COMMONWEALTH OF KENTUCKY
BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

Electronic Application Of Kentucky Power Company For (1) A General Adjustment Of Its Rates For Electric Service; (2) Approval Of Tariffs And Riders; (3) Approval Of Accounting Practices To Establish Regulatory Assets And Liabilities; (4) Approval Of A Certificate Of Public Convenience And Necessity; And (5) All Other Required Approvals And Relief	)))))))	Case No. 2020-00174

SECTION III

DIRECT TESTIMONY OF
MATTISON, WISEMAN, PHILLIPS, BLANKENSHIP,
OSBORNE, VAUGHAN, WEST, AND KAISER
ON BEHALF OF KENTUCKY POWER COMPANY

VOLUME 1 OF 2

June 29, 2020

COMMONWEALTH OF KENTUCKY

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DIRECT TESTIMONY OF

D. BRETT MATTISON

ON BEHALF OF KENTUCKY POWER COMPANY

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D. BRETT MATTISON ON BEHALF OF
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BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY

CASE NO. 2020-00174

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DIRECT TESTIMONY OF
D. BRETT MATTISON ON BEHALF OF
KENTUCKY POWER COMPANY
BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY

CASE NO. 2020-00174

I. INTRODUCTION AND BACKGROUND

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is D. Brett Mattison, and my business address is 1645 Winchester Avenue, Ashland, Kentucky 41101.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. I am President and Chief Operating Officer of Kentucky Power Company ("Kentucky Power" or the "Company").

Q. PLEASE SUMMARIZE YOUR EDUCATIONAL AND PROFESSIONAL BACKGROUND.

A. I hold a bachelor's degree in Business Finance from Louisiana Tech University and a Certified Commercial Banking degree from the American Institute of Banking. In 1986, I began my career in commercial banking with Pioneer Bank in a management training program, working in all areas of banking. I became a manager of branch operations and a commercial loan officer prior to leaving the banking profession in 1990 to join Kentucky Power affiliate, Southwestern Electric Power Company ("SWEPCO").

I have more than 30 years of electric utility experience. I joined SWEPCO as a residential marketing consultant and was promoted to residential marketing supervisor for Louisiana in 1992. Between 1992 and 2004, I performed various roles of increasing responsibility within SWEPCO's marketing and customer services organization, including serving as the marketing manager responsible for overseeing the development, management, and retention of new and existing customer accounts within SWEPCO's service territory, which included Texas, Louisiana, and Arkansas. In 2004, I was promoted to Director of Customer Services and Marketing for SWEPCO. I became President and Chief Operating Officer of Kentucky Power on January 1, 2019.

Q. WHAT ARE YOUR PRINCIPAL AREAS OF RESPONSIBILITY WITH KENTUCKY POWER?

A. I am responsible for Kentucky Power's safe, reliable, and efficient day-to-day operations and am accountable for the Company's financial performance and the quality of the services provided to our customers. Specifically, my responsibilities include Kentucky Power's community involvement and economic development activities, as well as ensuring the Company's compliance with federal and state laws and regulations. Additionally, I am accountable for the Company's distribution, customer service, transmission, and generation functions to provide safe, adequate, and reliable service to Kentucky Power's customers.

Q. HAVE YOU PREVIOUSLY FILED TESTIMONY IN ANY REGULATORY PROCEEDINGS?

A. Yes. I have filed testimony on behalf of SWEPCO before the Public Utility Commission of Texas in PUC Docket Nos. 37364, 40443, and 46449.

II. PURPOSE OF TESTIMONY

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

A. The purpose of my direct testimony is to provide a general overview of Kentucky Power and of the Company's request for a general adjustment of its electric rates. Specifically, I will:

- Provide an overview of Kentucky Power and its operations;
- Discuss Kentucky Power's commitment to its customers and several of the ways the Company is furthering that commitment;
- Summarize Kentucky Power's major proposals and requests in this proceeding; and
- Identify and introduce the Company's witnesses.

Q. WHAT EXHIBITS ARE YOU SPONSORING IN THIS PROCEEDING?

A. I am sponsoring the following exhibit:

- Exhibit BM-1 – Map of Kentucky Power's Service Territory

III. OVERVIEW OF KENTUCKY POWER'S OPERATIONS

Q. PLEASE PROVIDE A BRIEF OVERVIEW OF THE COMPANY AND ITS OPERATIONS.

A. Kentucky Power is a wholly-owned subsidiary of American Electric Power Company, Inc. ("AEP") and is engaged in the generation, purchase, transmission, and distribution of electric power. The Company is headquartered in Ashland, Kentucky and serves approximately 165,000 retail customers located in 20 eastern Kentucky counties, which include some of the more mountainous and heavily forested areas of the Commonwealth. The Company's total customer count has declined by approximately 3,000 customers since June 2017, when the Company filed its last rate case. Kentucky

Power also sells electric power at wholesale rates to the City of Olive Hill and the City of Vanceburg. Exhibit BM-1 is a map detailing the Company's service territory. Kentucky Power's service territory includes some of the most economically challenged and geographically challenging territory in the Commonwealth.

Q. DOES KENTUCKY POWER MAINTAIN OTHER OFFICES?

A. Yes. The Company maintains distribution operations centers in Hazard, Pikeville, and Ashland. These offices serve as a base of operations for each of the Company's three districts. Kentucky Power employs staff in each of these districts and maintains offices and equipment to assist in maintaining and restoring electric service.

Q. HOW LARGE IS KENTUCKY POWER'S WORKFORCE?

A. Kentucky Power directly employs approximately 554 persons. The Company pays competitive wages and benefits, enabling it to attract and retain the skilled workers required to provide safe, adequate, and efficient service to our customers. The Company continuously looks for opportunities to add staff in our service territory when the cost is justified by the service and customer benefits provided.

Kentucky Power's employment impact also extends beyond its direct employees. Overall, the Company employs approximately 580 contractors on a regular basis, who perform vegetation management and construction work in eastern Kentucky. The use of independent contractors allows Kentucky Power to complete work necessary to provide safe and reliable service to its customers in a cost-effective manner.

Q. DO KENTUCKY POWER AND ITS EMPLOYEES SUPPORT THE COMMUNITIES AND INSTITUTIONS IN THE COMPANY'S SERVICE TERRITORY?

A. Absolutely. The Company and its employees are active and productive members of the communities we serve. During 2019, the Company contributed to charitable, educational, and civic organizations serving Kentucky Power's service territory. Kentucky Power employees participate in numerous community causes, including those that promote economic development, civic pride, and customer safety.

Kentucky Power, AEP, and the American Electric Power Foundation collectively made over $1.7 million in philanthropic donations and economic development grants in the Commonwealth during 2019. Among other contributions, in 2019 Kentucky Power and the American Electric Power Foundation awarded grants to: Letcher County, Kentucky's fire departments to fund turnout gear; the Kentucky Coalition Against Domestic Violence to aid women in eastern Kentucky; the Red Cross to provide free smoke detectors and support the organization's home fire preparedness efforts; Ashland Community and Technical College to support science, technology, engineering, and math education in Lawrence County Schools; and Highlands Museum and Discovery Center in Ashland, Kentucky to fund a multi-use children's theater.

Q. WHAT IS THE AMERICAN ELECTRIC POWER FOUNDATION?

A. The American Electric Power Foundation supports the communities served by AEP operating companies like Kentucky Power and provides a permanent, ongoing resource for charitable initiatives involving higher dollar values and multi-year commitments in the communities Kentucky Power serves.

Kentucky Power's, AEP's, and the Foundation's charitable contributions are funded by the Company's shareholder; none are recovered through customer rates. Company Witness Wiseman also discusses the Company's community outreach, customer communication, and philanthropic efforts.

IV. KENTUCKY POWER'S COMMITMENT TO CUSTOMERS

Q. PLEASE DESCRIBE KENTUCKY POWER'S CUSTOMER PHILOSOPHY.

A. At Kentucky Power, customer service is not a department, but a culture. Our commitment to our customers is the guiding principle of everything that we do, from community and economic development activities; to customer experience and assistance initiatives and programs; to storm restoration, vegetation management, and other reliability improvements.

Q. PLEASE BRIEFLY DESCRIBE THE IMPORTANCE OF ECONOMIC DEVELOPMENT TO THE COMPANY AND ITS CUSTOMERS.

A. Economic development and retention are important priorities to both Kentucky Power and its customers. As discussed further in Company Witness Wiseman's testimony, the entire eastern Kentucky region, including the Company's service territory, is struggling economically. There is a critical need for the Company to assist with efforts to maintain existing customers and further develop the region's economy.

First and foremost, economic development is essential to ensure that the citizens in the communities Kentucky Power serves are meaningfully employed, have opportunities to create and expand businesses and industries in eastern Kentucky, and enjoy the benefits associated with an increased tax base in their communities. Moreover, the addition or expansion of business and industry results in increased load, which benefits all customers by spreading Kentucky Power's fixed costs of providing electric service and lowering customer rates.

Kentucky Power has had some recent successes working with specific industrial customers facing dire economic circumstances, such as Air Products and Chemicals, Inc. and MC Mining, LLC, in order to develop economic incentives to assist those customers and retain significant businesses and sources of employment in eastern Kentucky. In addition to these successes, as Company Witness Wiseman details, Kentucky Power has supported successful economic development projects through its Kentucky Power Economic Growth Grants ("K-PEGG") Program and other initiatives that have resulted in the location of new customers and creation of jobs in the Company's service territory. It is important to build upon this momentum and continue to support economic development efforts for the benefit of Kentucky Power's customers and the region as a whole.

Q. PLEASE EXPLAIN, AT A HIGH LEVEL, THE COMPANY'S RECENT CUSTOMER EXPERIENCE EFFORTS.

A. Knowledge is power. Kentucky Power uses several communication channels and formats in order to ensure customers are engaged, informed, and understand their electric bill and the services and programs available to them from Kentucky Power. Company Witness Wiseman's testimony details Kentucky Power's customer experience focus over the last several years. Company Witnesses Wiseman, Blankenship, and West also describe the Company's ongoing and planned customer experience initiatives, which include a Customer Relationship Management ("CRM") project, a Home Energy Management ("HEM") system, the deployment of Advanced Metering Infrastructure ("AMI"), and the Company's related offering to residential customers with AMI meters of the option to prepay for electric service in order to manage their electricity costs and avoid deposits and certain fees. Each of these initiatives will equip customers with additional information, resources, and options to better manage their electric usage and further customize the electric service they receive from Kentucky Power.

Q. PLEASE DESCRIBE THE CHALLENGES THAT KENTUCKY POWER FACES IN MEETING ITS CUSTOMERS' NEEDS.

A. A major challenge that Kentucky Power faces is how to meet the needs of, and provide solutions for, customers while continuing to provide affordable and reliable electric service at a time when the costs of providing reliable electric service are rising and customer needs and expectations are also changing and increasing. Today's modern digital age means residential customers are using more electronic devices and appliances than ever before, and industrial customers are relying more heavily on electronic controls and computers to manage their production facilities and processes. The many electronic devices and equipment used by our customers today are less tolerant of even minor service interruptions. This requires increasing diligence with respect to service reliability.

The importance of diligence to service reliability with minimal interruptions has never been more important than it is now, during the Coronavirus Disease of 2019 ("COVID-19") pandemic, where the environment in which customers are working and conducting business has changed, and in some cases permanently. Additionally, as discussed in more detail by Company Witness Phillips, the Company faces emerging reliability challenges in the form of service interruptions due to vegetation outside the rights-of-way that have increased significantly over the last several years as a result of heavy rainfalls, plant disease, and insect infestation, including by the destructive emerald ash borer. Although the Company has reasonably invested in maintaining and improving its facilities to ensure reliable service and high quality power, these changing needs and expectations require continual additional investment to serve our customers.

At the same time, deploying technology within electric utility infrastructure can change how Kentucky Power's customers use electricity and improve the way we operate our systems. As technology advances, the electric industry has the opportunity to enhance the way it does business to benefit both customers and utilities.

We know our customers want affordable service and our communities look to Kentucky Power to offer reasonable rates to attract and retain businesses. Kentucky Power is committed to effectively managing its business to meet customers' needs. Further, in order to meet customer needs and expectations, Kentucky Power requires support from its customers and regulators to help ensure its ability to provide reasonably priced, high quality electric distribution services. The ability to recover costs of capital investments and significant expenses in a timely manner remains important to the financial health of the Company.

Q. HAS THE COMPANY TAKEN ANY RECENT SIGNIFICANT ACTIONS DESIGNED TO BENEFIT CUSTOMERS?

A. Yes, it has. As I touched on earlier, Kentucky Power fully understands the economic challenges that its customers and the eastern Kentucky region have been facing over the last several years. COVID-19 has only worsened the economic situation. The Governor, the Public Service Commission of Kentucky ("Commission"), and the Company have taken several important steps to mitigate the financial impact of the COVID-19 pandemic on customers, including suspending utility service terminations and ceasing the collection of late payment fees from customers. Despite those efforts, and due to the impacts on business and industry associated with business closures, social distancing, and stay home orders during this public health emergency, a significant number of Kentucky Power's customers have been unable to pay for electric service.

In order to relieve customers' financial burden during this time, on May 29, 2020, Kentucky Power initiated Case No. 2020-00176, in which the Company proposes to utilize a portion of its unprotected excess accumulated deferred federal income tax ("ADFIT") balance to eliminate all customer balances that are 30 or more days past due as of May 28, 2020. Upon Commission approval of the Company's proposal, customers will receive payment relief in the form of a one-time bill credit totaling approximately $10.8 million in the aggregate. Kentucky Power is already committed to crediting the unprotected excess ADFIT to customers over approximately the next 15 years; its proposal in Case No. 2020-00176 will shorten the time period over which those funds are credited to customers in order to help them during this unprecedented time. Using unprotected excess ADFIT for this purpose also avoids additional future costs to customers associated with the delinquencies. Additional details regarding the Company's application in Case No. 2020-00176 are available in that case.

V. OVERVIEW OF THE COMPANY'S REQUEST TO ADJUST ITS RATES

Q. PLEASE SUMMARIZE KENTUCKY POWER'S MAJOR PROPOSALS IN THIS CASE?

A. In order to continue to provide safe, adequate, and reliable service to customers, enhance the customer experience, and empower customers with information and service options, Kentucky Power is making several key proposals in this proceeding.

As detailed by Company Witnesses Phillips and West, Kentucky Power is proposing to establish a Grid Modernization Rider, which would support capital funding for future distribution modernization investments, including the AMI deployment that the Company proposes in this case. As explained by Company Witness Blankenship, AMI provides benefits to both customers and the distribution system. AMI enables the Company to offer customers the ability to better understand their power usage and offer expanded payment options, such as usage management, immediate outage information, and monthly electric bill prepayment, which will increase customers' control over their monthly electric bill. Company Witness West describes the Company's proposed prepayment option, Flex Pay, for residential customers with AMI meters. AMI will also enable Kentucky Power to help improve electric service reliability by remotely establishing and reconnecting customers, including after a storm or other outage.

As I mentioned previously, Company Witness Wiseman describes the Company's commitment to continue to enhance customers' experience. Kentucky Power also proposes to continue its current level of K-PEGG grant funding in order to continue to support economic development and expansion in the Company's service territory.

Q. WHAT RATE ADJUSTMENT IS KENTUCKY POWER PROPOSING IN THIS PROCEEDING?

A. The rates proposed in the Company's application are designed to produce an increase in annual revenues of $65,001,789. This increase is based on the historical test year ending March 31, 2020, with known and measurable adjustments to test year revenues and operating expenses. Importantly, however, and in recognition of the unprecedented economic conditions in which the Company's customers, the Commonwealth, and the country find themselves, the Company is proposing the following measures to mitigate customer rate impacts. These measures collectively total approximately $73.6 million in rate increase mitigation to the benefit of Kentucky Power's customers:

1. **ADFIT Offset of First Year Rate Increase**. Kentucky Power proposes to utilize a portion of its unprotected excess ADFIT balance to offset all rate increases for the first year new rates are in effect, as Company Witness West describes in greater detail. If the Commission accepts this proposal, customers will not experience a rate increase until 2022.

2. **Discontinuation of Capacity Charge Tariff Collection**. As a way to further mitigate the rate increase in this case, Kentucky Power is proposing to discontinue collection of its Capacity Charge tariff, which recovers approximately $6.2

million annually through December 7, 2022. This proposal is conditioned upon Commission approval of the Company's requested rate increase as filed, as discussed further by Company Witness Vaughan.

3. <u>Reduction of Recommended Return on Equity ("ROE")</u>. Company Witness McKenzie's analysis demonstrates that an ROE of 10.3% is warranted for the Company. Although Mr. McKenzie's analysis supports a higher ROE, Kentucky Power is requesting an ROE of 10.0% as a third way to mitigate the rate increase in this case.

Each of these measures represents a one-time proposal that Kentucky Power is making, without prejudice to the Company's positions in future rate cases, in recognition of the unique economic and financial challenges that customers in the Company's service territory are facing as a result of COVID-19.

Q. WHAT HAS CHANGED SINCE THE COMMISSION'S ORDER IN CASE NO. 2017-00179 THAT NECESSITATES THE COMPANY'S PRESENT APPLICATION?

A. Kentucky Power's service territory continues to undergo historic changes, and it is critical to Kentucky Power's financial integrity to act now to address those changes. The Company's customer base continues to shrink, and the decline in usage requires the Company to spread the costs of operations over the smaller number of remaining customers. Customer usage since February 28, 2017, the end of the test year in the Company's last rate case, has declined by more than 576 million kilowatt-hours. This loss of load translates into roughly $19.5 million in annual net lost revenue. The effect of a decreasing customer base, and the resulting effect on Kentucky Power's financial health, are the largest drivers of the rate request.

Q. WHY IS ALLOWING KENTUCKY POWER THE OPPORTUNITY TO EARN A REASONABLE RETURN AND FINANCIAL PERFORMANCE IMPORTANT?

A. Kentucky Power is an important part of the fabric of eastern Kentucky as an employer, corporate citizen, and investor. It is important that public utilities are provided an opportunity to earn a reasonable financial return on investment to ensure shareholder investment. Failure to perform financially will adversely affect the capital available to the Company and its cost, as well as Kentucky Power's ability to provide safe and reliable service to customers while remaining an important part of eastern Kentucky. Company Witness McKenzie discusses the basis for his recommended ROE range and the importance of Kentucky Power being permitted the opportunity to earn it.

In addition, as a general proposition, public utilities are typically viewed as safe investment opportunities and their securities are sought by teacher retirement systems, unions, and other mainstream risk-adverse investors. These are the investors that provide the capital to support Kentucky Power's operations and look to the Commission to provide the opportunity to earn, and the Company to achieve, a fair return.

As a public utility, the Company abides by the rules and regulations of the Commonwealth and the Commission. Under the regulatory compact, Kentucky Power provides safe and reliable service in return for a fair opportunity to earn a reasonable return on its investment. Kentucky Power's existing rates do not provide it an opportunity to earn a reasonable return.

Q. WHY IS KENTUCKY POWER MAKING THIS FILING NOW?

A. Kentucky Power's earned ROE for the test year ending March 31, 2020 was 6.7%. This is far below the range of ROEs found to be reasonable by the Commission in Case No. 2017-00179. In fact, Kentucky Power has never achieved its authorized ROE since the Commission's January 18, 2018 Order in that case. Kentucky Power cannot continue to provide safe, efficient, and adequate service without the opportunity to attract the capital required to make the necessary investments.

Q. DID KENTUCKY POWER CONSIDER THE EFFECT OF ITS REQUESTED INCREASE ON ITS CUSTOMERS?

A. Yes. Kentucky Power balances its operations and requests for rate relief with the reality of the rapidly changing electric utility industry and the circumstances facing customers. It is with customers in mind that the Company is proposing the measures I describe above to offset and mitigate its proposed rate increase.

Kentucky Power's request is reasonable and necessary to position the Company to meet the significant challenges it and its customers face and will allow it to:

- meet customer expectations for safe and reliable electric service;
- continue to maintain and improve reliability;
- continue to invest in necessary capital improvements to the distribution system; and
- provide a safe work environment that sends each and every employee home injury-free.

Kentucky Power provides a valuable service to its customers and is a leader in the eastern Kentucky economy. The Company, however, is significantly challenged under its existing rates to continue to provide energy that is safe, reliable, efficient, and consistent with customers' increasing service expectations.

Q. ARE THERE OTHER OPTIONS THE COMPANY IS EXPLORING TO MITIGATE FUTURE CUSTOMER BILL IMPACTS?

A. The Company continues to explore all possible approaches to provide safe and reliable power, in compliance with all applicable regulations, in the most cost-effective manner. The Company is committed to continually review its operations and find more efficient and improved ways to achieve its core work providing electric service to customers. Ultimately, it is increased economic development within the Company's service territory, and with it the associated increased load across which costs can be spread, that is the best opportunity Kentucky Power and its customers have to address the increasing cost of providing safe, reliable, and efficient electric service. Kentucky Power remains deeply committed to leveraging any economic growth opportunities presented by a highly skilled and available workforce into the eastern Kentucky region.

Q. ARE THE RATES REQUESTED BY KENTUCKY POWER FAIR, JUST, AND REASONABLE?

A. Yes. Kentucky Power's goal is to provide reliable and cost-effective service to its customers while also producing a reasonable return for its shareholders. The evidence is provided by the Company for the Commission to review. Kentucky Power's proposed adjustments yield fair, just, and reasonable rates that will allow it to continue to provide the service that customers and KRS 278.030 require.

VI. INTRODUCTION OF WITNESSES IN THIS CASE

Q. WHAT WITNESSES WILL BE OFFERING TESTIMONY IN SUPPORT OF KENTUCKY POWER'S APPLICATION, AND WHAT IS THE GENERAL SUBJECT MATTER OF THEIR TESTIMONY?

A. Kentucky Power is presenting 16 witnesses supporting the Company's proposals in this case. Table 1 below summarizes and introduces each witness and provides a brief description of their testimony:

Table 1: Kentucky Power's Witnesses

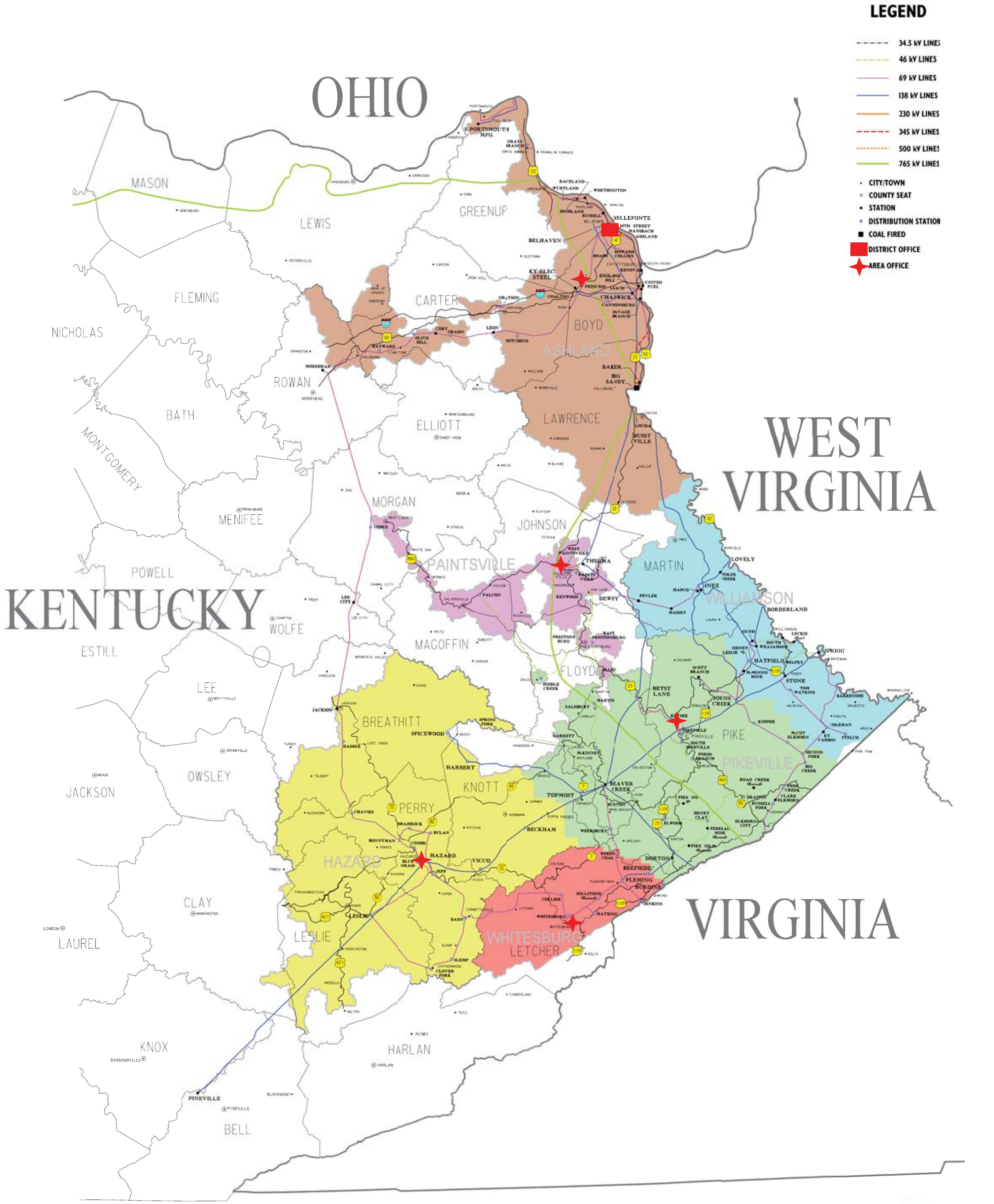
WITNESS	TOPICS
D. Brett Mattison	Company Organizational Structure and Service Territory; Overview of Case and Company Witnesses; Proposed Rate Increase Mitigation Measures and ROE; and Overview of Customer Service, Economic Development, and Reliability Priorities and Challenges
Cynthia G. Wiseman	Kentucky Power's Investment In Economic Development and Focus on Customer Experience; and Customer Engagement and Education Plan for AMI and Flex Pay Program
Everett G. Phillips	Overview of Kentucky Power Distribution Programs; Annual Distribution Operation and Maintenance ("O&M") Expenses and Capital Investment; Vegetation Management Plan Funding; Kentucky Power's Smart Grid Investments; and Overview of Investments to be Recovered through the Proposed Grid Modernization Rider
Stephen D. Blankenship	Advanced Metering Infrastructure
Debra L. Osborne	Overview of Kentucky Power Generation Assets; Big Sandy Plant Status; and Generation O&M Expenses
Alex E. Vaughan	Overview of the Relation Between the Company's Base Rates and its Surcharges and Riders; Rate Design; Tariff Changes; Grid Modernization Rider Revenue Requirement; and Certain Revenue and Operating Expense Adjustments

WITNESS	TOPICS
Brian K. West	Proposed Revenue Requirement; Proposed Year-One Offset to Approved Rates; Grid Modernization Rider Function; Certificate of Public Convenience and Need for AMI; Flex Pay Program and Time-of-Day Rates for AMI; Certain Capitalization Adjustments; Certain Revenue and Operating Expense Adjustments; Amortization Of Regulatory Assets And Liabilities; and Depreciation
Kimberly K. Kaiser	Employee Compensation Strategy
Lerah M. Scott	Environmental Surcharge Base Revenue Requirement; and Certain Revenue and Operating Expense Adjustments
Scott E. Bishop	Certain Operating Expense Adjustments; and Proposed Changes To Certain Tariffs
Heather M. Whitney	Certain Revenue And Operating Expense Adjustments; Certain Capitalization And Rate Base Adjustments; Rockport Capacity Deferral Amortization; and Grid Modernization Rider Accounting Treatment
Allyson L. Keaton	Calculation Of Gross Revenue Conversion Factor; and Tax Effects Of Certain Ratemaking Adjustments
Jaclyn N. Cost	Jurisdictional Cost-of-Service Study
Jason M. Stegall	Class Cost-of-Service Study; and Allocation Of Requested Increase To Customer Classes
Franz D. Messner	Kentucky Power's Proposed Capital Structure; Cost of Capital For Ratemaking Purposes; and Kentucky Power's Financial Position And Credit Rating
Adrien M. McKenzie	Calculation Of A Fair, Just, and Reasonable ROE Range

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, it does.

Map of Kentucky Power's Service Territory



AMERICAN ELECTRIC POWER

KY-S Nad27 Projection
10/8/2014
Issued by GIS Services-East
KY_Territory_KS27_2004.dgn

VERIFICATION

The undersigned, D. Brett Mattison, being duly sworn, deposes and says he is President & COO of Kentucky Power Company that he has personal knowledge of the matters set forth in the forgoing testimony and the information contained therein is true and correct to the best of his information, knowledge and belief after reasonable inquiry.

D. Brett Mattison

D. Brett Mattison

COMMONWEALTH OF KENTUCKY	)
	) Case No. 2020-00174
COUNTY OF BOYD	)

Subscribed and sworn to before me, a Notary Public in and before said County and State, by D. Brett Mattison, this 22nd day of June 2020.

Trisha Nance

Notary Public

Notary ID Number: 632421

My Commission Expires: 9-26-2023

OFFICIAL SEAL
TRISHA NANCE
NOTARY PUBLIC - KENTUCKY
STATE-AT-LARGE
My Comm. Expires September 26, 2023
ID # 632421

COMMONWEALTH OF KENTUCKY

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DIRECT TESTIMONY OF

CYNTHIA G. WISEMAN

ON BEHALF OF KENTUCKY POWER COMPANY

DIRECT TESTIMONY OF
CYNTHIA G. WISEMAN ON BEHALF OF
KENTUCKY POWER COMPANY
BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY

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DIRECT TESTIMONY OF
CYNTHIA G. WISEMAN ON BEHALF OF
KENTUCKY POWER COMPANY
BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY

CASE NO. 2020-00174

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME, POSITION AND BUSINESS ADDRESS.

A. My name is Cynthia G. Wiseman, and I am the Vice President, External Affairs and Customer Services for Kentucky Power Company ("Kentucky Power" or "Company"). My business address is 1645 Winchester Ave., Ashland, Kentucky 41101.

II. BACKGROUND

Q. PLEASE DESCRIBE YOUR EDUCATIONAL AND PROFESSIONAL BACKGROUND.

A. I received a Bachelor of Arts degree in Journalism with an emphasis in Public Relations from Marshall University in Huntington, West Virginia in 1989. Prior to joining American Electric Power Company, Inc. ("AEP"), the majority of my career had been spent in public relations and customer outreach. I worked for a large public library system in Charleston, West Virginia for 15 years. I joined Kentucky Power affiliate Appalachian Power Company ("Appalachian Power") in 2008 as a Senior Communications Consultant, where I was responsible for overseeing customer communications within Appalachian Power's three-state territory. In 2013, I was promoted to External Affairs Manager/Lobbyist, where my duties included building and maintaining relationships while serving as company liaison for local, state, federal government and community officials. I joined Kentucky Power and accepted my current position in April 2018.

Q. WHAT ARE YOUR RESPONSIBILITIES AS VICE PRESIDENT, EXTERNAL AFFAIRS AND CUSTOMER SERVICES?

A. I am responsible for the management of Kentucky Power's external affairs, economic development, customer and energy services, and corporate communications for the Company's twenty-county service territory.

As part of my external affairs responsibilities, I oversee the team that is responsible for maintaining the Company's relationships with federal, state, and local officials. In this role, my team and I keep Kentucky Power elected officials and community leaders apprised of how proposed legislation and regulations will affect the Company's operations and its customers.

With regard to economic development, my team is responsible for the administration of the Kentucky Power Economic Growth Grant ("K-PEGG") Program. My team works with the economic development organizations in the Company's service territory to identify and support projects that will attract new businesses to and promote business expansion within the region.

Finally, with regard to customer service, I oversee the team responsible for ensuring proactive and customized service is provided to our commercial, industrial, and residential customers. I am accountable for designing and implementing new customer-focused initiatives and policies to improve the customer's relationship with the Company as well as guiding the Company's corporate communications strategic plan. My team is responsible for the administration of Kentucky Power's Home Energy Assistance

("HEA") programs, including Home Energy Assistance in Reduced Temperatures ("HEART"), Donation HEART, and Temporary Heating Assistance in Winter ("THAW"), as well as implementing energy efficiency and electrification efforts.

III. PURPOSE OF TESTIMONY

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

A. The purpose of my testimony is to describe Kentucky Power's customer experience and economic development efforts and successes within the Company's service territory. In addition, my testimony covers the following specific topics:

- The Company's refocused attention on customer experience, multi-channel approach to customer communications, and increased community outreach.
- The Company's customer engagement strategy and education plan related to its proposed advanced metering infrastructure ("AMI") deployment in Kentucky.
- The Company's communications and education plan associated with the Kentucky Power Flex Pay Program for AMI customers.
- The status of the Company's economic development efforts and, specifically, the K-PEGG Program.

Q. ARE YOU SPONSORING ANY EXHIBITS IN YOUR TESTIMONY?

A. Yes. I am sponsoring the following exhibit:

- **EXHIBIT CGW-1** – Sample Flex Pay Program Marketing Information

Q. WERE THE EXHIBITS PREPARED OR ASSEMBLED BY YOU OR UNDER YOUR SUPERVISION?

A. Yes.

IV. KENTUCKY POWER'S CUSTOMER EXPERIENCE FOCUS

Q. WHAT DO YOU MEAN WHEN YOU USE THE TERM "CUSTOMER EXPERIENCE"?

A. Kentucky Power has always focused on customer service, but in the past several years there has been a shift to emphasizing overall customer experience. Customer service is just one of the many interactions that shape the customer experience. Customer experience is the sum of all interactions between Kentucky Power and its customers. It is about developing relationships with customers, conducting business in a proactive way, and ultimately becoming a company that is easier to do business with.

Q. HOW DOES KENTUCKY POWER CONNECT AND COMMUNICATE WITH ITS CUSTOMERS?

A. Kentucky Power understands the importance of open communication with its customers. With approximately 165,000 customers throughout the Kentucky Power service territory, our challenge is ensuring that we are engaging with customers using the method they prefer. We have adopted a "meet customers where they are" approach because we understand the importance of the messages we are sharing and want to ensure we are maximizing our opportunities to reach customers through a multi-channel approach.

The Company uses a number of strategies to connect and engage with its customers. We utilize phone messaging, emails, direct mail, advertising, traditional media channels, social media networks, legally required notices, customer newsletters, and in-person interaction at community meetings and events.

Q. WHAT CUSTOMER COMMUNICATION AND COMMUNITY OUTREACH ACTIVITIES DOES KENTUCKY POWER ENGAGE IN CURRENTLY?

A. In the latter part of 2018 and throughout 2019, Kentucky Power put renewed focused on helping customers become better familiar with tools that are available to them, such as mobile alerts, average monthly payment plans, and paperless billing, along with educational information, such as how to save on electric bills using energy efficiency. With a small advertising budget and a lot of grass roots components, the Company developed a customer communications and community outreach campaign. The Company deployed a multi-channel communication effort including social media, bill inserts and messages, and email in order to inform, build awareness, and encourage adoption of customer tools.

Further, in 2018, Kentucky Power created a customer handbook to help customers understand the Terms and Conditions of our business in a more user-friendly medium. The Company uses the handbook in all of our community outreach efforts, in addition to providing it to larger municipalities, county offices, community action agencies, and residential customers during home visits. The customer handbook is also available on the Company website.

Finally, in 2019, Kentucky Power celebrated its 100th anniversary. Among the activities to commemorate the anniversary was a thank you card initiative and social media campaign in which every contribution or outreach event was labeled an act of appreciation, both of which are continuing into 2020. These efforts were a way for employees of the Company to give back to our communities, enhance the customer experience, and to say thank you to our customers for letting us serve eastern Kentucky for 100 years.

Q. HOW HAS KENTUCKY POWER'S APPROACH TO CUSTOMER COMMUNICATIONS AND COMMUNITY OUTREACH EVOLVED SINCE THE LAST BASE CASE?

A. Since 2018, Kentucky Power has placed increased emphasis on improving customer communications and community outreach. The Company has taken a proactive approach for all customer classes with a communications and engagement strategy that has evolved to meet customer preference. The Company has utilized information from customer surveys and nationally recognized customer research organizations, such as J.D. Power, to better understand customer preferences. Furthermore, as described above, the Company has increased the volume and type of communications and ramped up community participation in a variety of outreach events.

One of the most significant shifts has been the increased use of social media platforms, like Facebook and Twitter, to inform customers and respond to their inquiries. Since 2017, we have increased our use of social media to share outage restoration information, energy efficiency tips, information about improvements to the electric grid, and public safety information. Social media is a cost-effective means of communication that allows the Company to provide customers with prompt, easy access to this information. Furthermore, Kentucky Power now has a social media center where trained representatives interact with customers using direct messaging to help with issues such as billing or outage questions. However, for customers who are not as comfortable with technology, the Company continues to reach out through other channels, including public presentations at senior centers and other locations, as well as the use of monthly bill inserts and bill messaging.

Q. DO CUSTOMERS BENEFIT FROM KENTUCKY POWER'S COMMUNICATIONS AND COMMUNITY OUTREACH?

A. Yes. Kentucky Power has taken great care to ensure that its efforts provide customers with accurate and timely information so they can benefit from the wide range of tools and resources the Company offers. The Company's increased use of social media platforms allows it to more quickly address customer concerns and provide timely information on topics such as outage restoration. Kentucky Power staff additionally monitors customer sentiment and engagement through previously mentioned customer surveys and social media monitoring.

The Company also believes it has a responsibility to help strengthen the communities where its customers and employees live and work. Kentucky Power is a strong supporter of non-profit organizations, directing the majority of its contributions toward science, technology, engineering, and mathematics ("STEM") education and helping to meet basic human needs. The Company is able to provide this support through its local contributions budget as well as the AEP Foundation.

Beyond the Company's financial support, Kentucky Power and its employees are productive members of the communities we serve. In eastern Kentucky alone, employees have participated in numerous community causes. Furthermore, Kentucky Power staff also regularly attend community events and meetings throughout our service territory. These events allow customers to have face-to-face interaction with Company employees and build trust among community members. Community outreach efforts also enable Kentucky Power staff to gain important feedback from customers and directly address customer concerns.

Q. DOES KENTUCKY POWER ALSO PROVIDE CUSTOMER BENEFITS THROUGH A HEA PROGRAM?

A. Yes. Kentucky Power's home energy assistance program began in December 2006 to assist low-income customers and others in need of help. In October 2018, the program was modified and expanded to broaden the reach of the program through amendments to the HEART program and the creation of the THAW program.

HEART is designed to assist low-income Kentucky Power residential customers with their electric bill, whereas THAW is designed to help customers who do not require the broader and more sustained help provided by HEART, but who nonetheless are at risk of losing their electric service because of a temporary situation. In order to continue to deliver meaningful help to customers in need, Kentucky Power is proposing to maintain the Residential Energy Assistance Tariff ("Tariff R.E.A.") and continue the Tariff R.E.A. rate at $0.30 per meter per month with a corresponding Company match.

Based on discussions with Community Action Kentucky and several local community action agencies, the Company proposed small changes to the eligibility requirements for the HEART and THAW programs to alleviate administrative burden and further improve customers' experience, which were approved by the Commission in September 2019.[1] Additionally, Kentucky Power was an active and supportive participant in the Commission's 2019 Investigation of HEA Programs to develop and implement superior program attributes that advance consistent, effective, and accountable HEA

[1] Case No. 2019-00245, *Electronic Application of Kentucky Power Company To: 1) Modify Kentucky Power Company's Residential Energy Assistance Program; 2) Approve The Amended Operating Agreement; and 3) Grant All Other Relief To Which If May Be Entitled* (Ky. PSC Sept. 11, 2019).

programs across the Commonwealth, and that are beneficial to and easily accessed by eligible low-income customers, resulting in increased benefits to all ratepayers.[2]

Q. DOES KENTUCKY POWER PLAN ON DEPLOYING ANY NEW CUSTOMER TOOLS OR PROGRAMS TO ENHANCE THE CUSTOMER EXPERIENCE?

A. Yes. Industry and customer expectations are evolving, and Kentucky Power must continue to offer market-relevant and personalized products, services, and experiences to our customers. Accordingly, AEP has launched the Customer Relationship Management ("CRM") project, which will be deployed to Kentucky Power beginning in 2020. The CRM project lays a foundation for providing an end-to-end, 360-degree view of the customer's business interactions with the Company. The capabilities that will be delivered are geared toward communicating and engaging with customers in relevant ways. "Personalization" of this type benefits customers with meaningful contacts that suit unique energy needs.

Additionally, Kentucky Power intends to deploy a Home Energy Management ("HEM") system in 2020, which presents residential customers with the opportunity to access and manage their energy usage and cost information that they do not have access to today.[3] This customer engagement platform, which is discussed further below, is a tool to provide customers access to energy usage and cost information during the billing period, allowing customers to take action during the month to manage their energy costs.

Finally, in association with the Company's AMI deployment proposed as part of this case, Kentucky Power plans to implement Flex Pay, which allows customers to choose

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[2] Case No. 2019-00366, *Electronic Investigation Of Home Energy Assistance Programs Offered By Investor-Owned Utilities Pursuant to KRS 278.285(4)* (Ky. PSC May 4, 2020).

[3] Kentucky Power is looking at similar energy management solutions for its commercial and industrial customers.

the amount they want to pay, and the method and frequency of their payments. As I discuss in more detail later in my testimony, customers will benefit from this program by having greater control over their budget. Instead of one bill at the end of the month, Flex Pay allows the customer to pay in smaller amounts, many times over the course of the month. This convenient payment method will even allow customers currently in arrears to keep the lights on while paying down their past due balance. Company Witness West discusses Kentucky Power's proposed Flex Pay program tariff and associated costs in his testimony.

Q. HOW DOES KENTUCKY POWER MEASURE CUSTOMER SATISFACTION?

A. Kentucky Power utilizes information from customer surveys and nationally recognized customer research organizations, such as J.D. Power, to measure customer satisfaction and adjusts its customer service efforts according to what is learned from customers. The Company has also started using a new customer feedback platform, Medallia, which provides timely feedback from customers, enabling Kentucky Power to address emerging issues more quickly. Furthermore, Kentucky Power participates in outreach events to talk to and interact with customers, attends various county and city public meetings to listen and engage in community matters, and monitors social media reactions and comments to gauge customer sentiment. The Company uses these qualitative measures in conjunction with J.D. Power's customer satisfaction surveys and other research studies to get a comprehensive view of customer satisfaction.

Q. HOW DOES KENTUCKY POWER PLAN TO IMPROVE THE CUSTOMER EXPERIENCE GOING FORWARD?

A. Interaction with customers is vital and will continue. The Company intends to continue to be in the community speaking and listening. Furthermore, Kentucky Power's approach to customer service continues to evolve and expand. As the expectations and preferences of customers continues to change, the Company strives to ensure a robust, proactive relationship with customers. Through increased communication and outreach, the Company is making itself more available to customers to quickly and satisfactorily address their needs. At Kentucky Power, customer service is not a department, but rather part of the Company's culture.

V. AMI CUSTOMER ENGAGEMENT AND EDUCATION

Q. PLEASE DESCRIBE THE PURPOSE OF YOUR TESTIMONY RELATED TO KENTUCKY POWER'S PROPOSED AMI DEPLOYMENT?

A. My testimony supports the following:

- Customer engagement strategy and education plan as AMI is deployed throughout the service territory;
- The technology that will enable customers to access data made available by AMI; and
- How AMI will equip customers with additional resources and options that will allow them to better manage their electric usage and further customize the service they receive from Kentucky Power.

Q. HOW DOES KENTUCKY POWER PROPOSE TO NOTIFY CUSTOMERS REGARDING THE INSTALLATION OF AMI METERS?

A. Kentucky Power recognizes that two critical components of rolling out new technology to customers are education and awareness. Prior to the installation of AMI meters, Kentucky Power will provide customers with a variety of opportunities to learn about AMI technology and explain the benefits that AMI meters can bring to customers.

The Company has developed a customer engagement and communications process for its AMI deployment, including utilizing the experience of Kentucky Power's sister companies during their AMI deployments. This process focuses on providing customers with the information necessary to understand the benefits they receive from AMI and to make informed decisions about the use of AMI technology. The customer engagement and communications process includes the following components:

- Postcard and E-Mail Notifications – At least sixty days prior to AMI meter installation, all customers will receive a postcard notifying them of the AMI deployment. The postcard will provide a high-level overview of the benefits of the technology, a link to the page on Kentucky Power's website specifically addressing the AMI deployment, and a phone number to the customer operations center to answer questions customers may have. In addition to the postcard, Kentucky Power will also send an e-mail containing similar information to customers to their e-mail address on file.
- Kentucky Power Website – Kentucky Power will establish a specific landing page on its website to address all matters related to AMI deployment. This webpage will explain details of the program, provide information about installation dates, include a list of Frequently Asked Questions ("FAQs"), and provide links to information about AMI meters from other credible sources.
- Customer Phone Call – At least ten days prior to AMI meter installation, all customers will receive a recorded phone call from Kentucky Power to notify them of a date range in which they will be receiving their new AMI meter and

providing them with a phone number to call if they have any questions or concerns.

- Door Hanger – At the time of meter installation, all customers will be left with a door hanger notifying them that either the meter has been successfully installed or that Kentucky Power was unable to gain access to install the AMI meter. If the AMI meter could not be installed, the door hanger will include a phone number for customers to call to schedule an appointment for installation.
- Follow-Up Phone Call – If the initial AMI meter installation was unsuccessful and Kentucky Power has not received a phone call from the customer to schedule an installation appointment within ten days of the door hanger being left, Kentucky Power will call the customer to schedule an appointment. If Kentucky Power is unable to make a connection with the customer to schedule an appointment after thirty days of the door hanger being left, Kentucky Power will follow its standard notification process for an inability to access situation. This process includes multiple notifications to contact the customer to gain access to install the AMI meter. In the rare instances that Kentucky Power is unable to contact the customer after multiple notifications and/or where a known hazardous situation exists, Kentucky Power will take action to disconnect the customer.
- Customer Engagement Platform – Between thirty and sixty days after a customer receives a new AMI meter, they will receive a letter and e-mail (if available) welcoming them to the new customer engagement platform. This letter and e-mail will highlight the benefits customers can receive by using the

customer engagement platform, the ways to enroll, and will provide them with a website address and phone number to call to enroll or ask questions. On the website, Kentucky Power will also provide a list of customer workshops taking place throughout Kentucky Power's service territory. Kentucky Power will provide facilitators to walk customers through the enrollment process, provide them with a step-by-step approach to access their customer data, and answer questions.

Q. WILL THE COMPANY DEVELOP ANY ADDITIONAL INFORMATIONAL RESOURCES FOR CUSTOMERS REGARDING AMI TECHNOLOGY?

A. Yes. On the Kentucky Power website, a landing page will be developed providing customers with a number of different resources to educate customers about AMI technology. Kentucky Power will utilize a FAQs format to provide customers with answers to many of the questions that have surfaced from other utilities that have already implemented AMI technology. The following are examples of types of topics that Kentucky Power will include on the website:

- How AMI technology works
- Customer benefits
- Accuracy of AMI meters
- Public safety
- Data privacy and access
- Notification process

For customers that require additional information, Kentucky Power's customer operations center can connect them to customer service professionals that will be available to answer questions.

Q. PLEASE EXPLAIN THE NEED FOR A CUSTOMER ENGAGEMENT PLATFORM AND CUSTOMER EDUCATION PROGRAM.

A. Company Witness Blankenship discusses the many operational benefits of AMI deployment. An additional, significant benefit associated with AMI technology is the opportunity for customers to have access to more detailed and readily accessible information to make more informed decisions about their energy consumption. AMI metering provides granular and timely data that Kentucky Power and its customers can use to better understand their energy usage and behaviors. Kentucky Power intends to fully utilize the data generated from AMI technology to develop a robust platform that provides residential customers access to information on energy usage and costs they do not have access to today.

The new customer engagement platform is a HEM system, which the Company intends to deploy in 2020. This platform will transform the Kentucky Power residential customer experience by providing access to monthly energy usage and cost information during the billing period. AMI interval data will make this information and the platform's benefits more robust by providing access to daily information on the amount of energy used and the costs for electric service. The ability to access this information can provide residential customers with the capability to take action during the month to manage their energy costs. This is a significant and positive change that will benefit all residential customers, but particularly income-qualified customers or fixed-income customers who are managing a tight monthly budget.

Q. WHAT INFORMATION WILL RESIDENTIAL CUSTOMERS BE ABLE TO ACCESS THROUGH THE CUSTOMER ENGAGEMENT PLATFORM?

A. The customer engagement platform will give residential customers access to a variety of information about their energy usage, including billing history, current amount due, comparative analysis of energy usage and billings from prior periods, and customized energy efficiency tips. Additionally, residential customers will be able to set alerts and push notifications. This will allow residential customers to make more informed decisions about their electric consumption and better manage their monthly budgets.

Q. HOW WILL RESIDENTIAL CUSTOMERS BE ABLE TO ACCESS THIS DATA?

A. Residential customers will be able to access information derived from the AMI data through the customer engagement platform linked to their online account and the Company's mobile app. Kentucky Power will continue to optimize the experience as part of its communications plan to provide residential customers the information that they want, when they want it.

Q. WILL KENTUCKY POWER ENGAGE IN CUSTOMER OUTREACH ACTIVITIES TO SUPPORT THIS PLATFORM?

A. Yes, Kentucky Power will roll-out a comprehensive education and awareness campaign. This will include customer workshops at locations throughout our service area, utilization of social media, e-mails, postcard mailers, recorded phone messaging, fact sheets, and general outreach. The goal of these workshops and communications will be to inform customers about the benefits of AMI technology, the customer engagement platform, and how to effectively use the new information to manage their energy usage and costs. This comprehensive customer outreach campaign will begin in 2021 and will continue throughout the AMI deployment process.

Q. HOW WILL KENTUCKY POWER EVALUATE THE EFFECTIVENESS OF THE CUSTOMER ENGAGEMENT PLATFORM?

A. During the initial stages of the program, Kentucky Power will monitor data such as the number of workshops conducted, number of customers attending the workshops, number of "opens" on e-mail messages, number of views on video messages, and customer feedback on the quality and content of the various communication methods.

With respect to the enrollment and engagement process, Kentucky Power will be tracking the number of customers who have enrolled in the mobile app, the number of people who access the platform, and the amount of customer activity in each of the channels.

Kentucky Power will also use various methods to obtain customer feedback on the program throughout the process, including customer surveys, social media posts, and through customer operations center activity.

Q. HOW WILL THE CUSTOMER ENGAGEMENT PLATFORM BENEFIT KENTUCKY POWER CUSTOMERS?

A. The customer engagement platform is the vehicle that unlocks the power of the data that AMI provides. The level of integration required to provide this platform is extensive and requires a significant upfront investment to build out, but the benefit to customers of being able to use all of this information to make better decisions about their electric consumption habits and manage their monthly budgets will be recognized for many years to come.

VI. KENTUCKY POWER FLEX PAY PROGRAM FOR AMI

Q. PLEASE PROVIDE AN OVERVIEW OF KENTUCKY POWER'S FLEX PAY PROGRAM.

A. Flex Pay is a voluntary payment option that allows customers to pay as they go, giving customers the ability to prepay for their electricity without having to pay a deposit or other fees associated with current post-pay billing. The Flex Pay option gives customers greater control over the frequency and timing of their payments, which can lead to a better understanding of consumption. Company Witness West discusses Kentucky Power's proposed Flex Pay program tariff and associated costs in his testimony.

Q. HOW WILL KENTUCKY POWER COMMUNICATE ACCOUNT INFORMATION WITH FLEX PAY CUSTOMERS?

A. As part of the enrollment process, customers must choose at least one preferred channel to receive all communications related to the Flex Pay program. The communication channels available to Flex Pay customers are e-mail, text, or both. In addition to the customer's selected communication channel, customers will also be able to check their account balance by calling the customer operations center, calling an Interactive Voice Response ("IVR"), or logging into their account at www.kentuckypower.com or on the Company's mobile app. Customers will be required to keep their contact information up-to-date to remain enrolled in the program. If Kentucky Power is unable to communicate with the customer either by e-mail or text, a letter will be sent to the customer letting them know they have 30 days to enroll in a chosen communication method in order to remain enrolled in the program, or the customer will be removed from the Flex Pay program and enrolled in traditional post-pay billing. The customer will receive information about this process when enrolling into the program.

In addition to selecting a preferred communication method(s), participants must also select a low-balance amount of at least $25 for notification purposes. The low balance notification amount is for notification purposes only, and does not represent the minimum amount that must be kept in the account in order to continue receiving electric service.[4] The customer will be notified when the account balance reaches the customer-selected low balance notification amount, or the amount of $25, whichever is greater. The customer will continue to receive daily alerts until their account is restored above the low balance notification amount. For example, if a customer establishes his account with a balance of $100 and selects a low balance notification amount of $25, the participant will receive an alert once the account reaches $25 and every day thereafter until the balance exceeds $25.

In addition to the individual communications, Flex Pay participants will also have access to the customer engagement platform. As discussed above, this tool provides access to energy usage and cost information during the billing period, allowing customers to take action during the month to manage energy costs.

Finally, both the preferred method of communication and the low balance notification amount can be changed at any time online at www.kentuckypower.com or by contacting the customer operations center.

[4] The customer must at least maintain an account balance greater than zero to continue receiving electric service.

Q. PLEASE DESCRIBE HOW KENTUCKY POWER WILL MARKET TO AND EDUCATE ITS CUSTOMERS ABOUT THE FLEX PAY PROGRAM.

A. Kentucky Power’s communications plan will include several means of outreach with its customers including printed materials, email, social media, and information on Kentucky Power’s website. The communications plan will include clear and concise information designed to manage customer expectations and ensure that customers fully understand Flex Pay prior to enrollment. **Exhibit CGW-1** contains draft samples of Flex Pay customer communications.

The education efforts will continue beyond the initial outreach for enrollment. When a customer initially enrolls in the program, they will begin receiving alert notifications via e-mail, text messaging, or both depending on their chosen communication method. Customers will know immediately that they are enrolled in the program by receiving a “Welcome to Flex Pay” alert message. After receiving the initial alert message, alerts are triggered by customer activity such as payments received and daily balance information, and notifications from Kentucky Power such as a change from on-to off-peak pricing. Flex Pay customers have the potential to receive up to 19 different alerts that will continue throughout a customer's participation in the program. Energy savings information and tools will also be available 24/7 on the customer engagement platform.

Prior to implementation of Flex Pay, Kentucky Power employees will receive specific training related to Flex Pay to better support both interested customers and ongoing participants.

VII. THE NEED FOR ECONOMIC DEVELOPMENT IN THE COMPANY'S SERVICE TERRITORY

Q. CAN YOU PLEASE DESCRIBE THE ECONOMIC TRENDS IN THE COMPANY'S SERVICE TERRITORY?

A. The region the Company serves has seen a downturn in economic activity since 2008. This economic downturn is widespread, but has been primarily driven by a decrease in coal and steel production in the region.

According to the Kentucky Energy and Environment Cabinet's fourth quarter 2019 Coal Report,[5] the number of employed coal miners in eastern Kentucky has dropped from an annual average of 14,373 in 2008 to 3,419 in 2019. Coal production has dropped even more steeply: from 91,045,224 tons in 2008 to 13,650,365 tons in 2019.

Additionally, as prices for steel have decreased in the global market, steel producers in the region have reduced output. AK Steel permanently shut down all operations at the Ashland Works in December 2019 resulting in a loss of over 260 jobs in the Company's service territory.

Q. WHAT HAS BEEN THE IMPACT OF THIS DOWNWARD ECONOMIC TREND ON THE COMPANY AND ITS SERVICE TERRITORY?

A. The primary impact of the downward economic trend is the loss of load and customers. Between 2008 and 2019, Kentucky Power's lost 10,184 customers or approximately 6.4 percent of its total customers. During the same period, the Company has seen its total annual weather normalized sales fall by approximately 23.4 percent from approximately 7.4 GWh to 5.7 GWh.

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[5] https://eec.ky.gov/Energy/News-Publications/Quarterly%20Coal%20Reports/2019-Q4.pdf.

Furthermore, unemployment and declining economic activity in the entire eastern Kentucky region has resulted in a concomitant population decline in 19 of the 20 counties comprising the Company's service territory.[6] Between 2008 and 2019, population in the Company's service territory has decreased by approximately 33,000 individuals or 7.6 percent.[7] Moreover, the overall unemployment rate in the 20 counties comprising Kentucky Power's service territory is markedly higher than the 4.3 percent unemployment rate for Kentucky as a whole.[8] Unemployment in the Company's service territory ranges from a high of 13.8 percent in Magoffin County to a low of 5.1 percent in Rowan County.

Q. WHY IS KENTUCKY POWER ENGAGED IN ECONOMIC DEVELOPMENT?

A. Since 2012, Kentucky Power has worked hard with economic development organizations to promote business investment, job creation, and load growth in eastern Kentucky. It is important to maintain and increase load in order to control rates. The Company's efforts are also aimed at recruiting industry and capital investment in its service territory, thereby increasing employment opportunities and expanding the tax base. Kentucky Power works closely with and supports local economic development organizations to focus on key aspects in its economic development efforts: industry retention, industry expansion, industry attraction, and site development. New and diversified economic activity in the Company's service territory benefits both customers and the Company. Together, through these key aspects of economic development, Kentucky Power and its community,

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[6] http://worldpopulationreview.com/us-counties/kv/. The population in Rowan County increased 5.17 percent. *Id*.
[7] http://worldpopulationreview.com/us-counties/kv/.
[8] https://kystats.ky.gov/Content/Reports/201900_CountyLAUSMaps.pdf?v=20200420020443. Kentucky's seasonally adjusted preliminary April 2020 unemployment rate was 15.4 percent, which is up 10.2 percentage points from March 2020 and up 11.1 percentage points from the 4.3 percent recorded for the Commonwealth in April 2019. https://kystats.ky.gov/Content/Reports/202004_CountyLAUSMaps.pdf?v=20200528020359.

government, and economic development partners work diligently to build a stronger eastern Kentucky.

VIII. KENTUCKY POWER ECONOMIC GROWTH GRANT PROGRAM

Q. PLEASE DESCRIBE THE K-PEGG PROGRAM?

A. The K-PEGG Program provides grant funding targeted specifically at projects designed to enhance the economic development potential of the communities in the Company's service territory. In Case No. 2014-00396, the Commission recognized the importance of a region's utility in economic development when it first approved the Company's Kentucky Economic Development Surcharge Tariff ("Tariff K.E.D.S."), which funds the K-PEGG Program. Grant funding for the K-PEGG program is awarded for use in the following categories: Economic Development Education, Sites and Buildings-Product Improvement, Marketing and Promotion, and Professional Consulting Services. The program allows Kentucky Power to work strategically with communities, government, and economic development partners to facilitate business location and expansion specific to the Company's twenty-county service territory.

Q. IS KENTUCKY POWER PROPOSING TO CONTINUE THE K-PEGG PROGRAM?

A. Yes. In order to continue to serve its role in the economic development of its service territory and to maintain the positive impact the K-PEGG Program has on the economic development efforts in the region, Kentucky Power is proposing to continue the program and maintain Tariff K.E.D.S. at the rate of $1.00 per meter per month for its non-residential customers with a corresponding Company match.

Q. HAS THE COMPANY BEEN ABLE TO QUANTIFY ANY SUCCESS ASSOCIATED WITH THE K-PEGG PROGRAM?

A. Yes. There are three projects that particularly highlight program successes. First, Kentucky Power issued a grant through the K-PEGG program to Perry County Fiscal Court to assist Dajcor Aluminum Ltd., a Canadian manufacturer of extruded and fabricated aluminum products, who plans to create up to 265 full-time jobs and invest nearly $19.6 million to locate its first U.S. operations near Hazard. Dajcor has located in the former American Woodmark facility in Perry County's Coal Fields Regional Industrial Park and the K-PEGG grant allowed Dajcor to retrofit and set up their facility at that location. The operation will provide Dajcor additional capacity for aluminum extrusion and fabrication to serve a variety of North American industries. The decision to locate in Kentucky will also help the company better reach its U.S. customers. Dajcor reports that it will be hiring new employees in waves as production ramps up.

Second, both Intuit Inc. and SKYES Enterprises Inc., also in Perry County, utilized K-PEGG Program funding through Kentucky Power's support of One East Kentucky and Coal Fields Regional Industrial Park to offset the costs of renovations of a facility in the Industrial Park in order to support the development of a new customer service center. The operation under the new partnership will support Intuit's products and services, and will result in 300 new full-time jobs.

Economic development can often be a long process, taking years for the project to come to fruition. The third success story, Logan Corporation, is an example of just that. Logan, a mining equipment manufacturer facing economic hardship as a result of the downturn in the coal mining industry, transitioned its business to manufacturing dump truck beds. Logan's facility in Martin County was of insufficient size to meet the growing demand for its new product. In 2016, Kentucky Power issued a grant through the K-PEGG Program to the Big Sandy Regional Industrial Development Authority to allow it to purchase the Logan facility in Martin County. This allowed Logan to purchase a larger facility in Magoffin County for its new truck bed business. As a result of this investment, none of the 35 jobs at the Martin County facility left the service territory, and Logan created an additional 80 jobs at the new facility in Magoffin County. Furthermore, in February of 2020, Logan announced plans to expand its facility with a $1.2 million investment.

Q. HOW WILL THE CONTINUATION OF THE K-PEGG PROGRAM BENEFIT KENTUCKY POWER'S CUSTOMERS?

A. Economic development is the engine that drives community economies in Kentucky Power's service territory. Through the collaborative work that Kentucky Power does with workforce development agencies, local economic development organizations, local units of governments, and private developers, we are helping to create jobs, diversify our economy, provide existing businesses with tools to compete and grow, increase the tax base for our local communities, and provide training and opportunities for an already highly skilled workforce in eastern Kentucky. A vibrant, growing economy helps all customers by increasing the customer base over which the fixed costs of Kentucky Power's operations can be spread.

The K-PEGG Program that Kentucky Power is proposing to continue in this case goes directly to the primary economic development challenges that exist today in Kentucky Power's service territory. In addition to having a skilled workforce, it is also critically important that economic development organizations in Kentucky Power's service area are equipped with an inventory of prospective buildings to incentivize business expansions within the service territory or new businesses to locate within the service territory. Kentucky Power currently works with many of our economic development organizations and local communities to aggressively pursue business opportunities for the Company's service area. Not having an adequate inventory of available facilities can be a competitive disadvantage when competing for some opportunities. Utilizing the K-PEGG Program to continue to incentivize local governments and developers to invest in our communities will result in new jobs for our customers, increased investments in our local communities, and an expanded customer base to share in Kentucky Power's fixed costs.

Q. DOES THIS CONCLUDE YOUR PRE-FILED TESTIMONY?

A. Yes, it does.

Flex Pay Available Text and E-mail Alert messages:

Pre-enrollment Summary
Pre-enrollment Payment
Flex Pay Account Pending
Welcome Message
Payment Received
Enrollment Failed
Daily Balance
Low Balance
Statement Available
Seasonal Rate Change
Zero Balance
Service Disconnected
Service Reconnected
Moratorium
Payment Returned Pending
Payment Returned
Unenrolled from Flex Pay
Balance Transferred
Balance Adjustment

Alert Examples

E-mail Example:

KENTUCKY POWER

Power Pay Payment Received

Kentucky Power has received your payment of **$5.00 on 09/13/19** for your Power Pay account.

Payment Received:
$5.00 on 09/13/19

Service Address:
306 1***

Account Ending:
03000429266

Thank you,

Kentucky Power Customer Service

Manage Your Preferences | Contact Us | Unsubscribe

Text Example:

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KY Pwr has recieved your payment of $5.00 at
306 1***. Thank you. Visit:
http://kypco.com/PowerPay
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VERIFICATION

The undersigned, Cynthia G. Wiseman, being duly sworn, deposes and says she is the Vice President External Affairs and Customer Service for Kentucky Power Company that she has personal knowledge of the matters set forth in the forgoing testimony and the information contained therein is true and correct to the best of her information, knowledge and belief after reasonable inquiry.

Cynthia G. Wiseman

Cynthia G. Wiseman

COMMONWEALTH OF KENTUCKY	)	
	)	Case No. 2020-00174
COUNTY OF BOYD	)	

Subscribed and sworn to before me, a Notary Public in and before said County and State, by Cynthia G. Wiseman, this 24th day of June 2020.

Trisha Nance

Notary Public

Notary ID Number: 632421

My Commission Expires: 9-26-2023

OFFICIAL SEAL
TRISHA NANCE
NOTARY PUBLIC - KENTUCKY
STATE-AT-LARGE
My Comm. Expires September 26, 2023
ID # 632421

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

Electronic Application Of Kentucky Power Company	)	
For (1) A General Adjustment Of Its Rates For	)	
Electric Service; (2) Approval Of Tariffs And Riders;	)	
(3) Approval Of Accounting Practices To Establish	)	Case No. 2020-00174
Regulatory Assets And Liabilities; (4) Approval Of A	)	
Certificate Of Public Convenience And Necessity;	)	
And (5) All Other Required Approvals And Relief	)	

DIRECT TESTIMONY OF

EVERETT G. PHILLIPS

ON BEHALF OF KENTUCKY POWER COMPANY

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BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY

CASE NO. 2020-00174

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DIRECT TESTIMONY OF
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KENTUCKY POWER COMPANY
BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY

CASE NO. 2020-00174

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME, BUSINESS ADDRESS AND POSITION.

A. My name is Everett G. Phillips. My business address is 1645 Winchester Avenue, Ashland, Kentucky 41101. I am the Vice President of Distribution Region Operations for Kentucky Power Company ("Kentucky Power" or "Company"). Kentucky Power Company is a subsidiary of American Electric Power Company, Inc. ("AEP").

Q. PLEASE BRIEFLY DESCRIBE YOUR EDUCATIONAL BACKGROUND AND PROFESSIONAL EXPERIENCE.

A. I earned a bachelor's degree in Electrical Engineering in 1985 from West Virginia University and a master's degree in Business Administration in 2007 from University of Phoenix. I am a registered professional engineer in the Commonwealth of Kentucky. I am a member of the National Society of Professional Engineers. Throughout my career, I have held positions of increasing responsibility within AEP. After graduation from college in 1985, I began my career as an electrical engineer in Huntington, WV for Appalachian Power Company, a subsidiary of AEP. In 1994, I was promoted to Appalachian Power area supervisor in Clintwood, VA. In 1998, I was promoted to the Kentucky Power Pikeville district superintendent position, and in 2000, I was promoted to the Pikeville district manager. In 2004, I moved to Ashland, Kentucky, where I served as Director of Customer and Distribution Operations. In

2017, I was promoted to Managing Director of Distribution Region Operations, and in 2019 my title changed to Vice President of Distribution Region Operations.

Q. WHAT ARE YOUR RESPONSIBILITIES AS VICE PRESIDENT OF DISTRIBUTION REGION OPERATIONS?

A. I am responsible for overseeing all aspects of the Company's distribution system, including its planning, construction, operation, and maintenance. My duties also include the oversight and management of service extensions to new customers, the safe and reliable delivery of service to customers, and the restoration of service when outages occur. I am also responsible for Kentucky Power's Distribution Vegetation Management Program and oversee distribution grid modernization investments.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THIS COMMISSION?

A. Yes. I testified before this Commission and filed testimony in the Company's base rate case filings, Case Nos. 2009-00459, 2014-00396, and 2017-00179. My testimony in each proceeding focused on the Company's Distribution Vegetation Management Program and system reliability.

II. PURPOSE OF TESTIMONY

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is to first provide an overview of Kentucky Power's current distribution power quality and service reliability programs, as well as the effectiveness of the Company's Distribution Vegetation Management Program. Second, I discuss the yearly Distribution Operation and Maintenance expenses and capital spending since the last base case (Case No. 2017-00179). Third, I describe the requested funding for the Vegetation Management Program ("Program") to maintain the five-year cycle. Fourth, I provide an update on Kentucky Power's Smart Grid investments in response to Case No. 2012-00428. Finally, I discuss the Company's proposed Grid Modernization Rider to fund continued reliability improvement.

Q. ARE YOU SPONSORING ANY EXHIBITS AS PART OF YOUR TESTIMONY?

A. Yes. I am sponsoring the following exhibit attached to my testimony:

Exhibit	Description
EXHIBIT EGP-1	2019 Distribution Vegetation Management Report

Q. WERE THESE EXHIBITS PREPARED BY YOU OR UNDER YOUR DIRECTION?

A. Yes.

III. DISTRIBUTION RELIABILITY PROGRAMS

Q. PLEASE DESCRIBE THE DISTRIBUTION SYSTEM THAT SERVES KENTUCKY POWER'S CUSTOMERS.

A. Kentucky Power serves approximately 165,000 retail customers in Kentucky in a service area that covers approximately 3,784 square miles. Kentucky Power's Distribution System includes approximately 10,060 line miles of underground and above-ground primary and secondary voltage lines.

1. RELIABILITY STRATEGY

Q. PLEASE DESCRIBE THE COMPANY'S STRATEGY FOR IMPROVED SYSTEM RELIABILITY.

A. Kentucky Power employs a balanced approach that includes monitoring, inspection, maintenance, and investment in replacing aging infrastructure and the implementation of new technologies. By monitoring and inspecting facilities, the Company identifies the causes that affect reliability, and then works to mitigate the causes through process improvements. The Distribution Vegetation Management Program seeks to limit outages resulting from trees and vines inside the Company's rights-of-way, and those caused by "danger trees" located outside the rights-of-way. Danger trees are trees outside the rights-of-way that have the potential of falling into the distribution circuit because they have been weakened due to physical damage, disease, soil erosion, or have died. The reliability programs described below provide oversight and improvements to key processes and facilities that are fundamental to providing reliable customer service. Finally, replacement of aging infrastructure and the installation of new facilities using the latest technology helps to ensure customers will have a reliable distribution grid that serves their needs and expectations.

Q. WHAT ARE KENTUCKY POWER'S RELIABILITY METRICS FOR THE PAST THREE CALENDAR YEARS?

A. Table 1 below provides the Company's distribution-related reliability metrics for the calendar years 2017-2019.

Table 1 – Kentucky Power Reliability Metrics for All Causes[1]

Year	SAIFI	CAIDI	SAIDI
2017	2.169	187.3	406.3
2018	2.342	206.8	484.2
2019	2.485	195.2	485.0

Note: Excludes Major Storm Events

[1] SAIDI (System Average Interruption Duration Index) indicates the total duration of interruption for the average customer for the year indicated; CAIDI (Customer Average Interruption Duration Index) represents the average time required to restore service to customers; and SAIFI (System Average Interruption Frequency Index) indicates how often the average customer experiences a sustained interruption on an annual basis.

Q. WHAT ARE MAJOR STORM EVENTS AND WHY ARE THEY EXCLUDED IN TABLE 1?

A. IEEE 1366-2017, the "IEEE Guide for Electric Power Distribution Reliability Indices," defines a major event as "an event that exceeds reasonable design and or operational limits of the electric power system. A major event includes at least one Major Event Day (MED)." A MED is defined as "a day in which the daily system SAIDI exceeds a threshold value, T_{MED}. For the purpose of calculating daily system SAIDI, any interruption that spans multiple calendar days is accrued to the day on which the interruption began. Statistically, days having a SAIDI greater than T_{MED} are days on which the energy delivery system experienced stresses beyond that normally expected (such as severe weather)." The IEEE standard uses an accepted statistical approach to determine when it is appropriate to exclude a major event. By excluding major storm events, which by definition are storm events that exceed reasonable design or operational limits, the Company is able to give the Commission a clearer picture of the progress being made to improve the Company's reliability.

Q. ALL THREE INDICES IN TABLE 1 HAVE INCREASED OVER THE PAST THREE YEARS. DOES THIS MEAN THAT THE COMPANY'S RELIABILITY PROGRAMS ARE INEFFECTIVE?

A. No. The increase indicated in Table 1 is not indicative of the many reliability improvements that have been completed. For example, Kentucky Power's Vegetation Management Program focuses on addressing vegetation inside the Company's rights-of-way. Over the same period presented in Table 1 above, the same three reliability metrics decreased, as shown in Table 2. As Table 2 demonstrates, over the three-year period, SAIDI has improved by 48.8% for trees inside the rights-of-way.

Table 2: Reliability Indices for Trees Inside the Rights-of-Way

Year	Tree Inside Rights-of-Way SAIFI	Tree Inside Rights-of-Way CAIDI	Tree Inside Rights-of-Way SAIDI
2017	0.1137	216.7	24.6
2018	0.0751	204.9	15.4
2019	0.0806	156.8	12.6

Q. WHY HAVE THE OVERALL RELIABILITY METRICS INCREASED IN LIGHT OF THE SUBSTANTIAL IMPROVEMENT IN THE RELIABILITY INDICES RELATED TO INSIDE THE RIGHTS-OF-WAY CAUSES.

A. The Company has seen a 41.5% increase in SAIDI for trees outside the rights-of-way (December 2017 through December 2019). At the end of 2019, SAIDI for trees outside the rights-of-way consisted of 51.1% of all SAIDI outages. Some of the key contributors to this increase include significantly above average rainfall, root disease, insects, and pathogens. Coupled with the steep terrain found in much of Kentucky Power's service territory, danger trees outside of the rights-of-way fall or slide into the Company's distribution poles and lines causing outages.

Q. HAS THE COMPANY TAKEN ANY STEPS TO ADDRESS THE PROBLEM PRESENTED BY TREES OUTSIDE ITS RIGHTS-OF-WAY?

A. Yes. In 2018, Kentucky Power initiated a pilot program in its Hazard District to address the threat presented by trees outside its rights-of-way. The Company saw an average 31.1% reduction in SAIDI for those circuits where outside the rights-of-way trees were targeted as compared to those Hazard district circuits that were not targeted. The Company's capital spend in 2018 and 2019 to widen the rights-of-way and to remove danger trees were $4,839,134 and $11,032,438. Details regarding this program were provided in the Company's most recent distribution vegetation management report, filed April 1, 2020 in Case No. 2017-00179.

2. KENTUCKY POWER'S RELIABILITY PROGRAMS

Q. HOW DOES KENTUCKY POWER MAINTAIN RELIABILITY ON ITS DISTRIBUTION SYSTEM?

A. Kentucky Power uses a combination of programs to maintain its distribution infrastructure. These programs are designed to reduce the number of service interruptions and to minimize their impact on customers. The Company's distribution management programs can be divided into three major categories:

1) Distribution Asset Management;
2) Major Distribution Reliability and Capacity Additions; and
3) Kentucky Power's Distribution Vegetation Management Program.

Distribution Asset Management and Major Distribution Reliability and Capacity Additions are described immediately below. The Distribution Vegetation Management Program has already been briefly described, but a more comprehensive presentation is provided later in my testimony.

Q. PLEASE DESCRIBE KENTUCKY POWER'S DISTRIBUTION ASSET MANAGEMENT PROGRAMS.

A. The Distribution Asset Management Programs are designed to maximize the efficiency of expenditures and optimize system performance. Kentucky Power has nine Distribution Asset Management Programs. The programs and their distribution system roles are:

1. *Overhead Circuit Facilities:* Inspection and Maintenance Program - Every two years Kentucky Power visually inspects its overhead facilities to identify and correct potential problems before they can lead to an outage or cause a hazardous situation for the public. Through identifying and repairing such potential problems, Kentucky Power's customers experience safer service with fewer service interruptions. In 2019, Kentucky Power corrected 2,458 problems found during inspections of 5,067 circuit miles of the distribution system.
2. *Animal Mitigation Program:* The objective of this program is to reduce the number of animal-caused outages by installing animal guards on line transformers and other equipment including distribution lines and substations at locations that have had, or potentially may have, a high risk of animal-caused outages.
3. *Capacitor Inspection and Maintenance Program:* The purpose of this program is to inspect and maintain all fixed and switched capacitor installations to ensure these devices function properly. Capacitor installations provide voltage support throughout the Kentucky Power service territory and are a critical component in the implementation of Volt/VAR Optimization, which improves the energy efficiency of the Company's distribution system. In 2019, the Company inspected 303 capacitors and 387 regulators.
4. *Underground Facilities Inspection and Maintenance Program:* Every two years Kentucky Power visually inspects the external, above-ground

portions of underground distribution facilities to identify and correct problems before they can cause an outage. Through these inspections, Kentucky Power identifies and repairs items such as transformers, pedestals, and switchgear. In 2019, Kentucky Power repaired 21 underground items that were identified through inspections.

5. *Pole Inspection and Maintenance Program:* This program maintains and prolongs the mechanical integrity of Kentucky Power's wood poles. As necessary, poles are treated, reinforced, or replaced. This program helps Kentucky Power identify and replace poles that might otherwise fail and cause power interruptions. During 2019, the Company replaced 481 poles and treated 5,705 poles.

6. *Recloser Maintenance / Replacement Program:* The Company performs preventive maintenance on reclosers, and replaces, as needed, recloser units that are not operating properly. When a recloser device senses a fault, the device will automatically open and allow a brief period for the cause of the fault to clear from the line. The reclosing equipment will then automatically re-energize the circuit. A recloser that does not open and close properly can turn a momentary interruption into a sustained interruption of service, or result in an interruption to more customers than necessary. In 2019, 195 reclosers were replaced as part of this program.

7. *Overhead Conductor Program*: This program minimizes primary and secondary conductor failures by replacing overhead conductors that show signs of wear. Targeted areas are identified using historical reliability

data, and also include areas with an above average number of splices identified through the overhead facilities inspection program. During 2019, 14,822 feet of small conductors were replaced on the system.

8. *__Lightning Mitigation Program__*: This program reduces the number of lightning-caused outages through the installation of new lightning arresters at locations known to be prone to lightning-caused outages. Lightning arrestors are installed on new line segments and new transformers.

9. *__Sectionalizing Program__*: This Asset Management Program improves the reliability of Kentucky Power's distribution circuits by adding new, or modifying existing, sectionalizing devices. These sectionalizing devices may be manual pole top switches, automatic devices such as reclosers, automatic switches, or fused cutouts. The addition of manual switches where warranted allows the outage duration to be lessened for the customers served by the unaffected portions of the circuit that can be re-energized. Fused cutouts or reclosers work to remove a faulted section of the circuit from service and prevent the entire circuit from experiencing a sustained outage. This enhanced sectionalizing capability results in smaller circuit segments and fewer customers being interrupted after faults occur on distribution circuits. In 2019, 3,797 cutouts were replaced or added.

Q. PLEASE DESCRIBE KENTUCKY POWER'S MAJOR DISTRIBUTION RELIABILITY AND CAPACITY ADDITION PROGRAM.

A. Kentucky Power identifies areas where the increasing or shifting demand for electricity is approaching the limit of the distribution system's existing load capacity. These specific projects re-conductor portions of the existing distribution circuits or re-configure portions of a circuit. The expansion of the distribution system to serve new customers may also result in the upgrade or replacement of distribution facilities to maintain and enhance reliable service to Kentucky Power's customers.

Q. BRIEFLY PROVIDE AN OVERVIEW OF KENTUCKY POWER'S CURRENT DISTRIBUTION VEGETATION MANAGEMENT PROGRAM.

A. Kentucky Power's vegetation management practices are conducted in accordance with standards established by the American National Standards Institute ("ANSI"), the Occupational Safety and Health Administration ("OSHA"), and the National Electrical Safety Code ("NESC"). These standards govern pruning and removing trees; safety and worker protection; work clearance and training requirements; and safety clearance guidelines.

The Company is currently in the second year of its Commission-approved five-year cycle-based Distribution Vegetation Management Program. The Kentucky Power service territory is located in an area with rugged terrain and dense forests. Of all areas within the Commonwealth, Kentucky Power has some of the most difficult and challenging terrain, which requires more frequent maintenance to ensure consistent reliability throughout the Company's service territory. The five-year cycle-based Program has seen improved inside the rights-of-way tree-related distribution circuit reliability through more frequent re-clearing of rights-of-way. Later, I provide more detail concerning the Company's Distribution Vegetation Management Program.

Q. PLEASE DESCRIBE THE TYPES OF CAPITAL INVESTMENTS KENTUCKY POWER IS MAKING TO IMPROVE AND MAINTAIN RELIABILITY.

A. Each year Kentucky Power completes capital projects that can be classified under several general categories:

1. *Asset Improvement*: Asset Improvement projects include replacement of obsolete equipment and other aging infrastructure, as well as the addition of new assets that support projects associated with grid modernization. This project category also has a significant impact on reducing the duration of customer outages and improving customer reliability.
2. *Customer Service*: These projects support new customer facilities, and include upgrading existing customer facilities, meter installations, and other customer requirements.
3. *Forestry*: Forestry capital projects generally involve widening of rights-of-way, the removal of trees greater than 18 inches in diameter within or outside the rights-of-way, as well as the removal of "cycle buster trees." "Cycle Buster Trees" are trees greater than 18 inches in diameter that must be trimmed or removed before the circuit is due for its next cycle.
4. *Planning Capacity*: These projects facilitate the increase of load in areas of growth in the service territory. These projects include increasing the

size of transformers in existing distribution stations and constructing new stations to serve customers.

5. *Reliability*: Reliability capital projects are specific projects that target known reliability issues affecting both groups of customers and entire circuits. These projects may also be used to add capacity to the system, and include new circuits or stations, additions to existing facilities, and replacing existing assets with higher capacity assets such as re-conductoring an existing line with an increased conductor size.

6. *System Restoration*: These projects replace assets that have failed. Capital projects completed during service restoration are typical system restoration projects, and include replacing poles and associated equipment, re-conductoring full length spans, and replacing transformers damaged during a storm or weather-related event.

7. *Other*: These include miscellaneous projects, as well as distribution projects that support other business units. These include distribution upgrades made in response to a transmission system change.

Q. PLEASE DESCRIBE THE MAJOR CATEGORIES OF THE COMPANY'S DISTRIBUTION OPERATION AND MAINTENANCE ("O&M") EXPENSE.

A. Kentucky Power's annual distribution O&M expense includes forestry, system restoration, customer service, asset improvement, reliability, and other activities.

Q. WHAT WAS KENTUCKY POWER'S DISTRIBUTION O&M EXPENSE FOR THE TEST YEAR?

A. Kentucky Power's unadjusted, actual Distribution Operation and Maintenance Expense for the Test Year ending March 31, 2020 was $42,690,617 as shown in Table 3 below.

Q. HOW DOES THE TEST YEAR LEVEL OF DISTRIBUTION O&M EXPENSE COMPARE WITH HISTORICAL LEVELS FOR KENTUCKY POWER?

A. Table 3 provides the Distribution O&M expense levels for 2017 through 2019 and the test year. Total O&M expenses have decreased by 12.9%. A majority of this has been due to the implementation of the five-year cycle in forestry. The O&M expenses remained relatively stable or increased slightly, except for forestry where the benefits of the full implementation of the five-year cycle based Program are being realized.

Table 3 - Kentucky Power Distribution
Operation and Maintenance Expenses by Year

Project Category	2017	2018	2019	Test Year
Asset Improvement	$2,523,921	$2,708,206	$2,973,793	$3,183,606
Customer Service	$800,656	$871,611	$1,066,761	$974,706
Forestry	$27,846,398	$21,791,012	$21,466,588	$21,880,891
Other	$6,495,890	$7,363,309	$7,896,822	$7,381,792
Reliability	$391,318	$427,936	$712,595	$706,508
System Restoration	$8,505,427	$8,443,170	$7,359,676	$6,496,558
Amortization of Major Storm Deferral	$2,429,196	$2,084,103	$2,066,556	$2,066,556
Grand Total	**$48,992,806**	**$43,689,347**	**$43,542,791**	**$42,690,617**

Q. PLEASE FURTHER DESCRIBE THE MAJOR COMPONENTS OF THE DISTRIBUTION O&M EXPENSE INCLUDED IN THE TEST YEAR.

A. The largest Test Year O&M expense is Forestry expense in connection with the implementation of the Company's Distribution Vegetation Management Program approved by the Commission in Case No. 2017-00179. This level of Forestry expense is expected to increase slightly over current levels, but remain significantly below historical levels, until the first five-year cycle is completed at the end of 2023.

The second largest expense over the period, System Restoration expense, can vary from year-to-year, and is largely dependent on weather events during a particular year. Customer Service Operation and Maintenance expenditures support customer programs and address customer issues. The Asset Improvement expense represents the Operation and Maintenance expense associated with capital additions such as the replacement of poles, towers, fixtures, conductors, line transformers and station equipment. Finally, "other" contains miscellaneous projects and overheads.

IV. VEGETATION MANAGEMENT

1. DEPLOYMENT OF THE COMPANY'S DISTRIBUTION VEGETATION MANAGEMENT PROGRAM

Q. DID THE COMPANY COMPLETE ITS TRANSITION FROM A PERFORMANCE-BASED TO A CYCLE-BASED VEGETATION MANAGEMENT PROGRAM?

A. Yes. By the end of 2018, the Company completed the initial and interim tasks necessary to transition from a performance-based to a cycle-based vegetation management program. The initial task work was completed by March 31, 2018, with the exception of two spans where the Company coordinated the work with a required scheduled outage to perform maintenance work at a nearby gas compressor station. The interim task work was completed by December 31, 2018. The final 2017 and 2018 transition costs will be discussed later in my testimony.

Q. PLEASE DESCRIBE KENTUCKY POWER'S VEGETATION MANAGEMENT PROGRAM.

A. The Company's Vegetation Management Program is a comprehensive program that includes multiple components to ensure the reliability of the Company's distribution system by minimizing outages due to contact with vegetation. The first component of the program is a cycle-based maintenance component that plans for the clearing of all distribution circuit rights-of-way once every five years. This activity addresses approximately twenty percent of the total number of line miles each year, so that over the course of five years, every primary line mile or circuit rights-of-way will be cleared from end to end. A second component of the program consists of spraying the circuit rights-of-way with a growth inhibitor to retard the growth of vegetation. Some types of vegetation can quickly regrow to pre-cut levels within the five-year cycle, so the growth inhibitor supplements the rights-of-way clearing. This activity also helps to prevent vegetation from growing into the distribution circuits within the five-year cycle. The third component is the removal of danger trees from outside the rights-of-way. As mentioned earlier, danger trees are trees outside the rights-of-way that have the potential of falling into the distribution circuit because they have been weakened due to physical damage, disease, soil erosion, or have died.

Q. PLEASE DESCRIBE THE ACTIVITIES THAT COMPRISE THE DISTRIBUTION VEGETATION MANAGEMENT PROGRAM AND THEIR RELATIVE COST.

A. Cycle maintenance activity constitutes approximately 85% of cost of the Vegetation Management Program. Work tasks include door-to-door planning with property owners, brush removal, trimming of trees, tree removals, and auditing work performed. Nearly all of this work is contracted through a third party working on behalf of Kentucky Power.

Ground and aerial spray activity constitutes approximately 11% of the Company's Vegetation Management Program cost. Beginning in 2019, Kentucky Power began transitioning from foliar spraying to cut stubble application of herbicide. It was able to do so because prior foliar spraying reduced the amount of vegetation in the rights-of-way. Because cut stubble spray application can be performed at the time the clearing is performed, the Company anticipates it will be able to eliminate the costs attendant to a second trip to the site to spray the foliage when it returns. It also allows Kentucky Power to control brush more effectively and to better address the rapid regrowth of brush.

The last two activities, internal and unscheduled maintenance, are approximately 4% of the Company's financial cost of the Vegetation Management Program. Of the 4%, internal expenses are approximately 2.5%. Work tasks associated with internal expenses include project management, oversight, and field audits for safety and work being cleared to contract specifications. Unscheduled maintenance expenses are approximately 1.5% of the 4% and work associated with this activity include off cycle maintenance of vines and customer yard trees where trimming was not able to provide five years of clearance.

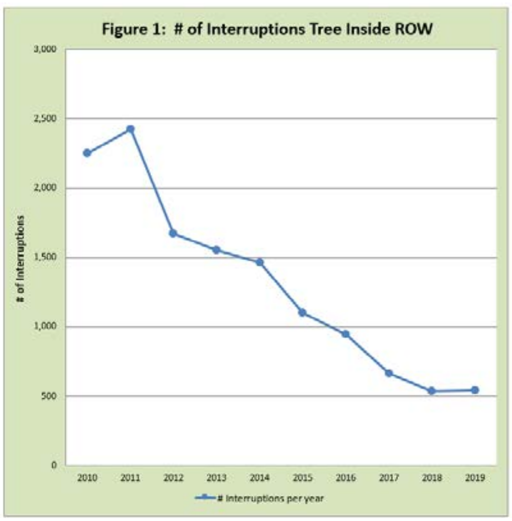
Q. DOES THE VEGETATION MANAGEMENT PROGRAM PROVIDE IMPROVED AND SUSTAINABLE RELIABILITY FOR THE COMPANY'S CUSTOMERS?

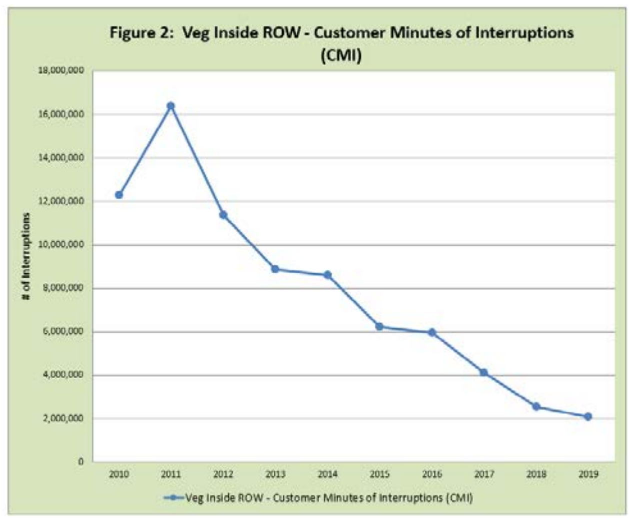
A. Yes. Kentucky Power's Vegetation Management Program O&M expenses focus on re-clearing and maintaining the Company's rights-of-way. As a result, the best measure of the effect of Kentucky Power's vegetation management efforts is the number of customer interruptions, total customers affected, as well as customer minutes interrupted, by trees and vines within the Company's rights-of-way. As shown on Table 4 below, the number of incidents of customer interruptions as a result of vines and trees in the Company's rights-of-way declined 78% from a high of 2,426 in the year ended December 2011 to a low of 538 in the year ended December 2018.

Table 4 – Summary Of Inside Rights-Of-Way-Related Outages

Year	Number of Interruptions	Total Customers Affected	Veg Inside ROW - Customer Minutes of Interruptions (CMI)
2010	2,250	64,360	12,280,664
2011	2,426	72,074	16,387,958
2012	1,674	43,934	11,369,680
2013	1,555	48,099	8,866,856
2014	1,462	36,471	8,617,318
2015	1,102	30,040	6,236,943
2016	943	28,713	5,949,862
2017	660	18,911	4,098,559
2018	538	12,391	2,539,186
2019	544	13,218	2,072,958

Consistent with this trend, the number of customers affected by trees and vines within the rights-of-way improved 82% with a reduction from 72,074 in 2011 to 13,218 last year. Finally, customer minutes interrupted as a result of trees and vines in the rights-of-way, which measure the total impact of the interruptions, declined from 16,387,958 minutes in 2011 to 2,072,958 minutes in the year ended December 31, 2019. That represents an 87% improvement between 2011 and 2019. These improvements are shown graphically in the two figures below:





The trend over a ten-year period, such as shown in Table 4, clearly shows the success the Company and its customers are enjoying from the investment in distribution vegetation management.

Q. PLEASE EXPLAIN THE FLATTENING IN RECENT YEARS OF THE DECLINE IN THE NUMBER OF INTERRUPTIONS AND CUSTOMER MINUTES OF INTERRUPTIONS SHOWN IN THE TWO FIGURES ABOVE.

A. Several factors have led to the flattening of the improvements. First, the Company has completed end-to-end clearing of the entire primary distribution system and gained control of its rights-of-way so that the reliability benefits of doing so are already reflected. Second, with the primary distribution grid cleared and now being maintained, outages on secondary distribution lines constitute a greater portion of total outages. The Company's distribution vegetation management work has less effect on secondary distribution lines because secondary lines, including service to the house attachments, are positioned lower on the poles and are more likely to be affected by customer-planted trees. Finally, there is an "irreducible minimum" of outages related to customers who will not permit the Company to remove trees from their property.

Q. DO THE VALUES IN TABLE 4 REFLECT OUTAGES CAUSED BY MAJOR STORM EVENTS?

A. They do not. However, I am comfortable the severity of outages related to major event storms has been lessened by the success of Kentucky Power's Distribution Vegetation Program. For example, a major storm occurred on April 12, 2020 that brought wind speeds of 79 miles per hour to the Company's service territory. While there were several outages due to trees and other items from outside the rights-of-way, there was an 18% reduction in customer minutes interrupted, and a 12% reduction for customers interrupted due to trees inside the rights-of-way as compared to a storm with 60 miles per hour wind speeds on May 8, 2009. The May 2009 storm occurred prior to the initiation of the 2010 Vegetation Management Plan.

Q. PLEASE SUMMARIZE THE COMPANY'S VEGETATION MANAGEMENT EFFORTS TO DATE.

A. The Company has successfully addressed outages caused by trees inside the rights-of-way which has greatly improved service for our customers. The appropriate planning and scheduling of individual circuits during the initial re-clear was carefully defined to try and maximize the improvements for all customers across the Company. The Company made necessary adjustments or modifications to its vegetation management plan, after appropriate approvals, when confronted with unforeseen challenges in connection with the initial re-clear. The Company has gained valuable knowledge allowing it to improve efficiencies, clear necessary right-of-way widths, and perform herbicide treatments. The completion of the initial re-clear work helped stabilize vegetation management expenditures.

Q. HAS KENTUCKY POWER BEEN MAKING CAPITAL EXPENDITURES IN SUPPORT OF ITS DISTRIBUTION VEGETATION MANAGEMENT PROGRAM?

A. Yes. Before I provide the specifics, I should note that in addition to expansion of rights-of-way and the removal of trees outside the Company's rights-of-way, the removal of trees within the rights-of-way larger than 18 inches in diameter is accounted for as a capital expenditure. With this caveat, Kentucky Power's forestry capital (capital work in progress expenditures related to vegetation management) since the last rate case totaled $28.2 million.

Q. PLEASE DESCRIBE THE INCREASE IN CAPITAL EXPENDITURES.

A. The Capital expenditures beginning March 2017 through March 2019 are split into two components. Capital expenditures for "Associated Capital Re-Clear," which includes capital expenditures that occur in connection with operational maintenance re-clearing, such as removal of cycle-buster trees over eighteen inches in diameter at breast height, have remained relatively level. The increase in capital widening in recent years reflects the Company's increased focus on right-of-way widening efforts to address the growing outages resulting from trees outside the rights-of-way. For example, SAIDI increased for trees outside the rights-of-way from 185.2 in June 2018 to 272.1 in June 2019 (excluding JMEDs).

Q. WHY HAS THERE BEEN AN INCREASE IN OUTAGES CAUSED BY TREES OUTSIDE THE RIGHTS-OF-WAY?

A. Over the last few years, there has been an above-average amount of rainfall that has contributed to the increase in the number of outages caused by trees outside the rights-of-way. Precipitation data from the National Weather Service for Jackson, Kentucky for the years of 1981 to 2010 shows a monthly average rainfall of 4.03 inches per month, or an annual normal of 48.34 inches of rainfall. By contrast, the average annual precipitation for the most recent five-year period (2015-2019) was 57.49 inches, while the average annual precipitation for the most recent three-year period (2017-2019) was 59.07 inches.

Figure 3: Jackson, Kentucky National Weather Service Historical Data

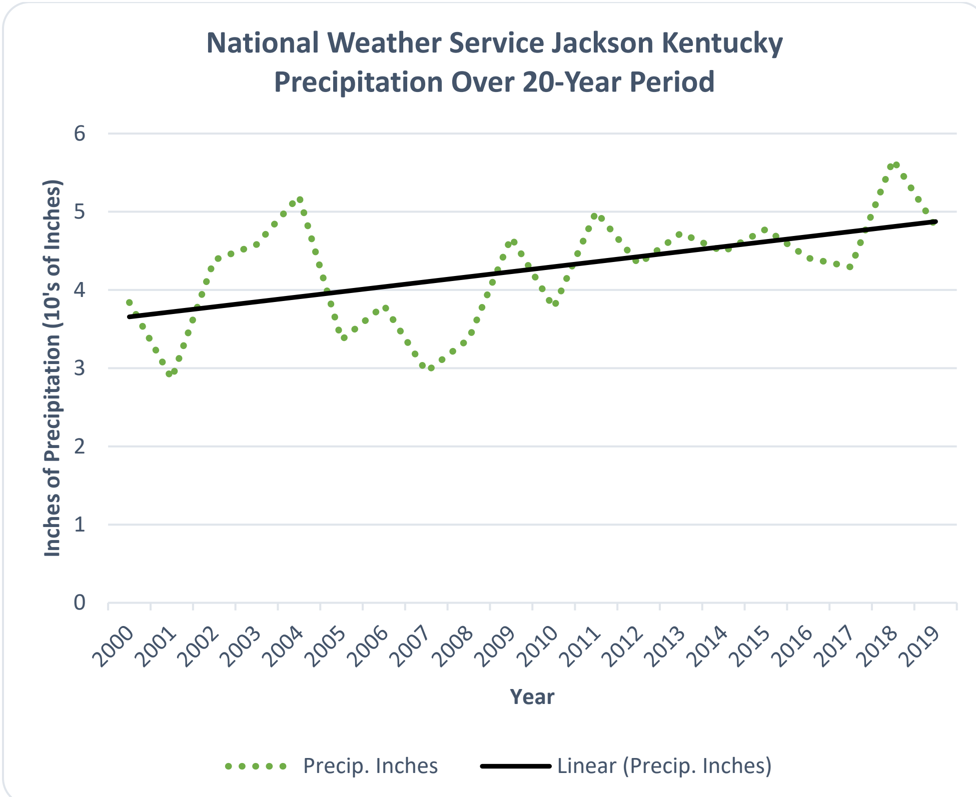
30 Yr Normal Precip (1981 - 2010)	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual Norm	Monthly Avg. 30 Yr Norm
Jackson Area, KY	3.61	3.75	4.12	3.83	5.20	4.70	4.65	3.69	3.46	3.19	3.96	4.18	48.34	4.03

Monthly Total Inches Precipitation for Jackson Area, KY

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual
2000	2.63	3.53	1.94	4.97	4.33	6.80	5.69	4.38	4.92	1.07	1.47	4.35	46.08
2001	2.50	3.72	2.17	1.69	4.39	4.19	6.43	2.41	1.09	1.41	1.82	2.55	34.37
2002	4.09	1.24	7.96	4.11	5.23	4.98	5.50	1.72	3.48	6.39	3.61	4.28	52.59
2003	2.10	7.88	1.47	5.14	5.98	7.54	3.95	5.12	4.33	2.20	5.49	3.78	54.98
2004	4.23	3.77	3.87	4.01	10.78	6.18	7.02	2.39	7.55	4.96	4.37	3.27	62.40
2005	5.12	3.03	3.52	7.47	2.50	2.78	4.08	3.92	0.51	1.57	2.66	3.18	40.34
2006	5.57	1.85	2.89	4.57	3.61	3.24	3.87	3.69	6.39	5.49	2.43	2.03	45.63
2007	2.83	1.20	2.71	3.22	1.82	2.15	4.05	2.64	2.49	3.80	3.37	5.18	35.46
2008	2.46	3.41	4.14	4.00	3.24	3.94	6.13	1.16	0.67	1.46	3.03	6.86	40.50
2009	5.80	1.73	3.52	3.64	9.22	7.03	6.40	3.55	4.88	3.54	0.80	5.96	56.07
2010	4.27	3.11	2.43	2.61	7.92	5.60	3.34	3.51	2.05	1.68	5.77	2.97	45.26
2011	2.72	3.97	4.74	10.20	6.69	5.49	6.02	3.07	3.20	4.25	5.48	4.18	60.01
2012	4.86	3.90	4.07	2.67	4.20	1.91	7.39	4.75	6.77	4.24	0.84	6.39	51.99
2013	5.73	1.91	4.63	3.70	4.23	6.36	6.62	10.04	1.27	2.13	3.01	7.09	56.72
2014	3.15	4.47	5.51	5.43	2.30	3.12	5.77	8.55	2.35	7.77	2.97	2.49	53.88
2015	2.12	4.06	6.26	10.29	1.74	7.42	8.87	5.02	2.09	2.40	2.41	4.64	57.32
2016	3.29	6.27	2.38	3.82	7.04	5.01	6.35	6.83	1.32	1.51	2.91	6.16	52.89
2017	4.71	2.86	4.42	4.02	7.41	6.21	4.13	4.56	3.33	5.29	1.30	3.28	51.52
2018	1.92	8.00	6.97	4.12	6.18	4.63	5.06	4.43	9.17	5.12	4.91	7.47	67.98
2019	4.26	8.87	2.40	2.80	4.90	8.01	6.97	1.25	0.15	6.01	5.80	6.30	57.72
20 Yr Average	3.72	3.94	3.90	4.62	5.19	5.13	5.68	4.15	3.40	3.61	3.22	4.62	50.84
3 Yr Mean ('17 - '19)	3.63	6.58	4.60	3.65	6.16	6.28	5.39	3.41	4.22	5.47	4.00	5.68	59.07
5 Yr Mean ('15 - '19)	3.26	6.01	4.49	5.01	5.45	6.26	6.28	4.42	3.21	4.07	3.47	5.57	57.49

Year	Mntly Avg.
2000	3.84
2001	2.86
2002	4.38
2003	4.58
2004	5.20
2005	3.36
2006	3.80
2007	2.96
2008	3.38
2009	4.67
2010	3.77
2011	5.00
2012	4.33
2013	4.73
2014	4.49
2015	4.78
2016	4.41
2017	4.29
2018	5.67
2019	4.81

Figure 4: National Weather Service – Precipitation of Jackson, Kentucky



Above average rainfalls in recent years have led to an increase in insects, pathogens, and root disease affecting trees, and a consequent increase in the weakening and death of trees outside the Company's rights-of-way. Root disease is exacerbated by soil moisture and temperature. Symptoms are discrete and are difficult to identify and track externally. Root diseases have affected multiple species, all size classes, and are highly prevalent. Non-root diseases, such as Oak Wilt, Hemlock Wooly Adelgid, and White Pine blister rust also increasingly are killing and weakening trees. As of 2016 in Kentucky over 6% of Oak trees are standing dead, 2.8% of hemlocks are standing dead, and over 10% of white pines are standing dead. A standing dead tree is more likely to fall during high wind or other weather events and cause outages. Another contributor to the poor health of the trees outside of the rights-of-way is the Emerald Ash Borer

("EAB") beetle. Kentucky is home to more than 220 million ash trees.[2] The destructive EAB infestation began in Kentucky in 2009, and spread throughout Kentucky and has now been discovered in most of Kentucky's counties.[3] Several counties have lost a significant amount of their ash trees to EAB since its arrival. When a tree becomes infested with EAB, it dies within a few years, which makes it much more vulnerable to falling or being blown over into the Company's facilities and causing customer outages.

For these reasons, the Company increased additional widening efforts starting with the Hazard District, which includes some of the Company's most difficult terrain.

2. <u>DISTRIBUTION VEGETATION MANAGEMENT PROGRAM: FIVE-YEAR CYCLE</u>

Q. WHAT IS KENTUCKY POWER PROPOSING FOR ITS CYCLE-BASED VEGETATION MANAGEMENT PROGRAM?

A. The Company is proposing two modifications:

- Kentucky Power proposes adjusting, effective Cycle 1 of the Company's January 2021 billing cycle, the amount of distribution Vegetation Management Program O&M expense in base rates to reflect the three-year average of the Company's distribution O&M expenses for the first three-year period (2021-2023) the rates established in this case will be in effect. This is the same methodology used to establish the Company's current base rates in Case No. 2017-00179. Although a slight increase (0.05%) from \$21,465,163 to \$21,586,046 over the amount currently in base rates, the three-year average

[2] https://entomology.ca.uky.edu/entfact/kentucky-emerald-ash-borer-eab-resources-updates

[3] Ibid.

represents a slightly greater than one percent ***reduction*** in the three-year average the Company projected for the same period in Case No. 2017-00179. With the initiation of the five-year cycle, Kentucky Power has been able to reduce the projected three-year cost despite substantial increases in contract labor, much-higher than average rainfall, and the costs associated with customer demands that trees, tree trimmings, and brush be removed from the customer's property. The calculations are presented below in Table 5:

Table 5 - Analysis of Five-Year Cycle Proposals and Three-Year Averages

Year	**Exhibit EGP - 5 5 Year Cycle (Case No. 2017-00179)**	**Recommended Proposal (Case No. 2020-00174)**
2019	$21,283,946	$21,312,894
2020	$21,472,777	$21,472,777
2021	$21,688,685	$21,733,094
2022	$21,881,312	$21,577,961
2023	$22,101,559	$21,447,083
TOTAL	**$108,428,279**	**$107,543,809**
3-Year Average (2021, 2022, 2023)	**$21,890,519**	**$21,586,046**

- Kentucky Power also proposes to amend vegetation management and planning reporting requirements.

Q. PLEASE PROVIDE AN UPDATE TO THE FIRST YEAR OF THE FIVE-YEAR CYCLE AND DESCRIBE THE VEGETATION MANAGEMENT WORK PLAN SCHEDULE AND PROJECTED EXPENDITURES.

A. Kentucky Power began its five-year maintenance cycle work effective January 1, 2019. The number of circuit miles completed for the first year and the work projected Vegetation Management Plan are shown in the tables below:

Table 6 – First Five-Year Cycle Vegetation Management Program Work Schedule

Vegetation Management 5 Year Cycle Work Schedule						
Cycle Mile Timing	**2019**		**2020**	**2021**	**2022**	**2023**
	Target	**Actual**	**Target**	**Target**	**Target**	**Target**
Year 1 Miles	1623	1543				
Year 2 Miles			1642			
Year 3 Miles				1643		
Year 4 Miles					1642	
Year 5 Miles						1643
Cycle Miles	1623	1543	3245	4868	6490	8113
Cumulative Miles	**1623**	**1543**	**3185**	**4828**	**6470**	**8113**

Kentucky Power targeted 1,623 miles for annual cycle maintenance and completed 1,543 miles (95.1%) of the 2019 Vegetation Management cycle work scheduled. The Company expects to complete the five-year cycle on time by distributing the 2019 shortfall of 80 miles over the remaining four years of the first five-year cycle.

Kentucky Power sprayed 5,037 acres in 2019. This represented an increase of 50.9% above the 3,338 acres projected in the work plan. The additional acres sprayed were part of the Company's transition from foliar spraying to cut stubble application. The 2019 total acres sprayed included both foliar application to previously cleared right-of-way plus cut stubble application for right-of-way cleared in 2019. By transitioning to cut stubble application, Kentucky Power expects to limit expenses by avoiding the costs associated with making a second trip for herbicide application required for foliar application.

Table 7 – First Five-Year Cycle Vegetation Management Program Projected Expenditures

Vegetation Management 5 Year Cycle Projected Costs						
Cycle Time	**2019**		**2020**	**2021**	**2022**	**2023**
	Target	**Actual**	**Target**	**Target**	**Target**	**Target**
Year 1 Miles	$21,283,946	$21,312,894				
Year 2 Miles			$21,472,777			
Year 3 Miles				$21,733,094		
Year 4 Miles					$21,577,961	
Year 5 Miles						$21,447,083
Annual Cost	$21,283,946	$21,312,894	$21,472,777	$21,733,094	$21,577,961	$21,447,083
Cumulative Cost	**$21,283,946**	**$21,312,894**	**$42,785,671**	**$64,518,765**	**$86,096,726**	**$107,543,809**

The Company's projected expenditures for the first year were $21,283,946. Actual expenditures were $21,312,894 or $28,948 (0.14%) above target as shown in Table 7 above.

Q. YOU INDICATED EARLIER THE COMPANY IS PROPOSING AN AMENDMENT TO ITS VEGETATION MANAGEMENT PROGRAM REPORTING REQUIREMENTS. WHAT IS KENTUCKY POWER PROPOSING?

A. Kentucky Power currently files two reports. First, the Company files its vegetation management plan for the upcoming year by October 1 of the preceding year. It also files a second report, providing information on the work performed and expenditures made in the preceding year by the following April 1. Kentucky Power proposes in this case to combine the two reports into a single report to be filed by April 1 of each year. The combined report would provide the same information currently provided concerning the prior year's activities. It also provides the vegetation management plan for the current year. Thus, if the Commission grants this request, the filing made on or before April 1, 2022 would report on calendar year 2021's vegetation management activities and provide the plan for calendar year 2022.

Q. WHY IS KENTUCKY POWER PROPOSING TO COMBINE THE TWO REPORTS?

A. The two report format was appropriate as Kentucky Power undertook for the first time to establish a cycle-based program to clear and maintain 8,112 miles of distribution lines. The effort required the removal of over two million trees, spraying over 27,000 acres, and trimming hundreds of thousands of trees. Because it was the Company's initial effort, and because the amount of vegetation far exceeded anything that could have been reasonably anticipated, Kentucky Power was forced to modify its program on multiple occasions to transition to a cycle-based program. Now that the Company has made its first pass through, and has established a cycle-based program, it anticipates the work will become much more routine and not require substantial modifications in scope on a year-to-year basis. Combining the report will provide the Company significant efficiencies, while providing the Commission and Kentucky Power's customers with the same information, and with the exception of a modest delay in filing the work plan, on the same schedule. The combined report would look similar to the recent 2019 Distribution Vegetation Management Report shown as Exhibit EGP-1 which shows the work completed in 2019 and lists the plan for 2020. Notwithstanding this reporting change, the Company would continue to file for a deviation if the expenditures vary from its annual obligation by more than 10%.

3. THE ONE-WAY BALANCING ACCOUNT AND THE COMPANY'S PROPOSED ADJUSTMENT TO ITS TEST YEAR VEGETATION MANAGEMENT O&M EXPENSES

Q. PLEASE FURTHER DESCRIBE THE ONE-WAY BALANCING MECHANISM ASSOCIATED WITH THE COMPANY'S VEGETATION MANAGEMENT PROGRAM.

A. The Commission established the one-way balancing mechanism in its June 22, 2015 Order approving the Settlement Agreement in Case No. 2014-00396. In Case No. 2017-00179, the Commission found that the one-way balancing adjustments should be continued, with an adjustment based upon the change in the vegetation management program's annual revenue requirement approved in that case. All expenses are to be recorded against each year's annual budget. Any annual shortfall or excess is to be applied to the balancing account. The Company proposes to continue the balancing account until further order of the Commission.

V. SMART GRID

Q. PLEASE DESCRIBE "SMART GRID" INVESTMENTS.

A. Smart grid technology uses advanced information tools to improve the efficiency, reliability, and safety of the electric distribution system. In its April 13, 2016 order in Case No. 2012-00428, the Commission directed each utility in the Commonwealth subject to its jurisdiction to identify its Smart Grid investments in each rate case. The information provided in this section fulfills the Commission's directive.

Q. WHAT SMART GRID INVESTMENTS HAVE BEEN PLACED IN SERVICE SINCE THE LAST BASE CASE?

A. Kentucky Power has either installed, or is in the process of installing, Distribution Automation Circuit Reconfiguration ("DACR") technology on 18 circuits since the last rate case. Kentucky Power utilizes a Distribution Management System that includes Supervisory Control and Data Acquisition ("SCADA") to provide system analysis of the distribution system. The Data Management System gathers information from electronic devices in the field, including the DACR equipment, and integrates it with the mapping system to provide the status of the automated circuits. It also allows remote operation of devices on those circuits by dispatchers.

As summarized in Table 8, Kentucky Power placed in service approximately $6.7 million in capital investment in Smart Grid technology since the last base case.

Table 8 – Smart Grid Plant In-Service

Smart Grid Project Description	Cost
DACR - Line	$4,693,150
DACR - Station	$1,992,495
Total	**$6,685,645**

Q. WHAT SMART GRID TECHNOLOGIES WILL BE CONSIDERED BY KENTUCKY POWER COMPANY IN THE FUTURE?

A. The Smart Grid technologies that will be considered but not necessarily limited to:

- Advanced Metering Infrastructure ("AMI")
- Volt/VAR Programs
- Communication Infrastructure necessary to support Smart Grid technology
- DACR
- Additional Distribution Sources and Radial Circuits

VI. PROPOSED GRID MODERNIZATION RIDER

Q. WHAT IS MEANT BY GRID MODERNIZATION AND WHY IS IT IMPORTANT?

A. Grid modernization is a term that is used to refer to and describe deployment of Smart Grid and other technologies to improve reliability and the efficient operation of the distribution system. These technologies include, but are not limited to, the technologies listed above. These technologies are imperative to sustaining the reliability of the distribution system.

Kentucky Power's strategy for system reliability improvement is a balanced approach that includes monitoring, inspection, maintenance, and investment in replacing aging infrastructure and the implementation of new technologies.

Q. WHAT IS THE PURPOSE OF KENTUCKY POWER'S GRID MODERNIZATION RIDER?

A. The Grid Modernization Rider ("GMR") will permit Kentucky Power to track and recover through a rider the costs of approved grid modernization projects that address public safety needs and leverage technology to benefit customers and the distribution grid. The GMR will support Smart Grid projects such as AMI and DACR projects which will improve customers' experiences and improve SAIDI. The GMR tariff is the mechanism by which the Company will recover the costs associated with new projects that are proposed and reviewed by the Commission in annual true-up filings. As explained below, the first such project Kentucky Power is proposing for inclusion in the GMR is the Company's proposed deployment of AMI, although the rider would also be used in connection with future grid modernization projects.

Q. WHAT PROPOSAL IS THE COMPANY MAKING FOR INCLUSION IN THE GMR IN THIS CASE?

A. The Company is proposing the recovery of costs for AMI deployment to be included in the GMR in this case. Specifically, the GMR will allow the Company to recover the costs of AMI deployment as the meters go into service. Customers can realize immediate benefits by using the AMI meter usage data to monitor and regulate their electric usage throughout the monthly billing cycle. The transition to AMI will permit the Company to replace an obsolete and increasingly unreliable technology and enhance the customer experience. AMI technology can sense the voltage at the customer premises, and can alert the Company more quickly if there is a power interruption. By receiving information from multiple AMI meters, the Company can evaluate the extent of an outage without waiting for additional customers to call and can pinpoint the isolation device such as a lateral or transformer fuse. Also, AMI meters can help the Company identify where momentary interruptions are occurring before receiving customer complaints. As a result, the Company can restore service more quickly. If isolated customer outages remain after service restoration has been completed, the Company can identify which customers are still out and can take immediate action without waiting for customers to call. Company Witness Blankenship discusses AMI technology in more detail, as well as the Company's planned deployment of AMI and associated costs. Company Witness West discusses how the costs will be recovered through the GMR.

Q. WHY IS THE COMPANY PLANNING TO USE THE GMR FOR FUTURE INVESTMENTS?

A. The electric utility industry is undergoing dramatic and disruptive change that is being driven by customer choice, advanced technology, resource diversity, and unprecedented connectivity. This scenario faced the telecommunications industry twenty years ago, and that industry has changed much since then. Kentucky Power's strategy is to modernize the power grid to support a reliable, multi-source energy future that will include modern technologies with a focus on building infrastructure and technology to give customers additional choice about how they use energy. The goal is to build a more flexible and resilient distribution power grid that will accommodate local generation of all types, optimize power flows and connect diverse resources while improving grid reliability. The Company understands that cost is a factor for the customers, and the Company is not asking for future investments in the present case.

Q. WHAT OTHER PROJECTS ARE BEING CONSIDERED BY THE COMPANY TO MODERNIZE ITS DISTRIBUTION GRID AND FURTHER ENHANCE RELIABILITY?

A. The Company is examining projects to extend distribution lines to remote areas and build additional substations and circuits to provide more robust and reliable distribution service to those remote areas. Additional projects, such as DACR technology, can be used in connection with these projects to provide circuit ties between the new and existing circuits to provide back-up sources. Company Witness West explains the details of how the GMR will work as a cost recovery mechanism for future reliability improvement.

Q. DOES THE GMR INCLUDE NON-SMART GRID COMPONENTS?

A. Yes, the company may propose at a later date non-Smart Grid aspects such as widening efforts to remove trees outside the rights-of-way in an effort to maintain reliability to the distribution system since trees from outside the rights-of-way currently account for over 49% of SAIDI.

Q. HOW WILL KENTUCKY POWER MONITOR AND EVALUATE THE PROGRESS AND COSTS OF THE COMPANY'S GRID MODERNIZATION EFFORTS?

A. Kentucky Power's Project Management Office will provide oversight for all facets of the grid modernization investments, including the development, project initiation, execution, monitoring, and closing of processes. This group will evaluate progress, quality, adjustments, and costs, which provides transparency and accountability for all programs and projects in the GMR. In addition, the Company will make an annual filing with the Commission concerning all costs to be recovered through the GMR.

VII. <u>CONCLUSION</u>

Q. PLEASE SUMMARIZE YOUR TESTIMONY.

A. The Company is in the second year of a five-year vegetation maintenance cycle for distribution circuits. Since the initiation of the Distribution Vegetation Management Program, Kentucky Power has improved and developed the plan based on the knowledge gained in conducting cycle-based vegetation management operations in the challenging terrain found in Kentucky Power's service territory.

The Company also recognizes it must look beyond the completion of the Program to identify new opportunities for reliability improvement, and develop a strategy going forward that will serve the needs and expectations of customers. This includes a Grid Modernization Rider to act as a cost-recovery mechanism for current and future distribution reliability needs.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

Filed in Conformity with the Commission's
January 18, 2018 Order in Case No. 2017-00179
Filed April 1, 2020
Page **1** of **17**

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

Pike County Kentucky

Johns Creek Station – Raccoon Circuit

The Raccoon Circuit is 85 miles in length and serves 1,667 customers. This circuit was fully re-cleared in 2016.

Targeted widening such as pictured provides an added benefit to customer reliability by reducing impact from trees outside of rights-of-way.

(Photo taken November 2019)

2019 DISTRIBUTION VEGETATION MANAGEMENT REPORT OF KENTUCKY POWER COMPANY

April 1, 2020

In accordance with the Public Service Commission's June 22, 2015 Order in Case No. 2014-00396, as modified by its January 18, 2018 Order in Case No. 2017-00179, Kentucky Power Company provides the following report regarding the operation of its 2019 Distribution Vegetation Management Program.

INTRODUCTION AND BACKGROUND

Kentucky Power began its five-year cycle on January 1, 2019, in accordance with the Commission's Order in Case No. 2017-00179. Vegetation growth in the Company's rights-of-way as of January 1, 2020 is slightly less than five (4.89) years. The previous miles cleared over the last five years, from January 1, 2015 through December 31, 2019, exceeded the Company's total primary miles of distribution.

With approval from the Public Service Commission in Case No. 2017-00179, Kentucky Power in 2018 modified its 2015 vegetation management plan to provide the most economical and reliable forestry plan for its customers. The modification permitted Kentucky Power to begin a five-year cycle-based vegetation management program effective January 1, 2019. Kentucky Power is now performing cycle-based vegetation management maintenance work on its distribution rights-of-way. The principal characteristics of its current distribution rights-of-way vegetation management program are:

- Vegetation within Kentucky Power's distribution system rights-of-way will be re-cleared on a five-year cycle. The Company will on average re-clear approximately one fifth of the total miles of rights-of-way each year;
- Annual O&M expenditures for the five-year cycle will average approximately $21.465 million;
- Kentucky Power will notify the Commission and obtain approval for any deviations from the filed work plan equal to or greater than 10% of the aggregate planned O&M expenditures; and
- The one-way balancing account established by the Commission's June 22, 2015 order in Case No. 2014-00396 remains in place. Expenditures are credited against the annual budget detailed in the Company's application in Case No, 2017-00179

(Table 9 of the direct testimony of Everett G. Phillips). Any annual shortfall or excess in expenditures is to be applied to the account balance.

2019 Distribution Vegetation Management Expenditures And Rights-of-Way Work Performed

Total 2019 O&M expenditures for Kentucky Power's Distribution Vegetation Management program were $21,312,894. Total 2019 Distribution Vegetation Management O&M expenditures exceeded the 2019 level of O&M expenditures ($21,283,946) proposed by Kentucky Power in its 2019 Vegetation Management Plan by $28,948 (0.14%).

Capital expenditures for 2019 totaled $13,961,984. This includes capital investment made in connection with O&M expenditures and a reliability widening pilot program in the Hazard district to combat established threats (*i.e.*, Oak Wilt, Root Rot – multiple species, Emerald Ash Borer, White Pine Blister Rust, and Hemlock Wooly Adelgid) to Eastern Kentucky forests. The Company saw an average of 31.1% SAIDI reduction in Hazard district for trees outside the rights-of-way for those circuits targeted for widening as compared to those not targeted within the district.

2019 Vegetation Management Mileage Cleared, Expenditures, and Cost/Unit

Kentucky Power's 2019 Work Plan is broken down into four major actions in Table 1: Cycle maintenance (field personnel completing cycle maintenance), Internal personnel (provide planning and oversight), Spray (future control of regrowth brush and density population of trees within Rights-of-Way), and Reactive maintenance (field personnel completing maintenance to circuits outside plan due to vegetation issues). Table 1 provides a comparison of the 2019 work completed, actual expenditures, and Cost/Unit to the projections contained for each of its actions within its 2019 Vegetation Work Plan.

Table 1: 2019 Vegetation Work Plan						
Action Description	Targeted			Actual		
	Miles/Acres	Expenses	Cost/Unit	Miles/Acres	Expenses	Cost/Unit
Cycle Maint (Miles)	1,623	$18,176,206	$11,199	1,543	$17,390,711	$11,271
Internal	-	$795,000	$490	-	$515,734	$334
Spray (Acres)	3,338	$1,940,740	$581	5,037	$3,125,579	$621
Reactive Maint	-	$372,000	$229	-	$280,870	$182
TOTALS	-	$21,283,946	$12,500	-	$21,312,894	$12,408

Kentucky Power targeted 1,623 miles of annual cycle maintenance and completed 1,543 miles (95.1%) of the 2019 Vegetation Work Plan. Associated expenditures were $17,390,711 (95.7%) or $785,495 below the targeted expenditure of $18,176,206. The Company's cost per unit for field cycle maintenance was approximately $72 (0.64%) more per mile than targeted due to increases in contracts for forestry vegetation. The Company successfully managed double digit percentage increase in contracts costs (labor, equipment, and material) in 2019 through efficiencies gained, in part from previous spray and control of rights-of-way efficiencies.

The Company targeted 3,338 acres of spray in 2019 and completed 5,037 acres or 1,699 acres (50.9%) above the acres work plan. Approximately 1,270 acres of this variance is due to cut stubble applications and the remaining 429 acres of the variance is due in part to spraying of expanded rights-of-way and to address areas of rapid brush regrowth. Cut stubble applications were used to treat brush cleared by mowing and more immediate application behind maintenance clearing. This method of application is less seasonal than foliar applications which allows the Company to control brush more effectively and to better address the rapid regrowth of brush. Typical control of cut stubble is directed at the tall woody species with the goal of releasing lower growing vegetation that will occupy the site and hinder tree species establishment within the rights-of-way. Previous foliar spray applications could only be completed during May through October even though annual cycle maintenance continued year around. The initial shift to cut stubble along with catch up from previous maintenance clearing outside the window of applications for foliar spray caused an increase in acres sprayed.

Kentucky Power's 2019 expenditures for internal and reactive maintenance totaled ($370,396) less than the targeted work plan. If spray for the 2019 vegetation plan had been limited to its targeted amount the Company would have achieved the targeted 1,623 miles. This is illustrated by the addition of $785,495 shortfall in annual cycle maintenance and adding the $370,396 of under expenditures in internal and reactive maintenance actions for a total of $1,155,891. These additional dollars ($1,155,891) divided by average cost per unit of $11,271 would have allowed for 102.6 additional miles of cycle maintenance. Kentucky Power expects to complete the vegetation cycle on time by distributing the 2019 shortfall of 80 miles over the remaining four years of the first five year cycle.

O&M and Capital work associated with the 2019 Vegetation Management activities included removing 195,074 trees, trimming 50,276 trees, and clearing 4,223 acres of brush.

2019 Distribution Vegetation Management Work by District

Table 2 below details the Company's 2019 District O&M vegetation expenditures by circuit within each district. Certain O&M expenditures, including Internal Labor & Fleet, unscheduled hotspot maintenance, trouble restoration work, tree ticket investigation, auditor expenses, third party flagging expenditures, and tree contractor's field supervision cannot be allocated on a per-circuit basis.

Table 2: 2019 District Level O&M Expenditures by Circuit

Nature of Expense	Ashland	Hazard	Pikeville	Total
Annual Cycle Maintenance	$5,706,409	$5,531,057	$8,048,978	$19,286,444
Internal	$171,199	$160,433	$184,102	$515,734
TOTAL	**$5,877,608**	**$5,691,490**	**$8,233,080**	**$19,802,178**

Table 3 below provides the 2019 Five Year Cycle work performed within each District in miles cleared and acres sprayed.

Table 3: 2019 District Level Cycle Work Performed				
Nature of Expense	**Ashland**	**Hazard**	**Pikeville**	**Total**
Annual Cycle Miles Cleared	471.9	495.2	576.2	1,543.3
Acres Sprayed	1,587.7	1,435.6	2,013.6	5,036.9

Attachment 1 to this report details the 2019 annual cycle vegetation management work and expenditures by circuit. The attachment provides the number of miles of circuit completed for each task, acres of brush cut, acres of brush sprayed, amount of tree growth regulator (soil injection) applied, number of trees removed, and number of trees trimmed.

Measures of Improvement in System Reliability
(SAIFI, CAIDI, SAIDI, and CMI)

Table 4 below provides total system reliability indices for Kentucky Power's distribution system from 2010 (when the Vegetation Management Program began) through December 31, 2019.

Table 4: Ten Year Reporting Indices for all Outage Cause Codes			
Year	**SAIFI**	**CAIDI**	**SAIDI**
2010	2.470	169.4	418.4
2011	3.085	195.4	602.8
2012	2.417	189.5	458.0
2013	2.144	178.5	382.7
2014	2.373	212.9	505.3
2015	2.467	189.8	468.1
2016	2.167	205.7	445.8
2017	2.169	187.3	406.3
2018	2.342	206.8	484.2
2019	2.485	195.2	485.0

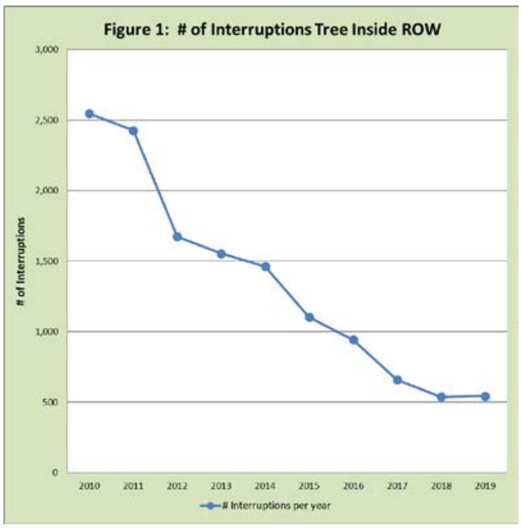
Table 5 below provides reliability indices limited to Tree Inside Rights-of-Way outages for the same period.

Table 5: Ten Year Reporting Indices for Tree Inside Rights-of-Way Outage Cause Codes			
Year	Tree Inside Rights-of-Way SAIFI	Tree Inside Rights-of-Way CAIDI	Tree Inside Rights-of-Way SAIDI
2010	0.3714	190.8	70.9
2011	0.4192	227.4	95.3
2012	0.2562	258.8	66.3
2013	0.2815	184.3	51.9
2014	0.2154	236.3	50.9
2015	0.1782	207.6	37.0
2016	0.1719	207.2	35.6
2017	0.1137	216.7	24.6
2018	0.0751	204.9	15.4
Average (2010-2018)	0.2314	214.9	49.8
2019	0.0806	156.8	12.6

Excluded from the calculation of the indices in both tables are major events as defined by IEEE standard 1366.

Table 5 highlights the efficacy of the Company's Distribution Vegetation Management Program. The 2019 Tree Inside Rights-of-Way SAIFI and SAIDI were respectively 65.2% below, and 74.6% below the average Tree Inside Rights-of-Way SAIFI and SAIDI metrics for the period 2010-2018. The CAIDI values improved 27% from an average duration of 214.9 minutes in 2010 to 156.8 minutes in 2019. CAIDI measures the time for crews to respond, assess and identify the trouble, remove any debris that may have caused the outage, perform repairs, and restore service.

Since the Distribution Vegetation Management Program began in July 2010, the annual number of Tree Inside Rights-of-Way Interruptions (excluding major event days) declined by approximately 78.6%, from 2,547 to 544. The annual number of customer minutes of interruption (CMI) associated with these events declined by approximately 83.1% from 12,280,664 to 2,072,958 over the same period (See Figure 1 and Figure 2).



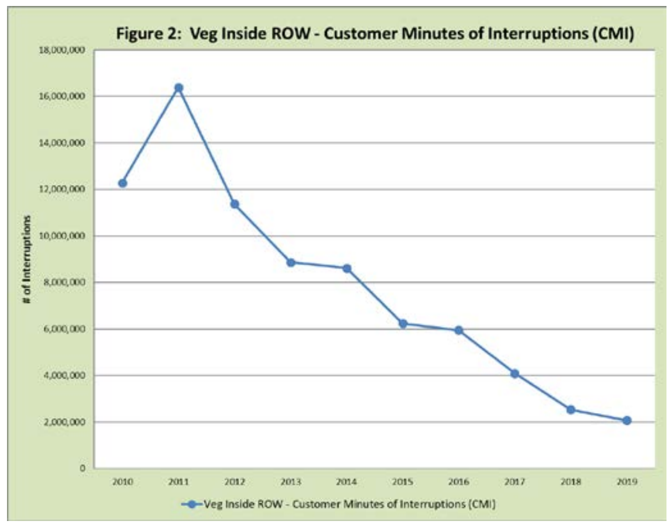


Figure 1 and Figure 2 for cause code Tree Inside Rights-of-Way is expected to continue to flatten in the future for the following reasons:

- The Company has completed end to end maintenance clearing for the entire primary distribution system and gained control of its rights–of-way;
- Refusals of customers to allow the Company to clear rights-of-way to the Company's vegetation specifications; and
- Outages on secondary distribution lines constitute a greater portion of the remaining total outages, limiting a reduction in the total number of outages beyond the current numbers. The Company's distribution vegetation management work has less effect on secondary distribution lines because secondary lines, including service to the house attachments, are positioned lower on the poles and are more likely to cross customer planted trees.

Vegetation Management Program-to-Date Expenditures

Kentucky Power filed vegetation management plans indicating it would spend $198,146,990 on Vegetation Management O&M from the beginning of the program on July 1, 2010 through December 31, 2019. In that period, the Company spent $200,050,563, or $1,903,573 (0.96%) more than planned.

Kentucky Power trimmed 707,000 trees, cleared 24,252 acres (37.89 square miles) of brush, sprayed 27,215 acres to control vegetation, and removed 2,419,871 trees since the vegetation management program began July 1, 2010.

Balancing Account

Paragraph 8 (e)(ii) of the Settlement Agreement in Case No. 2014-00396 established a one-way balancing account beginning July 1, 2015. Any regulatory liability associated with the balancing account would "continue to be recorded on the Company's books until the Commission set base rates in the Company's next base rate case." The Commission's January 18, 2018 order in Case No. 2017-00179 continued the balancing account and modified the required annual expenditure levels going forward to reflect the amounts detailed in Table 9 of Mr. Phillips' direct testimony in the case.

The calculation of the December 31, 2019 balancing account of $253,288 (expenditures in excess of the targeted amounts) is shown in Table 6 below:

Table 6: Kentucky Power Balancing Account Vegetation Management Program Dollars			
Year	**Required Expenditure**	**Actual Expenditure**	**Variance**
2015	$13,830,530	$13,620,717	**-$209,813**
2016	$27,661,060	$27,774,546	**$113,486**
2017	$27,661,060	$27,840,992	**$179,932**
2018	$21,638,766	$21,779,501	**$140,735**
2019	$21,283,946	$21,312,894	**$28,948**
Total	**$112,075,362**	**$112,328,650**	**$253,288**

Attachment Description

The following attachments are incorporated in this report:

Attachment 1 – provides a detailed summary of annual cycle maintenance work completed in 2019 at a circuit level within each district.

Attachment 2 – provides the annual cycle maintenance plan for 2020 at circuit level by district.

Attachment 3 – provides the annual Spray plan for 2020 at the district level.

Attachment 4 – provides a recapitulation of planned 2020 O&M expenditures (including amounts that cannot be allocated on a circuit basis) by district and projected 2020 capital expenditures by district. The 2020 capital expenditures include, as was detailed in the Company's 2020 Vegetation Management Plan, a pilot capital investment program to widen the Company's existing rights-of-way to address outside of the rights-of-way causes of outages, including particularly, trees killed by the emerald ash borer and root rot.

Attachment 1 – 2019 Annual Maintenance Cycle

2019 KY POWER FORESTRY CIRCUIT HISTORY
Five Year Cycle Maintenance Clearing

Costs that were not allocated to a circuit number include: Internal labor & fleet costs, some unscheduled hotspot maintenance, trouble restoration work, tree ticket investigation, and tree contractors field supervision

Ashland District

Circuit Number	Circuit Name	Cost (Includes O&M and Capital)	Total Line Miles	Reclearing Miles Planned	Reclearing Miles Complete	Trees Trimmed	Trees Removed	Brush Cut (Acres)	Brush Sprayed (Acres)	Tree Growth Regulator	Comments
3000801	**Hayward - Halderman**	**$349,985.49**	**118.7**	**28.9**	**28.9**	**1,479**	**2,449**	**24.5**	**0.0**	**0.0**	**Finish Full Circuit Clearing, from 2018**
3001401	**Louisa - City**	**$100,537.54**	**9.9**	**9.9**	**9.9**	**324**	**1,212**	**17.3**	**0.0**	**0.0**	**Full Circuit Clearing**
3001402	**Louisa - High Bottom**	**$140,278.44**	**13.4**	**13.4**	**12.4**	**515**	**1,130**	**13.7**	**0.0**	**0.0**	**Full Circuit Clearing**
3002001	**South Shore - Siloam**	**$363,397.87**	**38.5**	**38.5**	**38.5**	**1,285**	**2,197**	**35.7**	**28.9**	**0.0**	**Full Circuit Clearing**
3002002	**South Shore - Distribution**	**$145,923.17**	**9.1**	**9.1**	**9.1**	**271**	**1,027**	**23.5**	**40.8**	**0.0**	**Full Circuit Clearing**
3002101	**10th Street - 6th St.**	**$226.10**	**0.6**	**0.6**	**0.6**	**2**	**3**	**0.0**	**0.0**	**0.0**	**Full Circuit Clearing**
3002103	**10th Street - 12th St.**	**$99,988.43**	**7.0**	**7.0**	**7.0**	**507**	**273**	**6.9**	**14.5**	**0.0**	**Full Circuit Clearing**
3002104	**10th Street - 10-3**	**$32,721.13**	**2.9**	**2.9**	**2.9**	**157**	**98**	**0.6**	**0.0**	**0.0**	**Full Circuit Clearing**
3002105	**10th Street - Midtown**	**$13,160.81**	**3.7**	**3.7**	**3.7**	**67**	**17**	**0.4**	**0.0**	**0.0**	**Full Circuit Clearing**
3002106	**10th Street - Front Street**	**$7,810.16**	**1.8**	**1.8**	**1.8**	**33**	**63**	**1.1**	**0.0**	**0.0**	**Full Circuit Clearing**
3002107	**10th Street - West Central**	**$215,159.65**	**15.7**	**15.7**	**15.7**	**891**	**990**	**12.7**	**27.2**	**0.0**	**Full Circuit Clearing**
3003701	**Coalton - US 60 W**	**$996,481.54**	**87.1**	**87.1**	**87.1**	**3,402**	**5,160**	**114.6**	**207.6**	**0.0**	**Full Circuit Clearing**
3004301	**Siloam - Distribution**	**$257,530.73**	**18.1**	**18.1**	**18.1**	**523**	**1,630**	**20.9**	**12.5**	**0.0**	**Full Circuit Clearing**
3007904	**Busseyville - Torchlight**	**$82,402.74**	**98.1**	**17.0**	**0.0**	**0**	**19**	**26.7**	**2.8**	**0.0**	**Mowing and Planning, Clearing Deferred to 2020**
3007906	**Busseyville - Walbridge**	**$1,030,169.63**	**95.1**	**75.1**	**75.1**	**3,664**	**10,781**	**146.3**	**236.1**	**0.0**	**Finish Full Circuit Clearing, from 2018**
3008003	**47th Street - Catlettsburg**	**$204,336.08**	**26.8**	**26.8**	**26.8**	**1,212**	**692**	**33.6**	**33.1**	**0.0**	**Full Circuit Clearing**
3008701	**Cannonsburg - Cannonsburg**	**$784,888.93**	**62.6**	**62.6**	**62.0**	**2,658**	**4,230**	**121.6**	**92.6**	**0.0**	**Full Circuit Clearing**
3103101	**Olive Hill - Globe**	**$447,073.92**	**120.7**	**50.0**	**51.3**	**1,392**	**3,103**	**66.8**	**1.9**	**0.0**	**Begin Full Circuit Clearing**
3117601	**Princess - Meade**	**$250,589.89**	**46.0**	**29.2**	**21.0**	**1,368**	**1,580**	**39.0**	**25.0**	**0.0**	**Begin Full Circuit Clearing**
3000201	Big Sandy - Fallsburg South	$9,214.88	96.0	0.0	0.0	0	0	1.0	0.0	0.0	Mowing
3000202	Big Sandy - Burnaugh North	$22,362.88	85.1	0.0	0.0	0	0	16.2	0.0	0.0	Mowing
3000203	Big Sandy - Yatesville	$110,348.92	62.7	0.0	0.0	0	4	57.6	0.0	0.0	Mowing and Capital Work
3000303	Bellefonte - Bellefonte	$1,231.10	57.9	0.0	0.0	0	1	0.0	0.0	0.0	Capital Work
3000601	Grahn - Distribution	$4,968.90	42.0	0.0	0.0	2	34	0.0	0.0	0.0	Quality of Service Work
3000701	Graysbranch - Graysbranch	$16,314.06	69.0	0.0	0.0	0	0	9.8	0.0	0.0	Mowing
3000802	Hayward - Lawton	$275.97	37.3	0.0	0.0	1	0	0.0	0.0	0.0	Quality of Service Work
3000901	Highland - Russell	$539.25	24.6	0.0	0.0	0	1	0.0	0.0	0.0	Quality of Service Work
3001001	Hitchins - Damron Branch	$59,995.59	46.4	0.0	0.0	0	58	0.3	90.7	0.0	Ground Spray and Capital Work
3001002	Hitchins - Willard	$206,590.58	151.1	0.0	0.0	1	0	0.0	350.1	0.0	Ground Spray
3001004	Hitchins - EK Road	$32,517.50	31.6	0.0	0.0	0	0	0.0	57.6	0.0	Ground Spray
3001101	Hoodscreek - Summitt	$18,655.82	22.5	0.0	0.0	1	1	0.0	36.9	0.0	Ground Spray and Capital Work
3001102	Hoodscreek - Rural	$3,271.88	47.2	0.0	0.0	0	0	0.0	7.7	0.0	Ground Spray
3001202	Howard Collins - 29th St.	$3,693.07	13.2	0.0	0.0	4	5	0.0	0.0	0.0	Capital Work and Quality of Service Work
3001204	Howard Collins - Summitt	$9,418.52	26.1	0.0	0.0	0	0	0.0	60.9	0.0	Ground Spray
3003702	Coalton - Cannonsburg	$28,055.72	23.6	0.0	0.0	0	0	0.0	62.2	0.0	Ground Spray
3003703	Coalton - Trace Creek	$79,696.55	83.8	0.0	0.0	0	0	0.0	167.0	0.0	Ground Spray
3007905	Busseyville - Mattie	$36,145.28	91.2	0.0	0.0	0	0	10.6	1.8	0.0	Mowing
3008001	47th Street - 49th Street	$8,651.63	25.4	0.0	0.0	2	0	0.0	19.2	0.0	Ground Spray and Quality of Service Work
3008002	47th Street - 39th Street	$4,224.23	12.8	0.0	0.0	0	0	0.0	10.7	0.0	Ground Spray
3110902	Wurtland - Greenup	$15,843.02	51.2	0.0	0.0	0	30	0.6	0.0	0.0	Capital Work
3110903	Wurtland - Rt. 503	$13,559.73	46.3	0.0	0.0	0	0	6.7	0.0	0.0	Mowing
3116101	Grayson - Lansdowne	$1,544.40	35.4	0.0	0.0	1	3	0.0	0.0	0.0	Capital Work
3116701	Belhaven - Diedrich	$253.00	8.9	0.0	0.0	1	1	0.0	0.0	0.0	Quality of Service Work
	Ashland District Totals	**$6,210,034.73**		**497.4**	**471.9**	**19,763**	**36,792**	**808.5**	**1,587.7**	**0.0**	

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2019 KY POWER FORESTRY CIRCUIT HISTORY
Five Year Cycle Maintenance Clearing

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Hazard District

Circuit Number	Circuit Name	Cost (Includes O&M and Capital)	Total Line Miles	Reclearing Miles Planned	Reclearing Miles Complete	Trees Trimmed	Trees Removed	Brush Cut (Acres)	Brush Sprayed (Acres)	Tree Growth Regulator	Comments
3301701	Daisy - Leatherwood	$682,643.23	88.4	71.5	71.5	2,744	11,390	934.8	0.0	0.0	Finish Full Circuit Clearing, from 2018
3303902	Leslie - Wooton	$187,904.01	129.9	47.6	20.0	636	2,343	33.8	21.7	0.0	Begin Full Circuit Clearing
3303903	Leslie - Hals Fork	$425,472.24	76.6	30.6	30.6	1,407	8,670	123.6	0.0	0.0	Finish Full Circuit Clearing, from 2018
3307301	Bulan - Ary-Heiner	$92,655.76	52.7	0.7	0.7	214	797	4.3	154.2	0.0	Finish Full Circuit Clearing, from 2018
3307302	Bulan - Ajax-Dwarf	$68,938.44	40.5	0.8	0.8	107	390	2.9	121.8	0.0	Finish Full Circuit Clearing, from 2018
3308001	Jackson - South Jackson	$453,131.12	26.6	26.6	24.6	842	5,840	71.5	30.9	0.0	Full Circuit Clearing
3308002	Jackson - Panbowl	$483,859.01	31.4	31.4	31.2	963	6,597	70.2	34.0	0.0	Full Circuit Clearing
3308404	Beckham - Pippa Passes	$318,546.23	63.4	42.9	42.9	443	2,176	28.4	44.5	0.0	Finish Full Circuit Clearing, from 2018
3308502	Bonnyman - Hazard	$523,066.73	65.5	42.9	42.7	1,190	9,322	107.9	11.0	0.0	Finish Full Circuit Clearing, from 2018
3308503	Bonnyman - Big Creek	$295,221.58	87.4	13.8	13.8	933	4,638	43.2	146.3	0.0	Finish Full Circuit Clearing, from 2018
3308603	Collier - Smoot Creek	$834,888.07	79.7	79.7	79.7	2,640	10,715	177.3	112.6	0.0	Full Circuit Clearing
3309002	Jeff - Jeff	$69,909.00	5.7	5.7	5.7	63	1,367	8.9	16.6	0.0	Full Circuit Clearing
3309003	Jeff - Viper	$638,118.72	67.0	56.5	56.5	2,391	9,448	118.1	0.0	0.0	Finish Full Circuit Clearing, from 2018
3311701	Shamrock - Shamrock	$402,240.76	28.7	28.7	28.5	986	9,743	124.6	6.6	0.0	Full Circuit Clearing
3312201	Engle - Industrial Park	$14,728.85	4.1	4.1	4.1	14	360	9.1	21.4	0.0	Full Circuit Clearing
3312202	Engle - Grapevine	$486,323.64	100.2	53.0	41.9	1,350	8,899	118.9	4.2	0.0	Begin Full Circuit Clearing
3300601	Bluegrass - Walkertown	$2,477.60	28.7	0.0	0.0	0	4	0.0	2.0	0.0	Capital Work and Ground Spray
3302703	Hazard - Hazard	$2,601.18	11.0	0.0	0.0	0	0	0.0	1.3	0.0	Capital Work and Ground Spray
3302704	Hazard - Kenmont	$14,550.11	19.9	0.0	0.0	23	6	0.0	34.5	0.0	Capital Work and Ground Spray
3303901	Leslie - Hyden	$18,564.24	89.4	0.0	0.0	0	0	0.0	33.6	0.0	Ground Spray
3307303	Bulan - Lotts Creek	$4,211.88	2.2	0.0	0.0	0	0	0.0	9.5	0.0	Ground Spray
3308401	Beckham - Hindman	$45,021.48	97.3	0.0	0.0	0	0	0.0	116.7	0.0	Ground Spray
3308402	Beckham - Carr Creek	$66,337.99	51.3	0.0	0.0	8	347	1.5	146.8	0.0	Capital Work and Ground Spray
3308601	Collier - Upper Rockhouse	$1,379.34	37.3	0.0	0.0	0	0	0.0	29.4	0.0	Ground Spray
3308602	Collier - Lower Rockhouse	$16,578.83	62.9	0.0	0.0	3	19	0.0	14.8	0.0	Ground Spray and Quality of Service Work
3309001	Jeff - Boone Ledge	$8,108.64	5.0	0.0	0.0	8	24	0.0	0.0	0.0	Captial Work
3309101	Whitesburg - Whitesburg	$1,959.10	8.8	0.0	0.0	0	0	0.0	5.5	0.0	Ground Spray
3309102	Whitesburg - Hospital	$5,527.58	7.1	0.0	0.0	0	0	0.0	15.0	0.0	Ground Spray
3309103	Whitesburg - Cowan	$2,325.98	43.9	0.0	0.0	0	28	0.0	0.0	0.0	Quality of Service Work
3309104	Whitesburg - Crafts Colley	$1,035.90	27.9	0.0	0.0	0	0	0.0	1.1	0.0	Quality of Service Work
3309301	Vicco - Red Fox	$1,202.10	47.8	0.0	0.0	0	8	0.0	0.0	0.0	Quality of Service Work
3309302	Vicco - Jeff	$4,546.42	88.9	0.0	0.0	1	80	0.0	0.0	0.0	Capital Work and Quality of Service Work
3310501	Haddix - Quicksand	$32,005.97	111.3	0.0	0.0	0	0	0.0	167.2	0.0	Ground Spray
3310502	Haddix - Canoe	$18,681.28	124.1	0.0	0.0	0	0	0.0	1.3	0.0	Ground Spray and Work Planning
3310503	Haddix - Troublesome Creek	$10,157.84	91.7	0.0	0.0	0	0	0.0	66.6	0.0	Ground Spray
3311101	Stinnett - Redbird	$1,821.90	117.7	0.0	0.0	0	25	0.0	0.0	0.0	Capital Work
3311103	Stinnett - Wendover	$3,465.81	36.8	0.0	0.0	0	1	0.0	5.5	0.0	Ground Spray and Capital Work
3311401	Reedy - Deane	$1,968.24	43.7	0.0	0.0	0	0	0.0	2.2	0.0	Quality of Service Work
3312901	Jenkins - Kona	$3,891.40	26.0	0.0	0.0	0	0	0.0	11.7	0.0	Ground Spray
3312902	Jenkins - Jenkins	$11,147.30	22.2	0.0	0.0	3	5	1.5	32.1	0.0	Ground Spray and Quality of Service Work
3314401	Mayking - Ermine	$5,364.60	28.1	0.0	0.0	40	8	0.1	0.0	0.0	Quality of Service Work
3401301	Fleming - Neon	$2,302.24	20.4	0.0	0.0	0	0	0.0	1.6	0.0	Ground Spray, Quality of Service
3451202	Beefhide - Dunham	$4,949.50	8.7	0.0	0.0	0	0	0.0	11.6	0.0	Ground Spray
	Hazard District Totals	**$6,269,831.84**		**536.5**	**495.2**	**17,009**	**93,250**	**1,980.3**	**1,435.6**	**0.0**	

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2019 KY POWER FORESTRY CIRCUIT HISTORY
Five Year Cycle Maintenance Clearing

Costs that were not allocated to a circuit number include: Internal labor & fleet costs, some unscheduled hotspot maintenance, trouble restoration work, tree ticket investigation, and tree contractors field supervision

Pikeville District

Circuit Number	Circuit Name	Cost (Includes O&M and Capital)	Total Line Miles	Reclearing Miles Planned	Reclearing Miles Complete	Trees Trimmed	Trees Removed	Brush Cut (Acres)	Brush Sprayed (Acres)	Tree Growth Regulator	Comments
3120101	**Stanville - Mud Creek**	**$655,658.54**	**77.5**	**32.9**	**32.9**	**1,814**	**6,496**	**94.2**	**0.0**	**0.0**	**Finish Full Circuit Clearing, from 2018**
3200204	**Barrenshe - Pounding Mill**	**$180,731.45**	**16.1**	**16.1**	**16.1**	**461**	**2,274**	**31.0**	**0.0**	**0.0**	**Full Circuit Clearing**
3400601	**Burton - Bevinsville**	**$355,833.32**	**19.6**	**19.6**	**19.6**	**483**	**3,309**	**66.7**	**0.0**	**0.0**	**Full Circuit Clearing**
3400602	**Burton - Wheelwright**	**$504,356.71**	**20.8**	**20.8**	**20.8**	**611**	**2,974**	**49.3**	**0.0**	**0.0**	**Full Circuit Clearing**
3401101	**Falcon - Oil Springs**	**$350,851.55**	**48.0**	**48.0**	**48.0**	**748**	**3,610**	**109.8**	**0.0**	**0.0**	**Full Circuit Clearing**
3402202	**McKinney - Gibson**	**$552,709.26**	**41.9**	**41.9**	**41.9**	**1,117**	**5,467**	**80.6**	**0.0**	**0.0**	**Full Circuit Clearing**
3403002	**Pikeville - Main Street**	**$138,088.84**	**6.4**	**6.4**	**6.4**	**385**	**436**	**6.0**	**0.0**	**0.0**	**Full Circuit Clearing**
3403201	**Beaver Creek - Ligon**	**$811,465.11**	**80.2**	**62.3**	**49.0**	**982**	**7,916**	**159.1**	**0.0**	**0.0**	**Full Circuit Clearing**
3403202	**Beaver Creek - Price**	**$488,150.56**	**25.7**	**25.7**	**25.7**	**427**	**3,259**	**67.6**	**0.0**	**0.0**	**Full Circuit Clearing**
3403302	**Prestonsburg - University**	**$325,167.03**	**16.9**	**16.9**	**16.9**	**531**	**2,374**	**24.3**	**0.2**	**0.0**	**Full Circuit Clearing**
3408303	**Coleman - Peter Creek**	**$431,221.40**	**39.3**	**39.3**	**39.3**	**816**	**3,640**	**54.7**	**3.7**	**0.0**	**Full Circuit Clearing**
3408304	**Coleman - Calloway**	**$351,012.00**	**36.5**	**36.5**	**36.5**	**636**	**2,456**	**100.7**	**0.0**	**0.0**	**Full Circuit Clearing**
3409502	**Burdine - Levisa**	**$418,750.77**	**39.9**	**25.9**	**25.9**	**702**	**3,383**	**82.9**	**0.0**	**0.0**	**Finish Full Circuit Clearing, from 2018**
3410502	**So. Pikeville - Island Creek**	**$320,433.53**	**38.5**	**25.5**	**25.5**	**494**	**2,167**	**57.5**	**6.4**	**0.0**	**Finish Full Circuit Clearing, from 2018**
3411801	**Johns Creek - Meta**	**$902,111.89**	**167.0**	**114.4**	**114.4**	**1,649**	**9,725**	**277.6**	**0.0**	**0.0**	**Finish Full Circuit Clearing, from 2018**
3411901	**Fords Branch - Shelby**	**$102,961.64**	**40.5**	**0.1**	**0.1**	**0**	**0**	**0.0**	**108.1**	**0.0**	**Finish Full Circuit Clearing, from 2018**
3411902	**Fords Branch - Robinson Ck**	**$157,728.78**	**69.9**	**0.4**	**0.4**	**0**	**35**	**0.0**	**194.1**	**0.0**	**Finish Full Circuit Clearing, from 2018**
3412901	**Weeksbury - Distribution**	**$518,193.30**	**26.5**	**26.5**	**26.5**	**744**	**1,840**	**73.1**	**0.0**	**0.0**	**Full Circuit Clearing**
3421001	**Breaks - City**	**$375,794.17**	**30.3**	**30.3**	**30.3**	**669**	**2,699**	**75.3**	**0.0**	**0.0**	**Full Circuit Clearing**
2150103	Sprigg-Sprigg	$25,884.08	9.0	0.0	0.0	0	14	0.6	39.1	0.0	Ground Spray and Quality of Service Work
2150105	Sprigg - Matewan	$11,539.32	2.7	0.0	0.0	0	0	0.0	17.0	0.0	Ground Spray
3120102	Stanville - Tram	$16,335.42	33.4	0.0	0.0	25	86	1.0	0.0	0.0	Quality of Service Work
3120103	Stanville - Harold	$122,096.56	55.5	0.0	0.0	0	45	1.0	173.7	0.0	Ground Spray
3150501	Borderland - Nolan	$65,043.75	18.5	0.0	0.0	0	0	0.0	99.6	0.0	Ground Spray
3150502	Borderland - Chattaroy	$44,039.88	10.1	0.0	0.0	0	0	0.0	69.5	0.0	Ground Spray
3200201	Barrenshe - Freeburn	$5,729.50	12.2	0.0	0.0	6	59	0.4	0.0	0.0	Quality of Service Work
3200301	Belfry - Belfry	$9,594.26	13.3	0.0	0.0	0	0	0.0	13.9	0.0	Ground Spray
3200302	Belfry - Toler	$14,979.30	40.5	0.0	0.0	71	50	0.0	7.1	0.0	Ground Spray and Quality of Service Work
3202201	Lovely - Lovely	$7,157.10	41.2	0.0	0.0	0	4	0.0	8.8	0.0	Ground Spray and Capital Work
3202203	Lovely - Mt. Sterling	$55,599.10	13.1	0.0	0.0	0	0	0.0	79.9	0.0	Ground Spray
3400702	Draffin - Yellow Hill	$9,978.33	11.8	0.0	0.0	12	83	0.8	0.0	0.0	Capital Work
3401001	Elwood - Dorton	$112,723.48	43.4	0.0	0.0	0	0	0.0	132.1	0.0	Ground Spray
3401002	Elwood - Virgie	$17,141.14	80.4	0.0	0.0	0	9	0.0	28.1	0.0	Ground Spray
3401102	Falcon - Salyersville	$35,446.25	45.0	0.0	0.0	0	31	1.1	44.0	0.0	Ground Spray
3401103	Falcon - Burning Fork	$1,623.20	72.6	0.0	0.0	0	0	0.0	0.0	0.0	Work Planning
3401702	Henry Clay - Regina	$13,301.78	113.1	0.0	0.0	0	3	0.0	24.0	0.0	Ground Spray and Capital Work
3401801	Index - Distribution	$2,297.14	55.1	0.0	0.0	0	1	0.0	0.0	0.0	Capital Work
3402001	Keyser - Thompson Road	$1,163.20	10.6	0.0	0.0	0	2	0.0	0.0	0.0	Capital Work
3402002	Keyser - Stonecoal	$4,405.38	36.5	0.0	0.0	9	7	0.1	0.0	0.0	Capital Work and Quality of Service Work
3403001	Pikeville - City	$5,706.00	20.4	0.0	0.0	0	1	0.0	0.0	0.0	Capital Work
3403801	Second Fork - Distribution	$49,128.71	7.4	0.0	0.0	0	0	0.0	55.0	0.0	Ground Spray
3408101	Salisbury - Printer	$46,660.96	19.6	0.0	0.0	0	0	0.0	60.6	0.0	Ground Spray
3408103	Salisbury - Martin	$128,019.74	45.7	0.0	0.0	0	14	0.7	177.0	0.0	Ground Spray
3409001	W. Paintsville - Paintsville	$6,308.74	3.4	0.0	0.0	0	0	2.9	6.7	0.0	Ground Spray
3409002	W. Paintsville - Staffordsville	$126,954.42	47.0	0.0	0.0	0	0	0.0	177.2	0.0	Ground Spray
3409003	West Paintsville - Plaza	$47,004.16	23.2	0.0	0.0	0	0	1.6	63.1	0.0	Ground Spray
3409301	Kenwood - W Van Lear	$43,968.78	18.9	0.0	0.0	0	23	1.2	54.2	0.0	Ground Spray
3409302	Kenwood - Auxier	$53,021.55	41.2	0.0	0.0	110	225	1.2	24.8	0.0	Ground Spray and Quality of Service Work
3409303	Kenwood - Hagerhill	$152,870.55	49.3	0.0	0.0	0	104	10.0	122.6	0.0	Ground Spray and Capital Work
3409402	Feds Creek - Lick Creek	$4,680.17	17.5	0.0	0.0	0	41	0.0	0.0	0.0	Capital Work
3410602	E. Prestonsburg - Lancer	$975.70	24.6	0.0	0.0	0	2	0.0	0.0	0.0	Quality of Service Work
3411802	Johns Creek - Raccoon	$6,624.06	85.0	0.0	0.0	0	16	0.0	0.0	0.0	Capital Work
3414901	Fishtrap - Distribution	$29,730.98	4.5	0.0	0.0	0	0	0.0	30.0	0.0	Ground Spray
3420101	Mayo Trail-Nippa	$45,417.59	22.5	0.0	0.0	2	13	0.0	54.3	0.0	Ground Spray and Capital Work
3420102	Mayo Trail-Euclid	$33,853.07	19.5	0.0	0.0	0	0	0.0	44.7	0.0	Ground Spray
3420103	Mayo Trail - Davis Branch	$91,884.47	32.1	0.0	0.0	0	139	1.9	67.0	0.0	Ground Spray
3421002	Breaks - Grassy	$23,575.94	4.2	0.0	0.0	0	0	0.0	18.3	0.0	Ground Spray
970603	Hurley - Race Fork	$5,792.26	4.9	0.0	0.0	0	0	0.0	8.8	0.0	Ground Spray
	Pikeville District Totals	**$9,419,475.87**		**589.5**	**576.2**	**13,504**	**65,032**	**1,434.5**	**2,013.6**	**0.0**	

Kentucky Power 2019 Totals	**$21,899,342.44**		**1,623.4**	**1,543.3**	**50,276**	**195,074**	**4,223.3**	**5,036.9**	**0.0**

Attachment 2 – 2020 Annual Maintenance Cycle Plan

2020 Kentucky Power Distribution Five Year Cycle VM Plan						Costs that are not allocated to a circuit include: internal labor & fleet costs, unscheduled hotspot miantenance, ground & aerial spray, and aerial saw				
District	Station Name	Circuit Name	Circuit Number	Circuit Line Miles	Miles Planned	Projected O&M Cost per Mile	O&M Cost	Capital Assoc. with Clearing	Total Cost	Comments
ASH	Ashland	25th St	3000101	1.3	1.3	$11,983	$15,578	$1,429	$17,008	Full Circuit Reclear
ASH	Ashland	29th St	3000102	6.8	6.8	$11,983	$81,486	$7,476	$88,963	Full Circuit Reclear
ASH	Ashland	14th St	3000103	1.4	1.4	$11,983	$16,777	$1,539	$18,316	Full Circuit Reclear
ASH	Ashland	3rd St	3000104	0.2	0.2	$11,983	$2,397	$220	$2,617	Full Circuit Reclear
ASH	Ashland	1st St	3000105	1.7	1.7	$11,983	$20,372	$1,869	$22,241	Full Circuit Reclear
ASH	Big Sandy	Burnaugh North	3000202	85.1	56.7	$11,983	$679,453	$62,340	$741,793	Begin Full Circuit Reclear
ASH	Bellefonte	Flatwoods	3000302	3.1	3.1	$11,983	$37,148	$3,408	$40,557	Full Circuit Reclear
ASH	Bellefonte	Town Center	3000304	2.7	2.7	$11,983	$32,235	$2,958	$35,193	Full Circuit Reclear
ASH	Highland	Russell	3000901	24.6	24.6	$11,983	$294,789	$27,047	$321,836	Full Circuit Reclear
ASH	Highland	Flatwoods	3000902	20.0	20.0	$11,983	$239,666	$21,989	$261,655	Full Circuit Reclear
ASH	Highland	Wurtland	3000903	15.3	15.3	$11,983	$183,344	$16,822	$200,166	Full Circuit Reclear
ASH	Howard Collins	13th St	3001201	13.0	13.0	$11,983	$155,783	$14,293	$170,076	Full Circuit Reclear
ASH	Howard Collins	Floyd	3001203	11.1	11.1	$11,983	$132,775	$12,182	$144,957	Full Circuit Reclear
ASH	Louisa	Highbottom	3001402	13.4	1.0	$11,983	$11,983	$1,099	$13,083	*Finish Full Circuit Reclear, from 2019*
ASH	Coalton	US 60 West	3003701	87.1	0.1	$11,983	$1,198	$110	$1,308	*Finish Full Circuit Reclear, from 2019*
ASH	Siloam	Distribution	3004301	18.1	0.1	$11,983	$1,198	$110	$1,308	*Finish Full Circuit Reclear, from 2019*
ASH	Busseyville	Torchlight	3007904	97.4	97.4	$11,983	$1,167,173	$107,088	$1,274,261	Full Circuit Reclear
ASH	Cannonsburg	Cannonsburg	3008701	62.6	0.6	$11,983	$7,190	$660	$7,850	*Finish Full Circuit Reclear, from 2019*
ASH	Russell	Bear Run	3010602	12.0	12.0	$11,983	$143,800	$13,194	$156,993	Full Circuit Reclear
ASH	Russell	Ashland Oil	3010603	0.8	0.8	$11,983	$9,587	$880	$10,466	Full Circuit Reclear
ASH	Olive Hill	Globe	3103101	121.1	69.8	$11,983	$836,434	$76,743	$913,177	Finish Full Circuit Reclear, from 2019
ASH	Grayson	Lansdowne	3116101	35.4	35.4	$11,983	$424,209	$38,921	$463,130	Full Circuit Reclear
ASH	Grayson	Dixie Park	3116102	33.1	33.1	$11,983	$396,647	$36,392	$433,039	Full Circuit Reclear
ASH	Belhaven	Diedrich	3116701	8.9	8.9	$11,983	$106,651	$9,785	$116,437	Full Circuit Reclear
ASH	Belhaven	Indian Run	3116702	19.1	19.1	$11,983	$228,881	$21,000	$249,881	Full Circuit Reclear
ASH	Belhaven	Argillite	3116703	27.7	12.5	$11,983	$150,151	$13,776	$163,927	Begin Full Circuit Reclear
ASH	Princess	Meade	3117601	46.0	25.0	$11,983	$299,582	$27,487	$327,069	Finish Full Circuit Reclear, from 2019
ASH	Princess	Route 180	3117602	23.3	23.3	$11,983	$279,211	$25,618	$304,828	Full Circuit Reclear
Ashland District Totals					**497.0**		**$5,955,700**	**$546,434**	**$6,502,134**	

2020 Kentucky Power Distribution Five Year Cycle VM Plan						Costs that are not allocated to a circuit include: internal labor & fleet costs, unscheduled hotspot miantenance, ground & aerial spray, and aerial saw				
District	Station Name	Circuit Name	Circuit Number	Circuit Line Miles	Miles Planned	Projected O&M Cost per Mile	O&M Cost	Capital Assoc. with Clearing	Total Cost	Comments
HAZ	Bluegrass	Hazard	3300602	11.1	11.1	$11,180	$124,102	$11,790	$135,892	Full Circuit Reclear
HAZ	Hazard	Blackgold	3302701	30.3	30.3	$11,180	$338,766	$32,183	$370,949	Full Circuit Reclear
HAZ	Hazard	Hazard	3302703	11.1	11.1	$11,180	$124,102	$11,790	$135,892	Full Circuit Reclear
HAZ	Leslie	Hyden	3303901	89.4	89.4	$11,180	$999,528	$94,955	$1,094,483	Full Circuit Reclear
HAZ	Leslie	Wooton	3303902	129.9	109.9	$11,180	$1,228,723	$116,729	$1,345,452	Finish Full Circuit Reclear - from 2019
HAZ	Jackson	South Jackson	3308001	26.6	2.0	$11,180	$22,361	$2,124	$24,485	*Finish Full Circuit Reclear - from 2019*
HAZ	Jackson	Panbowl	3308002	31.4	0.2	$11,180	$2,236	$212	$2,449	*Finish Full Circuit Reclear - from 2019*
HAZ	Bonnyman	Hazard	3308502	65.5	0.2	$11,180	$2,236	$212	$2,449	*Finish Full Circuit Reclear - from 2019*
HAZ	Collier	Upper Rockhouse	3308601	37.3	37.3	$11,180	$416,805	$39,597	$456,402	Full Circuit Reclear
HAZ	Whitesburg	Cowan	3309103	43.9	43.9	$11,180	$490,820	$46,628	$537,447	Full Circuit Reclear
HAZ	Vicco	Redfox	3309301	47.8	47.8	$11,180	$534,535	$50,781	$585,316	Full Circuit Reclear
HAZ	Slemp	Beechfork	3309903	1.7	1.7	$11,180	$19,230	$1,827	$21,057	Full Circuit Reclear
HAZ	Slemp	Royal Diamond	3309904	2.3	2.3	$11,180	$25,715	$2,443	$28,158	Full Circuit Reclear
HAZ	Shamrock	Shamrock	3311701	28.7	0.2	$11,180	$2,236	$212	$2,449	*Finish Full Circuit Reclear - from 2019*
HAZ	Engle	Grapevine	3312202	99.6	57.7	$11,180	$645,109	$61,285	$706,394	Finish Full Circuit Reclear - from 2019
HAZ	Mayking	Ermine	3314401	28.1	28.1	$11,180	$313,826	$29,813	$343,639	Full Circuit Reclear
HAZ	Mayking	Millstone	3314402	53.5	23.1	$11,180	$258,502	$24,558	$283,060	Begin Full Circuit Reclear
HAZ	Softshell	Leburn	3420002	49.7	49.7	$11,180	$555,666	$52,788	$608,454	Full Circuit Reclear
Hazard District Totals					**546.0**		**$6,104,498**	**$579,927**	**$6,684,425**	

2020 Kentucky Power Distribution Five Year Cycle VM Plan						Costs that are not allocated to a circuit include: internal labor & fleet costs, unscheduled hotspot miantenance, ground & aerial spray, and aerial saw				
District	Station Name	Circuit Name	Circuit Number	Circuit Line Miles	Miles Planned	Projected O&M Cost per Mile	O&M Cost	Capital Assoc. with Clearing	Total Cost	Comments
PKV	Allen	Distribution	3400101	27.2	27.2	$10,811	$294,052	$26,465	$320,517	Full Circuit Reclear
PKV	Falcon	Salyersville	3401102	45.0	45.0	$10,811	$486,483	$43,783	$530,266	Full Circuit Reclear
PKV	Falcon	Burning Fork	3401103	72.6	72.6	$10,811	$784,859	$70,637	$855,496	Full Circuit Reclear
PKV	Keyser	Mullins	3402003	29.6	29.6	$10,811	$319,998	$28,800	$348,797	Full Circuit Reclear
PKV	Pikeville	City	3403001	20.0	20.0	$10,811	$216,215	$19,459	$235,674	Full Circuit Reclear
PKV	Pikeville	Cedar Creek	3403003	28.0	28.0	$10,811	$302,700	$27,243	$329,944	Full Circuit Reclear
PKV	Beaver Creek	Ligon	3403201	80.2	31.2	$10,811	$337,295	$30,357	$367,651	*Finish Full Circuit Reclear - from 2019*
PKV	Spring Fork	Single Phase	3404002	8.2	8.2	$10,811	$88,648	$7,978	$96,626	Full Circuit Reclear
PKV	Sidney	Coburn Mtn	3404302	46.1	46.1	$10,811	$498,375	$44,854	$543,228	Full Circuit Reclear
PKV	W. Paintsville	Staffordsville	3409002	47.0	47.0	$10,811	$508,104	$45,729	$553,834	Full Circuit Reclear
PKV	Kenwood	Auxier	3409302	40.2	40.2	$10,811	$434,591	$39,113	$473,705	Full Circuit Reclear
PKV	Feds Creek	Feds Creek	3409401	41.0	41.0	$10,811	$443,240	$39,892	$483,132	Full Circuit Reclear
PKV	Feds Creek	Lick Creek	3409402	17.0	17.0	$10,811	$183,782	$16,540	$200,323	Full Circuit Reclear
PKV	E. Prestonsburg	Lancer	3410602	25.0	25.0	$10,811	$270,268	$24,324	$294,592	Full Circuit Reclear
PKV	Dewey	Inez	3411401	15.3	15.3	$10,811	$165,404	$14,886	$180,291	Begin Full Circuit Reclear
PKV	Johns Creek	Raccoon	3411802	84.0	84.0	$10,811	$908,101	$81,729	$989,831	Full Circuit Reclear
PKV	Garrett	Garrett	3413401	38.4	16.7	$10,811	$180,539	$16,249	$196,788	Begin Full Circuit Reclear
PKV	Beefhide	Beefhide	3451201	4.0	4.0	$10,811	$43,243	$3,892	$47,135	Full Circuit Reclear
PKV	Big Rock	Conaway	3974101	0.9	0.9	$10,811	$9,730	$876	$10,606	Full Circuit Reclear
Pikeville District Totals					**599.0**		**$6,475,629**	**$582,807**	**$7,058,436**	

Kentucky Power Totals	**1,642.0**		**$18,535,827**	**$1,709,168**	**$20,244,995**

Attachment 3 – 2020 Annual Spray Plan

Kentucky Power 2020 Distribution VM Spray Plan - Cycle Based		
District	**Acres**	**O&M Budget**
Ashland	720	$468,199
Hazard	790	$513,719
Pikeville	1,200	$780,332
KY Total	**2,710**	**$1,762,250**

Attachment 4 – 2020 Recapitulation Expenditures by District

Kentucky Power Company 2020 Distribution VM O&M Forestry Plan - Summary				
Activity	**Total O&M**	**Ashland**	**Hazard**	**Pikeville**
5 Year Cycle Maintenance	$18,535,827	$5,955,700	$6,104,498	$6,475,629
Spray - Ground and Aerial	$1,762,250	$468,199	$513,719	$780,332
Internal - KY Forestry Staff	$817,500	$272,500	$272,500	$272,500
Unscheduled/Reactive Maintenance	$357,200	$75,734	$160,733	$120,733
2020 Total 5 yr. Cycle O&M Budget	**$21,472,777**	**$6,772,133**	**$7,051,450**	**$7,649,194**

Kentucky Power Company 2020 Distribution VM Capital Forestry Plan - Summary				
Activity	**Total CAP**	**Ashland**	**Hazard**	**Pikeville**
Capital Assoc. w/ 5 Yr. Cycle Maintenance	$1,709,168	$546,434	$579,927	$582,807
Internal - KY Forestry Staff	$190,500	$63,500	$63,500	$63,500
Capital Reliability Pilot Program	$6,500,000	$100,000	$100,000	$6,300,000
Internal - KY Forestry Staff	$200,000	$3,000	$3,000	$194,000
2020 Total Capital Budget	**$8,599,668**	**$712,934**	**$746,427**	**$7,140,307**

VERIFICATION

The undersigned, Everett G. Phillips, being duly sworn, deposes and says he is Vice President of Distribution Region Operations for Kentucky Power Company that he has personal knowledge of the matters set forth in the forgoing testimony and the information contained therein is true and correct to the best of his information, knowledge and belief after reasonable inquiry.

Everett G. Phillips

COMMONWEALTH OF KENTUCKY	)	
	)	Case No. 2020-00174
COUNTY OF BOYD	)	

Subscribed and sworn to before me, a Notary Public in and before said County and State, by Everett G. Phillips, this 22nd day of June 2020.

Notary Public

Notary ID Number: 632421

My Commission Expires: 9-26-2023

OFFICIAL SEAL
TRISHA NANCE
NOTARY PUBLIC - KENTUCKY
STATE-AT-LARGE
My Comm. Expires September 26, 2023
ID # 632421

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

Electronic Application Of Kentucky Power Company For (1) A General Adjustment Of Its Rates For Electric Service; (2) Approval Of Tariffs And Riders; (3) Approval Of Accounting Practices To Establish Regulatory Assets And Liabilities; (4) Approval Of A Certificate Of Public Convenience And Necessity; And (5) All Other Required Approvals And Relief	)))))))	Case No. 2020-00174

DIRECT TESTIMONY OF

STEPHEN D. BLANKENSHIP

ON BEHALF OF KENTUCKY POWER COMPANY

DIRECT TESTIMONY OF
STEPHEN D. BLANKENSHIP ON BEHALF OF
KENTUCKY POWER COMPANY
BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY

CASE NO. 2020-00174

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DIRECT TESTIMONY OF
STEPHEN D. BLANKENSHIP ON BEHALF OF
KENTUCKY POWER COMPANY
BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY

CASE NO. 2020-00174

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME, POSITION AND BUSINESS ADDRESS.

A. My name is Stephen D. Blankenship. My business address is 12333 Kevin Avenue, Ashland, Kentucky 41102. I am the Region Support Manager for Kentucky Power Company ("Kentucky Power" or the "Company"). Kentucky Power Company is a subsidiary of American Electric Power Company, Inc. ("AEP").

II. BACKGROUND

Q. PLEASE SUMMARIZE YOUR EDUCATIONAL BACKGROUND AND BUSINESS EXPERIENCE.

A. I earned a bachelor degree in Industrial Relations in 1995 from the West Virginia Institute of Technology, and an associate degree in Electronics and Computer Engineering Technology in 2019 from Grantham University. Throughout my 22-year career, I have held positions of increasing responsibility within the AEP family of companies, which have focused primarily on distribution operations. I began my career in 1998 as a Customer Service Representative in Hurricane, WV for American Electric Power Service Corporation ("AEPSC"), a subsidiary of AEP. From 2002 to 2016, I held distribution dispatching positions of increasing responsibility in locations that included Ft. Wayne, Indiana; Columbus, Ohio; and Ashland, Kentucky. In 2016, I was promoted to Distribution Dispatch Supervisor for Kentucky Power. In 2019, I was promoted to Meter Revenue Operations Manager for Kentucky Power and in 2020, I was promoted to Region Support Manager.

III. PURPOSE OF TESTIMONY

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

A. The purpose of my direct testimony is to describe Kentucky Power's planned deployment of Advanced Metering Infrastructure ("AMI"). This includes an overview of the Company's current Automatic Meter Reading ("AMR") infrastructure and its need to be replaced, the customer benefits of AMI, and AMI's reliability benefits. I also discuss the projected cost of the planned deployment.

IV. ADVANCED METERING INFRASTRUCTURE

Q. PLEASE DESCRIBE THE CURRENT STATE OF AMR METERS.

A. Currently, Kentucky Power has 172,233 AMR meters in its service territory. Kentucky Power first installed AMR meters, primarily supplied by General Electric ("GE") (now Aclara) in 2005-2006, and those meters have been in service since that time. The AMR meters were first generation meters, and GE projected they had a ten- to fifteen-year life expectancy. These AMR meters are equipped with an Encoder Receiver Transmitter ("ERT") module, designed by Itron. The ERT module allows meter readers to walk or drive through neighborhoods to electronically capture meter data via radio transmission and thereby avoid the need to manually read each individual meter. Data is then transferred to the customer management system by two different Standard Consumption Messaging ("SCM") platforms: SCM and SCM+. The difference between the two platforms is the radio frequency at which the data is transferred from the meter to the meter reading device. Kentucky Power currently operates on an SCM platform, and it is no longer supported by the vendor. AMR meters only allow for one-way communication and thus require company meter personnel to perform all services manually, thereby foreclosing many of the efficiencies and benefits available with two-way communication.

Q. WHAT IS THE KEY CHARACTERISTIC OF ADVANCED METERING INFRASTRUCTURE THAT SEPARATES IT FROM OLDER TECHNOLOGY?

A. The key difference between AMI and earlier meter technology is that AMI allows for two-way communication, which provides significant benefits to both customers and Kentucky Power. Two-way communication with hundreds of thousands of devices provides visibility into the distribution system that was not previously available and enables programs and capabilities that are not possible with AMR meters. These include customer access to monthly usage data and energy efficiency programs, as well as increased capabilities to improve system reliability and service restoration. I discuss these customer and reliability benefits in greater detail later in my testimony.

V. AMI DEPLOYMENT

Q. WHY IS KENTUCKY POWER PLANNING TO REPLACE AMR METERS WITH AMI METERS?

A. The primary factor for the planned replacement of meters is the age and life expectancy of the meters and the technological obsolescence of the current SCM platform that AMR meters use. 74.6% of Kentucky Power's AMR meters currently are between 10-15 years old. Most were installed in 2005-2006 and were at or nearing the end of their useful life by 2019. In the past three years, the failure rate of the Company's 10-15 year old AMR meters has been in the 10% range, while AMR meters under warranty (less than 3 years old) have a failure rate of less than 1%. With a significant majority of the Company's meters already at the end of their expected useful life, the Company expects that AMR meter failure rates will increase over time. Only one vendor, Itron, continues to manufacture an SCM+ AMR meter, and its technology is proprietary. Installing new AMR meters supplied by that vendor thus would lock the Company into a single vendor and supplier of meters and spare parts, SCM+ technology, which is based on a rapidly outdated technology.

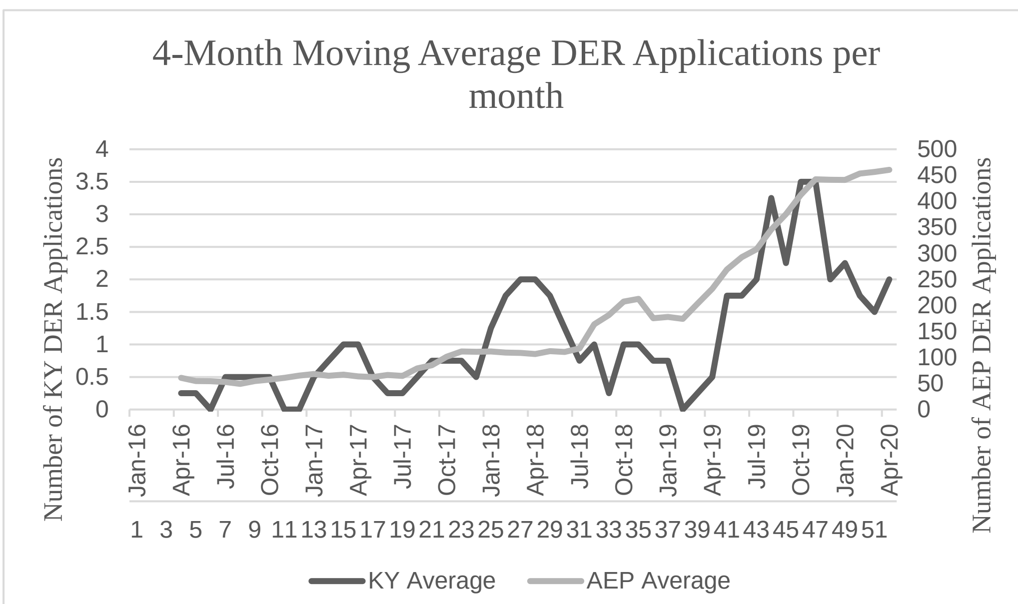
In addition, the Company's existing AMR meters' current SCM platform is no longer being supported. As a result, to continue to support both existing and new AMR meters with the SCM+ platform, the existing AMR meter reading system equipment would need to be replaced with SCM+ technology and enhancements would be required to Kentucky Power's Meter Reading Information Technology ("IT") systems due to the differences in the meter data structure between the SCM and SCM+ platforms. Furthermore, repairing the current SCM meter reading equipment has become more difficult, as it is no longer supported by the current vendor, Neptune Technologies Inc. If the Company were to move to the SCM+ platform, it would be required to maintain multiple communication infrastructures for reading two types of AMR meters, one using an SCM platform and the other using an SCM+ platform, during the multi-year transition. This investment in antiquated technology is neither practical nor cost efficient.

The alternative to the installation of AMI, or the upgrade of the existing SCM AMR meters to SCM+ AMR technology is to recycle old, used, obsolete AMR meters from other companies without regard to their age and hoping the technologically obsolete meters will work for an extended period of time. This alternative is neither logical nor practical. It would require acquiring meters without regard to their age or condition. Nor is there any guarantee the Company ultimately could obtain the number of meters necessary to replace existing AMR meters as they fail. In addition, the supply of ERT meter reading devices, required for AMR meters, is dwindling.

Q. ARE THERE OTHER REASONS TO TRANSITION TO AMI METERS?

A. Yes. Due to an increased number of customers installing distributed energy resources (mostly solar) it is even more imperative that the Company transition to AMI to facilitate these resources. The graph in Figure 1 shows an increase in the number of applications for distributed energy resources from 2016-2020.

Figure 1: Four-Month Moving Average of Distributed Energy Resource Applications Every Month in Kentucky Power and AEP as a Whole



To date, the company currently has 33 solar distributed energy resource customers in service. In addition, so far in 2020 Kentucky Power received nine new applications, six of which were approved and are awaiting installation. Kentucky Power is on pace for an estimated 30 total applications by the end of 2020.

AMI also facilitates other customer benefits, which I explain in more detail later in my testimony.

Q. IS EMPLOYEE SAFETY A CONSIDERATION IN KENTUCKY POWER'S DECISION TO DEPLOY AMI METERS?

A. Yes, safety is always of paramount concern to Kentucky Power. Company meter personnel face many hazards, including hostile customers, vicious animals, and other dangers when dispatched to a customer's premises to service, connect, or disconnect meters. The implementation and use of AMI meters largely eliminates these hazards. In some areas of Kentucky Power's service territory, customers have brandished guns when threatening Kentucky Power employees who are attempting to enter customer property to disconnect a meter, consequently requiring company personnel to request that law enforcement accompany them to customer premises to complete their assigned tasks.

In addition, dog attacks are a concern for employee safety due to some customers having released dogs into the areas where employees were working. Other hazards include slips, trips, and falls from hidden hazards, slippery surfaces, uneven walkways, and objects or debris in yards. Some meter locations also have limited access and are difficult to reach under the best circumstances. The advanced communication network of AMI meters significantly reduces the number of required on-site visits and thereby reduces the exposure to these hazards faced by Kentucky Power's company meter personnel.

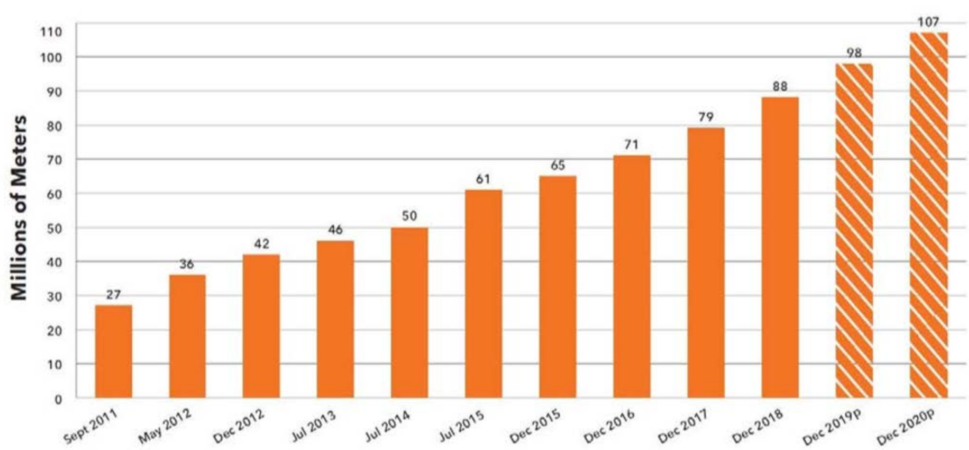
Q. WHAT IS THE CURRENT STANDARD METERING TECHNOLOGY IN THE ELECTRIC UTILITY INDUSTRY?

A. AMI has become the industry standard for metering over the last decade, due to the continued advancement of technology and wireless communication. AMI deployment and implementation is widespread across the country. The Institute for Electric Innovation reports that AMI meter installations have grown dramatically since 2011:

> As of year-end 2018, electric companies had installed more than 88 million smart meters, covering nearly 70 percent of U.S. households. Based on survey results and approved plans, estimated deployments are expected to reach 98 million smart meters by the end of 2019 and 107 million by year-end 2020.[1]

Figure 2 below demonstrates how the implementation of AMI meters has increased over the last several years.

Figure 2 – AMI Meter Penetration in the U.S.[2]



[1] INSTITUTE for ELECTRIC INNOVATION, Electric Company Smart Meter Deployments: Foundation for a Smart Grid, December 2019, Prepared by: Adam Cooper.

[2] *Id.*

Figure 3 shows the number of AMI meters installed in Kentucky as of 2018, the vast majority by municipal electric utilities and electric cooperatives.

Figure 3: AMI Meters in Kentucky[3]

	2018 Meter Installations		
	AMI	**Non-AMI**	**Total**
Total Kentucky	921,987	1,370,804	2,292,791
Total KY IOU	152,483	1,101,593	1,254,076
Total KY Muni / Co-op	769,504	269,211	1,038,715

	2018 Meter Installations (%)		
	AMI	**Non-AMI**	**Total**
Total Kentucky	40%	60%	100%
Total KY IOU	12%	88%	100%
Total KY Muni / Co-op	74%	26%	100%

In fact, AMI meters are now widely considered to be an integral, essential, and required component of the electric grid in order to provide reliable and cost-efficient service to all customers.

Q. HOW WILL KENTUCKY POWER SELECT AN AMI SYSTEM AND VENDOR?

A. Kentucky Power will use a competitive bidding process that ensures the AMI system selected meets current industry meter standards while still being flexible enough to accommodate future growth and advancements in technology. Once the AMI system is selected, the Company will negotiate a contract with the vendor to provide materials and equipment based on volume pricing.

[3] EIA's Annual Electric Power Industry Report, Form EIA-861

Q. PLEASE DESCRIBE KENTUCKY POWER'S AMI METER DEPLOYMENT STRATEGY.

A. The planned installation of AMI meters throughout the Company's service territory is a multi-year improvement project to ensure the reliability of the distribution system and maintain continuity of service to customers. This multi-year deployment minimizes costs by using economies of scale to complete the most densely populated areas first, and then adjusting resources to complete the deployment in rural areas, which is more travel intensive.

Q. DOES THE COMPANY HAVE A CUSTOMER ENGAGEMENT STRATEGY TO NOTIFY AND EDUCATE CUSTOMERS ABOUT THE CHANGE TO AMI METERS?

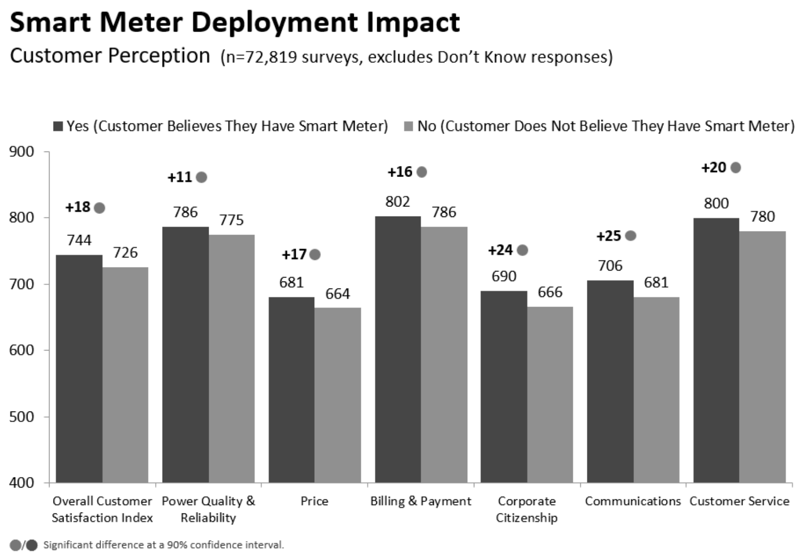
A. Yes. Company Witness Wiseman's testimony describes the Company's customer engagement strategy.

Q. TO YOUR KNOWLEDGE, ARE CUSTOMERS GENERALLY SATISFIED WITH AMI METERS?

A. Yes, they are. In a 2019 JD Power Survey, customers that were aware they have AMI meters are on average 18 index points more satisfied, as shown in Figure 4.[4]

[4] J.D Power, "Smart Meter Implementation Impact on Satisfaction," March, 2019.

Figure 4 – JD Power Survey – AMI Meter Customer Satisfaction



Based on U.S. Energy Information Administration AMI data, utilities with 60% or greater AMI meter implementation have higher customer satisfaction.[5]

Q. IS THE COMPANY SEEKING A CERTIFICATE OF PUBLIC CONVENIENCE AND NEED (CPCN) FOR AMI DEPLOYMENT?

A. Yes. This is further explained in the direct testimony of Company Witness West.

Q. IS THE COMPANY PROPOSING A RECOVERY MECHANISM TO RECOVER THE COST OF AMI METER DEPLOYMENT?

A. Yes. As described by Company Witnesses Phillips and West, Kentucky Power is proposing a Grid Modernization Rider ("GMR") in this case. The Company is proposing to recover the costs of implementing the planned AMI meter deployment through the GMR. The GMR will allow the Company to recover AMI deployment costs in a timely manner as AMI meters are placed in-service.

[5] Id. at 3.

VI. CUSTOMER BENEFITS

Q. HOW WILL AMI METERS BENEFIT CUSTOMERS?

A. Customers can realize immediate benefits by using AMI meter data to monitor and regulate their electric usage throughout the monthly billing cycle. Customer consumption data is currently available to customers through the "Green Button" initiative, which enables customers to access their energy usage on Kentucky Power's website, but only the total consumption for each monthly period. In other words, a customer currently can receive 12 meter readings or data points each year. With AMI meters, customers will have near immediate access to their electric usage information with 15-minute interval data, meaning a meter reading every 15 minutes. That is over 35,000 meter readings or data points each year. That level of information will provide customers the opportunity to make incremental adjustments to their electricity usage and be able to review the resultant bill impact.

The near immediate access to usage information also enables customers to receive a High Bill Alert. These alerts will notify a customer with a highly accurate reading of mid-cycle energy usage and provide bill projections. Notifying a customer of usage and bill projections provides a significant benefit to customers who are managing their energy costs as part of a monthly budget. Currently, more than 50% of Ohio Power Company's eligible residential customers are signed up to receive high bill alerts, and over 50% of those customers have received at least one high bill alert on their account.

In addition, if customers notice higher than normal consumption, they can try to pinpoint the cause, or they can contact Kentucky Power to do so. The AMI meter also provides the necessary functions to support time-of-day rate schedules and other demand-side management programs. Kentucky Power currently offers residential and commercial time-of-day rates, but current AMR metering does not facilitate or fully enable their use. The information to be provided customers through AMI meters will allow customers to choose the rate that best fits their usage. Company Witness West describes how these tariffs could be more fully utilized to help customers manage their energy bills in connection with AMI meters.

Q. WHAT ARE SOME OF THE OTHER CUSTOMER BENEFITS THAT AMI OFFERS?

A. Ultimately, the change to AMI is about enhancing the customer experience while at the same time modernizing the grid and making it more reliable and more efficient. In addition to assisting customers in making immediate informed decisions regarding their energy usage, AMI will also enable the Company to offer Flex Pay billing that allows customers to pay as they go in lieu of the traditional post-pay billing options. Public Service Company of Oklahoma ("PSO"), a Kentucky Power sister company, offers a pre-paid billing option to customers with AMI meters and has observed numerous customer benefits associated with the program, which Company Witness West discusses.

In addition, AMI will give Kentucky Power the ability to remotely and more quickly perform service connections and credit reconnections to better accommodate customers' needs. AMI technology has enabled Ohio Power Company to remotely reconnect customers on average within ten minutes, which is significantly faster than the 4.4 hours it has typically taken for AMR customers. Also, the AMI technology will enable Kentucky Power to identify against meter tampering. Finally, AMI will allow the Company to develop and provide more innovative solutions for customers' convenience, to reduce energy consumption, and, ultimately, to reduce their electric bills.

Q. IS THERE A COST ASSOCIATED WITH RECONNECTING AMI CUSTOMERS?

A. Although the Company anticipates IT costs associated with obtaining the ability to reconnect AMI customers remotely, the Company expects the resulting automation of the reconnection process to minimize such costs. Kentucky Power therefore does not plan at this time to charge a fee to reconnect AMI meters.

Q. HAS KENTUCKY POWER EVALUATED THE COSTS AND BENEFITS OF AMI METERS?

A. Yes, the forecasted costs of implementing AMI have been evaluated and are set forth in Figure 5 below. The Company expects the majority of benefits to come from the previously mentioned customer benefits, and the reliability benefits described below. In addition, the Company expects the transition to AMI meters to result in a reduction in fleet costs and other savings from streamlining of departments. The Company evaluated these benefits against the forecasted costs of AMI and determined that the customer, reliability, and cost savings benefits are sufficient to support AMI's implementation; however, because many of the foregoing benefits are not readily quantifiable, the Company did not prepare a formal cost/benefit analysis regarding its planned AMI implementation.

VII. RELIABILITY BENEFITS

Q. DO AMI METERS IMPROVE CUSTOMER RELIABILITY?

A. Yes. The only way the Company currently can be alerted to an outage is through a customer call to the Operations Center. AMI meters, on the other hand, can sense the voltage at a customer's premises and can alert the Company more quickly if there is a power interruption. By receiving information from multiple AMI meters, the Company can evaluate the extent of an outage without waiting for additional customers to call. The Company will also often be able to pinpoint the isolation device such as a lateral or transformer fuse affecting the outage. As a result, AMI technology will enable the Company to restore service more quickly.

Q. CAN AMI METERS PROVIDE OTHER RELIABILITY BENEFITS?

A. Yes. If isolated customer outages remain after service restoration has been completed, the Company can identify which customers are still out and can take immediate action without again waiting for those customers to call. A recent example of this occurred in PSO. AMI enabled PSO to "poll" hundreds of thousands of meters overnight during a storm recovery. The polling process avoided the need to send field personnel to individual premises to locate outages. PSO was able to make specific restoration resource work assignments prior to the start of the second day of storm restoration work. AMI meter polling allowed PSO to complete the restoration process approximately 24 hours earlier than would have been possible with AMR meters.

By monitoring voltage, the Company will also be able to identify distribution line transformers that are approaching failure and replace them proactively before the failure causes an outage. Currently, the Company can only identify potential transformer failures through a time-intensive manual process. AMI meters can monitor and detect other power quality issues such as a loose neutral, which is a common cause for voltage fluctuation at a customer's premises. In addition, AMI meters can monitor and report the health of the meter itself. For example, Ohio Power Company, another Kentucky Power sister company, performs daily hot socket analyses for all residential AMI meters, which are used to detect conditions prone to causing a fire. This leads to improved power quality and voltage to customers while monitoring the temperature of the meter.

Q. WHAT ARE SOME OF THE OTHER OPERATIONAL BENEFITS OF AMI TO KENTUCKY POWER?

A. AMI allows for additional infrastructure synergies with automated equipment. It can support equipment automation, energy efficiency programs, equipment failure prediction, phasing identification, and gathering load information for devices and network systems in order to design for future load increases. For example, Volt/VAR Optimization is an energy efficiency program that requires a precise narrow voltage bandwidth over the entire length of a distribution feeder. AMI meters can monitor the voltage of a feeder from end-to-end, and alert the Company if the voltage is outside the bandwidth. The Company can have voltage readings at every end-of-line point where the meters are placed, and therefore assist with satisfying the Voltage Survey and Records statute of Section 7 of 807 KAR 5:041. AMI technology also can support distributed energy resources, such as wind, solar, microgrids, and battery storage, by providing real-time, bi-directional measurements of the energy metrics required to support these resources. Another advantage of AMI meter technology is its ability to install firmware upgrades remotely. With AMI technology, firmware upgrades from the manufacturer can be pushed remotely over the communication network to the meter. Currently, with AMR meters, meter personnel are required to visit each meter and manually install a firmware upgrade.

Q. DO AMI METERS PROVIDE MORE ACCURATE METER ERROR READINGS IN COMPARISON TO AMR?

A. Yes, AMI meters will provide more accurate meter failure information to Kentucky Power. With non-AMI metering, meter errors are often difficult to detect and time consuming to correct. For example, if a meter has an error at the beginning of the billing cycle, Kentucky Power may not be aware of the error until the end of the billing cycle when the meter is read, or even after the billing cycle. With AMI meters, Kentucky Power will be able to detect various reading errors quickly through diagnostic reports that run multiple times a day (every four hours) and then are available for immediate review by the Company's analytics group. This will lead to more accurate billing and a reduction in estimated bills due to meter errors.

Q. WHAT ARE THE EXPECTED COSTS ASSOCIATED WITH KENTUCKY POWER'S AMI DEPLOYMENT?

A. Figure 5 provides a summary of the planned meter replacement schedule and the forecasted costs for the 2021 – 2024 deployment years.

Figure 5 – Summary of Kentucky Power AMI Deployment

Project Category	2021	2022	2023	2024	Grand Total
Capital Plant	$5,640,442	$5,603,695	$11,687,329	$7,595,308	**$30,526,774**
Capital IT/Other	$2,877,362	$359,842	$395,342	$334,525	**$3,967,071**
O&M	$257,635	$615,554	$725,504	$867,722	**$2,466,414**
Total Cost	**$8,775,439**	**$6,579,091**	**$12,808,175**	**$8,797,555**	**$36,960,260**
Number of Meters Planned	38,635	35,100	60,100	38,398	172,233

Q. WHAT IS THE BASIS OF THIS COST ESTIMATE?

A. Although Kentucky Power's AMI cost estimate is based upon a detailed review of the cost of required AMI equipment, installation of AMI equipment in necessary locations and potential risk factors that may affect the cost estimate, the numbers above may be subject to change based upon final vendor selection, and contract negotiations.

Q. WILL KENTUCKY POWER BE ABLE TO BUILD ON THE EXPERIENCE OF DEPLOYMENT OF AMI BY OTHER AEP OPERATING COMPANIES?

A. Yes. Kentucky Power's AMI cost estimate is aided by experience gained by the AEPSC and other AEP operating companies that have installed AMI meters. Other AEP operating companies have benefited from the buying power and experience of AEPSC's procurement function, which purchases AMI meters in bulk. Kentucky Power affiliate PSO completed deployment of AMI in July 2019, and AEP Texas, another Kentucky Power affiliate, completed deployment of AMI in 2014. AMI deployment is currently underway for Ohio Power Company and Appalachian Power Company. These experiences by affiliate utilities will benefit Kentucky Power's selection and deployment of AMI meters.

VIII. CONCLUSION

Q. PLEASE SUMMARIZE YOUR TESTIMONY.

A. Kentucky Power's proposed AMI deployment will enable the Company to retire its current AMR meters that are nearing or have reached the end of their useful life and replace them with AMI meters, which have become the standard in the utility industry. AMI meters will enable customers to monitor energy usage more closely and enroll in time-of-use rate schedules. Customers will also benefit from the Company's ability to restore outages more efficiently and to maintain reliability of the system through remote analysis of the distribution infrastructure. AMI meters are a new opportunity for customers and for reliability improvement, and one that the Company will serve customers' needs and expectations into the future.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes, it does.

VERIFICATION

The undersigned, Stephen D. Blankenship, being duly sworn, deposes and says he is the Region Support Manager for Kentucky Power Company that he has personal knowledge of the matters set forth in the forgoing testimony and the information contained therein is true and correct to the best of his information, knowledge and belief after reasonable inquiry.

Stephen D Blankenship

Stephen D. Blankenship

COMMONWEALTH OF KENTUCKY)
) Case No. 2020-00174
COUNTY OF BOYD)

Subscribed and sworn to before me, a Notary Public in and before said County and State, by Stephen D. Blankenship, this 23rd day of June 2020.

Trisha Nance

Notary Public

Notary ID Number: 632421

My Commission Expires: 9-26-2023

OFFICIAL SEAL
TRISHA NANCE
NOTARY PUBLIC - KENTUCKY
STATE-AT-LARGE
My Comm. Expires September 26, 2023
ID # 632421

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

Electronic Application Of Kentucky Power Company	)	
For (1) A General Adjustment Of Its Rates For	)	
Electric Service; (2) Approval Of Tariffs And Riders;	)	
(3) Approval Of Accounting Practices To Establish	)	Case No. 2020-00174
Regulatory Assets And Liabilities; (4) Approval Of A	)	
Certificate Of Public Convenience And Necessity;	)	
And (5) All Other Required Approvals And Relief	)	

DIRECT TESTIMONY OF

DEBRA L. OSBORNE

ON BEHALF OF KENTUCKY POWER COMPANY

DIRECT TESTIMONY OF
DEBRA L. OSBORNE ON BEHALF OF
KENTUCKY POWER COMPANY
BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY

CASE NO. 2020-00174

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DIRECT TESTIMONY OF
DEBRA L. OSBORNE ON BEHALF OF
KENTUCKY POWER COMPANY
BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY

CASE NO. 2020-00174

I. INTRODUCTION AND BACKGROUND

Q. PLEASE STATE YOUR NAME, POSITION, AND BUSINESS ADDRESS.

A. My name is Debra L. Osborne. My business address is 500 Lee Street East, Charleston, WV, 25301. I am Vice President Generating Assets for Appalachian Power Company ("Appalachian Power") and Kentucky Power Company ("Kentucky Power" or the "Company"). Appalachian Power and Kentucky Power are wholly-owned subsidiaries of American Electric Power Company, Inc. ("AEP").

Q. PLEASE BRIEFLY DESCRIBE YOUR EDUCATIONAL BACKGROUND AND BUSINESS EXPERIENCE.

A. I earned a Bachelor of Science degree in Electrical Engineering from West Virginia University and have completed both a Leadership Development program at The Ohio State University Fisher College of Business and a Utility Management Certification from Willamette University. I joined Ohio Power Company in 1987 as a performance engineer at Gavin Plant, progressing to various positions until I transferred to Appalachian Power's Philip Sporn Plant as Energy Production Manager. Since 2005, I have been Plant Manager at four of Appalachian Power's coal-fired plants, as well as Manager of the AEP Simulator Learning Center. I assumed my current position as Vice President Generating Assets for Appalachian Power and Kentucky Power in January 2017.

Q. PLEASE BRIEFLY DESCRIBE YOUR DUTIES AND RESPONSIBILITIES AS VICE PRESIDENT GENERATING ASSETS FOR APPALACHIAN POWER AND KENTUCKY POWER.

A. I am responsible for the safe, reliable, and economic operation of the fossil-fueled generating assets owned or operated by Kentucky Power, Appalachian Power, and Wheeling Power. Specifically, I plan, organize, coordinate, direct, and control plant activities, including the operations, maintenance, engineering, and construction of the plant facilities. I also oversee plant budgets and interface with other AEP functional groups such as accounting, regulatory, and commercial operations to ensure the needs of the generating plants are met. Additionally, I am responsible for the decommissioning, demolition, and disposition of generating assets owned or operated by Kentucky Power, Appalachian Power, and Wheeling Power.

Q. HAVE YOU PREVIOUSLY TESTIFIED IN ANY REGULATORY PROCEEDINGS?

A. Yes, I testified and submitted testimony before the Kentucky Public Service Commission in Case No. 2017-00179 and submitted testimony in Case No. 2019-00389. I have submitted testimony before the Public Service Commission of West Virginia in Docket Nos. 18-0646-E-42T, 18-0645-E-D, 19-0063-E-PC, and 20-0262-E-ENEC. I have also submitted testimony before the Virginia State Corporation Commission in Case No. PUR-2020-00015.

II. PURPOSE OF TESTIMONY

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

A. The purpose of my testimony is to:

- Describe Kentucky Power's generation assets.
- Provide an update on decommissioning activities for Big Sandy Unit 2.
- Describe and support the reasonableness of Kentucky Power's generation non-fuel, non-labor operation and maintenance ("O&M") expenses for the Mitchell and Big Sandy Plants.

III. KENTUCKY POWER'S GENERATING ASSETS

Q. PLEASE DESCRIBE KENTUCKY POWER'S GENERATION ASSETS.

A. Kentucky Power's generation assets consist of both owned and contracted generation capacity totaling 1,468 MW.

Q. PLEASE BRIEFLY DESCRIBE KENTUCKY POWER'S OWNED GENERATION.

A. Kentucky Power's generation assets consist of a total of 1,075 MW of capacity from two generating plants, Big Sandy and Mitchell. The Company's assets and their characteristics are listed in Table 1.

Table 1: Kentucky Power Generation Assets

Plant	Kentucky Power-Owned Capacity(MW)	No. of Units	Location	Fuel	Expected Retirement Date
Big Sandy	295	1	Louisa, KY	Natural Gas	2031
Mitchell	780	2	Moundsville, WV	Coal	2040

Kentucky Power owns and operates the Big Sandy Plant located near Louisa, Kentucky. The plant currently has a single operating unit with a generating capacity of 295 MW. Big Sandy Unit 1 was originally placed in service in 1963 and operated as a 278 MW sub-critical coal-fired generating unit through mid-November 2015. As approved by the Commission in Case No. 2013-00430, and described later in my testimony, Big Sandy Unit 1 was converted to a natural gas-fired unit and returned to service May 31, 2016. The unit is equipped with low nitrogen oxide (“NO_x”) burners with overfire air for reduction of NO_x emissions.

The Mitchell Plant is located approximately 12 miles south of Moundsville, West Virginia on the Ohio River. Kentucky Power owns an undivided 50% interest in the Mitchell Plant; the other 50% interest is owned by Wheeling Power. The plant comprises two super-critical pulverized coal-fired base-load generating units. Mitchell Unit 1 has a capacity of 770 MW and Mitchell Unit 2 has a capacity of 790 MW for a total capacity of 1,560 MW. Both units were placed in service in 1971. Each unit is equipped with an electrostatic precipitator for control of particulate matter, a flue gas desulfurization system for sulfur dioxide control, and both selective catalytic reduction technology and low-NO_x burners for control of NO_x emissions. Both units also utilize a dry fly ash handling system.

Q. PLEASE DESCRIBE WHAT COMPRISES KENTUCKY POWER’S CONTRACTED GENERATION.

A. Kentucky Power is a party to a unit power agreement with AEP Generating Company for power from the Rockport Plant. The Rockport Plant is located along the Ohio River in southern Indiana and consists of two supercritical pulverized coal-fired generating units. Kentucky Power’s contractual share of the Rockport output totals 393 MW.

Q. HAVE THE RETIREMENT DATES FOR BIG SANDY UNIT 1 OR MITCHELL GENERATING UNITS CHANGED?

A. There have been no changes to the expected retirement dates of either Big Sandy Unit 1 or the Mitchell Plant. With continued maintenance, Big Sandy Unit 1 is expected to reach its retirement date of 2031 and the Mitchell plant is expected to reach its retirement date of 2040.

IV. STATUS OF BIG SANDY UNIT 2 DECOMMISSIONING

Q. WHAT IS THE STATUS OF BIG SANDY UNIT 2?

A. Kentucky Power retired Big Sandy Unit 2 in 2015. The Company is currently decommissioning and demolishing the unit.

Q. PLEASE DESCRIBE THE DECOMMISSIONING AND DEMOLITION ACTIVITIES AT BIG SANDY PLANT.

A. Following the retirement of Big Sandy Unit 2 and the conversion of Big Sandy Unit 1 to natural gas, the Company's decommissioning and demolition activities at Big Sandy include:

- Closure of the fly ash pond
- Asbestos removal
- Removal of coal handling equipment
- Demolition of the Big Sandy Unit 2 cooling tower
- Removal of coal impacted soils from the former coal yard

Q. WHAT ACTIVITIES HAVE TAKEN PLACE AT THE SITE OVER THE PAST YEAR?

A. Site activities focused mainly on the closure of the Big Sandy Plant Coal Ash Impoundment and site demolition activities.

Big Sandy Plant Coal Ash Impoundment. Kentucky Power is in the final stages of closing the coal ash impoundment and anticipates completing the project by December 31, 2020. Further detail regarding the activities over the past 12 months may be found in the quarterly status reports filed in Case No. 2015-00152.

Demolition Activities. During the last year, Kentucky Power continued the following demolition activities:

- Completed removal of asbestos and polychlorinated biphenyl-containing cables and cable trays in March 2019.
- Completed turbine building demolition in August 2019.
- Removed siding containing asbestos from buildings in September 2019.
- Demolished the heater bay section of the boiler in November 2019.
- Demolished the primary furnace portion of the main boiler building in February 2020.

V. KENTUCKY POWER GENERATION O&M

Q. WHAT ARE THE O&M REQUIREMENTS OF KENTUCKY POWER'S GENERATION ASSETS?

A. Each of Kentucky Power's plants must provide safe, economical, and reliable generation output to serve load and accommodate fluctuating consumer demand. In addition, a unit's maintenance needs vary based on its type, design, age, condition, and operational characteristics. All units must be maintained to operate when required, and to do so in a safe manner in compliance with all local, state, and federal regulations.

Q. HOW ARE O&M COSTS CONTROLLED AT THE PLANTS?

A. To minimize O&M expenses, Kentucky Power relies on a system of maintenance and operations management programs to ensure optimal performance of the generating assets. These maintenance programs are:

- Predictive Maintenance: monitoring, inspections, and/or data analyses conducted to diagnose potential maintenance issues early and usually while the equipment is running to minimize downtime.
- Preventive Maintenance: protocols, testing, and physical work conducted on equipment to address anticipated or diagnosed vulnerabilities.

In addition, continuous improvements are incorporated into the operations and maintenance of the generating units to eliminate waste and increase process efficiencies. Together, these maintenance and operations management programs help to optimize operation of the assets and limit O&M cost escalations.

Q. WHAT PERIOD WAS USED TO DEVELOP THE TEST YEAR GENERATION O&M EXPENSE FOR KENTUCKY POWER?

A. The test year is the twelve-month period from April 1, 2019 through March 31, 2020.

Q. WHAT IS KENTUCKY POWER'S TEST YEAR LEVEL OF GENERATION O&M EXPENSE?

A. Kentucky Power's non-fuel, non-labor test year Generation O&M expense is $22.7 million. The Generation O&M expense comprises two categories of expenses: steam maintenance and steam operations. As shown in Table 2 below, Kentucky Power's test year Generation O&M expenses include steam maintenance and steam operations amounts for Big Sandy, the Company's 50% undivided interest in

Mitchell, and shared plant costs not attributable to a specific generating unit (known as Non-Plant costs).

Table 2: Kentucky Power Non-Fuel, Non-Labor Test Year Generation O&M

Category	Mitchell	Big Sandy	Non-Plant	Total
Steam Maintenance	$11,053,852	$3,343,008	$33,946	$14,430,807
Steam Operations	$4,464,190	$2,314,270	$1,502,329	$8,280,788
Total	**$15,518,042**	**$5,657,278**	**$1,536,275**	**$22,711,595**

Q. DOES THE TOTAL AMOUNT OF $22.7 MILLION REPRESENT AN APPROPRIATE AND REASONABLE ONGOING LEVEL FOR O&M FOR KENTUCKY POWER'S GENERATION ASSETS?

A. Yes. This total level is reasonable and fairly reflects an appropriate level of O&M for Big Sandy and Kentucky Power's undivided 50% share of the Mitchell Plant.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, it does.

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E-Signature Summary

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dlosborne@aep.com (Principal) (Personally Known)

E-Signature Notary: Sarah Smithhisler (SRS)
June 24, 2020 12:34:10 -8:00 [D162FAC7814B] [161.235.2.88]
srsmithhisler@aep.com
I, Sarah Smithhisler, did witness the participants named above electronically sign this document.

VERIFICATION

The undersigned, Debra L. Osborne, being duly sworn, deposes and says she is the Vice President, Generating Assets for Kentucky Power Company and Appalachian Power Company that she has personal knowledge of the matters set forth in the forgoing testimony and the information contained therein is true and correct to the best of his information, knowledge and belief after reasonable inquiry.

Debra L. Osborne

Debra L. Osborne

STATE OF OHIO)
) Case No. 2020-00174
COUNTY OF FRANKLIN)

Subscribed and sworn to before me, a Notary Public in and before said County and State, by Debra Osborne, this 24th day of June 2020.

NOTARY PUBLIC
STATE OF OHIO
Sarah Smithhisler
Commission # 2019-RE-775042
Electronic Notary Public
State of Ohio
My Comm Exp. Apr 29, 2024

S. Smithhisler

Notary Public

Notary ID Number: 2019-RE-775042

My Commission Expires: April 29, 2024

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

Electronic Application Of Kentucky Power Company	)	
For (1) A General Adjustment Of Its Rates For	)	
Electric Service; (2) Approval Of Tariffs And Riders;	)	
(3) Approval Of Accounting Practices To Establish	)	Case No. 2020-00174
Regulatory Assets And Liabilities; (4) Approval Of A	)	
Certificate Of Public Convenience And Necessity;	)	
And (5) All Other Required Approvals And Relief	)	

DIRECT TESTIMONY OF

ALEX E. VAUGHAN

ON BEHALF OF KENTUCKY POWER COMPANY

DIRECT TESTIMONY OF
ALEX E. VAUGHAN ON BEHALF OF
KENTUCKY POWER COMPANY
BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY

CASE NO. 2020-00174

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EXHIBITS

DIRECT TESTIMONY OF ALEX E. VAUGHAN ON BEHALF OF KENTUCKY POWER COMPANY BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY

CASE NO. 2020-00174

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME, BUSINESS ADDRESS AND PRESENT POSITION.

A. My name is Alex E. Vaughan, and I am employed by American Electric Power Service Corporation ("AEPSC") as Director-Regulated Pricing and Renewables. My business address is 1 Riverside Plaza, Columbus, Ohio 43215. AEPSC is a wholly-owned subsidiary of American Electric Power Company, Inc. ("AEP"), the parent Company of Kentucky Power Company (the "Company" or "Kentucky Power").

Q. PLEASE DESCRIBE YOUR CURRENT RESPONSIBILITIES.

A. My responsibilities include the oversight of cost of service analyses, rate design, special contracts, and renewables for the AEP System operating companies.

Q. PLEASE SUMMARIZE YOUR PROFESSIONAL EXPERIENCE AND EDUCATIONAL BACKGROUND.

A. I graduated from Bowling Green State University with a Bachelor of Science degree in Finance in 2005. Prior to joining AEPSC, I worked for a retail bank and a holding company where I held various underwriting, finance, and accounting positions. In 2007, I joined AEPSC as a Settlement Analyst in the RTO Settlements Group. I later became the PJM Settlements Lead Analyst, where I was responsible for reconciling AEP's settlement of its activities in the PJM market with the monthly PJM invoices and for resolving issues with PJM. In 2010, I transferred to Regulatory Services as a Regulatory Analyst and was later promoted to the position of Regulatory Consultant. My responsibilities included supporting regulatory filings across AEP's eleven state jurisdictions and at the FERC. I also performed financial analyses related to AEP's generation resources and loads, power pools, and PJM. In September 2012, I was promoted to Manager, Regulatory Pricing and Analysis, where I was responsible for cost of service, rate design, and special contract analysis for the AEP east operating companies. In September 2018, I was promoted to my current position.

Q. HAVE YOU PREVIOUSLY TESTIFIED IN REGULATORY PROCEEDINGS?

A. Yes. I have presented testimony on behalf of the AEP operating companies numerous times before the regulatory bodies in Virginia, West Virginia, Kentucky, Tennessee and Indiana. In Kentucky, I have testified before the Kentucky Public Service Commission (the "Commission") in Case No. 2013-00197, Case No. 2014-00396, and Case No. 2017-00179 on behalf of the Company. I have also participated in and provided information to the Commission in several informal conferences and the recent public hearing on net metering rule changes.

II. <u>PURPOSE OF TESTIMONY</u>

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is to:

(1) to provide an overview of how the Company's base rates relate to the various surcharges and riders it utilizes;

(2) to describe the Company's proposed rate design, including the changes to the residential service charge, residential winter heating declining block, residential off peak electric vehicle charging provision, the addition of light emitting diode ("LED") standard lighting options, the Company's new flexible lighting option, and changes in time of day rate pricing;

(3) to describe certain changes to the Company's tariffs, including (i) the closure and replacement of the Company's net metering service tariff; (ii) the

Company's conditional proposal for tariff Capacity Charge; (iii) changes to the Non-Utility Generator tariff, the Purchase Power Adjustment ("PPA") tariff, and the Federal Tax Cut tariff; (iv) changes to the current CS-IRP tariff and the Company's proposed peak shaving option tariff Demand Response Serivce ("DRS"); (v) the revenue requirement for the Company's proposed Grid Modernization Rider ("GMR"), as well as the cost allocation and rate design for the advanced metering infrastructure ("AMI") project proposed for inclusion in that rider;

(4) to support the marginal cost of service analysis related to the test year operation of the Company's Economic Development Rider; and

(5) to support certain operation and maintenance expense and operating revenue adjustments detailed in Section V, Exhibit 2.

Q. ARE YOU SPONSORING ANY EXHIBITS OR SCHEDULES?

A. Yes, I am sponsoring the following exhibits:

- Exhibit AEV-1 – Base Rate Revenue Target Summary & Rate Design
- Exhibit AEV-2 – Marginal Customer Connection Analysis
- Exhibit AEV-3 – NMS II Avoided Cost Pricing & Customer Example
- Exhibit AEV-4 – Proposed NMS II Tariff
- Exhibit AEV-5 – Tariff PPA Base Amount Detail
- Exhibit AEV-6 – Redlined FTC Tariff
- Exhibit AEV-7 – Proposed Tariff DRS & Cost/Benefit Analysis
- Exhibit AEV-8 – Grid Modernization Rider Revenue Requirement and Rate Design
- Exhibit AEV-9 – Economic Development Rider Customer Analysis

Additionally I support Section II Exhibits I, J and K of the Company's standard filing requirements.

III. BASE RATE COST OF SERVICE OVERVIEW

Q. CAN YOU DESCRIBE GENERALLY THE MECHANISMS THROUGH WHICH KENTUCKY POWER CHARGES ITS CUSTOMERS FOR THE ELECTRIC SERVICE IT PROVIDES?

A. Yes. Kentucky Power charges its customers for electric service through two types of mechanisms: (1) base rates; and (2) surcharges and riders. Through base rates, the Company recovers its operating expenses and a return on and of the capital investments it has prudently made to provide safe and reliable electric service to its customers. The Company also recovers through surcharges and riders certain operating expenses and returns on investments that are volatile or otherwise better suited for recovery through base rates.

Q. ARE THERE ANY NEW SURCHARGES OR RIDERS SINCE THE COMPANY'S LAST BASE RATE CASE?

A. Yes. There is one new rider in the test year, the Federal Tax Cut rider that I will briefly describe below.

Q. HOW DOES THE INTERRELATION BETWEEN BASE RATES AND THE COMPANY'S SURCHARGES AFFECT THE COST OF SERVICE STUDY PERFORMED IN THIS CASE?

A. Kentucky Power's test year revenues and operating expenses included revenues and expenses relating to a number of surcharges and riders.

To properly determine the portion of the cost of service to be recovered through base rates, the Company had to address the revenues and expenses associated with each surcharge. How each surcharge is addressed depends on the manner in which the surcharge operates.

Q. ARE THERE ANY SURCHARGES FOR WHICH THE ASSOCIATED REVENUES AND EXPENSES ARE FULLY REMOVED FROM BASE RATES?

A. Yes. The Company removed all revenues and expenses associated with the following surcharges from base rates:

- Decommissioning Rider
- DSM Adjustment Clause
- Capacity Charge
- Home Energy Assistance Program ("HEAP") Surcharge
- Kentucky Economic Development Surcharge ("KEDS")
- Purchased Power Adjustment
- Federal Tax Cut Rider
- System Sales Clause ("SSC")
- Fuel Adjustment Clause
- Environmental Surcharge (Mitchell FGD portion)

Each of these surcharges recovers specifically identified costs that are separate from the Company's base rates requirements.

- <u>Decommissioning Rider</u> – through the Decommissioning Rider, the Company recovers the remaining net book value of the retired Big Sandy Unit 2 and the incurred decommissioning costs for coal-related assets at the Big Sandy plant.

- <u>Demand Side Management ("DSM") Adjustment Clause</u> – through the DSM Adjustment Clause, the Company recovers the program costs and lost revenues associated with the Company's single demand side management and energy efficiency program.

- <u>Capacity Charge</u> – through the Capacity Charge, the Company recovers $6.2 million annually as approved by the Commission's final order in Case No. 2004-00420 regarding the extension of the Rockport plant unit power service agreement. The Commission's Order specifically requires the Company to remove these revenues from the cost of service.

- Residential Energy Assistance surcharge – the Residential Energy Assistance surcharge is a fixed charge levied on each residential account, and matched on a dollar-for-dollar basis by the Company, to provide financial assistance to low-income residential customers.

- Kentucky Economic Development Surcharge (“KEDS”) – The KEDS is a fixed charge levied on each account, and matched on a dollar-for-dollar basis by the Company, to support economic development in the Company’s service territory.

- Purchased Power Adjustment – The PPA collects certain purchase power costs not recoverable through the fuel adjustment clause, CS-IRP credits paid to interruptible customers, 80% of incremental PJM Load Serving Entity (“LSE”) Open Access Transmission Tariff (“OATT”) expense, and costs associated with the Rockport deferral from the Company’s last base rate case.

- Fuel Adjustment Clause – This mechanism collects from or credits to customers the difference between actual fuel costs and the $.02851 $/kWh embedded in base energy rates for fuel on a monthly basis.

- System Sales Clause (“SSC”) – The SSC is the Company’s tracking mechanism for off system sales margins achieved versus the credit amount embedded in base rates. The test year SSC retail revenues and deferral were removed from the proposed base rate cost of service; test year off system sales margins were included in the base rate cost of service as I discuss later in my testimony.

- Environmental Surcharge (Mitchell FGD Portion) – Generally test year environmental surcharge costs are included in base rates as part of a base rate cost of service. In accordance with the Commission-approved settlement agreement in Case No. 2012-00578, the cost of service associated with the Mitchell plant FGD (scrubber) remains in the environmental surcharge for recovery purposes.

- Federal Tax Cut Rider – This rider provides a rate credit to customers related to the amortization of excess accumulated deferred federal income taxes (“ADFIT”) related to the Tax Cuts and Jobs Act of 2017.

Q. CONVERSELY, ARE THERE ANY SURCHARGES FOR WHICH THE ASSOCIATED REVENUES AND EXPENSES ARE INCLUDED IN BASE RATES?

A. Yes. The Company included the revenues and expenses associated with non-Mitchell FGD portion of the test year environmental surcharge in its proposed base rate cost of service.

Q. WHY WERE A PORTION OF THE ENVIRONMENTAL SURCHARGE REVENUES INCLUDED IN BASE RATES?

A. The Company incurred costs during the test year associated with projects included in the Company's approved environmental compliance plan. Through the environmental surcharge, the Company recovers from or credits to customers the costs for its environmental projects that exceed or are below the corresponding monthly amounts included in base rates. The Company's test year non-FGD environmental compliance costs and non-FGD environmental surcharge revenues are included in base rates and serve as the monthly baselines against which actual costs are compared.

Q. ARE ALL OF THE TEST YEAR ENVIRONMENTAL COMPLIANCE COSTS INCLUDED IN BASE RATES?

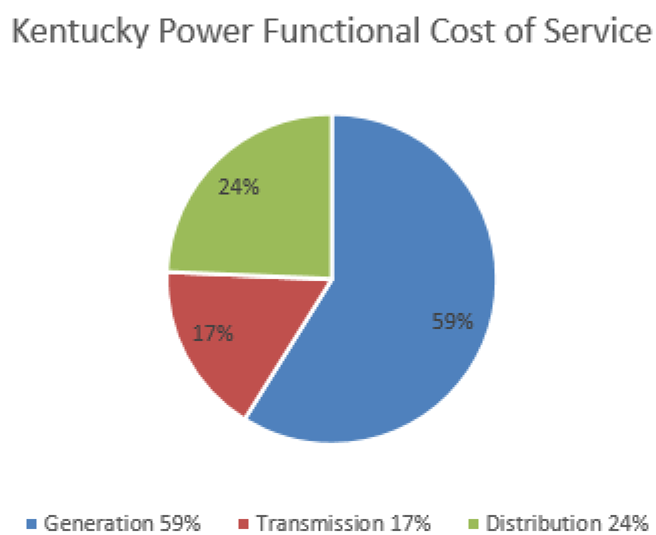
A. No. In accordance with a settlement agreement approved in Case No. 2012-00578, the Company recovers the costs associated with the flue gas desulfurization ("FGD") project at the Mitchell Plant exclusively through the environmental surcharge (as opposed to just the variance from the prior year's costs).

Q. WHY DOES THE COMPANY INCLUDE OFF SYSTEM SALES MARGINS FROM THE SYSTEM SALES CLAUSE IN BASE RATES?

A. Through the SSC, the Company shares with customers the difference between the embedded base rate credit for off system sales margins and the actual off system sales margins realized. The Company included the test year level of off system sales margins in the base rate cost of service because the Company is proposing to reset the embedded base rate credit to the test year level of off system sales margins. Cost of service adjustment number 7 removes the test year level of SSC retail sales revenue and the over/under deferral amounts from the test year, thus leaving only the test year amount of system sales margins in the cost of service. I will discuss the impact of this reset in more detail later in my testimony.

Q. PLEASE PROVIDE A BRIEF SUMMARY REGARDING THE COMPONENTS OF THE COMPANY'S BASE RATE COST OF SERVICE AND GENERALLY WHICH CUSTOMERS ARE RESPONSIBLE FOR THOSE COSTS.

A. The Company's Kentucky retail jurisdictional cost of service consists of the basic functions of generation, transmission and distribution service as follows:



The generation function comprises the majority of customers' cost of service. Both the generation function and transmission functions are utilized by all customers and included in all customers' rates. Unlike generation and transmission costs, distribution costs are only included in the rates of distribution voltage level customers, except for a small amount primarily related to metering and billing. Approximately 32% of the Company's adjusted test year usage (and associated billing units) was for customers taking service at voltage levels above distribution. Therefore, roughly a quarter of the Company's cost of service is paid by distribution level customers that make up about two thirds of adjusted test year billing units.

IV. RATE DESIGN

Q. IS THE COMPANY PROPOSING TO ELIMINATE ANY OF THE CURRENT INTER-CLASS SUBSIDY IN THIS CASE?

A. No, it is not. The Company's analysis showed that the residential class percentage increase was already above the average percentage increase with the existing subsidies in place. Kentucky Power elected not to propose an even higher residential increase by proposing to remove some level of existing subsidies at this time given current circumstances. The residential class is currently receiving a $31.8 million subsidy being paid by the other customer classes[1]. If the Commission were to approve a lower increase than what the Company has requested in this case, the Company would be in favor of removing as much of the existing inter-class subsidy as reasonable. Although the Company decided not to propose reducing the existing inter-class subsidies, cost based rates continue to be the Company's goal.

Q. PLEASE DESCRIBE THE PROCESS USED TO DEVELOP THE COMPANY'S PROPOSED RATES.

A. The Company's underlying approach in designing rates is to design its rates and rate components so that they reflect the Company's costs to provide service to each of its customer classes. This approach includes collecting basic service-related costs through basic service charges and recognizing the differences in the costs to serve customers at different service delivery voltages.

[1] Current inter-class subsidies can be found in Company Witness Stegall's Exhibit JMS-2.

The rate design process involved multiple steps that varied with each tariff. The cost components developed by Company Witness Stegall in the class cost of service study informed the relative amounts of revenue that should be recovered from service charges, energy charges and demand charges. In general, where sufficient metering data was available for a customer class, the Company designed full-cost service charges, energy rates, and demand rates by dividing the component-allocated proposed revenues by the test year billing units. These initial rates were then compared to the current rates to determine whether the Company needed to moderate the full-cost price changes to mitigate rate impacts on groups of customers. The proposed base rate revenue targets and rate design workpapers are included as Exhibit AEV-1.

Q. FOR WHICH TARIFFS IS THE COMPANY PROPOSING BASE RATE DESIGN CHANGES IN THIS PROCEEDING?

A. The Company is refining the rate design for residential customers, customers that take service on time of use rates, and adding options to its lighting tariffs.

i. <u>Residential Service Rate Design</u>

Q. WHAT CHANGES TO THE RESIDENTIAL SERVICE RATE DESIGN IS THE COMPANY PROPOSING IN THIS PROCEEDING?

A. The Company is proposing to increase the basic service charge to $17.50 per month from $14 and to add a winter month declining block to aid the Company’s customers who utilize electricity to heat their homes.

Q. WHAT IS THE RATIONALE FOR INCREASING THE RESIDENTIAL BASIC SERVICE CHARGE?

A. The Company is proposing to increase the basic service charge for residential customers to more accurately reflect the actual fixed cost of providing service to those customers. The rate structures for customer classes that employ demand charges are better aligned with cost causation principles than those that do not because fixed costs are generally recovered through a demand charge. Because the residential class does not include a separate demand charge, the majority of fixed distribution costs are recovered through the energy charge. These fixed distribution costs, or at least a larger portion of them, should be recovered in the basic service charge since they do not vary with usage and are instead solely the costs associated with connecting a customer to the distribution system and maintaining that connection. The current basic service charge is too low relative to the fixed cost of providing electric service creating intra-class subsidies between residential customers. Because of these intra-class subsidies, the current basic service charge disadvantages higher usage customers, including electric heating and lower income customers.

Q. DID THE BASIC SERVICE CHARGE INCREASE GRANTED IN THE COMPANY'S LAST RATE CASE ELIMINATE THE INTRA-CLASS SUBSIDY?

A. No. The basic service charge increase in the last rate case from $11 to $14 per month helped to reduce the intra-class subsidy being paid by higher use customers but did not eliminate it. As can be seen on Exhibit AEV-1, the total proposed base rate revenue target for the residential class is $257.8 million of which the energy portion is $64.8 million. The $193 million balance is comprised of demand and customer related costs that are commonly referred to as "fixed costs" as they do not vary with kWh usage levels.

However the current residential base rate design only recovers $22.4 million (1,603,152 bills x $14 service charge) of fixed costs from non-kWh charges with the other $170.6 million of fixed costs being collected through kWh rates and thus creating the large intra-class subsidy being paid by above average users like electric heating and lower income customers to below average users. The proposed $3.50 increase in the basic service charge will reduce the existing intra-class subsidy by shifting $5.6 million to a fixed recovery (1,603,152 bills x $3.5), which is a reasonable and gradual step in the right direction.

Q. PLEASE DESCRIBE THE PROPOSED WINTER HEATING BLOCK CHANGE TO RESIDENTIAL RATE DESIGN AND ITS IMPACT ON THE INTRA-CLASS SUBSIDY.

A. The Company is proposing the winter heating block to further reduce the intra-class subsidy, provide winter bill relief and reduce monthly bill volatility for the Company's electric heating and lower income customers. The winter heating block is a declining rate, second block added to the residential rate design that will apply to all kWh usage over 1,100 kWh during the months of December, January and February. The block differential from the all other standard kWh rates is 0.06 $/kWh. The 1,100 kWh threshold was set based upon the average usage of electric heating customers in the months of March – November, therefore the assumption is that the usage from these customers in the months of December, January and February above 1,100 kWh pertains to heating their homes.

The winter heating declining block rate of 0.06265 $/kWh is still greater than what a pure energy cost-only rate would be for the residential class (0.03251 $/kWh), so the kWh subject to the lower rate during the winter months is covering the variable cost of service and still contributing to fixed cost collection but at a reduced rate. This leads to a further reduction in the intra-class subsidy (over-collection of fixed costs) for the Company's electric heating and lower income customers. As proposed, the winter heating block rate discount is worth $14.6 million during the winter months (243,427,590 kWh times .06 $/kWh). That discount is then collected from all other kWh throughout the entire year, so the same customers that are receiving it will pay a portion of the discount back. The end result is still a reduction in the intra-class subsidy being paid by higher usage customers, winter bill relief for heating and lower income customers, and a reduction in month to month bill volatility.

Q. WILL THE INCREASED BASIC SERVICE CHARGE ALSO IMPACT MONTHLY BILL VOLATILITY?

A. Yes. Because less of the fixed costs will be recovered through the usage-related energy charge, the average customer will see less volatility in bills in high usage months. This is especially true for the Company's electric heating customers who tend to experience very high usage months in the winter to heat their homes. This proposed rate design change also will lessen the bill impact in those months because the increased usage will not result in even greater subsidization of lower usage customers. Further, as described above, this is an appropriate result based upon cost causation principles and works in tandem with the Company's proposed winter declining block structure to further reduce bill volatility.

Q. WHAT IMPACT WOULD THE HIGHER BASIC SERVICE CHARGE HAVE ON LOWER INCOME AND ELECTRIC HEATING CUSTOMERS?

A. A higher basic service charge will help lower income customers who, because they often do not have the resources to invest in weatherization and energy efficient appliances, have higher than average usage. Based on test year data, the average kWh usage for the

Company's low income energy assistance customers (1,367 kWh/month) is greater than the average usage for the residential class as a whole (roughly 1,240 kWh/month). Because the increased service charge benefits higher usage customers by reducing intra-class subsidies, the change will benefit the average low income customer.

The Company's electric heating customers will also benefit from the increased service charge because their average usage (1,480 kWh/month) is also above the residential class average. During the test year, 71% of the Company's low income energy assistance customers were also electric heating customers.

Q. HOW WAS THE NEW BASIC SERVICE CHARGE DETERMINED?

A. The Company is proposing a gradual but material step increase in the basic service charge. The amount of the proposed increase ($3.50) was limited by the proposed winter tail block as to help limit bill impacts that result from subsidy reductions on the residential customers that are currently enjoying the intra-class subsidy being paid by higher use customers.

Q. IS THE PROPOSED BASIC SERVICE CHARGE OF $17.50 PER MONTH APPROACHING FULL COST?

A. No, it is not. In Case No. 2017-00179 I calculated the full cost basic service charge to be roughly $38 per customer per month using two different studies. The $38 is simply the cost of connecting a customer to the Company's radial distribution system and maintaining that connection. That figure does not include any generation, transmission or demand related distribution costs. Because these customer connection costs are fixed one would not expect them to vary in a material fashion during the time between rate cases. Just to confirm that, I updated what I refer to as "the marginal customer connection" study. The study is included as Exhibit AEV-2. This study identifies the Company's current average cost to connect a residential customer to its distribution system. The total cost of the residential connection is then multiplied by the appropriate levelized carrying charge and divided by 12 to compute the monthly full cost basic service charge.

Using this method, I calculated the full cost basic service charge for a Kentucky Power residential customer to be approximately $35 per month. In other words, the fixed monthly cost associated with connecting the next customer to the distribution system is $35. Thus the Company's proposed basic service charge of $17.50 is still short of full cost and what cost causation principals would dictate.

Q. WILL THE COMPANY'S PROPOSED RESIDENTIAL BASIC SERVICE CHARGE OR WINTER HEATING BLOCK DETER ENERGY CONSERVATION?

A. No. In addition to its proposal to increase the basic service charge, the Company has also proposed to increase its base rate kWh charge. Because the amount charged in a customer's bill is still largely driven by the amount of kWh consumed, the increase in basic service charge is not providing customers a price signal that would encourage additional consumption. An increase in usage will still result in an increased bill.

Ideally, the Company would recover little to none of the residential class distribution revenue requirement through a per kWh charge because the distribution revenue requirement does not vary with the amount of kWh consumed. Instead, the Company would institute a per kW demand charge for residential customers to collect residential distribution costs not recovered through the service charge. However, the Company's current residential class metering infrastructure does not provide the information necessary to institute a per kW demand charge for all customers.

Q. WHAT KIND OF RATE DESIGN WOULD RESULT IN CLEARER PRICE SIGNALS?

A. Using a per kW demand charge to recover the remaining residential distribution system costs would be preferred because the fixed costs of the distribution system are incurred in two ways. First, costs are incurred by simply connecting a customer to the radial distribution system. These connection costs do not vary with the kWh consumed or the kW demands of customers. The Company is proposing to include a larger portion of these connection costs through the increased basic service charge. Second, the Company incurs residential system distribution costs by sizing the distribution system to meet customer peak kW demand. These sizing costs vary by peak demand requirements, not by kWh usage or by simply connecting a customer to the system. These sizing costs would ideally be collected through a demand charge, but this cannot be done for all customers due to the current limitations of the Company's metering infrastructure. In fact, under the Company's proposal, nearly 90% of the Company's residential customer revenues are still being recovered through a per kWh usage charge. In the absence of a peak demand charge, the Company is proposing to move a portion of those fixed distribution costs that only vary with the number of customers connected to the system from the per kWh charge to the basic service charge.

Likewise the addition of the winter heating declining block will not deter energy conservation as it only applies to the winter months and is targeted at the level of usage represented by customers' heating load. One would not expect the declining block to cause customers to heat their homes more, rather customers will continue to heat their homes to a comfortable level but will pay less for it during the winter months, and a slightly higher per kWh charge for all usage in all other months.

Q. IS SENDING THE CORRECT PRICE SIGNALS TO CUSTOMERS THROUGH RATES THAT REFLECT THE TRUE COST OF SERVICE IMPORTANT TO THE LONG TERM SUCCESS OF CONSERVATION EFFORTS?

A. Yes. While in the short term a higher kWh charge that does not reflect the true cost of service could encourage conservation, in the long term it provides confusion to customers and can result in customers making uneconomic decisions and causing the inefficient allocation of customers' capital. Customers expect that when they use less energy, the usage-related portion of their bills will decrease. However, to the extent that the usage-related portion of rates are designed to include a portion of the fixed costs as well, it is likely that as those fixed cost collections diminish because the cost savings from reduced usage are less than the loss in fixed cost collection, the Company will need to increase the usage-related portion of rates. When that happens, customers will see the usage-related portion of their bills increase even though they have conserved energy. It is important to send accurate, cost-based price signals to customers, which is exactly what the Company's proposed residential rate design takes a step towards.

Q. ARE THERE OTHER COST OF SERVICE JUSTIFICATIONS FOR THE COMPANY TO REQUIRE A HIGHER RESIDENTIAL SERVICE CHARGE THAN THE OTHER KENTUCKY INVESTOR OWNED UTILITIES?

A. Yes, there are two. First, the Company finds itself in a unique position compared to the other investor-owned utilities in Kentucky in regards to the overall density of its service territory. The Company has many fewer customers per distribution line (circuit) mile than does its peers. The absence of densely populated urban areas in the Company's service territory results in its makeup being more akin to the rural cooperatives of Kentucky than its fellow investor-owned utilities. As a result, the Company must make more distribution plant investments and incur more maintenance costs per customer to provide service. Second, the topography of the Company's service territory adds to the cost. Kentucky Power's service territory is primarily mountainous creating challenges for distribution system installation and maintenance that other utilities in the Commonwealth do not experience to the same degree. The combination of lower customer density and challenging topography results in a comparatively higher cost based basic service charge.

Q. IN SUMMARY, DOES THE COMPANY'S PROPOSED RESIDENTIAL RATE DESIGN BENEFIT THE COMPANY'S ELECTRIC HEATING AND LOWER INCOME CUSTOMERS?

A. Yes. Because electric heating and lower income customers on average use more kWh than the class average, the reduction of the intra-class subsidy being paid through the volumetric energy charge will benefit them. To put a fine point on it, under the Company's proposed rate design electric heating and lower income customers are better off than they would be on the current rate design at any level of increase.

ii. <u>Residential Electric Vehicle ("EV") Charging Provision</u>

Q. PLEASE DESCRIBE THE COMPANY'S PROPOSED EV CHARGING PROVISION FOR RESIDENTIAL CUSTOMERS.

A. The Company is proposing to add a provision to the residential tariff that will allow customers through a separately wired time-of-use ("TOU") meter to take advantage of TOU rates for their electrical vehicle charging load only. This option encourages customers to charge the vehicles off-peak without having to put their entire household usage on a TOU rate offering. The on-peak and off-peak rates for the proposed EV charging provision are the same as those offered under the load management time of day and standard time of day provisions that are already a part of the residential tariff offering. The Company has not proposed an extra basic service charge for customers that subscribe to the EV charging provision because the cost of the separate second meter for the customer is being offset by the additional fixed cost contributions from the on-peak and off-peak energy charges. Additional EV charging load is a benefit to all customers as it can increase fixed cost collection and thus the Company is not requesting an additional meter charge for these potential incremental loads as an added incentive for their use.

Q. DID THE COMPANY ADD EV CHARGING PROVISIONS FOR NON-RESIDENTIAL CUSTOMERS?

A. Yes. The Company modified the existing separate meter load management time of day provisions in tariffs General Service and Large General Service to now also include EV charging.

iii. <u>Standard LED Lighting Options</u>

Q. PLEASE DESCRIBE THE COMPANY'S PROPOSED CHANGES TO THE OUTDOOR LIGHTING AND STREET LIGHTING TARIFFS RELATED TO LED LAMP OPTIONS.

A. The Company is proposing to add standard LED lamp offerings to both its outdoor lighting ("OL") and street lighting ("SL") tariffs. The Company is also proposing to cease new installations of non-LED lamps as of January 1, 2021. Current OL and SL customers can continue their current non-LED lighting service under the proposed rates in the Company's

OL and SL tariffs. The Company is also proposing to continue repairing existing non-LED lamps as long as it has replacement lamps and parts in inventory.

Q. WHY ARE YOU PROPOSING TO ADD LED LIGHTING OPTIONS TO THE OL AND SL TARIFFS?

A. The Company has received numerous inquiries from customers as LED technology has become more prevalent. In addition, the Department of Energy[2], states that LEDs are longer-lasting, more durable and offer comparable to better quality of light than traditional lighting included in the Company's current offerings, all at a fraction of the energy usage. It is becoming increasing difficult to obtain traditional lighting technologies, such as High Pressure Sodium ("HPS") or High Intensity Discharge ("HID"), in sufficient volumes and at a reasonable cost. Converting to LED products will provide customers with a better light, more attractive color temperature options and reduced monthly energy consumption and associated energy cost. Additionally, LED technology will be much more compatible with future technology enhancements to the system, such as dimming and smart street light technology.

Q. WILL CUSTOMERS HAVE THE OPTION TO REPLACE CURRENT LIGHTING WITH LED LIGHTS?

A. Yes, customers will be able to replace current lighting with LED technology. Kentucky Power is proposing a conversion charge for any customer that has a functioning non-LED luminaire. This conversion charge would not apply to a Customer if the ballast or housing

2 LED Lighting, Department of Energy, https://www.energy.gov/energysaver/save-electricity-and-fuel/lighting-choices-save-you-money/led-lighting (March 10, 2020)

of the existing luminaire fails, or if their existing luminaire is out of stock. In this case, the Company would replace such luminaire with an LED luminaire of similar lumen output and light distribution, if the customer requests that luminaire as the replacement.

Q. PLEASE EXPLAIN THE NEED FOR A CONVERSION CHARGE?

A. In the event a customer wishes to replace a working non-LED luminaire with a new LED option, the conversion charge is intended to recover the average remaining book value of the non-LED luminaire. The Company proposes to collect the conversion charge over 84 months. Calculations supporting the conversion charge can be found in Exhibit AEV-1 Rate Design Calculations

<u>iv. Flexible Lighting Option Rate Design</u>

Q. PLEASE DESCRIBE THE FLEXIBLE LIGHTING OPTION THE COMPANY IS PROPOSING WITH ITS OL AND SL TARIFFS.

A. The flexible lighting option provides customers with lighting options and solutions beyond the standard offerings in the Company's tariffs. For example, a particular customer may want a lighting system with decorative fixtures or in a wattage that is not offered by the Company. This tariff provision will allow the Company to provide the desired equipment for the customer and appropriately charge the customer on its bill from KPCo.

The rate design for the flexible lighting option includes a monthly lamp charge for the system, a monthly maintenance charge, a non-fuel energy charge, a base fuel charge and all applicable adjustment clauses. The lamp charges will be computed using the same monthly levelized fixed cost rate used to compute the cost based lamp charges in the Company's standard lighting options. The monthly maintenance charge is based upon an average of the Company's monthly maintenance charges for its standard lighting options, while the monthly non-fuel energy charge is the same rate used to compute the cost based lamp charges in the Company's standard lighting options. All of the flexible lighting rate components are subject to update in the Company's future base rate cases, the same as its other standard lighting rates.

Q. WITH ALL OF THE SIMILARITIES TO THE STANDARD OL AND SL TARIFFS, WHAT IS DIFFERENT REGARDING THE FLEXIBLE LIGHTING OPTION?

A. From a rate design, accounting and operational perspective there is little difference between the Company's standard OL and SL offerings and the flexible lighting option. The main difference is that under the flexible lighting option customers have the opportunity to get their preferred, non-standard equipment while still paying for utility lighting service in a way they are accustomed.

<u>v. Time of Day Rate Design</u>

Q. PLEASE DESCRIBE THE REFINEMENT TO THE TIME OF DAY ("TOD") RATES THAT THE COMPANY IS PROPOSING.

A. Generally speaking, the Company has increased the amount of fixed cost collection included in off-peak rates, thus decreasing the rate differentials between on-peak and off-peak rates. This is appropriate because a growing amount of the Company's cost of service is comprised of fixed costs related to infrastructure investments. Additionally, market price signals for the marginal cost of energy have decreased and flattened out, and are estimated to remain lower and flat. By this I mean that the difference between on-peak and off-peak PJM locational marginal prices ("LMPs") has decreased as well as the total average LMP. Said another way the on-peak premium to off-peak prices has decreased as well as the total average level of LMPs over time. This declining difference further erodes the support for higher on-peak and off-peak rate differentials in the Company's TOD tariff offerings.

V. TARIFF CHANGES AND NEW OFFERINGS

i. Net Metering Service Tariff Changes

Q. PLEASE DESCRIBE THE PROPOSED CHANGES TO THE NET METERING SERVICE ("NMS") TARIFF.

A. The Company is proposing to close its current NMS tariff to all new customers as of January 1, 2021 and institute a new NMS tariff ("NMS II") that aligns with the changes in Kentucky law occasioned by SB 100 ("the Net Metering Act") that was enacted in 2019. The Net Metering Act, codified at KRS 278.465 to KRS 278.468 provides for the end of, or at least a drastic reduction in, the intra class subsidies the previous net metering statute produced. In order to accomplish those priorities of the Net Metering Act, the Company is proposing the following changes in its NMS II tariff:

1. A change in the netting periods applicable to the monthly billing for customers taking service under NMS II.
2. A change to the compensation rate paid for excess generation from customers' self-generation.
3. A change in the cost recovery of payments made for NMS II customers' excess self-generation.
4. A change to the application fee that reflects the cost of processing an NMS application.

Q. BEFORE YOU DISCUSS THE PROPOSED CHANGES TO THE NMS TARIFF, CAN YOU CLARIFY WHETHER OR NOT THE CHANGES WILL APPLY TO CURRENT CUSTOMERS TAKING SERVICE UNDER THE COMPANY'S NMS TARIFF?

A. The Company's proposed changes to the NMS tariff will only apply to customers whose eligible electric generating facility begins service after January 1, 2021. Existing NMS customers will continue their current service under the existing NMS I tariff. This proposal comports with the requirements of KRS 278 466 and is a reasonable outcome because current NMS customers made their investment decisions based on the old 1 to 1 net metering policy and the underlying economics. They thus will be grandfathered under the previous compensation regime for up to 25 years. This filing however should serve as notice to customers that the NMS tariff is changing and that a new compensation system will be in place for customers who choose to net meter in the future.

Q. PLEASE DESCRIBE THE COMPANY'S CHANGE TO THE NETTING PERIODS UNDER ITS PROPOSED TARIFF NMS II.

A. The Company is proposing two time of use ("TOU") netting periods, 8 AM to 6 PM and 6 PM to 8 AM, for each day of the year. All net kWh (and kW where applicable) usage (negative or positive) will be accumulated for each netting period for the billing period. If a customer's eligible generator produces more kWh than are consumed by the customer's load in a netting period for the billing period then the customer's eligible generator has produced excess generation which is referred to as "net negative energy" ("NNE") in proposed tariff NMS II. If a customer's load requirements (kWh usage) is greater than the kWh produced by its eligible generator during a netting period for the billing period then the customer has net positive billing energy and demand (where applicable).

Q. WHAT NET AMOUNTS OF BILLABLE ENERGY AND NNE DOES THE COMPANY EXPECT USING THE PROPOSED NETTING PERIODS FOR A TYPICAL RESIDENTIAL CUSTOMER THAT IS NET METERING?

A. The Company would expect a typical residential customer having a typical solar net metering installation to have approximately 639 kWh of billing energy and produce 783 kWh of excess generation in a billing period. I have calculated these amounts based on the test year average residential usage of 1,240kWh per month, the average load shape of the residential class, the average solar net metering installation size in the Company's service territory, and the solar generation shape that can be expected in eastern Kentucky.

Q. HOW ARE THE OTHER KWH OF USAGE TREATED?

A. In the above average customer example, the NMS II tariff billing for the month results in only 639 kWh of billing energy when we know that an average customer uses 1,240 kWh each month on average. The other 601 kWh of customer usage was netted by the customer's self-generation and is not being billed by the Company and thus receiving a credit equal to the full retail rate.

Q. PLEASE DESCRIBE THE CURRENT MAKEUP OF THE COMPANY'S NET METERING CUSTOMERS AND THEIR GENERATION SYSTEMS?

A. As of the end of the test year, the Company has 44 net metering customers, all of whom are using solar generation systems. Forty two of these are residential installations with an average installed capacity of 9.35 kW per system.

Q. WHAT RATES APPLY TO THE NET AMOUNTS OF BILLABLE ENERGY AND NNE UNDER THE COMPANY'S PROPOSED NMS II TARIFF?

A. Any net billing kWh or kW (where applicable) will be charged at the rates applicable under the standard service tariff the customer would otherwise be served absent the customer's generating facility. So a residential net metering customer will pay residential rates for net billing kWh.

All excess generation will be compensated at the dollar denominated avoided cost rate of 0.03659 $/kWh.

Q. HOW DID YOU CALCULATE THE AVOIDED COST RATE OF 0.03659 $/KWH?

A. I used the on-peak and off-peak avoided energy cost rates from the Company's Cogen-SPP tariff of .0306 $/kWh and .0228 $/kWh and weighted it 5/7th on-peak and 2/7th off-peak as a reasonable approximation of when solar generation actually occurs to arrive at an avoided energy price of .02837 $/kWh. These avoided energy price amounts are based upon PJM LMP forward pricing for the Kentucky Power load aggregate.

I then calculated the full fixed cost reduction value, as a load reducer, of the full solar generation shape. Said another way, I calculated the full value of a solar generator's output as if it were not netting a retail customer's load. I then discounted the full solar shape value to account for the fact that net metering installations are netting customer's load requirements some hours of the day. One could argue that the fixed cost reduction value should be discounted further or eliminated altogether because NMS II customers are still receiving full retail rates as compensation for netted usage during the netting periods. The residual unitized fixed cost reduction value of 0.00821 $/kWh is added to the avoided energy price of .02837 $/kWh to arrive at the total compensation rate of .03659 $/kWh. This calculation is included in Exhibit AEV-3.

Q. PLEASE DESCRIBE WHAT IS AND WHAT IS NOT INCLUDED IN THE AVOIDED COST RATE OF 0.03659 $/KWH?

A. The following items are included in the avoided cost rate because they are cost of service related:

- Avoided energy costs at the Company's marginal cost of energy, including marginal losses and congestion
- Distribution losses
- Avoided generation and transmission fixed costs

The following items are not included in the avoided cost rate nor are they cost of service items:

- The societal cost of carbon
- The value of customer generators' renewable energy credits ("RECs")
- Other externalities

For purposes of determining the dollar-denominated avoided cost rate for excess net metering customer generation the Company is only considering cost of service items for which the Company and its other non-net metering customers would see an actual cost reduction as a result of an NMS II customer's excess generation. The items discussed above that are not included are appropriately excluded because they do not pertain to the Company's cost of electric service, which is what its Kentucky retail jurisdictional rates are based upon. The REC value is specifically excluded because net metering customers either retain the RECs associated with their renewable self-generation or sell them to other entities to lower the cost of their renewable generation systems. It would be inappropriate for the avoided cost rate to compensate net metering customers a second time for their RECs, which are the legal entitlement to 1 MWh of renewable generation and all associated environmental attributes.

Q. HOW DOES THE COMPANY PROPOSE TO COLLECT THE AVOIDED COST PAYMENTS MADE TO CUSTOMERS UNDER TARIFF NMS II?

A. The Company proposes to collect from all customers the cost of these excess generation payments through its PPA tariff. In the alternative, it would also be appropriate to collect these costs through the Company's FAC as the payments are no different than other purchased power expenses.

Q. PLEASE DESCRIBE THE PROPOSED CHANGE TO THE NMS TARIFF APPLICATION FEE.

A. Proposed tariff NMS II includes higher application fee levels for both level 1 and level 2 net metering applications. Although the application fee levels are still not at full cost, they are closer to recovering the cost of these services than the previous charges were. NMS II also removes the $1,000 limit on level 2 system impact study costs if a study is deemed necessary for the proposed level 2 installation. Those studies require engineering expertise and can cost in excess of $10,000. Currently all costs in excess of $1,000 would be borne by the Company and its other customers, not the customer causing the cost.

Q. IS PROPOSED TARIFF NMS II FAIR, REASONABLE, COST BASED AND CONSISTENT WITH THE NET METERING ACT?

A. Yes it is. As I have discussed, the proposed netting periods will result in net positive billing units which will result in NMS II customers making a more appropriate fixed cost contribution towards the Company's cost of retail electric service that a net metering customer uses every day when their renewable self-generation is not producing at all or not producing enough generation to meet the customer's load requirements. Because all of the Company's current net metering customers are using solar systems, I can confidently say that they are using the Company's generation, transmission, and distribution infrastructure each and every day when the sun sets and they continue to have load requirements.

Tariff NMS provides for a dollar-denominated price for customers' excess generation and still allows 1 for 1 net metering within the TOU netting periods.

Proposed tariff NMS II is attached to my testimony as Exhibit AEV-4.

Q. IF THE COMPANY'S AMI PROPOSAL IS APPROVED WOULD YOU PROPOSE A CHANGE TO THE NETTING PERIOD IN NMS II IN A FUTURE CASE?

A. Yes. The Company's current metering infrastructure and billing system are not capable of netting energy on an hourly basis which would be the most exact solution for determining monthly billing energy and excess generation under tariff NMS II and could be accomplished with the AMI technology. In lieu of that capability, the netting periods proposed in NMS II in this case are appropriate for determining monthly billable energy and excess generation.

ii. Capacity Charge Tariff Changes

Q. PLEASE DESCRIBE THE COMPANY'S PROPOSAL REGARDING THE CAPACITY CHARGE TARIFF.

A. The Company is proposing to discontinue collection of its Capacity Charge tariff for the last two years of its existence (2021 and 2022) as a way to mitigate the rate increase in this case. The Company however is not willing to forego the collection of the $6.2 million[3] annually produced by the Capacity Charge if the Commission approves a rate increase in this case that is lower than that which the Company has requested in its application.

If the Company were to discontinue the Capacity Charge as a result of the outcome in this case, the Company proposes to include any remaining over or under collection Capacity Charge deferrals in the revenue requirement of its next annual update filing for the PPA tariff.

iii. Non-Utility Generator Tariff Changes

Q. PLEASE DESCRIBE THE PROPOSED CHANGES TO THE NON-UTILITY GENERATOR ("NUG") TARIFF.

A. The Company is proposing to close the NUG tariff to new customers as of January 1, 2021 and eliminate the commissioning and startup power provisions of the tariff as they are un-used by the single customer taking service under tariff NUG. Any new non-utility generator's load requirements would be served under the Company's standard industrial tariff.

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[3] 2021 Capacity Charge collection amount if not discontinued.

iv. <u>Proposed Changes to the Purchase Power Adjustment Rider</u>

Q. WHAT COST OF SERVICE ITEMS ARE CURRENTLY APPROVED FOR INCLUSION IN THE PURCHASE POWER ADJUSTMENT RIDER?

A. The Company's Purchase Power Adjustment Rider ("tariff PPA") currently authorizes the Company to recover through the monthly Purchase Power Adjustment factor the cost of (1) demand credits paid to CS-IRP customers for their commitment to interrupt service during PJM-initiated demand response events, (2) certain purchase power expenses that are not recoverable through the Company's fuel adjustment clause ("FAC"), (3) the cost of power purchased by the Company through new Purchase Power Agreements, (4) 80% of PJM LSE OATT charges above or below the base amount, and (5) costs associated with the Rockport Unit Power Agreement ("UPA") deferral that resulted from the Company's last rate case.

Q. IS THE COMPANY REQUESTING ADDITIONAL COST CATEGORIES FOR INCLUSION IN THE PURCHASE POWER ADJUSTMENT RIDER?

A. The Company is not requesting any new category of cost of service items to be included in the PPA, however it is requesting to recover avoided cost purchased power expense through the PPA. This would be payments made to qualifying facilities under the Company's approved COGEN/SPP tariffs and payments made to customer generators for excess generation under proposed tariff NMS II. Such payments are akin to purchased power expense included as item 3 in the above discussion.

The Company is also requesting to recover interruptible load credits paid to customers under its proposed new demand response peak shaving tariff DRS, as it does currently with the credits paid under tariff CS-IRP.

Finally, the Company is also proposing to increase the PJM LSE OATT charge recovery from 80% to 100%.

Q. WHY SHOULD THE COMPANY RECOVER 100% OF PJM LSE CHARGES THROUGH TARIFF PPA?

A. As the Company discussed in its previous base rate case, these PJM charges and credits are volatile and can have a significant financial impact on the Company. The annual level of such charges and credits can vary greatly from year to year and are largely out of the Company's control. Also, as the Company expected, PJM transmission owners have continued to increase their investment in the transmission grid. This increasing level of investment, which is necessary to maintain and improve the grid, will increase transmission charges allocated to LSEs in PJM, including Kentucky Power. The PJM LSE OATT charges are the Company's single largest growing expense;[4] without a full tracking mechanism for these costs allocated to the Company by a FERC approved rate schedule, the Company does not have an opportunity to earn its allowed ROE.

Q. ARE THERE ANY ADDITIONAL REASONS FOR INCLUDING 100% OF THE PJM OATT LSE CHARGES AND CREDITS IN A TRACKING MECHANISM?

A. Yes. During 2018 and 2019 customers benefited from the PPA tracking mechanism by receiving refund credits that resulted from the settlement in FERC docket number EL05-121 regarding the cost allocation methodology historically used by PJM to allocate the costs of transmission enhancement projects to the LSEs in PJM's footprint. Additionally, with the Company's proposal to defer the rate increase implementation in this case until January 1, 2022, 100% coverage of these FERC approved costs through the PPA is even

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[4] Fuel expense is larger in total but has been flat to decreasing in recent years.

more necessary as the level of PJM LSE OATT charges in base rates will be over 2 years old when the associated rates go into effect.

If the Company's proposed treatment of 100% of PJM LSE OATT charges and credits is approved, the Company would recover from customers only the actual amount of its cost incurred for wholesale transmission service, not a dollar less or more.

Q. WHAT IS THE PROPOSED LEVEL OF PJM LSE OATT CHARGES AND CREDITS TO BE INCLUDED IN BASE RATES?

A. The adjusted test year Kentucky retail jurisdictional total of net PJM LSE OATT charges and credits included in base rates is $96,896,495. This amount has grown from $74,377,364 in Case No. 2017-00179, and from $53,779,456 in Case No. 2014-00396. This single expense is now 16% of the Company's total proposed revenues.

Q. WHAT IS THE NEW TOTAL BASE RATE AMOUNT FOR TARIFF PPA ITEMS?

A. The new base rate amount for tariff PPA items is $98,165,699, the details of which can be seen in Exhibit AEV-5.

v. <u>Proposed Changes to the Federal Tax Cut ("FTC") Tariff</u>

Q. PLEASE DESCRIBE THE COMPANY'S PROPOSED CHANGES TO TARIFF FTC.

A. As a result of the Company's proposal to delay the implementation of the rate increase ordered in this proceeding to January 1, 2022 by funding the year one proposed increase in rates with an amortization of $48,334,936[5] of unprotected excess ADFIT, the current 18 year amortization of unprotected excess ADFIT through the FTC needs to be reevaluated. The Company's proposal is to freeze tariff FTC rate credits for 2021 at the same level, and

[5] Proposed total net revenue increase of $65,001,789 / ADFIT gross revenue conversion factor of 1.34482 = $48,334,936 amortization of excess unprotected ADFIT.

same rates, as 2020. The Company proposes to continue crediting customers with the actual annual amortizations of generation and distribution function protected excess ADFIT through the tariff FTC. The amount of unprotected excess ADFIT amortized in 2021 would be the appropriate amount needed to cover the difference between the annual rate credit produced by the FTC rates and the amount of generation and distribution function protected excess ADFIT amortized in 2021.

Beginning in 2022, a new level of the remaining unprotected excess ADFIT balance reflecting the outcome of this case could also be included in the FTC. A redlined version of proposed tariff FTC is attached to my testimony as Exhibit AEV-6.

vi. <u>Tariff CS-IRP and New Demand Response Service ("DRS") Offering</u>

Q. PLEASE DESCRIBE THE COMPANY'S CURRENT DEMAND RESPONSE OFFERING.

A. The Company currently offers a PJM capacity construct product for demand response ("DR") in the form of its tariff contract service interruptible power ("CS-IRP"). Under Tariff CS-IRP, a customer that is able to interrupt its operations can be a capacity resource in the Company's FRR plan. CS-IRP is an optional tariff for customers that meet the availability of service requirements.

The Company has a number of customers taking service under tariff CS-IRP.

Q. WHAT IS THE COMPANY'S PROPOSAL FOR ITS CURRENT DEMAND RESPONSE OFFERINGS?

A. The Company proposes to continue tariff CS-IRP, but eliminate the expiring special coal provision in tariff CS-IRP and to add a new option tariff DRS for customers. tariff DRS is designed to be a peak shaving tariff for the purpose of reducing the Company's cost causing peaks instead of a resource in the FRR plan.

Q. WHY IS THE COMPANY PROPOSING TO ELIMINATE THE SPECIAL COAL PROVISION IN TARIFF CS-IRP?

A. The special coal provision under CS-IRP served to shorten the minimum initial contract period from four to two years for coal companies. This provision has been difficult to manage operationally and is no longer necessary as the Company's new DRS tariff offering contains a one (1) year contract period for customers willing and able to interrupt their load requirements in return for demand-based bill credits.

Q. PLEASE EXPLAIN THE COMPANY'S PROPOSED NEW DRS TARIFF.

A. The Company's new tariff DRS offering would be similar in structure to the current offering but with new pricing, terms, and intended use. In exchange for agreeing to 60 annual hours of interruptions, a participating customer would receive a monthly interruptible demand credit. The Company will use the 60 hours in twenty 3-hour events at its sole discretion to reduce its 1, 5, and 12 coincident peaks. The penalty for not complying with a called interruption will be the progressive loss of the interruptible demand credit the customer would have received, which should encourage customers to interrupt when called.

Q. PLEASE EXPLAIN THE PRICING STRUCTURE OF PROPOSED TARIFF DRS.

A. Participating customers will receive an interruptible demand credit of $5.50/kW-month that will apply to their nominated interruptible demand reservation kW.[6] For example, a DRS participating customer that can interrupt 1,000 kW of load when called to do so would

[6] DRS interruptible capacity reservation will be the average on-peak kW above a customer's firm capacity over the previous 12 months.

receive a monthly bill credit of $5,500, or $66,000 annually if the customer interrupts when called on by the Company to do so.

Q. PLEASE FURTHER EXPLAIN THE PENALTY FOR FAILURE TO INTERRUPT UNDER PROPOSED TARIFF DRS.

A. The proposed penalty for failing to interrupt when called is an escalating repayment by the participating customer of its total annual discount. Included in the table below is the escalation schedule for failing to interrupt, as well as what the penalty payments would be for a hypothetical customer that is participating in optional tariff DRS and has an interruptible demand reservation of 1,000 kW, which means that the customer's annual DRS bill credit would equal $66,000.

Number of Failures	Penalty Payment %	Penalty Amount*	
Failure 1	5%	$	3,300
Failure 2	10%	$	6,600
Failure 3	10%	$	6,600
Failure 4	15%	$	9,900
Failure 5	15%	$	9,900
Failure 6	20%	$	13,200
Failure 7	25%	$	16,500
Totals	100%	$	66,000
***Based on a 1,000 kW interruptible capacity reservation**			

The first failure to interrupt is only charged back to the customer at 5% of its total annual interruptible credit, but the amount escalates with subsequent interruptions and ends with the 7th failure to interrupt (out of 20) as the tariff DRS customer has lost all of its annual interruptible credit.

Q. UNDER PROPOSED TARIFF DRS, WHAT CONSTITUTES A FAILURE TO INTERRUPT?

A. Participating customers will be expected to achieve at least 90% of their agreed upon interruptible capacity reservation during an event. For example, a participating customer with a 2,000 kW on-peak demand, 1,000 kW interruptible capacity reservation and a 1,000 kW firm service level would need to drop their load from whatever level they are using prior to a discretionary interruption to at least 1,100 kW for the duration of the event (3 hours) to not fail the event.

Q. PLEASE DISCUSS THE OTHER MAJOR TERMS OF PROPOSED TARIFF DRS.

A. The other major terms of proposed tariff DRS are as follows:

- Available to standard tariff customers able to provide a minimum of 500 kW of interruptible capacity which is defined as Customer's 12 month average on-peak demand, less Customer's chosen firm service level, equals at least 500 kW.
- Customers will contract to participate for at least 1 year.
- Participating customers commit to provide no more than 20 interruptions of 3 hours in length (60 annual hours) during each interruption year, which runs from June 1 to May 31 each year.
- Customers will be notified of an interruption event as far in advance as possible, but no later than 90 minutes prior to the start of the event.
- Customers will be notified through the Company's "web distribute" system, which will notify as many of a Customers' representatives as they wish through various communication channels.
- Customers will receive a monthly bill credit equal to their contracted amount of interruptible capacity in kW times the interruptible credit of $5.50/kW.
- Interval metering is required.
- Customers will complete and sign a tariff DRS Contract Addendum to participate in optional tariff DRS.

The Company's proposed changes to its DRS tariff, which includes all of the terms of the proposed offering, are also included in Exhibit AEV-7.

Q. CAN CUSTOMERS THAT CHOSE TO PARTICIPATE IN THE COMPANY'S PROPOSED TARIFF DRS ALSO PARTICIPATE IN PJM AS A DEMAND RESPONSE CAPACITY RESOURCE?

A. No, tariff DRS customers cannot also participate as a PJM demand response capacity resource. Customers cannot participate in PJM's DR capacity program because optional tariff DRS as proposed is designed to reduce the Company's cost causing peaks for PJM billing purposes and as such will reduce a Customer's peak load contribution eligible for PJM capacity credit (if participating in PJM as a DR resource). Thus, dual participation is not possible. Customers that choose to participate in tariff DRS will be compensated for their capacity value (as a load reduction, not a capacity resource) through the monthly interruptible demand credit they will receive.

Q. IF APPROVED BY THE COMMISSION, WILL ALL OF THE COMPANY'S CUSTOMERS BENEFIT FROM PROPOSED TARIFF DRS?

A. Yes, they will. Through successful tariff DRS participation, the Company will lower its generation and transmission cost of service, and all customers will benefit, not just those receiving the monthly interruptible credits under the tariff. Thus, the resulting cost of service benefits are greater than the tariff DRS credits being proposed by the Company as shown in Exhibit AEV-7.

Q. HOW DOES THE COMPANY PROPOSE TO RECOVER THE PROGRAM COSTS OF PROPOSED TARIFF DRS?

A. The Company is requesting that the Commission give the Company authority to defer the interruptible credits paid to participating tariff DRS customers and recover the combined amount of DRS and CS-IRP credits above the test year level of CS-IRP credits in the PPA tariff revenue requirement, as it does currently only for CS-IRP interruptible credits.

VI. GRID MODERNIZATION RIDER REVENUE REQUIREMENT, COST ALLOCATION, AND RATE DESIGN FOR THE PROPOSED AMI PROJECT

Q. PLEASE DESCRIBE YOUR CALCULATION OF THE PROPOSED GMR REVENUE REQUIREMENT.

A. I was given yearly AMI project capital and O&M estimates by Company Witness Blankenship and useful life assumptions by Company Witness West. I then modeled the estimated yearly revenue requirements for the proposed AMI project. For modeling purposes the estimated capital was identified as either meter plant capital (which includes communications equipment) or intangible capital (information technology/software) so that the correct depreciation and amortization rates[7] could be applied to the annual capital additions.

Included in my GMR revenue requirement calculations is a return on invested capital (net of accumulated depreciation and ADFIT), depreciation expense, O&M expense, and incremental property tax expense. The calculation of these items resulted in an estimated year 1 GMR revenue requirement for the proposed AMI project of $1,105,046. The entirety of the AMI project revenue requirement is assigned to the Kentucky retail jurisdiction, as there is no non-jurisdictional component. The calculation of this figure is shown in Exhibit AEV-8.

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[7] 15 years for meter plant and communications equipment and 5 years for intangible plant, as discussed by Company Witness West.

Q. HOW IS THE COMPANY PROPOSING TO ALLOCATE THE GMR AMI REVENUE REQUIREMENT AND RECOVER THOSE COSTS FROM CUSTOMERS IN RATES?

A. The Company is proposing to allocate the AMI project GMR revenue requirement to the classes using the meter plant allocator and to recover the class revenue requirements using a monthly charge. This is reasonable allocation and recovery proposal because this revenue requirement pertains solely to the cost of metering customers. The associated calculations and proposed rates are also included in Exhibit AEV-8.

Q. IS THE COMPANY PROPOSING THIS ALLOCATION AND RATE DESIGN FOR ALL GMR PROJECTS IN THE FUTURE?

A. No. The Company proposes to evaluate each future GMR project based on its specific costs to determine how those costs should be allocated to the customer classes and recovered through rates. All such proposals would be filed with the Commission for review and approval.

VII. ECONOMIC DEVELOPMENT RIDER PARTICIPATING CUSTOMER ANALYSIS

Q. HAVE YOU CONDUCTED A MARGINAL COST OF SERVICE ANALYSIS FOR THE COMPANY'S ECONOMIC DEVELOPMENT RIDER ("EDR") CUSTOMER AND WHAT ARE ITS RESULTS?

A. Yes. The marginal cost of service analysis shows that the Company's sole EDR customer is covering its variable cost of service and contributing the Company's fixed cost of service while taking service under the discounted EDR rates. This analysis is attached to my testimony as Exhibit AEV-9 that was filed with the Commission on March 31, 2020 in Case No. 2014-00336.

VIII. REVENUE AND OPERATING EXPENSE ADJUSTMENTS

Q. PLEASE IDENTIFY AND DISCUSS EACH OF THE REVENUE AND OPERATING EXPENSE ADJUSTMENTS THAT YOU ARE SPONSORING.

A. The details of the revenue and operating expense adjustments are set forth on various pages of Section V, Exhibit 2 to the application. Specifically, I am sponsoring the following adjustments:

Adjustment	Exhibit 2, Page No.
Adjustment to Remove Test Year Capacity Charge Revenues	W1
Remove Test Year FAC Revenue and Over/Under	W6
Adjust Test Year Off System Sales (“OSS”) Margins	W7
Adjust Firm Sales for Specific Customers	W12
Year End Number of Customers Annualization	W13
Adjust Firm Sales for Normal Weather	W14
Adjust PJM LSE OATT Expense to Going Level	W23
Adjust PJM Admin Fees to Going Level	W24
Adjust KPSC Maintenance Assessment	W38
Surcharge Book to Bill Adjustment	W43
Book to Bill Adjustment	W44
Adjust Test Year Rockport UPA Expense	W47
Adjust Test Year Capacity Performance Insurance Expense	W48
Remove Federal Tax Cut Rider Revenues	W59

Annualize End of Period Base Fuel Rates W63

Remove Rockport Capacity Charge Revenues
(Section V, Exhibit 2, W1)

Q. PLEASE EXPLAIN THE ADJUSTMENT YOU MADE TO THE TEST YEAR LEVEL OF SALES REVENUES.

A. In accordance with the Stipulation and Settlement Agreement approved by the Commission in Case No. 2004-00420, revenues associated with its Capacity Charge tariff ("tariff C.C.") are not to be used when designing rates in a general rate case proceeding. Accordingly, the Company has removed $6,200,000 in revenues received through tariff C.C. or booked as accounting deferrals from its test year revenue amounts.

Remove Fuel Adjustment Clause Revenues and Over/Under
(Section V, Exhibit 2, W6)

Q. PLEASE EXPLAIN THE ADJUSTMENT YOU MADE TO THE TEST YEAR LEVEL OF SALES REVENUES AND FUEL EXPENSE.

A. There are three distinct items in the Company's cost of service related to fuel:

1. Fuel revenues, base and FAC;
2. Fuel expense; and
3. Deferred fuel expense.

Adjustment 6 removes the test year FAC revenues from the cost of service and synchronizes the remaining level of base fuel revenue, fuel expense, and deferred fuel expense so that total fuel expense and fuel revenue is equal in the cost of service and does not impact base rate net income for purposes of calculating the revenue requirement increase. The FAC revenues were removed so that various adjustments to retail billing units did not have to include a change in FAC revenues. The net impact of this adjustment is a decrease in fuel expense of $381,757.

<u>Reset Off System Sales (OSS) Margins Baseline</u>
<u>(Section V, Exhibit 2, W7)</u>

Q. PLEASE EXPLAIN THE ADJUSTMENT YOU MADE TO TEST YEAR OSS MARGINS.

A. The purpose of this adjustment is to include in the base rate cost of service only the test year level of OSS margins. The test year amount of OSS margins is $7,343,330, and this is the amount that the Company proposes to include as the new base credit that will be tracked through the System Sales Clause.

Q. HOW WAS THIS ADJUSTMENT CALCULATED?

A. To adjust the base rate cost of service so that it only reflects the test year amount of OSS margins, two items must be accounted for:

1. System Sales Clause retail revenues; and
2. The deferral related to the System Sales Clause.

During the test year, the System Sales Clause collected $1,418,449 from customers because actual OSS margins were less than the amount included in base rates. This $1.4 million of retail revenues were removed from the base rate cost of service as part of Adjustment W7. During the test year, an accounting deferral relating to the System Sales Clause was recorded on the Company's books in the amount of 1,109,363. This amount was reversed as part of this adjustment to remove the test year deferral's effect on the base rate cost of service.

The net effect of these two items in Adjustment W7 is a $309,086 decrease to the base rate cost of service and re-sets the base rate OSS margin credit level to $7,343,330.

Adjust Firm Sales for Specific Customers
(Section V, Exhibit 2, W12)

Q. PLEASE EXPLAIN THE ADJUSTMENT YOU MADE TO TEST YEAR FIRM SALES REVENUE.

A. The purpose of the specific customer adjustment is to account for the effects on firm revenues of specific larger customers either materially decreasing or increasing their operations and load during or after the test year.

Q. HOW IS THE SPECIFIC CUSTOMER ADJUSTMENT CALCULATED?

A. To calculate this adjustment the test year billing units were quantified for all customer accounts identified by the Company's customer service team that manages these larger accounts. The test year billing units are then adjusted accordingly for each customer's specific circumstance. For instance, some of the accounts identified ceased operations entirely so their billing units were removed from the adjusted test year billing analysis, some customers reduced or increased their operations so their test year billing units were adjusted down or up. In addition to the impact on firm sales revenue, the specific customer adjustment reflects a change in variable operating expense that would also change based on load growth or decline. The specific customer adjustment reduces firm sales revenues by $9,504,100 and reduces operation and maintenance expense by $6,412,416.

Year-End Number of Customers Annualization
(Section V, Exhibit 2, W13)

Q. PLEASE EXPLAIN THE ADJUSTMENT YOU MADE TO TEST YEAR FIRM SALES REVENUE.

A. The purpose of the year-end customer annualization adjustment is to restate test year revenues and expenses to reflect, on an annual basis, changes in customers that occurred during the test year. For example, if the number of residential customers increased during the test year, per books residential kWh sales would have to be increased to reflect the impact of annualizing load growth that occurred within the test year. In addition to the revenue adjustment, test year variable operating expenses would also have to be increased or decreased to reflect the incremental costs associated with annualizing test year load growth or decline.

Q. HOW IS THE YEAR-END CUSTOMER ANNUALIZATION ADJUSTMENT CALCULATED?

A. The year-end customer annualization adjustment begins with the number of customers in each tariff class at the end of the historic test year and adds or subtracts usage from the test year amounts by the average amount of usage per customer. These adjusted billing units then calculate the new adjusted firm sales revenues for the various tariffs.

To ensure that the customer annualization adjustment reflects only actual customer growth or decline, the impact of the specific customer adjustments has been eliminated by starting with the data adjusted for the specific customer adjustment.

In addition to the impact on firm sales revenue, the year-end customer annualization adjustment reflects a change in variable operating expense that would also change based on load growth or decline. The year-end customer annualization adjustment reduces firm sales revenues by $14,546,115 and reduces operation and maintenance expense by $9,814,264.

<u>Adjust Firm Sales for Normal Weather</u>
<u>(Section V, Exhibit 2, W14)</u>

Q. PLEASE DESCRIBE THE WEATHER NORMALIZATION ADJUSTMENT.

A. The purpose of the weather normalization adjustment is to restate test year revenues and expenses to reflect a 30-year average load for weather sensitive customers compared to the weather experienced during the test year. The Company bases its weather normalization on deviations from normal in both heating and cooling degree-days.

Using data provided by the Company's Economic Forecasting Group, the adjustment was calculated to increase test year energy usage to the level of the 30-year average. The result of this adjustment was to increase total usage by approximately 43.4 million kilowatt-hours and increase revenues by $4,254,356. The weather normalization adjustment also reflects the change in variable operating expense that the Company would experience based on this positive adjustment to test year load. Accordingly, this adjustment increases operation and maintenance expense by $2,870,414.

<u>Adjust Test Year PJM LSE OATT Expense to Going Level</u>
<u>(Section V, Exhibit 2, W23)</u>

Q. PLEASE EXPLAIN THE ADJUSTMENT YOU MADE TO THE TEST YEAR LEVEL OF PJM LSE OATT EXPENSE.

A. The FERC-approved OATT includes rates and billing units that are different in 2020 than they were in 2019. I adjusted test year PJM LSE OATT expense to account for these differences. This adjustment increases the Kentucky retail jurisdiction base rate cost of service by $14,299,049 for a total adjusted test year OATT LSE expense level of $96,896,495.

Adjust PJM Admin Fees to Going Level
(Section V, Exhibit 2, W24)

Q. PLEASE EXPLAIN THE ADJUSTMENT YOU MADE TO THE TEST YEAR LEVEL OF PJM ADMINISTRATION FEE EXPENSE.

A. This adjustment annualizes test year PJM administrative fee expense and accounts for the FERC-approved[8] 2.5% increase in PJM administrative fees from the 2020 level. This adjustment increases the Kentucky retail jurisdiction base rate cost of service by $208,436.

KPSC Maintenance Fee Adjustment
(Section V, Exhibit 2, W38)

Q. PLEASE EXPLAIN THE ADJUSTMENT YOU MADE TO THE TEST YEAR LEVEL OF OTHER TAX EXPENSE.

A. This adjustment simply adjusts the test year amount of KPSC maintenance fee expense in the cost of service to the current assessment amount. The result is a $5,435 increase to test year other tax expense.

Surcharge Book to Bill Adjustment
(Section V, Exhibit 2, W43)

Q. PLEASE EXPLAIN THE ADJUSTMENT YOU MADE TO THE TEST YEAR LEVEL OF SALES REVENUES.

A. This adjustment accounts for the difference between the cost of service adjustments that remove various surcharges from the test year sales revenues and the billing analysis for the same surcharges. This adjustment reduces firm sales revenues by $214,197.

[8] FERC Docket No. ER17-249-000.

Book to Bill Adjustment
(Section V, Exhibit 2, W44)

Q. PLEASE EXPLAIN THE ADJUSTMENT YOU MADE TO THE TEST YEAR LEVEL OF SALES REVENUES.

A. This adjustment compares the test year billing analysis for firm sales revenue and compares it to the test year income statement (books) level of firm sales revenue and adjusts the cost of service to the level supported by the billing analysis. In the sequence of revenue adjustments related to billing units, the book to bill adjustment is computed first and utilizes unadjusted test year billing units. This adjustment increases test year firm sales revenue by $630,046.

Adjust Rockport UPA Demand Expense
(Section V, Exhibit 2, W47)

Q. PLEASE EXPLAIN THE ADJUSTMENT YOU MADE TO TEST YEAR BASE RATE PURCHASE POWER EXPENSE RELATED TO THE ROCKPORT UPA.

A. This adjustment was made to account for a known and measurable change to the test year Rockport UPA billing to the Company. The Rockport UPA billing formula includes a component known as the operating ratio which adjusts how much of the total Rockport capital investment is included in the equity return calculation. The operating ratio is the percentage of the Rockport capital investment that is in service; it essentially reduces the equity return billed through the agreement when there is a construction work in progress ("CWIP") balance. During the test year there was a large CWIP balance due to the Rockport Unit 2 selective catalytic reduction ("SCR") facility construction that materially lowered the amount of equity return that was billed through the UPA to the Company. The unit 2 SCR was placed in service in early June 2020. The operating ratio thus will increase to normal levels because the related CWIP has been moved to plant in service. There are no other large construction projects planned for the Rockport plant, thus the return to a higher, more normal level of operating ratio included in the monthly billing is known to occur. This adjustment increased base rate purchased power expense by $1,695,513.

Adjust Test Year Capacity Performance Insurance Premiums to Going Level (Section V, Exhibit 2, W48)

Q. PLEASE EXPLAIN THE ADJUSTMENT YOU MADE TO TEST YEAR INSURANCE EXPENSE RELATED TO CAPACITY PERFORMANCE.

A. This adjustment increases the base rate cost of service by $51,527 to account for two months of capacity performance insurance premiums that were not in the test year but will be in the Company's costs going forward. The Company, along with the other AEP fixed resource requirement ("FRR") companies share in an insurance policy that indemnifies the companies, including KPCo, up to a certain level against PJM capacity performance charges. Capacity performance is a PJM construct that first applied to the Company's FRR capacity obligations in the 2019/2020 deliver year, which began on June 1, 2019. Under the capacity performance construct, costly charges can be incurred for generating unit non- or under-performance during specific performance intervals that are determined at PJM's sole discretion. The AEP companies have secured a low cost insurance policy in order to prudently manage the potentially costly charges that could result from PJM capacity performance interval non-compliance.

Q. HOW DID YOU CALCULATE THIS ADJUSTMENT?

A. The Company's test year included 10 months of the insurance policy premiums. I simply added in two more months of policy premiums through this adjustment to get to the annualized and on-going level of insurance expense.

Remove Federal Tax Cut Rider Revenues
(Section V, Exhibit 2, W59)

Q. PLEASE EXPLAIN THE ADJUSTMENT YOU MADE TO THE TEST YEAR LEVEL OF SALES REVENUES.

A. Test year revenue credits resulting from the FTC rider are included in firm sales and need to be removed in order to arrive at the correct level of adjusted base rate revenues which are the subject of this case. The removal of the test year FTC rate credits increases firm sales revenue by $9,739,267.

Annualize End of Period Base Fuel Rates
(Section V, Exhibit 2, W63)

Q. PLEASE EXPLAIN THE ADJUSTMENT YOU MADE TO THE TEST YEAR LEVEL OF SALES REVENUES AND FUEL EXPENSE.

A. The Company's base fuel rate changed during the test year. This adjustment annualizes the amount of base fuel revenue as if the end of period base fuel rates had been in effect for the entire test year. An equal and offsetting amount of fuel expense is also included in this adjustment so the net effect on the base rate cost of service level of net income is $0. Even though there is a net $0 effect on the base rate cost of service, this adjustment is necessary to ensure that the correct amount of base fuel revenue and expense is reflected in the adjusted cost of service for rate design purposes.

Q. DOES THIS CONCLUDE YOUR PRE-FILED DIRECT TESTIMONY?

A. Yes, it does.

Exhibit AEV -1
Base Rate Revenue Target Summary
KPCo Kentucky Retail Jurisdiction

	Total Retail	RS	Total GS	Total LGS	Total IGS	Total PS	MW	OL	SL
From CCOS									
Demand	$ 256,316,014	$ 116,564,708	$ 37,728,137	$ 25,412,926	$ 69,704,043	$ 6,263,544	$ 88,292	$ 454,840	$ 99,524
Energy	$ 156,851,436	$ 65,087,602	$ 19,169,635	$ 14,256,698	$ 53,176,993	$ 3,430,460	$ 61,150	$ 1,379,768	$ 289,130
Dist Primary	$ 74,599,754	$ 42,886,747	$ 14,793,757	$ 9,466,288	$ 5,011,413	$ 2,407,330	$ 34,219	$ -	$ -
Dist Secondary	$ 31,490,216	$ 20,643,519	$ 6,281,958	$ 2,993,153	$ 110,774	$ 901,534	$ 11,805	$ 447,270	$ 100,202
Customer	$ 26,750,170	$ 13,525,407	$ 4,788,753	$ 480,326	$ 253,870	$ 65,527	$ 6,583	$ 6,532,461	$ 1,097,243
TOTAL	$ 546,007,590	$ 258,707,983	$ 82,762,240	$ 52,609,391	$ 128,257,094	$ 13,068,396	$ 202,048	$ 8,814,339	$ 1,586,099
Adjustments									
Unbilled	$ 1,117,539	$ 899,657	$ 291,044	$ 99,828	$ (67,302)	$ 47,888	$ 1,214	$ (153,180)	$ (1,610)
D	$ 789,610	$ 577,301.82	$ 193,104	$ 63,702	$ (37,769)	$ 30,942	$ 717.24	$ (37,976.70)	$ (412.28)
E	$ 327,929	$ 322,354.78	$ 97,940	$ 36,126	$ (29,533)	$ 16,946	$ 496.76	$ (115,203.30)	$ (1,197.72)
Base Rate Revenue Targets									
Demand	$ 256,316,014	$ 115,987,406	$ 37,535,033	$ 25,349,224	$ 69,741,811	$ 6,232,603	$ 87,574	$ 492,817	$ 99,936
Energy	$ 155,733,897	$ 64,765,247	$ 19,071,695	$ 14,220,572	$ 53,206,527	$ 3,413,514	$ 60,653	$ 1,494,972	$ 290,328
Dist Primary	$ 74,599,754	$ 42,886,747	$ 14,793,757	$ 9,466,288	$ 5,011,413	$ 2,407,330	$ 34,219	$ -	$ -
Dist Secondary	$ 31,490,216	$ 20,643,519	$ 6,281,958	$ 2,993,153	$ 110,774	$ 901,534	$ 11,805	$ 447,270	$ 100,202
Customer	$ 26,750,170	$ 13,525,407	$ 4,788,753	$ 480,326	$ 253,870	$ 65,527	$ 6,583	$ 6,532,461	$ 1,097,243
	$ 544,890,051	$ 257,808,327	$ 82,471,196	$ 52,509,563	$ 128,324,396	$ 13,020,508	$ 200,834	$ 8,967,519	$ 1,587,709

I. Proposed Revenue

	Billed & Accrued Revenue	Fuel Revenue	Base Revenue	
Total RS Revenue Requirement				
Demand	179,517,673	$0	$179,517,673	q
Energy	64,765,247	0	$64,765,247	
Customer	13,525,407	0	$13,525,407	
Total	$257,808,327	$0	$257,808,327	

II. Customer Charge

	Proposed Customer Charge		=	**$17.50** /mo.	
Proposed Customer Charge Revenue	1,603,152	x	$17.50	=	$28,055,160

III. Off-Peak Energy Charge

Energy Revenue Requirement	$64,765,247				
Total Energy (kWh)	1,992,407,328				
Total Secondary Energy Charge	$0.03251 /kWh				
Fixed Cost Adder	$0.05000 /kWh				
Proposed Off-Peak Energy Charge	$0.08251 /kWh				
Off-Peak % Usage	56.18%				
Off-Peak kWh Energy	1,119,334,437				
Off-Peak Revenue	1,119,334,437	x	$0.08251	=	$92,356,284

IV. On-Peak Energy Charge

Total RS Base Revenue	$257,808,327
Less: Customer Revenue	28,055,160
Less: Off-Peak Energy Revenue	92,356,284
On-Peak Revenue	$137,396,883
Total RS Energy	1,992,407,328
Less: Off-Peak kWh Energy	1,119,334,437
On-Peak kWh Energy	873,072,891
Proposed On-Peak Energy Charge	$0.15737 /kWh

V. Revenue Verification

	Units	Rate	Revenue	Difference	Current R
On-Peak	873,072,891 kWh	$0.15737 /kWh	$137,395,481		0.136
Off-Peak	1,119,334,437 kWh	$0.08251 /kWh	92,356,284		0.05094
Customer	1,603,152 Bills	$17.50 /Mo.	28,055,160		
Total	1,992,407,328 kWh		$257,806,925	(1,402)	

VI. Time-of-Day Customer Charges

Current TOD Charge	$16.00			
Proposed Standard Charge	$17.50		Separate Meter Charge	
Actual Differential:				
TOD Meter Cost	$367.32		$367.32	
Standard Meter Cost	$108.50			
Cost Differential	$258.82		$367.32	
Carrying Cost	14.07%		14.07%	15 Year Annual Investment CC
Over 12 Months	12		12	
Differential	$3.04		$4.31	
Proposed RS-TOD/RS-LM-TOD/ RS TOD 2	$21.00		$4.30	
Separate Meter Customer Charge:		Current	$3.75	
		Use:	$4.30	

VII. RS-TOD / RS-LM-TOD Proposed Revenue

	Units	Rate	Revenue
On-Peak	1,200,172 kWh	$0.15737 /kWh	$188,871
Off-Peak	1,975,538 kWh	$0.08251 /kWh	163,002
Customer - Std TOD	1,896 Bills	$21.00 /Mo.	39,816
Customer - Sep Meter	95 Bills	$4.30 /Mo.	407
Total	3,175,711 kWh		$392,096

VIII. Customer Revenue

Customer Charge Revenue	1,603,152	Bills	x	$17.50 /mo.	=	$28,055,160

IX. Standard Energy Rates

Storage Water Heating Revenue	246,977	kWh	x	$0.08251 /kWh (Off-Pk) =	$20,378

Adjusted Base Revenue	257,808,327
Less RS-TOD/RS-LM-TOD Revenue	392,096
Less: Customer Revenue	28,055,160
Less: Storage Water Htg Revenue	20,378
Add Winter Tail Block Discount	14,605,655
Energy Charge Revenue - All Blocks	$243,946,348
All kWh	1,988,984,640
Standard Energy Rate - All kWh	$0.12265 /kWh

Winter Tail block

>1100 kWh Dec-Feb	243,427,590
Block Discount	-0.06
Discount	(14,605,655)

X. RS Revenue Verification

	Units	Rate	Revenue	Difference
All Standard kWh	1,745,557,050 kWh	$0.12265 /kWh	$214,092,572	
Winter Heating Block	243,427,590	$0.06265	$15,250,739	
Storage Water Heating	246,977 kWh	$0.08251 /kWh	20,378	
Customer	1,603,152 Bills	$17.50 /mo.	28,055,160	
Total	1,989,231,617 kWh	Proof	$257,418,849	
		Standard Target	$257,416,231	
		Difference	-$2,618	

*Revised after revenue verification

XIV. Residential Summary

Schedule	Bills	kWh	Revenue	Difference
RS	1,603,152	1,989,231,617	$257,418,849	
RS-TOD / RS LMTOD	1,991	3,175,711	392,096	
Total Billed	1,605,143	1,992,407,328	$257,810,945	$2,618

Optional Residential Demand Rate

Revenue Targets		
Distribution Primary	$	42,886,747
Distribution Secondary	$	20,643,519
Prod and Trans Demand	$	115,987,406
Energy	$	64,765,247
Customer	$	13,525,407
Total	$	257,808,327

RS-D Billing Units	
On Peak kWh	267,248,588
Off Peak Energy	1,725,158,740
Total kWh	1,992,407,328
Total On-Peak Billing Demand	10,379,140
Total Bills	1,603,152

RS-D Rates		
On Peak Energy Charge	**0.14374**	$/kWh
Off Peak Energy Charge	**0.08251**	$/kWh
On-Peak Demand Charge	**4.18**	$/kW
Customer Charge	**21.00**	$/customer/month

Revenue Verification	**Units**	**Rates**	**Revenue**	
On Peak Energy Charge	267,248,588	0.14374	$	38,414,312
Off Peak Energy Charge	1,725,158,740	0.08251	$	142,342,848
On-Peak Demand Charge per kW	10,379,140	4.18	$	43,384,805
Customer Charge	1,603,152	21.00	$	33,666,192
			$	257,808,157
			$	(170)

I. Proposed Revenue

	Total (1)	Production (2)	All Other (3) = (1) - (2)
Demand	179,517,673	$116,564,708	$62,952,965
Energy	64,765,247	$0	$64,765,247
Customer	13,525,407	$0	$13,525,407
Total	$257,808,327	$116,564,708	$141,243,619

III. Basic Energy Charge Rate Design

All Other Revenue	$257,808,327
Less: Customer Charge Revenue - STD	$28,055,160
Customer Charge Revenue - TOD	$40,223
add block diff	$160,409,292
Basic Energy Revenue	$390,122,236
Total kWh	1,992,407,328
Summer Energy	$0.195804
Winter	$0.170834
other	$0.098164

IV. Variable Energy Charge Rate Design

	Market Generation (Excluding Losses)					
	Seasonal Weighting (1)	Capacity (2)	Total (3) = (1) + (2)	Production Charge (4) on (3)	kWh (5)	Variable Energy Charge (6) = (4) / (5)
Summer	1	5,272,909	5,272,910	$34,130,147	148,589,309	$0.229694
Winter	1	9,386,067	9,386,068	$60,753,522	270,002,747	$0.225011
Other	1	3,349,594	3,349,595	$21,681,039	1,573,815,272	$0.013776
	3	18,008,570	18,008,573	$116,564,708	1,992,407,328	
			Percentage:	647.27%		

summer	148,589,309	0	
winter	270,002,747	0.02497	$ 6,741,969

other	1,573,815,272	0.09764	$	153,667,323

V. Energy Base Rate Total

	Basic Energy Charge (1)	Variable Energy Charge (2)	Subtotal (3) = (1) + (2)	Fuel Adjustment (4)	Base Rate (5) = (3) - (4)
Summer	$0.195804	$0.229694	$0.425498	$0.0004515	$0.42505
Winter	$0.195804	$0.225011	$0.420815	$0.0004515	$0.42036
Other	$0.195804	$0.013776	$0.209580	$0.0004515	$0.20913

VI. Revenue Verification

	Units (1)		Rate (2)	Revenue (3) = (1) x (2)		
Customer Charge - STD	1,603,152	Bills	$17.50	$28,055,160		
Customer Charge - TOD	1,896	Bills	$21.00	$39,816		
Customer Charge - TOD - Sep Meter	95	Bills	$4.30	$407		
Summer	148,589,309	kWh	$0.19580	$29,094,381	0.18005	
Winter	270,002,747	kWh	$0.17083	$46,125,649	0.15508	0.02497
Other	1,573,815,272	kWh	$0.09816	$154,492,002	0.08241	0.09764
Fuel	1,992,407,328	kWh	$0.0000000	$0		
				$257,807,415	$257,808,327	($912)

* Revised after revenue verification

SGS TOD Rate Design

I. Proposed Revenue

	Total (1)	Production (2)	All Other (3) = (1) - (2)
Demand	$57,868,766	$36,985,161	$20,883,605
Energy	$18,768,157	$0	$18,768,157
Customer	$4,521,729	$0	$4,521,729
Total	$81,158,652	$36,985,161	$44,173,492

II. Incremental Meter Charge Rate Design

Annual Incremental Meter Charge		Months		Carrying Charge		Incremental Customer Charge		Plus Standard		Proposed Customer Charge
$0.00	/	12	x	10.95%	=	$0.00	+	$25.00	=	$25.00

III. Basic Energy Charge Rate Design

All Other Revenue			$81,158,652
Less: Customer Charge Revenue - STD			$8,787,300
Customer Charge Revenue - LM-TOD			$21,900
Customer Charge Revenue - NM			$248,580
Customer Charge Revenue - TOD			$147,300
Add Block Diff			$54,175,562
Basic Energy Charge			$126,129,134
Total kWh			587,310,967
Summer			$0.214757
Winter			$0.188017
Other			$0.119087
summer	10,521,888		
winter	14,592,325	$	390,199
other	562,196,754	$	53,785,363

IV. Variable Energy Charge Rate Design

	Market Generation (Excl. Losses)					
	RT LMP	Capacity	Total	Production Charge	kWh	Variable Energy Charge
	(1)	(2)	(3) = (1) + (2)	(4) on (3)	(5)	(6) = (4) / (5)
Summer	477,085	340,330	817,414	$6,147,797	10,521,888	$0.584286
Winter	453,464	463,071	916,535	$6,893,291	14,592,325	$0.472392
Other	2,953,837	229,779	3,183,616	$23,944,073	562,196,754	$0.042590
	3,884,386	1,033,180	4,917,566	$36,985,161	587,310,967	
			Percentage:	752.10%		

V. Energy Base Rate Total

	Basic Energy Charge	Variable Energy Charge	Subtotal	Fuel Adjustment	Base Rate
	(1)	(2)	(3) = (1) + (2)	(4)	(5) = (3) - (4)
Summer	$0.214757	$0.584286	$0.799043	$0.0004515	$0.79859
Winter	$0.214757	$0.472392	$0.687149	$0.0004515	$0.68670
Other	$0.214757	$0.042590	$0.257347	$0.0004515	$0.25690

VI. Revenue Verification

	Units		Rate	Billing		
	(1)		(2)	(3) = (1) x (2)		
Customer Charge - STD	351,492	Bills	$25.00	$8,787,300		
Customer Charge - LM-TOD	876	Bills	$25.00	$21,900		
Customer Charge - NM	16,572	Bills	$15.00	$248,580		
Customer Charge - TOD	5,892	Bills	$25.00	$147,300		
Summer	10,521,888	kWh	$0.21476	$2,259,649		
Winter	14,592,325	kWh	$0.18802	$2,743,605		
Other	562,196,754	kWh	$0.11909	$66,950,325		
Fuel	587,310,967	kWh	$0.0000000	$0		
				$81,158,659	$81,158,652	$7

* Revised after revenue verification

VII. Revenue From Exisiting SGS-TOD Customers

	Units	Rate	Billing	Current	
SGS-TOD					
Summer	576,857	$0.21476	$123,884	0.172380	
Winter	626,447	$0.18802	$117,783	0.145640	0.026740
Other	6,791,271	$0.11909	$808,752	0.076710	0.095670
Customer	5,892	$25.00	$147,300		
Total			$1,197,719		

GS Secondary for TOD/LMTOD/AF Calcs

I. Proposed Revenue

	Billed & Accrued Revenue	Fuel Revenue	Billed & Accrued Revenue Excld Fuel	Base Revenue
Demand	$57,868,766	$0	$57,868,766	$57,868,766
Energy	18,768,157	0	$18,768,157	18,768,157
Customer	4,521,729	0	$4,521,729	4,521,729
Total	$81,158,652	$0	$81,158,652	$81,158,652

II. Non-Metered Customer Charge

Meter Plant (370)	$8,509,957	Customer Base Revenue	$4,521,729
Net Plant/Gross Plant Percentage	64.75%	Less: Meter Plant Revenue	732,710
Depreciated Meter Plant	5,510,197	Meter O&M Expense (586 & 597)	438,552
Return on Rate Base - Class Proposed	9.83%	Meter Reading Expense (902)	130,923
Income	541,652	Adj. Customer Revenue	3,219,544
GRCF	1.352731	/ Bills	374,832
Meter Plant Revenue	732,710	Calculated Non-Metered Customer Charge	8.59
		Current	$14.00
		Use:	$15.00

III. Standard Customer Charge

Customer Revenue	$4,521,729						
Less: Non-Metered Customer Rev.	248,580						
Residual Customer Revenue	$4,273,149	/	351,492	Bills	=	$12.16	/mo.
				Current	=	$22.50	/mo.
				Use:		$25.00	/mo.
GS Sec			342,480				
SGS TOD			5892				
GS AF			1020				
MGS TOD			1224				
GS LMTOD			876				
Standard	$25.00	x	351,492	Bills	=	$8,787,300	
GS Non-Metered	$15.00	x	16,572	Bills	=	$248,580	

IV. Energy Charges

Current

Rate

Revenue Requirement	$81,158,652
Less: Standard Customer Revenue	8,787,300
Less: Non-Metered Customer Revenue	248,580
	$72,122,772

GS Sec Standard Energy	560,314,303
SGS TOD	7,994,574
GS AF	1,280,317
MGS TOD	4,013,593
GS LMTOD	1,115,843
GS NM	3,481,919
Total GS Sec Energy	578,200,550

Avg Secondary Rate	$72,122,772	/	578,200,550	=	$0.12474

V. Revenue Verification

	Units		Rate		Revenue	Difference	
							current rates
Energy - First 500 kWh	61,576,549	kWh	$0.00000	/kWh	$0		0.11711
- Over 500 kWh	69,783,638	kWh	$0.12474	/kWh	$8,704,811		0.07267
Standard Customer	351,492	Bills	$25.00	/mo	8,787,300		17.5
Non-Metered Customer	16,572	Bills	$15.00	/mo	248,580		13.5
Total Base Revenue					$17,740,691	($63,417,961)	

* Revised after revenue verification

VI. Off-Peak Energy Charge

Energy Revenue Requirement	$18,768,157	/	578,200,550 kwh	$0.03246
Fixed Cost Adder				0.05000
Calculated Off-Peak Energy Charge				$0.08246
Use				$0.08246
Off-Peak % Usage				50.92%
Off-Peak kWh				294,419,720
Off-Peak Revenue				$24,277,850

VII. On-Peak Energy Charge

Total GS Sec Base Revenue	$81,158,652
Less: Standard Customer Revenue	8,787,300
Non-Metered Customer Revenue	248,580
Time-of-Day Off-Peak Revenue	24,277,850
On-Peak Revenue	$47,844,922
On-Peak kWh Energy	283,780,830
Proposed On-Peak Energy Charge	$0.16860 /kWh

VIII. Secondary Revenue Verification

	Units		Rate	Revenue	Difference
On-Peak	283,780,830	kWh	$0.16860	$47,845,448	
Off-Peak	294,419,720	kWh	$0.08246	24,277,850	
Standard Customer	351,492	Bills	$25.00	8,787,300	
Non-Metered Customer	16,572	Bills	$15.00	248,580	
Total Base Revenue				$81,159,178	$526

*Revised after revenue verification.

IX. Revenue From Existing TOD Customers

	Units	Rate	Proposed Revenue	Current Rates
GS-LM TOD				
On-Peak Energy	428,234	$0.16860	72,200	0.1462
Off-Peak Energy	687,609	$0.08246	56,700	0.06212
Customer	876	$25.00	21,900	22.5
Total			$150,800	
MGS TOD				
On-Peak Energy	1,593,203	$0.16860	268,614	0.16888
Off-Peak Energy	2,420,390	$0.08246	199,585	0.06212

Customer	1,224	$25.00	30,600	22.5
Total			$498,799	

General Service (GS)

I. Proposed Revenue

	Secondary	Primary	Subtran	Trans	Total
Proposed Base Revenue					
Demand	$57,868,766	$677,583	$64,399		
Energy	$18,768,157	$256,123	$47,415		
Customer	$4,521,729	$232,025	$34,999		
	$81,158,652	$1,165,730	$146,814		$82,471,196
Fuel Revenue	$0	$0	$0		
Total Base Revenue	$81,158,652	$1,165,730	$146,814		$82,471,196

Secondary Tariff Provisions Base Rev

Less	SGS TOD	$1,197,719
Less	MGS TOD	$498,799
Less	GS LMTOD	$150,800
Less	Rec Lighting	$172,404
		$2,019,722

Standard GS Base Revenue Targets

	Secondary	Primary	Subtran
Demand	$56,428,638	$677,583	$64,399
Energy	$18,301,091	$256,123	$47,415
Customer	$4,409,201	$232,025	$34,999
	$79,138,931	$1,165,730	$146,814

II. Billing Determinant Summary

	Secondary	Primary	Subtran
Standard Service Charge	342,480	900	72
Non-Metered Service Charge	16,572		
First 4450 kWh	355,482,505	2,550,907	305,866
Over 4450 kWh	204,831,799	5,565,510	838,000
Total kWh	560,314,303	8,116,417	1,143,867
Billing Demand Greater Than 10 kW	1,092,917	20,871	4,422

III. GS LMTOD

	Revenue	Units	Rates
On Peak	$72,200	428,234	0.16860
Off Peak	$56,700	687,609	0.08246
Customer	$21,900	876	25.00
	$ 150,800		

IV. Recreational Lighting

	Units	Rates	Revenue
Service Charge	1,020	$ 25.00	$ 25,500
Energy Charge	1,280,317	$0.11474 *	$ 146,904
			$ 172,404

* Limited after Revenue Verification

V. Service Charge Revenue

	Customer Revenue	Bills	Full Cost Rate	Current Rate	Proposed Rate
Secondary	$4,409,201	342,480	$ 12.87	$ 22.50	$ 25.00
Primary	$232,025	900	$ 257.81	$ 75.00	$ 100.00
Subtransmission	$34,999	72	$ 486.10	$ 364.00	$ 400.00

Proposed Customer Revenue

	Proposed Rate	Bills	Revenue
Secondary	$ 25.00	342,480	$ 8,562,000
Primary	$ 100.00	900	$ 90,000
Subtransmission	$ 400.00	72	$ 28,800
Non-Metered	$ 15.00	16,572	$ 248,580
			$ 8,929,380

VI. **Proposed Energy Charges and Revenue**

Proposed Energy Charges

	Units	Proposed Charges	Proposed Energy Revenue	current	class avg inc
Secondary					
First 4450 kWh	355,482,505	0.11146	$ 39,622,933	0.09952	12%
Over 4450 kWh	204,831,799	0.10440	$ 21,384,747	0.09943	5%
Primary					
First 4450 kWh	2,550,907	0.09813	$ 250,332	0.08762	
Over 4450 kWh	5,565,510	0.09232	$ 513,786	0.08792	
Subtransmission					
First 4450 kWh	305,866	0.08902	$ 27,227	0.07948	
Over 4450 kWh	838,000	0.08380	$ 70,225	0.07981	
Total Energy Revenue			$ 61,869,250		

VII. **Proposed Demand Charges and Revenue**

Total Base Revenue	$82,471,196
less Secondary Tariff Provisions (TODs)	$2,019,722
less Service Charge Revenue	$8,929,380
less Energy Charge Revenue	$61,869,250
less Equipment Credit Revenue	-$19,775
Proposed Demand Revenue	$9,672,620
Loss Adjusted Billing Demand	1,117,928
Residual Demand Charge	8.65

	Billing Demand	Loss Factor	Loss Adjusted Demand
Secondary	1,092,917	1.000	1,092,917
Primary	20,871	0.990	20,663
Subtransmission	4,422	0.983	4,348
Total	1,118,210		1,117,928

Equipment Credit Revenue	Billing Demand	20% of Equipment Credit	Revenue
Secondary	1,092,917	$ -	$ -
Primary	20,871	$ (0.55)	$ (11,479)
Subtransmission	4,422	$ (1.88)	$ (8,296)
Total	1,118,210		$ (19,775)

Demand Rates	Secondary Rate	Loss Factor	Demand Rate	Equipment Credit	Proposed Rate	Proposed Revenue	Current Rates

Secondary	8.65	1.000	8.65	$ -	8.65	$ 9,453,728	$ 6.00
Primary	8.65	0.990	8.56	$ (0.55)	8.01	$ 167,179	$ 7.18
Subtransmission	8.65	0.983	8.51	$ (1.88)	6.63	$ 29,319	$ 5.74
Transmission	8.65	0.973	8.42	$ (1.88)	6.54		
						$ 9,650,226	

VIII. **Revenue Verification**

Secondary	Units	Rates	Revenue	Target	Difference
First 4450 kWh	355,482,505	0.11146	$ 39,622,933		
Over 4450 kWh	204,831,799	0.10440	$ 21,384,747		
Billing Demand	1,092,917	$ 8.65	$ 9,453,728		
Customer - Standard	342,480	$ 25.00	$ 8,562,000		
Customer - Non-Metered	16,572	$ 15.00	$ 248,580		
Primary				$ 79,271,988	
First 4450 kWh	2,550,907	0.09813	$ 250,332		
Over 4450 kWh	5,565,510	0.09232	$ 513,786		
Billing Demand	20,871	$ 8.01	$ 167,179		
Customer	900	$ 100.00	$ 90,000		
Subtransmission				$ 1,021,296	
First 4450 kWh	305,866	0.08902	$ 27,227		
Over 4450 kWh	838,000	0.08380	$ 70,225		
Billing Demand	4,422	$ 6.63	$ 29,319		
Customer	72	$ 400.00	$ 28,800		
				$ 155,571	
			$ 80,448,856	$80,451,475	$ (2,619)

Large General Service Rate Design

I. Proposed Revenue

		Billed and Accrued Revenue	Fuel Revenue	Base Revenue
Secondary	Includes Schools again			
Demand		$41,555,737	$0	$41,555,737
Energy		15,294,251	0	15,294,251
Customer		362,059	0	362,059
Total		$57,212,048	$0	$57,212,048
Secondary LM-TOD & TOD		$1,065,529	$0	$1,065,529
Secondary Excl. LM-TOD				
Demand		$40,781,795	$0	$40,781,795
Energy		15,009,408	0	15,009,408
Customer		355,316	0	355,316
Total		$56,146,519	$0	$56,146,519
Primary	Includes Schools again			
Demand		$5,038,524	$0	$5,038,524
Energy		1,924,131	0	1,924,131
Customer		80,191	0	80,191
Total		$7,042,846	$0	$7,042,846
Subtransmission				
Demand		$723,521	$0	$723,521
Energy		396,688	0	396,688
Customer		91,195	0	91,195
Total		$1,211,404	$0	$1,211,404
Transmission				
Demand		$32,351	$0	$32,351
Energy		19,015	99,828	-80,813
Customer		12,408	0	12,408
Total		$63,774	$99,828	-$36,054
Total LGS Excld LMTOD				
Demand		$46,576,191	$0	$46,576,191
Energy		17,349,242	99,828	17,249,414
Customer		539,110	0	539,110
Total		$64,464,542	$99,828	$64,364,714

II. Billing Determinant Summary

	Secondary	Primary	Subtransmission	Transmission
Total LGS with Schools				

Billing Demand	1,420,318	264,980	38,060	1,169
Billing Reactive	67,000	75,211	8,876	227
Billing kWh	468,360,442	66,147,609	13,838,704	527,075
Bills	8,184	653	143	12

Schools	Secondary	Primary
Billing Demand	389,301	7,233
Billing Reactive	10,072	164
Billing kWh	102,420,279	2,082,784
Bills	1,836	12

Standard LGS	Secondary	Primary	Subtransmission	Transmission
Billing Demand	1,031,017	257,747	38,060	1,169
Billing Reactive	56,928	75,047	8,876	227
Billing kWh	365,940,162	64,064,826	13,838,704	527,075
Bills	6,348	641	143	12
avg kWh	57,229	101,298	96,774	43,923
avg kW	174	406	266	97

III. Proposed Customer Charges & Revenue

Proposed Customer Charge	Customer Revenue	Bills	Full Cost Rate	Proposed Rate	
Secondary	$355,316	8,184	$43.42	$85.00	*
Primary	80,191	653	$122.80	$127.50	*
Subtransmission	91,195	143	$637.73	$660.00	*
Transmission	12,408	12	$1,034.00	$660.00	*
Total	$539,110	8,992			

* Use Current.
** Full cost.
*** Equal to Subtrans

Proposed Customer Revenue	Proposed Rate	Bills	Customer Revenue
Secondary	$85.00	8,184	$695,640
Primary	$127.50	653	83,258
Subtransmission	$660.00	143	94,380
Transmission	$660.00	12	7,920
Total		8,992	$881,198

IV. Proposed Excess KVA Charges & Revenue

Proposed KVA Revenue	Proposed/Current Rate	Excess KVA	Revenue
Secondary	$3.46	67,000	$231,820
Primary	$3.46	75,211	260,232
Subtransmission	$3.46	8,876	30,712
Transmission	$3.46	227	785
Total		151,315	$523,549

V. Proposed Demand Charges and Revenue

Demand Charges	Proposed GS Demand Rate	Current LGS Dem Rate	10% Increase	USE THIS ONE
Secondary	$8.65	$ 7.97	$ 8.77	8.77
Primary	$8.01	$ 7.18	$ 7.90	7.90
Subtransmission	$6.63	$ 5.74	$ 6.31	6.63
Transmission	$6.54	$ 5.60	$ 6.16	6.54

Proposed Demand Revenue	Billing Demand	Proposed Rate	Demand Revenue
Secondary	1,420,318	$8.77	$12,451,932
Primary	264,980	$7.90	2,092,812
Subtransmission	38,060	$6.63	252,339

Transmission	1,169	$6.54	7,648
Total	1,724,528		$14,804,731

VI. Proposed Energy Charges and Revenue

Loss Adjusted Energy	Billing Energy	Loss Factor	Loss Adj Energy
Secondary	468,360,442	1.000	468,360,442
Primary	66,147,609	0.986	65,252,914
Subtransmission	13,838,704	0.978	13,536,713
Transmission	527,075	0.970	511,275
Total	548,873,829		547,661,344

Equipment Credit Revenue	Billing Energy	100% of Equipment Credit	Equipment Credit Revenue
Secondary	468,360,442	--	0
Primary	66,147,609	(0.00966)	(638,986)
Subtransmission	13,838,704	(0.03155)	(436,611)
Transmission	527,075	(0.03155)	(16,629)
Total	548,873,829		($1,092,226)

Total Revenue	$64,364,714
Less: Customer Revenue	881,198
Excess KVA Revenue	523,549
Demand Revenue	14,804,731
Equipment Credit Revenue	(1,092,226)
Energy Revenue	$49,247,462
Loss Adjusted Billing Energy	547,661,344
Secondary Energy Charge	$0.08992

	Secondary Rate	Loss Factor	Energy Rate	Equipment Credit	Proposed Rate
Secondary	$0.08992	1.000	$0.08992	0.00000	$0.08992
Primary	0.08992	0.986	$0.08870	(0.00966)	$0.07904
Subtransmission	0.08992	0.978	$0.08796	(0.03155)	$0.05641
Transmission	0.08992	0.970	$0.08722	(0.03155)	$0.05567

VII. LGS Total Revenue Verification

		Units		Rate		Revenue
Secondary	Demand	1,420,318	kW	$8.77	/kW	$12,451,932
	Excess KVA	67,000	KVA	3.46	/KVA	231,820
	Energy	468,360,442	kWh	0.08992	/kWh	42,114,971
	Customer	8,184	Bills	85.00	/Mo	695,640
	Total Billed					$55,494,363
Primary	Demand	264,980	kW	$7.90	/kW	$2,092,812
	Excess KVA	75,211	KVA	3.46	/KVA	260,232
	Energy	66,147,609	kWh	0.07904	/kWh	5,228,307
	Customer	653	Bills	127.50	/Mo	83,258
	Total Billed					$7,664,609
Subtran	Demand	38,060	kW	$6.63	/kW	$252,339
	Excess KVA	8,876	KVA	3.46	/KVA	30,712
	Energy	13,838,704	kWh	0.05651	/kWh	782,025
	Customer	143	Bills	660.00	/Mo	94,380
	Total Billed					$1,159,456
Tran	Demand	1,169	kW	$6.54	/kW	$7,648
	Excess KVA	227	KVA	3.46	/KVA	785
	Energy	527,075	kWh	0.05567	/kWh	29,342
	Customer	12	Bills	660.00	/Mo	7,920
	Total Billed					$45,695
Total Tariff LGS						$64,364,123
Target						$64,364,714
Difference						($591)

* Revised after revenue verification

VIII. Off-Peak Energy Charge For LM-TOD

Secondary Energy Revenue Reqt	$15,294,251	/	475,274,914	kwh	=	$0.03218
Fixed Cost Adder						0.05000
Calculated Off-Peak Energy Charge						$0.08218
Use:						$0.08218

Off-Peak % Usage - secondary	47.71%
Off-Peak kWh	226,753,661
Off-Peak Revenue	$18,634,616

IX. On-Peak Energy Charge

Total LGS Secondary Base Revenue	$57,212,048
Less: Customer Revenue	695,640
Time-of-Day Customer Revenue	14,280
Off-Peak Energy Revenue	18,634,616
On-Peak Revenue	$37,867,512
On-Peak kWh Energy	248,521,253
Proposed On-Peak Energy Charge	$0.15237 /kWh

X. Revenue Verification

	Units		Rate		Revenue	Difference
On-Peak	248,521,253	kWh	$0.15237	/kWh	$37,867,183	
Off-Peak	226,753,661	kWh	$0.08218	/kWh	18,634,616	
Customer - Standard	8,184	Bills	$85.00	/Mo	695,640	
- Time-of-Day	168	Bills	$85.00	/Mo	14,280	
Total Base Revenue					$57,211,719	($329)

*Revised after revenue verification

XI. Revenue From Existing TOD Customers

	Units		Rate		Proposed Revenue
LGS-LM-TOD					
On-Peak Energy	815,432	kWh	$0.15237	/kWh	$124,247
Off-Peak Energy	990,112	kWh	$0.08218	/kWh	81,367
Customer	84	Bills	$85.00	/Mo *	7,140
					$212,754
LGS TOD SEC					
On-Peak Energy	2,261,552	kWh	$0.10917		$ 246,894
Off-Peak Energy	2,847,376	kWh	$0.05691		$ 162,044
Billing demand	10,298	kW	$11.23		$ 115,647
Excess kVa	106	kVa	$3.46		$ 367
Customer	84	Bills	$85.00		$ 7,140
					$ 532,091
LGS TOD Primary					
On-Peak Energy	1,390,705	kWh	$0.10769		$ 149,765
Off-Peak Energy	1,948,569	kWh	$0.05648		$ 110,055
Billing demand	6,591	kW	$8.39		$ 55,297
Excess kVa	945	kVa	$3.46		$ 3,271
Customer	18	Bills	$127.50		$ 2,295
Total					$ 320,684

*Use same as standard	$1,065,529

LGS TOD Rate Design

I. Proposed Revenue

	Secondary	Primary	Subtran	Trans
Proposed Base Revenue				
Demand	$41,555,737	$5,038,524	$723,521	$32,351
Energy	15,294,251	1,924,131	396,688	-80,813
Customer	362,059	80,191	91,195	12,408
Total Base Revenue	$57,212,048	$7,042,846	$1,211,404	-$36,054

II. Customer Revenue

	Secondary	Primary	Subtran	Trans
Full Cost Customer Revenue	$362,059	$80,191	$91,195	$12,408
All Bills	8,268	653	143	12
Calculated Customer Charge	$43.79	$122.80	$637.73	$1,034.00
Proposed Customer Charge	$85.00	$127.50	$660.00	$660.00
All Bills	8,268	653	143	12
Proposed Customer Revenue	$ 702,780	$ 83,258	$ 94,380	$ 7,920

III. Off-Peak Energy Charge

	Secondary	Primary	Subtran	Trans	Total
Energy Revenue Requirement	$15,294,251	$1,924,131	$396,688	-$80,813	$17,534,257
Total Billing kWh	470,165,986	66,147,609	13,838,704	527,075	
Loss Factor	1.000	0.986	0.978	0.970	
Loss Adjusted Energy	470,165,986	65,252,914	13,536,713	511,275	549,466,888
Total Energy Charge	$0.03191	$0.03148	$0.03122	$0.03095	$0.03191
Fixed Cost Adder	$0.02500	$0.02500	$0.02500	$0.02500	
Calculated Off-Peak Energy Charge	$0.05691	$0.05648	$0.05622	$0.05595	
Proposed Off-Peak Energy Charge	$0.05691	$0.05648	$0.05622	$0.05595	

Off-Peak % Usage	47.71%	47.74%	47.49%	47.69%
Off-Peak kWh	224,316,192	31,578,869	6,572,000	251,362
Proposed Off-Peak Charge	$0.05691	$0.05648	$0.05622	$0.05595
Off-Peak Revenue	$12,765,834	$1,783,575	$369,478	$14,064

IV. Demand Charge

	Billing Demand	Proposed Rate *	Demand Revenue
LGS - Secondary	1,420,318	11.23	$15,950,177
- Primary	264,980	8.39	2,223,183
- Subtransmission	38,060	1.82	69,270
- Transmission	1,169	1.80	2,105
Total			$18,244,734

* Full cost off-peak rates

V. On-Peak Energy Charge

	Secondary	Primary	Subtran	Trans	Total
Total Revenue	$57,212,048	$7,042,846	$1,211,404	-$36,054	
Less: Customer Revenue	702,780	83,258	94,380	7,920	
Demand Revenue	15,950,177	2,223,183	69,270	0	
Off-Peak Energy Revenue	12,765,834	1,783,575	369,478	14,064	
On-Peak Revenue	$27,793,257	$2,952,831	$678,276	-$58,038	$31,366,326
On-Peak kWh	245,849,794	34,568,740	7,266,704	275,713	
Loss Factor	1.000	0.986	0.978	0.970	
Loss Adjusted Energy	245,849,794	34,101,173	7,108,128	267,448	287,326,542
Calculated On-Peak Energy Charge	$0.10917	$0.10769	$0.10678	$0.10589	$0.10917
Proposed On-Peak Energy Charge	$0.10917	$0.10769	$0.10678	$0.10589	
On-Peak kWh	245,849,794	34,568,740	7,266,704	275,713	
On-Peak Revenue	$26,839,422	$3,722,708	$775,939	$29,195	$31,367,264

IGS Rate Design

I. Proposed Revenue

	Base Revenue
Demand	$74,863,999
Energy	53,206,527
Customer	253,870
Total	$128,324,396

II. Billing Determinant Summary

Billing Data	Secondary	Primary	Subtransmission	Transmission
On-Peak Billing Demand	30,611	637,126	2,152,811	439,271
Off-Peak Billing Demand	26,256	574,844	1,909,963	411,073
Minimum Billing Demand	15,927	114,283	101,272	42,072
Maximum Monthly Demand kW	46,539	751,409	2,254,083	481,343
Billing Reactive	5,261	159,601	197,012	71,602
Billing kWh	19,524,195	313,016,880	1,357,576,816	257,519,889
Bills	60	486	204	42

III. Proposed Customer Charges & Revenue

Proposed Customer Charge	Customer Revenue	Bills	Full Cost Rate	Use: Current Rate
Secondary	2,021	60	$33.68	$276
Primary	55,291	486	$113.77	$276
Subtransmission	152,183	204	$746.00	$794
Transmission	44,376	42	$1,056.57	$1,353
Total	$253,870	792		

Proposed Customer Revenue	Proposed Rate	Bills	Customer Revenue
Secondary	$276	60	16,560
Primary	$276	486	134,136
Subtransmission	$794	204	161,976
Transmission	$1,353	42	56,826
Total		792	$369,498

IV. Proposed Excess KVAR Charges & Revenue

Proposed KVAR Revenue	Use: Current Excess KVAR Rate	Excess KVAR	Revenue

Secondary	$0.69	5,261	3,630
Primary	$0.69	159,601	110,125
Subtransmission	$0.69	197,012	135,939
Transmission	$0.69	71,602	49,405
Total		433,477	$299,099

V. Proposed Off-Peak Demand Charges and Revenue

	Off-peak Demand	Proposed Rate	Revenue
Secondary	26,256	$1.85	48,573
Primary	574,844	$1.83	1,051,965
Subtransmission	1,909,963	$1.82	3,476,132
Transmission	411,073	$1.80	739,931
Total	2,922,135		$5,316,601

VI. Proposed Energy Charges and Revenue

Loss Adjusted Energy	Billing Energy	Loss Factor	Loss Adj Energy
Secondary	19,524,195	1.000	19,524,195
Primary	313,016,880	0.986	308,783,095
Subtransmission	1,357,576,816	0.978	1,327,951,550
Transmission	257,519,889	0.970	249,800,547
Total	1,947,637,780		1,906,059,387

Energy Revenue	$53,206,527
Loss Adjusted Billing Energy	1,906,059,387
Secondary Energy Charge	$0.02791

	Secondary Rate	Loss Factor	Proposed Energy Rate	Current Base Fuel Rate
Secondary	$0.02791	1.000	$0.02791	0.02851
Primary	0.02791	0.986	$0.02753	0.02851
Subtransmission	0.02791	0.978	$0.02730	0.02851
Transmission	0.02791	0.970	$0.02707	0.02851

Proposed Energy Revenue

	Billing	Proposed

	Energy	Rate	Revenue
Secondary	19,524,195	$0.02937	573,482
Primary	313,016,880	$0.02898	9,071,516
Subtransmission	1,357,576,816	$0.02874	39,020,094
Transmission	257,519,889	$0.02851	7,341,892
Total	1,947,637,780		$56,006,984

VII. Proposed Minimum Demand Charges and Revenue

Calculation of Loss Adj Demand	Maximum Demand	Loss Factor	Loss Adj Demand
Secondary	46,539	1.000	46,539
Primary	751,409	0.990	743,897
Subtransmission	2,254,083	0.983	2,216,541
Transmission	481,343	0.973	468,477
Total	3,533,373		3,475,454

Equipment Credit Revenue	Maximum Demand	Equipment Credit	Credit Revenue
Secondary	46,539	0.00	$0
Primary	751,409	(2.75)	($2,066,375)
Subtransmission	2,254,083	(9.38)	($21,143,296)
Transmission	481,343	(9.38)	($4,514,994)
Total	3,533,373		($27,724,665)

Total Required Demand Revenue	$74,863,999
Less: Equipment Credit Revenue	(27,724,665)
Demand Revenue	$102,588,664
Loss Adjusted Maximum Demand	3,475,454
Full Cost Demand Charge	$29.52

Demand Charges	Secondary Rate	Loss Factor	Demand Rate	Equipment Credit	Proposed Rate
Secondary	$29.52	1.000	$29.52	0.00	$29.52
Primary	$29.52	0.990	$29.22	(2.75)	$26.47
Subtransmission	$29.52	0.983	$29.03	(9.38)	$19.65
Transmission	$29.52	0.973	$28.73	(9.38)	$19.35

Proposed Minimum Demand Revenue

	Minimum Demand	Proposed Rate	Revenue

Secondary	15,927	$29.52	470,179
Primary	114,283	$26.47	3,025,076
Subtransmission	101,272	$19.65	1,989,987
Transmission	42,072	$19.35	814,090
Total	273,554		$6,299,332

VII. Proposed On-Peak Demand Charges and Revenue

Calculation of Loss Adj Demand	Billing Demand	Loss Factor	Loss Adj Demand
Secondary	30,611	1.000	30,611
Primary	637,126	0.990	630,757
Subtransmission	2,152,811	0.983	2,116,956
Transmission	439,271	0.973	427,530
Total	3,259,819		3,205,854

Equipment Credit Revenue	Billing Demand	Equipment Credit	Credit Revenue
Secondary	30,611	0.00	$0
Primary	637,126	(2.75)	($1,752,096)
Subtransmission	2,152,811	(9.38)	($20,193,368)
Transmission	439,271	(9.38)	($4,120,360)
Total	3,259,819		($26,065,824)

Total Required Base Revenue		$128,324,396
Less: Customer Revenue		$369,498
Excess KVAR Revenue		299,099
Off-peak Revenue		5,316,601
CS-IRP Credit Revenue		-421,345
Energy Revenue		56,006,984
Minimum Demand Revenue		6,299,332
Equipment Credit Revenue		(26,065,824)
Demand Revenue		$86,520,051
Loss Adjusted Billing Demand		3,205,854
Full Cost Demand Charge		$26.99
% of Full Cost	100%	$26.99

Demand Charges	Secondary Rate	Loss Factor	Demand Rate	Equipment Credit	Proposed Rate	**Current Rate**
Secondary	$26.99	1.000	$26.99	0.00	$26.99	**24.13**

Primary	$26.99	0.990	$26.72	(2.75)	$23.97	**20.57**
Subtransmission	$26.99	0.983	$26.54	(9.38)	$17.16	**13.69**
Transmission	$26.99	0.973	$26.27	(9.38)	$16.89	**13.26**

Proposed On-Peak Demand Revenue

	On-Peak Demand	Proposed Rate	Revenue
Secondary	30,611	$26.99	826,196
Primary	637,126	$23.97	15,271,905
Subtransmission	2,152,811	$17.16	36,942,238
Transmission	439,271	$16.89	7,419,284
Total	3,259,819		$60,459,623

VIII. Revenue Verification		Units	Rate	Revenue	Target	Difference
Secondary	On-Peak Demand	30,611 kW	$26.99 /kW	$826,196		
	Off-peak Demand	26,256 kW	1.85 /kW	48,573		
	Minimum Demand	15,927 kW	29.52 /kW	470,179		
	Excess KVAR	5,261 KVAR	0.69 /KVAR	3,630		
	Energy	19,524,195 kWh	0.02937 /kWh	573,482		
	Customer	60 Bills	276.00 /Mo	16,560		
	Total Billed			$1,938,620	$ 1,827,945.00	
Primary	On-Peak Demand	637,126 kW	$23.98 /kW	$15,278,277		
	Off-peak Demand	574,844 kW	1.83 /kW	1,051,965		
	Minimum Demand	114,283 kW	26.47 /kW	3,025,076		
	CS-IRP Demand Credit	25,800	-3.68 /kW	-94,945		
	Excess KVAR	159,601 KVAR	0.69 /KVAR	110,125		
	Energy	313,016,880 kWh	0.02899 /kWh	9,074,646		
	Customer	486 Bills	276.00 /Mo	134,136		
	Total Billed			$28,579,280	$ 25,714,889.00	
Subtran	On-Peak Demand	2,152,811 kW	$17.16 /kW	$36,942,238		
	Off-peak Demand	1,909,963 kW	1.81 /kW	3,457,032		
	Minimum Demand	101,272 kW	19.65 /kW	1,989,987		
	CS-IRP Demand Credit	83,041	-3.68 /kW	-305,590		
	Excess KVAR	197,012 KVAR	0.69 /KVAR	135,939		
	Energy	1,357,576,816 kWh	0.02874 /kWh	39,020,094		
	Customer	204 Bills	794.00 /Mo	161,976		
	Total Billed			$81,401,676	$ 72,411,600.00	
Tran	On-Peak Demand	439,271 kW	$16.90 /kW	$7,423,676		
	Off-peak Demand	411,073 kW	1.80 /kW	739,931		
	Minimum Demand	42,072 kW	19.35 /kW	814,090		
	CS-IRP Demand Credit	5,655	-3.68 /kW	-20,810		
	Excess KVAR	71,602 KVAR	0.69 /KVAR	49,405		
	Energy	257,519,889 kWh	0.02851 /kWh	7,341,892		
	Customer	42 Bills	1,353.00 /Mo	56,826		
	Total Billed			$16,405,010	$ 14,581,538.00	
Total Tariff IGS			Base	$128,324,586	$ 114,535,972.00	
			Fuel	$0		
* Revised after revenue verification			tot	$128,324,586		
				$128,324,396	$190	

Kentucky Power Company
MW Rate Design

I. Revenue

	Billed & Accrued Revenue	Fuel	Base Revenue
Demand	133,598	0	133,598
Energy	60,653	0	60,653
Customer	6,583	0	6,583
Total	200,834	0	200,834

II. Customer Charge

Full Cost Customer Charge	$	6,583	/		108	bills	$ 60.95	/mo.
						Use current:	$ 25.00	/mo.
Customer Revenue		108	Bills	X	$25.00	/mo.	$ 2,700	

III. Demand Charge

Demand Revenue Requirement	$	133,598
Monthly Demand (SNCP)		3,690
Full Cost Demand Charge		36.21
Current Minimum Demand Charges		8.89
Class Increase		10.00%
Proposed Minimum Demand Charge		9.78
Minimum kW		949
Minimum Demand Charge Revenue	$	9,281

IV. Energy Charge

Energy Revenue Requirement		
Total MW Revenue Requirement	$	200,834
Less: Customer Revenue		2,700
Less: Minimum Demand Revenue		9,281
Energy Charge Revenue	$	188,853
Billing kWh		1,832,822
Proposed Energy Charge		0.10304

V. Revenue Verification

	Units	Proposed Charges	Revenue	Target Revenue	Difference
Energy	1,832,822	$0.10304	188,854		
Demand	949	$ 9.78	9,281		
Customer	108	$25.00	2,700		
Total MW Verified Revenues			200,835	200,834	1

OL Rate Design

Tariff #	Lamp Type & Size (1)	Annual Number of Lamps (2)	Present Rate (3)	Present Revenue (4)=(2*3)	Cost Based Rate (5)	Proposed Rate (6)	Proposed Revenue (7)=(2*6)	Annual Increase (8)	Percent Increase (9)=(8/4)	Monthly kWh	Base Fuel Revenue 0.02851	Non-Fuel Base Rate
Tariff #	**High Pressure Sodium**											
94	100 Watt	254,150	$9.30	$2,363,597	$9.99	$9.30	$2,363,597	$0	0.00%	40.3	$ 1.15	$9.30
113	150 Watt	264,684	$10.58	$2,800,360	$11.49	$10.65	$2,818,888	$18,528	0.66%	58.7	$ 1.67	$10.65
97	200 Watt	20,423	$12.30	$251,200	$14.26	$13.20	$269,581	$18,381	7.32%	84.3	$ 2.40	$13.20
103	250 Watt	24.00	$17.63		$18.81	$18.80	$451	$451	6.64%	103	$ 2.94	$18.80
98	400 Watt	2,712	$19.01	$51,555	$22.52	$20.85	$56,545	$4,990	9.68%	166.7	$ 4.75	$20.85
111	100 Watt Post Top	9,514	$14.10	$134,147	$28.36	$16.85	$160,311	$26,164	19.50%	40.3	$ 1.15	$16.85
122	150 Watt Post Top	811	$23.13	$18,758	$29.97	$27.65	$22,424	$3,666	19.54%	58.7	$ 1.67	$27.65
107	200 Watt Floodlight	20,936	$14.40	$301,478	$16.40	$15.15	$317,180	$15,702	5.21%	84.3	$ 2.40	$15.15
109	400 Watt Floodlight	48,580	$20.16	$979,373	$23.91	$22.10	$1,073,618	$94,245	9.62%	166.7	$ 4.75	$22.10
121	100 Watt Shoebox	-	$32.85	$0	$30.59	$30.60	$0	$0	-6.85%	40.3	$ 1.15	$30.60
120	250 Watt Shoebox	24	$25.83	$620	$36.28	$30.85	$740	$120	19.43%	103	$ 2.94	$30.85
126	400 Watt Shoebox	36.00	$42.96	$1,547	$42.00	$42.00	$1,512	-$35	-2.23%	166.7	$ 4.75	$42.00
	Metal Halide											
110	250 Watt Floodlight	1,671	$17.88	$29,877	$18.80	$17.90	$29,911	$34	0.11%	100.3	$ 2.86	$17.90
116	400 Watt Floodlight	11,279	$22.57	$254,567	$24.01	$22.55	$254,341	-$226	-0.09%	158	$ 4.50	$22.55
131	1000 Watt Floodlight	1,148	$41.06	$47,137	$44.87	$41.50	$47,642	$505	1.07%	378.3	$ 10.79	$41.50
130	250 Watt Mongoose	47.00	$24.63	$1,158	$24.14	$24.15	$1,135	-$23	-1.95%	100.3	$ 2.86	$24.15
136	400 Watt Mongoose	19.00	$29.42	$559	$29.38	$29.40	$559	$0	-0.07%	158	$ 4.50	$29.40
	Mercury Vapor *											
93	175 Watt	8,117	$10.47	$84,985		$11.85	$96,186	$11,201	13.18%	72.0	$ 2.05	$11.85
95	400 Watt	944	$18.07	$17,058		$20.40	$19,258	$2,200	12.89%	158	$ 4.50	$20.40
99	175 Post Top	109	$12.02	$1,310		$13.60	$1,482	$172	13.14%	72.0	$ 2.05	$13.60
	Light Emitting Diode (LED)											
TBD	55W LED			$1	$5.38	$6.66				22.44	$ 0.64	$6.66
TBD	100W LED			$2	$6.94	$9.26				40.8	$ 1.16	$9.26
TBD	175W LED			$4	$7.69	$11.74				71.4	$ 2.04	$11.74
TBD	300W LED			$7	$11.18	$18.13				122.4	$ 3.49	$18.13
TBD	65W LED Postop			$2	$17.58	$19.09				26.52	$ 0.76	$19.09
TBD	175W LED Flood			$4	$20.81	$24.87				71.4	$ 2.04	$24.87
TBD	265W LED Flood			$6	$24.44	$30.58				108.12	$ 3.08	$30.58
	Facilities Charge											
	Pole	50,824	$3.10	$157,555	$10.03	$3.70	$188,049	$30,494	19.35%			
	Span	54,442	$1.80	$97,996	$2.15	$2.00	$108,885	$10,889	11.11%			
	Lateral	574	$6.75	$3,878	$7.51	$6.95	$3,993	$115	2.96%			
	Base Revenue			$7,599,139			$7,836,288	$237,573				
	Base Fuel						$1,133,293					
	Total						$8,969,581					
	Revenue Target						$8,967,519					
	Difference						$2,062					
	Class Increase	12.99%										
	Maximum Increase (1.5 x class increase)	19.49%										

Scale Factor 0.9250

OL Continued Lamp Type & Size (1)	Estimated Installed Cost (2)	Monthly Facility Cost (3)=(2)*FCCR	Annual Maintenance Cost (4)	Consumption in kWh Annual (5)	Consumption in kWh Monthly (6)	Energy Cost no Fuel @ $0.05677 per kWh (7)=(6)*EC	Estimated Monthly Maintenance (8)	Lighting Cost Estimate (9)=(3+7+8)
High Pressure Sodium (HPS)								
100 Watt	$283.12	$4.05	$30.01	484	40.3	$3.44	$2.50	$9.99
150 Watt	$280.86	$4.02	$29.55	704	58.7	$5.01	$2.46	$11.49
200 Watt	$321.65	$4.60	$29.65	1,012	84.3	$7.19	$2.47	$14.26
250 Watt	$529.31	$7.57	$29.53	1,236	103.0	$8.78	$2.46	$18.81
400 Watt	$405.63	$5.80	$29.96	2,000	166.7	$14.22	$2.50	$22.52
100 Watt Post Top	$1,572.06	$22.48	$29.24	484	40.3	$3.44	$2.44	$28.36
150 Watt Post Top	$1,573.64	$22.50	$29.55	704	58.7	$5.01	$2.46	$29.97
200 Watt Floodlight	$471.29	$6.74	$29.65	1,012	84.3	$7.19	$2.47	$16.40
400 Watt Floodlight	$503.05	$7.19	$29.96	2,000	166.7	$14.22	$2.50	$23.91
100 Watt Shoebox	$1,728.32	$24.71	$29.24	484	40.3	$3.44	$2.44	$30.59
250 Watt Shoebox	$1,751.27	$25.04	$29.53	1,236	103.0	$8.78	$2.46	$36.28
400 Watt Shoebox	$1,767.70	$25.28	$29.96	2,000	166.7	$14.22	$2.50	$42.00
Metal Halide								
250 Watt Floodlight	$530.46	$7.59	$31.88	1,204	100.3	$8.55	$2.66	$18.80
400 Watt Floodlight	$547.40	$7.83	$32.48	1,896	158.0	$13.47	$2.71	$24.01
1000 Watt Floodlight	$696.51	$9.96	$31.75	4,540	378.3	$32.26	$2.65	$44.87
250 Watt Mongoose	$903.89	$12.93	$31.88	1,204	100.3	$8.55	$2.66	$24.14
400 Watt Mongoose	$922.89	$13.20	$32.48	1,896	158.0	$13.47	$2.71	$29.38

	Fixed Cost CC Rate Using 10-Yr Inv Life
Return	7.07%
Depreciation	8.04%
F.I.T.	0.64%
Prop Taxes, Adm & Gen'l	1.45%
Annual Total	17.20%

Outdoor Lighting (OL) Cost of Service

Demand Revenue Requirement	$940,086
Energy Revenue Requirement	$1,494,972
Cust. Related Revenue Reqt.	
O&M Expenses	$637,529
Taxes Other	$302,830

Monthly Total FCCRR	1.43%

State Income Tax	$122,901
Less: Acct. 598	$0
B&A Rev Excl Direct Ltg Costs	$3,498,318
Class Metered Energy	41,021,575
Energy Rate ($/kWh)	$0.08528

Lamp Type & Size (1)	Annual Number of Lamps (2)	Present Rate (3)	Present Revenue (4)=(2*3)	Cost Based Lamp (5)	Cost Based Lamp w/pole (6)	Proposed Rate (7)	Proposed Revenue (8)=(2*7)	Annual Increase (9)	Percent Increase (10)=(8/4)	Monthly kWh	Base Fuel Revenue 0.02851	**Non-Fuel Base Rate**	Revenue Chec
Service on Existing Wood Poles													
9,500 Lumen HPS	92,622	$7.03	651,131	8.03	n.a.	$7.90	731,712	80,581	12.38%	40.3	1.15	$7.90	
16,000 Lumen HPS	1,338	$7.55	10,104	8.92	n.a.	$8.45	11,308	1,204	11.92%	58.7	1.67	$8.45	
22,000 Lumen HPS	27,295	$8.95	244,293	10.59	n.a.	$10.05	274,318	30,025	12.29%	84.3	2.4	$10.05	
50,000 Lumen HPS	252	$11.71	2,956	14.69	n.a.	$13.15	3,319	363	12.30%	166.7	4.75	$13.15	
Service on New Wood Poles													
9,500 Lumen HPS	5,433	$10.80	58,677	8.03	14.12	$12.10	65,740	7,063	12.04%	40.3	1.15	$12.10	
16,000 Lumen HPS	337	$11.55	3,887	8.92	15.01	$12.95	4,358	471	12.12%	58.7	1.67	$12.95	
22,000 Lumen HPS	6,371	$12.95	82,499	10.59	16.68	$14.55	92,692	10,193	12.36%	84.3	2.4	$14.55	
50,000 Lumen HPS	5,931	$16.61	98,511	14.69	20.78	$18.65	110,610	12,099	12.28%	166.7	4.75	$18.65	
Service on New Metal or Concrete Poles													
9,500 Lumen HPS	-	$27.45	0	8.03	26.75	$26.75	0	0	-2.55%	40.3	1.15	$26.75	
16,000 Lumen HPS	-	$28.15	0	8.92	27.64	$27.65	0	0	-1.78%	58.7	1.67	$27.65	
22,000 Lumen HPS	-	$26.70	0	10.59	29.31	$29.30	0	0	9.74%	84.3	2.4	$29.30	
50,000 Lumen HPS	1,936	$27.11	52,485	14.69	33.41	$30.40	58,854	6,369	12.14%	166.7	4.75	$30.40	
Subtotal							$1,352,911	$148,368					
Base Fuel							$231,909						
Total							$1,584,820						
Revenue Target							$1,587,709						
Difference							-$2,889						
Maximum Increase (1.5 x class increase)	12.22%												
Scale Factor	1.0000												

Lamp Type & Size (1)	Estimated Installed Cost (2)	Monthly Facility Cost (3)=(2)*FCCRR	Annual Maintenance Cost (4)	Consumption in kWh Annual (5)	Consumption in kWh Monthly (6)	Energy Cost No Fuel @ $0.04533 per kWh (7)=(6)*EC	Estimated Monthly Maintenance (8)	Lighting Cost Estimate (9)=(3+7+8)
Service on Existing Wood Poles								
High Pressure Sodium (HPS)								
9,500 Lumen	$359.58	$3.76	$29.24	484	40.3	$1.83	$2.44	$8.03
16,000 Lumen	$363.00	$3.80	$29.55	704	58.7	$2.66	$2.46	$8.92
22,000 Lumen	$410.81	$4.30	$29.65	1,012	84.3	$3.82	$2.47	$10.59
50,000 Lumen	$442.78	$4.63	$29.96	2,000	166.7	$7.56	$2.50	$14.69
LED	**Lumens**							
55 Watt OH	5400	$6.43			22	$1.02	$1.28	$8.74
100 Watt OH	10500	$7.64			41	$1.85	$1.76	$11.25
175 Watt OH	18430	$8.21			71	$3.24	$1.99	$13.44
65 Watt Post Top	7230	$5.53			27	$1.20	$2.36	$9.09
90 Watt Dec Post Top	7038	$13.20			30	$1.36	$5.55	$20.11
175 Watt Flood	21962	$9.39			71	$3.24	$2.16	$14.79

Lamp Type & Size (1)	Lamp Cost (2)	Pole Type (3)	Pole Cost (4)	Estimated Installed Cost (5)	Monthly Facility Cost (6)=(5)*FCCRR	Annual Maintenance Cost (7)	Consumption in kWh Annual (8)	Consumption in kWh Monthly (9)	Energy Cost @ $0.04533 per kWh (10)=(6)*EC	Estimated Monthly Maintenance (11)	Lighting Cost Estimate (12)=(5+10+11)
Service on New Wood Poles											
High Pressure Sodium (HPS)											
9,500 Lumen	$359.58		582.53	$942.11	$9.85	$29.24	484	40.3	$1.83	$2.44	$14.12
16,000 Lumen	$363.00		582.53	$945.53	$9.89	$29.55	704	58.7	$2.66	$2.46	$15.01
22,000 Lumen	$410.81		582.53	$993.34	$10.39	$29.65	1,012	84.3	$3.82	$2.47	$16.68
50,000 Lumen	$442.78		582.53	$1,025.31	$10.72	$29.96	2,000	166.7	$7.56	$2.50	$20.78
LED	**Lumens**										
55 Watt OH	5,400	$6.43			$ 12.53			22	$1.02	$1.28	$14.83
100 Watt OH	10,500	$7.64			$ 13.73			41	$1.85	$1.76	$17.34
175 Watt OH	18,430	$8.21			$ 14.30			71	$3.24	$1.99	$19.53
65 Watt Post Top	7,230	$5.53			$ 11.63			27	$1.20	$2.36	$15.18
90 Watt Dec Post Top	7,038	$13.20			$ 19.29			30	$1.36	$5.55	$26.20
175 Watt Flood	21,962	$9.39			$ 15.48			71	$3.24	$2.16	$20.89
Service on New Metal or Concrete Poles											
High Pressure Sodium (HPS)											
9,500 Lumen	$359.58		1,790.13	$2,149.71	$22.48	$29.24	484	40.3	$1.83	$2.44	$26.75
16,000 Lumen	$363.00		1,790.13	$2,153.13	$22.52	$29.55	704	58.7	$2.66	$2.46	$27.64
22,000 Lumen	$410.81		1,790.13	$2,200.94	$23.02	$29.65	1,012	84.3	$3.82	$2.47	$29.31
50,000 Lumen	$442.78		1,790.13	$2,232.91	$23.35	$29.96	2,000	166.7	$7.56	$2.50	$33.41
LED	**Lumens**										
55 Watt OH	5400	$6.43			$ 25.16			0	$0.00	$1.28	$26.44
100 Watt OH	10500	$7.64			$ 26.36			0	$0.00	$1.76	$28.12
175 Watt OH	18430	$8.21			$ 26.93			13	$0.57	$1.99	$29.49
65 Watt Post Top	7230	$5.53			$ 24.26			14	$0.62	$2.36	$27.23
90 Watt Dec Post Top	7038	$13.20			$ 31.92			14	$0.65	$5.55	$38.12
175 Watt Flood	21962	$9.39			$ 28.12			12	$0.53	$2.16	$30.81

	FCCRR 20-Yr Inv Life
Return	7.07%
Depreciation	3.23%
F.I.T.	0.80%

Street Lighting (SL) Cost of Service

Demand-Related Revenue Reqmt	$200,138
Energy-Related Revenue Reqmt	290,328
Customer-Related Revenue Requirement	
O&M Expenses	216,967

Prop Taxes, Adm & Gen'l	1.45%
Annual Total	12.55%
Monthly Total FCCRR	1.05%

Taxes Other	44,659
State Income Tax	20,010
Less: Account 585	85,965
Account 596	61,349
B&A Rev Excl Direct Ltg Cost	$624,788
Class Metered Energy	8,461,026
Energy Rate ($/kWh)	$0.07384

Conversion Charge Calculation for Changing Non-LED Luminaire to LED Luminaire

OL	**B&A Number of Lamps**	**53,912**	
	Net Book Value	**$16,225,580**	
	Ratio of Lamp Count	**93.0%**	
	Ratioed Net Book Value	**$15,087,112**	
	Conversion Charge	**$279.85**	$3.33
SL	**B&A Number of Lamps**	**11,923**	
	Net Book Value	**$2,339,212**	
	Ratio of Lamp Count	**93.1%**	
	Ratioed Net Book Value	**$2,178,460**	
	Conversion Charge	**$182.71**	$2.18

KENTUCKY POWER COMPANY

Alternate Feed Service (AFS) Rate Design

AFS Monthly Cost / Reservation Demand Charge

Primary Demand Revenue Requirement		$31,678,788	
Functional Demand kW @ Secondary	/	$4,776,919	
Monthly Cost @ Secondary	=	$6.63	
Loss Factor Secondary to Primary	x	0.99000313	
AFS Monthly Cost @ Primary	=	**$6.57**	$/kW

AFS Transfer Switch Monthly Testing Rate

Total Annual AFS Transfer Switch Testing Cost		$189.00	
Divided by 12	/	12	
Total Monthly AFS Transfer Switch Testing Rate	=	**$15.75**	$/bill

KENTUCKY POWER COMPANY
Full Cost Off-Peak Demand Charges

	Demand Loss Factors	Production	Full Cost Charges
Functional Demand Cost		18.50	
Off-Peak Recovery %		10%	
Off Peak Demand Cost		1.85	
Secondary Charge	1.000	1.85	$1.85
Primary Charge	0.990	1.83	$1.83
Subtran Charge	0.983	1.82	$1.82
Transmission Charge	0.973	1.80	$1.80

KENTUCKY POWER COMPANY
Equipment Credits Relative to Secondary
Twelve Months Ended March 31, 2020

Current Metered Energy Summary	Secondary	Primary	Subtran	Bulk Tran	Production
GS	566,724,056	8,116,417	1,143,867		
LGS	478,614,187	66,147,609	13,838,704	527,075	
IGS	19,524,195	313,016,880	1,357,576,816	257,519,889	
Total	1,064,862,439	387,280,907	1,372,559,386	258,046,963	
Relative Loss Factor	1.00000	0.98647	0.97818	0.97002	
Loss Adj Energy	1,064,862,439	382,042,645	1,342,607,168	250,311,822	
	77.4%	77.4%			
Energy Served by Subtran S	823,777,583	295,548,190	1,342,607,168		
Functional Demand Rev	10,287,420	31,678,788	0	0	138,858,671
Functional Energy	1,064,862,439	1,446,905,084	2,461,932,941	3,039,824,074	3,039,824,074
Functional Cost	0.00966	0.02189	0.00000	0.00000	0.04568

Full Cost Equipment Credits	Secondary	Primary	Subtran	Total	
Primary	0.00966			0.00966	-0.00966
Subtransmission	0.00966	0.02189		0.03155	-0.03155
Transmission	0.00966	0.02189	0.00000	0.03155	-0.03155

TOD and AF Energy

Metered

	kWh
GS-Sec	560,314,303
MGS-TOD	4,013,593
GS-LM-TOD	1,115,843
GS-AF	1,280,317
Total MGS-Sec	566,724,056
LGS-Sec	468,360,442
LGS-LM-TOD	1,805,544
LGS-TOD	8,448,202
Total LGS-Sec	478,614,187

KENTUCKY POWER COMPANY
Equipment Credits Relative to Secondary
Twelve Months Ended March 31, 2020

Current Billing Demand Summary

	Secondary	Primary	Subtran	Bulk Tran	Production
GS	2,249,693	32,098	4,567		
LGS	1,442,682	264,980	38,060	1,169	
IGS	46,539	751,409	2,254,083	481,343	
Total	3,738,914	1,048,487	2,296,710	482,512	
Relative Loss Factor	1.00000	0.99000	0.98334	0.97327	
Loss Adj Demand	3,738,914	1,038,005	2,258,458	469,616	
	77.36%	77.36%			
Demand Served by Subtran System	2,892,424	803,001	2,258,458		
Functional Demand Rev	10,287,420	31,678,788	0	0	138,858,671
Functional Demand	3,738,914	4,776,919	5,953,883	7,504,993	7,504,993
Functional Cost	2.75	6.63	0.00	0.00	18.50

Full Cost Equipment Credits (Relative to Secondary)

	Secondary	Primary	Subtran	Total	
Primary	2.75			**2.75**	-2.75
Subtransmission	2.75	6.63		**9.38**	-9.38
Transmission	2.75	6.63	0.00	**9.38**	-9.38

KENTUCKY POWER COMPANY
Full Cost Off-Peak Excess
Twelve Months Ended March 31, 2020

	Demand Loss Factors	Distribution Secondary	Distribution Primary	Subtran	Bulk Tran	Production	Full Cost Charges
Functional Demand Cost		2.75	6.63	0.00	0.00	18.50	
Off-Peak Recovery %		100%	100%	10%	10%	10%	
Off Peak Demand Cost		2.75	6.63	0.00	0.00	1.85	
Secondary Charge	1.000	2.75	6.63	0.00	0.00	1.85	$11.23
Primary Charge	0.990		6.56	0.00	0.00	1.83	$8.39
Subtran Charge	0.983			0.00	0.00	1.82	$1.82
Transmission Charge	0.973				0.00	1.80	$1.80

I. Assumptions

		Variable	Value	
A)	Capital Cost per kW of Capacity	V	$700	/kW
B)	Weighted Cost of Capital (Workpaper S-2)	R	7.07%	
C)	Carrying Charge Rate	CCR	10.24%	
D)	Operation & Maintenance Cost per Year (Fixed & Variable)	O	$34.93	/kW
E)	Line Losses	L	5.40%	
F)	Estimated Unit Life	N	40	years
G)	Present Value of Carrying Charge for $1 Investment for N years	D	1.3542	
H)	Fixed Operation and Maintenance Cost Escalation Rate	IO	2.00%	
I)	Construction Cost Escalation Rate	IP	2.00%	

II. Calculation of Present Value of Carrying Charge

$$\boxed{D = CCR \times \frac{(1+R)^N - 1}{R \times (1+R)^N}}$$

$$D = 10.24\% \times \frac{14.3714}{1.0868} = \mathbf{1.3542}$$

III. Calculation of Unadjusted Monthly Avoided Cost of Capacity

$$C = \left(\frac{1}{12}\right) \times \left[\frac{\left(D \times V \times \frac{S1}{S2} \times S3\right) + (S4 \times S5)}{S6}\right]$$

Where:

$$S1 = 1 - \frac{1 + IP}{1 + R}$$

$$S2 = 1 - \left(\frac{1 + IP}{1 + R}\right)^{N}$$

$$S3 = (1 + IP)^{(T-1)}$$

$$S4 = O \times \left(\frac{1 + IO}{1 + R}\right)$$

$$S5 = (1 + IO)^{(T-1)}$$

$$S6 = 1 - \frac{L}{2}$$

Calculation for First Year

T =	1		
S1 =	0.0474	S4 =	33.2760
S2 =	0.8564	S5 =	1.0000
S3 =	1.0000	S6 =	0.9730

$$C = \left(\frac{1}{12}\right) \times \left[\frac{\left(1.4258 \times 828 \times \frac{0.0577}{0.8316} \times 1\right) + (5.6729 \times 1)}{0.9605}\right]$$

C = $7.34

Calculation for Second Year

T =	2		
S1 =	0.0474	S4 =	33.2760
S2 =	0.8564	S5 =	1.0200
S3 =	1.0200	S6 =	0.9730

C = $7.49

Calculation for Third Year

T =	3		
S1 =	0.0474	S4 =	33.2760
S2 =	0.8564	S5 =	1.0404
S3 =	1.0404	S6 =	0.9730

C = $7.64

Three Year Average Avoided Cost of Capacity = $7.49 on peak
TOD Measurement

Three Year Average Avoided Cost of Capacity = $3.12 average
Standard Measurement

Cost Calculations (Support Page 1, Assumptions A & D)

I. Operations & Maintenance Cost per kW (2020 Dollars)

Fixed & Variable Operations & Maintenance Cost		17.72	mills/kWh
Hours per Year	x	8,760	hours
Unit Size	x	490,000	kW
Capacity Factor	x	25%	
Planned Outage Rate	x	10.00%	
Total Variable O&M Cost		$17,113,799	/year
Unit Size	/	490,000	kW
Per Unit Variable O&M Cost		$34.93	/kW

I. Energy Payment Calculation *

		On-Peak	Off-Peak	Non-TOD	
A	**Potential Loss Savings**				
	Primary Losses			1.35%	
	Divided by 2	/		2	
	Loss Adjustment (Potential Loss Savings)			0.68%	
B	**Time-of-Day Energy Payments**				
	Avoided Energy Costs (2020-2022 Average)	3.04	2.27		¢/kWh
	Divided by (1 - Loss Savings)	0.9932	0.9932		
	Time-of-Day Energy Payments	**3.06**	**2.28**		¢/kWh
C	**Non-Time-of-Day Energy Payment**				
	Time-of-Day Energy Payments	3.06	2.280		¢/kWh
	Hours per Year x	3,650	5,110		hours
	Weighted Average of Hourly TOD Payments	11,169	11,651	22,820	
	Hours Per Year			8,760	
	Non-Time-of-Day Energy Payment			**2.61**	¢/kWh

* On-Peak Period is 7am - 9pm, Monday through Friday
Off-Peak Period is all other hours

II. Demand and Energy Loss Calculations **

System	Demand	Energy
Transmission	2.7%	3.0%
Subtransmission	1.7%	2.2%
Primary	1.0%	1.35%
Compound Loss Factor	**5.4%**	**6.7%**

** Assuming COGEN/SPP Service at Primary

I. Annual Carrying Charge Rates

	Variable	Value
Fixed Costs		10.9%
O&M		4.6%
Carrying Costs	**CC**	**15.5%**

II. Charges

Contingencies		5%
Stores Expense		26%
Total Charges on Material	**MC**	**31%**
Labor		56%
Transportation Expense		22%
Total Charges on Labor	**LC**	**78%**

III. Overheads

Company Construction Overheads	**OC**	**23%**

IV. Monthly Charge on Incremental Material

IM = Incremental Material Cost
IL = Incremental Labor Cost (50% of Material) = 0.5 x IM

$$\boxed{Monthly\,Charge\ on\ IM = (1+OC)\times[(1+MC)\times IM + (1+LC)\times IL]\times\frac{CC}{12}}$$

Monthly Charge on IM = **3.51%** of Incremental Material Cost

V. Monthly Meter Charges

	Incremental Material (IM)	Monthly Charge 3.51%				Average Charge
Standard Measurement						
Single Phase						
Option 2 - Primary - Transformer Rated	391	$13.72				
Option 2 - Secondary - Self-Contained	38	1.33				
Option 3 - Primary - Transformer Rated	391	13.72				
Option 3 - Secondary - Transformer Rated	391	13.72				
Option 3 - Secondary - Self Contained	38	1.33				
Total		$ 43.82	/	5	=	$8.76
			Use:			**$9.25**
			current			9.25
Polyphase						
Option 2 - Primary - Transformer Rated	391	$13.72				
Option 2 - Secondary - Self-Contained	230	8.07				
Option 3 - Primary - Transformer Rated (or Sec. >200 Amps)	391	13.72				
Option 3 - Secondary - Transformer Rated (Below 200 Amps)	391	13.72				
Option 3 - Secondary - Self Contained (Below 200 Amps)	230	8.07				
Total		$ 57.30	/	5	=	$11.46
			Use:			**$12.10**
			current			12.1
Time-of-Day Measurement						
Single Phase						
Option 2 - Primary - Transformer Rated	400	$14.04				
Option 2 - Secondary - Self-Contained	96	3.37				
Option 3 - Primary - Transformer Rated	400	14.04				
Option 3 - Secondary - Transformer Rated	400	14.04				
Option 3 - Secondary - Self Contained	38	1.33				
Total		$ 46.82	/	5	=	$9.36
			Use:			**$9.85**
			Current			9.85
Polyphase						
Option 2 - Primary - Transformer Rated	400	$14.04				
Option 2 - Secondary - Self-Contained	239	8.39				
Option 3 - Primary - Transformer Rated	400	14.04				
Option 3 - Secondary - Transformer Rated	400	14.04				
Option 3 - Secondary - Self Contained	239	8.39				
Total		$ 58.90	/	5	=	$11.78
			Use:			**$12.40**

Kentucky Power
Annual Investment Carrying Charges
For Economic Analyses

	Investment Life (Years)											
	2	3	4	5	10	15	20	25	30	33	40	50
Return (1)	7.07	7.07	7.07	7.07	7.07	7.07	7.07	7.07	7.07	7.07	7.07	7.07
Depreciation (2)	49.04	31.91	23.32	18.19	8.04	4.78	3.23	2.35	1.81	1.57	1.18	0.85
FIT (3) (4)	1.06	0.77	0.82	0.68	0.64	0.77	0.80	0.69	0.62	0.59	0.54	0.49
Property Taxes, General & Admin Expenses	1.45	1.45	1.45	1.45	1.45	1.45	1.45	1.45	1.45	1.45	1.45	1.45
	58.62	41.19	32.66	27.39	17.20	14.07	12.55	11.57	10.95	10.68	10.24	9.86
					1.4333							

(1) Company Proposed Rate of Return

(2) Sinking Fund annuity with R1 Dispersion of Retirements

(3) Assuming MACRS Tax Depreciation

(4) @ 21% Federal Income Tax Rate

Exhibit AEV-2 Marginal Customer Connection Study
Kentucky Power 2020

Kentucky Power MCAC (Customer Hookup Cost): 7.2kV

Account	Description	Qty	Material Cost	Std Labor Cost	Admin Overhd	Transpt Overhd	Material Overhd	Labor Overhd	Total	% of Total Cost
CONSTRUCTION										
3640000	**Poles, Towers & Fixtures**									
	ANC,Expanding,8in,72in,Sg Eye 5/8in	2	$35.36	$80.64	$42.54	$54.17	$6.83	$193.54	**$413.08**	
	BKT,Arrestor/CO 12in (1Ph),Fbrgls	1	$28.28	$7.20	$10.08	$4.84	$5.46	$17.28	**$73.14**	
	GYD,Marker-Plastic-Yellow	2	$4.41	$8.64	$4.71	$5.80	$0.85	$20.74	**$45.15**	
	GYF,3/8,Down,78in Pole mt,EyePlate	1	$42.42	$17.28	$17.83	$11.61	$8.19	$41.47	**$138.80**	
	GYW,3/8 in. EHS (15,400 lbs)	80	$20.66	$0.00	$5.17	$0.00	$3.99	$0.00	**$29.82**	
	Pole,40ft,Class 4	1	$234.38	$97.92	$99.52	$65.78	$45.24	$235.01	**$777.85**	
	SAA,3 inch,Clevis	1	$5.27	$6.48	$4.03	$4.35	$1.02	$15.55	**$36.70**	
Total Company Direct Charges A/C			$370.78	$218.16	$183.88	$146.55	$71.58	$523.59	**$1,514.54**	**51.99%**
3650000	**OH Conductor & Devices**									
	CON,#2 AWG,Alum Alloy,One,Bare	400	$55.44	$54.00	$36.43	$36.28	$10.70	$129.60	**$322.45**	
	DEC,#4 - #2/0 AA,AL,AS	2	$13.55	$24.48	$13.62	$16.45	$2.61	$58.75	**$129.46**	
	DEG,#2,Primary Neutral Al	2	$2.23	$5.76	$2.96	$3.87	$0.43	$13.82	**$29.07**	
	GND,Cu Rod Adr,#4	1	$29.34	$51.84	$29.00	$34.83	$5.66	$124.42	**$275.09**	
	GND,Extend Gnd To Guy/Eq,#4	1	$14.88	$5.76	$6.13	$3.87	$2.87	$13.82	**$47.33**	
	INS,15kV,Deadend,Polymer	2	$16.82	$0.00	$4.21	$0.00	$3.25	$0.00	**$24.28**	
Total Company Direct Charges A/C			$132.26	$141.84	$92.35	$95.30	$25.52	$340.41	**$827.68**	**28.41%**
3680000	**Transformer Devices**									
	EQL,1 Ph,#4, CU Sol,#4,CU Sld, Xfr	1	$21.80	$28.08	$17.18	$18.86	$4.21	$67.39	**$157.52**	
	XCO,15kV,100 Amp,10kA	1	$82.61	$11.52	$25.47	$7.74	$15.94	$27.65	**$170.93**	
Total Company Direct Charges A/C			$104.41	$39.60	$42.65	$26.60	$20.15	$95.04	**$328.45**	**11.28%**
3690000	**Services**									
	SVC,#2 AWG,Trip,All Alum,Res	1	$6.75	$37.44	$17.34	$25.15	$1.30	$89.86	**$177.84**	
	SVW,#2 AWG,Trip,All Alum,Res	80	$44.72	$0.00	$11.18	$0.00	$8.63	$0.00	**$64.53**	
Total Company Direct Charges A/C			$51.47	$37.44	$28.52	$25.15	$9.93	$89.86	**$242.37**	**8.32%**
										avg
									$2,913.04	
MAINTENANCE										
5830000	**Overhead Line Expense**									
			PreCap							
	XFR,15KVA,7.2/12.4kVY,120/240,1BC	1	$556.00	$53.28	$161.27	$35.79	$107.31	$127.87	**$1,041.52**	
									$1,041.52	
Total Company Direct Charges A/C										
5860000	**Meter Expense**		**PreCap**							
	MTR-Type 0A006 Class200,240v RF	1	$39.18	$5.04	$11.90	$3.39	$7.56	$12.10	**$79.17**	
Total Company Direct Charges A/C									**$79.17**	
Total Work Request Charges									**$4,033.73**	$3,705.28

Marginal Cost Per Month to Connect a Residential Customer	
Levelized 33 Year Carrying Charge	10.68%
Total Capital Cost	$4,034
Monthly Capital Recovery $	$35.90
Total Basic Service Charge $/month	**$35.90**

Exhibit AEV-3

Example of Typical Customer and Typical Solar Install

Hour of the Day begin	end	Typical Res Customer 1240 kWh/Month	Typical NMS Solar System 9.35 kW-ICAP	Typical Solar Net Excess Gen	Summer Peak 5CP Excess %	Summer Peak 5CP Hours wt	Summer Peak 5CP Wtd Hours Excess	12 CP Excess %	12CP Hours Wt	12CP Hours Wt Wtd Excess Gen %
midnight	1 AM	42	-	-						
1	2 AM	41	-	-						
2	3 AM	41	-	-						
3	4 AM	41	-	-						
4	5 AM	44	-	-						
5	6 AM	49	-	-						
6	7 AM	49	-	-						
7	8 AM	49	6	-				0%	36%	0%
8	9 AM	51	33	-				0%	8%	0%
9	10 AM	50	82	32				39%	3%	1%
10	11 AM	51	130	79						
11	12 AM	52	163	111						
12	1 PM	53	177	125						
1	2 PM	55	181	126				70%	3%	2%
2	3 PM	58	179	121	68%	5%	3%	68%	6%	4%
3	4 PM	60	162	102	63%	15%	9%	63%	6%	4%
4	5 PM	62	129	66	52%	70%	36%	52%	31%	16%
5	6 PM	62	82	20	24%	10%	2%	24%	3%	1%
6	7 PM	61	34	-				0%	3%	0%
7	8 PM	61	7	-				0%	3%	0%
8	9 PM	60	-	-						
9	10 PM	55	-	-						
10	11 PM	49	-	-						
11	midnight	45	-	-						
		1,240	1,365	783		1	**51.39%**		1	**26.72%**

	Avg Monthly kWh
Net Billing kWh	639
Net Excess Gen	783
Netted kWh	601

Exhibit AEV-3
NMS II Excess Generation Pricing

Full Solar Output Shape Value From Example Solar Plant

	Solar Pk Reduction MW	Price	$ Value	$/kWh Price	
				38,460	Total annual MWh from solar plant
G Capacity	9.55	$ 100	$ 348,593	0.0091	
T Avoided Cost	5.51	$ 93,054	$ 512,424	0.0133	

Net Metering Shape Discount

Gen Capacity	**51.39%**	0.00466
T Avoided Cost	26.72%	0.00356

Cogen SPP Energy	$/kWh	
On Pk	0.0306	input from cogen spp rate design
Off Pk	0.0228	input from cogen spp rate design
Solar	0.02837	5/7 on-pk 2/7 off-pk

NMS II Excess Generation Pricing

Energy	0.02837
G Capacity	0.00466
T Fixed Cost	0.00356
NMS Price for Excess Gen	**0.03659**

TARIFF N.M.S. II
(Net Metering Service II) DN

AVAILABILITY OF SERVICE.

Net Metering is available to eligible customer-generators in the Company's service territory, upon request, and on a first-come, first-served basis up to a cumulative capacity of one percent (1%) of the Company's single hour peak load in Kentucky during the previous year. If the cumulative generating capacity of net metering systems reaches 1% of the Company's single hour peak load during the previous year, upon Commission approval, the Company's obligation to offer net metering to a new customer-generator may be limited. An eligible customer-generator shall mean a retail electric customer of the Company with a generating facility that:

(1) Generates electricity using solar energy, wind energy, biomass or biogas energy, or hydro energy;
(2) Has a rated capacity of not greater than forty-five (45) kilowatts;
(3) Is located on the customer's premises;
(4) Is owned and operated by the customer;
(5) Is connected in parallel with the Company's electric distribution system; and
(6) Has the primary purpose of supplying all or part of the customer's own electricity requirements.

At its sole discretion, the Company may provide Net Metering to other customer-generators not meeting all the conditions listed above on a case-by-case basis.

The term "Customer" hereinafter shall refer to any customer requesting or receiving Net Metering services under this tariff.

METERING.

Net energy metering shall be accomplished using a time of use ("TOU") kilowatt-hour meter capable of measuring the flow of electricity in two (2) directions. If the existing electrical meter installed at the customer's facility is not capable of measuring the flow of electricity in two directions, the Company will provide the customer with the appropriate metering at no additional cost to the customer. If the customer requests any additional meter or meters or if distribution upgrades are needed to monitor the flow in each direction, such installations shall be at the customer's expense.

BILLING/MONTHLY CHARGES.

For determining monthly billing kWh and excess customer generation kWh, two TOU netting periods will be used:

1. TOU period 1 shall be from 8:00 AM to 6:00 PM all days of the week and holidays
2. TOU period 2 shall be from 6:00 PM to 8:00 AM all days of the week and holidays

All net billing kWh and kW in each netting period, accumulated for the billing period, shall be charged at the rates applicable under the Company's standard service tariff under which the customer would otherwise be served, absent the customer's electric generating facility.

Energy charges under the customer's standard tariff shall be applied to the customer's net energy for the billing period to the extent that the net energy exceeds zero. If the customer's net energy is zero or negative during the billing period, the customer shall pay only the non-energy charge portions of the standard tariff bill.

All excess customer generation, (net negative energy or "NNE"), in each netting period, accumulated for the billing period, shall be credited at the avoided cost rate of .03659 $/kWh each month.

Bill credits to customers for NNE at the avoided cost rate each month is a purchased power expense and shall be recovered from all customers through the Company's Purchased Power Adjustment Rider. If the NNE credit exceeds the customer's billed charges that month, the amount in excess of the billed charges will be carried over for use in subsequent billing periods.

(Cont'd on Sheet No. 28-2)

TARIFF N.M.S. II (Cont'd)
(Net Metering Service II)

N

APPLICATION AND APPROVAL PROCESS.

The Customer shall submit an Application for Interconnection and Net Metering ("Application") and receive approval from the Company prior to connecting the generator facility to the Company's system.

Applications will be submitted by the Customer and reviewed and processed by the Company according to either Level 1 or Level 2 processes defined below.

The Company may reject an Application for violations of any code, standard, or regulation related to reliability or safety; however, the Company will work with the Customer to resolve those issues to the extent practicable.

Customers may contact the Company to check on the status of an Application or with questions prior to submitting an Application. Company contact information can be found on Kentucky Power Company's Application Form or on the Company's website.

LEVEL 1 AND LEVEL 2 DEFINITIONS.

LEVEL 1
A Level 1 Application shall be used if the generating facility is inverter-based and is certified by a nationally recognized testing laboratory to meet the requirements of Underwriters Laboratories Standard 1741 "Inverters, Converters, Controllers and Interconnection System Equipment for Use With Distributed Energy Resources" (UL 1741).

The Company will approve the Level 1 Application if the generating facility also meets all of the following conditions:

(1) For interconnection to a radial distribution circuit, the aggregated generation on the circuit, including the proposed generating facility, will not exceed 15% of the Line Section's most recent annual one hour peak load. A line section is the smallest part of the primary distribution system the generating facility could remain connected to after operation of any sectionalizing devices.
(2) If the proposed generating facility is to be interconnected on a single-phase shared secondary, the aggregate generation capacity on the shared secondary, including the proposed generating facility, will not exceed the smaller of 20 kVA or the nameplate rating of the transformer.
(3) If the proposed generating facility is single-phase and is to be interconnected on a center tap neutral of a 240 volt service, its addition shall not create an imbalance between the two sides of the 240 volt service of more than 20% of the nameplate rating of the service transformer.
(4) If the generating facility is to be connected to three-phase, three wire primary Company distribution lines, the generator shall appear as a phase-to-phase connection at the primary Company distribution line.
(5) If the generating facility is to be connected to three-phase, four wire primary Company distribution lines, the generator shall appear to the primary Company distribution line as an effectively grounded source.
(6) The interconnection will not be on an area or spot network.
(7) The Company does not identify any violations of any applicable provisions of IEEE 1547, "Standard for Interconnecting Distributed Resources with Electric Power Systems."
(8) No construction of facilities by the Company on its own system will be required to accommodate the generating facility.

(Cont'd on Sheet No. 28-3)

TARIFF N.M.S.II (Cont'd)
(Net Metering Service II)

LEVEL 1, continued N

If the generating facility does not meet all of the above listed criteria, the Company, in its sole discretion, may either: 1) approve the generating facility under the Level 1 Application if the Company determines that the generating facility can be safely and reliably connected to the Company's system; or 2) deny the Application as submitted under the Level 1 Application.

The Company shall notify the customer within 20 business days whether the Application is approved or denied, based on the criteria provided in this section.

If the Application lacks complete information, the Company shall notify the customer that additional information is required, including a list of such additional information. The time between notification and receipt of required additional information will add to the time to process the Application.

When approved, the Company will indicate by signing the approval line on the Level 1 Application Form and returning it to the customer. The approval will be subject to successful completion of an initial installation inspection and witness test if required by the Company. The Company's approval section of the Application will indicate if an inspection and witness test are required. If so, the customer shall notify the Company within 3 business days of completion of the generating facility installation and schedule an inspection and witness test with the Company to occur within 10 business days of completion of the generator facility installation or as otherwise agreed to by the Company and the customer. The customer may not operate the generating facility until successful completion of such inspection and witness test, unless the Company expressly permits operational testing not to exceed two hours. If the installation fails the inspection or witness test due to noncompliance with any provision in the Application and Company approval, the customer shall not operate the generating facility until any and all noncompliance is corrected and re-inspected by the Company.

If the Application is denied, the Company will supply the customer with reasons for denial. The customer may resubmit under Level 2 if appropriate.

LEVEL 2

A Level 2 Application is required under any of the following:

(1) The generating facility is not inverter based;
(2) The generating facility uses equipment that is not certified by a nationally recognized testing laboratory to meet the requirements of UL 1741; or
(3) The generating facility does not meet one or more of the additional conditions under Level 1.

The Company will approve the Level 2 Application if the generating facility meets the Company's technical interconnection requirements, which are based on IEEE 1547. The Company shall make its technical interconnection requirements available online and upon request.

(Cont'd on Sheet No. 28-4)

TARIFF N.M.S. I I (Cont'd)
(Net Metering Service II)

N

LEVEL 2, continued

The Company will process the Level 2 Application within 30 business days of receipt of a complete Application. Within that time the Company will respond in one of the following ways:

(1) The Application is approved and the Company will provide the customer with an Interconnection Agreement to sign.
(2) If construction or other changes to the Company's distribution system are required, the cost will be the responsibility of the customer. The Company will give notice to the customer and offer to meet to discuss estimated costs and construction timeframe. Should the customer agree to pay for costs and proceed, the Company will provide the customer with an Interconnection Agreement to sign within a reasonable time.
(3) The Application is denied. The Company will supply the customer with reasons for denial and offer to meet to discuss possible changes that would result in Company approval. Customer may resubmit Application with changes.

If the Application lacks complete information, the Company shall notify the customer that additional information is required, including a list of such additional information. The time between notification and receipt of required additional information will add to the 30-business-day target to process the Application.

The Interconnection Agreement will contain all the terms and conditions for interconnection consistent with those specified in this tariff, inspection and witness test requirements, description of and cost of construction or other changes to the Company's distribution system required to accommodate the generating facility, and detailed documentation of the generating facilities which may include single line diagrams, relay settings, and a description of operation.

The customer may not operate the generating facility until an Interconnection Agreement is signed by the customer and Company and all necessary conditions stipulated in the agreement are met.

APPLICATION, INSPECTION AND PROCESSING FEES.

The Company will require each customer to submit with each Level 1 Application a non-refundable application, inspection and processing fee of $150.

The Company will require each customer to submit with each Level 2 Application a non-refundable application, inspection and processing fee of $150. In the event the Company determines an impact study is necessary with respect to a Level 2 Application, the customer shall be responsible for any reasonable costs for the initial impact study. The Company shall provide documentation of the actual cost of the impact study. Any other studies requested by the customer shall be at the customer's sole expense.

(Cont'd on Sheet No. 28-5)

TARIFF N.M.S. II (Cont'd)
(Net Metering Service II)

TERMS AND CONDITIONS FOR INTERCONNECTION. N

To interconnect to the Company's distribution system, the customer's generating facility shall comply with the following terms and conditions:

(1) The Company shall provide the customer net metering services, without charge for standard metering equipment, through a standard kilowatt-hour metering system capable of measuring the flow of electricity in two (2) directions. If the customer requests any additional meter or meters or distribution upgrades are needed to monitor the flow in each direction, such installations shall be at the customer's expense.

(2) The customer shall install, operate, and maintain, at customer's sole cost and expense, any control, protective, or other equipment on the customer's system required by the Company's technical interconnection requirements based on IEEE 1547, the NEC, accredited testing laboratories such as Underwriters Laboratories, and the manufacturer's suggested practices for safe, efficient and reliable operation of the generating facility in parallel with Company's electric system. Customer shall bear full responsibility for the installation, maintenance and safe operation of the generating facility. Upon reasonable request from the Company, the customer shall demonstrate generating facility compliance.

(3) The generating facility shall comply with, and the customer shall represent and warrant its compliance with: (a) any applicable safety and power quality standards established by IEEE and accredited testing laboratories such as Underwriters Laboratories; (b) the NEC as may be revised from time to time; (c) Company's rules, regulations, and Company's Terms and Conditions of Service as contained in Company's Retail Electric Tariff as may be revised from time to time with the approval of the Kentucky Public Service Commission (Commission); (d) the rules and regulations of the Commission, as such rules and regulations may be revised from time to time by the Commission; and (e) all other applicable local, state, and federal codes and laws, as the same may be in effect from time to time. Where required by law, customer shall pass an electrical inspection of the generating facility by a local authority having jurisdiction over the installation.

(4) Any changes or additions to the Company's system required to accommodate the generating facility shall be considered excess facilities. Customer shall agree to pay Company for actual costs incurred for all such excess facilities prior to construction.

(5) Customer shall operate the generating facility in such a manner as not to cause undue fluctuations in voltage, intermittent load characteristics or otherwise interfere with the operation of Company's electric system. At all times when the generating facility is being operated in parallel with Company's electric system, customer shall so operate the generating facility in such a manner that no adverse impacts will be produced thereby to the service quality rendered by Company to any of its other customers or to any electric system interconnected with Company's electric system. Customer shall agree that the interconnection and operation of the generating facility is secondary to, and shall not interfere with, Company's ability to meet its primary responsibility of furnishing reasonably adequate service to its customers.

(Cont'd on Sheet No. 28-6)

N

TARIFF N.M.S. II
(Net Metering Service II)

TERMS AND CONDITIONS FOR INTERCONNECTION, continued

(6) Customer shall be responsible for protecting, at customer's sole cost and expense, the generating facility from any condition or disturbance on Company's electric system, including, but not limited to, voltage sags or swells, system faults, outages, loss of a single phase of supply, equipment failures, and lightning or switching surges, except that the Company shall be responsible for repair of damage caused to the generating facility resulting solely from the negligence or willful misconduct on the part of the Company.

(7) After initial installation, Company shall have the right to inspect and/or witness commissioning tests, as specified in the Level 1 or Level 2 Application and approval process. Following the initial testing and inspection of the generating facility and upon reasonable advance notice to customer, Company shall have access at reasonable times to the generating facility to perform reasonable on-site inspections to verify that the installation, maintenance, and operation of the generating facility comply with the requirements of this tariff.

(8) For Level 1 and 2 generating facilities, where required by the Company, an eligible customer shall furnish and install on customer's side of the point of common coupling a safety disconnect switch which shall be capable of fully disconnecting the customer's energy generating equipment from Company's electric service under the full rated conditions of the customer's generating facility. The external disconnect switch (EDS) shall be located adjacent to Company's meters or the location of the EDS shall be noted by placing a sticker on the meter, and shall be of the visible break type in a metal enclosure which can be secured by a padlock. If the EDS is not located directly adjacent to the meter, the customer shall be responsible for ensuring that the location of the EDS is properly and legibly identified for so long as the generating facility is operational. The disconnect switch shall be accessible to Company personnel at all times. The Company may waive the requirement for an EDS for a generating facility at its sole discretion, and on a case-by-case basis, upon review of the generating facility operating parameters and if permitted under the Company's safety and operating protocols.

The Company shall establish a training protocol for line workers on the location and use of the EDS, and shall require that the EDS be used when appropriate, and that the switch be turned back on once the disconnection is no longer necessary.

(9) Company shall have the right and authority at Company's sole discretion to isolate the generating facility or require the customer to discontinue operation of the generating facility if Company believes that: (a) continued interconnection and parallel operation of the generating facility with Company's electric system creates or contributes (or may create or contribute) to a system emergency on either Company's or customer's electric system; (b) the generating facility is not in compliance with the requirements of this tariff, and the noncompliance adversely affects the safety, reliability, or power quality of Company's electric system; or (c) the generating facility interferes with the operation of Company's electric system. In non-emergency situations, Company shall give customer notice of noncompliance including a description of the specific noncompliance condition and allow customer a reasonable time to cure the noncompliance prior to isolating the generating facilities. In emergency situations, when the Company is unable to immediately isolate or cause the customer to isolate only the generating facility, the Company may isolate the customer's entire facility.

(Cont'd on Sheet No. 28-7)

DATE OF ISSUE: June 29, 2020
DATE EFFECTIVE: Service Rendered On And After December 30, 2020
ISSUED BY: /s/ Brian K. West
TITLE: Director, Regulatory Services
By Authority Of an Order of the Public Service Commission
In Case No. 2020-00174 Dated XXXXXX

N

TARIFF N.M.S. II
(Net Metering Service II)

TERMS AND CONDITIONS FOR INTERCONNECTION, continued

(10) Customer shall agree that, without the prior written permission from Company, no changes shall be made to the generating facility as initially approved. Increases in generating facility capacity will require a new "Application for Interconnection and Net Metering" which will be evaluated on the same basis as any other new application. Repair and replacement of existing generating facility components with like components that meet UL 1741 certification requirements for Level 1 facilities and not resulting in increases in generating facility capacity are allowed without approval.

(11) To the extent permitted by law, the customer shall protect, indemnify, and hold harmless the Company and its directors, officers, employees, agents, representatives and contractors against and from all loss, claims, actions or suits, including costs and attorneys fees, for or on account of any injury or death of persons or damage to property caused by the customer or the customer's employees, agents, representatives and contractors in tampering with, repairing, maintaining, or operating the customer's generating facility or any related equipment or any facilities owned by the Company except where such injury, death or damage was caused or contributed to by the fault or negligence of the Company or its employees, agents, representatives, or contractors.

The liability of the Company to the customer for injury to person and property shall be governed by the tariff(s) for the class of service under which the customer is taking service.

(12) The customer shall maintain general liability insurance coverage (through a standard homeowner's, commercial, or other policy) for both Level 1 and Level 2 generating facilities. Customer shall, upon request, provide Company with proof of such insurance at the time that application is made for net metering.

(13) By entering into an Interconnection Agreement, or by inspection, if any, or by non-rejection, or by approval, or in any other way, Company does not give any warranty, express or implied, as to the adequacy, safety, compliance with applicable codes or requirements, or as to any other characteristics, of the generating facility equipment, controls, and protective relays and equipment.

(14) A customer's generating facility is transferable to other persons or service locations only after notification to the Company has been made and verification that the installation is in compliance with this tariff. Upon written notification that an approved generating facility is being transferred to another person, customer, or location, the Company will verify that the installation is in compliance with this tariff and provide written notification to the customer(s) within 20 business days. If the installation is no longer in compliance with this tariff, the Company will notify the customer in writing and list what must be done to place the facility in compliance.

(15) The customer shall retain any and all Renewable Energy Credits (RECs) that may be generated by their generating facility.

(Cont'd on Sheet No. 28-8)

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TARIFF N.M.S. II
(Net Metering Service II)

TERM OF CONTRACT.

Any contract required under this tariff shall become effective when executed by both parties and shall continue in effect until terminated. The contract may be terminated as follows: (a) Customer may terminate the contract at any time by giving the Company at least sixty (60) days' written notice; (b) Company may terminate upon failure by the customer to continue ongoing operation of the generating facility; (c) either party may terminate by giving the other party at least thirty (30) days prior written notice that the other party is in default of any of the terms and conditions of the contract or the rules or any rate schedule, tariff, regulation, contract, or policy of the Company, so long as the notice specifies the basis for termination and there is opportunity to cure the default; (d) the Company may terminate by giving the customer at least thirty (30) days notice in the event that there is a material change in an applicable law, regulation or statute affecting this Agreement or which renders the system out of compliance with the new law or statute.

SPECIAL TERMS AND CONDITIONS.

This tariff is subject to the Company's Terms and Conditions of Service and all provisions of the standard service tariff under which the customer takes service. This tariff is also subject to the applicable provisions of the Company's Technical Requirements for Interconnection.

(Cont'd on Sheet No. 28-9)

N

TARIFF N.M.S. II
(Net Metering Service II)

Application For Interconnection And Net Metering – Level 1

Use this Application only for: 1.) a generating facility that is inverter based and certified by a nationally recognized testing laboratory to meet the requirements of UL 1741, 2.) less than or equal to 45 kW generation capacity, and 3.) connecting to Kentucky Power distribution system.

Submit this Application (along with the application fee of $150) to:

D.G. Coordinator American Electric Power
1 Riverside Plaza
Columbus, Ohio 43215-2373
614-716-4020 Office / 614-716-1414 Fax
dgcoordinator@aep.com

(Contract person listed is subject to change. Please visit our website for up-to-date-information http://www.kentuckypower.com)

Applicant

Name:

Mailing Address:

City: State: Zip:

Phone: ( ) Phone: ( )

E-mail address:

Service Location

Name:

Street Address:

City: State: Zip:

Electric Service Account Number

Provide names and contact information for other contractors, installers, or engineering firms involved in the design and installation of the generating facilities:

Alternate Contacts

Name	Company	Telephone/Email

(Cont'd on Sheet No. 28-10)

N

TARIFF N.M.S. II
(Net Metering Service II)

APPLICATION FOR INTERCONNECTION AND NET METERING, LEVEL 1 – CONTINUED

Equipment Qualifications

Energy Source: ( ) Solar ( ) Wind ( ) Hydro ( ) Biogas ( ) Biomass

Inverter Manufacturer: Model:

Inverter Power Rating: Voltage Rating:

Power Rating of Energy Source (i.e., solar panels, wind turbine):

Battery Storage: ( ) Yes ( ) No If Yes, Battery Power Rating:

Attach documentation showing that inverter is certified by a nationally recognized testing laboratory to meet the requirements of UL 1741.

Attach site drawing or sketch showing locations of Kentucky Power Company meter, energy source, accessible disconnect switch and inverter.

Attach single line drawing showing all electrical equipment from the metering location to the energy source including switches, fuses, breakers, panels, transformers, inverters, energy source, wire size, equipment ratings, and transformer connections.

Expected Start-up Date: _

(Cont'd on Sheet No. 28-11)

N

TARIFF N.M.S. II
(Net Metering Service II)

TERMS AND CONDITIONS FOR LEVEL 1:

1 The Company shall provide customer net metering services, without charge for standard metering equipment, through a standard kilowatt-hour metering system capable of measuring the flow of electricity in two (2) directions. If the customer requests any additional meter or meters or distribution upgrades are needed to monitor the flow in each direction, such installations shall be at the customer's expense.

2 Customer shall install, operate, and maintain, at customer's sole cost and expense, any control, protective, or other equipment on the customer's system required by the Company's technical interconnection requirements based on IEEE 1547, the NEC, accredited testing laboratories such as Underwriters Laboratories, and the manufacturer's suggested practices for safe, efficient, and reliable operation of the generating facility in parallel with Company's electric system. Customer shall bear full responsibility for the installation, maintenance, and safe operation of the generating facility. Upon reasonable request from the Company, customer shall demonstrate generating facility compliance.

3 The generating facility shall comply with, and the customer shall represent and warrant its compliance with: (a) any applicable safety and power quality standards established by the Institute of Electrical and Electronics Engineers (IEEE) and accredited testing laboratories such as Underwriters Laboratories (UL); (b) the National Electrical Code (NEC) as may be revised from time to time; (c) Company's rules, regulations, and Company's Terms and Conditions of Service as contained in Company's Retail Electric Tariff as may be revised from time to time with the approval of the Kentucky Public Service Commission (Commission); (d) the rules and regulations of the Commission, as such rules and regulations may be revised from time to time by the Commission; and (e) all other applicable local, state, and federal codes and laws, as the same may be in effect from time to time. Where required by law, customer shall pass an electrical inspection of the generating facility by a local authority having jurisdiction over the installation.

4 Any changes or additions to the Company's system required to accommodate the generating facility shall be considered excess facilities. Customer shall agree to pay Company for actual costs incurred for all such excess facilities prior to construction.

5 Customer shall operate the generating facility in such a manner as not to cause undue fluctuations in voltage, intermittent load characteristics, or otherwise interfere with the operation of Company's electric system. At all times when the generating facility is being operated in parallel with Company's electric system, customer shall so operate the generating facility in such a manner that no adverse impacts will be produced thereby to the service quality rendered by Company to any of its other customers or to any electric system interconnected with Company's electric system. Customer shall agree that the interconnection and operation of the generating facility is secondary to, and shall not interfere with, Company's ability to meet its primary responsibility of furnishing reasonably adequate service to its customers.

6 Customer shall be responsible for protecting, at customer's sole cost and expense, the generating facility from any condition or disturbance on Company's electric system, including, but not limited to, voltage sags or swells, system faults, outages, loss of a single phase of supply, equipment failures, and lightning or switching surges, except that the Company shall be responsible for repair of damage caused to the generating facility resulting solely from the negligence or willful misconduct on the part of the Company.

(Cont'd on Sheet No. 28-12)

N

TARIFF N.M.S. II
(Net Metering Service II)

TERMS AND CONDITIONS FOR LEVEL 1, continued

7 After initial installation, Company shall have the right to inspect and/or witness commissioning tests, as specified in the Level 1 or Level 2 Application and approval process. Following the initial testing and inspection of the generating facility and upon reasonable advance notice to customer, Company shall have access at reasonable times to the generating facility to perform reasonable on-site inspections to verify that the installation, maintenance and operation of the generating facility comply with the requirements of this tariff.

8 For Level 1 generating facilities, where required by the Company, an eligible customer shall furnish and install on customer's side of the point of common coupling a safety disconnect switch which shall be capable of fully disconnecting the customer's energy generating equipment from Company's electric service under the full rated conditions of the customer's generating facility. The external disconnect switch (EDS) shall be located adjacent to Company's meters or the location of the EDS shall be noted by placing a sticker on the meter, and shall be of the visible break type in a metal enclosure which can be secured by a padlock. If the EDS is not located directly adjacent to the meter, the customer shall be responsible for ensuring the location of the EDS is properly and legibly identified for so long as the generating facility is operational. The disconnect switch shall be accessible to Company personnel at all times. The Company may waive the requirement for an EDS for a generating facility at its sole discretion, and on a case-by-case basis, upon review of the generating facility operating parameters and if permitted under the Company's safety and operating protocols.

The Company shall establish a training protocol for line workers on the location and use of the EDS, and shall require that the EDS be used when appropriate, and that the switch be turned back on once the disconnection is no longer necessary.

9 Company shall have the right and authority at Company's sole discretion to isolate the generating facility or require the customer to discontinue operation of the generating facility if Company believes that: (a) continued interconnection and parallel operation of the generating facility with Company's electric system creates or contributes (or may create or contribute) to a system emergency on either Company's or customer's electric system; (b) the generating facility is not in compliance with the requirements of this tariff, and the noncompliance adversely affects the safety, reliability or power quality of Company's electric system; or (c) the generating facility interferes with the operation of Company's electric system. In non-emergency situations, Company shall give customer notice of noncompliance including a description of the specific noncompliance condition and allow customer a reasonable time to cure the noncompliance prior to isolating the generating facilities. In emergency situations, when the Company is unable to immediately isolate or cause the customer to isolate only the generating facility, the Company may isolate the customer's entire facility.

10 Customer shall agree that, without the prior written permission from Company, no changes shall be made to the generating facility as initially approved. Increases in generating facility capacity will require a new "Application for Interconnection and Net Metering" which will be evaluated on the same basis as any other new application. Repair and replacement of existing generating facility components with like components that meet UL 1741 certification requirements for Level 1 facilities and not resulting in increases in generating facility capacity are allowed without approval.

(Cont'd on Sheet No. 28-13)

N

TARIFF N.M.S. II
(Net Metering Service II)

TERMS AND CONDITIONS FOR LEVEL 1, continued

11 To the extent permitted by law, the customer shall protect, indemnify, and hold harmless the Company and its directors, officers, employees, agents, representatives and contractors against and from all loss, claims, actions or suits, including costs and attorneys fees, for or on account of any injury or death of persons or damage to property caused by the customer or the customer's employees, agents, representatives and contractors in tampering with, repairing, maintaining or operating the customer's generating facility or any related equipment or any facilities owned by the Company except where such injury, death or damage was caused or contributed to by the fault or negligence of the Company or its employees, agents, representatives, or contractors.

The liability of the Company to the customer for injury to person and property shall be governed by the tariff(s) for the class of service under which the customer is taking service.

12 The Customer shall maintain general liability insurance coverage (through a standard homeowner's, commercial, or other policy) for Level 1 generating facilities. Customer shall, upon request, provide Company with proof of such insurance at the time that application is made for net metering.

13 By entering into an Interconnection Agreement, or by inspection, if any, or by non-rejection, or by approval, or in any other way, Company does not give any warranty, express or implied, as to the adequacy, safety, compliance with applicable codes or requirements, or as to any other characteristics, of the generating facility equipment, controls, and protective relays and equipment.

14 Customer's generating facility is transferable to other persons or service locations only after notification to the Company has been made and verification that the installation is in compliance with this tariff. Upon written notification that an approved generating facility is being transferred to another person, customer, or location, the Company will verify that the installation is in compliance with this tariff and provide written notification to the Customer(s) within 20 business days. If the installation is no longer in compliance with this tariff, the Company will notify the customer in writing and list what must be done to place the facility in compliance.

15 The customer shall retain any and all Renewable Energy Credits ("RECs") that may be generated by their generating facility.

(Cont'd on Sheet No. 28-14)

N

TARIFF N.M.S. II
(Net Metering Service II)

TERMS AND CONDITIONS FOR LEVEL 1, continued

Effective Term and Termination Rights

This Agreement becomes effective when executed by both parties and shall continue in effect until terminated. This Agreement may be terminated as follows: (a) Customer may terminate this Agreement at any time by giving the Company at least sixty (60) days' written notice; (b) Company may terminate upon failure by the Customer to continue ongoing operation of the generating facility; (c) either party may terminate by giving the other party at least thirty (30) days prior written notice that the other party is in default of any of the terms and conditions of the Agreement or the Rules or any rate schedule, tariff, regulation, contract, or policy of the Company, so long as the notice specifies the basis for termination and there is opportunity to cure the default; (d) the Company may terminate by giving the Customer at least thirty (30) days notice in the event that there is a material change in an applicable law, regulation or statute affecting this Agreement or which renders the system out of compliance with the new law or statute. I hereby certify that, to the best of my knowledge, all of the information provided in this Application is true, and I agree to abide by all the Terms and Conditions included in this Application for Interconnection and Net Metering and Company's Net Metering Tariff.

Customer Signature: **Date:**

COMPANY APPROVAL SECTION

When signed below by a Company representative, Application for Interconnection and Net Metering is approved subject to the provisions contained in this Application and as indicated below.

Company inspection and witness test: ( ) Required ( ) Waived

If Company inspection and witness test is required, Customer shall notify the Company within three (3) business days of completion of the generating facility installation and schedule an inspection and witness test with the Company to occur within ten (10) business days of completion of the generating facility installation or as otherwise agreed to by the Company and the Customer. Unless indicated below, the Customer may not operate the generating facility until such inspection and witness test is successfully completed. Additionally, the Customer may not operate the generating facility until all other terms and conditions in the Application have been met.
Call: to schedule an inspection and witness test.

Pre-Inspection operational testing not to exceed two (2) hours: ( ) Allowed ( ) Not Allowed

If Company inspection and witness test is waived, operation of the generating facility may begin when installation is complete, and all other terms and conditions in the Application have been met.

Additions, Changes, or Clarifications to Application Information: ( ) None ( ) As specified here:

Approved by: **Date**:

Printed Name: **Title:**

(Cont'd on Sheet No. 28-15)

N

TARIFF N.M.S. II

(Net Metering Service II)

Application for Interconnection and Net Metering – Level 2

Use this Application form for connecting to the Kentucky Power distribution system and: 1.) the generating facility is not inverter based or is not certified by a nationally recognized testing laboratory to meet the requirements of UL 1741 or 2.) does not meet any of the additional conditions under a Level 1 Application (inverter based and less than or equal to 45kW generation).

Submit this Application (along with the application fee of $150) to:

D.G. Coordinator
American Electric Power
1 Riverside Plaza
Columbus, Ohio 43215-2373
614-716-4020 Office / 614-716-1414 Fax
dgcoordinator@aep.com

(Contact person listed is subject to change. Please visit our website for up-to-date information http://www.kentuckypower.com)

Applicant

Name:

Mailing Address:

City: State: Zip:

Phone: ( ) Phone: ( )

E-mail address:

Service Location

Name:

Street Address:

City: State: Zip:

Electric Service Account Number

Provide names and contact information for other contractors, installers, or engineering firms involved in the design and installation of the generating facilities:

Alternate Contacts

Name	**Company**	Telephone/Email

(Cont'd on Sheet No. 28-16)

TARIFF N.M.S. II N
(Net Metering Service II)

APPLICATION FOR INTERCONNECTION AND NET METERING, LEVEL 2 - CONTINUED

Equipment Qualifications

Total Generating Capacity (kW) of the Generating Facility:

Type of Generator: ( ) Inverter-Based ( ) Synchronous ( ) Induction

Energy Source: ( ) Solar ( ) Wind ( ) Hydro ( ) Biogas ( ) Biomass

Attach documentation showing that inverter is certified by a nationally recognizes testing laboratory to meet the requirements of UL 1741.

Attach site drawing or sketch showing locations of Kentucky Power Company meter, energy source, accessible disconnect switch and inverter.

Attach single line drawing showing all electrical equipment from the metering location to the energy source including switches, fuses, breakers, panels, transformers, inverters, energy source, wire size, equipment ratings, and transformer connections.

Expected Start-up Date:

(Cont'd on Sheet No. 28-17)

N

TARIFF N.M.S. II
(Net Metering Service II)

Interconnection Agreement – Level 2

This Interconnection Agreement (Agreement) is made and entered into this day of _, 20 _, by and between Kentucky Power Company (Company), and _ (Customer). Company and Customer are hereinafter sometimes referred to individually as "Party" or collectively as "Parties"

Witnesseth:

Whereas, Customer is installing, or has installed, generating equipment, controls, and protective relays and equipment (Generating Facility) used to interconnect and operate in parallel with Company's electric system, which Generating Facility is more fully described in Exhibit A, attached hereto and incorporated herein by this Agreement, and as follows:

Location: _

Generator Size and Type:

Now, therefore, in consideration thereof, Customer and Company agree as follows:

Company agrees to allow Customer to interconnect and operate the generating Facility in parallel with the Company's electric system and Customer agrees to abide by Company's Net Metering Tariff and all Terms and Conditions listed in this Agreement including any additional conditions listed in Exhibit A.

(Cont'd on Sheet No. 28-18)

TARIFF N.M.S. II
(Net Metering Service II) N

TERMS AND CONDITIONS FOR LEVEL 2:

To interconnect to the Kentucky Power Company (Company) distribution system, the customer's generating facility shall comply with the following terms and conditions:

1. Company shall provide customer net metering services, without charge for standard metering equipment, through a standard kilowatt-hour metering system capable of measuring the flow of electricity in two (2) directions. If the customer requests any additional meter/meters or distribution upgrades are needed to monitor the flow in each direction, such installations shall be at the customer's expense.

2. Customer shall install, operate, and maintain, at customer's sole cost and expense, any control, protective, or other equipment on the customer's system required by the Company's technical interconnection requirements based on IEEE 1547, the NEC, accredited testing laboratories such as Underwriters Laboratories, and the manufacturer's suggested practices for safe, efficient, and reliable operation of the generating facility in parallel with Company's electric system. Customer shall bear full responsibility for the installation, maintenance, and safe operation of the generating facility. Upon reasonable request from the Company, customer shall demonstrate generating facility compliance.

3. The generating facility shall comply with, and the customer shall represent and warrant its compliance with: (a) any applicable safety and power quality standards established by the Institute of Electrical and Electronics Engineers (IEEE) and accredited testing laboratories such as Underwriters Laboratories (UL); (b) the National Electrical Code (NEC) as may be revised from time to time; (c) Company's rules, regulations, and Company's Terms and Conditions of Service as contained in Company's Retail Electric Tariff as may be revised from time to time with the approval of the Kentucky Public Service Commission (Commission); (d) the rules and regulations of the Commission, as such rules and regulations may be revised from time to time by the Commission; and (e) all other applicable local, state, and federal codes and laws, as the same may be in effect from time to time. Where required by law, customer shall pass an electrical inspection of the generating facility by a local authority having jurisdiction over the installation.

4. Any changes or additions to the Company's system required to accommodate the generating facility shall be considered excess facilities. Customer shall agree to pay Company for actual costs incurred for all such excess facilities prior to construction.

5. Customer shall operate the generating facility in such a manner as not to cause undue fluctuations in voltage, intermittent load characteristics, or otherwise interfere with the operation of Company's electric system. At all times when the generating facility is being operated in parallel with Company's electric system, customer shall so operate the generating facility in such a manner that no adverse impacts will be produced thereby to the service quality rendered by Company to any of its other customers or to any electric system interconnected with Company's electric system. Customer shall agree that the interconnection and operation of the generating facility is secondary to, and shall not interfere with, Company's ability to meet its primary responsibility of furnishing reasonably adequate service to its customers.

(Cont'd on Sheet No. 28-19)

TARIFF N.M.S. II N
(Net Metering Service II)

TERMS AND CONDITIONS FOR LEVEL 2, continued

6. Customer shall be responsible for protecting, at Customer's sole cost and expense, the generating facility from any condition or disturbance on Company's electric system, including, but not limited to, voltage sags or swells, system faults, outages, loss of a single phase of supply, equipment failures, and lightning or switching surges, except that the Company shall be responsible for repair of damage caused to the generating facility resulting solely from the negligence or willful misconduct on the part of the Company.

7. After initial installation, Company shall have the right to inspect and/or witness commissioning tests, as specified in the Level 1 or Level 2 Application and approval process. Following the initial testing and inspection of the generating facility and upon reasonable advance notice to customer, Company shall have access at reasonable times to the generating facility to perform reasonable on-site inspections to verify that the installation, maintenance and operation of the generating facility comply with the requirements of this tariff.

8. For Level 2 generating facilities, where required by the Company, an eligible customer shall furnish and install on customer's side of the point of common coupling a safety disconnect switch which shall be capable of fully disconnecting the customer's energy generating equipment from Company's electric service under the full rated conditions of the customer's generating facility. The external disconnect switch (EDS) shall be located adjacent to Company's meters or the location of the EDS shall be noted by placing a sticker on the meter, and shall be of the visible break type in a metal enclosure which can be secured by a padlock. If the EDS is not located directly adjacent to the meter, the customer shall be responsible for ensuring the location of the EDS is properly and legibly identified for so long as the generating facility is operational. The disconnect switch shall be accessible to Company personnel at all times. The Company may waive the requirement for an EDS for a generating facility at its sole discretion, and on a case-by-case basis, upon review of the generating facility operating parameters and if permitted under the Company's safety and operating protocols.

   The Company shall establish a training protocol for line workers on the location and use of the EDS, and shall require that the EDS be used when appropriate, and that the switch be turned back on once the disconnection is no longer necessary.

9. Company shall have the right and authority at Company's sole discretion to isolate the generating facility or require the customer to discontinue operation of the generating facility if Company believes that: (a) continued interconnection and parallel operation of the generating facility with Company's electric system creates or contributes (or may create or contribute) to a system emergency on either Company's or customer's electric system; (b) the generating facility is not in compliance with the requirements of this tariff, and the noncompliance adversely affects the safety, reliability or power quality of Company's electric system; or (c) the generating facility interferes with the operation of Company's electric system. In non-emergency situations, Company shall give customer notice of noncompliance including a description of the specific noncompliance condition and allow customer a reasonable time to cure the noncompliance prior to isolating the generating facilities. In emergency situations, when the Company is unable to immediately isolate or cause the customer to isolate only the generating facility, the Company may isolate the customer's entire facility.

(Cont'd on Sheet No. 28-20)

DATE OF ISSUE: June 29, 2020
DATE EFFECTIVE: Service Rendered On And After December 30, 2020
ISSUED BY: /s/ Brian K. West
TITLE: Director, Regulatory Services
By Authority Of an Order of the Public Service Commission
In Case No. 2020-00174 Dated XXXXXX

TARIFF N.M.S. II
(Net Metering Service II)

N

TERMS AND CONDITIONS FOR LEVEL 2, continued

10. Customer shall agree that, without the prior written permission from Company, no changes shall be made to the generating facility as initially approved. Increases in generating facility capacity will require a new "Application for Interconnection and Net Metering" which will be evaluated on the same basis as any other new application. Repair and replacement of existing generating facility components with like components not resulting in increases in generating facility capacity are allowed without approval.

11. To the extent permitted by law, the customer shall protect, indemnify, and hold harmless the Company and its directors, officers, employees, agents, representatives and contractors against and from all loss, claims, actions or suits, including costs and attorneys fees, for or on account of any injury or death of persons or damage to property caused by the customer or the customer's employees, agents, representatives and contractors in tampering with, repairing, maintaining or operating the customer's generating facility or any related equipment or any facilities owned by the Company except where such injury, death or damage was caused or contributed to by the fault or negligence of the Company or its employees, agents, representatives, or contractors.

    The liability of the Company to the customer for injury to person and property shall be governed by the tariff(s) for the class of service under which the customer is taking service.

12. The customer shall maintain general liability insurance coverage (through a standard homeowner's, commercial, or other policy). Customer shall provide Company with proof of such insurance at the time that application is made for net metering.

13. By entering into an Interconnection Agreement, or by inspection, if any, or by non-rejection, or by approval, or in any other way, Company does not give any warranty, express or implied, as to the adequacy, safety, compliance with applicable codes or requirements, or as to any other characteristics, of the generating facility equipment, controls, and protective relays and equipment.

14. Customer's generating facility is transferable to other persons or service locations only after notification to the Company has been made and verification that the installation is in compliance with this tariff. Upon written notification that an approved generating facility is being transferred to another person, customer, or location, the Company will verify that the installation is in compliance with this tariff and provide written notification to the customer(s) within 20 business days. If the installation is no longer in compliance with this tariff, the Company will notify the customer in writing and list what must be done to place the facility in compliance.

15. The customer shall retain any and all Renewable Energy Credits (RECs) that may be generated by their generating facility.

(Cont'd on Sheet No. 28-21)

N

TARIFF N.M.S. II
(Net Metering Service II)

TERMS AND CONDITIONS FOR LEVEL 2, continued

Effective Term and Termination Rights

This Agreement becomes effective when executed by both parties and shall continue in effect until terminated. This Agreement may be terminated as follows: (a) Customer may terminate this Agreement at any time by giving the Company at least sixty (60) days' written notice; (b) Company may terminate upon failure by the Customer to continue ongoing operation of the generating facility; (c) either party may terminate by giving the other party at least thirty (30) days prior written notice that the other party is in default of any of the terms and conditions of the Agreement or the Rules or any rate schedule, tariff, regulation, contract, or policy of the Company, so long as the notice specifies the basis for termination and there is opportunity to cure the default; (d) the Company may terminate by giving the Customer at least thirty (30) days notice in the event that there is a material change in an applicable law, regulation or statute affecting this Agreement or which renders the system out of compliance with the new law or statute.

IN WITNESS WHEREOF, the Parties have executed this Agreement, effective as of the date first above written.

Customer Signature: _ **Date:**

Printed Name: _ **Title:**

Company Signature: _ **Date:**

Printed Name: **Title:**

(Cont'd on Sheet No. 28-22)

TARIFF N.M.S. II
(Net Metering Service II)

N

Interconnection Agreement – Level 2
Exhibit A

- Exhibit A will contain additional detailed information about the Generating Facility such as a single line diagram, relay settings, and a description of operation.

- When construction of the Company's facilities is required, Exhibit A will also contain a description and associated cost.

- Exhibit A will also specify requirements for a Company inspection and witness test and when limited operation for testing or full operation may begin.

PPA Rider Base Rate Amounts
12 Months Ended March 31, 2020
KPCo KY Retail Jurisdiction

PPA - Form 5.0

Line	Account	Description	Adjusted Test Year Total	Classification
(1)	4561005	Point to Point Transmision Revenues	($766,100)	Demand
(2)	4561002	RTO Formation Costs	$135,212	Demand
(3)	4561035	PJM Affiliated Trans NITS Cost	$41,633,169	Demand
(4)	4561036	PJM Affiliated Trans TO Cost	$175,036	Energy
(5)	4561060	Affil PJM Trans Enhancmnt Cost	$1,012,417	Demand
(6)	5650012	PJM Trans Enhancement Charge	$8,898,999	Demand
(7)	5650016	PJM NITS Expense - Affiliated	$39,470,780	Demand
(8)	5650019	Affil PJM Trans Enhncement Exp	$5,829,122	Demand
(9)	5650021	PJM NITS Expense - Non-Affiliated	$302,340	Demand
(10)	5650015	PJM TO Serv Expense - Affiliated	$205,520	Energy
(11)	PJM LSE OATT Base Amount		$96,896,495	
(11a)	PJM LSE OATT Monthly Base Amount		**$8,074,708**	
(12)	Forced Outage Purchase Power Limitation Base Amount - Acct 555		$ 814,208	Energy
(13)	CS IRP Credits Base Amount - Acct 44X		$ 454,997	Demand
(13a)	Non-PJM LSE OATT Monthly Base Amount		**$ 105,767**	
(12)	**Total PPA Base Amount**		**$ 98,165,699**	
(13)	Monthly PPA Base Amount to be used for Periods less than 12 months (Line 12/12)		**$8,180,475**	

KENTUCKY POWER COMPANY P.S.C. KY. NO. ~~11 1ST REVISED~~12 ORIGINAL SHEET NO. 23-1 T
CANCELLING P.S.C. KY. NO. 11 1ST REVISED~~ORIGINAL~~ SHEET NO. 23-1 T

FEDERAL TAX CUT TARIFF

(F.T.C.)

APPLICABLE.

To Tariffs R.S., R.S.D., R.S.-L.M.-T.O.D., R.S.-T.O.D., Experimental R.S.-T.O.D.2, G.S., S.G.S.-T.O.D., M.G.S.-T.O.D., L.G.S., L.G.S.-T.O.D., I.G.S., C.S.- I.R.P., C.S. Coal, M.W., O.L., and S.L~~.~~.

RATE.

1. Pursuant to the final order of the Kentucky Public Service Commission in Case No. 2018-00035 and the Stipulation and Settlement Agreement dated April 25, 2018 as filed and approved by the Commission, Kentucky Power Company is to credit to retail ratepayers the approved annual amount of excess accumulated deferred federal income taxes (ADIT) beginning July 1, 2018 and continue to do so until the Company's base rates are re-set in a future base rate proceeding.

2. The ~~Annual Total Rate Credit Amount (AC) was calculated as follows:~~Company proposes to maintain the same rates in calendar year 2021 as are in effect in calendar year 2020. DT T

~~AC = the sum of~~ The Company shall amortize the ~~(1/18th of estimated retail Generation and Distribution related Unprotected Excess ADIT) +~~ calendar year ~~estimated~~ retail Generation and Distribution related ARAM of Protected Excess ADIT and the amount of retail Generation and Distribution related Unprotected Excess ADIT needed to support the remainder of the actual calendar year rate credits provided to customers through this rider. DT T

~~3. The allocation of the actual Annual Tax Credit Amount between residential and all other customers shall be based upon their respective contribution to total retail revenues, according to the following formula:~~ D

~~Residential Allocation RA(y) = AC(y) x KY Residential Retail Revenue RR / KY Retail Revenue R~~

~~All Other Allocation OA(y) = AC(y) x KY All Other Classes Retail Revenue OR / KY Retail Revenue R~~

~~Where:~~
~~(y) = the credit year;~~
~~RR = $236,006,728;~~
~~OR = $316,554,577; and~~
~~R = $552,561,305.~~

3~~4~~. The Residential ~~Allocation~~ rate credits and All Other ~~Allocation~~ rate credits shall be credited to customers on a kWh basis as follows: T

	Residential ($/kWh)	All Other ($/kWh)	
~~July – December 2018~~	~~$0.004803~~	~~$0.003188~~	D
~~January – March and December 2019~~	~~$0.003593~~	~~$0.001604~~	
~~April – November 2019~~	~~$0.001000~~	~~$0.001604~~	
January – March and December 2020~~*~~	$0.003686	$0.001635	
April – November 2020~~*~~	$0.001000	$0.001635	
January – March and December 2021	$0.003686	$0.001635	N
April – November 2021	$0.001000	$0.001635	

~~* And continuing thereafter for the applicable months until the Company's rates are changed as part of a base rate proceeding, but not to exceed a period longer than 18 years total from January 1, 2018.~~ T

Post 2021:
4~~3~~. The allocation of the actual retail Generation and Distribution related ARAM of Protected Excess ADIT and any Commission authorized amount of Unprotected Excess ADIT, between residential and all other customers shall be based upon their respective contribution to total retail revenues, according to the following formula:

T

Residential Allocation RA(y) = AC(y) x KY Residential Retail Revenue RR / KY Retail Revenue R

All Other Allocation OA(y) = AC(y) x KY All Other Classes Retail Revenue OR / KY Retail Revenue R

Where:
(y) = the credit year;
RR = $269,181,515;
OR = $328,960,189; and
R = $598,141,704.

DATE OF ISSUE: June 29, 2020
DATE EFFECTIVE: Service Rendered On And After December 30, 2020
ISSUED BY: /s/ Brian K. West
TITLE: Director, Regulatory Services
By Authority Of an Order of the Public Service Commission
In Case No. 2020-00174 Dated XXXXXX

KENTUCKY POWER COMPANY P.S.C. KY. NO. 12 ORIGINAL SHEET NO. 36-1 T
CANCELLING P.S.C. KY. NO. 11 ORIGINAL SHEET NO. 36-1 T

RIDER D.R.S. T
(Demand Response Service)

AVAILABILITY OF SERVICE N

Available for Demand Response Service ("DRS") to customers that take firm service from the Company under a standard demand-metered rate schedule and that have the ability to curtail load under the provisions of this Schedule. Each customer electing service under this Schedule shall contract, via a Contract Addendum, for a definite amount of firm and interruptible capacity agreed to by the Company and the customer. The interruptible capacity amount shall not exceed the Customer's average on-peak demand for the past 12 months. The Company reserves the right to limit the aggregate amount of interruptible capacity contracted for under this Schedule. The Company will take Customer DRS requests in the order received. Customers taking service under this Schedule shall not participate in any PJM demand response program for Capacity.

CONDITIONS OF SERVICE

1. The Company, in its sole discretion, reserves the right to call for curtailments of the Customer's interruptible load at any time. Such interruptions shall be designated as "Discretionary Interruptions" and shall not exceed sixty (60) hours of interruption during any Interruption Year. The "Interruption Year" shall be defined as the consecutive twelve (12) month period commencing on June 1 and ending on May 31. Should this Schedule become effective on a date other than June 1, the period from the effective date of this Schedule until the next May 31 after such effective date shall be referred to as the "Initial Partial Interruption Year." In any Initial Partial Interruption Year, Discretionary Interruptions shall not exceed a number of hours equal to the product of the number of full calendar months during the Initial Partial Interruption Year and the annual interruption hours divided by 12.

2. The monthly Interruptible Demand Credit Rate shall be $5.50/kW-month, credited to participating Customers' bills for standard tariff service.

3. The Company will endeavor to provide the Customer with as much advance notice as possible of a Discretionary Interruption. The Company shall provide notice at least 90 minutes prior to the commencement of a Discretionary Interruption. Such notice shall include both the start and end time of the Discretionary Interruption. For any Discretionary Interruption, the Customer shall be permitted to choose not to interrupt and to continue to operate during the event, provided that the Customer pays the DRS Event Failure Charge. Discretionary Interruptions shall begin and end on the clock hour.

4. Discretionary Interruption events shall be three (3) consecutive hours and there shall not be more than six (6) hours of Discretionary Interruption per day.

5. The Company will inform the Customer regarding the communication process for notices to curtail. The Customer is ultimately responsible for receiving and acting upon a curtailment notification from the Company.

(Cont'd On Sheet 36-2)

DATE OF ISSUE: June 29, 2020
DATE EFFECTIVE: Service Rendered On And After December 30, 2020
ISSUED BY: /s/ Brian K. West
TITLE: Director, Regulatory Services
By Authority Of an Order of the Public Service Commission
In Case No. 2020-00174 Dated XXXXXX

RIDER D.R.S. (Cont'd)
(Demand Response Service)

N

6. The minimum interruptible capacity contracted for under this Schedule will be 500 kW. Customers with multiple electric service accounts at a single location may aggregate those individual accounts to meet the 500 kW minimum interruptible capacity requirement under this Schedule; however, the interruptible capacity committed for each individual account shall not be less than 100 kW.

7. All Customer meter data required under this Schedule shall be determined from 15- or 30-minute integrated metering, as applicable based on the Customer's rate schedule, with remote interrogation capability and demand recording equipment. Such metering equipment shall be owned, installed, operated, and maintained by the Company.

8. **NO RESPONSIBILITY OR LIABILITY OF ANY KIND SHALL ATTACH TO OR BE INCURRED BY THE COMPANY FOR, OR ON ACCOUNT OF, ANY LOSS, COST, EXPENSE, OR DAMAGE CAUSED BY OR RESULTING FROM, EITHER DIRECTLY OR INDIRECTLY, ANY CURTAILMENT OF SERVICE UNDER THE PROVISIONS OF THIS SCHEDULE.**

INTERRUPTIBLE CAPACITY RESERVATION

The Customer shall have established a total Capacity Reservation under its Contract for Service under the applicable demand-metered rate schedule. In a Contract Addendum, the Customer shall designate a set amount of kW of that total Capacity Reservation as the Firm Service Capacity Reservation, which is not subject to interruption under this Schedule. The Interruptible Capacity Reservation shall be the Customer's average on-peak demand over the past 12 months in excess of the Firm Service Capacity Reservation.

The Interruptible Capacity Reservation is subject to annual review and adjustment by the Company and the Customer.

MONTHLY INTERRUPTIBLE DEMAND CREDIT

The monthly Interruptible Demand Credit shall be equal to the product of Demand Credit per kW-month and the Customer's Interruptible Capacity Reservation kW.

INTERRUPTION EVENT COMPLIANCE

A Customer will be determined to have failed a DRS interruption event if the Customer has not achieved at least ninety (90) percent of their agreed upon interruptible capacity reservation during the duration of a DRS event.

(Cont'd On Sheet 36-3)

N

RIDER D.R.S. (Cont'd)
(Demand Response Service)

DRS EVENT FAILURE CHARGE

A Customer that fails one or more DRS interruption events shall repay a portion of the Customer's total annual DRS Interruptible Demand Credit per the following table:

Number of Failures	Penalty Payment %
Failure 1	5%
Failure 2	10%
Failure 3	10%
Failure 4	15%
Failure 5	15%
Failure 6	20%
Failure 7	25%
Totals	100%

The DRS Event Failure Charge equals the Customer's Interruptible Capacity Reservation kW, times the DRS Interruptible Demand Credit Rate, times 12, times the corresponding DRS Event Failure Charge Penalty Payment % set forth in the table above. Under no circumstance will a Customer be charged for DRS interruption event failures in an amount greater than the annual amount of DRS Interruptible Demand Credits the Customer would have or has received in an Interruption Year.

SETTLEMENT

The net amount of the monthly Interruptible Demand Credit and any DRS Event Failure Charge will be included in the Customer's monthly bill for electric service under its demand-metered rate schedule.

TERM

A Contract Addendum term under this Schedule shall be at least one (1) Interruption Year and shall continue for each subsequent Interruption Year until either party provides written notice no later than April 2 of its intention to discontinue service effective June 1 under the terms of this Schedule. Any participating Customer must participate for at least one full Interruption Year, therefore a Customer that begins service under this rider during the Initial Partial Interruption Year must then also participate in the subsequent full Interruption Year.

D

Exhibit AEV-7
Tariff DRS Interruptible Credit and Cost Benefit Calculations

60 Hours		$/MW-year		$/kW-Month
T	$	39,582	$	3.30
G	$	41,939	$	3.49
Total	$	81,521	$	6.79

DRS Interruptible Credit	$	5.50	$/kW-Month
	$	66,000	$/MW-yr
	$	181	$/MW-day

Annual Discount Cost vs. Cost of Service Benefit		
Interruptible kW		1,000
Annual DRS Interruptible Credit	$	(66,000)
Cost of Service Savings*	$	81,521

***Does not include any energy savings**

AEP LSE OATT PJM Incremental Cost Estimate
Used to estimate incremental cost from loads and decremental costs from peak shaving

NSPL	Existing MW	%	Add Inc/Dec MW MW	%
AEP (Including CRES)	19,131	85.12%	19,130	85.12%
Non-Affiliate	3,345	14.88%	3,345	14.88%
	22,476		22,475	
		% Increase	0.00%	

12CP	Existing MW	%	Add Inc/Dec MW MW	%
AP - 12CP	4,960	29.73%	4,959	29.73%
OP - 12CP	7,016	42.05%	7,016	42.06%
IM - 12CP	2,940	17.62%	2,940	17.62%
KP - 12CP	944	5.66%	944	5.66%
WPC - 12CP	506	3.03%	506	3.03%
KGP - 12CP	318	1.91%	318	1.91%
Operating Company Sum	16,684	100.00%	16,683	100.00%

NITS Expense			
OpCo ATRR	$	871,336,638	2020 PTRR
Transco ATRR	$	935,533,420	2020 PTRR
Schedule 12 Expense (RTEP)	$	182,724,919	Test Year Historic
Total Zonal ATRR		1,989,594,977	

	Existing	Add Project MW	Increase/(Decrease)
Allocated to AEP %	85.12%	85.12%	-0.001%
Allocated to AEP $	1,693,492,681	1,693,479,506	(13,175)
Allocated to APCo	503,436,198	503,396,616	(39,582)
Allocated to OPCo	712,197,772	712,213,576	15,804
Allocated to I&M	298,377,175	298,383,796	6,621
Allocated to KPCo	95,808,898	95,811,024	2,126
Allocated to WPCo	51,393,476	51,394,617	1,140
Allocated to KGPCo	32,279,162	32,279,878	716

	NSPL	12CP
APCo	(1)	(0.50)
OPCo	-	-
I&M	-	-
KP	-	-
WPCo	-	-
Total East Change	(1.00)	(0.50)

PJM LSE OATT Cost Reduction Based on 2020 Filed Rate $ 39,582 $/MW-Year

Generation Capacity Credit Calculation

$/MW-Day	$	100
IRM		15%
1 MW annual Value	$	41,939

Exhibit AEV-8 - GMR AMI Revenue Requirement and Rate Design Calculations

	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
AMI Meter Capital Additions	**$ 5,640,442**	**$ 5,603,695**	**$ 11,687,329**	**$ 7,595,308**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**
AMI Intangible Capital Additions	**$ 2,877,362**	**$ 359,842**	**$ 395,342**	**$ 334,525**						
Gross Meter Plant In Service	$ 5,640,442	$ 11,244,137	$ 22,931,466	$ 30,526,774	$ 30,526,774	$ 30,526,774	$ 30,526,774	$ 30,526,774	$ 30,526,774	$ 30,526,774
Gross Intangible Plant In Service	$ 2,877,362	$ 3,237,204	$ 3,632,546	$ 3,967,071	$ 3,967,071	$ 3,967,071	$ 3,967,071	$ 3,967,071	$ 3,967,071	$ 3,967,071
Total Gross Plant	$ 8,517,804	$ 14,481,341	$ 26,564,012	$ 34,493,845	$ 34,493,845	$ 34,493,845	$ 34,493,845	$ 34,493,845	$ 34,493,845	$ 34,493,845
Net Plant In Service	$ 8,042,053	$ 12,831,314	$ 23,087,823	$ 28,475,754	$ 25,647,221	$ 23,106,425	$ 20,889,349	$ 18,747,792	$ 16,679,221	$ 14,644,102
Accumulated Depreciation	$ 475,751	$ 1,650,027	$ 3,476,188	$ 6,018,091	$ 8,846,624	$ 11,387,420	$ 13,604,496	$ 15,746,054	$ 17,814,624	$ 19,849,743
ADFIT	$ 219,957	$ 530,850	$ 1,029,454	$ 1,479,126	$ 1,821,527	$ 2,019,595	$ 2,128,357	$ 2,161,238	$ 2,159,932	$ 2,152,571
Rate Base	$ 7,822,096	$ 12,300,464	$ 22,058,369	$ 26,996,628	$ 23,825,694	$ 21,086,830	$ 18,760,992	$ 16,586,553	$ 14,519,289	$ 12,491,532
Pre-Tax WACC	8.12%									
Return on Rate Base	$ 317,577	$ 816,976	$ 1,394,969	$ 1,991,633	$ 2,063,386	$ 1,823,448	$ 1,617,822	$ 1,435,110	$ 1,262,897	$ 1,096,639
Meter Depreciation Exp @ 15 Years	$ 188,015	$ 562,819	$ 1,139,187	$ 1,781,941	$ 2,035,118	$ 2,035,118	$ 2,035,118	$ 2,035,118	$ 2,035,118	$ 2,035,118
Intangible Amortization @ 5 Years	$ 287,736	$ 611,457	$ 686,975	$ 759,962	$ 793,414	$ 505,678	$ 181,958	$ 106,439	$ 33,453	$ -
Total Depreciation Expense	$ 475,751	$ 1,174,276	$ 1,826,162	$ 2,541,903	$ 2,828,532	$ 2,540,796	$ 2,217,076	$ 2,141,558	$ 2,068,571	$ 2,035,118
Property Tax Expense	$ 54,083	$ 140,373	$ 241,556	$ 346,765	$ 363,977	$ 327,868	$ 295,872	$ 266,560	$ 238,247	$ 210,649
Other O&M	$ 257,635	$ 615,554	$ 725,504	$ 867,722	$ 936,282	$ 936,282	$ 936,282	$ 936,282	$ 936,282	$ 936,282
Revenue Requirement	**$ 1,105,046**	**$ 2,747,179**	**$ 4,188,190**	**$ 5,748,023**	**$ 6,192,178**	**$ 5,628,395**	**$ 5,067,051**	**$ 4,779,510**	**$ 4,505,997**	**$ 4,278,689**
	$ -	$ -	$ -	$ -						
Meter Plant - 10 Yr MACRS half yr conv										
Tax Depreciation Year	1	2	3	4	5	6	7	8	9	10
Tax Depreciation Rates =	10.000%	18.000%	14.400%	11.520%	9.220%	7.370%	6.550%	6.550%	6.560%	6.550%
Capital Year = 2021	564,044	1,015,280	812,224	649,779	520,049	415,701	369,449	369,449	370,013	369,449
Capital Year = 2022		560,370	1,008,665	806,932	645,546	516,661	412,992	367,042	367,042	367,602
Capital Year = 2023			1,168,733	2,103,719	1,682,975	1,346,380	1,077,572	861,356	765,520	765,520
Capital Year = 2024				759,531	1,367,156	1,093,724	874,980	700,287	559,774	497,493
Capital Year = 2025					-	-	-	-	-	-
Annual Tax Depreciation Expense	$ 564,044	$ 1,575,649	$ 2,989,622	$ 4,319,961	$ 4,215,725	$ 3,372,466	$ 2,734,993	$ 2,298,135	$ 2,062,349	$ 2,000,064
Annual Deferred Tax Expense	$ 78,966	$ 212,694	$ 388,591	$ 532,984	$ 457,927	$ 280,843	$ 146,974	$ 55,233	$ 5,719	$ (7,361)
Accumulated DIT	$ 78,966	$ 291,660	$ 680,252	$ 1,213,236	$ 1,671,163	$ 1,952,006	$ 2,098,980	$ 2,154,213	$ 2,159,932	$ 2,152,571
Intangible Plant - 3 Yr SL										
Tax Depreciation Year	1	2	3	4	5	6	7	8	9	10
Tax Depreciation Rates =	33.333%	33.333%	33.333%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%
Capital Year = 2021	959,121	959,121	959,121							
Capital Year = 2022		119,947	119,947	119,947						
Capital Year = 2023			131,781	131,781	131,781					
Capital Year = 2024				111,508	111,508	111,508				
Capital Year = 2025					-	-	-			
Annual Tax Depreciation Expense	$ 959,121	$ 1,079,068	$ 1,210,849	$ 363,236	$ 243,289	$ 111,508	$ -	$ -	$ -	$ -
Annual Deferred Tax Expense	$ 140,991	$ 98,198	$ 110,013	$ (83,312)	$ (115,526)	$ (82,776)	$ (38,211)	$ (22,352)	$ (7,025)	$ -
Accumulated DIT	$ 140,991	$ 239,189	$ 349,203	$ 265,890	$ 150,364	$ 67,588	$ 29,377	$ 7,025	$ (0)	$ (0)

KENTUCKY POWER COMPANY
COST OF CAPITAL
TEST YEAR ENDED MARCH 31, 2020

SECTION V
WORKPAPER S-2
PAGE 1 OF 3

Line No. (1)	Description (2)	Reapportioned Kentucky Jurisdictional Capital 1/ (3)	Percentage of Total (4)	Annual Cost Percentage Rate (5)		Weighted Average Cost Percent (6) = (4) X (5)	GRCF		Pre -Tax WACC
1	Long Term Debt	$752,127,351	53.73%	4.040%	2/	2.17%	1.006056	Maint Fee & Uncollectible	2.18%
2	Short Term Debt	0	0.00%	2.230%	3/	0.00%			
3	Accounts Receivable Financing 4/	42,248,932	3.02%	2.802%	5/	0.08%	1.00606	Maint Fee & Uncollectible	0.08%
4	Common Equity	605,509,950	43.25%	**10.00%**	6/	4.33%	1.3527	Full GRCF	5.86%
		-------------------	-------------------			-------------------			
5	Total	$1,399,886,232	100.00%			**6.58%**			**8.12%**
		==========	==========			==========			

1/ Schedule 3, Column 14, Lines 1, 2, 3 & 4
2/ Per workpaper S-3, Pg 1, Ln 15, Col 14
3/ Per workpaper S-3, Pg 2, Ln 16
4/ Per Commission Order March 31, 2003 Case No. 2002-00169
5/ 13 Month Average Accounts Receivable Balance and 13 Month Average Annual Carrying Cost
6/ Per Recommendation of Company Witnesses McKenzie

GMR AMI - Class Allocation and Rate Design

Year 1 Revenue Requirement $ 1,105,046

	Meter Plant Allocator	Class Rev Req	Bills	GMR AMI Rates ($/Customer/Month)	Rev Proof
RS	0.44737	$ 494,367	1,605,143	$ 0.31	$ 497,594
GS-SEC	0.33730	$ 372,728	351,492	$ 1.24	$ 435,850
GS-PRI	0.04848	$ 53,569	900	$ 1.24	$ 1,116
GS-SUB	0.00817	$ 9,024	72	$ 1.24	$ 89
LGS/PS-SEC	0.06157	$ 68,039	8,352	$ 12.21	$ 101,978
LGS/PS-PRI	0.01728	$ 19,090	671	$ 12.21	$ 8,193
LGS-SUB	0.02008	$ 22,192	143	$ 12.21	$ 1,746
LGS-TRA	0.00251	$ 2,774	12	$ 12.21	$ 147
IGS-SEC	0.00032	$ 356	60	$ 78.43	$ 4,706
IGS-PRI	0.01209	$ 13,361	486	$ 78.43	$ 38,117
IGS-SUB	0.03376	$ 37,304	204	$ 78.43	$ 16,000
IGS-TRA	0.01004	$ 11,096	42	$ 78.43	$ 3,294
MW	0.00104	$ 1,144	108	$ 10.60	$ 1,145
OL	-	$ -		$ -	
SL	-	$ -		$ -	
	1	$ 1,105,046			$ 1,109,974

Exhibit AEV-9
Summary of EDR Customer Incremental Costs and Revenues

Marginal Costs - Energy

Customer Annual kWh	16,416,000
DA LMP $/kWh	0.02541
Marginal Costs - Energy	$417,131

Marginal Costs - Distribution

Distribution WO Total	$267,807
Levelized Carrying Cost	10.98%
Annual Dist Incremental Cost	$29,405

Summary of Incremental Costs and Revenues

Energy	$417,131
Distribution	$29,405
PJM LSE Transmission	$288,898
Generation Capacity	$0
	$735,434
Customer Incremental Revenue	$978,909
Net Revenue/(Cost)	**$243,476**

VERIFICATION

The undersigned, Alex E. Vaughan, being duly sworn, deposes and says he is a Director-Regulatory Pricing & Renewables for American Electric Power Service Company that he has personal knowledge of the matters set forth in the forgoing testimony and the information contained therein is true and correct to the best of his information, knowledge and belief after reasonable inquiry.

Alex E. Vaughan
Signed on 2020/06/18 06:21:31 -8:00
____
Alex E. Vaughan

STATE OF OHIO	)	
	)	Case No. 2020-00174
COUNTY OF FRANKLIN	)	

Subscribed and sworn to before me, a Notary Public in and before said County and State, by Alex Vaughan, this 18th day of June 2020.

S Smithhisler
Signed on 2020/06/18 06:21:31 -8:00
____
Notary Public

Notary ID Number: 2019-RE-775042

My Commission Expires: April 29, 2024

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

Electronic Application Of Kentucky Power Company For (1) A General Adjustment Of Its Rates For Electric Service; (2) Approval Of Tariffs And Riders; (3) Approval Of Accounting Practices To Establish Regulatory Assets And Liabilities; (4) Approval Of A Certificate Of Public Convenience And Necessity; And (5) All Other Required Approvals And Relief	)))))))	Case No. 2020-00174

DIRECT TESTIMONY OF

BRIAN K. WEST

ON BEHALF OF KENTUCKY POWER COMPANY

DIRECT TESTIMONY OF
BRIAN K. WEST ON BEHALF OF
KENTUCKY POWER COMPANY
BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY

CASE NO. 2020-00174

TABLE OF CONTENTS

Section | Page

EXHIBITS

Exhibit	Description
EXHIBIT BKW-1	Flex Pay Program Tariff
EXHIBIT BKW-2	Flex Pay Customer Statement Draft

DIRECT TESTIMONY OF
BRIAN K. WEST ON BEHALF OF
KENTUCKY POWER COMPANY
BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY

CASE NO. 2020-00174

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME, POSITION, AND BUSINESS ADDRESS.

A. My name is Brian K. West. My position is Director of Regulatory Services, Kentucky Power Company ("Kentucky Power" or the "Company"). My business address is 1645 Winchester Avenue, Ashland, Kentucky 41101.

II. BACKGROUND

Q. PLEASE DESCRIBE YOUR EDUCATIONAL AND PROFESSIONAL BACKGROUND.

A. I received an Associate's degree in Applied Science (Electronics Technology) and a Bachelor's degree in Business Management, both from Ohio University, in 1987 and 1988, respectively. I obtained a Master of Business Administration degree from Ohio Dominican University in 2008.

I began my utility industry career when I joined Ohio Power Company as a customer services assistant in Portsmouth, Ohio in 1989. This was a supervisor-in-training position, where I worked in each area of the office (*e.g.*, cashiering, new service, and credit and collections) to gain knowledge and experience with every aspect of managing an area office. After completing the training program, I initially supervised meter readers in the Portsmouth office until being promoted to office supervisor in 1993. In 1997, when the area offices closed, I transferred to Chillicothe, Ohio and accepted the position of customer services field supervisor, with responsibility for managing customer field representatives who primarily worked with customers on high-bill and other inquiries.

In 2000, after American Electric Power Company ("AEP") merged with Central and South West Corporation, I moved to Columbus, Ohio, where I held various positions in Customer Operations, mostly in process improvement and supporting regulatory filings. In 2008, I transferred to AEP's Regulatory Services department, where I supported various filings before public service commissions in Arkansas, Indiana, Michigan, Ohio, Oklahoma, Tennessee, Texas, Virginia, and West Virginia, as well as the Public Service Commission of Kentucky ("Commission").

In 2010, I was promoted to regulatory case manager, with responsibility for energy efficiency/demand response filings, integrated resource plan filings, and various renewable filings across AEP's service territory. In 2016, I moved to a case manager role with primary responsibility for most Appalachian Power Company filings before the Public Service Commission of West Virginia, the Virginia State Corporation Commission, and the Tennessee Public Utility Commission. I assumed my current position as Director of Regulatory Services for Kentucky Power in February 2019.

Q. WHAT ARE YOUR RESPONSIBILITIES AS DIRECTOR OF REGULATORY SERVICES FOR KENTUCKY POWER?

A. I am responsible for the supervision and direction of Kentucky Power's Regulatory Services Department, which has responsibility for all rate and regulatory matters involving the Company.

Q. HAVE YOU PREVIOUSLY SUBMITTED TESTIMONY IN ANY REGULATORY PROCEEDINGS?

A. Yes. I have submitted testimony in Case No. 2019-00140, concerning the Commission's six-month review of the Company's monthly environmental surcharge filings. I have also submitted testimony in Case No. 2019-00245 in support of certain changes to the Company's residential energy assistance programs. In addition, I have submitted testimony in support of the special contract filed in Case No. 2020-00019.

III. PURPOSE OF TESTIMONY

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

A. The purpose of my testimony is to support:

- Case organization and filing requirements;
- Proposed increase in annual revenues;
- Year one offset to approved rates;
- Grid Modernization Rider;
- Certificate of Public Convenience and Necessity for Advanced Metering Infrastructure ("AMI");
- Kentucky Power Flex Pay program for AMI customers;
- Time-of-Day Rates with AMI Meters;
- Depreciation;
- Capitalization adjustments;
- Certain revenue and operating expense adjustments; and
- Amortization periods for certain other deferrals.

Q. ARE YOU SPONSORING ANY EXHIBITS?

A. I am sponsoring the following exhibits:

- Exhibit BKW-1 – Flex Pay Program Tariff
- Exhibit BKW-2 – Flex Pay Customer Statement Draft

Q. ARE YOU SPONSORING ANY SCHEDULES?

A. Yes, I am sponsoring the following schedules, which are located in Section V of the Company's Application:

- Schedule 1: Fully Adjusted Base Case Summary
- Schedule 2: Revenue Requirement
- Schedule 3: Capitalization

They provide details of the Capitalization and Rate Base amounts, as well as the Revenue Requirement. Finally, I am sponsoring two specific adjustments to test year revenues and expenses.

Q. WERE THESE EXHIBITS AND SCHEDULES PREPARED BY YOU OR UNDER YOUR DIRECTION?

A. Yes.

IV. CASE ORGANIZATION AND FILING REQUIREMENTS

Q. PLEASE DESCRIBE HOW THE COMPANY HAS ORGANIZED THE VARIOUS ELEMENTS OF THE CASE.

A. The case has been organized into the following components:

- Section I – Application;
- Section II – Minimum filing requirements in support of the Company's application in conformity with 807 KAR 5:001, Section 16 and 807 KAR 5:011, and other applicable provisions;

- Section III – Prepared testimony and exhibits in support of the Company's application in conformity with 807 KAR 5:001, Section 16;
- Section IV – Financial exhibit in the form prescribed by 807 KAR 5:001, Section 12. Balance sheet data is shown as of March 31, 2020, and income statement data is shown for the twelve months ended March 31, 2020; and
- Section V – Description and quantification of all proposed adjustments, with proper support for any proposed changes as prescribed by 807 KAR 5:001 Section 16.

Q. HAS THE COMPANY COMPLIED WITH THE COMMISSION'S REGULATIONS REQUIRING CERTAIN ADDITIONAL DATA TO BE FILED?

A. Yes. The information required to be filed with a general rate case, including those requirements set forth in 807 KAR 5:001, Section 16 and 807 KAR 5:011, are presented in Section II (filing requirements) of the Company's filing, Section III (testimony), and Section V (adjustments).

V. PROPOSED INCREASE IN ANNUAL REVENUES

Q. PLEASE DESCRIBE THE REVENUE REQUIREMENT INCREASE BEING PROPOSED BY THE COMPANY.

A. The Company is proposing a total annual revenue requirement increase of $70,096,743. Schedule 2 shows how Kentucky Power derived the change in revenue requirement increase. This calculation is prior to the inclusion of $1,105,046 for the installation of AMI meters and the exclusion of $6,200,000 for the conditional proposed decrease in the Capacity Charge to produce the proposed annual revenue requirement increase of $65,001,789, or approximately 12.2%, over the Test Year ended March 31, 2020 adjusted revenues of $532,505,823. The rates proposed by the Company are designed to produce $597,507,612 in annual revenues. Please refer to Section V, the Summary Tab, for the derivation of the proposed revenue requirement.

Q. CAN YOU SUMMARIZE THE DEVELOPMENT OF THE PROPOSED BASE CASE ANNUAL REVENUE REQUIREMENT PRESENTED IN SCHEDULE 1 OF SECTION V?

A. The development of the revenue requirement increase is shown on Schedule 1 (Fully Adjusted Base Case Summary) of Section V of the Company's filing. Schedule 1 summarizes the components of Net Electric Operating Income for the twelve months ended March 31, 2020, as adjusted, under present rates in Column 3, and the effects of the proposed rate increase on those components in Column 4. Also shown are the components of Net Electric Operating Income after giving effect to the proposed rate increase in Column 5. The total amount of rate base and capitalization is also shown, along with the calculated overall rates of return.

Q. PLEASE DESCRIBE THE INFORMATION PROVIDED BY SCHEDULE 3 (CAPITALIZATION) OF SECTION V.

A. Schedule 3 shows the Company's development of the adjusted capitalization amount used to develop the base case annual revenue requirement.

VI. YEAR ONE OFFSET TO APPROVED RATES

Q. PLEASE EXPLAIN THE PROPOSAL TO OFFSET THE FIRST YEAR OF THE CHANGE IN APPROVED RATES PAID BY CUSTOMERS BY USING EXCESS UNPROTECTED DEFERRED FEDERAL INCOME TAX DOLLARS.

A. Kentucky Power's customers have faced unprecedented economic challenges in recent years. From the decline of the coal industry in eastern Kentucky to the more recent losses of AK Steel and Our Lady of Bellefonte Hospital, employment opportunities in the region have declined. As a result, customers have had to leave the area to find work. From 2008 to 2019, the population of the 20 counties served by the Company declined by approximately 29,000 persons – of which more than 10,000 were Kentucky Power customers. This is all prior to the late February 2020 emergence of the COVID-19 pandemic in the area.

Not in many decades have Americans experienced a pandemic of this magnitude, nor one with such a detrimental economic impact. The closure of businesses for several months, some never to reopen, has resulted in additional job losses in a part of the Commonwealth and country where such losses can be least afforded. This has further strained the ability of customers in eastern Kentucky to meet their financial obligations, including those associated with paying their utility bills.

The pandemic and its effects could not have been anticipated at the time the Commission approved the creation of the Federal Tax Cut Tariff ("Tariff F.T.C."), the mechanism through which Kentucky Power is presently returning unprotected retail generation and distribution excess Accumulated Deferred Federal Income Tax ("ADFIT") to customers over an 18-year amortization period.

On May 29, 2020, the Company filed its application in Case No. 2020-00176 (the "Debt Forgiveness Case"), in which it proposes to use approximately $10.8 million of its remaining unprotected excess ADFIT balance to eliminate all customer account balances that are 30 or more days delinquent as of May 28, 2020 though a one-time bill credit to all Kentucky Power customer accounts with such balances. Kentucky Power's unprotected excess ADFIT as of April 30, 2020, and prior to accounting for the relief requested in Case No. 2020-00176, totaled approximately $113.5 million.

In further recognition of the unique and often financially dire circumstances in which the Company's customers find themselves, the Company proposes in this case to use an additional portion of its remaining unprotected excess ADFIT balance to offset the increase in its revenue requirement for base rates for 2021 approved in this case. Under the Company's proposal, customers' base rates would not increase for a full year, until the January 2022 billing cycle, when predictions are that the economy will have returned closer to normal.

Q. HAS THE COMPANY CALCULATED THE AMOUNT OF UNPROTECTED EXCESS ADFIT REQUIRED TO OFFSET THE FIRST YEAR INCREASE?

A. The Company estimates that approximately $65 million[1] of its existing unprotected excess ADFIT balance will be required to offset the first year rate increase Kentucky Power is proposing in this case.

Q. WHAT IS THE COMPANY'S PROPOSAL WITH REGARD TO TARIFF F.T.C.?

A. The per-kilowatt hour rates for Tariff F.T.C. for calendar years 2018 and 2019, and through at least November 2020, were prescribed by Tariff F.T.C. Tariff F.T.C. further provides that its rates are to be reset in Kentucky Power's next base rate case. The Company proposes to shorten the 18-year amortization period for Tariff F.T.C. and maintain the 2020 rates shown on Tariff F.T.C., based upon the outcome of this case

[1] Proposed total net revenue increase of $65,001,789 / ADFIT gross revenue conversion factor of 1.34482 = $48,334,936 amortization of excess unprotected ADFIT.

and the Debt Forgiveness Case, until the remaining excess ADFIT balance has been returned to customers through the tariff. The combined effect of the Company's proposals in the Debt Forgiveness Case and this case, which if approved will return to customers the unprotected excess ADFIT balance more quickly than agreed to in Case No. 2018-00035.

VII. GRID MODERNIZATION RIDER

Q. PLEASE GENERALLY DESCRIBE THE PURPOSE OF THE GRID MODERNIZATION RIDER.

A. The Grid Modernization Rider ("GMR") is the proposed recovery mechanism for projects to modernize the distribution grid or to improve its reliability and resiliency. The Company's proposed AMI project is the first such distribution grid modernization project. Company Witness Phillips discusses other modernization and reliability projects that may be proposed in a future preceding and recovered, subject to Commission approval, through the GMR.

Q. EXPLAIN WHY A RIDER IS NECESSARY TO RECOVER THE PROPOSED AMI PROJECT OR OTHER GRID MODERNIZATION PROJECTS.

A. Traditionally, riders are used to recover costs that are more volatile in nature and occur over a relatively short period of time. They also ensure that customers pay no more, nor less, than the cost, while providing the Commission a more frequent opportunity to review project status and costs through the annual true-up filings. With the increasing pace of technological advancements, riders provide the Company with the ability to propose new projects for Commission review in the annual filings rather than waiting for the next base rate case. Projects that will benefit customers with improved customer experience, reliability and help to modernize the distribution grid will be brought in-service more quickly with more transparency than possible through base rate case filings. By creating the GMR, the Commission will be creating a cost recovery mechanism that will provide Kentucky Power the opportunity to potentially lengthen the period between base rate case filings. Finally, it would smooth out rate increases by allowing for smaller, more manageable annual increases as opposed to larger increases every two to three years with base rate cases. In simple terms, the GMR is the right tool for the job.

Q. PLEASE DESCRIBE HOW THE PROPOSED GRID MODERNIZATION RIDER WILL FUNCTION.

A. The proposed GMR will recover capital, including carrying costs, and incremental operation and maintenance ("O&M") expense associated with the AMI project along with future distribution grid modernization expenses approved by the Commission in future proceedings. The GMR is an important part of the Company's proposal to provide needed capital funding for advanced technologies, including the deployment of AMI, to modernize the distribution grid. The GMR includes components to recover property taxes, depreciation, and to earn a return on plant-in-service based on the cost of debt, return on common equity, and capital structure approved in this case.

Q. CAN YOU ILLUSTRATE THE OPERATION OF THE GMR BY USING THE COMPANY'S PROPOSED AMI PROJECT AS AN EXAMPLE?

A. Yes. As presented by Company Witness Blankenship, the deployment of AMI is projected to take place over a four-year period, beginning in 2021 and ending in 2024. Company Witness Vaughan used the Company's forecasted first-year AMI investment to develop a revenue requirement. The Company proposes to make an annual true-up filing on June 15 each year, with rates becoming effective with cycle 1 of the September billing period, to reconcile the amount collected through the rider in the previous year with the past year's actual spend. Any historic over- or under-recovery would be included in the GMR revenue requirement for the next 12-month period.

Q. WOULD FORECASTED EXPENDITURES ALSO BE RECOVERED THROUGH THE GMR?

A. Yes. Once the over/under calculation is complete, a forecast of the upcoming year's expenditures would then be used to determine the final revenue requirement for the next 12 months.

Q. HOW DOES USING A FORECAST FOR COSTS INCURRED IN 2021 BENEFIT CUSTOMERS?

A. As proposed by the Company, the approved base rate increase, plus the proposed revenue requirement for the GMR, would be offset in 2021 with unprotected excess ADFIT. This means that customers will not see an increase in their bills during the first year of the AMI deployment. If cost recovery through the GMR were postponed until after first-year AMI deployment costs were incurred, those costs would be collected from customers rather than offset with other first year rate increases.

Q. WHAT WOULD HAPPEN TO THE GMR IF KENTUCKY POWER WERE TO FILE A BASE RATE CASE PRIOR TO THE COMPLETION OF ITS AMI DEPLOYMENT?

A. If Kentucky Power were to file a base rate case prior to the completion of its AMI deployment (presently expected to be complete in 2024), the Company would propose to roll any GMR revenue requirement into base rates. At that point, there would be a basing point for AMI costs included in base rates and any incremental costs would continue to be recovered through the GMR going forward until included in base rates or the project was completed and all costs were recovered.

Q. WILL KENTUCKY POWER PROVIDE ANNUAL REPORTS TO THE COMMISSION REGARDING THE PROGRESS OF THE AMI DEPLOYMENT?

A. Yes. The Company is proposing to file an annual true-up of the GMR by June 15 each year. As a part of that filing, Kentucky Power will include a status report detailing, among other things, the number of AMI meters and accompanying infrastructure installed during the period covered by the true-up filing.

Q. WOULD THE GMR TERMINATE ONCE AMI IS DEPLOYED?

A. No. Kentucky Power proposes to recover through the GMR the costs associated with all distribution grid modernization projects approved by the Commission. AMI will be the first distribution grid modernization project included in the GMR. The GMR also would continue to recover costs associated with any other projects the Commission approves for inclusion in the rider. Company Witness Phillips explains the need for various distribution projects to improve reliability and resiliency and further modernize the distribution grid. The GMR is designed to recover the capital and incremental O&M that such distribution projects require. More and more in a digital world, people rely on a strong electric grid to power their homes and businesses. Nowhere has that point been made better than with many Kentuckians working from home through the COVID-19 pandemic. Kentucky Power understands this and with Commission support will make investments in its electric grid for the betterment of its customers and the communities we serve.

VIII. CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY FOR AMI

Q. PLEASE PROVIDE A BRIEF OVERVIEW OF AMI.

A. AMI is meter reading technology using two-way communications such that a meter can send information back to the utility and the utility can communicate instructions to the meter. The Company's current meter reading technology, Automatic Meter Reading ("AMR") technology, is only capable of communicating in one direction – from the meter to a receiver. The details of the Company's AMI proposal, along with the associated benefits for customers, are explained in the direct testimony of Company Witness Blankenship.

Q. WHY IS THE COMPANY PROPOSING TO REPLACE ITS EXISTING AMR METERS WITH AMI METERS?

A. The Company started installing AMR metering in 2005. At the time, Kentucky Power, like many other utilities, was transitioning away from electro-mechanical meters. It took approximately two years to complete the installation of AMR meters across the Company's service territory.

Now fifteen years later, AMR technology is obsolete for several key reasons. First, the Company's existing AMR meters are experiencing a high rate of failure and quickly approaching the end of their design life. According to Company Witness Blankenship, in the past three years, the failure rate for the Company's AMR residential meters has been approximately 10%. To put this in context, AMR meters under warranty (3 years) have a failure rate of less than 1%. By 2021, nearly 70% of the

Company's existing AMR meters will reach the end of their 15-year design life. Second, nearly all vendors have stopped manufacturing and supporting AMR meters. Currently, there is only one manufacturer in the United States making the type of AMR meters used by the Company. Even this vendor is shifting its focus to AMI meters. Continuing with AMR metering when the Company is experiencing an increasing rate of failure coupled with no choice in manufacturers from which to purchase replacement meters is untenable and potentially costly. If the vendor were to go out of business or choose to stop making AMR meters, Kentucky Power would be forced to continue operating with a majority of meters in the field at or exceeding their design life and without a readily available source of replacement meters or parts. If AMR meters were in great demand, there likely would be more than one company manufacturing them. Relying on a single-source supplier is neither a reasonable nor prudent business strategy.

Q. HAS THE COMMISSION PREVIOUSLY ADDRESSED THE APPROPRIATENESS OF REPLACING OBSOLETE METER TECHNOLOGY WITH AMI METERS?

A. Yes, the Commission has addressed that issue in several cases and has approved the replacement with AMI meters of existing, one-way communicating meter technology that was or soon would be obsolete.[2] The Commission recently further elaborated upon

[2] *See, e.g.*, Order, *In the Matter of: Application Of Grayson Rural Electric Cooperative Corporation Of Grayson, Kentucky, For Commission Approval Pursuant To 807 KAR 5:001 And KRS 278.020 For A Certificate Of Public Convenience And Necessity To Install An Advanced Metering Infrastructure (AMI) System*, Case No. 2017-00419, at 8 (Ky. P.S.C. July 16, 2018); Order, *In the Matter of: Application Of Licking Valley Rural Electric Cooperative Corporation For An Order Issuing A Certificate Of Public Convenience And Necessity*, Case No. 2016-00077, at 6-7 (Ky. P.S.C. Jan. 10, 2017); Order, *In the Matter*

its reasoning in those cases, explaining that its approvals of AMI were based upon those utilities providing substantial evidence that: (1) "the existing meters were either no longer available or supported or in the near future would no longer be available or supported;" (2) the utilities "could not provide reliable, adequate service with the existing meters;" and (3) "the proposed AMI system was the least-cost alternative."[3] With regard to the third listed criterion, the Commission has explained that "a cost-benefit analysis is not a statutory requirement" and, rather, "is a tool to assist the Commission in its determination whether the proposed project is economic. When an asset is obsolete, and thus has a shortened operational life, the economic analysis typically focuses on replacement options."[4] Each of these considerations is addressed in my testimony and the testimony of Company Witness Blankenship and supports approval of the Company's AMI proposal in this case.

Q. COULD KENTUCKY POWER REPLACE AMR METERS WITH AMI METERS AS THE AMR METERS BEGIN TO FAIL?

A. No. Doing so would require the Company to support two different metering systems for an undetermined period of time until all AMR meters were replaced with AMI meters. Also, maintaining two metering systems would increase costs. This is because

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of: Application Of Clark Energy Cooperative, Inc. For A Certificate Of Public Convenience And Necessity To Install An Advanced Metering Infrastructure (AMI) System, Case No. 2016-00220, at 7-8 (Ky. P.S.C. Dec. 22, 2016).

[3] Order, *In the Matter of: Electronic Joint Application Of Louisville Gas And Electric Company And Kentucky Utilities Company For A Certificate Of Public Convenience And Necessity For Full Deployment Of Advanced Metering Systems*, Case No. 2018-00005, at 9 (Aug. 30, 2018).

[4] Order, *In the Matter of: Application Of Licking Valley Rural Electric Cooperative Corporation For An Order Issuing A Certificate Of Public Convenience And Necessity*, Case No. 2016-00077, at 6 (Ky. P.S.C. Jan. 10, 2017).

the reactive approach would require the installation of additional equipment to accommodate AMI meters throughout the Company's service territory because AMR meters will fail at unknown times and locations across the Company's service territory. Given the geographic breadth of the Company's service territory, as well as the many relatively inaccessible locations served by Kentucky Power outside urban areas, it can be difficult and costly to travel to a location, change out the meter and install the needed equipment for the single AMI meter to operate properly. The planned and systematic deployment of AMI as the Company has proposed on the other hand would minimize costs and maximize benefits for customers.

It takes careful planning and execution to make the transition from one metering system to another and to do so in an efficient, cost-effective manner. The time to make the transition from AMR to AMI is now when the Company has time to build a plan and execute that plan. There are no improvements in the ordinary course of business that will allow AMR meters to last longer or fail at a significantly reduced rate. Replacement of the Company's existing AMR meters in the near-term is inevitable and replacing like-for-like would put an outdated technology in service for an indeterminate period. Further, a "run to failure" approach would increase costs, decrease reliability, and create a fragmented customer experience decreasing the effectiveness of any customer education or engagement campaign.

Q. THE COMPANY IS APPLYING AS PART OF ITS APPLICATION IN THIS CASE FOR A CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY TO INSTALL THE AMI METERS. THE COMMISSION HAS INDICATED THAT IN ADDITION TO NEED, THE PROPOSED CONSTRUCTION MUST NOT RESULT IN WASTEFUL DUPLICATION TO AUTHORIZE THE GRANT OF A CERTIFICATE. WILL KENTUCKY POWER'S PROPOSED AMI METER DEPLOYMENT RESULT IN WASTEFUL DUPLICATION?

A. I am not an attorney, but the Commission has defined wasteful duplication to mean "an excess of capacity over need" and "an excessive investment in relation to productivity or efficiency, and an unnecessary multiplicity of physical properties."[5] Far from constituting wasteful duplication, the deployment of the AMI meters is not only required, but maintenance of the status quo is no longer feasible.

Q. PLEASE EXPLAIN YOUR CONCLUSION.

A. As I explained above, the Company's AMR residential meters are failing at a rate of 10% and nearly 70% of them are at or near the end of their design life. As a result, the maintenance of the status quo is no longer feasible. The Company thus is faced with two choices. The first is that Kentucky Power can attempt to repair and replace the increasingly obsolete AMR meters, which are only supported by a single manufacturer. The Company's ability to obtain new repair parts and replacement meters is tied to the fortunes, decision-making, and pricing strategy of a single supplier. Alternatively,

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[5] *In the Matter of: Electronic Application Of Kentucky Power Company For A Certificate Of Public Convenience And Necessity To Construct A 138 kV Transmission Line In Boyd County, Kentucky*, Case No. 2018-00072 at 6-7 (Ky. P.S.C. October 5, 2018) quoting *Kentucky Utilities C. v. Public Service Comm'n*, 252 S.W.2d 885, 890 (Ky. 1952).

Kentucky Power could purchase used AMR meters from its sister companies as they replace their AMR meters. Again, the Company would be deploying used meters that embody an obsolete technology that is at risk of no longer being supported by its manufacturer, and the Company would have no control over the number or age of the AMR meters it was able to purchase.

Maintaining the status quo also will require the Company to make new investments in its meter reading platform and IT systems to support the obsolete AMR meters. Company Witness Blankenship addresses this issue in his testimony. But the bottom line is that Kentucky Power would still be using outdated AMR meters with a newer meter reading platform that does not provide the efficiencies and benefits available with AMI. Maintaining the status quo in this fashion is a classic example of throwing good money after bad; it would be wasteful to continue to prop up the Company's existing AMR meters.

The second choice, and the one the Company is proposing in this case, is to address the operational and technological obsolescence of the existing AMR meter systems in a planned and efficient fashion by introducing AMI technology over the next four years. This is not only the prudent course operationally, but will allow the Company to achieve O&M cost savings and provide additional benefits to its customers. One significant such customer benefit is the Company's proposed Flex Pay program, discussed in detail in Section IX of my testimony below. Without AMI meters, Kentucky Power customers could not receive the many benefits of the proposed Flex Pay program.

Q. HAS KENTUCKY POWER EXAMINED ALTERNATIVES TO ITS PROPOSAL?

A. Yes. In addition, to retaining the existing AMR meters using the new platform, Kentucky Power also examined transitioning to AMI meters in the ordinary course of business. That approach would be untenable for several reasons. Deploying AMI meters in the ordinary course of business as existing meters fail would require the Company to maintain two meter reading platforms with all of the IT costs that go with each. It could also require additional equipment in order to make the necessarily dispersed installed AMI meters function properly. Further, any possibility of economies of scale in purchasing large numbers of AMI meters would be lost. A slow transition to AMI would also be confusing to customers who would not know when they would receive an AMI meter; it also would make education efforts and outreach more difficult and costly. The only logical course, and the option providing the most customer benefit, is to transition to AMI meters as the Company has proposed in this case.

Q. HOW WILL THE COMPANY'S AMI INVESTMENT BE FUNDED?

A. Kentucky Power plans to fund the cost of its AMI deployment through its operating cash flow (Tariff G.M.R.) and other internally generated funds. The Company does not anticipate issuing debt to finance the project.

Q. WILL THE COST OF THE PROJECT AFFECT MATERIALLY THE COMPANY'S FINANCIAL CONDITION?

A. No, it will not. Kentucky Power's assets, net of regulatory assets and deferred charges, as of March 31, 2020 totaled $1,849,615,357. The cost of the Company's AMI deployment thus represents an increase of approximately 1.9% in those assets. The AMI deployment will not affect the completion of any other current capital project.

IX. KENTUCKY POWER FLEX PAY PROGRAM

Q. WILL THE COMPANY BE PROVIDING ANY TARIFF OFFERINGS IN CONNECTION WITH ITS PROPOSED AMI DEPLOYMENT?

A. Yes. The Company is proposing the Flex Pay program, a voluntary prepayment program. Flex Pay allows customers to pay as they go and gives customers greater control over the frequency and timing of their payments.

Q. PLEASE PROVIDE AN OVERVIEW OF KENTUCKY POWER'S FLEX PAY PROGRAM.

A. The Flex Pay program is a voluntary payment option that allows residential customers to prepay for their electric service without incurring the cost of a deposit or other fees associated with current post-pay billing. Flex Pay customers will make deposits to their Flex Pay accounts at such times and in such amounts as are most convenient to them. The only requirement is that the Flex Pay customers maintain a positive balance in their Flex Pay account. With greater control over the frequency and timing of their payments, customers will be able to gain a better understanding of their consumption and better manage their account with the Company.

Q. WHAT ARE THE ELIGIBILITY REQUIREMENTS TO PARTICIPATE IN THE FLEX PAY PROGRAM?

A. Kentucky Power Company's Flex Pay program will be available to all residential services with an AMI meter rated up to 200 amps, except residential customers taking service under Schedule Residential Demand-Metered (R.S.D.). In addition, customers with certain medical and/or life-threatening conditions, customers on partial payment plans, Average Monthly Payment plan ("AMP") customers, Equal Payment Plan ("Budget") customers, and customers having on-site generation operated in parallel with the Company's system will not be eligible for the Company's Flex Pay Program because of the unique characteristics of their situation.

Q. WHAT RATE SCHEDULE WILL APPLY TO FLEX PAY CUSTOMERS?

A. Flex Pay customers will continue to be billed under their current, applicable tariff with portions of the rate converted to a daily rate. In other words, the standard tariff remains the basis for the bill calculation. It will be based on the customer's daily usage within a 24-hour period, the effective base rate, the rate, and all applicable riders and fees at the time of purchase. Fixed charges will be charged daily and prorated based on the number of days in the billing cycle. These amounts will be subtracted from the customer's daily account balance. A copy of the Flex Pay Program Tariff is attached as **Exhibit BKW-1**.

Figure 1 sets forth a comparison of Flex Pay to traditional (post-pay) billing.

Figure 1		
Comparison Category	**Traditional Post-pay Billing**	**Flex Pay Billing**
Timing of Payments	▪ Energy billed and paid after consumption	▪ Daily bill amounts are subtracted from the account balance each day
Account Establishment	▪ Service connection fee ▪ Deposit required	▪ Service connection fee ▪ No deposit required ▪ Initial payment of $40
Fee Requirements	▪ Late fees ▪ Reconnection fees	▪ No late fees ▪ No reconnection fees
Debt/Customer Balances	▪ Service disconnection typically occurs after a substantial notice period during which credit is extended creating accumulation of a sizable debt	▪ Service disconnected the next business day after balance reaches $0.00
Service Reconnect	▪ After disconnection, customer pays balance owed plus reconnection fee. ▪ Average reconnect time of 4.4 hours following receipt of payment.	▪ Customer reconnected within 15 minutes following positive account balance

Note: Termination notices generate the day after a new monthly bill is issued for customers who have a past due balance and are eligible for termination. This timeframe allows on average 30 days following the original bill issue date before a termination notice is generated. The termination notice provides 15 calendar days from the date the notice is issued before service termination.

The initial payment of $40 is not a fee. It is an initial deposit to the Flex Pay account balance approximately equal to one week of service based on the daily cost of approximately $5.00 for an average residential customer.

Q. HOW WILL CUSTOMERS ENROLL IN THE FLEX PAY PROGRAM?

A. Eligible customers can enroll by calling Kentucky Power's Customer Solutions Center. Based on a customer's situation, they may be required to satisfy different requirements prior to enrolling in the program. To help illustrate the enrollment process, I describe below three different scenarios that may apply to customers enrolling in the program: a new account, an existing customer with a deposit, and an existing customer with a deposit and arrears amount:

New Account: A customer establishing a new account must make an initial payment of $40 to enroll in the program. Although an initial payment is required to fund the Flex Pay account, the $40 payment is immediately available to pay for electric service. In addition, new customers establishing a Flex Pay account do not have to make a deposit. The initial payment must be made within two days of enrollment into the program; otherwise, the new customer will automatically revert to the post-payment option.

Existing customer with deposit and no arrears balance: An existing customer with a deposit who wishes to enroll in Flex Pay would still need to make an initial payment of $40. However, if the customer's deposit credit is sufficient to cover the initial $40 prepayment, the customer would not be required to make an additional payment to enroll. Any remaining deposit balance also would be applied to the Flex Pay balance and would be available for future electric use.

Existing customer with a deposit and arrears amount: Customers with a deposit and a past due amount who want to enroll in Flex Pay would be required to pay at least 50% of the entire account balance plus an initial $40 payment. However, the customer's deposit could be credited against this 50% payment. The remaining account balance will be carried into an arrears amount that will be paid with each future payment at an

80/20 split: 80% will be applied to the Flex Pay balance, and the remaining 20% will be applied to the arrears amount.

Figure 2 summarizes these enrollment scenarios.

Figure 2

Scenario	Deposit	Initial Payment	Payments Going Forward
New Customer	No deposit required	$40 Initial Flex Pay payment	No required amount for future payments. Customers are only required to keep a positive balance.
Existing Customer with deposit	Existing deposit will be applied to customer's account as a credit	$40 Initial Flex Pay payment. If deposit credit is sufficient to cover the $40, no other payment is necessary.	No required amount for future payments. Customers are only required to keep a positive balance.
Existing Customer with deposit and a past due amount	Existing deposit will be applied to customer's account as a credit	Customers required to pay at least 50% of entire account balance. However, the customer's deposit would be included as part of this 50 percent amount.	No required amount for future payments. Customers are only required to keep a positive balance.

Q. HAS FLEX PAY OR A SIMILAR PROGRAM IMPLEMENTED BY A KENTUCKY POWER AFFILIATE HELPED TO REDUCE OVERALL ARREARAGES?

A. Yes. Public Service Company of Oklahoma's ("PSO") Power Pay™ similar program has been in operation since November 2016. The 80/20 split, where 80% of a customer's payment is applied to the Power Pay balance, with the remaining 20%

applied to the arrears amount, enabled Power Pay customers to reduce their beginning arrearages of $5.1 million by approximately $3.5 million since the program began.

Q. WHAT HAPPENS WHEN A PARTICIPANT'S ACCOUNT BALANCE REACHES ZERO?

A. In addition to the availability of daily account balances, the customer will be notified through the customer's preferred communication method when a participant's account balance reaches zero. The customer will have until the beginning of the next business day to make a payment to re-establish a positive balance. Otherwise, the customer's meter will automatically be disconnected during normal business hours (normal business hours are 8:00 a.m. to 5:00 p.m., Monday through Friday, excluding Company-observed holidays). Customers will be required to adjust their payment to cover any accrued balance for usage during weekends, holidays, and moratoriums. For example, if a customer's account balance is positive on a Thursday, with Friday being a holiday, and the customer's balance goes negative over the long weekend, in addition to the daily minimum balance alerts, discussed by Company Witness Wiseman, the customer would be sent a disconnect notice on Monday. Actual disconnection of their service would occur on Tuesday unless the customer made a payment sufficient to establish a positive account balance.

Q. HOW WILL SERVICE BE RECONNECTED FOLLOWING DISCONNECTION FOR AN INSUFFICIENT BALANCE?

A. Following disconnection, a participant must re-establish a positive account balance through an authorized payment channel. Electric service is then automatically reconnected, typically within 15 minutes after the payment has posted. Other than establishing a positive balance, there are no minimum payments necessary, nor are there any reconnection or late fees assessed to customers.

Q. WILL FLEX PAY CUSTOMERS HAVE ACCESS TO AVAILABLE FINANCIAL ASSISTANCE PROGRAMS?

A. Generally, yes. Flex Pay customers will have the same access to energy assistance as they would on standard billing. Flex Pay customers who receive energy assistance will be able to apply payments from the Low Income Home Energy Assistance Program ("LIHEAP") or Social Agencies. Kentucky Power will apply all payments to the customer's account when received. However, any customer on Flex Pay who seeks Winter Hardship Reconnection, Certificate of Need or Medical Certificate under 807 KAR 5:006, Sections 14, 15 and 16 would be removed from Flex Pay and placed back onto a tariff that is otherwise applicable to the customer's post-pay service.

Q. PLEASE DESCRIBE THE PAYMENT CHANNELS THAT PROGRAM PARTICIPANTS MAY UTILIZE.

A. Authorized payment channels available to Flex Pay participants include immediate payment via telephone or website using electronic check, debit or credit cards, and any authorized in-person pay stations.

Q. WHEN DOES KENTUCKY POWER PLAN TO BEGIN ENROLLMENT OF FLEX PAY?

A. The Flex Pay program is directly tied to the Company's request for a certificate of public convenience and necessity authorizing Kentucky Power to deploy AMI meters. Subject to the Commission's approval, the Company expects to begin deploying AMI meters in the third quarter of 2021. Customers wishing to enroll in Flex Pay will be able to do so once an AMI meter is installed at their residence.

Q. ARE THERE COSTS ASSOCIATED WITH THE FLEX PAY PROGRAM?

A. The estimated one-time capital expense for establishing the Flex Pay program is approximately $605,000. These costs include software and programming changes necessary to enable the Company's billing system to accommodate Flex Pay. The one-time capital cost is included in the overall estimated cost for AMI meters supported by Company Witness Blankenship.

Q. WHAT ARE THE BENEFITS OF THE FLEX PAY PROGRAM?

A. Flex Pay provides a number of benefits. First, the program provides Kentucky Power's customers with more choices regarding when and how to pay for electric service. Offering customers additional payment options, and providing more choices to customers, allows them to decide which payment options and schedules best meet their individual needs. Customers may choose to make smaller, but more frequent payments that may be more in-line with their cash flows, rather than a larger, single monthly payment. Not only does a prepay program help customers avoid larger than expected bills, but it also provides customers more flexibility in many situations.

For example, roommates who share the cost of electricity would be able to work out various payment dynamics with each roommate being afforded the ability to make payments on the account; landlords who are managing rental properties can keep the account in their names without risk of a large balance accumulating against the account; and people assisting adult children or other family members pay for their electric service can stay informed of their usage and account balance while having a convenient method to make payments as needed. In all of these examples, each party is able to receive daily alerts, either through text messaging, email, or both, regarding account balances to ensure that everyone is kept informed throughout the month.

Second, as previously mentioned, Flex Pay allows participants to avoid deposits, reconnection fees, and late fees. By avoiding these fees, Flex Pay provides participants with flexibility, removes barriers arising as a result of the need for new customers to make deposits to establish electric service, and helps customers remain current on payment of their electric bill. Avoiding additional fees can also help to decrease account balances, benefiting all customers through a potential of reducing bad debt.

Additionally, Flex Pay enables participants to better observe the correlation between usage and cost, thus fostering more control over energy usage and the opportunity to achieve savings. In other words, customers gain a better understanding of how much their electricity usage actually costs, making them more aware of how long their dollars last and are able to better manage energy consumption.

Q. ANY WAIVERS REQUIRED TO IMPLEMENT THE FLEX PAY PROGRAM?

A. Yes. The Company is seeking a waiver from the below requirements in order to implement the Flex Pay program:

807 KAR 5:006, Section 15(1)(f) Refusal or Termination of Service. This regulation requires a utility to mail or otherwise deliver an advance termination notice. As discussed by Company Witness Wiseman, the electronic notification features of the Flex Pay program mean that customers will receive frequent and timely notice of balances and warnings of disconnection. Thus, they will receive both more, and more frequent, notices of a potential service termination, which will obviate the need for the traditional forms of notice contemplated in the regulation.

807 KAR 5:006, Section 7 Billings, Meter Readings, and Information. This regulation identifies the information that is required to appear on a customer's monthly bill. The current bill format does not allow for a transactional view of a Flex Pay participant's monthly activity. A Flex Pay participant's monthly activity could include multiple transactions. Kentucky Power proposes to provide Flex Pay customers with a modified statement that would include daily transactions.

Q. WHAT INFORMATION IS THE COMPANY PROPOSING TO PROVIDE CUSTOMERS IN CONNECTION WITH FLEX PAY?

A. **Exhibit BKW-2** contains a draft of the proposed Flex Pay customer statement (bill). This statement would be provided to the customer monthly and is the same information the customer could access online. The proposed Flex Pay customer statement will provide Flex Pay customers with substantially all applicable billing information required by 807 KAR 5:006, Section 7. Due to the nature of the Flex Pay program, however, some information – such as meter reading and consumption data – will be available to customers and reflected on their bill on a daily, rather than monthly, basis. Providing Flex Pay customers with this information daily gives them access to more detailed information, which they can use to better manage their usage and electricity bills.

The proposed Flex Pay customer statement would not include specific line items for taxes and adjustments, as identified in 807 KAR 5:006, Section 7(1)(a)(8)-(9). Including these items as separate line items on a daily basis would needlessly complicate the billing information and be unnecessary as those amounts will be reflected in the customer's daily Flex Pay amount and balance. Finally, the meter constant, the gross amount of the bill, and the date after which a penalty may apply to the gross amount identified in 807 KAR 5:006, Sections 7(1)(a)(6), (10), and (11), respectively will not be included on the Flex Pay customer statement as that information is not applicable to the proposed Flex Pay program. As such, the proposed Flex Pay bill format is appropriate given the possibility for multiple payment transactions during the month and the daily account balance calculation.

The Company will also provide multiple channels through which customers enrolled in the Flex Pay program can communicate with the Company and obtain information about the program, their account balance and minimum balance amount, and their energy usage and costs. Company Witness Wiseman's testimony details the ways in which Kentucky Power will communicate account information with Flex Pay customers.

X. TIME-OF-DAY RATES WITH AMI METERS

Q. WILL CUSTOMERS HAVE MORE INFORMATION FROM AMI METERS TO DECIDE WHETHER THEY CAN TAKE ADVANTAGE OF THE COMPANY'S TIME-OF-DAY RATE SCHEDULES?

A. Yes. The Company currently offers Time-Of-Day tariffs for residential, commercial, and industrial customers. Once customers have access to 15-minute interval data available with AMI metering – over 35,000 meter readings or data points each year – they can better take advantage of Time-Of-Day rates. Industrial customers already are more likely to have access to 15-minute interval data through special metering. Having access to all of these meter readings can help customers to more closely monitor their usage and what devices in their homes or businesses are running at different times. Customers who can identify these processes or devices and shift their usage to off-peak times have the potential to save money on a Time-Of-Day tariff.

XI. DEPRECIATION

Q. WHEN WERE THE COMPANY'S CURRENT DEPRECIATION RATES ESTABLISHED AND UPON WHAT BASIS?

A. The Company's current depreciation rates were approved in multiple rate cases. The Company's Steam Production Plant rates were last updated as part of the approved settlement agreement in Case No. 2017-00179. The depreciation rates for Big Sandy Unit 1 are based on plant in-service balances at December 31, 2016. Although the depreciation rates for the Mitchell Plant were last updated as a result of the settlement approved by the Commission in Case No. 2017-00179, the current depreciation rates are based on plant in-service balances at December 31, 2013. The Company's Transmission and General Plant rates were last updated as part of the approved settlement agreement in Case No. 2014-00396 and were calculated using plant in-service balances at December 31, 2013. The Company's Distribution depreciation rates were approved in Case No. 91-066 and were calculated using plant in-service balances at December 31, 1989.

Q. IS THE COMPANY PROPOSING NEW OR REVISED DEPRECIATION RATES FOR AMI OR AMR METERS IN THIS CASE?

A. No. The Company will propose depreciation rates for AMI and AMR meters in its next base rate case.

Q. IF THE COMPANY'S AMI PROPOSAL IS APPROVED, WHAT DEPRECIATION PERIOD WILL BE USED FOR AMI METERS AND RELATED COMMUNICATION EQUIPMENT?

A. The Company will propose a 15-year depreciation period for AMI meters and related communication equipment.

Q. WILL THE COMPANY USE A DIFFERENT DEPRECIATION PERIOD FOR AMI-RELATED SOFTWARE?

A. Yes. The Company will propose a 5-year depreciation period for AMI-related software.

XII. CAPITALIZATION ADJUSTMENTS

Q. WOULD YOU PLEASE IDENTIFY AND EXPLAIN EACH OF THE CAPITALIZATION ADJUSTMENTS THAT YOU ARE SPONSORING?

Q. PLEASE IDENTIFY EACH OF THE REVENUE AND OPERATING EXPENSE ADJUSTMENTS THAT YOU ARE SPONSORING.

A. Yes. The Capitalization adjustments I am sponsoring are set forth in Section V, Schedule 3. They are shown in Columns 5 through 13. Information regarding each of these capitalization adjustments is provide below. Specifically, I am sponsoring the following adjustments:

Adjustment	Schedule 3
Decommissioning	Column 5
Mitchell FGD Consumables	Column 6
Mitchell FGD Base to Environmental Surcharge	Column 7
Deferred Plant Maintenance	Column 8

NERC Compliance Cybersecurity	Column 9
Rockport Deferral	Column 10
Mitchell Coal Stock	Column 11
Franklin Realty Company Account No. 124 Property	Column 12
Non-Utility Property	Column 13

Additional information regarding each of these adjustments is provided below.

Decommissioning
(Schedule 3, Column 5)

The Company removed all costs related to the decommissioning of Big Sandy Unit 2 and the other coal-related assets at the Big Sandy plant. Those costs are recovered exclusively through the Decommissioning Rider. The Decommissioning Rider reflects the amortization of related unprotected accumulated deferred income tax over 18 years as ordered by the Commission in its June 28, 2018 order in Case No. 2018-00035.

Mitchell FGD Consumables
(Schedule 3, Column 6)

Kentucky Power removed all costs associated with consumables used in the operation of the flue gas desulfurization system (FGD) at the Mitchell Plant from base rates. Those costs are recovered exclusively through the Environmental Surcharge Tariff. Information regarding the derivation of Mitchell FGD consumables is included in the testimony of Company Witness Scott.

Mitchell FGD Base to Environmental Surcharge
(Schedule 3, Column 7)

As with the consumables used to operate the FGD, Kentucky Power removed the entire Mitchell FGD balance from base rates. Those costs will be recovered through the Company's Environmental Surcharge Tariff in conformity with the terms of the

Stipulation and Settlement Agreement approved in Case No. 2012-00578. Information regarding the derivation of Mitchell FGD consumables is included in the testimony of Company Witness Scott.

Deferred Plant Maintenance
(Schedule 3, Column 8)

In Case No. 2017-00179, the Commission approved the Company's request to defer the actual annual steam plant maintenance cost above or below the 3-year average included in base rates and establish a regulatory asset or liability as appropriate. The regulatory asset or liability was to be recovered by the Company or returned to customers in the Company's next base rate case. The Company recorded a regulatory asset in May 2020. Because that entry was recorded after the close of the test year in this case, Kentucky Power is increasing capitalization for this known and measurable regulatory asset. I discuss Kentucky Power's proposed amortization of the regulatory asset in Section XIV below.

NERC Compliance Cybersecurity
(Schedule 3, Column 9)

In Case No. 2014-00589, the Commission approved the deferral of certain North American Electric Reliability Corporation ("NERC") Compliance and Cybersecurity costs. Because the related intangible plant investment is earning a Weighted Average Cost of Capital ("WACC") return through the approved deferral mechanism, the Company is removing the related intangible plant and regulatory asset balances from capitalization.

Rockport Deferral
(Schedule 3, Column 10)

In Case No. 2017-00179, the Commission approved the deferral of certain Rockport charges. Because the regulatory asset is earning a WACC return through the approved deferral mechanism, the Company is removing the total deferral from capitalization.

Mitchell Coal Stock
(Schedule 3, Column 11)

The coal inventory targets at the Mitchell Plant are separately developed for the low and high sulfur coal piles. At March 31, 2020, the Mitchell Plant had 192,912 tons (Kentucky Power's 50% share) of low sulfur coal on hand at an average cost of $69.42 per ton, and a total value of $13,392,198. The target low sulfur coal inventory is 92,145 tons (Kentucky Power's 50% share). Thus, the difference between the March 31, 2020 low sulfur coal inventory and the target low sulfur coal inventory yields a downward adjustment of 100,767 tons at a March 31, 2020 value of $6,995,492.

At March 31, 2020, the Mitchell Plant had 206,631 tons (Kentucky Power's 50% share) of high sulfur coal on hand at an average cost of $45.03 per ton and a total value of $9,305,363. The target inventory level for high sulfur coal is 71,430 tons (Kentucky Power's 50% share). Thus, the difference between the March 31, 2020 high sulfur coal inventory and the target high sulfur coal inventory yields a downward adjustment of 135,201 tons at a March 31, 2020 value of $6,088,870.

The total adjustment (of both low and high sulfur coal), on a jurisdictional basis, is a reduction in capitalization of $12,888,097 based upon the March 31, 2020 value. Because coal inventory is financed with short-term debt, the Company first eliminated the short-term debt balance of $10,685,291 and then allocated the remaining capital adjustment of $2,202,806 ratably between long-term debt and common equity.

Franklin Realty Company Account No. 124 Property
(Schedule 3, Column 12)

Consistent with prior practice, the Franklin Realty Company investment, recorded in Account No. 124, was removed from the Company's capitalization.

Non-Utility Property
(Schedule 3, Column 13)

Consistent with prior practice, the non-utility property investment was removed from the Company's capitalization.

Q. IN PREVIOUS BASE RATE FILINGS, THERE WAS AN ADJUSTMENT TO REMOVE THE CARRS SITE PROPERTY FROM CAPITALIZATION. WHY IS THERE NOT A SPECIFIC ADJUSTMENT IN THIS FILING TO REMOVE THE CARRS SITE INVESTMENT?

A. The Carrs Site investment has been transferred from plant held for future use (FERC account 105) to non-utility property (FERC account 121) and included in the adjustment to remove non-utility property shown on Schedule 3, Column 13. The amount included in non-utility property for the Carrs Site investment was $5,675,578 as of March 31, 2020.

Q. HOW ARE THE CAPITALIZATION ADJUSTMENTS ALLOCATED AMONG LONG-TERM DEBT, SHORT-TERM DEBT, AND COMMON EQUITY?

A. After the adjustment relating to coal stock, the Company allocated the capitalization adjustments ratably between long-term debt and common equity based on each component's share of total adjusted capitalization at the end of the test year ending March 31, 2020.

XIII. REVENUE AND OPERATING EXPENSE ADJUSTMENTS

Q. PLEASE IDENTIFY EACH OF THE REVENUE AND OPERATING EXPENSE ADJUSTMENTS THAT YOU ARE SPONSORING.

A. The details of the revenue and operating expense adjustments are set forth on various pages of Section V, Exhibit 2 to the application. Specifically, I am sponsoring the following adjustments:

Adjustment	Adjustment No.
Rate Case Expense	W18
Coal Stock Adjustment	W41

Additional information regarding each of these adjustments is provided below.

Rate Case Expense
(Section V, Exhibit 2, W18)

Q. WHAT IS THE RATE CASE EXPENSE ADJUSTMENT?

A. The Company is entitled to recover its reasonable expenses for the preparation and litigation of this rate case proceeding, including reasonable consulting and legal expenses. The test year does not include any rate case expenses. The Company estimates a total rate case expense of $1,583,375. The estimated expenses should be amortized over three years at the rate of $527,792 per year.

Coal Stock Adjustment
(Section V, Exhibit 2, W41)

Q. WHY IS A COAL STOCK ADJUSTMENT NECESSARY?

A. The coal stock adjustment adjusts the coal pile investment at the Mitchell Plant to the supply level allowed for recovery. The supply level is based on many factors, including the means of transportation to the plant and the location of the supplier in relation to the plant. For the Mitchell Plant, the necessary supply level is 30 days for low sulfur coal and 15 days for high sulfur coal. The effect of this adjustment is to reduce Kentucky Power's Materials and Supplies – Fuel Stock working capital by $12,888,097 for Mitchell.

XIV. AMORTIZATION PERIODS FOR CERTAIN OTHER DEFERRALS

Q. OVER WHAT PERIOD IS THE COMPANY SEEKING TO RECOVER THE REGULATORY ASSETS ADDRESSED BY COMPANY WITNESS WHITNEY?

A. The Company is proposing to amortize over a three-year period the following regulatory assets: the GreenHat Default Charges in conformity with its proposal, if approved by the Commission, in Case No. 2020-00034; Plant Maintenance Cost Deferral approved by the Commission in Case No. 2017-00179; and the Big Sandy Unit 1 Operations Rider Deferral. The proposed three-year amortization period is the period the rates set in this case are expected to be in effect. The Company is proposing to amortize the NERC Compliance and Cybersecurity Cost Deferral over five years, which aligns with the five-year depreciable life of such projects, as well as with the amortization period of the current NERC Compliance and Cybersecurity Cost Deferral approved in Case No. 2017-00179. Finally, Kentucky Power proposes to amortize the Rockport Deferral regulatory asset over 5 years through Tariff P.P.A. beginning in December 2022, when the Rockport Unit Power Agreement terminates.[6] This period is consistent with the Settlement Agreement approved in Case No. 2017-00179.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, it does.

[6] At that time, the cost of service would likely be reduced; however, the extent of the difference in cost will be a function of actual PJM market energy costs after the Unit Power Agreement terminates.

TARIFF F.P.
(Flex Pay Program) TN

AVAILABILITY OF SERVICE.

This tariff is available on a voluntary basis to all residential customers who have an Advanced Metering Infrastructure (AMI) meter rated up to 200 amps installed at their residence, except those residential customers taking metered service under the Company's Tariff R.S.D.

This tariff is not available to residential customers taking metered service under Tariff R.S.D. or customers with medical, life threatening, or life support conditions; customers having on-site generation operated in parallel with the Company's system; or customers on the Average Monthly Payment (AMP) plan or Equal Payment Plan (Budget). This tariff also is not available to customers without a valid and operable electronic communication method (*i.e.*, text messaging or electronic mail). This tariff also is not available to any customer scheduled for a disconnection of service for nonpayment and who has initiated the process for enrollment in this tariff two or more times within a thirty (30) day period without completing all of the requirements for enrollment.

PROGRAM DESCRIPTION.

Kentucky Power's Flex Pay Program, is a voluntary payment option that allows customers to prepay for electric service.

TERMS AND CONDITIONS.

1. Service under the Flex Pay Program will be offered to customers under the customer's otherwise applicable standard residential rate schedule. Billing will be based on a customer's actual daily usage, the effective base rate, the tax rate, and all applicable riders and fees. Fixed charges will be applied to the account on a daily basis based on 1/30 of the total fixed charges and will be subtracted daily from the customer's Flex Pay account balance.

2. To enroll in the Flex Pay Program, a customer must make an initial payment of at least $40.00. Any deposit that an existing customer has previously paid to the Company will be applied to the customer's current account balance, with the remaining credit/debit balance from the customer's existing account, if any, transferred to the customer's Flex Pay account balance. A customer with an outstanding current balance or final account balance from a previous account may carry-over up to $1,500 of the account balance to their Flex Pay account balance to be paid off through the Flex Pay Program. Any payments to the Flex Pay account will first have a 20% portion of the payment applied to the arrears balance, with the remaining portion of the payment credited to the customer's Flex Pay account until the arrears balance is fully paid.

(Cont'd on Sheet 8-2)

N

TARIFF F.P.
(Flex Pay Program)

3. The customer is responsible for monitoring usage under this program and ensuring that the account balance is sufficient to continue electric service. The customer must maintain an account balance greater than zero, not including any arrears amount carried over from another account, to continue electric service under this program. The customer will be notified when the account reaches the customer-selected low balance amount or the amount of $25.00, whichever is greater. Notification will occur through the customer's selected form of communication, including email, and/or text message. A customer web portal will be available to view the customer's usage information.

4. Should a customer's balance reach zero, the customer will be notified via the customer's chosen communication method. The customer will have until the beginning of the next business day to reestablish a positive balance or the customer's meter will automatically be disconnected during normal business hours regardless of weather or temperature as the customer is responsible for ensuring that the Flex Pay account is adequately funded. Normal business hours are 8:00 a.m. to 5:00 p.m. ET, Monday through Friday, excluding Company-observed holidays and moratoriums. Customers will be required to pay in full any accrued balance for usage during weekends, holidays and moratoriums before service will be restored. Once the customer's payment is received and accepted, and the customer's Flex Pay account balance is greater than zero, service will be restored by the Company in a timely manner.

5. Financial assistance received for a Flex Pay account will be credited to the balance of the Flex Pay account upon receipt of the funds.

6. Customers presenting a Winter Hardship Reconnect, Certificate of Need, or Medical Certificate as provided in 807 KAR 5:006, Sections 14, 15, and 16 will be removed from the Flex Pay Program and placed on the tariff that is otherwise applicable to the customer's service.

7. No deposit, reconnect, or late fee charges shall be assessed to customers enrolled in the Flex Pay Program.

(Cont'd on Sheet 8-3)

N

TARIFF F.P.
(Flex Pay Program)

8. When the Company receives a dishonored negotiable instrument (i.e. returned check), any account credits associated with that instrument will be removed from the customer's account. If the removal of the credits results in the customer's balance reaching zero, the customer will be notified and will have until the beginning of the next business day to reestablish a positive balance or the customer's meter will automatically be disconnected during normal business hours.

9. Actual billing will continue to be based upon the applicable rate and meter readings obtained to determine consumption. Flex Pay customers are required to participate in and receive their information through the Company's paperless billing program. Customers will continue to receive an online monthly statement summary containing all of the charges, usage and payments applied during their normal 30-day billing cycle.

10. Customer accounts must be funded through a Company authorized payment channel, including immediate payment via telephone or website using electronic check, debit or credit cards, or any in-person pay station. Each authorized payment method is subject to Company guidelines. Timing of payments to accounts cannot be guaranteed if payment is made through an unauthorized pay agent or by mail.

11. The customer may cancel service under this tariff at any time and will be returned to the applicable traditional post-pay billing option in accordance with Kentucky Power's Commission approved tariffs.

12. Account settlement shall occur when participation in the plan is terminated. Termination occurs when an account is final billed or if the customer requests termination. If the account terminates off-cycle during the billing period, the remaining monthly fixed charges and fees that have not yet been collected will be applied to the final bill. After settlement of the Flex Pay account, any remaining unused balance will be transferred to the customer's other active account(s), if any. If the customer does not have any other active accounts the Company shall refund the remaining unused balance by one of the following means: a prepaid card, a check or electronic funds transfer (EFT).

TERMS AND CONDITIONS OF SERVICE (Cont'd) T

N

KENTUCKY POWER

Non-Payment/Return Mail:
PO BOX 24401
CANTON, OH 44701-4401

Flex Pay Balance as of April 30, 2020 **-$XX.XX**
Your statement date is Apr 30, 2020
Account #XXX-XXX-XXX-X-X

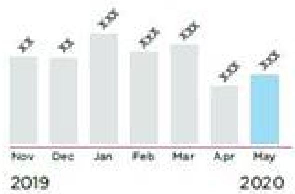
CY 02

KY PREPAY CUST
4676 N MAIN ST
ANYWHERE, KY
74126-3154

Notes from KYPO:

Your current Power Pay balance is **-$XX.XX**. Last statement balance was **-$XX.XX**, and the amount used this month was **$XX.XX**. Your total energy usage was **XXX kWh**.

Usage History (kWh):



Current statement summary:

Service from 04/01/20 - 04/30/20 (30 days)	
Power Pay payments	$X.XX
Power Pay balance	-$XX.XX
Carryover amount remaining	-$XXX.XX
$0.00 has been applied to your carryover balance.	

Methods of Payment

kentuckypower.com

PO Box 371496
Pittsburgh, PA 15250-7496

1-800-611-0964 (fee may apply)

Need to get in touch?

Customer Operations Center: 1-800-572-1113
Outages: kentuckypower.com/outages
or 1-800-572-1113

Please tear on dotted line.

Turn over for important information!

(Cont'd on Sheet No. 2-24) T

TERMS AND CONDITIONS OF SERVICE (Cont'd)

N

KENTUCKY POWER

Service Address:

KY PREPAY CUST
4676 N MAIN ST
ANYWHERE, KY 74126-3154

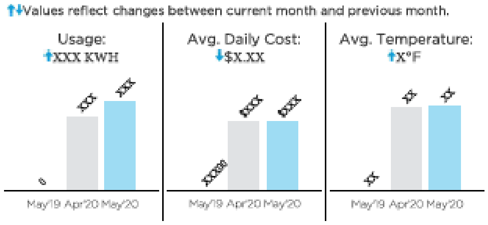
Account #XXX-XXX-XXX-X-X

Line Item Charges:

Date	Transaction	Amount	Balance	Carryover
Tariff: 015 - RESIDENTIAL SERVICE				
04/01/20	Daily Billing 5.0 kWh	-$X.X	-$XX.X	-$XXX.XX
04/02/20	Daily Billing 10.0 kWh	-$X.XX	-$XX.XX	-$XX.XX
04/03/20	Daily Billing 16.0 kWh	-$X.XX	-$XX.X	-$XXX.XX
Ending Balance			-$XX.XX	-$XXX.XX

Usage Details:

Values reflect changes between current month and previous month.



Total usage for the past X months: X,XXXX kWh
Average (Avg.) monthly usage: XXX kWh

Notes from KPCO:

Kentucky Power provides online access to customer rate schedules at https://kentuckypower.com/account/bills/rates/. You can access a copy of your rates by clicking the "Kentucky Tariffs" link at that website. You can also view rates at our office, or request that a copy be sent to you via U.S. Postal Service or via email by calling customer service at 1-800-572-1113.

Homeserve USA is optional. Homeserve USA is not the same as KPCO and is not regulated by the KY Public Service Commission. A customer does not have to buy the Warranty Service in order to continue to receive quality regulated services from KPCO www.kyelectricalprotectionplan.com

DATE OF ISSUE: June 29, 2020
DATE EFFECTIVE: Service Rendered On And After December 30, 2020
ISSUED BY: /s/ Brian K. West
TITLE: Director, Regulatory Services
By Authority Of an Order of the Public Service Commission
In Case No. 2020-00174 Dated XXXXXX

VERIFICATION

The undersigned, Brian K. West, being duly sworn, deposes and says he is Director Regulatory Services for Kentucky Power Company that he has personal knowledge of the matters set forth in the forgoing testimony and the information contained therein is true and correct to the best of his information, knowledge and belief after reasonable inquiry.

Brian K. West

COMMONWEALTH OF KENTUCKY)
) Case No. 2020-00174
COUNTY OF BOYD)

Subscribed and sworn to before me, a Notary Public in and before said County and State, by Brian K. West, this 22nd day of June 2020.

Trisha Nance
Notary Public

Notary ID Number: 632421

My Commission Expires: 9-26-2023

OFFICIAL SEAL
TRISHA NANCE
NOTARY PUBLIC - KENTUCKY
STATE-AT-LARGE
My Comm. Expires September 26, 2023
ID # 632421

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

Electronic Application Of Kentucky Power Company For (1) A General Adjustment Of Its Rates For Electric Service; (2) Approval Of Tariffs And Riders; (3) Approval Of Accounting Practices To Establish Regulatory Assets And Liabilities; (4) Approval Of A Certificate Of Public Convenience And Necessity; And (5) All Other Required Approvals And Relief	)))))))	Case No. 2020-00174

DIRECT TESTIMONY OF

KIMBERLY KAISER

ON BEHALF OF KENTUCKY POWER COMPANY

DIRECT TESTIMONY OF
KIMBERLY KAISER ON BEHALF OF
KENTUCKY POWER COMPANY
BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY

CASE NO. 2020-00174

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**DIRECT TESTIMONY OF
KIMBERLY KAISER ON BEHALF OF
KENTUCKY POWER COMPANY
BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY**

CASE NO. 2020-00174

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME, POSITION AND BUSINESS ADDRESS.

A. My name is Kimberly Kaiser. My business address is 1 Riverside Plaza, Columbus, Ohio 43215. My position is Director of Compensation for American Electric Power Service Corporation ("AEPSC"), a wholly owned subsidiary of American Electric Power Company, Inc. ("AEP"). AEP is the parent company of Kentucky Power Company (the "Company" or "Kentucky Power"). AEPSC supplies engineering, financing, accounting and other services to AEP's seven electric operating companies, including the Company. In this testimony, I will refer to AEPSC, Kentucky Power, and other AEP utility operating companies collectively as the "AEP System."

II. BACKGROUND

Q. PLEASE SUMMARIZE YOUR EDUCATIONAL BACKGROUND AND BUSINESS EXPERIENCES.

A. I received a Bachelor of Science in Business Administration from The Ohio State University in 1985. From 1986 to 1992, I worked for Society Bank as Compensation and Benefits Coordinator, completed the management-training program, and became a Retail Branch Manager. From 1995 to 2008, I worked for Bank One Corporation and J.P. Morgan Chase in a variety of compensation-based individual contributor and leadership roles. From 2008 to 2012, I was a Compensation Consultant at State Auto

Insurance. I was an Executive Compensation Consultant at Nationwide Insurance from 2012 to 2013. In 2013, I joined AEP as a Compensation Manager and received a promotion to Director of Compensation in 2017.

Q. BRIEFLY DESCRIBE YOUR DUTIES AND RESPONSIBILITIES AS DIRECTOR OF COMPENSATION.

A. I am responsible for the design, development, and administration of the AEP System's employee compensation programs. The compensation group evaluates and recommends changes to employee compensation programs as necessary. My team also develops employee communication materials in support of the compensation programs and monitors compliance with related federal and state regulations. I am also responsible for the payroll department, which processes employees' work hours, employee pay and required taxes on behalf of AEP System employees.

Q. HAVE YOU PREVIOUSLY SUBMITTED TESTIMONY IN ANY REGULATORY PROCEEDINGS?

A. Yes. I have submitted testimony on behalf of Appalachian Power Company and Wheeling Power Company in Public Service Commission of West Virginia Case No. 18-0646-E-42T, Appalachian Power Company in Virginia State Corporation Commission Case No. PUR–2020-00015, and Indiana Michigan Power Company before the Michigan Public Service Commission in Case No. U-20359.

III. <u>PURPOSE OF TESTIMONY</u>

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

A. The purpose of my testimony is to describe the AEP System's total compensation philosophy. I will also present information that demonstrates that the AEP System's employee variable pay programs are reasonable and in the best interests of customers. Accordingly, my testimony will establish that short-term and long-term compensation are necessary components of the AEP System's employee compensation package that is used to attract and retain experienced, skilled, and knowledgeable employees needed to provide safe and reliable electric service to Kentucky Power customers.

IV. OVERVIEW OF THE AEP SYSTEM'S COMPENSATION PRACTICES

Q. WHAT IS THE OVERALL PHILOSOPHY OF THE COMPENSATION PROGRAM USED BY THE AEP SYSTEM?

A. The AEP System's compensation philosophy focuses on providing employees with the opportunity to earn market-competitive total compensation while ensuring financially responsible compensation costs. This compensation approach enables Kentucky Power and other AEP System companies to attract and retain employees with the skills and experience necessary to efficiently and effectively provide reliable electric service to customers at a cost that is disciplined and necessary. Labor costs are generally built into the price of any product or service and the AEP System compensation philosophy ensures that labor costs across the AEP System are at the appropriate level.

Q. WHAT ARE THE OPTIONS GENERALLY AVAILABLE FOR EMPLOYEE COMPENSATION IN THE MARKET?

A. The basic choices in employee pay strategy are: (1) to use a 100% fixed base pay to provide market-competitive total compensation; or (2) to use a combination of lower fixed base pay with variable incentive pay opportunities tied to performance, the combination of which brings the employees' total compensation opportunities to market-competitive levels. Both of these strategies pay employees at the same level for similar positions assuming target performance is achieved for the variable component of pay in the second option.

Q. WHAT COMPENSATION STRATEGY DOES THE AEP SYSTEM, INCLUDING THE COMPANY, IMPLEMENT?

A. The Company, and the AEP System as a whole, uses a multi-element compensation method for all levels of employees. This method utilizes lower base pay in combination with goal-driven incentive opportunities that vary based on the performance of the individual employee and the overall AEP System.

Q. WHY DOES THE AEP SYSTEM COMPENSATE EMPLOYEES IN THIS MANNER?

A. The AEP System uses the multi-element compensation method for its employees because it provides the Company the ability to offer customary wage packages that include base and incentive pay, to maintain employee wages at reasonable and market-comparable levels, and to incentivize employees to spend effectively, operate efficiently, and conserve financial resources for the benefit of its customers.

Q. DOES THE COMPANY PROVIDE BONUS PAY TO ITS EMPLOYEES?

A. No. Historically, the terms 'bonus' and 'incentive' pay have been used interchangeably, but they are very different. Bonus pay provides compensation that is in addition to a market-competitive base pay salary and is tied to financial profit. Bonus pay is not required to maintain employee total compensation at market-competitive pay levels. Comparatively, incentive pay is used to supplement lower base pay to reach market-competitive levels and to motivate employees to improve performance.

The AEP System's variable incentive pay programs brings employee compensation to a market-competitive level and is tied to customer-focused operational and financial goals. Therefore, the Company's incentive pay programs are not "bonuses" as defined above.

Q. CAN YOU EXPLAIN THE INCENTIVE PAY OPTIONS THAT ARE AVAILABLE TO AEP SYSTEM EMPLOYEES?

A. The AEP System offers two types of incentive pay to its employees: variable annual (or short-term) incentive compensation ("STI"), for which all employees are eligible, and long-term incentive compensation ("LTI"), which is offered to employees in more highly-compensated positions. For the purposes of the remainder of my testimony, I will refer to the combination of base pay, STI and LTI as "Total Compensation".

V. SHORT-TERM INCENTIVE COMPENSATION

Q. PLEASE DESCRIBE THE MECHANISM USED TO FUND THE STI PROGRAM.

A. During the test year, the STI program budget was funded based on AEP's earnings per share ("EPS"), safety and compliance measures, and strategic initiatives. The EPS funding measures are set annually by the Human Resources Committee ("HRC") of AEP's Board of Directors in consultation with AEP executive management and the HRC's independent, third-party compensation consultant. Safety and compliance measures focused on the number and criticality of employee and contractor injuries, environmental stewardship and North American Electric Reliability Corporation ("NERC") compliance. Strategic initiative measures included infrastructure investment, customer experience improvements, and employee culture and diversity.

Q. DESCRIBE HOW THE STI FUNDING WAS ALLOCATED TO AEP EMPLOYEES DURING THE TEST YEAR.

A. The AEP System's STI program is available to all employees. For the test year period, incentives earned by employees were based on their business unit's performance. For example, there were separate STI plans for employees in Customer & Distribution Services, Generation, Transmission, shared services, and each operating company. Available funding was allocated to the business units and operating companies, including Kentucky Power, based on their relative performance in certain customer experience, financial, operational, and employee and contractor safety metrics. Tying compensation to these metrics incentivizes employees to spend effectively, operate efficiently, increase customer engagement and satisfaction, improve reliability and conserve financial resources, all of which provide direct benefits to the Company's customers.

Q. IS THE COMPANY REQUESTING THE INCLUSION OF ALL TEST YEAR STI COSTS IN ITS REVENUE REQUIREMENT IN THIS CASE?

A. No. The Company is including in its cost of service only the target (1.0 payout amount) of direct Kentucky Power STI for the test year. Direct STI during the test year was higher than the target amount requested in the cost of service, and, in fact, the AEP System has exceeded the 1.0 score in nine of the last ten years. The Company has normalized these direct costs to the target level in its requested cost of service, which is the amount of direct STI that the Company expects to pay in an average year. It is also the direct amount of STI that the Company needs to pay its employees, on average, in order to provide reasonable and customary, market-competitive Total

Compensation. Direct STI was adjusted to this level as described in the testimony of Company Witness Whitney.

Q. IS STI A REASONABLE EXPENSE TO BE INCLUDED AS PART OF THE COMPANY'S COST OF SERVICE?

A. Yes. The costs associated with obtaining any product or service logically comes with a cost of the labor needed to provide that product or service. The Company's STI provides substantial benefits to customers by ensuring the Company and the AEP System as a whole, can attract, retain and motivate employees to provide safe and reliable electric service to the Company's customers. Having part of employee Total Compensation tied to performance measures in the form of STI incentivizes employees to spend effectively, operate efficiently, and conserve financial resources, the benefits of which are then passed on to the Company's customers in the form of savings.

Further, the purpose of STI is to provide market-competitive compensation for employees who work to provide safe and reliable electric service to the Company's customers. The target level expense of the Company's incentive compensation program does not increase the Company's compensation expense beyond that which is required to provide reasonable and market-competitive Total Compensation to its employees. As such, any reduction or elimination of employee STI would need to be replaced with increases in base pay, thus becoming fixed costs, to maintain comparable employee Total Compensation.

VI. LONG-TERM INCENTIVE COMPENSATION

Q. PLEASE EXPLAIN THE LTI PROGRAM.

A. The primary purpose of the LTI program is to encourage leaders within the AEP System to make business decisions to serve the long-term interest of the AEP System, the Company, and its customers. During the Test Year, the Company provided LTI awards in the form of 75 percent performance shares and 25 percent restricted stock units ("RSUs").

Performance shares are similar in value to shares of AEP common stock except that participants must generally continue their AEP employment over a three-year period to earn a payout, and the number of performance shares that participants ultimately earn is tied to AEP's long-term performance.

RSUs are solely tied to the participants' continued AEP employment through vesting dates that last over a little more than a three-year vesting period. Participants who remain employed with AEP through the vesting date receive a share of AEP common stock for each vesting RSU.

Q. IS THE COMPANY REQUESTING THE INCLUSION OF ALL TEST YEAR LTI COSTS IN ITS REVENUE REQUIREMENT IN THIS CASE?

A. No. The Company is including in its cost of service only the target (1.0 payout amount) for the performance shares paid to Kentucky Power employees during the test year. RSUs are included in the Company's revenue requirement on a per books basis. A further explanation of the adjustments related to LTI is included in the testimony of Company Witness Whitney.

Q. WHAT ARE THE DIRECT BENEFITS TO CUSTOMERS OF THE COMPANY'S LTI PROGRAM?

A. As with STI, tying the variable LTI to financial performance measures promotes the efficient use of financial resources, which is paramount to providing reliable electric service at a reasonable cost to customers with a long-term perspective. Maintaining long-term financial discipline is imperative for the benefit of the Company, its customers, and shareholders, particularly given the long-term nature of the assets that comprise the Company's electric system.

Q. IS THE LONG-TERM INCENTIVE PROGRAM A REASONABLE AND NECESSARY EXPENSE TO INCLUDE IN THE COST OF RELIABLE ELECTRIC SERVICE?

A. Yes. The AEP System's LTI is a substantial component of the compensation for leaders and is critical to maintaining the market-competitiveness of such employee compensation. As with STI compensation, the LTI that the Company has included in cost-of-service is not pay that is over and above an already market-competitive level of Total Compensation and it provides significant benefits to the Company and its customers. Any reduction in LTI would need to be replaced with increases in other types of compensation in order to maintain comparable employee Total Compensation that attracts and retains the suitably skilled and experienced employees that the Company needs to efficiently, effectively, and safely provide electric service to its customers.

VII. REVIEW OF INCENTIVE COMPENSATION

Q. DO YOU HAVE ANY FURTHER COMMENTS REGARDING INCENTIVE PAY?

A. Yes, I would respectfully ask that the Commission consider the reasonableness and market competitiveness of the wages earned by employees through the Company's Total Compensation package as a whole, rather than by making a determination as to whether each individual portion of the Company's compensation package should be a part of Total Compensation. The manner in which the Company determines, measures, and allocates incentive pay is disciplined, financially responsible, and necessary to stay competitive in the utility market.

Employee compensation is but one element of the Company's cost of providing electric service. As with other such elements, it is important to evaluate whether the costs are reasonably and prudently incurred in the provision of electric service. In making that determination, the total level of compensation, and not how the compensation is structured, is the most relevant consideration. Separating out an element of compensation, in this case incentive compensation, and setting a higher standard for inclusion in cost of service could undermine a utility's ability to make decisions regarding how to properly compensate and motivate its employees. Incentive compensation is a common form of employee compensation in both the utility industry and the overall labor market. As such, many of the services that the Company procures to provide utility service to its customers will include some level of incentive compensation built into the pricing of those services.

Q. HAS THE COMPANY DEMONSTRATED THAT THE COSTS ASSOCIATED WITH INCENTIVE COMPENSATION PROVIDE APPRECIABLE BENEFITS TO CUSTOMERS?

A. Yes. The primary benefit of the Company's incentive compensation plan to customers is that it allows the Company to attract and retain suitably skilled and experienced employees necessary to provide safe and reliable electric service. Further, both STI and LTI incentivize employees to spend effectively, operate efficiently, and conserve financial resources, which provides additional benefits to the Company's customers.

Q. IN DETERMINING WHAT ELEMENTS OF EMPLOYEE COMPENSATION SHOULD BE INCLUDED IN THE COMPANY'S COST OF SERVICE, DO YOU HAVE ANY RECOMMENDATIONS?

A. Yes. The Company's incentive compensation costs were prudently incurred as part of its labor expense in providing electric service, and the level of its labor expense, including incentive compensation, is reasonable and market-competitive. Therefore, I recommend and respectfully request that the Commission permit the Company to recover the compensation and benefit costs, including STI and LTI, included in the Company's cost of service.

Q. DOES THIS CONCLUDE YOUR PRE-FILED DIRECT TESTIMONY?

A. Yes, it does.

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E-Signature Summary

E-Signature 1: Kimberly Kaiser (KK)
June 18, 2020 06:09:05 -8:00 [934909B5B2EE] [161.235.221.83]
kkkaiser@aep.com (Principal) (Personally Known)

E-Signature Notary: Sarah Smithhisler (SRS)
June 18, 2020 06:09:05 -8:00 [34B2339D13D4] [161.235.221.85]
srsmithhisler@aep.com
I, Sarah Smithhisler, did witness the participants named above electronically sign this document.

VERIFICATION

The undersigned, Kimberly Kaiser, being duly sworn, deposes and says she is Director of Compensation for American Electric Power Service Company that she has personal knowledge of the matters set forth in the forgoing testimony and the information contained therein is true and correct to the best of his information, knowledge and belief after reasonable inquiry.

Signed on 2020/06/18 06:09:05 -8:00

Kimberly Kaiser

STATE OF OHIO)
) Case No. 2020-00174
COUNTY OF FRANKLIN)

Subscribed and sworn to before me, a Notary Public in and before said County and State, by Kimberly Kaiser, this 18th day of June 2020.

Signed on 2020/06/18 06:09:05 -8:00

Notary Public

NOTARY PUBLIC
STATE OF OHIO
Sarah Smithhisler
Commission # 2019-RE-775042
Electronic Notary Public
State of Ohio
My Comm Exp. Apr 29, 2024
Notary Stamp 2020/06/18 06:09:05 PST 34B2339D13D4

Notary ID Number: 2019-RE-775042

My Commission Expires: April 29, 2024