 128
Duke Energy Progress, LLC	A2 Stable	$ 1,489	$ 8,329	18%	$ 1,701	$ 124
Texas-New Mexico Power Company	A3 Stable	$ 93	$ 524	18%	$ 162	$ 36
Public Service Company of Oklahoma	A3 Negative	$ 286	$ 1,606	18%	$ 248	$ 65
Connecticut Light and Power Company	Baa1 Rating(s) Under Review	$ 703	$ 3,977	18%	$ 855	$ 268
Public Service Co. of North Carolina, Inc.	A3 Rating(s) Under Review	$ 131	$ 740	18%	$ 289	$ 41
Consolidated Edison Company of New York, Inc.	A2 Negative	$ 2,743	$ 15,877	17%	$ 3,190	$ 808
Hawaiian Electric Company, Inc.	Baa2 Stable	$ 340	$ 2,007	17%	$ 475	$ 94
DTE Gas Company	A2 Negative	$ 286	$ 1,692	17%	$ 434	$ 106
CenterPoint Energy Resources Corp.	Baa2 Stable	$ 492	$ 2,918	17%	$ 537	$ 579
Entergy Arkansas, Inc.	Baa1 Stable	$ 637	$ 3,780	17%	$ 798	$ 16
Northwest Natural Gas Company	A3 Negative	$ 183	$ 1,093	17%	$ 235	$ 53
Duke Energy Ohio, Inc.	Baa1 Positive	$ 418	$ 2,502	17%	$ 734	$ 25
Atlantic City Electric Company	Baa2 Positive	$ 219	$ 1,338	16%	$ 299	$ 67
Southwestern Electric Power Company	Baa2 Stable	$ 475	$ 2,923	16%	$ 472	$ 116

Source: Moody's Investors Service

Appendix B (continued) - Operating company peer group

Exhibit 15

Companies 91-102 of 102 operating companies, sorted by highest to lowest CFO / Debt
$ in millions, as of the last twelve months available

Issuer	Rating and Outlook	CFO	Total Debt	CFO / Debt	Capex	Dividends
Idaho Power Company	A3 Stable	$ 386	$ 2,418	16%	$ 274	$ 115
Entergy Mississippi, Inc.	Baa1 Stable	$ 239	$ 1,513	16%	$ 412	$ 26
Entergy Texas, Inc.	Baa3 Stable	$ 257	$ 1,627	16%	$ 369	$ -
NorthWestern Corporation	Baa2 Stable	$ 339	$ 2,166	16%	$ 277	$ 103
Wisconsin Electric Power Company	A2 Stable	$ 861	$ 5,665	15%	$ 685	$ 241
Commonwealth Edison Company	A3 Stable	$ 1,436	$ 9,489	15%	$ 2,163	$ 434
Berkshire Gas Company	A3 Positive	$ 10	$ 68	14%	$ 17	$ -
Duke Energy Florida, LLC.	A3 Stable	$ 1,072	$ 7,577	14%	$ 1,256	$ -
South Carolina Electric & Gas Company	Baa3 Rating(s) Under Review	$ 754	$ 5,504	14%	$ 813	$ 322
Kentucky Power Company	Baa2 Negative	$ 129	$ 946	14%	$ 110	$ 26
Interstate Power and Light Company	Baa1 Negative	$ 338	$ 2,834	12%	$ 756	$ 154
South Jersey Gas Company	A2 Negative	$ 99	$ 994	10%	$ 246	$ 20

Source: Moody's Investors Service

Appendix C - Holding company capital spending peer group

The 25 holding companies incorporated into Exhibit 5 were selected based upon having 3-year publicly disclosed capital spending projections since in every year since 2009 and being a part of our larger 42 holding company peer group. Those companies are listed in Exhibit 16 below, sorted by rating category.

Exhibit 16

Capital spending for 25 holding companies has increased, in aggregate, year-over-year since 2016
($ millions)

		Capital Expenditures					
			2016		2017		LTM Mar 18
Consolidated Edison, Inc.	A3 Negative	$	3,898	$	3,703	$	3,701
Edison International	A3 Negative	$	3,790	$	3,879	$	4,072
OGE Energy Corporation	A3 Negative	$	660	$	810	$	728
Pinnacle West Capital Corporation	A3 Stable	$	1,289	$	1,424	$	1,439
Xcel Energy, Inc.	A3 Stable	$	3,225	$	3,238	$	3,363
Alliant Energy Corporation	Baa1 Negative	$	1,182	$	1,456	$	1,520
Ameren Corporation	Baa1 Stable	$	2,164	$	2,204	$	2,264
American Electric Power Company, Inc.	Baa1 Stable	$	5,039	$	5,945	$	6,505
CenterPoint Energy, Inc.	Baa1 Negative	$	1,423	$	1,435	$	1,485
CMS Energy Corporation	Baa1 Stable	$	1,689	$	1,682	$	1,739
DTE Energy Company	Baa1 Stable	$	2,082	$	2,294	$	2,266
PG&E Corporation	Baa1 Negative	$	5,662	$	5,646	$	5,900
Duke Energy Corporation	Baa1 Negative	$	8,089	$	8,116	$	8,043
Public Service Enterprise Group Inc.	Baa1 Stable	$	4,098	$	4,058	$	4,049
Sempra Energy	Baa1 Negative	$	4,153	$	3,951	$	3,994
Dominion Energy, Inc.	Baa2 Negative	$	6,054	$	5,768	$	5,436
Entergy Corporation	Baa2 Negative	$	4,005	$	3,900	$	3,940
Exelon Corporation	Baa2 Stable	$	8,672	$	7,741	$	7,612
Evergy, Inc.	Baa2 Stable	$	626	$	591	$	595
NiSource Inc.	Baa2 Stable	$	1,517	$	1,733	$	1,791
PPL Corporation	Baa2 Stable	$	2,999	$	3,210	$	3,287
Southern Company (The)	Baa2 Negative	$	7,537	$	8,940	$	9,251
FirstEnergy Corporation	Baa3 Stable	$	3,253	$	3,117	$	3,002
PNM Resources, Inc.	Baa3 Positive	$	622	$	521	$	524
SCANA Corporation	Ba1 Rating(s) Under Review	$	1,566	$	1,229	$	1,114
Group Total		**$**	**85,291**	**$**	**86,592**	**$**	**87,620**

Source: Company 10K filings, Moody's standard adjustments

Appendix D - 2018-2022 forecast assumptions

Key Base Case assumptions

» Projected numbers are based on the consolidated financials of a fully regulated utility holding company

» "Forward test year" (e.g., 2019 net income is derived from 2018 rate base plus 2019 capex less 2019 depreciation less 2019 deferred tax liability (DTL), adjusted for normalization of excess DTLs returned to customers)

» 50% equity layer used for rate making purposes, as opposed to the holding company capital structure that is roughly 60/40 debt/equity

» Cash tax rates: 2018- 0%, 2019- 0%, 2020- 5%, 2021- 10%, 2022- 15%

» Additional cash inflow from operations that exactly offsets the cash outflow due to normalized excess deferred tax liabilities returned to customers

» Capex - 5 year projected CAGR is 5.0% versus the 5 year historical CAGR of 5.7%

» Dividend growth is set to match Net Income growth, which is roughly 8% year-over-year

» $20 billion of equity issuance in 2018 to reflect holdco efforts to strengthen their balance sheets

» Funding percentage of negative free cash flow is 88/12 debt/equity; set to keep debt and equity CAGR equivalent at about 6%

Key differences in Upside Case assumptions

» 53% equity layer in rates

» Cash tax rates: 2018- 0%, 2019- 0%, 2020- 3%, 2021- 5%, 2022- 10%

» Regulators approve a cash inflow that is twice the size of the cash outflow due to normalized excess deferred tax liabilities returned to customers

» 2019 Capex is flat to 2018 and declines 5% year-over-year thereafter

» Funding percentage of negative free cash flow is 60/40 debt/equity (debt CAGR of 2%, equity CAGR of 7%)

Key differences in Downside Case assumptions

» 4% inflation on O&M, Taxes and Other OpEx

» Regulators approve a cash inflow that is half the size of the cash outflow due to normalized excess deferred tax liabilities returned to customers

» 7% Capex growth year-over-year

» Funding of negative free cash flow is 100% debt (debt CAGR of 7.8% vs. equity CAGR of 5.0%)

Moody's related publications

Sector In-Depth:

» Offshore Wind is Ready for Prime Time 29 March 2018

» Tax Reform is Credit Negative for Regulated Utilities Sector, but Impact Varies by Company 24 January 2018

» Cross-Sector – US: FAQ on the Credit Impact of New Tax Law 24 January 2018

» Cross-Sector – US: Corporate Tax Cut is Credit Positive, While Effects of Other Provisions Vary by Sector 21 December 2017

» Regulated Electric & Gas Utilities – US: Insulating Utilities from Parent Contagion Risk is Increasingly a Focus of Regulators 18 September 2017

» Renewable Energy - Global: Falling Cost of Renewables Reduces Risks to Paris Agreement Compliance 6 September 2017

» Renewable Energy – Global: Renewables Sector Risks Shift as Competition Reduces Reliance on Government Subsidy 6 September 2017

Rating Methodologies:

» Regulated Electric and Gas Utilities 23 June 2017

» Unregulated Utilities and Unregulated Power Companies 17 May 2017

» Regulated Electric and Gas Networks 16 March 2017

» U.S. Electric Generation & Transmission 15 April 2013

» Natural Gas Pipelines 6 November 2012

Endnotes

1 Our cash flow analysis consists of three primary measures, including: cash flow from operations (CFO), funds from operations (FFO) and CFO before changes in working capital. For purposes of this report we reference FFO due to our forecast scenarios' focus on Net Income, Depreciation and Deferred Taxes (including regulatory liabilities associated with deferred taxes).

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MOODY'S
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Exhibit DKA-6
Comparative Cost of Debt

Utilty Cost of Debt Comparison
12 Months Ending June 30, 2018

Rank	Company	Per Public Data
1.	Public Service Electric and Gas Company	3.718%
2.	**LG&E***	**3.773%**
3.	Indiana Michigan Power Company	3.992%
4.	AEP Texas	3.996%
5.	**KU***	**4.050%**
6.	DTE Electric Company	4.189%
7.	Duke Energy Ohio	4.246%
8.	PECO Energy Company	4.264%
9.	NiSource	4.381%
10.	PPL Electric Utilities	4.406%
11.	Dayton Power and Light	4.427%
12.	Commonwealth Edison	4.429%
13.	Duke Energy Indiana Inc.	4.443%
14.	Kentucky Power Company	4.525%
15.	Appalachian Power Company	4.540%
16.	Union Electric Company	4.910%
17.	Ameren Illinois Company	4.922%
18.	DTE Gas Company	5.021%
19.	Pennsylvania Electric Company	5.137%
20.	Ohio Power Company	5.212%
21.	Metropolitan Edison Company	5.373%
22.	Jersey Central Power & Light Co.	5.720%
23.	Ohio Edison Company	7.154%
24.	Toledo Edison Company	9.240%

Notes: