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

POST-HEARING BRIEF OF KENTUCKY POWER COMPANY

Mark R. Overstreet
Katie M. Glass
STITES & HARBISON PLLC
421 West Main Street
P.O. Box 634
Frankfort, Kentucky 40602-0634
Telephone: (502) 223-3477
moverstreet@stites.com
kglass@stites.com

Christen M. Blend (*pro hac vice*)
Hector Garcia-Santana (*pro hac vice*)
Tanner S. Wolffram (*pro hac vice*)
American Electric Power Service Corporation
1 Riverside Plaza, 29th Floor
Columbus, Ohio 43215
Telephone: (614) 716-1915 (Blend)
cmblend@aep.com
hgarcia1@aep.com
tswolffram@aep.com

COUNSEL FOR
KENTUCKY POWER COMPANY

TABLE OF CONTENTS

I. INTRODUCTION

Since Kentucky Power Company's ("Kentucky Power" or the "Company") last base rate case in 2017, the Company's service territory has continued to undergo historic changes – the economy of southeastern Kentucky, the Company's customer base, and customers' electricity usage all continue to decline, and with them, the Company's ability to receive a fair return in exchange for the public service it is providing. The Company's earned return on equity ("ROE") as of the end of the test year was well below a recognized fair return, at 6.7%. Earnings have further eroded, to 5.3% as of September 30, 2020. These returns fall 25-40% below even the lowest end of the range of reasonableness presented in this case by the intervenors.

Kentucky Power's management and employees also are Company customers. The Company understands that this is an unprecedented time in history and that its service territory already faces challenging economic conditions. The decision to file for a rate increase was not lightly undertaken; nor was it the Company's first response to its financial straits. Kentucky Power was forced to initiate this case as a last resort to restore its financial integrity so that the Company may continue to provide safe, adequate, and reliable service to its customers. The current rates for providing that service impede the Company's ability to continue to do so, are constitutionally confiscatory, and are unfair, unjust, and unreasonable.

Kentucky Power proposes to adjust its rates to produce fair, just, and reasonable additional annual revenues of $64,692,762.[1] To temper the impact of its rate request on customers, and to provide additional time for its service territory's economy to recover, the Company made the extraordinary proposal to completely offset all first year rate increases,

[1] *See* Company Hearing Ex. 1/Record Ex. 8. This total is inclusive of the Company's conditional Capacity Charge Tariff proposal, detailed below, and the proposed Grid Modernization Rider's estimated first year revenue requirement.

ensuring that the Company's rates in total will not increase from this case until January 2022. Kentucky Power offered an innovative proposal through its debt relief filing in Case No. 2020-00176 to address the financial effect of the pandemic on its customers. The Company also made other significant proposals and compromises to further lessen the financial burden on customers. The overall value of the package of mitigation measures Kentucky Power is offering is approximately $96 million in 2021 – or nearly one and a half times the Company's $64.7 million requested rate increase.

To minimize the impact of its requested rate increase and the effect on the Company's customers, Kentucky Power narrowed the terms of its substantive proposals by focusing on those proposals that are necessary to the provision of safe and reliable service in a financially sustainable way, and that provide the most significant benefits to customers. Those proposals include:

1. The proactive deployment of advanced metering infrastructure ("AMI") technology to replace the Company's obsolete and failing automated meter reading ("AMR") meters and to provide customers with reliability, greater control, payment flexibility, data access, and other benefits;

2. The implementation of a Grid Modernization Rider ("GMR") to provide the Company with the necessary flexibility to efficiently invest capital to improve and modernize the distribution grid with proper Commission oversight, while ensuring customers pay no more nor no less than the costs of the investments;

3. The contemporaneous recovery of all of the Company's Federal Energy Regulatory Commission ("FERC") jurisdictional and FERC-approved costs of wholesale transmission costs through Tariff PPA (Purchase Power Adjustment), which ensures that the

Company timely and fully recovers those costs in a way that minimizes retail bill volatility and avoids the need for more frequent base rate cases;

4. A 10.0% ROE (a level that Company President Mattison adjusted downward from 10.3% to further limit the impacts of this case), which will permit the Company to operate successfully and maintain financial integrity while not unreasonably burdening customers;

5. Reasonable and market-competitive employee compensation and benefits that are necessary to attract and retain the employees the Company needs to provide adequate service;

6. A new net metering tariff, Tariff NMS II (Net Metering Service II), which will bring the Company's net metering compensation into compliance with recently enacted Kentucky law and protect customers by eliminating inappropriate net metering subsidies inherent in the previous statutory framework;

7. Residential rate design improvements, including an increase in the residential basic service charge and a proposed winter heating declining block rate design, which will benefit high usage electric heating and low-income customers; and

8. Other proposals, which implement previous orders of the Public Service Commission of Kentucky ("Commission"), update tariffs to provide flexible and innovative customer offerings, and which are otherwise necessary, reasonable, and beneficial to the Company and its customers.

As detailed in the Company's Application, testimony, responses to data requests, and as set forth below, the record in this case supports the relief the Company seeks in this case. As the Commission knows, its mission is to foster the Company's provision of safe and reliable service at a reasonable price to Kentucky Power's customers <u>while also providing for the Company's financial stability</u> by setting fair and just rates, and supporting he Company's operational competence by overseeing regulated activities.[2] The Commission, consistent with its mission, should approve the Company's requests in this case and provide Kentucky Power with the tools it needs to improve its financial wellbeing and enhance customers' service experience.

II. BACKGROUND

A. Overview of Kentucky Power Company

1. Customers and Service Territory

Kentucky Power generates and purchases electricity that it distributes and sells at retail to approximately 165,000 customers located in all, or portions of, the Counties of Boyd, Breathitt, Carter, Clay, Elliott, Floyd, Greenup, Johnson, Knott, Lawrence, Leslie, Letcher, Lewis, Magoffin, Martin, Morgan, Owsley, Perry, Pike, and Rowan.[3] The Company also furnishes electric service at wholesale to the City of Olive Hill and the City of Vanceburg.[4] Kentucky Power's service territory includes some of the most economically challenged and geographically challenging territory in the Commonwealth.[5] Its service territory is located in an area with rugged terrain and dense forests,[6] and includes some of the most difficult and challenging terrain in the Commonwealth.[7]

The Company's service territory also has been in economic decline since 2008.[8] This decline is widespread and has been primarily driven by the collapse of coal and steel production in the region.[9] The number of coal miners employed in eastern Kentucky dropped more than

---

[2] Kentucky Public Service Commission, About the Public Service Commission, Mission, *available at* https://psc.ky.gov/Home/About#AbtComm.
[3] Application at 2.
[4] *Id.*
[5] *Id.* at 4.
[6] Phillips Direct Test. at 11.
[7] *Id.*
[8] Wiseman Direct Test. at 21.
[9] *Id.*

75% from an annual average of 14,373 in 2008 to 3,419 in 2019.[10] Coal production has dropped even more steeply: from 91,045,224 tons in 2008 to 13,650,365 tons in 2019.[11] Declining steel prices in the global market forced steel producers in the region to reduce output.[12] For example, 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.[13]

Unemployment and declining economic activity in the entire eastern Kentucky region have resulted in a concomitant population decline in 19 of the 20 counties comprising the Company's service territory.[14] Between 2008 and 2019, population in the Company's service territory decreased by approximately 33,000 individuals or 7.6%.[15] The overall unemployment rate in the 20 counties comprising Kentucky Power's service territory is markedly higher than the 4.3% unemployment rate for Kentucky as a whole.[16] Unemployment in the Company's service territory ranges from a high of 13.8% in Magoffin County (or slightly less than one of seven persons in the labor force) to a low of 5.1% in Rowan County.[17]

As a direct result of this economic decline, Kentucky Power lost 10,184 customers or approximately 6.4% of its total customers between 2008 and 2019.[18] The Company lost over 3,000 customers since the Company filed its last base rate case alone.[19] Between 2008 and 2019 the Company's total annual weather normalized sales fell by approximately 23.4%, or from

---

[10] *Id.*
[11] *Id.*
[12] *Id.*
[13] *Id.*
[14] *Id.* at 22.
[15] *Id.*
[16] *Id.*
[17] *Id.*
[18] *Id.* at 21.
[19] Mattison Direct Test. at 3.

approximately 7.4 gigawatt hours ("GWh") to 5.7 GWh.[20] Customer usage since February 28, 2017, the end of the test year in the Company's last rate case, declined by more than 576 million kilowatt-hours.[21]

Although the economic decline and resulting symptoms of the same remain outside of the Company's control, the Company is "as committed and involved in economic development in Eastern Kentucky as [it] ha[s] always been,"[22] as explained detailed more fully herein below.

2. Generation, Transmission, and Distribution Facilities

a. Generation Facilities

The Company's Big Sandy Power Plant consists of a 285 megawatt ("MW") gas-fired steam-electric generating unit located at the Big Sandy generating station near Louisa, in Lawrence County, Kentucky.[23] In addition, Kentucky Power owns and operates a 50% undivided interest in the coal-fired Mitchell generating station, located approximately ten miles south of Moundsville, West Virginia.[24] Kentucky Power's share of the Mitchell generating station comprises 780 MW.[25] Kentucky Power also is a party to a Unit Power Agreement ("UPA") and is responsible for its contractual share of the costs associated with Rockport Plant

---

[20] Wiseman Direct Test. at 21.
[21] Mattison Direct Test. at 13 (also noting that this loss of load represents approximately $19.5 million in annual net lost revenue).
[22] Wiseman Test., Hearing Transcript ("Tr.") (filed Dec. 4, 2020) Vol. II at 548.
[23] Application at 3.
[24] *Id.*; Order, *In the Matter of: Application of Kentucky Power Company for (1) A Certificate of Public Convenience and Necessity Authorizing the Transfer to the Company of an Undivided Fifty Percent Interest in the Mitchell Generating Station and Associated Assets; (2) Approval of the Assumption by Kentucky Power Company of Certain Liabilities in Connection with the Transfer of the Mitchell Generating Station; (3) Declaratory Rulings; (4) Deferral of Costs Incurred in Connection with the Company's Efforts to Meet Federal Clean Air Act Requirements; and (5) All Other Required Approvals and Relief*, Case No. 2012-00578 (Ky. P.S.C. Oct. 7, 2013).
[25] Application at 3.

Generating Units No. 1 and No. 2 located near Rockport, Indiana.[26] Through the Rockport Unit Power Agreement, the Company possesses an additional generating capacity of 393 MW.[27]

b. Transmission and Distribution Facilities

The Company's electric transmission system includes substation capacity of approximately 3,941,000 KVA and approximately 1,326 circuit miles of line, and is interconnected with the systems of neighboring utilities.[28]

The Company's electric distribution system includes substation capacity of approximately 1,413,000 KVA and approximately 10,060 circuit miles (including secondary) of above-ground and underground line.[29] Since the last base rate case, the Company has made a Smart Grid investment in the form of Distribution Automation Circuit Reconfiguration ("DACR") technology on 18 circuits[30] but needs to do much more. Kentucky Power's Data Management System is able to gather information from electronic devices in the field, including DACR, and integrates it with the mapping system to provide the status of automated circuits.[31] The Company is considering other Smart Grid investments, including AMI, Volt/VAR programs, and others, which will improve reliability and customer experience.[32]

3. Community Involvement

Kentucky Power and its employees are active and productive members of the communities the Company serves.[33] The Company and its employees regularly contribute to

---

[26] *Id.* at 4.
[27] *Id.*
[28] *Id.* at 3.
[29] *Id.*; Phillips Direct Test. at 3.
[30] *Id.* at 30.
[31] *Id.*
[32] *Id.* at 30-31.
[33] Mattison Direct Test. at 5.

charitable, educational, and civic organizations serving Kentucky Power's service territory. Company employees participate in numerous community causes, including those that promote economic development, civic pride, and customer safety.[34] Kentucky Power and its parent, American Electric Power Company, Inc. ("AEP"), also support and participate in the local community through their involvement in and funding of charitable organizations active in the region. In 2019 alone, the Company, AEP, and the American Electric Power Foundation collectively made over $1.7 million in philanthropic donations and economic development grants in the Commonwealth.[35] Those contributions benefitted, among others, local fire departments and the Red Cross; victims of domestic violence in eastern Kentucky; science, technology, engineering, and math education programs; and a multi-use children's theater.[36] These contributions are funded 100% by the Company's shareholder for the benefit of Kentucky Power's customers and their communities.[37]

4. Customer Engagement

The Company's commitment to customers is the "guiding principle of everything that [it does]."[38] Since the Company's last base rate case in 2017, the Company has expanded its focus from a narrower view of customer service to a broader view emphasizing the overall customer experience.[39] Vital to improving the customer experience is customer communication. The Company "meets customers where they are" to enable the Company to understand the importance of its messages to customers and to maximize opportunities to engage customers

---

[34] *Id.*
[35] *Id.* This amount is incremental to the contributions made through the K-PEGG Program.
[36] *Id.*
[37] *Id.* at 6.
[38] *Id.*
[39] Wiseman Direct Test. at 4.

through a "multi-channel" approach.[40] The Company meets customers where they are by using 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.[41]

The Company also focuses on educating customers and helping them become better informed about the tools available to them.[42] Through a grass-roots community outreach campaign, the Company uses social media, bill inserts and messages, and email in order to inform, build awareness, and encourage adoption of customer tools 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.[43] In 2018, Kentucky Power also created a customer handbook to help customers understand the Terms and Conditions of the business in a more user-friendly medium.[44]

The Company also is deploying a customer engagement platform, also known as a Home Energy Management ("HEM") system.[45] The purpose of the HEM is to "transform the Kentucky Power residential customer experience by providing access to monthly energy usage and cost information during the billing period."[46] Customers will have access to information about energy usage including billing history, current amount due, comparative analysis of energy usage

---

[40] *Id.*
[41] *Id.*
[42] *Id.* at 5; Tr. Vol. II at 505 (Company Witness Wiseman explaining the importance of engaging with customers through multiple channels to ensure customers are equipped to use the tools the Company is providing).
[43] Wiseman Direct Test. at 5.
[44] *Id.*
[45] *Id.* at 15.
[46] *Id.*

and billings from prior periods, and customized energy efficiency tips.[47] Customers can also set alerts and push notifications.[48] Ultimately, the HEM will allow residential customers to make more informed decisions about electric consumption and better manage their monthly budgets.[49]

5. Economic Development

The Company is "as committed and involved in economic development in Eastern Kentucky as [it] ha[s] always been."[50] However, the Company's service territory, continues to struggle economically.[51] Although Kentucky Power cannot unilaterally cure the systemic or societal issues contributing to this prolonged economic decline, the Company's economic development efforts aim to ensure the citizens in Kentucky Power's service territory 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."[52] Moreover, the addition or expansion of business and industry also results in increased load, which benefits all customers by spreading Kentucky Power's fixed costs of providing electric service and lowering customer rates.[53]

One of Kentucky Power's important economic development tools is the Kentucky Power Economic Growth Grant ("K-PEGG") Program, which grants funding targeted specifically at projects designed to enhance the economic development potential of the communities in the Company's service territory[54] – specifically, to attract customers and jobs to the service

---

[47] *Id.* at 16.
[48] *Id.*
[49] *Id.*
[50] Tr. Vol. II at 548.
[51] *See* notes 6-19; Mattison Direct Test. at 6.
[52] Mattison Direct Test. at 6-7.
[53] *Id.* at 7.
[54] Wiseman Direct Test. at 23.

territory.[55] The K-PEGG Program is funded through Tariff K.E.D.S. at the rate of $1.00 per meter per month for its non-residential customers with a dollar-for-dollar Company match.[56] Since the Company's last base rate case, the Company has issued 40 grants totaling approximately $2,089,476 to K-PEGG Program participants.[57] Half of that of these dollars came directly from the Company via the Company match. The Company proposes to continue the K-PEGG Program at its current finding level in this case, including the dollar-for-dollar Company match.

The importance of continuing the K-PEGG Program is illustrated by three recent major successes resulting from the program. 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, which plans to create up to 265 full-time jobs and invest nearly $19.6 million to locate its first U.S. operations near Hazard.[58] Dajcor located in the former American Woodmark facility in Perry County's Coal Fields Regional Industrial Park. The K-PEGG grant allowed Dajcor to retrofit and set up its facility at that location.[59] Company President Mattison testified that Dajcor's CEO and owner recently touted the skills of former coal employees in Eastern Kentucky.[60] Specifically the Dajcor CEO said that "one shift in Hazard is more productive than three shifts in Canada. And so he's looking at that seriously, thinking about the possibility of expanding [in Hazard]."[61]

---

[55] Tr. Vol. II at 531.
[56] Wiseman Direct Test. at 23. The Company match is not included in the Company's cost of service for ratemaking purposes and is 100% funded by shareholders.
[57] *See* KPCO_R_KPSC_6_16Attachment1.xlsx filed herein on November 2, 2020.
[58] Wiseman Direct Test. at 24.
[59] *Id.*
[60] Tr. Vol. I at 28.
[61] *Id*.

Second, both Intuit Inc. and SYKES Enterprises Inc., also in Perry County, utilized K-PEGG Program funding 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.[62] SYKES went through a workforce reduction and Intuit, aided by funds from the K-PEGG Program, was able to partner with SYKES, and re-hire many SYKES employees.[63] In doing so, Intuit protected approximately 300 jobs.[64] Moreover, the new partnership will support Intuit's products and services, and will result in 300 new full-time jobs.[65]

Third (demonstrating that economic development can often be a long process), Logan Corporation, 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.[66] Logan's facility in Martin County was of insufficient size to meet the growing demand for its new product.[67] 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.[68] This allowed Logan to purchase a larger facility in Magoffin County for its new truck bed business.[69] 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.[70] This in turn provided the basis for Logan's announcement in February 2020 of its plans to expand its facility with a $1.2 million investment.[71]

---

[62] Wiseman Direct Test. at 24.
[63] Tr. Vol. II at 505.
[64] *Id.*
[65] Wiseman Direct Test. at 24.
[66] *Id.*
[67] *Id.* at 25.
[68] *Id.*
[69] *Id.*
[70] *Id.*
[71] *Id.*

These success stories demonstrate what can be achieved by combining even modest investments in the service territory's infrastructure through the K-PEGG Program with the work ethic and skills of many of the Company's customers. In short, the K-PEGG Program is vital to Kentucky Power's continued successful economic development efforts, and to helping its service territory climb out of a prolonged economic decline.

Kentucky Power has and will continue to play an important role through its economic development efforts in addressing the issues facing the economy of its service territory. But Kentucky Power is not responsible for the macroeconomic forces battering its service territory, and its rates are not an appropriate means of addressing those forces. Kentucky law requires that the Company's rates be established at levels sufficient to permit Kentucky Power to provide the same level of service received by customers anywhere in the Commonwealth, and that the Company be provided a realistic opportunity through its rates to earn a fair return, at least the same return on equity received by those utilities providing service in these more affluent areas.

6. Developments Since the Company's Last Rate Case

As discussed in Section II.A.1 above, the Company's service territory has continued to experience a downturn in economic activity since the Company's 2017 rate case.[72] The Company, like other businesses and customers in its service territory, has been impacted by a continuing decline in customers, and in the case of the Company, in load.[73] The COVID-19 pandemic made an already bad situation worse, and its impacts have resulted in unprecedented increased delays in receipt of customer payments and increased customer arrearages.[74] Despite Kentucky Power's prudent management of its operations and continuing economic development

[72] *Id.* at 21.
[73] *Id.*
[74] Messner Rebuttal Test. at R8.

efforts, these circumstances have seriously impaired the Company's financial health.[75] The Company has experienced approximately $19.5 million of lost revenue from lost load since the Company's last rate case alone, approximately three quarters of which was industrial load.[76] Kentucky Power's earnings have steadily declined over the same period to a low of 5.3% for the twelve months ended September 30, 2020.[77] The economic situation increases the risk that the Company will not be able to realize its authorized ROE. Indeed, as Company President Mattison's Rebuttal Testimony demonstrates, Kentucky Power never earned the ROE authorized by the Commission in the Company's last rate case.[78] The Company's sustained poor financial health and insufficient earnings, and the effect they are having on Kentucky Power's ability to provide adequate service, compelled the Company to file this case. Failure to set the Company's cost recovery and rates at levels sufficient for it to improve its credit metrics and financial viability would result in not only economic hardship to Kentucky Power but also to the service territory for which Kentucky Power is a backbone.

B. Procedural History

Kentucky Power filed its Notice of Election to Use Electronic Filings procedures on May 29, 2020, and filed its Application on June 29, 2020.

Seven parties were granted full intervention in this case: Kentucky Industrial Utility Customers, Inc. ("KIUC")[79]; the Attorney General of the Commonwealth of Kentucky, by and through his Office of Rate Intervention ("AG")[80]; Walmart Inc. ("Walmart")[81]; Kentucky Solar

---

[75] Mattison Rebuttal Test. at R3.
[76] Tr. Vol. I at 26-27.
[77] Mattison Rebuttal Test. at R3, Figure DBM-1.
[78] *Id.*
[79] Order (Ky. P.S.C. June 8, 2020).
[80] Order (Ky. P.S.C. June 9, 2020).
[81] Order (Ky. P.S.C. July 9, 2020).

Industries Association, Inc. ("KYSEIA")[82]; (jointly) Mountain Association for Community Economic Development, Kentuckians for the Commonwealth, and the Kentucky Solar Energy Society (collectively, "Joint Intervenors")[83]; SWVA Kentucky, LLC ("SWVA")[84]; and Sierra Club.[85] The AG and KIUC jointly filed[86] intervenor testimony of three witnesses: Stephen J. Baron, Richard A. Baudino, and Lane Kollen.[87] Walmart filed intervenor testimony of one witness: Lisa V. Perry.[88] KYSEIA filed intervenor testimony of three witnesses: Justin R Barnes, Benjamin D. Inskeep, and James M. Van Nostrand.[89] The Joint Intervenors filed intervenor testimony of three witnesses: Joshua Bills, Andrew McDonald, and James Owen.[90]

The Commission conducted a six-day formal hearing from November 17-24, 2020.[91] The hearing was conducted remotely, with all parties appearing via videoconference due to the COVID-19 pandemic. Thirty-one witnesses took the stand on behalf of Kentucky Power and the intervenors. Following the hearing, Kentucky Power is responding to additional post-hearing data requests for information from Commission Staff, AG/KIUC, Walmart, and KYSEIA.[92] In total, Kentucky Power responded to 604 separate written questions, not including subparts, from Commission Staff and intervenors in discovery in this proceeding.

---

[82] Order (Ky. P.S.C. July 15, 2020).
[83] Order (Ky. P.S.C. Aug. 4, 2020).
[84] Order (Ky. P.S.C. Aug. 13, 2020).
[85] Order (Ky. P.S.C. Aug. 6, 2020).
[86] KIUC and the AG entered into an agreement to share the expenses of expert witnesses and more or less participated jointly in these proceedings. *See* Joint Notice of KIUC and the Attorney General Regarding Expert Witness Expense Sharing (Aug. 17, 2020).
[87] *See* Testimony of Expert Witnesses (Oct.7, 2020).
[88] *See* Direct Testimony and Exhibit of Lisa V. Perry (Oct. 7, 2020).
[89] *See* Pre-filed Intervenor Testimonies of KYSEIA (Oct. 7, 2020).
[90] *See* Direct Testimony of James Owen, Direct Testimony of Joshua Bills, Direct Testimony of Andrew McDonald on behalf of Joint Intervenors (Oct. 7, 2020).
[91] Order, (Ky. P.S.C. Aug. 5, 2020).
[92] The Company's responses to post-hearing data requests are due December 9, 2020.

Through the record the Company developed in this case, a compelling basis exists to approve the Company's Application.

III. COMMISSION JURISDICTION AND STANDARD OF REVIEW

Kentucky Power Company is a "utility" as defined in KRS 278.010(3) and is subject to the Commission's jurisdiction pursuant to KRS 278.040.[93] It is firmly established that "the regulation of public utilities has and does serve a public purpose. It has a substantial relation to the public welfare, safety and health and, in a real degree, promotes these objects."[94] The Commission is a creature of statute and has only such powers as granted by the General Assembly.[95] The Commission's jurisdiction therefore is limited to the "rates" and "service" of the Company.[96] As the Kentucky Supreme Court has recognized, "rates are merely the means for achieving a predetermined objective, which in this instance was how much additional revenue should the Company be allowed to earn."[97] The Company's rates may be increased pursuant to the procedures set forth in KRS 278.180, 278.190, 278.192, and the regulations promulgated thereunder.

It is well established that "[t]he manifest purpose of the Public Service Commission is to require and insure fair and uniform rates, prevent unjust discrimination, and prevent ruinous

---

[93] *See* Application at 1-2.
[94] *City of Florence v. Owen Elec. Co-op., Inc.*, 832 S.W.2d 876, 882 (Ky. 1992).
[95] *See Boone Co. Water and Sewer District v. Public Service Comm'n,* 949 S.W.2d 588, 591 (Ky. 1997); *Simpson County Water Dist. v. City of Franklin,* 872 S.W.2d 460, 462 (Ky. 1994); *Com., ex rel. Stumbo v. Kentucky Public Service Comm'n,* 243 S.W.3d 374, 378 (Ky. App. 2007); *Cincinnati Bell Telephone Co. v. Kentucky Public Service Comm'n,* 223 S.W.3d 829, 836 (Ky. App. 2007); *Public Service Comm'n v. Jackson County Rural Electric Coop., Inc.,* 50 S.W.3d 764, 67 (Ky. App. 2000).
[96] *See Public Service Comm'n v. Blue Grass Natural Gas Co.,* 197 S.W.2d 765, 768 (Ky. 1946) ("We have held that the jurisdiction of the Public Service Commission is clearly and unmistakably limited to the regulation of rates and service of utilities.") *citing Smith v. Southern Bell Telephone and Telegraph Co.,* 104 S.W.2d 961 (Ky. 1937); *Benzinger, etc., v. Union Light, etc.,* 170 S.W.2d 38 (Ky. 1943); *Peoples Gas Co. of Kentucky v. City of Barbourville,*165 S.W.2d 567 (Ky. 1942).
[97] *Kentucky Power Co. v. Energy Reg. Comm'n,* 623 S.W.2d 904,908 (Ky. 1981).

competition."[98] In undertaking this purpose, the Commission is affecting the natural property rights of Kentucky Power.[99] Accordingly, the principles of due process, equal protection, and other rights and guarantees afforded under the Constitutions of the United States of America and the Commonwealth of Kentucky apply with full force and effect.[100] The Commission "has no authority to impose a new duty on utilities when that duty has no foundation in law. To do so is an unconstitutional legislative act by the Commission."[101]

The Commission's statutory mandates therefore provide "an integrated, comprehensive system aimed at providing stability and notice to all entities involved in the rate process."[102] The result the Commission reaches in undertaking this process must be reasonable.[103] Although circumscribed by the limits of its jurisdiction, the Commission may consider a broad spectrum of factors in establishing fair, just, and reasonable rates. The Kentucky Court of Appeals has explained that the Commission's discretion is

> certainly broad enough to consider such things as replacement cost, debt retirement, operating cost, and at least some excess capacity in order to insure continuation of adequate service during periods of high demand and some potential for growth and expansion. It also allows for consideration of whether expansion investments were prudently or imprudently made, and whether a particular utility is investor owned or a cooperative organization. Any of these factors might be extremely significant in varying situations when

---

[98] *Simpson County,* p. 464.
[99] *See Bobinchuck v. Levitch,* 380 S.W.2d 233,236 (Ky. 1964). In contrast, the right to receive utility service is merely a right that may be conferred by statute and lacks the same fundamental constitutional protections. *See Smith v. Southern Bell Tel. & Tel. Co.,* 104 S.W.2d 961, 964 (Ky. 1937).
[100] *See Kentucky Indus. Utility Customers, Inc. v. Kentucky Utilities Co.,* 983 S.W.2d 493, 497 (Ky. 1998).
[101] *Henry v. Parrish*, 211 S.W.2d 418 (Ky. 1948).
[102] *Cincinnati Bell,* pp. 837-38 (Ky. App. 2007) *quoting* KRS 278.160, KRS 278.180, KRS 278.190, KRS 278.260, KRS 278.270 and KRS 278.390.
[103] *Kentucky Indus. Utility Customers,* p. 498 *citing Federal Power Comm'n v. Hope Natural Gas,* 320 U.S. 591 (1944) (superseded on other grounds by statute); *see also National-Southwire Aluminum Co. v. Big Rivers Elec. Corp.,* 785 S.W.2d 503, 515 (Ky. App. 1990) *citing Louisville & Jefferson County Met. Swr. Dist. v. Joseph E. Seagram & Sons,* 211 S. W.2d 122 (Ky. 1948).

> determining what ultimately would be a fair, just and reasonable rate and would allow for a balancing of interests.[104]

Ultimately, however, the Commission must approve retail rates that are "fair, just and reasonable."[105] Accordingly, approved rates must "enable the utility to operate successfully, to maintain its financial integrity, to attract capital and to compensate its investors for the risks assumed ...."[106] In considering the Company's proposed rates, the Commission must consider both the present *and the future* impact of such rates upon the Company's financial condition.[107] It is critically important for Kentucky Power to meet its financial objectives and maintain credit quality and financial health.[108] As the Applicant, the Company bears the burden of proof.[109]

IV. KENTUCKY POWER COMPANY'S PROPOSED INCREASE IN BASE RATES, AS UPDATED IN THE COMPANY'S REBUTTAL TESTIMONY, YIELDS FAIR, JUST, AND REASONABLE RATES.

A. In Recognition of the Unprecedented Economic Circumstances Facing Kentucky Power's Customers During the COVID-19 Pandemic, the Company Has Offered a Meaningful Package of Measures to Mitigate Customer Rate Impacts and Provide Significant Benefits to Kentucky Power Customers.

Although the rate changes described in the Application and the Company's written and hearing testimony are imperative and cannot be delayed, in recognition of the unprecedented economic conditions facing the Company's customers, the Commonwealth, and the country, the Company is proposing multiple measures to mitigate customer rate impacts and its overall

---

104 *National Southwire*, p. 512.
105 KRS 278.030(1).
106 *National-Southwire,* pp. 512-13 *quoting Commonwealth ex rel. Stephens v. South Central Bell Tel. Co.,* 545 S.W.2d 927, 930-31 (1976).
107 *Public Service Comm'n of Kentucky v. Dewitt Water District,* 720 S.W.2d 725, 730 (Ky. 1986) ("When considering the concept of confiscation, the future as well as the present must be considered. It must be determined whether the rates complained of are yielding and will yield a sum sufficient to meet operating expenses."), *citing McCardle v. Indianapolis Water Company,* 272 U.S. 400 (1926).
108 Mattison Direct Test. at 15.
109 *See Energy Regulatory Comm'n v. Kentucky Power Co.,* 605 S.W.2d 46, 49 (Ky. App. 1980) *citing Lee v. International Harvester Co.,* 373 S.W.2d 418 (Ky. 1963).

requested revenue requirement in this case. The measures collectively total approximately $96 million in rate increase mitigation to the benefit of Kentucky Power's customers in the first year following Commission approval of the Company's Application:

Proposed Mitigation	**2021 Value to Customers in ($ Millions)**
ADFIT Offset of First Year Rate Increase	**$64.7**[110]
Customer Debt Forgiveness ADFIT Proposal	**$10.8**
Discontinuation of Capacity Charge Tariff Collection	**$6.2**
Reduction of Recommended Return on Equity	**$2.5**
Rockport UPA Base Rate Demand Expense Mitigation Deferral	**$1.7**
Rockport Unit 2 SCR Depreciation Expense Mitigation Deferral	**$10.1**
TOTAL MITIGATION VALUE IN 2021	**$96.0**

This offer, which is nearly 1.5 times larger than the Company's total requested revenue increase in this case, provides substantial and extraordinary customer benefits.

The Company offered several of the above measures (ADFIT Offset of First Year Rate Increase, Conditional Discontinuation of Capacity Charge Tariff Collection, and Reduction of Recommended ROE) in its direct case.[111] The Company's Customer Debt Forgiveness ADFIT Proposal was filed on May 29, 2020, in Case No. 2020-00176;[112] the Commission subsequently indicated in that docket that this proceeding is the appropriate place to address the Company's

---

[110] On a revenue basis. The Company would amortize $58.9 million of ADFIT.
[111] *See* Mattison Direct Test. at 12-13.
[112] *In the Matter of: Electronic Application of Kentucky Power Company to Amend the Settlement Agreement Approved in Case No. 2018-00035 to Provide for the One-Time Amortization of Unprotected Accumulated Deferred Federal Income Tax in an Amount Sufficient to Eliminate Customer Delinquencies Greater than 30 Days as of May 28, 2020*, Case No. 2020-00176 ("Debt Forgiveness Case"), Verified Application (May 29, 2020).

proposal.[113] The Company subsequently accepted two Rockport UPA expense-related mitigation measures in its rebuttal testimony in this case.[114]

Each proposed mitigation measure is described in greater detail below, and each represents a one-time proposal that the Company is making, without prejudice to the Company's position in future rate cases, and in recognition of the financial difficulties facing Kentucky Power's service territory, along with the economic and financial challenges posed as a result of the COVID-19 pandemic.[115] Kentucky Power is offering this meaningful suite of mitigation measures as a collective proposal, and they should be considered together to ensure that the rates the Commission sets in this proceeding are fair, just, reasonable, and do not further impair Kentucky Power's financial condition.[116]

1. ADFIT Proposals

The Company has made two proposals to utilize its unprotected excess accumulated deferred federal income tax ("ADFIT") balance on a limited and short-term (one-year and one-time) basis to provide immediate rate and payment relief to its customers. These proposals, if approved, would shorten the remaining approximately 15-year time period over which the Company will otherwise return unprotected excess ADFIT to customers through Tariff FTC (Federal Tax Cut Tariff).[117] The Company proposes to maintain current 2020 Tariff FTC rates until its remaining excess ADFIT balance that is not subject to these mitigation proposals is fully amortized.[118]

---

[113] Debt Forgiveness Case, Order at 7 (Ky. P.S.C. Oct. 2, 2020); Mattison Rebuttal Test. at R6.
[114] *See* Vaughan Rebuttal Test. at R7-R9.
[115] Mattison Direct Test. at 13.
[116] Mattison Rebuttal Test. at R5.
[117] West Direct Test. at 8-9.
[118] *Id.* at 8-9; Vaughan Direct Test. at 33-34, Ex. AEV-6; West Rebuttal Test. at R2-R3.

a. ADFIT Offset of First Year Rate Increase in Case No. 2020-00174.

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.[119] Under the Company's modified proposals as set forth in the table above, the amount of this mitigation equals approximately $64.7 million. Company Witness Vaughan explained how the Company would implement this relief, if approved by the Commission:

> [Kentucky Power would i]mplement new base rates that reflect the ordered increase resulting from this case and increase the revenue credit in [T]ariff FTC by the net amount of rate increase[,] taking into account any potential rate credits that could arise from the Company's capacity charge and ES proposals. This would result in a net zero increase in total rates.[120]

Thus, if the Commission accepts this perhaps unprecedented proposal, the base rates that customers pay will not increase until 2022, when predictions are that the economy will have returned to closer to normal.[121]

b. Customer Debt Forgiveness ADFIT Proposal in Case No. 2020-00176.

In order to address customers' financial burden during the height of the recent economic hardships occasioned by the COVID-19 pandemic, in May 2020 Kentucky Power initiated Case No. 2020-00176, in which the Company has made the extraordinary and unique proposal to utilize a portion of its unprotected excess ADFIT to eliminate all customer balances that are 30 or more days past due as of May 28, 2020.[122] Specifically, the Company proposed to provide payment relief to customers in the form of a one-time bill credit, totaling approximately $10.8

---

[119] Mattison Direct Test. at 12; West Direct Test. at 8.
[120] Vaughan Rebuttal Test. at R12.
[121] *Id.*; Mattison Direct Test. at 12; West Direct Test. at 8.
[122] Debt Forgiveness Case, Verified Application at 11 (May 29, 2020).

million in aggregate relief.[123] This proposal benefits all customers, not only those who would receive a bill credit, by lowering the Company's bad debt expense ultimately recovered in rates.[124] As Company President Mattison explained, the Company stands by its commitment in Case No. 2020-00176 and is willing to address customer arrearages by amortizing that amount in the manner directed by the Commission in this case.[125]

c. The Company's One-Time and One-Year ADFIT Amortization Proposals Are Reasonable and Will Not Adversely Impact Its Credit Metrics on a Long-Term Basis.

Kentucky Power's ADFIT-related mitigation proposals are unique, extraordinary, and reflect the significant lengths to which the Company has gone to mitigate the impact on customers of its critically needed request for a rate increase. As Company Witness Mattison explained, the Company would not now be seeking a rate increase if the Company's financial condition did not threaten its ability to provide adequate service to customers over the long term.[126] Each dollar of unprotected excess ADFIT amortized reduces the Company's cash flow by a dollar without a compensating reduction in the Company's expenses; thus, the more quickly the unprotected excess ADFIT is amortized, the greater the impact on Kentucky Power's cash flow.[127] That, in turn, places pressure on the Company's credit metrics and ultimately its cost of capital.[128] Nonetheless, as Mr. Mattison testified, the Company, "in an unprecedented way … is willing to make some short-term sacrifices in [its] credit metrics" through its ADFIT and other mitigation proposals in order to achieve a balanced and reasonable result in this case.[129]

---

[123] *Id.*; Mattison Direct Test. at 10; West Rebuttal Test. at R2-R3.
[124] *See, e.g.*, Tr. Vol. IV at 1056.
[125] Mattison Rebuttal Test. at R6.
[126] *E.g.*, Tr. Vol. I at 50-51, 84; Tr. Vol. II at 459-460, 480.
[127] Messner Rebuttal Test. at R7.
[128] *Id.*
[129] Tr. Vol. I at 83-84; *see also id.* at 33-34.

In its October 2, 2020 Order in the Company's Debt Forgiveness Case, the Commission indicated that it looked forward to Kentucky Power presenting evidence in this case that addressed the impact of its ADFIT proposals on the Company's financial statements and credit metrics.[130] Company Witness Messner explained that the COVID-19 pandemic its related economic implications, have warranted the change in the time period over which the Company proposes to amortize its unprotected excess ADFIT.[131] Company Witness West provided an estimate of the remaining amortization period, on both an ADFIT basis and a revenue basis, for Tariff FTC if the Company's ADFIT proposals are accepted.[132] Company Witness Messner also addressed this request in his rebuttal testimony in this case, explaining that although the short-term and one-time ADFIT amortization proposals the Company has made in this case and the Debt Forgiveness Case will negatively impact the Company's cash flows and credit metrics, ratings agencies are likely to view the amortization as a "one time, single year, limited duration event." This in turn is likely to produce a lesser impact on Kentucky Power's credit rating than if the amortization occurred over a sustained two to five year period.[133] He also critically explained that in long term, the cash flow and credit impacts of the Company's ADFIT proposals are the same as they otherwise will be under the existing 18-year amortization period the Commission approved in Case No. 2018-00035.[134]

Explaining that the Company can accept the negative cash flow and credit impacts associated with its ADFIT proposals for one year, Company Witnesses Mattison, West, and Messner emphasized that the Company cannot bear them over the longer, two-year time period

---

[130] Debt Forgiveness Case, Order at 7 (Ky. P.S.C. Oct. 2, 2020).
[131] Messner Rebuttal Test. at R8.
[132] West Rebuttal Test. at R2-R3.
[133] Messner Rebuttal Test. at R8; Tr. Vol. III at 816-817.
[134] Messner Rebuttal Test. at R9.

proposed by AG/KIUC Witness Kollen.[135] The Company and the Commission established a reasonable method to deal with the change in tax law in 2018 in Case No. 2018-00035. Kentucky Power is offering a limited modification to that approach in this case to recognize the unique situation it finds itself, its customers, and the region and to help customers, while also limiting the concomitant negative impacts to Kentucky Power's cash flows and credit metrics. Kentucky Power Company's cash flows are already "out-of-bounds" low for its current credit rating.[136] Longer term negative cash flow impact, longer than a one-time or single year event are "[t]hings that generally lead to being put on negative outlook and/or downgrade."[137] No evidence was offered to the contrary.

Kentucky Power's credit rating is at the very bottom of the investment grade scale.[138] Based on Mr. Messner's considerable experience, rating agencies are less likely to be understanding of a proposal, like Mr. Kollen's, that "puts continued pressure on a [credit] metric that is already below investment grade." The Commission should not accept Mr. Kollen's proposal to turn the Company's well-considered and balanced set of mitigation measures into a package that harms, rather than protects, the Company's medium- to long-term financial condition and credit ratings.

---

[135] Mattison Rebuttal Test. at R5; West Rebuttal Test. at R2; Messner Rebuttal Test. at R6-R7; Tr. Vol. III at 817-818; *see also* Kollen Test. at 47-49.
[136] Tr. Vol. III at 814; *see also id.* at 862.
[137] *Id.* at 817.
[138] *Id.* at 942.

2. Discontinuation of Capacity Charge Tariff Collection

Kentucky Power is authorized to collect $6.2 million on an annual basis through the Capacity Charge Tariff until the Rockport UPA terminates on December 7, 2022.[139] The Company's collection of this revenue through the Capacity Charge, as authorized by the Commission in Case No. 2004-00420, was a condition precedent and a key requisite for the Company's agreement in that proceeding to extend the Rockport UPA through December 7, 2022.[140] The additional revenue recovered through the Capacity Charge was considered as part of the total economics of the UPA extension, as the Commission recognized in that case:

> Under the terms of the Stipulation, the Rockport purchase power contract will be extended through December 7, 2022. The current wholesale pricing for the power purchase will continue through the extended term of the contract, but there will also be an annual supplemental payment by retail ratepayers to Kentucky Power. This supplemental payment, as set forth in the Stipulation, will be $5.1 million annually in 2005 through 2009, and then increases to $6.2 million annually in 2010 through 2021, and then decreases to $5,792,329 in 2022. Kentucky Power will be entitled to receive these annual supplemental payments in addition to the base retail rates established by the Commission as being fair, just, and reasonable, and the supplemental payments will not be considered in establishing Kentucky Power's base retail rates.[141]

The Commission further recognized that "[a]lthough the price to be paid by retail customers for this power does reflect market forces since it is priced above cost of service, the price now being fixed will insulate retail ratepayers from the risk of future market price volatility" and that "[e]ven with this supplemental payment, the purchase price for Rockport power is favorable

---

[139] Vaughan Direct Test. at 30 ($6.2 million in 2020 and 2021; approximately $5.8 million in 2022).
[140] Vaughan Rebuttal Test. at R9; *In the Matter of: Application of Kentucky Power Company for Approval of a Stipulation and Settlement Agreement Resolving State Regulatory Matters*, Case No. 2004-00420, Order at 7 and Appx. A, ¶III(1)(b), III(1)(f) ("Rockport UPA Extension Order") (Ky. P.S.C. Dec. 13, 2004).
[141] *Id.* at 2-3.

compared to today's cost to construct new coal-fired generation."[142] Kentucky Power customers benefited for years from the relatively low-cost energy Kentucky Power received under that agreement as compared to high market energy prices.[143]

In this case, as part of its comprehensive package of mitigation measures, Kentucky Power is conditionally proposing to discontinue collection of the Capacity Charge tariff revenues it is otherwise entitled to receive in 2021 and 2022.[144] If the Company were to discontinue the Capacity Charge as a result of the outcome in this case, Kentucky Power proposes to include any remaining over- or under-collection Capacity Charge deferrals in the revenue requirement of its next annual update filing for Tariff PPA.[145] This mitigation proposal is conditioned upon Commission approval of the Company's requested rate increase, as modified and updated by the Company in data responses and rebuttal testimony.[146]

AG/KIUC Witness Kollen's argument that the Commission should abrogate both the settlement agreement entered and approved in Case No. 2004-00420, for reasons that are contrary to the Commission's express basis for approving the agreement (providing the Company's customers with long-term capacity and energy that are shielded from market forces), is without merit and should be rejected.[147] As an initial matter, both the AG and KIUC are parties to that settlement and agreed unconditionally to the Company's collection of the Capacity charge as approved by the Commission; they are precluded from now seeking to unilaterally alter

---

[142] *Id.* at 6, 7.
[143] Tr. Vol. IV at 1189.
[144] Mattison Direct Test. at 12-13.
[145] Vaughan Direct Test. at 30.
[146] Tr. Vol. IV at 1132-1133 (Company Witness West explaining that the capacity charge mitigation is conditional on the Company's "as amended" proposal in this case).
[147] Kollen Test. at 57.

that agreement.[148] Moreover, Mr. Kollen's assertion that "circumstances have changed" since the Commission's Rockport UPA Extension Order is irrelevant because the allegedly changed conditions to which Mr. Kollen points are not those that were to be addressed by the Commission-approved settlement.[149] The Commission explicitly recognized in the Rockport UPA Extension Order that market conditions could change in the future, and that the additional revenues recovered through the Capacity Charge were a material part of the overall consideration for Kentucky Power's agreement to extend the UPA,[150] and were a fair, just, and reasonable price for achieving the Commission's long-standing and oft-expressed objective of "mitigating to the extent possible market price and fuel price fluctuations."[151]

Kentucky Power entered in the extension of the Rockport UPA Extension in direct response to the Commission's repeated admonition that the Company not rely on market purchases. Mr. Kollen's suggestion that the Commission modify its final Rockport UPA Extension Order 16 years later – after customers have enjoyed substantial benefits from the Company's extension of the Rockport UPA – to deprive Kentucky Power of agreed upon consideration to which it is entitled is inappropriate and unreasonable. Such a result would be, at best, fundamentally unfair and would undermine parties' confidence in the finality and enforceability of contracts approved by this Commission. It would also be unlawful by depriving the Company of the benefit of the long-term bargain accepted by the AG and KIUC

[148] Rockport UPA Extension Order at Appx. A ¶III(1)(f) ("This Stipulation and Settlement Agreement is made upon the express agreement by the Parties that the receipt by Kentucky Power of the additional revenues called for by Section ... III(1)(b) [the annual Capacity Charge tariff amounts at issue here] shall be accorded the ratemaking treatment set out in this Section III. In any proceeding affecting the rates of Kentucky Power during the extension of the UPSA under this Stipulation and Settlement Agreement, the provisions of this Section III are an express exception to Section VI(4) of this Stipulation and Settlement Agreement."); *id.* at ¶VI(4).
[149] Kollen Test. at 57.
[150] Rockport UPA Extension Order at 6.
[151] *Id*.

and approved by the Commission. Certainly, both the AG and KIUC would be talking out the other sides of their respective mouths if Kentucky Power earlier on had sought to deny its customers of the benefits of the Settlement Agreement by abrogating the agreement and committing the Rockport UPA capacity and energy to the more lucrative energy market.

3. Reduction of Recommended Return on Equity

Although Company Witness McKenzie's analysis demonstrates that a 10.3% ROE is warranted for Kentucky Power (as detailed *infra*),[152] the Company has requested an ROE of 10.0% as a further mitigation on the rate increase in this case, as Company President Mattison described.[153] This represents a nearly $2.5 million annual reduction in the Company's revenue requirement.[154]

4. Rockport UPA Expense-Related Mitigation Measures

a. Rockport UPA Base Rate Demand Expense

The Company initially proposed Adjustment W47 to test year expense to increase test year base rate purchase power expense by $1.696 million to account for a known and measurable change that increased the Rockport UPA operating ratio billing formula after the Rockport Unit 2 selective catalytic reduction system ("SCR") was placed in service in early June 2020 and transferred from construction work in progress to plant in service.[155] In recognition of the current economic circumstances in the Company's service territory, the Company agreed on rebuttal to AG/KIUC Witness Kollen's proposal to defer the additional expense and accumulate it in the Rockport UPA regulatory asset.[156] Thus, the Company is agreeable to adding the

[152] *See generally* McKenzie Direct Test.; McKenzie Rebuttal Test.
[153] Mattison Direct Test. at 13.
[154] *See* KPCO_R_KPSC_3_1_Attachment 11_MattisonWP1.xlsx.
[155] Vaughan Direct Test. at 48-49; Application Section V, Exhibit 2, Adjustment W47.
[156] Kollen Test. at 33-34; Vaughan Rebuttal Test. at R7-R8.

$1,695,513 included in Adjustment W47 to the Rockport deferral regulatory asset in 2021 and adding $1,554,220 (eleven-twelfths of the annual amount included in Adjustment W47) to the Rockport deferral regulatory asset in 2022.[157]

The Rockport deferral regulatory asset, including the additional demand expense amounts that were the subject of Adjustment W47, should accrue a carrying charge at the Company's approved weighted average cost of capital ("WACC") until it is fully recovered, consistent with the Commission-approved Settlement Agreement in Case No. 2017-00179.[158] This mitigation measure reduces demand expense by $1.696 million and the base revenue requirement by $1.706 million.[159]

b. Rockport Unit 2 SCR Depreciation Expense

Kentucky Power will recover its share of the cost of the Rockport Unit 2 SCR, including depreciation expense, through its Environmental Surcharge ("ES") pursuant to the Commission's Order in Case No. 2019-00389.[160] KRS 278.183(1) entitles the Company to the current recovery of those costs, including a reasonable return on construction and other capital expenditures and reasonable operating expenses, including depreciation expenses. AG/KIUC Witness Kollen is opposed to the three-year time period over which AEGCo, the counterparty to the Rockport UPA, is depreciating the SCR and will bill depreciation expense to Kentucky Power.[161] Mr. Kollen has proposed that the Commission extend recovery of the depreciation expense over a ten-year period, direct the Company to defer the difference in depreciation expense from January

---

[157] Vaughan Rebuttal Test. at R7.
[158] *Id.*
[159] Kollen Test. at 33.
[160] *In the Matter of: Electronic Application of Kentucky Power Company for Approval of an Amended Environmental Compliance Plan and a Revised Environmental Surcharge*, Case No. 2019-00389, Order (May 18, 2020).
[161] Kollen Test. at 50.

2021 through December 7, 2022, and authorize the Company to begin amortizing the deferral on December 8, 2022.[162]

In addition to being contrary to the express requirements of KRS 278.183 and thus beyond the Commission's authority to implement absent the Company's agreement, Mr. Kollen's suggested ten-year recovery period is inappropriate because it could negatively impact Kentucky Power's cash flow and credit metrics, in addition to accruing a decade worth of additional carrying charges to be recovered from customers.[163]

Nonetheless, in the interest of mitigating the overall rate increase in this case, the Company is willing to accept a 4-year recovery period for the Rockport Unit 2 SCR depreciation expense.[164] Specifically, the Company is willing to agree to defer a portion of the Rockport Unit 2 SCR depreciation expense that will be billed to the Company through the UPA for January 2021 through December 2022.[165]

Company Witness Vaughan explained that a "simple way to effectuate this would be to defer half of the billed Rockport Unit 2 SCR depreciation expense recoverable from Kentucky retail customers through the ES to reflect 4-year recovery of the roughly 2 years of billed expenses," establish a regulatory asset for the ES deferral amounts that earns a WACC carrying charge, and then amortize the deferred amounts through the ES over 24 months beginning January 2023.[166] This mitigation measure would reduce the net increase in total rates resulting from this case by approximately $10 million annually.[167]

* * *

---

[162] *Id.* at 50-51.
[163] Vaughan Rebuttal Test. at R8.
[164] *Id.*
[165] *Id.*
[166] *Id.* at R9.
[167] *Id.*

The robust package of mitigation measures the Company proposed in this case provides meaningful customer benefits that temper the impacts associated with a rate increase. Moreover, the total dollar value of that package far exceeds the Company's requested revenue requirement increase in this case. As set forth above, the Company's unique and unprecedented mitigation proposals, which should be viewed collectively, are significant, reasonable, and should be considered favorably by the Commission as it evaluates the Company's requests in this case.

B. The Public Convenience and Necessity Requires the Company to Replace Obsolete AMR Meters with AMI Meters.

The record demonstrates that the public convenience and necessity require the grant of a certificate of public convenience and necessity ("CPCN") authorizing the Company to deploy AMI meters. The intervenors' principal argument in opposition appears to be that the Company failed to perform what the intervenors erroneously contend is the requirement that the Company perform a formal cost-benefit study.

The statute does not require a formal cost-benefit analysis or study, and the Commission has recognized this fact.[168] The cost-benefit analysis in the case of AMI meters is simple—spending $37 million to implement industry-standard AMI meters costs much less than spending $22 million now to replace obsolete AMR meters with other, soon-to-be obsolete AMR meters, and then spending an additional $37 million to replace those AMR meters with AMI meters in the relatively near future. It also costs less than replacing AMR meters with AMI meters as they fail, and operating two metering systems for an undetermined period of time.

---

[168] *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, Order at 6 (Ky. P.S.C. Jan. 10, 2017).

None of the intervenors offered evidence controverting the fact that the Company's existing stock of AMR meters is rapidly failing as those meters reach the end of their 15-year useful life. Instead, the point of contention is whether Kentucky Power's customers are to be shortchanged with an obsolete and increasingly unsupported technology and yet pay a higher than necessary cost, or whether, like many customers of other utilities throughout the Commonwealth, the Company's customers will be provided with the many benefits of the industry standard AMI meters[169] at a lesser ultimate price.

1. The CPCN Standard for AMI Implementation

The Commission has addressed previously the utility of replacing existing, one-way communicating meter technology that was or soon would be obsolete with AMI meters.[170] The Commission recently further explained that its approvals of AMI deployments 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."[171] With respect to the intervenors' flawed arguments concerning the need for a formal cost-benefit study to meet the third criterion, the

---

[169] Tr. Vol. IV at 990.

[170] *See, e.g., 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, Order at 8 (Ky. P.S.C. July 16, 2018); *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, Order at 6-7 (Ky. P.S.C. Jan. 10, 2017); *In the Matter 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, Order at 7-8 (Ky. P.S.C. Dec. 22, 2016).

[171] *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, Order at 9 (Aug. 30, 2018).

Commission 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."[172] The Company has addressed and satisfied each of these considerations.

2. The Company's Existing AMR Meters Are Obsolete, Are No Longer Manufactured, and Operate on a Platform that is No Longer Supported.

Kentucky Power currently has 172,233 AMR meters in its service territory.[173] It first installed AMR meters, primarily supplied by General Electric ("GE") (now Aclara) in 2005-2006, have been in service since that time.[174] In 2005 and 2006 GE projected the AMR meters had a ten- to fifteen-year life expectancy.[175] Kentucky Power's AMR meters are equipped with an encoder receiver transmitter module, designed by Itron, which 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.[176] Data is then transferred to the customer management system by a Standard Consumption Messaging ("SCM") platform.[177]

Kentucky Power's meters, which operate on the SCM platform,[178] are no longer manufactured by any vendor and are no longer supported by Itron.[179] The only vendor that

---

[172] *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, Order at 6 (Ky. P.S.C. Jan. 10, 2017).
[173] Blankenship Direct Test. at 2.
[174] *Id.*
[175] *Id.*
[176] *Id.*
[177] *Id.*
[178] *Id.* at 2-3.
[179] Blankenship Rebuttal Test. at R3-R4.

supports AMR does so on a platform that the Company does not have—SCM+.[180] Kentucky Power would have to replace the existing SCM platform with an SCM+ platform if it replaces existing failed AMR meters with AMR meters instead of AMI meters.[181]

The SCM+ platform itself is becoming rapidly outdated and thus represents a $22 million investment risk.[182] Itron is the only vendor that manufactures an SCM+ AMR meter, and its technology is proprietary.[183] Installing new AMR meters supplied by a single source vendor would lock the Company into a single vendor for meters and spare parts, both of which are soon likely to become obsolete as well.[184] The cost to upgrade the Company's obsolete AMR SCM meters to soon-to-be obsolete AMR SCM+ meters would be approximately $22 million.[185] Company Witness West described the lose-lose proposition advanced by the intervenors:

> So much — much like electromechanical meters, nobody makes those anymore. You know, the industry standard moved to AMR, and then now the industry standard has moved to AMI, and it's only a matter of time before that one manufacturer decides, "Hey, we're out of the game now. We're all AMI. That's the industry standard." And what -- what Mr. [Blankenship] was saying is that I would have to spend $22 million, and then at an [indeterminate] period, I've got to spend $37 million then to go to AMI, and that's far more expensive than just doing AMI right now.[186]

Despite their suggestions that the Company continue pouring money into an obsolete technology, none of the intervenors have come to grips with the simple math of Company Witness West's testimony.

---

[180] *Id.* at R4.
[181] *Id.*
[182] Blankenship Direct Test. at 4.
[183] *Id.*
[184] *See id.*
[185] Blankenship Rebuttal Test. at R4; Tr. Vol. IV at 984.
[186] Tr. Vol. IV at 1090-1091.

Simply put, the record demonstrates that Kentucky Power's AMR meters are obsolete and that further investment in the obsolete technology will cost customers more in the long run.

3. Kentucky Power Soon Will Be Unable to Provide Reliable, Adequate Service With its Existing AMR Meters.

At the time the Company filed this case, 74.6% of Kentucky Power's AMR meters were between 10-15 years old.[187] Most were installed in 2005-2006 and by 2019 were at or approaching the end of their useful life.[188] In the past three years, the failure rate of the Company's 10-15 year old AMR meters has been approximately 10%.[189] With a significant majority of the Company's meters already at the end of their expected useful life,[190] the Company is experiencing higher than normal failure rates and expects those rates to grow exponentially as the meters get older.[191]

The Company's current AMR meters are no longer being manufactured and are no longer supported by their manufacturer.[192] The Company cannot buy new versions of its current AMR meters. The Company only has about 2,000 of its existing AMR meters in stock to replace failed AMR meters.[193] The Company estimates that it would exhaust this limited inventory in about one year.[194] Without replacement meters or parts in hand, the meters would run to the point of failure, and the customer would simply be left with a failed meter. Therefore, the Company's ability to provide reliable service with its current meters will be compromised beginning in a year.[195]

---

[187] Blankenship Direct Test. at 3.
[188] *Id.*
[189] *Id.* at 3-4.
[190] *Id.* at 4.
[191] Tr. Vol. IV at 979.
[192] Blankenship Direct Test. at 4.
[193] Tr. Vol. IV at 1027.
[194] *Id.*
[195] *Id*.

The record in this case is clear that Kentucky Power's current AMR meters are obsolete and that the Company must replace them with new technology or risk not being able to provide reliable service to its customers.

4. The Proposed AMI System is the Least-Cost Alternative.

Kentucky Power's AMR meters are obsolete and must be replaced. The Company has two options for replacing its obsolete AMR meters: 1) replace AMR meters with AMI meters as proposed in this case; or 2) upgrade its existing AMR SCM meters to AMR SCM+ meters now and then replace those meters with AMI meters when they soon also become obsolete. The Company's AMI proposal in this case is the least-cost alternative.

Intervenors make much ado about the notion that the Company did not perform a "formal" cost-benefit study to determine whether an AMI system is the most beneficial choice to upgrade its obsolete meters.[196] However, 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."[197] The Commission should not be distracted by the intervenors' argument that the Company was required to submit a formal cost-benefit analysis, or that such an exercise would provide meaningful evidence. Instead, the Commission should look – as it did in other cases – at the economics of the replacement options.

---

[196] *See* Kollen Direct Test. at 61; Owen Direct Test. at 58.
[197] *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, Order at 6 (Ky. P.S.C. Jan. 10, 2017).

Both AG/KIUC and Joint Intervenors allege, without providing any evidence or having done any cost-benefit analysis of their own, that 1) replacing the Company's obsolete AMR SCM meters with AMR SCM+ meters,[198] or 2) simply replacing the current AMR meters with available replacement parts,[199] would cost less or be more economic than the Company's AMI proposal in this case. Neither proposal addresses the fact that they provide only a short-term Band-Aid fix that ultimately will cost significantly more. In both instances, the Company would eventually (likely not too far in the future) be required to upgrade all of its meters to AMI meters; any amounts expended on the Band-Aid options now will only increase the ultimate cost borne by customers. The Company's AMI proposal is the most economic replacement option.

The analysis as to whether installing AMI meters as proposed in this case is more economic than upgrading to AMR SCM+ meters now, and then to AMI meters in the relatively near future, is simple. The cost to upgrade the Company's obsolete AMR SCM meters to soon-to-be obsolete AMR SCM+ meters would be approximately $22 million.[200] The cost to then upgrade to AMI meters once the SCM+ meters also become obsolete is approximately $37 million.[201] Therefore, this replacement option would ultimately cost $59 million.[202] By contrast, the cost to upgrade the current AMR meters to industry-standard AMI meters now would be only $37 million. Simply put, the Company's proposal costs $22 million less than the AMR SCM+ option.[203] As Company Witness Blankenship aptly explained, the intervenors' proposal is "the

[198] Kollen Direct Test. at 62.
[199] Owen Direct Test. at 54.
[200] Blankenship Rebuttal Test. at R4; Tr. Vol. IV at 984.
[201] Tr. Vol. IV at 984.
[202] *Id.* at 992.
[203] *Id.* at 984.

most-cost option."[204] Clearly, the Company's AMI proposal is more economic than this replacement option.

Replacing the Company's current AMR meters with whatever amount of used, salvaged AMR meters might be available from Kentucky Power's affiliates also is neither possible nor the least-cost option. There is an insufficient inventory of such meters to replace the Company's failed AMR meters,[205] and that equipment is as old as, or only slightly newer than, Kentucky Power's existing inventory of AMR meters and parts.[206] Compounding the issue is the fact that several of the Company's affiliates are in various phases of their own AMI deployments, and they are still using the AMR meters that intervenors hypothesize could be recycled by Kentucky Power.[207] Kentucky Power thus would be in competition for these meters and replacement parts.[208] In sum, the use of affiliate companies' "hand-me-down" equally obsolete AMR meters, even if they were available in numbers required by Kentucky Power, would provide only the thinnest of Band-Aids while denying Kentucky Power's customers the dual benefits of AMI metering discussed below, and financial that will accrue if the Commission approves the Company's proposal to offset the first year increase through application of ADFIT. .

The Company's AMI proposal is the most economic option for replacing the Company's obsolete AMR meters and will permit the Company to better meet its customers' needs.

5. AMI Provides Significant Additional Customer and Operational Benefits.

Although the Company met its burden for approval of the requested CPCN for AMI meters, AMI meters also come with a host of additional benefits.

---

[204] *Id.* at 993.
[205] Tr. Vol. IV at 1027.
[206] Blankenship Rebuttal Test. at R3.
[207] Tr. Vol. IV at 978.
[208] *Id.*

a. Flex Pay Program

The Flex Pay program is a voluntary prepayment program that allows customers to pay as they go, while giving customers greater control over the frequency and timing of their payment.[209] The Flex Pay program is only possible with the implementation of AMI meters.[210]

Flex Pay customers make deposits to their Flex Pay accounts at such times and in such amounts as are most convenient to them.[211] The Flex Pay program requires only an initial payment of $40, which is approximately equal to one week of service based on the daily cost of approximately $5.00 for an average residential customer.[212] The only requirement is that the Flex Pay customers maintain a positive balance in their Flex Pay accounts.[213] If a customer's account balance reaches zero, the customer will be notified that he or she has until the next business day to establish a positive balance or the customer's service will be automatically disconnected.[214] Further, "the great thing about [Flex Pay] is that…there's no reconnect fee, there's no late fees, there's no deposit charge, and all the customer has to do to get reconnected is pay enough … to get a positive balance on their account, and then they're reconnected within 15 minutes."[215]

The Flex Pay program will be available to all residential customers with an AMI meter rated up to 200 amps, except for those residential customers taking service under Schedule Residential Demand-Metered (R.S.D.).[216] Also, customers with certain medical and/or life-

---

[209] West Direct Test. at 20.
[210] *Id*. at 26-27.
[211] *Id*. at 20.
[212] *Id*. at 22.
[213] *Id*.
[214] *Id*. at 25.
[215] Tr. Vol. IV at 1102.
[216] West Direct Test. at 20.

threatening conditions, customers on partial payment plans, Average Monthly Payment plan customers, Equal Payment Plan 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.[217] Flex Pay customers will continue to be billed under their current, applicable tariff with portions of the rate converted to a daily rate.[218] In other words, the standard tariff remains the basis for bill calculation.[219] The bill will be calculated using the customer's daily usage within a 24-hour period, the effective base rate, and all applicable riders and fees at the time of purchase.[220] Fixed charges will be charged daily and prorated based on the number of days in the billing cycle.[221] These amounts will be subtracted from the customer's daily account balance.[222] The Company's Application further details other terms and conditions of service under the tariff.[223]

Kentucky Power affiliate Public Service Company of Oklahoma ("PSO") implemented a similar prepay program in 2016 after installing AMI meters.[224] PSO has observed numerous customer benefits associated with the program,[225] and Kentucky Power has been able to learn from and model some of its proposals in this case after PSO's program[226] allowing the Company's customers to benefit from this earlier experience. By drawing on PSO's past experience, the Company also may be able to reduce certain prepay program costs.

---

[217] *Id.* at 21.
[218] *Id.*
[219] *Id.*
[220] *Id.*
[221] *Id.*
[222] *Id.*
[223] *See* Application, Section II, Exhibit D at p. 57 of 185.
[224] West Direct Test. at 24.
[225] Blankenship Direct Test. at 12.
[226] *See id.* at 14; Tr. Vol. II at 543.

Further benefits of the Flex Pay program include: providing customers with more choices regarding when and how to pay for electric service[227]; allowing participants to avoid deposits, reconnection fees, and late fees[228]; and enabling participants to better observe the correlation between usage and cost, thus fostering more control over energy usage and the opportunity to achieve savings.[229] The Company also provided real life examples of customer issues that could be addressed with the implementation of the Flex Pay program:

> We have a lot of customers -- and I read one today, a social media administrator for our Facebook page, and there was a gentlemen asking our customer service rep if he said -- you know, I know my bill is due, I want -- I need to pay, but I need a couple more days to pay. And so with prepay, I mean, that takes away that concern for our customer where they can pay $10 on Wednesday then pay the remaining amount on Friday once the paycheck comes in, or whatever their situation is.[230]

Moreover, for customers who are on a fixed income or who are low-income, it is a "game-changer," allowing people to "manage their budgets a little better" and "control their finances."[231]

In short, the Company's proposed Flex Pay program offers customers another way to pay their electric bills and stay educated on their usage. When customers are in tune with their usage they are in a better position to make changes to lower their bills. Flex Pay allows customers more flexibility and the ability to pay their bill on their own time frame, while simultaneously eliminating the risk of incurring large and ultimately unpayable debt.

For these reasons, the Commission should approve the Flex Pay Program and Tariff F.P.

---

[227] West Direct Test. at 27.
[228] *Id.* at 28
[229] *Id.*
[230] Tr. Vol. II at 517.
[231] *Id.* at 542-543.

b. Other AMI Benefits

AMI meters provide several additional benefits to customers. In addition to replacing the Company's current obsolete meters and making possible the new prepay program, customers would also enjoy the following benefits:

- Reconnection of service remotely within about 10 minutes;[232]
- Faster service restoration. Currently, the only way the Company can be alerted to an outage is if a customer calls the Operations Center.[233] AMI meters will instead sense the voltage at the customer's premises and alert the Company to an interruption.[234] Moreover, information from multiple AMI meters allows the Company to gauge the extent of an outage without relying on the customer to call.[235] Finally, the Company will also often be able to pinpoint the isolation device such as a lateral or transformer fuse affecting the outage;[236]
- Remote identification of outages. For example, AMI could allow the Company to "poll" meters during a storm recovery.[237] The polling process will eliminate the need to physically send field personnel to individual premises to locate outages;[238]
- Remote monitoring and detection of power quality issues. By monitoring voltage, the Company will be able to identify distribution line transformers that are approaching failure and replace them proactively before the failure causes an outage.[239] AMI meters

---

[232] Blankenship Direct Test. at 12.
[233] *Id*. at 14.
[234] *Id.*
[235] *Id.*
[236] *Id.*
[237] *Id.*
[238] *Id.*
[239] *Id.*

also 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.[240] AMI meters can even monitor and report the health of the meter itself;[241]

- Increased access to energy usage data. Customers would go from having access to 12 data points per year (with AMR meters) to over 35,000 data points per year with AMI meters, which offer 15-minute interval data;[242]
- Ability to monitor and regulate electric usage throughout the month and make incremental adjustments to electricity usage with the goal of reducing their bill;[243]
- Access to high-bill alerts. These alerts notify a customer with a highly accurate reading of mid-cycle energy usage and provide bill projections.[244] If customers notice higher than normal consumption, they can try to pinpoint the cause, or they can contact Kentucky Power to do so;[245]
- Enhanced data available through the Company's Customer Engagement Platform. The Customer Engagement Platform would provide customers access to daily energy usage and cost information during the billing period, including billing history, current amount due, comparative analysis of energy usage and billings from prior periods, and customized energy efficiency tips.[246] Customers can see their energy usage data and the resulting costs essentially in real time rather than once a month;[247]

---

[240] *Id*. at 15.
[241] *Id*.
[242] Tr. Vol. IV at 976; Blankenship Direct Test. at 11.
[243] Blankenship Direct Test. at 11.
[244] *Id*.
[245] *Id*.
[246] Wiseman Direct Test. at 16.
[247] *Id*. at 15.

- The elimination of non-recurring charges where a service can be provided remotely with an AMI meter,[248] including the elimination of reconnection fees;[249]
- The ability to better take advantage of Time-Of-Day rates. Once customers have access to 15-minute interval data available with AMI metering – over 35,000 meter readings or data points each year – they will have the ability to identify what processes or devices in their homes are running at different times and shift their usage to off-peak times, thus presenting the potential to save money;[250]
- Greater satisfaction with their meter;[251]
- Infrastructure synergies with automated equipment. AMI meters 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;[252]
- Support of 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;[253]
- Ability to install firmware upgrades remotely, thereby reducing operations and maintenance ("O&M") expense. Firmware upgrades from the manufacturer can be pushed remotely over the communication network to the meter.[254] Currently, with AMR

---

[248] West Rebuttal Test. at R7.
[249] Blankenship Direct Test. at 13.
[250] West Direct Test. at 31.
[251] Blankenship Direct Test. at 9-10.
[252] *Id.*
[253] *Id.*
[254] *Id.* at 16.

meters, meter personnel are required to visit each meter and manually install a firmware upgrade;[255] and

- More accurate meter failure information. Currently, if an AMR 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.[256] 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, which will lead to more accurate billing and a reduction in estimated bills due to meter errors.[257]

6. The Company's Proposed AMI Deployment and Cost Recovery Through the GMR.

Kentucky Power plans to fund the cost of its AMI deployment through the Grid Modernization Rider, or GMR, proposed in this case.[258] If the AMI proposal in this case is approved, the Company proposes to install AMI meters over four years, beginning in 2021 and concluding in 2024.[259] Figure 5 below provides a summary of the planned meter replacement schedule and the forecasted costs for the 2021 – 2024 deployment years.[260]

[255] *Id.*
[256] *Id.*
[257] *Id.*
[258] West Direct Test. at 19.
[259] Blankenship Direct Test. at 16-17.
[260] *Id.* at 17.

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

If the GMR is approved, the Company will make as part of the annual GMR filing discussed below 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.[261] If Kentucky Power were to file a base rate case prior to the completion of its AMI deployment, the Company would roll any GMR revenue requirement into base rates.[262] 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.[263]

An added benefit to customers is that the approved base rate increase, plus the proposed revenue requirement for the GMR, will be offset in 2021 with unprotected excess ADFIT.[264] This means that customers will not see an increase in their bills during the first year of the AMI deployment.[265] However, if cost recovery through the GMR were postponed until after first-year

---

[261] West Direct Test. at 12.
[262] *Id.* at 11-12.
[263] *Id.* at 12.
[264] *Id.* at 11.
[265] *Id.*

AMI deployment costs were incurred, customers would lose this benefit and the costs instead would be collected from customers rather than offset.[266]

Finally, the Company has planned a comprehensive customer engagement and education campaign to be rolled out to customers at the time AMI meters are installed.[267] While the AMI customer education and awareness campaign will terminate at the end of the AMI deployment process, access to resources through Kentucky Power will not end.[268] The Company will continue to provide information related to its AMI deployment through customer service professionals and by maintaining information on the Company website.[269] Further, the Company will continue customer outreach activities for the Customer Engagement Platform (HEM system) and Flex Pay program.[270]

* * *

The benefits of AMI meters to customers are numerous and undisputed. In addition to being the <u>least cost</u> meter replacement option, Kentucky Power's AMI proposal is also the <u>most benefit</u> meter replacement option. If the Commission were to take the intervenors' suggestions, in addition to paying an additional $22 million to replace the Company's meters with soon-to-be obsolete SCM+ meters, customers would not see any of the above-listed benefits with an AMR SCM+ meter.

Kentucky Power customers <u>need</u> AMI meters to replace their obsolete ones; and Kentucky Power customers <u>deserve</u> AMI meters and all of the advantages that come with

---

[266] *Id.*
[267] *See* Wiseman Direct Test. at 11-17.
[268] *See* Kentucky Power's Response to AG/KIUC's First Set of Data Requests, Item 108.
[269] *Id.*
[270] *Id.*

them.[271] Accordingly, the Commission should grant Kentucky Power's requested CPCN and permit the Company to move forward with its proactive AMI deployment as proposed.

C. The Proposed Grid Modernization Rider Is Reasonable, Appropriate, and Will Provide Kentucky Power With Necessary Flexibility to Efficiently Make Important Grid Modernization Projects.

The Grid Modernization Rider provides the Company and its customers with an efficient and fair means fund projects to modernize the distribution grid and to improve its reliability and resiliency.[272] Such projects will address public safety needs and leverage technology to benefit customers and the distribution grid.[273] Kentucky Power has a growing need to maintain and modernize its grid[274], but an earned ROE steadily declining to 5.3% as of September 2020,[275] is both confiscatory and prevents Kentucky Power from obtaining access to sufficient capital for reliability projects required to improve the grid and, ultimately, customer experience, and reliability metrics.[276] Currently, distribution projects compete internally with transmission and generation projects for the limited available capital.[277] The Company needs an alternative means to obtain the cash flow necessary to modernize its grid, and the GMR provides a mechanism that makes sense: it gives the Company access to cash flow and capital that it otherwise would not have between base rate cases, while ensuring customers pay no more or no less than required to implement the projects.[278] The GMR's annual review and reconciliation process also provides the Commission with enhanced oversight over the Company's distribution modernization efforts,

---

[271] *See generally* Tr. Vol. I at 64.
[272] West Direct Test. at 9.
[273] Phillips Direct Test. at 31.
[274] Tr. Vol. IV at 967.
[275] Tr. Vol. I at 33; Mattison Rebuttal Test. at R3.
[276] Tr. Vol. IV at 966; Phillips Direct Test. at 31.
[277] Tr. Vol. IV at 966.
[278] *Id.* at 1059.

enabling the Commission and Kentucky Power to partner together to implement needed and important distribution improvements.

1. Function of the GMR

The proposed GMR will recover capital, including carrying costs, and incremental O&M expense associated with the AMI project proposed in this case along with future distribution grid modernization expenses approved by the Commission in future proceedings.[279] The GMR further 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.[280]

The Company's first proposed project to be recovered through the GMR is the required deployment of AMI.[281] The Company will allocate the AMI project GMR revenue requirement to customer classes on a per-meter basis, and then proposes to recover the class revenue requirements using a monthly charge.[282] For AMI deployment, this allocation and recovery proposal is reasonable because the AMI project pertains solely to the cost of metering the Company's customers.[283] The allocation and recovery of costs for future GMR projects will be evaluated based on the nature of the specific costs.[284]

Kentucky Power's project management office will provide oversight for all facets of grid modernization investments to be recovered through the GMR.[285] The Company will make an annual true-up filing on June 15 each year, with rates becoming effective with cycle 1 of the

---

[279] West Direct Test. at 10.
[280] *Id.*
[281] *Id.* at 9.
[282] Vaughan Direct Test. at 40.
[283] *Id.*
[284] *Id.*
[285] Phillips Direct Test. at 34.

subsequent September billing period, to reconcile the amount collected through the rider in the previous year with the past year's actual revenue requirement.[286] Any historical over- or under-recovery would be included in the GMR revenue requirement for the next 12-month period.[287] 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.[288]

2. The GMR Will Provide Complete Transparency and Give the Commission More Oversight Over Proposed Grid Modernization Projects.

The Company is considering several projects that would be supported by the GMR, such as extending distribution lines to remote areas and building additional substations and circuits to provide more robust and reliable distribution service to remote areas.[289] Kentucky Power aims to modernize the power grid to improve reliability and build a more flexible and resilient grid to optimize power flows, which consequently improves reliability.[290]

All GMR project proposals will be filed with the Commission for review and approval.[291] For projects that do not require a CPCN, the GMR would provide more transparency and provide the Commission the opportunity to review the Company's grid modernization projects in between base rate cases.[292] New proposed GMR projects would be presented to the Commission at the time of the annual true-up filing, wherein the Company would present the GMR project and make all necessary showings for approval of the project for inclusion in the GMR (and

[286] West Direct Test. at 10.
[287] *Id.* at 11.
[288] *Id.*
[289] Phillips Direct Test. at 33.
[290] *Id.*
[291] *Id.*
[292] Tr. Vol. IV at 968.

application for a CPCN when necessary).[293] During that review process, the Commission "would have full control…full transparency, [and could] look at anything they want."[294] The Company will "happily work with the Commission to develop [GMR project parameters],"[295] and is "more than willing to provide reports and any data that [the Commission] would need to review [proposed GMR projects]."[296]

3. The GMR is Essential to Kentucky Power's Ability to Make Needed Distribution Modernization Investments.

AG-KIUC Witness Kollen argues, without any evidentiary support, that the Commission should reject the proposed GMR.[297] Mr. Kollen claims that there is no "compelling" need for the GMR[298] and that the costs of new distribution investments historically have not been carved out for recovery through riders between base rate proceedings.[299] But these arguments merely represent Mr. Kollen's opinions and should be rejected. Most importantly, Mr. Kollen never addresses the challenges the Company faces that other Kentucky utilities do not – it has a "limited amount of capital," and its "service territory is experiencing little to no load growth."[300] The Company does not have the "opportunity to do many capacity-driven [distribution] projects that help[] upgrade the facilities."[301]

Equally unsupported is Mr. Kollen's contention that the Company failed to demonstrate any special financial or other need to recover incremental distribution costs through a rider rather

[293] *See* Tr. Vol. IV at 1070; *Id.* at 1057-1058.
[294] *Id.* at 1070.
[295] *Id.* at 1073.
[296] *Id.* at 968.
[297] Kollen Direct Test. at 60.
[298] *Id.* at 59.
[299] *Id.*
[300] Tr. Vol. IV at 966.
[301] *Id.*

than base rates.[302] To the contrary, Company Witness Phillips testified at the hearing that the Company lacks the capital and revenue growth required to support the projects without the GMR, and that undertaking the required distribution projects more seasonably would require the Company to delay needed reliability work:

> The challenge that we have this in distribution is with the limited amount of capital that we have and the fact that Kentucky Power's service territory is experiencing little to no load growth. We don't have the opportunity to do many capacity-driven projects that helps upgrade the facilities as you're increasing your revenue. So with that increase in revenue, we need a way to make sure we capital available to do distribution projects and not have to compete with generation and transmission projects, which what we have to do today.
>
> …
>
> The reason that I introduced the GMR in my testimony was I'm the one that's requested the Company to develop a mechanism that we could be able to additional capital without reducing my current spend for reliability projects which benefit our customers today.[303]

Mr. Kollen similarly ignores the non-operational benefits that will flow to the Company's customers through the GMR because "in between rate cases, a mechanism like the GMR would provide more concurrent recovery on an annual basis, which would increase cash flow, and that would have the effect of possibly lengthening the time between rate cases."[304] Indeed, the GMR provides the Company with the ability to do grid modernization projects that it otherwise could not do without more frequent base rate case filings:

> [J]ust to be clear, the proposal here isn't to always collect it through the [GMR]. It would just be that incremental cost between the base rate cases. So let's say we go two years and then we have a base rate case. We would roll that GMR amount into base rates. We're not asking to be treated special always. We're looking for the flexibility to help -- again all things being considered, keeping

[302] Kollen Direct Test. at 59.
[303] Tr. Vol. IV at 966-967.
[304] *Id.* at Tr. Vol. IV at 1056.

> Kentucky Power financially healthy and give it the opportunity to make the needed distribution grid investments that it needs to make.[305]

The Company has demonstrated both the need for the GMR and the particular advantages it would provide to the Company, customers, and the Commission in the ability to review and scrutinize proposed grid modernization projects. The Commission should reject the intervenors' unsupported arguments against approval of the GMR and give the appropriate weight to the Company's evidence showing the need for the GMR and its benefits.

D. Kentucky Power Company's Proposal to Recover 100% of PJM LSE OATT Charges Through Tariff PPA is Necessary, Reasonable, and Should Be Approved.

As approved in Case No. 2017-00179, Kentucky Power currently collects 80% of incremental PJM Load Serving Entity ("LSE") Open Access Transmission Tariff ("OATT") expense through Tariff PPA.[306] The incremental 20% is borne by Kentucky Power. The Company proposes in this proceeding to amend Tariff PPA to recover 100% of those FERC-approved costs through the rider.[307]

Kentucky Power is entitled as a matter of fundamental federal law to recover these FERC-approved costs in retail rates.[308] It is necessary and appropriate for the Company to contemporaneously recover all of its FERC-approved PJM LSE OATT charges, given that they

---

[305] *Id.* at 1205-1206.

[306] *In the Matter of: Electronic Application of Kentucky Power Company for (1) A General Adjustment of its Rates for Electric Service; (2) An Order Approving its 2017 Environmental Compliance Plan; (3) An order Approving its Tariffs and Riders; (4) An Order Approving Accounting Practices to Establish Regulatory Assets and Liabilities; and (5) An Order Granting All Other Required Approvals and Relief*, Case No. 2017-00179 ("2017 Rate Case"), Order at 53-54 (Jan. 18, 2018).

[307] Vaughan Direct Test. at 32.

[308] U.S. Const. Art. 6, cl. 2; 16 U.S.C.A. § 824(a), (c); *In the Matter of: The Application Of Kentucky Power Company For Approval Of An Amended Compliance Plan For Purposes Of Recovering Additional Costs Of Pollution Control Facilities And To Amend Its Environmental Cost Recovery Surcharge Tariff*, Case No. 2006-00307, Order at 11 (Ky. P.S.C. Jan. 24, 2007).

are significant, increasing, volatile, and largely outside of Kentucky Power's control, as discussed below. Without contemporaneous transmission cost recovery, Kentucky Power will have no ability to earn any ROE the Commission authorizes in this case.[309] Moreover, complete transmission cost tracking not only helps the Company financially but also provides many customer benefits, including by avoiding the more frequent and costly base rate cases that will otherwise be required to recover FERC-approved transmission costs. Additionally, with the Company's proposal to defer the rate increase implementation in this case until January 1, 2022, recovery of 100% of these costs through Tariff PPA is even more necessary, as the level of PJM LSE OATT charges in base rates will be nearly 2 years old when the associated rates go into effect.[310]

Kentucky Power proposes no other changes to the transmission cost recovery portion of Tariff PPA. Thus, the Company will continue, to customers' benefit, to credit against the incremental PJM LSE OATT charges used in calculating the purchase power adjustment under Tariff PPA 100% of the difference between the return on its incremental transmission investments calculated using the FERC-approved PJM OATT return on equity, and the return on its incremental transmission investments calculated using the return on equity the Commission approves in this case.[311] The Company's proposal also will allow customers to receive 100% of any post-test year credits flowing back to the Company between rate cases.

---

[309] Vaughan Rebuttal Test. at R14.
[310] Vaughan Direct Test. at 32-33.
[311] 2017 Rate Case, Order at 53.

1. Kentucky Power's PJM LSE OATT Charges

As an LSE within PJM, Kentucky Power and its customers receive the benefits of a robust transmission system and access to a diverse market for energy.[312] Each year, PJM allocates the cost of Network Integrated Transmission Service ("NITS") to LSEs in the AEP Zone (the transmission zone in which Kentucky Power is an LSE) pursuant to PJM's FERC-approved OATT.[313] A portion of costs assigned to the AEP Zone are then allocated to Kentucky Power through the FERC-approved AEP Transmission Agreement.[314] Recently, Kentucky Power's share of the AEP Zone transmission costs has averaged approximately 6% of the total AEP Zone transmission costs.[315] Kentucky Power's adjusted test year PJM OATT LSE charges totaled $96,896,495.[316]

2. The Company's PJM LSE OATT Charges Are Significant, Increasing, Volatile, and Largely Outside of Kentucky Power's Control.

It is appropriate and necessary for the Company to continue to track and recover PJM LSE OATT expense through Tariff PPA, and to increase the level of tracking and recovery through that mechanism to 100% of expense. The costs are significant to Kentucky Power, representing 16% of the Company's total proposed revenues in this case, and constitute the Company's single largest growing expense.[317] As the Company predicted in Case No. 2017-00179, PJM LSE OATT charges have increased by more than $20 million over the last three

[312] Pearce Rebuttal Test. at R5-R6. References to Dr. Pearce's Rebuttal Testimony are to his corrected supplemental Rebuttal Testimony filed on November 12, 2020. *See also* Tr. Vol. II at 302, 317, 320, 339.
[313] Pearce Rebuttal Test. at R6; Tr. Vol. II at 267.
[314] Pearce Rebuttal Test. at R6.
[315] *Id.* at R7; *see also* Tr. Vol. II at 304.
[316] Vaughan Direct Testimony at 33. This amount is included in the $98,165,699 total Tariff PPA costs that will be used to calculate the annual purchase power adjustment factor. *Id.*
[317] *Id.* at 32-33.

years.[318] Kentucky Power anticipates that these costs will continue to increase in the future as transmission owners continue to make required investments in the transmission system to, among other things, maintain and improve the grid, comply with regulatory mandates, address cyber and physical security threats, and satisfy customer interconnection and service requirements.[319]

Indeed, since the Company filed its Application in this case, updated annual transmission rates have been filed at FERC.[320] Those rates are effective January 1, 2021, and increase Kentucky Power's FERC-approved PJM LSE OATT costs by approximately $14 million.[321] This increase in the Company's FERC-filed wholesale transmission costs will be recovered incrementally in the Company's 2021 Tariff PPA update; however, if the Commission declines to approve continued recovery of incremental transmission costs through that mechanism, the known and measurable $14 million increase reflecting rates on file with FERC during the time period the Company's new base rates will be in effect must be added to the Company's base rates approved in this case.[322]

As the Commission has recognized, PJM LSE OATT charges and credits are volatile, and their level can vary greatly from year to year.[323]

---

[318] *See* 2017 Rate Case, Application, Section III, Volume IV; 2017 Rate Case, Vaughan Direct Test. at 29 (Kentucky Power's adjusted test year PJM LSE OATT expense was $74,038,517); 2017 Rate Case, Attachment 1 to the Company's response to KIUC 1-67 (estimating that this expense would increase to approximately $93 million in 2019 and approximately $105 million in 2020).
[319] Vaughan Direct Test. at 32; Ali Rebuttal Test. at R3-R4 (describing the numerous drivers of transmission investment and costs).
[320] Vaughan Rebuttal Test. at R15.
[321] *Id.* at R15 and Ex. AEV-R1.
[322] *Id.*
[323] 2017 Rate Case, Order at 53; Ali Rebuttal Test. at R3-R4; Vaughan Direct Test. at 32.

PJM LSE OATT charges also are largely outside of the Company's control.[324] As Company Witnesses Vaughan and Ali testified, and despite AG/KIUC Witness Kollen's theoretical musings otherwise,[325] Kentucky Power has no control over the capital spending of any other transmission owner, whether or not affiliated with the Company.[326] Mr. Ali, who is responsible for transmission planning across the AEP system, explained:

> The fact that the other transmission owners may be Kentucky Power affiliates does not change the obligation that each transmission owner has to pursue prudent projects needed to address safety, security, efficiency as well as asset condition, performance, and risk to provide reliable services in that owner's service territory. Nor does those transmission owners' status as affiliates provide Kentucky Power with control over what those companies' needs are or what projects are needed to meet those needs.[327]

Mr. Ali's testimony gets to the heart of the misapprehension AG/KIUC and others appear to have regarding this issue. Transmission capital expenditures are driven not by a transmission owner's financial targets, earnings, or other business objectives, but rather by critical and important needs on the transmission system itself. The timing of certain transmission investments, such as asset replacements made before an asset's failure, may, to a degree, be within the control of a transmission owner. The underlying drivers of transmission investment more broadly – including equipment age, abnormalities, and condition; environmental conditions; customer requirements; and changing government or industry standards – simply are not and there is no testimony to the contrary.[328]

---

[324] Vaughan Rebuttal Test. at R13-R14; Ali Rebuttal Test. at R4-R6.
[325] Kollen Test. at 52-54.
[326] Vaughan Rebuttal Test. at R-13; Ali Rebuttal Test. at R5-R6.
[327] Ali Rebuttal Test. at R5-R6.
[328] *Id.* at R5.

Indeed, each transmission owner in the AEP Zone has an obligation to ensure capital investments are prudent and necessary to maintain the reliability of the transmission grid.[329] The FERC-approved AEP Transmission Agreement, of which Kentucky Power is a member, requires "[e]ach member [to] maintain its respective portion of the Bulk Transmission System, together with all associated facilities and appurtenances, in a suitable condition of repair at all times in order that said system will operate in a reliable and satisfactory manner."[330] Transmission projects thus are driven by the underlying need for infrastructure improvements and each regional transmission organization ("RTO") transmission owner's obligation to provide safe, adequate, and reliable transmission service and facilities in accordance with Good Utility Practice[331] requirements. Good Utility Practice has long been the foundation for utility planning and operations and, and Good Utility Practice requirements continue to be imposed on RTO transmission owners by FERC.[332] AEP's structure does not supplant the respective obligations of the RTO transmission owners to fulfill their respective public utility obligations to serve.[333] Rather, AEP's structure facilitates the planning process and helps AEP and Kentucky Power achieve the joint transmission system benefits the entire RTO system was created to foster.[334]

---

[329] *Id.* at R4.
[330] *Id.* at R4-R5.
[331] *Id.* at R6 (noting also that FERC has defined "Good Utility Practice" in Section 1.14 of the pro forma Open Access Transmission Tariff in Order 888 as: "Any of the practices, methods and acts engaged in or approved by a significant portion of the electric utility industry during the relevant time period, or any of the practices, methods and acts which, in the exercise of reasonable judgment in light of the facts known at the time the decision was made, could have been expected to accomplish the desired result at a reasonable cost consistent with good business practices, reliability, safety and expedition. Good Utility Practice is not intended to be limited to the optimum practice, method, or act to the exclusion of all others, but rather to be acceptable practices, methods, or acts generally accepted in the region").
[332] *Id.*
[333] *Id.*
[334] *Id.*

The only small measure of control, other than limited flexibility in connection with timing, the Company enjoys over its allocated level of PJM LSE OATT expenses comes from its participation in the AEP Transmission Agreement, which allocates those expenses to Kentucky Power on a 12CP basis rather than 1CP basis.[335] Kentucky Power's participation in the Transmission Agreement has the effect of normalizing annually the level of PJM LSE OATT expense the Company incurs.[336] In this regard, it is important to recognize that AG/KIUC's suggestion that Kentucky Power should withdraw from the Transmission Agreement, and the resultant change in PJM LSE OATT cost allocation, "could lead to wild and material swings in the amount of allocated PJM LSE OATT costs to the Company," further supporting the need to recover such costs through Tariff PPA.[337] Thus, because PJM LSE OATT charges continue to be significant, variable, and outside of Kentucky Power's control, it is appropriate to continue to track them through Tariff PPA.

3. Continued Recovery of PJM LSE OATT Expense Through Tariff PPA Benefits Customers.

Continued tracking and recovery of PJM LSE OATT charges through Tariff PPA, rather than through base rates, also provides significant benefits to the Company's customers. First, recovery of the costs through Tariff PPA ensures that the Company recovers only the actual amount of its cost incurred for wholesale transmission service, not a dollar less or more.[338] Recovering the charges through a tracker also ensures that any benefits of the changes in these costs, be it through the pending FERC proceedings, changes in the tax code, or otherwise, flow through Tariff PPA and the purchase power adjustment factor to customers. For example, during

[335] Vaughan Rebuttal Test. at R13; Pearce Rebuttal Test. at R6-R7.
[336] *Id.*
[337] Vaughan Rebuttal Test. at R13-R14.
[338] Vaughan Direct Test. at 33.

2018 and 2019 customers benefited from wholesale transmission cost tracking 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.[339]

Moreover, tracking and recovery of 100% of incremental PJM LSE OATT charges allows Kentucky Power to recover these costs without the expense to the Company and burden to the Commission and intervenors of more frequent base rate cases.[340] As Company Witness Vaughan explained, Kentucky Power does not have an opportunity to earn its allowed return on equity without contemporaneous recovery of PJM LSE OATT expense because, to the extent the Company incurs such costs at a level higher than embedded in base rates, its earned ROE will decrease due to non-recovery of FERC-approved purchased transmission expense.[341]

Finally, customers also benefit from contemporaneous transmission cost recovery through Tariff PPA because the rider mechanism avoids "lumpy" rate increases that result from addressing such costs in base rate cases.[342] Recovery of all of the Company's incremental PJM LSE OATT charges through Tariff PPA is a gradual, lower cost way to recover these costs and is more desirable for both the Company and its customers than large step increases resulting from more frequent and costly base rate proceedings.[343]

---

[339] *Id*. at 32.
[340] Vaughan Rebuttal Test. at R14.
[341] *Id.*
[342] *Id.*
[343] *Id.*

4. Contrary to AG/KIUC Witness Baron's Arguments, Kentucky Power's Participation in the AEP Transmission Agreement and AEP Zone in PJM Provide Significant Benefits to Customers and the Company.

Far afield from the proper scope of this base rate case proceeding, the AG and KIUC argue that the Kentucky Commission should initiate an investigation, following the completion of this rate case, into whether Kentucky Power's continued participation in the Transmission Agreement is in the public interest.[344] This distraction is ill-conceived for numerous reasons, and the Commission should disregard it.[345]

First, and most importantly, AG/KIUC's request is unlawful. The Supremacy Clause of the United States Constitution[346] and Section 201(b) of the Federal Power Act[347] preempt state public service commissions from intruding upon FERC-approved wholesale contracts like the Transmission Agreement.[348] Under the filed rate doctrine, FERC-mandated or FERC-approved cost allocations cannot be second guessed by state regulators."[349] The Commission's consideration of AG/KIUC's argument on this subject must stop here as a matter of federal law.

Nonetheless, the record developed in this proceeding demonstrates that, contrary to AG/KIUC Witness Baron's inaccurate and selective portrayal of the Transmission Agreement, that agreement provides benefits to both Kentucky Power and its customers.[350] The

---

[344] Baron Test. at 54-55.

[345] As the Company confirmed at hearing, however, Kentucky Power is willing to informally discuss transmission issues, including those AG/KIUC raise, outside the context of this rate case, where the sole transmission issue within the Commission's purview is the retail ratemaking treatment of FERC-approved wholesale transmission costs. Tr. I at 195-196.

[346] U.S. Const. Art. 6, cl. 2.

[347] 16 U.S.C.A. § 824(a), (c).

[348] *Accord Entergy Louisiana, Inc. v. Louisiana Pub. Serv. Comm.*, 539 U.S. 39, 123 S.Ct. 2050 (2003); *Mississippi Power & Light Co. v. Mississippi ex rel. Moore*, 487 U.S. 354, 108 S.Ct. 2428 (1988) ("*Mississippi Power & Light*"); *Nantahala Power and Light Co. v. Thornburg*, 476 U.S. 953, 106 S.Ct. 2349 (1986) ("*Nantahala*").

[349] *Entergy Louisiana*, 539 U.S. at 41-42, citing *Mississippi Power & Light* and *Nantahala*.

[350] Pearce Rebuttal Test. at R4-R9.

Transmission Agreement provides for the equitable sharing among its members of the costs the members incur in connection with their ownership and use of the transmission system.[351] AEP has developed an extensive transmission network that integrates the power supply resources of member companies and moves power to widely separated load areas throughout the PJM East Zone system via high voltage and extra-high-voltage transmission.[352] The 12CP cost allocation utilized in the Transmission Agreement also better reflects the LSEs' use of the transmission system throughout the year and not just on one single hour when the PJM system peak occurs.[353] It also de-incentivizes gaming to shift cost to other LSEs, as the 1CP cost allocation may.[354]

As Company Witness Pearce explained, the allocation of NITS costs to Kentucky Power on a 12CP, rather than 1CP, basis also benefits the Company (and all Transmission Agreement members) by helping to manage costs through reduced volatility.[355] For the seven year period 2014-2020, Dr. Pearce compared Kentucky Power's NITS expenses under the 12CP method called for in the Transmission Agreement to what those costs would have been under the 1CP method.[356] His analysis demonstrates that the Company's membership in the Transmission Agreement saved Kentucky Power approximately $37.5 million in PJM LSE OATT expense over that period.[357] Those savings also benefitted the Company's customers. As Dr. Pearce's findings demonstrate, participation in the FERC-approved Transmission Agreement is good for the Company and its customers, and Kentucky Power's participation in that agreement should continue in order for those benefits to continue to be realized.

---

[351] *Id.* at R4.
[352] *Id.* at R5.
[353] *Id.* at R6.
[354] *Id.*
[355] *Id.*
[356] *Id.* at R7-R8.
[357] *Id.* at R7.

For similar reasons, the Commission too should reject AG/KIUC Witness Baron's suggestion that Kentucky Power seek to become its own transmission load zone in PJM.[358] As a preliminary matter, Section 7.4 of the FERC-approved PJM Consolidated Transmission Owners Agreement ("CTOA") prohibits the Company from doing so:

> For purposes of developing rates for service under the PJM Tariff, transmission rate Zones smaller than those shown in Attachment J to the PJM Tariff, or subzones of those Zones, shall not be permitted within the current boundaries of the PJM Region; provided, however, that additional Zones may be established if the current boundaries of the PJM region is expanded to accommodate new Parties to this Agreement.[359]

Simply put, the Company is not permitted to establish its own transmission load zone in PJM. Establishing a Kentucky Power-specific transmission load zone also would not benefit the Company or its customers, nor would it enable Kentucky Power to avoid financial responsibility for legacy transmission investments made by other companies in the AEP Zone, from which it has benefitted.[360] Thus, as with the Transmission Agreement, leaving the AEP Zone could very well result in Kentucky Power and its customers incurring more costs than they are currently responsible for under the existing, FERC-approved framework.

* * *

The substantial evidence demonstrates that it is necessary and appropriate for Kentucky Power to recover all of its incremental PJM LSE OATT expenses through Tariff PPA. The Commission should disregard the intervenors' speculative and baseless arguments in opposition to that proposal. Likewise, the Commission should reject their red herring arguments regarding

---

[358] Baron Test. at 13.
[359] Pearce Rebuttal Test. at R9.
[360] *Id.* at R10; Tr. Vol. II at 300-301.

the Company's participation in the AEP Transmission Agreement and PJM's AEP Zone and approve the Company's request to amend Tariff PPA as filed.

E. The Company's Proposed 10.0% ROE Is Required to Permit Kentucky Power Company to Operate Successfully and Maintain its Financial Integrity and Will Not Place an Unreasonable Burden on its Customers.

The requirement that Kentucky Power's base rates be set to provide the real world opportunity to earn a just and reasonable return on equity is a cornerstone of the regulatory compact that requires Kentucky Power to provide service to its customers.[361] The rate of return for a utility <u>must</u> be comparable to the return on investments in other enterprises having corresponding risks, sufficient to assure confidence in the financial integrity of the utility, maintain support of the utility's credit, and attract capital.[362]

The proposed 10% ROE that Company President Mattison selected as mitigation in this case satisfies each these requirements. It is well within the reasonable ROE range described by Company Witness McKenzie, and in fact is 30 basis points lower than the ROE level supported by Mr. McKenzie's analysis, taking into consideration the realities of the financial market environment in which Kentucky Power competes for capital.[363]

As conceded by AG/KIUC Witness Baudino, it is neither good for customers nor Kentucky Power if the Company is unable to earn its authorized rate of return for an extended period of time.[364] For an extended period of time the Company has significantly under-earned its authorized ROE (set in the Company's previous rate case at 9.7%).[365] In fact, the Company

---

[361] *See Fed. Power Comm'n v. Hope Natural Gas Co.*, 320 U.S. 591 (1944) ("*Hope*"); *Bluefield Water Works & Improvement Co. v. Pub. Serv. Comm'n,* 262 U.S. 679 (1923) ("*Bluefield*").
[362] *Id.*
[363] McKenzie Direct Test. at 8-19, 68-74; McKenzie Rebuttal Test. at R37-R42.
[364] Tr. Vol. VI at 1583.
[365] Mattison Rebuttal Test. at R3.

never earned the ROE authorized by the Commission in the previous base rate case, and as of the twelve months ended September 30, 2020, it earned a dismal 5.3%.[366] This is not sustainable.

For the Company to continue to be able to provide safe, affordable, and reliable electric service to its customers it is critical that its authorized ROE be set in this case at a just and reasonable level.[367] During the period after the Commission's order in Case Number 2017-00179, the Company's credit rating was downgraded by Moody's to Baa3, reflecting the significant deterioration of the Company's credit metrics, and illustrating the dire need to set the Company's base rates at a level that reflects the reality of its cost of service.[368]

It would be illogical and arbitrary to lower Kentucky Power's authorized ROE as recommended by AG/KIUC Witnesses Kollen and Baudino. Their proposed 9.0% ROE is confiscatory and cannot be justified in light of recent ROEs authorized by the Commission for other electric utilities in Kentucky that are a less risky investment than Kentucky Power.[369] In fact, if the Commission were to adopt their confiscatory recommendation, this erosion "would send an unmistakable signal to the investor community as they consider whether to commit capital in Kentucky, and at what cost."[370]

The unjust and unreasonable character of Mr. Baudino's and Mr. Kollen's ROE reduction recommendation is nowhere better illustrated than by Mr. Baudino's own proxy group year-end

---

[366] *Id.*
[367] *Id.* at 4, McKenzie Rebuttal Test. at R4-R6.
[368] Messner Rebuttal Test. at R6.
[369] *Compare* Tr. Vol. VI at 1558 (Baudino, conceding the point) *and* Tr. Vol V at 942 (McKenzie, highlighting that at the bottom of the investment grade where the Company currently is this consideration becomes even more important); *see also* Company Confidential Hearing Ex. Nos. 4, 5 and 6 (illustrating that Kentucky Utilities, Louisville Gas and Electric and Duke Energy Kentucky are less risky investments than Kentucky Power, justifying that Kentucky Power's authorized ROE should be set higher than these other utilities).
[370] Mattison Rebuttal Test. at R4; McKenzie Rebuttal Test. at R35.

ROE projected by Value Line Investment Survey. As discussed in detail in Company Witness McKenzie's Rebuttal Testimony, the implied average cost of equity for Mr. Baudino's proxy group is 10.6%, a whopping <u>160 basis points above</u> his recommended ROE.[371]

The Constitutional requirements under the well-cemented precedent of *Hope* and *Bluefield* direct that Kentucky Power's ROE be set substantially above the level recommended by Mr. Baudino and Kollen, and in fact must be set <u>at a level higher than comparable investments of lesser risk</u>, such as those recently determined by the Commission for Duke Energy Kentucky, for example. As the Supreme Court of the United States explained in *Hope*:

> The ratemaking process under the Act, *i.e.,* the fixing of "just and reasonable" rates, involves a balancing of the investor and the consumer interests. Thus, we stated in the *Natural Gas Pipeline Co.* case that "regulation does not insure that the business shall produce net revenues." But, such considerations aside, the investor interest has a legitimate concern with the financial integrity of the company whose rates are being regulated. From the investor or company point of view, it is important that there be enough revenue not only for operating expenses, but also for the capital costs of the business. These include service on the debt and dividends on the stock. By that standard, <u>the return to the equity owner should be commensurate with returns on investments in other enterprises having corresponding risks.</u> That return, moreover, should be sufficient to assure confidence in the financial integrity of the enterprise, so as to maintain its credit and to attract capital.[372]

This much glossed-over language is not an abstraction in Kentucky Power's case. There is no dispute about facts regarding the actual ROE earned by the Company in the past several years, including the test year. There is no factual dispute that Kentucky Power's revenues are entirely insufficient for it to maintain its financial integrity. No matter the circumstances, Kentucky Power has consistently and continuously managed its operations zealously to be able to provide

---

[371] McKenzie Rebuttal Test. at R7.
[372] *Hope*, 320 U.S. at 603 (emphasis added) (citations omitted).

the service it is committed to provide to its customers and has diligently worked to support its customers and grow the economy of its service territory.

As even Mr. Baudino conceded, Kentucky Power should be allowed to have a real world opportunity to earn a just and reasonable ROE:

> Q. Just to verify, I think you said at the beginning -- and I just wanted to make sure the record is clear. So you would agree with me that it's bad for customers and bad for the company if for an extended period of time Kentucky Power is not able to earn its authorized ROE, correct? Just to keep it simple. It's bad for customers and it's bad for the company?
>
> A. <u>Yes. That's right. And if that kind of situation occurred over a long period of time, I think the Commission -- that's something the Commission ought to investigate and find out what's responsible because, really, for regulatory purposes and for revenue requirement purposes, the company should be allowed a reasonable level of expenses and reasonable level of rate base to provide service to its customers. And if that's not happening over a period of time or a period of years, then rate cases are one way to correct that, and that's what we're here for now</u>.[373]

The recommended 9.0% ROE proposed by Mr. Baudino and Mr. Kollen is simply insufficient to resolve the very problem Mr. Baudino conceded is bad for customers and bad for the Company. It defies reason to state that the Company should be allowed to have sufficient revenues to earn an ROE that is sufficient "to maintain and support its credit and enable it to raise money necessary for the proper discharge of its public duties" (as required under *Bluefield*[374]) and at the same time recommend lowering Kentucky Power's authorized ROE to a level below that of other utilities in Kentucky that are less risky investment opportunities.[375]

---

[373] Tr. Vol. VI at 1583 (emphasis added).
[374] *See Bluefield*, 262 U.S. at 693.
[375] *See, e.g.*, Tr. Vol. VI at 1570.

The result recommended by Mr. Kollen and Mr. Baudino would capriciously ignore, for example, the investment risk inherent in the higher concentration of commercial and industrial load in Kentucky Power's service territory.[376] Their proposed ROE would ignore the significantly increased market volatility risk for investors compared with the levels at the time the Company's 9.7% ROE (which Mr. Kollen and Mr. Baudino seek to reduce) was authorized. As conceded by Mr. Baudino during cross-examination, the VIX (also called the "fear index") is significantly higher now than it was in 2017.[377]

The very factors that led the Company to propose a 10% ROE instead of the 10.3% level resulting from Mr. McKenzie's analysis further highlight the confiscatory nature of Mr. Kollen's and Mr. Baudino's recommendation. As Mr. Baudino conceded during cross-examination, the Federal Reserve's intervention in March of 2020 to lower interest rates and increase its treasury securities holdings to all time-high levels, which dwarf even the highest levels during the 2008 Great Recession, was unprecedented.[378] Moreover, this intervention was on the heels of interest rate reductions in 2019 to address international trade tensions causing disturbance to financial markets and increasing the overall risk faced by investors – and consequently putting upward pressure on the ROE required for Kentucky Power.[379]

Far from justifying a reduction, the interests of customers are aligned with Kentucky Power's request for a just and reasonable ROE that is set 30 basis points higher than its currently-authorized level. That would help the Company maintain its financial integrity, mitigate the risk of costly further deterioration of its credit rating, and allow it to attract the

---

[376] *Id.*
[377] *Id*. at 1566.
[378] *Id.* at 1563-1564.
[379] *Id*. at 1563.

capital required to energize its service territory and continue to provide affordable, safe, and reliable service.[380] The alignment of the Company's and its customers' needs in this regard is particularly clear given the relatively thin equity layer of the Company's capital structure. Kentucky Power's capital structure, and the resulting 4.33% weighted cost of equity, further buffers the impact to customers of the 30 basis points adjustment proposed as part of the Company's application.[381]

Against that backdrop, it is inescapable that the anomalous market conditions during and after the test year make it particularly pernicious to depress Kentucky Power's ROE at this time.[382] Mr. Baudino's and Mr. Kollen's recommendation, simply put, is unrealistic and confiscatory.[383] Nothing in Mr. Baudino's testimony addresses the detailed discussion in Mr. McKenzie's testimony identifying the multiple and arbitrary ways in which Mr. Baudino's analysis is biased to lower Kentucky Power's ROE.[384] Financial strength is necessary for a utility to attract capital at a reasonable cost in order to make the investments necessary for the utility to fulfill its service obligations at a reasonable cost. Mr. Baudino's and Mr. Kollen's ROE recommendation, particularly together with the AG's and KIUC's proposal to eliminate the tracking mechanism for the Company's transmission costs and their other proposed erosion of the Company's revenue requirement, would simply not allow the Company to maintain its financial integrity.

---

[380] Mattison Rebuttal Test. at R2-R6, *see also* Tr. Vol. VI at 1583; Tr. Vol. V at 948-949.
[381] McKenzie Direct Test. at 15-16; *see also* Tr. Vol V at 946-947.
[382] McKenzie Rebuttal Test. at R11-R15.
[383] *Id*. at R16.
[384] *Id*. at R16-R35; Tr. Vol V at 939-940 (Company Witness McKenzie, highlighting how the DCF method can produce results that are unrepresentative, and underlying this weakness in Mr. Baudino's depressed ROE analysis).

Mr. McKenzie's analytical results based on a proxy group of electric utilities, together with the risk factors associated with Kentucky Power's service territory, load projections, commercial and industrial customer concentration, cost recovery mechanisms, regulatory lag, the costs of issuing common stock, review of current changing capital market conditions and high levels of instability, and comparison to authorized ROEs for other utilities in Kentucky are grounded in the real world facing the Company and are not an academic exercise. The robust analysis provided by Mr. McKenzie demonstrates that based on sound methodological observations the proposed 10% ROE is just and reasonable, and the reduction proposed by other parties is insufficient to satisfy the *Hope* and *Bluefield* requirements.[385]

Mr. McKenzie's analysis also takes into consideration four well-grounded ROE methodologies that together provide the necessary assurance that indeed the proposed 30 basis point increase is necessary and appropriate.[386] It would be irrational and arbitrary to reduce Kentucky Power's ROE, particularly to the level recommended by Mr. Baudino and Mr. Kollen. The Commission should not follow their biased reliance on Discounted Cash Flow ("DCF") results that are known to be vulnerable to anomalies in market conditions, which would result in an impermissibly low ROE in violation of *Hope* and *Bluefield*.[387] A decision to reduce Kentucky Power's currently authorized ROE would be unjust and unreasonable, send a decisively negative signal to the investment community that is a crucial component of Kentucky Power's financial integrity and ability to provide service, and ultimately fail the regulatory compact under which Kentucky Power serves its customers.

---

[385] *See, e.g.*, McKenzie Direct Test. at 8-82, McKenzie Rebuttal Test. at R2-R42.
[386] Company Hearing Ex. 9.
[387] Tr. Vol V at 939-941.

F. The Company's Proposed Capital Structure and Cost of Capital Are Reasonable and Appropriate.

Company Witness Messner presented the Company's proposed capital structure based on the test year ended March 31, 2020, as well as known and measurable adjustments:[388]

Table 1

Line No. (1)	Description (2)	Reapportioned Kentucky Jurisdictional Capital (3)	Percentage of Total (4)	Annual Cost Percentage Rate (5)	Weighted Average Cost Percent (6) = (4) X (5)
1	Long Term Debt	$752,127,351	53.73%	4.040%	2.17%
2	Short Term Debt	0	0.00%	2.230%	0.00%
3	Accounts Receivable Financing 4/	42,248,932	3.02%	2.802%	0.08%
4	Common Equity	605,509,950	43.25%	**10.00%**	4.33%
5	Total	$1,399,886,232	100.00%		**6.58%**

Mr. Messner also calculated the Company's weighted average cost of capital of 6.58%.[389] The facts underpinning Mr. Messner's testimony regarding the Company's proposed capital structure and cost of capital were not challenged.[390] The only points in dispute regarding cost of capital are Mr. Kollen's unjustified proposal to ignore the Commission's established practice in evaluating test year results and applicable adjustments.[391] His recommendation would further erode the Company's ability to earn its authorized ROE, and ultimately result in harm to customers and undermine the Company's financial integrity, particularly in the long run.

Mr. Kollen's attempt to supplant the Company's actual costs with arbitrary figures is illustrated by his egregious recommendation to use a 0.51% rate to set the level for the Company's short-term debt, when there is no dispute that factually the interest rate expense for

---

[388] Messner Direct Test. at 4.
[389] *Id.*
[390] *Id*. at 1-7.
[391] Messner Rebuttal Test at R1-R9.

the 12 months ended March 31, 2020 (i.e., the test year) divided by the average short-term debt borrowings for the same period is 2.230%.[392]

Similarly, Mr. Kollen arbitrarily proposes to ignore the actual end of test year short-term balance of $10.536 million, even though it is well established that the actual end of test year short-term balance is the relevant number to establish the Company's cost of capital for ratemaking purposes.[393] Mr. Kollen's proposal is even more puzzling given that the long-term loan that in fact reduced the Company's short-term balance to its end of test year level was at a rate *lower* than the applicable test-year short-term interest rate.[394]

Taken together, Mr. Kollen's recommendations would have a punitive effect on Kentucky Power's financial condition, and further erode, rather than support, the Company's already alarmingly weak credit metrics. Mr. Kollen's recommendations regarding cost of capital should be summarily rejected.

G. Kentucky Power's Employee Compensation and Post-Retirement Benefits Are Necessary to Provide Market-Competitive Compensation to Attract and Retain the Employees it Needs to Provide Adequate Service.

The costs Kentucky Power incurs for employee compensation and post-retirement benefits, including incentive compensation, Supplemental Executive Retirement Plan ("SERP") and other post-retirement plan expenses provided to Kentucky Power and American Electric Power Service Corporation ("AEPSC") personnel, are a reasonable cost of providing safe and reliable service to customers. The Company's Total Compensation (which includes a combination of base pay and short-term incentive ("STI") and long-term incentive ("LTI") plans) and post-retirement benefits paid to Kentucky Power and AEPSC employees and included in the

[392] *Id.* at R4.
[393] *Id.* at R2-R3.
[394] *Id.* at R3.

Company's cost of service are all market competitive, meaning that they are neither excessive nor insufficient.[395] The Company's compensation and post-retirement benefit strategy is critical to the Company's ability to recruit and retain employees with the required level of skill necessary to provide safe and reliable service to its customers, while incentivizing employees to spend effectively, operate efficiently, and conserve financial resources, all of which provide direct benefits to the Company's customers.[396]

Furthermore, as explained further below, both the cash balance formula pension and 401(k) matching plans, and the expenses associated with those plans, are consistent with the information provided by the Company and approved by the Commission in the Company's previous rate case.[397] The Company made no changes to the cash balance formula pension or 401(k) match plans since the Commission's January 18, 2018 Order in Case No. 2017-00179, and the Commission should allow expenses related to these post-retirement plans for ratemaking purposes, consistent with its previous ruling on the issue.[398] Denying recovery of a portion or all of the Company's incentive compensation or post-retirement plan expenses would undermine the Company's ability to attract and retain talent necessary to provide safe and reliable service to its customers and/or necessitate changes to the Company's compensation strategy, which would reduce the benefits to customers associated with the current compensation framework.

---

[395] Kaiser Rebuttal Test. at R4-R5, R13; Kaiser Direct Test. at 7, 9; Tr. Vol. III at 680-681; 2017 Rate Case, Order at 16.
[396] Kaiser Direct Test. at 7, 11; Kaiser Rebuttal Test. at R12.
[397] 2017 Rate Case, Order at 15.
[397] Tr. Vol. III at 703-704; 2017 Rate Case, Hearing Tr. Vol. II at 679-680 (Dec. 21, 2017).
[398] *See* 2017 Rate Case, Order at 15.

1. The Company's Incentive Compensation Plan is Reasonable and Provides Direct Benefits to Customers.

As Company Witness Kaiser explained in her Direct Testimony, the Company, and the AEP System as a whole, has adopted a multi-element approach to compensating its employees.[399] Specifically, the Company uses a combination of base pay, STI, and LTI to pay employees at market-competitive levels and to incentivize employees to spend effectively, operate efficiently, and conserve financial resources for the benefit of its customers.[400] The undisputed evidence presented in this case demonstrates that the Company, and the AEP System as a whole, uses industry data to target market median Total Compensation for each of its positions. The record in fact establishes that the Company's Total Compensation levels are at, or slightly below, market median compensation levels.[401]

None of the intervenors claims that the Company's Total Compensation is in any way excessive in amount or otherwise beyond what is necessary to provide safe and reliable service to the Company's customers. Instead, AG/KIUC Witness Kollen recommends the Commission disallow recovery of all of the Company's STI and LTI expenses based on an incorrect claim that the Company's incentive compensation expenses were incurred to achieve shareholder goals and are not directly tied to the achievement of regulated utility service requirements.[402] In support of his position, Mr. Kollen selectively quotes and mischaracterizes portions of the Commission's orders in the Company's two previous rate cases, Case Nos. 2017-00179 and 2014-00396, respectively.[403] Despite Mr. Kollen's claims to the contrary, however, the record unequivocally

---

[399] Kaiser Direct Test. at 4.
[400] *Id.* at 3-4.
[401] Kaiser Rebuttal Test. at R3-R5.
[402] Kollen Test. at 29.
[403] *Id.* at 29-30.

shows that the Company's STI and LTI expenses are directly tied to the achievement of regulated utility service requirements.

a. AG/KIUC Witness Kollen's Characterization of the Settlements in the Company's Last Two Rate Cases is Incorrect.

First, Mr. Kollen's reliance on the Settlement Agreement and the Commission's subsequent approval of that Settlement Agreement in Case No. 2017-00179 is misplaced. While the Company agreed to reduce a portion of its total incentive compensation expense as part of the Settlement Agreement in that proceeding, Company Witness Satterwhite's testimony in support of the settlement makes clear that the Company supported full recovery of its incentive compensation plan as an important part of attracting and retaining talent.[404] Further, the parties to the Settlement Agreement, including KIUC, agreed that the Settlement Agreement would not be used or construed for any purpose to imply, suggest, or otherwise indicate that the results produced through the compromise reflected the full objectives of the parties and that the agreement would not have any precedential value in any future proceedings.[405] In its Order approving the Settlement Agreement, the Commission similarly made clear that its approval of the Settlement Agreement was based solely on the settlement's reasonableness and did not constitute precedent on any issue except as specifically provided for otherwise.[406] The Commission did not make any precedential rulings regarding the agreed upon reduction in incentive compensation expense other than to find that the proposed reduction was reasonable and should be approved.[407] Simply put, the agreed upon reduction to the Company's incentive compensation expense approved in Case No. 2017-00179 cannot support a finding that the

[404] 2017 Rate Case, Satterwhite Settlement Test. at S19 (Nov. 22, 2018).
[405] *Id.* at Exhibit MJS-1S, at 18, ¶ 24 (a) & (b) ("Settlement Agreement").
[406] 2017 Rate Case, Order at 67.
[407] *Id.* at 14-15.

Company's incentive compensation expenses sought to be recovered as part of this proceeding should be excluded.

Additionally, Mr. Kollen's assertion that the agreed upon reduction in the Company's incentive compensation expense in Case No. 2017-00179 represented "all incentive compensation expense tied to financial performance" is untrue.[408] Neither the Order nor the record supports Mr. Kollen's claim. Rather, in its Order, the Commission found that the reduction in incentive compensation, which was a greater reduction than the adjustment recommended by the Attorney General, was reasonable and should be approved.[409] As there was no finding that the agreed upon reduction represented a reduction in incentive compensation expense tied to financial performance measures, the Commission should give no weight to Mr. Kollen's claim otherwise.

Further, Mr. Kollen's focus on the Company's earnings per share ("EPS") funding mechanism, especially as it pertains to STI, as the basis for excluding the Company's incentive compensation expenses is misplaced. In support of his recommendation to exclude all of the Company's STI and LTI expense, Mr. Kollen quotes the Commission's Order in Case No. 2014-00396.[410] However, Mr. Kollen neglects to mention that the selective quote used to support his position was specific to the Company's STI expenses in that case and that the Commission went on to hold that, "[w]hile the Commission agrees with the AG conceptually, we find that the amount that should be removed for ratemaking purposes should be based on the performance measures of the plan, not the funding measures."[411]

---

[408] *Id.*
[409] 2017 Rate Case, Order at 14.
[410] Kollen Test. at 29-30 (quoting the Order, Case No. 2014-00396, at 25 (June 22, 2015)).
[411] *In the Matter of: Application Of Kentucky Power Company For: (1) A General Adjustment Of Its Rates For Electric Service; (2) An Order Approving Its 2014 Environmental Compliance Plan; (3) An Order*

This is an important distinction as it relates to STI because the Company's EPS funding mechanism is simply that: a pool of resources that is allocated to the Company based on employees, and the Company overall, achieving customer-specific, safety and financial performance metrics.[412] As the Company is only seeking to recover its STI expense to a target 1.0 level,[413] the costs the Company is seeking to recover in its cost of service are only the actual STI costs incurred to achieve those customer-specific, safety, and financial performance measures identified in Table 3 of Company Witness Kaiser's rebuttal testimony.[414]

b. The Company's STI Expense is Reasonable.

The Company agrees that the Commission's review of STI expense should be focused on the Company's performance measures rather than the EPS funding mechanism, consistent with its Order in Case No. 2014-00396.[415] However, as explained by Company Witness Kaiser, the costs associated with achieving the Company's STI financial performance metrics, which were excluded in that proceeding,[416] are critical components of the Company's market competitive compensation plan that enables the Company to provide safe and reliable service to its customers.[417] The financial performance metrics also directly benefit customers by incentivizing employees to control costs and improve efficiency, which is passed back as a benefit to customers in the form of lower cost of service.[418] Without the STI financial performance

Approving Its Tariffs And Riders; And (4) An Order Granting All Other Required Approvals And Relief, Case No. 2014-00396, Order at 24-26 (Ky. P.S.C. June 22, 2015) ("2014 Rate Case Order") (emphasis added).

[412] Kaiser Rebuttal Test. at R6.

[413] Kaiser Direct Test. at 6.

[414] Kaiser Rebuttal Test. at R6, Table 3.

[415] 2014 Rate Case Order at 24-26.

[416] *Id*. at 25-26.

[417] Kaiser Rebuttal Test. at R8.

[418] *Id.* at R11.

measures, the compensation signal shifts to incentivize achieving the performance measures at the expense of cost consciousness and, in that instance, could lead to a higher cost of service.[419] Thus, the record demonstrates that the Company's STI expense, including that which is tied to achieving responsible financial performance metrics, does not primarily benefit shareholders, but rather provides direct benefits to customers by incentivizing employees to control costs which, in turn, lowers the Company's cost of service, contrary to Mr. Kollen's claims.

There is no dispute in the record that the Company's STI compensation levels are reasonable and that the costs associated with STI are incurred to provide market competitive compensation to employees. Furthermore, the Company has shown that its STI costs, including those costs tied to financial performance metrics, are necessary costs incurred to provide safe and reliable service to its customers and directly benefit customers. Therefore, the STI expenses the Company seeks to recover are reasonable and prudently incurred expenses necessary to provide service to customer and should be allowed for ratemaking purposes.

Finally, if the Commission were to accept Mr. Kollen's recommendation to exclude STI expenses in a manner consistent with its June 22, 2015 Order, the only STI amounts at issue would be the 10% of STI expense incurred during 2019 and the 20% of the STI expense incurred in 2020 tied to the financial performance metrics, not the amounts related to the EPS funding mechanism.[420]

---

[419] *Id.* at R8.

[420] Kaiser Rebuttal Test. at R6-R7; Tr. Vol. III at 648-649 (stating that for 2019, 10% of Kentucky Power's STI performance metric were based on financial performance and, for 2020, 20% of Kentucky Power's STI performance metrics were based on financial performance).

c. The Company's LTI Expense is Reasonable.

Turning to LTI, Mr. Kollen similarly recommends the Commission exclude all of the Company's LTI expenses based, again, on his claim that these expenses are financial goals that primarily benefit shareholders.[421] Mr. Kollen's claim again is incorrect. As with STI, the primary objective of the Companies' long-term incentive plan is to provide an integral component of the reasonable and market competitive compensation needed to attract, retain and motivate the appropriately skilled and experienced employees necessary to efficiently and effectively provide electric service to customers.[422] As demonstrated in Table 2 of Company Witness Kaiser's testimony, for positions within the Company that are eligible for LTI pay, the Total Compensation for those employees is at or slightly below market median levels.[423]

Additionally, the LTI plan is tied to financial performance measures that promote 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.[424] 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.[425] Conversely, without these compensation signals, employees in executive and managerial positions would have more incentive to focus on, and implement, short-term measures that may provide immediate benefits to customer but ultimately lead to higher costs in the longer term, which is not in the interest of the Company's customers, especially given the long-term nature of utility assets necessary to serve customers.

---

[421] Kollen Test. at 29.
[422] Kaiser Rebuttal Test. at R10.
[423] *Id*. at R5, Table 2. Specifically, Job 4 referenced in the table is a position that would receive LTI. As shown in the table, LTI is necessary to compensate that position at a market competitive level.
[424] Kaiser Direct Test. at 9.
[425] *Id.*

For example, should a transformer fail on the Company's distribution system, a short-term solution may be to replace the transformer with a similar vintage model nearing the end of its useful life. However, the LTI plan incentivizes eligible employees in decision-making positions to analyze the issue with a more long-term view and determine whether it would be more prudent to replace that failed equipment with a newer model or different equipment that may improve the overall performance of the system and/or develop a long-term solution that, in the short-term, is the more costly option but will ultimately result in the least cost alternative to customers as the Company would not have to continually replace the failed equipment with a similar vintage or less reliable equipment each time that equipment failed. The LTI plan also takes this analogy a step further by ensuring that the Company does not make long-term investments unnecessarily. LTI pay incentivizes long-term financial discipline by providing an incentive to control costs, which is the primary and often the only lever most utility employees have available to improve company financial performance.[426] Therefore, although the Company's LTI compensation does not have a performance measure similar to the Company's STI plan, LTI pay provides direct benefits to the Company's customers by incentivizing employees to control costs and make long-term decisions that are in the best interest of customers. As such, Mr. Kollen's recommendation that the Commission exclude all of the Company's incentive compensation costs tied to LTI should also be rejected.

---

[426] Kaiser Rebuttal Test. at R10.

d. Kentucky Power's Total Compensation Strategy is Appropriate and Necessary to Provide Market Competitive Compensation to its Employees.

Finally, the undisputed evidence is clear that the Company's Total Compensation expense represents the amounts required to provide market competitive compensation to its employees.[427] Allowing the Company to recover its incentive compensation expenses related to both STI and LTI is a crucial component of providing safe and reliable service to its customers. Without STI and LTI, the Company's base pay compensation would fall to levels well below market and, at those below market base pay levels, the Company would be unable to attract and retain the employees who ensure we can provide safe and reliable service to our customers.[428] In that instance, the Company would be forced to explore compensation alternatives, all of which would be to the detriment of its customers.

Specifically, if Kentucky Power is unable to recover its incentive compensation costs, it may be forced to increase its fixed costs by increasing base pay, which is something the Company has already begun to explore.[429] In that scenario, employee compensation would remain at similar levels, but the Company's customers would lose the benefits associated with tying a portion of employees' market-competitive compensation to improving reliability, customer experience, employee and contractor safety, and encouraging financial responsibility.[430] Similarly, if the Commission denied recovery of STI expenses related to financial performance metrics and/or LTI expenses, the Company may similarly have to increase base pay commensurately to provide the same market-competitive compensation it currently

---

[427] Kaiser Direct Test. at 7; Kaiser Rebuttal Test. at R10.
[428] *See* Kaiser Direct Test. at 7, 9; Kaiser Rebuttal Test. at R8, R11.
[429] Tr. Vol. III 715-716.
[430] *See id.*

provides employees, but customers again lose the customer benefits associated with incentivizing employees to control costs and make decisions that serve the customers long-term interests.

Ultimately, looking at the Company's compensation strategy as a whole, the record is devoid of any evidence that the Company's Total Compensation levels are unreasonable and, while the Company understands the Commission's reservations about certain compensation practices, the Company's compensation practices are in line with the market and is the strategy that provides the most benefits to our customers.[431] As such, the Company recommends the Commission analyze the Company's STI and LTI expenses within the context of determining whether the Company's Total Compensation package is reasonable. Based on the record, it indisputably is. However, should the Commission determine it is more appropriate to analyze STI and LTI as distinct aspects of the Company's overall compensation strategy, the record demonstrates that the STI and LTI expenses sought to be recovered as part of this proceeding are only those necessary to retain and attract the talent necessary to best provide safe and reliable service to its customers and, as such, should be recovered as part of the Company's cost of service.

2. The Company's SERP Expenses Are Reasonable and Should Be Allowed for Ratemaking Purposes.

Despite Mr. Kollen's claim to the contrary,[432] the SERP expenses the Company seeks to recover are not excessive expenses incurred pursuant to multiple retirement plans. The Company maintains SERP, which is a non-qualified post-retirement benefit plan, for its employees to provide benefits that cannot be provided under qualified post-retirement plans due to IRS limits imposed on Employee Retirement Security Act of 1974 ("ERISA")-qualified plans.[433] As the

---

[431] Kaiser Direct Test. at 4.
[432] Kollen Test. at 32.
[433] Kaiser Rebuttal Test. at R12.

record makes clear, the Company utilizes the same benefit formulas for SERP that are used to establish the qualified Retirement Plan for each respective employee, which is then reduced by the amount of the qualified benefits, to provide the same retirement benefits to employees compensated at levels above the IRS limits as those that are provided under ERISA-qualified retirement plans.[434] As such, SERP expenses are only incurred to provide employees with a market-competitive total rewards package and are not an additional benefit above and beyond what is needed to provide market-competitive total rewards to these employees.[435] The Commission recognized this point in its January 18, 2020 Order in Case No. 2017-00179 when it found the Company's SERP expenses reasonable.[436] Consistent with its Order in that case – which Mr. Kollen fails even to acknowledge – the Commission should reject Mr. Kollen's recommendation that SERP expenses be disallowed in this case and should, again, find SERP expense reasonable and allowed for ratemaking purposes.

3. The Company's Retirement Package is Market Competitive When Evaluated as a Whole and Should Be Allowed for Ratemaking Purposes, Consistent with the Commission's Previous Rulings.

Consistent with referenced record pertaining to defined benefit and 401(k) retirement plans in Case No. 2017-00179,[437] Kentucky Power contributes to both a cash balance formula pension and 401(k) matching plan.[438] However, as Company Witness Carlin explained at hearing, there is an important distinction between the now-frozen final average pay pension formula and the Company's current cash balance pension formula.[439] Participation in the final

---

[434] *Id*. at R13; Tr. Vol. III at 680-681.
[435] Kaiser Rebuttal Test. at R13.
[436] 2017 Rate Case, Order at 16.
[437] Tr. Vol. III at 699-70.
[438] *Id.* at 699.
[439] *Id.* at 703-704.

average pay pension formula, which is a traditional defined benefit pension formula, ended in 2000 and the benefits were frozen in 2010,[440] which is consistent with the Commission's finding in Case No. 2017-00179.[441]

The Company's current cash balance pension formula provides a "defined contribution" of 3% to 8.5% (depending on age and years of service) of each participant's eligible earnings to an individual cash balance pension account that grows with interest and, as the records in Case No. 2017-00179 and this proceeding make clear, was designed together, with the Company's 401(k) matching plan, to provide post-retirement benefits at a market-competitive level.[442] Thus, the Commission's 2018 treatment of the Company's cash balance pension formula as providing a 'defined contribution' type benefit similar to a 401k, rather than a traditional defined benefit pension formula is correct. While governed by the ERISA rules around defined benefit plans,[443] the Company's cash balance pension formula provides a "defined contribution" benefit and, in combination with the Company's 401(k) plan, only provides retirement benefits at market-competitive level as illustrated by Company Witness Carlin swirl cone analogy.[444] As the Company is only seeking to recover cost of service expenses related to post-retirement benefit plans that the Commission has previously found reasonable, and no other parties have otherwise challenged the post-retirement benefit expenses as being excessive or otherwise unreasonable

---

[440] *Id.*; KPCO_R_KPSC_PH_3 (to be filed Dec. 9, 2020).
[441] 2017 Rate Case, Order at 15.
[442] Tr. Vol. III at 703-704; KPCO_R_KPSC_PH_3 (to be filed Dec. 9, 2020); 2017 Rate Case, Hearing Tr. Vol. II at 679-680 ("[The Company has] designed these two plans together to do what other companies are doing, to provide the median amount of pension benefits together as a total, and so yes, [the Company has] two plans, but they're not creating a value for participants that's any greater than if [it] had a full-blown 401(k) plan with 100 percent or 125 percent match or a full-blown pension plan with a greater employee contribution there as well.").
[443] Tr. Vol. III at 704.
[444] *Id.* at 688.

when compared to market levels for post-retirement benefits, the Commission should, consistent with its Order in Case No. 2017-00179, allow these expenses for ratemaking purposes.

H. The Company's Proposal to Use Capitalization to Calculate the "Return On" Component is Reasonable and Should Be Followed. In the Event the Commission Nevertheless Uses a Rate Base Approach It Must Reject AG/KIUC's Proposed Adjustments to Rate Base.

1. The Company's Use of the Capitalization Methodology is Reasonable, Has Repeatedly Been Accepted by This Commission, and Should Again Be Approved in This Case.

As it has consistently done in the past, the Company calculated its return on component of rate base using a capitalization approach.[445] The only witness to opine on this topic, AG/KIUC Witness Kollen, recommends the Commission calculate the Company's return on component using rate base rather than capitalization.[446] Relying on statements made in separate Commission proceedings involving Duke Energy Kentucky ("Duke"), Mr. Kollen asserts that, because Duke determined a rate base calculation was appropriate for its respective businesses, it is equally appropriate for the Company.[447] However, because of the distinct differences between the Company and Duke and the type of cases each filed with the Commission, Mr. Kollen's arguments are an exercise in conflating apples with machine tools. Most notably, Mr. Kollen overlooks the facts that Duke is a gas and electric utility that filed a forecasted test year; the Company by contrast is an electric-only utility that filed a historic test year in this case. The Company's use of capitalization is a reasonable measure of the return on component of revenue, which the Commission has recognized since at least 2009.[448]

---

[445] *See* Kentucky Power's Application, Section V, Schedule 3; 2017 Rate Case, Order; 2014 Rate Case Order; *In The Matter Of: Application Of Kentucky Power Company For A General Adjustment Of Electric Rates*, Case No. 2009-00459, Order (Ky. P.S.C. Jun. 28, 2010) ("2009 Rate Case Order").
[446] Kollen Test. at 12.
[447] *Id*. at 8-9 (quoting Duke witnesses Sara E. Lawler and Amy B. Spiller and William Don Wathen, Jr.).
[448] *Id*.; 2017 Rate Case Order; 2014 Rate Case, Order; 2009 Rate Case Order.

Mr. Kollen goes on to claim that the rate base approach is more appropriate because it is more precise and accurate than capitalization, which he asserts is demonstrated by the Company's reconciliation between its capitalization and net investment rate base for the test year.[449] Although he states that the reconciliation provided by the Company in discovery shows there are, "many assets and many liabilities from the Company's balance sheet accounts that are not included in the Company's calculation of rate base,"[450] he tellingly fails to provide any specific examples or show that the differences have any impacts on the Company's capitalization. Mr. Kollen's recommendation is flawed and should be rejected.

2. AG/KIUC Witness Kollen's Recommended Adjustments to the Company's Calculation of Rate Base Are Not Supported by the Record in this Case and Should Be Rejected.

AG/KIUC Witness Kollen recommends that the Company make four adjustments to the calculation of the Company's rate base.[451] Specifically, he recommends: (1) the cash working capital ("CWC") be calculated using the lead/lag approach, or alternatively set to $0, (2) the construction work in progress ("CWIP") included in rate base should be reduced by the accounts payable related to CWIP, (3) the prepayments should be reduced by the accounts payable related to those prepayment accounts and (4) the prepaid pension asset and prepaid other postretirement employee benefit ("OPEB") asset be excluded from rate base.[452] These adjustments are not necessary under the Company's capitalization approach and are unsupported by the record in this case if the Commission elects to use rate base to calculate the "return on" component.

[449] Kollen Test. at 10-11.
[450] *Id*. at 12.
[451] *Id.* at 12-13.
[452] *Id*. at 12.

a. CWC, Accounts Receivable, and Prepayments

As to his first recommended adjustment, the Company calculated CWC using the standard formula of one-eighth of the total Company O&M expenses.[453] Mr. Kollen recommends the Commission reject the Company's calculation and, instead, calculate CWC using the lead/lag approach or, alternatively, include $0 for CWC in rate base because the Company did not use a lead/lag approach and takes issue with the fact that the Company did not conduct a lead/lag study.[454] First, the Company did not conduct a lead/lag study as part of this case because such study is not necessary under the capitalization methodology, which is the methodology the Company utilized to measure its return on component of its base rate revenue requirement in this case.[455] Moreover, as Mr. Kollen conceded on cross-examination, there was no requirement that the Company perform a lead/lag study in connection with calculating the Company's rate base in this case.[456] Mr. Kollen's recommendation that the Commission retroactively impose such a requirement, and penalize the Company by taking CWC to zero, is arbitrary and inequitable.

Next, Mr. Kollen's recommendation that the Commission include $0 for CWC in rate base because the Company did not use a lead/lag approach appears to be based on his assumption that a lead/lag study would produce $0 or less of CWC for inclusion in rate base because the Company sells its receivables by factoring them to AEP Credit, Inc.[457] But that is unsupported speculation on his part. Certainly, he offers no study to support his contention. However, Mr. Kollen fails to recognize that, because the Company proposes to use end of period capitalization,

---

[453] Cost Direct Test. at 9.
[454] Kollen Test. at 17.
[455] Vaughan Rebuttal Test. at R6.
[456] Tr. Vol. IV at 1529-1530.
[457] Kollen Test. at 15-16.

the base revenue requirement reflects the Company's actual working capital needs as of the end of the test year and, as such, there is no estimate of CWC included in the Company's request that would require an adjustment.[458]

Mr. Kollen's recommendations that CWIP included in rate base be reduced by the accounts payable related to CWIP and that the prepayments be reduced by the accounts payable related to those prepayment accounts are also inappropriate. He offers no support beyond his opinion. Further, by using capitalization as the basis for the return on component, any non-financed items have already been excluded from the Company's request.[459]

b. Prepaid Pension and Prepaid OPEB Assets

Mr. Kollen's final proposed adjustment to exclude the prepaid pension asset and prepaid OPEB asset is similarly without merit. Mr. Kollen hangs his justification for this recommendation on his demonstrably false assertion that there is no prepaid pension or OPEB asset and studied indifference to the most basic principles of double entry accrual accounting.[460]

Mr. Kollen's contention that the prepaid pension and OPEB assets are not cash assets[461] is directly contradicted by Company Witness Whitney's testimony. As shown in Company Exhibits HMW-R1 and HMW-R2, since the Company's last base rate case, AEP, on behalf of its affiliate companies, made cash payments to the Bank of New York in June 2017 and September 2020.[462] Kentucky Power was then allocated its portion of these cash payments, which it reimbursed through the AEP Money Pool.[463] Therefore, the Company's prepaid pension and

---

[458] Vaughan Rebuttal Test. at R6.
[459] *Id*. at R7.
[460] Kollen Test. at 19.
[461] *Id*. at 21.
[462] Whitney Rebuttal Test. at Ex. HMW-R1 and HMW-R2.
[463] *Id*. at R7.

OPEB assets are "cash assets," which Mr. Kollen admitted on the record,[464] because they were established based on cash transactions the Company's prepaid pension and OPEB assets are cash assets.[465] This, in addition to the accounting evidence Company Witness Whitney presented showing that the prepaid pension and OPEB assets were in fact financed, demonstrates that the Company's prepaid and OPEB assets are cash assets and, as such, should be allowed to earn a return through inclusion in rate base, a point that Mr. Kollen agrees with.[466] Simply stated, the balances in Accounts 1650010 and 1650035, totaling $44,879,334 for the prepaid pension asset and $20,174,958 for the prepaid OPEB asset, reflect cumulative *cash* contributions in excess of cumulative pension and OPEB costs.[467]

Mr. Kollen attempts an end run around this evidence by improperly characterizing the Company's noncash accrual adjustments. Consistent with accrual, double entry-accounting, the Company made non-cash ASC 715 accrual adjustments in Accounts 1290000, 1290001, 1290002, 1290003, 1650014, 1650037, 1823165, 1823166, 1900010, 1900011, 2190006, 2190007, 2283006, and 2283016 that result from the Non-Cash ASC 715 Reclass entries required by ASC 715 to separate the calculated prepayment into two separate components – the funded status and accumulated other comprehensive income (or regulatory asset) for gains and losses that have not yet been recognized as components of net periodic benefit cost, which is shown in the lines 2-7 of the table titled "AG/KIUC 2-17, Subpart a" in Company Witness Whitney's rebuttal testimony.[468] As shown in line 9 of that table, the non-cash ASC 715

---

[464] Tr. Vol. VI at 1535 (stating, "[w]ell, there is cash outlay through a fund, the pension test fund and the OPEB trust fund ….").
[465] Whitney Rebuttal Test. at R7.
[466] Kollen Test. at 21 (stating, "If the former [accounts are assets that 4 the Company financed], then they should be included in rate base.").
[467] Whitney Rebuttal Test. at R14.
[468] *Id*. at R6 and R11.

Reclasses (lines 2-7) net to $0 and are excluded from rate base, leaving the total prepayment contributions financed by the Company, as shown in line 9.[469]

Mr. Kollen improperly nets the prepaid contribution included in line 1 against the non-cash ASC 715 prepayment reclass included in line 2.[470] As explained above, this accounting treatment is inappropriate because, in accordance with double-entry accounting, the non-cash ASC 715 accrual adjustment in Accounts 1650014 and 1650037 (line 2) must be netted against the remaining non-cash ASC 715 accrual adjustments in Accounts 1290000, 1290001, 1290002, 1290003, 1823165, 1823166, 1900010, 1900011, 2190006, 2190007, 2283006, which then leaves the Total Prepayment Contributions (line 9) that is properly included in rate base.[471] This is exactly what the Company did in this case and directly contradicts Mr. Kollen's claim that the Company ignored the negative amounts in Accounts 1650014 and 1650037.[472] Thus, Mr. Kollen's recommended accounting treatment of the Company's prepaid pension and OPEB assets is inappropriate and should be rejected.

Finally, Mr. Kollen, consistent with his recommendation to remove the prepaid pension and OPEB assets from rate base, fails to make a corresponding adjustment to remove the related benefits of reduced pension and OPEB costs from the cost of service.[473] The cumulative prepaid pension and OPEB assets have reduced the Company's total pension and OPEB cost by approximately $3.8 million annually, which resulted in an approximate $3.7 million reduction in the Company's cost of service.[474] Thus, if the Commission were to remove the pension and

---

[469] *Id*.
[470] Kollen Test. at 20.
[471] Whitney Rebuttal Test. at R6.
[472] *Id*. at R10.
[473] *Id*. at R19.
[474] *Id*. at R9-R10.

OPEB prepayments from rate base, the Company's cost of service for the test year ended March 31, 2020 should be increased in order to remove the $3.7 million benefit resulting from these additional contributions.[475]

3. The Company's Allocation of the Mitchell Coal Stock Adjustment to Short-Term Debt is Appropriate and Consistent with the Commission's Prior Rulings.

As explained by Company Witness Vaughan, the Company first allocates the Mitchell coal stock adjustment to short-term debt and, then reduces the remaining components of its capitalization proportionally to avoid the totality of the Company's capitalization adjustment from resulting in a negative short-term debt balance.[476] Setting the short-term debt to zero, rather than allowing it to be negative, and then adjusting the other components of capitalization was accepted by the Company and, ultimately, by the Commission in the Company's previous two general rate cases, Case Nos. 2014-00396 and 2017-00179 respectively.[477] AG/KIUC Witness Kollen's recommendation to allocate the Mitchell coal stock adjustment proportionately across the capital structure rather than first to short-term debt on the base revenue requirement is contrary to the Commission's prior rulings on this issue and, as such, should be rejected.

---

[475] *Id*. at R20 and Ex. HMW-R3.
[476] Vaughan Rebuttal Test. at R11.
[477] *See In the Matter of: Application Of Kentucky Power Company For: (1) A General Adjustment Of Its Rates For Electric Service; (2) An Order Approving Its 2014 Environmental Compliance Plan; (3) An Order Approving Its Tariffs And Riders; And (4) An Order Granting All Other Required Approvals And Relief*, Case No. 2014-00396, Wohnhas Rebuttal Testimony at 2-3 (April 29, 2015); 2017 Rate Case Order; 2014 Rate Case Order.

I. Proposed Tariff NMS II Appropriately Implements The Requirements of KRS 278.466, Is Reasonable, and Should Be Approved.

Senate Bill 100, An Act Related to Net Metering (the "Net Metering Act") was signed into law on March 26, 2019, and became effective on January 1, 2020.[478] The Net Metering Act provides for the end of, or at least a drastic reduction in, the subsidies to net metering customers that the previous net metering statute produced.[479] Unlike prior Kentucky law, which permitted the netting of excess net metering generation on a volumetric basis, the Net Metering Act makes clear that netting under the current law is financial in nature, and not volumetric. This is manifest in the definition of "net metering" in KRS 278.456(4):

> "Net metering" means the difference between the:
>
> (a) <u>Dollar value</u> of all electricity generated by an eligible customer-generator that is fed back to the electric grid over a billing period and priced as prescribed in KRS 278.466; and
> (b) <u>Dollar value</u> of all electricity consumed by the eligible customer-generator over the same billing period and priced using the applicable tariff of the retail electric supplier.[480]

The Net Metering Act mandates that each retail electric supplier is "entitled to implement rates," set by the Commission using the ratemaking processes under KRS 278.466, that recover from the retail electric supplier's eligible customer-generators[481] "<u>all</u> costs necessary to serve its eligible customer-generators, including but not limited to fixed or demand-based costs, without regard for the rate structure for customers who are not eligible customer-generators."[482] The law is also clear about the process to set the rate at which a retail electric supplier compensates an

---

[478] *See* KRS 278.265 through KRS 278.465, *et seq.*
[479] Vaughan Direct Test. at 23.
[480] KRS 278.265(4) (emphasis added).
[481] KRS 278.465(1) defines "eligible customer-generator" to mean "a customer of a retail electric supplier who owns and operates an electric generating facility that is located on the customer's premises, for the primary purpose of supplying all or part of the customer's own electricity requirements."
[482] KRS 278.466(5) (emphasis added).

eligible customer-generator for the customer-generator's excess generation:[483] "The rate to be used for such compensation shall be set by the commission using the ratemaking processes under this chapter during a proceeding initiated by a retail electric supplier or generation and transmission cooperative on behalf of one (1) or more retail electric suppliers."[484]

Kentucky Power proposes in this proceeding to implement the Net Metering Act's requirements by closing its current Tariff NMS (Net Metering Service) to new customers as of January 1, 2021, and instituting Tariff NMS II (Net Metering Service II).[485] By approving the Company's proposal, the Commission will eliminate the more than 6.5 cent/kilowatt-hour ("kWh") subsidy that net metering customer-generators currently receive under Tariff NMS, send appropriate price signals regarding the actual value of excess generation, and establish a fair and reasonable net metering compensation methodology for Kentucky Power's service territory.[486]

1. Overview of Tariff NMS II

Tariff NMS II contains two time of use ("TOU") netting periods for each day of the year, one from 8AM to 6PM, and a second from 6PM to 8AM.[487] All net kWh usage and kW demand (where applicable) will be accumulated for each netting period and then accumulated for each

[483] "Excess generation" is the "electricity produced by [a] customer's eligible electric generating facility that flows to the retail electric supplier," and thus is not consumed by the customer-generator. KRS 278.466(3).
[484] KRS 278.466(3) (emphasis added).
[485] *See* Vaughan Direct Test. at 23-30, Ex. AEV-3 and AEV-4; Vaughan Rebuttal Test. at R20-R43, Ex. AEV-R4 through AEV-R7.
[486] *See, e.g.,* Vaughan Rebuttal Test. at 24-25 (demonstrating that Tariff NMS customers are being paid approximately 10.33 cents/kWh for a commodity the Company could otherwise purchase for 3.85 cents/kWh, or 6.48 cents/kWh less).
[487] Vaughan Direct Test. at 24, Ex. AEV-4 at 1. If the Company's AMI proposal is approved, the Company in a future case could propose to net energy on an hourly basis, which would be the most exact solution for billing energy and excess generation under Tariff NMS II. *Id.* at 29. Until AMI is in place, Mr. Vaughan testified that the netting periods proposed in this proceeding are appropriate. *Id.*

monthly billing period. If a customer-generator's usage in a netting period exceeds the amount of energy its eligible generator produces, then the customer has net positive billing energy (and demand, where applicable).[488] If a customer-generator produces more energy than is consumed by the customer-generator's load in a daily netting period, then the customer-generator will produce excess generation, which the tariff defines as "net negative energy" or "NNE".[489]

Under Tariff NMS II, all net positive billing kWh and kW in each netting period, accumulated for the billing period, will be charged at the rates applicable under the Company's standard service tariff under which the customer would otherwise be served if the customer did not net meter.[490] Similarly, all of a customer-generator's generation against which the customer-generator's usage in a netting period is netted will be credited at the full retail rate the customer-generator would otherwise have been charged for that usage.[491] Finally, all NNE in each netting period, accumulated for the billing period, will be credited monthly at the applicable dollar denominated avoided cost rate – \$0.03553/kWh for residential customers and \$0.03778/kWh for commercial systems.[492]

Kentucky Power proposes to recover the purchased power costs of NNE payments to customer-generators under Tariff NMS II through the Company's Tariff PPA (Power Purchase Adjustment) or, alternatively, through Tariff FAC (Fuel Adjustment Clause).[493] In order to better align the Company's costs associated with the review of net metering applications with the customer causing those costs, Tariff NMS II also includes application fees of \$150 for both level

[488] *Id.* at 24-25, Ex. AEV-4.
[489] *Id.* at 24, Ex. AEV-4.
[490] *Id.* at 26, Ex. AEV 4.
[491] *Id.* at 25, Ex. AEV-4.
[492] *Id.* at 26, Ex. AEV-4; Vaughan Rebuttal Test. at R34, Ex. AEV-R5 and AEV-R6.
[493] Vaughan Direct Test. at 28.

1 and level 2 net metering applications and eliminates the $1,000 cap on level 2 system impact study costs.[494]

2. Tariff NMS II Is Driven By KRS 278.466's Requirements.

Tariff NMS II satisfies each of KRS 278.466's requirements. Consistent with KRS 278.466(1), the tariff provides that the Company has no further obligation to offering net metering to any new customer-generator if the cumulative generative capacity of net metering systems reached 1% of the Company's single hour peak load during a calendar year.[495] Net metering under Tariff NMS II will be accomplished using a standard TOU kWh meter capable of measuring the flow of electricity in two directions, as KRS 278.466(2) requires.[496] Kentucky Power proposes to compensate eligible customer-generators for excess generation, as described above.[497] Kentucky Power has initiated this proceeding and is requesting that the Commission approve its proposed compensation rate using the ratemaking processes under KRS Chapter 278.[498] The Company proposes to compensate eligible customer-generators each billing period through a dollar-denominated bill credit, as KRS 278.466(4) requires.[499] Tariff NMS II provides that if the net negative energy credit paid to a customer-generator exceeds the customer's billed charges that month, the amount of credit in excess of the billed charges will be carried over for use in subsequent billing periods.[500] The tariff does not permit cash refunds of accumulated net negative energy credits, a provision also required by KRS 278.466(4).

---

494 *Id.* at 28-29.
495 Vaughan Direct Test. at Ex. AEV-4, p. 1; Vaughan Rebuttal Test. at R42.
496 Vaughan Direct Test. at Ex. AEV-4, p. 1.
497 KRS 278.466(3).
498 *Id.*
499 Vaughan Direct Test. at Ex. AEV-4, p. 1; Vaughan Rebuttal Test. at R34.
500 Vaughan Direct Test. at Ex. AEV-4, p. 1; KRS 278.466(4).

The rates that Kentucky Power seeks to implement through Tariff NMS II, and the structure of the tariff itself, also would enable the Company to recover from its eligible customer-generators its "costs necessary to serve its eligible customer-generators, including but not limited to fixed and demand-based costs," as KRS 278.466(5) provides.[501] As Mr. Vaughan explained, the proposed netting periods in Tariff NMS II will result in net positive billing units, which will require NMS II customers to make "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 either not producing, or not producing enough generation to meet the customer's requirements.[502] The application fee provisions of Tariff NMS II described *supra* also ensure that the net metering customers causing application review and system impact study costs actually pay those costs, and that those costs are not being shifted to other customers.[503]

In compliance with KRS 278.466(6), existing Tariff NMS customers will continue to take service under Tariff NMS and will be grandfathered under that tariff's compensation framework for up to 25 years.[504] Consistent with KRS 278.466(7), Tariff NMS II requires eligible customer-generators to meet all applicable safety and power quality standards established by the National Electrical Code, Institute of Electrical and Electronics Engineers, and accredited testing laboratories.[505] As required by KRS 278.466(8), a customer's generating facility is transferrable to other persons at the same premises upon notice to Kentucky Power and verification that the

---

[501] *See* Vaughan Rebuttal Test. at Ex. AEV-R7; Vaughan Direct Test. at 23.
[502] Vaughan Direct Test. at 29.
[503] *Id*. at 28-29; Vaughan Rebuttal Test. at R40-R41.
[504] Vaughan Direct Test. at 24.
[505] Vaughan Direct at Ex. AEV-4, p. 5.

installation is in compliance with applicable safety and power quality standards.[506] Finally, pursuant to KRS 278.466(9), Tariff NMS II requires the customer-generator to pay for the costs of any upgrade of the interconnection between it and Kentucky Power.[507] Accordingly, the Company's net metering proposals satisfy each of the statutory requirements outlined in Section 278.466 of the Net Metering Act.

3. Tariff NMS II's Avoided Cost Rates Appropriately Value Customer-Generators' Excess Generation.

The avoided cost rates proposed in Tariff NMS II also appropriately value the "dollar value of electricity generated by an eligible customer-generator that is fed back to the electric grid over a billing period," as the Net Metering Act requires.[508] Company Witness Vaughan explained that he calculated the avoided cost rates by first calculating an avoided energy price and then adding to it a unitized fixed cost reduction value, calculated utilizing avoided cost of service related items.[509] Mr. Vaughan explained in his rebuttal testimony that he refined that analysis based on discovery and intervenor testimony to arrive at the $0.03553/kWh residential and $0.03778/kWh commercial avoided cost rates the Company proposes.[510] Those rates reflect a full accounting of the costs and benefits of eligible customer-generators' distributed generation systems, including benefits associated with reduced transmission and distribution losses, reduced distribution level congestion, peak load reductions or shifts, reduced costs along the fuel supply line, reduced environmental liabilities and/or environmental compliance costs, avoided generation capacity investments, reduced grid support services, and improved grid resiliency.[511]

---

[506] *Id.* at Ex. AEV-4, p. 7.
[507] *Id.* at Ex. AEV-4, p. 5.
[508] KRS 278.465(4)(a) (emphasis added).
[509] Vaughan Direct Test. at 26-27.
[510] Vaughan Rebuttal Test. at R33-R34.
[511] *Id.* at R28-R31.

Importantly, the avoided cost rates that Company Witness Vaughan sponsors are the <u>sole</u> compensation rates for net metering excess generation for Kentucky Power calculated and offered in evidence in this proceeding. AG/KIUC agree with the Company's original and refined avoided cost rates to address and reduce the subsidy currently paid by non-participating customers for net metering customers' excess generation, and with the methodology Mr. Vaughan used to calculate the rates.[512] Although KYSEIA and Joint Intervenors take issue with several aspects of the Company's Tariff NMS II proposal, and in particular with the Company's proposed avoided cost rates, neither provided its own analysis to support its arguments.

The Commission recently addressed customer compensation for solar generation in Case No. 2020-00016, and it found that the actual avoided cost of energy was the appropriate compensation measure.[513] There, Louisville Gas and Electric Company and Kentucky Utilities Company ("LG&E/KU") sought approval of a 100 MW solar power purchase agreement ("PPA") and two renewable power agreements ("RPA") through which two industrial customers in the companies' service territory would buy the majority of the 100 MW PPA's output.[514] LG&E/KU proposed to compensate the two industrial customers for the solar output they were purchasing in addition to their standard tariff billings at the avoided cost of energy charges and peak and intermediate generation demand charges.[515] Under the proposed structure, the customer off-takers would continue to pay full base demand charges, as those costs are designed to recover

---

[512] Baron Test. at 21-24; Tr. Vol. VI at 1588-1589.
[513] *In the Matter of: Electronic Application of Louisville Gas and Electric Company and Kentucky Utilities Company for Approval of a Solar Power Contract and Two Renewable Power Agreements to Satisfy Customer Requests for Renewable Energy Source Under Green Tariff Option # 3*, Case No. 2020-00016, Order at 21 (Ky. P.S.C. May 8, 2020).
[514] *Id.* at 5.
[515] *Id.* at 20.

costs associated with the transmission and distribution systems.[516] Any excess energy from the PPAs above the customer off-takers' 15-minute interval load would be purchased back by LG&E/KU at the avoided cost pricing under the companies' Cogen/SPP tariff.[517] Although the Commission agreed that the customers should continue to pay base demand charges, it disagreed with the provision of the RPAs that reduced intermediate and peak demand charged by coincident solar energy production because it held that such costs "should not be re-allocated to other customers in a future rate proceeding."[518]

The Commission's approach to solar RPA compensation in the LG&E/KU case is consistent with the Company's proposal to compensate solar and other net metering customer-generators at the avoided cost rates in this proceeding. KYSEIA and Joint Intervenors' compensation arguments, however, which effectively seek to pretend that a net metering customer's bill acts as a battery, are contrary to the Commission's reasoning in the LG&E/KU case.[519] They also fall far short of demonstrating that the Company's excess generation compensation proposal is unreasonable or inappropriate.

As an initial matter, contrary to KYSEIA Witness Barnes' suggestion, there is no requirement that net metering tariff designs and compensation rates be identical across all utilities in the Commonwealth.[520] Rather, the Net Metering Act explicitly provides that the Commission's net metering ratemaking processes consider utility-specific costs, as the Commission recognized last year.[521] Indeed, a uniformity requirement would make little sense,

---

[516] *Id.*
[517] *Id.* at 9.
[518] *Id.* at 21.
[519] Vaughan Rebuttal Test. at R27.
[520] Barnes Test. at 7.
[521] *In the Matter of: Electronic Consideration of the Implementation of the Net Metering Act*, Case No. 2019-00256, Order at 32 (Ky. P.S.C. Dec. 18, 2019) (recognizing that "the Net Metering Act provides

as each retail electric supplier in the Commonwealth is situated differently in terms of how it provides service and what its actual avoided costs are.[522]

Nor is the Net Metering Act rendered inapplicable until a large (or larger) subsidization of net metering customer-generators by other customers exists in the Company's service territory, as Mr. Barnes and Mr. Owen advocate.[523] As Company Witness Vaughan explained, in addition to being contrary to the governing law, "it is bad policy and rate design to wait while a subsidy builds to a material size and to then address it."[524] Existing net metering customers under Tariff NMS are already being paid roughly three times what their generation is worth.[525] As demonstrated by politically charged proceedings in Arizona, Nevada, and other western states, it is best to address the inequity before it becomes large.[526]

* * *

In summary, the Company has produced a substantial amount of evidence, including a cost of service analysis, demonstrating the reasonableness and appropriateness of its proposed Tariff NMS II and the avoided cost pricing under that tariff. The Company has also demonstrated that the tariff is fully consistent with the Kentucky Net Metering Act. Intervenors opposing the Company's net metering proposals, on the other hand, have offered editorial commentary and policy arguments lacking any cost of service or rate design basis applicable to Kentucky Power or its customers.[527] Most importantly, they were rejected by the General Assembly in enacting SB 100. The Commission should give little weight to opposing

---

that the net metering ratemaking processes consider utility-specific costs, and not a uniform rate for all electric utilities"); KRS 278.466(5).

[522] Vaughan Rebuttal Test. at R23.
[523] Barnes Test. at 20; Owen Test. at 38.
[524] Vaughan Rebuttal Test. at R24.
[525] *Id.* at R24-R26, Ex. AEV-R4.
[526] *Id.*; Tr. Vol. V at 1315.
[527] Vaughan Rebuttal Test. at R41-R42.

intervenors' arguments as it considers the voluminous and definitive evidence the Company has proffered supporting Tariff NMS II, and the Commission should approve the proposed tariff and its rates for the reasons set forth above

J. Kentucky Power's Application Includes Other Reasonable Proposals That the Commission Should Approve.

The Company's Application included several other proposals designed to benefit customers. Those proposals include, but are not limited to, retail rate design proposals designed to reduce intra-class subsidies and aid high usage electric heating and low-income customers, a proposal to carry out the Rockport regulatory asset amortization approved in the Company's last rate case, an amendment to Tariff FAC to recovery fuel-related PJM Customer Payment Defaults, the recovery of Edison Electric Institute ("EEI") dues properly included in the Company's cost of service, and several unopposed tariff changes that offer customer flexible EV charging, lighting, peak shaving, economic development discount options. Each of these proposals is reasonable, appropriate, and should be approved.

1. The Company's Residential Rate Design Proposals Provide for an Equitable Recovery of Costs that Balances the Interests of All Customers and Reduces Intra-class Subsidies.

The Company has offered two rate design proposals to benefit its residential customers. First, it proposes an increase in the monthly residential basic service charge from $14.00 to $17.50.[528] Second, the Company proposes to include a winter month declining block rate design.[529] The winter heating block would be applicable only during the winter months of December, January, and February to usage above 1,100 kWh.[530] Both rate design proposals are

[528] Vaughan Direct Test. at 10.
[529] *Id.* at 12.
[530] *Id.*

intended to better reflect the underlying cost of service, reduce intra-class subsidies, and reduce monthly bill volatility for the Company's electric heating and low-income, high usage customers.[531]

a. The Increase in the Residential Basic Service Charge Represents a Required Gradual Step Towards Reflecting the Actual Fixed Cost of Providing Service to Residential Customers, Will Aid High Energy Users, and Sends Appropriate Price Signals.

The Company's proposed increase to the residential basic service charge to reflect more accurately the Company's actual fixed cost of serving residential customers is well-supported by the testimony of Company Witness Vaughan.[532] This change is designed – in the spirit of gradualism – to move the residential basic service charge towards the actual fixed monthly cost of providing service and, in doing so, to reduce the intra-class subsidy paid by high-use residential customers, many of whom in Kentucky Power's service territory are low-income customers.[533] As Company Witness Vaughan explained at hearing, high-use residential customers – and in particular electric heating customers in winter – pay a disproportionate share of the fixed cost contribution under the current residential rate design.[534] Gradually increasing the fixed service charge, as the Company proposes to continue to do in this proceeding, will reduce this intra-class subsidy.[535]

Two studies support the Company's calculation of the monthly fixed cost of providing service. In the first, in Case No. 2017-00179, the Company calculated the full cost of connecting a customer to the Company's radial distribution system and maintaining that connection –

---

[531] *Id.* at 12-13.
[532] *Id.* at 10-11.
[533] *Id.* at 14-15, Ex. AEV-2.
[534] Tr. Vol. V at 1356.
[535] Vaughan Direct Test. at 13.

without any generation, transmission, or demand-related distribution costs.[536] The Company determined there that the full cost basic service charge is roughly $38 per residential customer.[537] As Company Witness Vaughan explained in his Direct Testimony in this case, "[b]ecause … customer connection costs are fixed one would not expect them to vary in a material fashion during the time between rate cases."[538] The Company confirmed this expectation and the results of the 2017 cost of service analysis through a marginal customer connection method study.[539] The marginal monthly cost to connect a customer was calculated to be approximately $35 per customer.[540] The Company's proposed $17.50 basic service charge represents only half of this cost.[541]

Moving the residential basic customer charge closer to the actual cost of providing service to customers provides benefits beyond simply following cost-causation principles. Shifting more of the fixed portion of the cost to provide service to the fixed charge will reduce bill volatility, especially for electric heating customers during winter months.[542] Perhaps most importantly, the Company's proposal to recover more of its fixed costs through the residential basic service charge will benefit the Company's low-income customers. The Company's test year data demonstrates that the Company's low-income customers have higher usage than the average customer.[543] By reducing the intra-class subsidy that high-use residential customers pay for the benefit of lower-use customers, the Company is reducing the subsidy paid by its low-

---

[536] *Id*. at 14.
[537] *Id.*
[538] *Id.*
[539] *Id.* at 15, Ex. AEV-2.
[540] *Id*. at 15.
[541] *Id.*
[542] *Id.* at 13.
[543] *Id*. at 13-14.

income customers to the below-average-use customer. Moreover, contrary to Joint Intervenors Witness Owen's editorial musings, usage data also demonstrates that increasing the residential basic service charge to reduce intra-class subsidies has led to a reduction in the Company's residential customers' weather normal usage over time; it has not increased system energy usage.[544]

The Company's proposed residential basic service charge represents a gradual shift towards recovering the full fixed cost of providing service, reduces the residential intra-class subsidy to the benefit of many low-income customers, and should be approved.

b. The Company's Winter Heating Declining Block is a Modest Change in Rate Structure that Will Significantly Benefit Those Who Need it Most.

The Company's proposed winter heating block is a limited proposal that applies to usage above 1,100 kWh during the months of December, January, and February.[545] The proposal is designed to reduce the burden on customers using electric heating during the winter months when they will likely be generating high bills. for the reduced rate for higher usage aligns with cost causation principles by recognizing that higher usage customers pay a higher portion of the Company's fixed costs, yet because these costs are by definition fixed, the customers' higher usage does not mean that they impose a higher level of fixed costs on the Company. Moreover, because the block rate discount is collected from all other usage (including winter heating customers' other usage) throughout the entire year, those customers who directly benefit from the winter block will still pay a portion of the discount back.[546] This will result in a reduction in

---

[544] Vaughan Rebuttal Test. at R16-R17.
[545] Vaughan Direct Test. at 12.
[546] *Id.* at 13; Tr. Vol. V at 1338-1339, 1356, 1440-1441.

the intra-class subsidy paid by high usage customers, winter bill relief for electric heating and low-income customers, and a reduced monthly bill volatility.[547]

Ultimately, the winter tail block is a measured adjustment to the Company's rate design that is only applicable for a short period during the year. It is in line with cost causation principles and will provide a meaningful benefit to those customers who have non-discretionary usage above the 1,100 kWh threshold.

2. The Company's Proposed Five-Year Amortization of the Rockport Deferral Asset is Consistent with Commission's Order Approving the Settlement Agreement in the Company's Last Rate Case and Should Be Approved.

In its January 18, 2020, Order in Case No. 2017-00179, the Commission approved the deferral of $50 million of Rockport Unit 2 non-fuel and non-environmental lease expenses plus a WACC carrying charge.[548] The Commission also provided that "this approval is for accounting purposes only, and the appropriate ratemaking treatment for this regulatory asset account will be addressed in Kentucky Power's next general rate case."[549] Consistent with the Commission-approved settlement agreement in Case No. 2017-00179, the Company is now requesting to amortize and recover the approximate $59 million December 8, 2022 balance of the Rockport deferral regulatory asset[550] beginning in December 2022 over 5 years through Tariff PPA.[551] As prescribed in the Settlement Agreement approved by the Commission,[552] the Rockport deferral

[547] *Id.*
[548] Whitney Direct Test. at 34-36; 2017 Rate Case, Order at 37-40.
[549] 2017 Rate Case, Order at 40.
[550] Whitney Direct Test. at 36.
[551] West Direct Test. at 39; Vaughan Rebuttal Test. at R8.
[552] 2017 Rate Case, Satterwhite Settlement Test. at S10 (Nov. 22, 2017) (stating, "The [settlement] agreement reflects a deferral of fifty million dollars ($50 million) over five years and provides that the deferral will be established as a regulatory asset for later recovery ("Rockport Deferral Regulatory Asset"). The Rockport Deferral Regulatory Asset, plus a WACC carrying charge, will be recovered through the Company's Tariff PPA over a five-year period starting in December 2022."); *Id.*, Settlement Agreement, at 5 ¶ 3(c).

asset will be subject to the authorized WACC carrying charge until it is fully recovered.[553] The intervening parties presented no evidence challenging the Company's proposed five-year amortization and, given that the proposed amortization is consistent with the Commission's Order in Case No. 2017-00179, the Company's proposal should be approved.

Although the record is undisputed that the Company's proposed five-year amortization of the Rockport deferral asset is reasonable and should be approved, there was concern at hearing surrounding the total amount that would be recovered through Tariff PPA once the Company begins to amortize the Rockport deferral asset.[554] The Commission approved deferral of the Rockport Unit 2 non-fuel and non-environmental lease expense plus a WACC carrying charge.[555] The $50 million Rockport deferral asset plus the WACC carrying charge is estimated to have a total balance of $59 million when the Rockport UPA terminates in December 2022.[556] At that point, the $59 million balance, consisting of the Rockport deferral asset and the WACC carrying charges, will be amortized through Tariff PPA over a period of 5 years.[557] During the Company's amortization of the Rockport deferral asset through Tariff PPA, the WACC carrying charge will continue to be applied to the unamortized balance until the Rockport deferral asset is fully recovered from customers.[558]

Applying the WACC carrying charge to the unamortized balance serves the same purpose as the carrying charge applied to the deferral asset, which is to make the Company financially whole because the Company will need to finance the unamortized balance of the Rockport

---

[554] Tr. Vol. II at 594-604.
[555] 2017 Rate Case, Order at 40.
[556] Whitney Direct Test. at 36.
[557] *Id.*
[558] Tr. Vol. II at 594-604.

deferral asset through a combination of debt and equity until the deferral asset is fully recovered from customers.[559] Furthermore, the Settlement Agreement itself makes clear that, "[t]he Rockport UPA Expense of $50 million described in Paragraph 3(b) above will be deferred into a regulatory asset … and will be subject to carrying charges based on a weighted average cost of capital … of 9.11% until the Regulatory Asset is fully recovered."[560] In its Order approving the Settlement Agreement, the Commission stated, "[t]he carrying charges associated with this rider shall be based on the WACC approved in this Order and are effective as of the date of this Order."[561] In approving the Settlement Agreement, the Commission did not limit the agreement to terminate the carrying charge once amortization begins, or require that the Company agree to a lower carrying charge during the amortization period. Therefore, consistent with the Commission's Order and the Settlement Agreement in Case No. 2017-00179, the WACC carrying charge to be applied to the unamortized balance of the Rockport deferral asset after the Company begins to amortize the asset through Tariff PPA is appropriate. The Commission should approve without modification the Company's proposed amortization of the Rockport deferral regulatory asset.

3. It is Necessary, Reasonable, and Appropriate to Amend Tariff FAC To Include Fuel-Related PJM BLI 1999 As a Category of Fuel Costs Recoverable Through that Tariff.

The Commission should approve the Company's request to amend Tariff FAC to add PJM billing line item ("BLI") 1999, through which PJM allocates to Kentucky Power PJM Customer Payment Defaults,[562] to the types of fuel costs recoverable through that mechanism. In

[559] 2017 Rate Case, Order at 39 (citing the Company's Jan. 5, 2018 Post-Hearing Brief at 48).
[560] 2017 Rate Case, Settlement Agreement at Paragraph 3(c).
[561] 2017 Rate Case, Order at 40.
[562] Bishop Direct Test. at 6.

the Company's last base rate case, the Commission approved the addition of the following language in the "Fuel costs" section of Tariff FAC:

> The fuel-related costs charged to the Company by PJM Interconnection LLC ***including but not limited to*** those costs identified in the following Billing Line Items, as may amended from time to time by PJM Interconnection LLC: Billing Line Items 1210, 2210, 1215, 1218, 2217, 2218, 1230, 1250, 1260, 2260, 1370, 2370, 1375, 2375, 1400, 1410, 1420, 1430, 1478, 1340, 2340, 1460, 1350, 2350, 1360, 2360, 1470, 1377, 2377, 1480, 1378, 2378, 1490, 1500, 2420, 2220, 1200, 1205, 1220, 1225, 2500, 2510, 1930, and 2930.[563]

Tariff FAC as approved in Case No. 2017-00179 does not specifically list BLI 1999 as a fuel cost. In approving the tariff, the Commission nevertheless explained that "BLIs represent charges and credits that relate to fuel consumed by resources that are running and online."[564] The Company, at that time, understood that the language "including but not limited to" would allow for additional PJM BLIs that were fuel-related costs charged to the Company by PJM to be recovered as fuel costs under Tariff FAC, although not specifically enumerated.

On February 11, 2019, the Commission established Case No. 2019-00002 to review and evaluate the operation of Kentucky Power's FAC for the period November 1, 2016 through October 31, 2018, and to determine the amount of fuel costs that should be included in its base rates.[565] Although the Company understood the GreenHat default charges to be properly recoverable through the FAC as a fuel-related PJM BLI, the Company elected to present the question to the Commission in the two-year FAC review prior to flowing through the charges.[566] The Company proposed to recover the fuel-related portion of the GreenHat FTR market default

---

[563] 2017 Rate Case, Order at 44.
[564] *Id.*
[565] *See* Order, *In the Matter of: Electronic Examination Of The Application Of The Fuel Adjustment Clause Of Kentucky Power Company From November 1, 2016 Through October 31, 2018*, Case No. 2019-00002 at 1 (Ky. P.S.C. December 26, 2019).
[566] *Id.* at 4.

charges allocated to Kentucky Power through PJM BLI 1999A not billed to customers during the review period by billing one-third of the total $70,561.32 over a three-month period ($23,520.44 per month) beginning the first day of the billing cycle beginning after the Commission's order in that case.[567]

The Commission denied Kentucky Power's proposal to recover the fuel related portion of the GreenHat FTR market default charges through Tariff FAC.[568] In its December 26, 2019 Order in Case No. 2019-00002, the Commission held that although "FTR costs are associated with the cost of generation…Kentucky Power should not pass through the costs of the GreenHat default under Billing Line Item 1999[a] as the [i]tem code is not listed in its FAC tariff for acceptable fuel-related costs charged to the Company by PJM."[569] The Commission instead directed:

> Should Kentucky Power want to recover fuel-related costs such as the GreenHat default costs that are not passed through the FAC tariff via listed PJM billing line items, it has a number of options such as seeking recovery through base rates in a base rate case or requesting to update its FAC Tariff in a base rate case.[570]

The Company now seeks to do exactly as the Commission directed in Case No. 2019-00002 – to update Tariff FAC to include PJM BLI 1999 as a category of fuel costs recoverable through the tariff.[571] The Company also seeks to remove the GreenHat default costs from the cost of service, to establish a regulatory asset, and to amortize the proposed deferral over three years.[572]

---

[567] *Id.*
[568] Order, *In the Matter Of: An Examination Of The Application Of The Fuel Adjustment Clause Of Kentucky Power Company From November 1, 2016 Through October 31, 2018*, Case No. 2019-00002 (Ky. P.S.C. December 26, 2019).
[569] *Id.* at 4.
[570] *Id.*
[571] *See* Bishop Direct Test. at 6-7.
[572] Whitney Direct Test. at 25; *see also* West Direct Test. at 38.

The Commission has held that BLIs that "represent charges and credits that relate to fuel consumed by resources that are running and online" are "appropriate for inclusion in the FAC."[573] Thus, because the Commission explicitly recognized that costs such as those billed through PJM BLI 1999 are associated with the cost of generation, the Commission should allow the amendment of Tariff FAC to explicitly include BLI 1999 in the section comprising "Fuel costs." Any GreenHat default costs incurred after December 31, 2020, or any similar charges billed to the Company through BLI 1999 in the future, would be recovered through Tariff FAC.[574]

4. The Company's Blended State Income Tax Rate is Reasonable and Represents the Company's True Cost of Service.

In his testimony, AG/KIUC Witness Kollen recommends the Commission calculate state income expense using only the Kentucky corporate state income tax rate of 5.0% for the Company's base and rider revenue requirements.[575] As support for his recommendation, Mr. Kollen argued that using only Kentucky's 5.0% state income tax rate is appropriate because it otherwise would result in prohibited "affiliate cross-subsidization."[576] Mr. Kollen's errs.

Kentucky Power's proposal treats the Company as a standalone entity for state income tax purposes; its 5.8545% blended state income rate represents the income tax cost of Kentucky Power's stand-alone operations and sales.[577] Specifically, the Company has operations in Kentucky and in West Virginia (the Mitchell Plant), for which it incurs costs and receives revenues.[578] The Company also receives revenues (and incurs Illinois and Michigan income tax

---

[573] 2017 Rate Case, Order at 44.
[574] Bishop Direct Test. at 7.
[575] Kollen Test. at 36.
[576] *Id.* at 35-36.
[577] Keaton Rebuttal Test. at R3.
[578] *Id.* at R3, Ex. AMK-R1; KPCO_R_KPSC_PH_1 (to be filed Dec. 9, 2020).

liability) from PJM wholesale power sales the Company makes in Illinois and Michigan.[579] As a result of its operations and sales in these states, the Company incurs a state income tax liability at the respective state corporate income tax rates, just as individual tax payers would if they receive taxable income in different states. As a result, the Company's effective state income tax rate is the 5.8545% blended tax rate presented in this case.

Additionally, contrary to Mr. Kollen's apparent misunderstanding, the Company's blended tax rate does not include income tax expense allocated to Kentucky Power from any state other than those from which the Company incurs a state income tax liability; similarly, the Company's blended state income tax rate does not include any state income tax liability incurred by the other AEP System affiliate companies' for their operations in any other state.[580] Thus, the record demonstrates that Kentucky Power <u>is</u> treated as a standalone entity for state income tax purposes and that Kentucky Power's blended state income tax rate reflects <u>only</u> the cost of the Company's operations. The Company's state income tax expense in its cost of service for the test period, as a standalone entity, includes income taxes Kentucky Power paid in West Virginia, Illinois, and Michigan.[581] As such, the Company's blended state income tax rate, which has been approved as part of the Company's cost of service in previous proceedings,[582] is appropriate and should be accepted.

[579] *Id.*
[580] *Id.*
[581] *Id.*; *see also* Application Section V, Exhibit 1.
[582] Tr. Vol. III at 642.

5. The Company Properly Excluded EEI Dues Related to Lobbying Expenses and the Remaining EEI Dues Included in the Company's Cost of Service are Appropriately Included in its Cost of Service.

AG/KIUC Witness Kollen recommends that the Commission reduce the cost of EEI dues, which he states is $0.106 million for the test year, by 45.35%, thereby reducing the Company's base revenue requirement by $0.048 million.[583] However, Mr. Kollen fails to provide any evidence that the 45.35% reduction is supported by the record in this case, misstates the amount of EEI dues the Company incurred during the test year, fails to recognize that the Company properly excluded EEI dues related to lobbying expenses, and provides an incorrect allocation factor of EEI dues to Kentucky Power.

As shown in Table 2 of Company Witness West's Rebuttal Testimony and the EEI invoice Kentucky Power provided in discovery, EEI dues for the AEP System as a whole were $2,701,951.[584] The EEI invoice was broken out into four line items: (1) Regular Activities of EEI, (2) Industry Issues, (3) Restoration, Operations, and Crisis Management Program, and (4) 2020 Contribution to the Edison Foundation.[585] The Company was allocated a 3.88% share of each of those line items, which totals $104,806.74.[586] As shown in the EEI invoice, an estimated 13% of line item (1) and 24% of line item (2) is tied to influencing legislation.[587] Once allocated to the Company at its 3.88% share, the Company was allocated a total of $14,505.94 of the EEI dues tied to influencing legislation.[588] The Company excluded that entire amount from its costs

---

[583] Kollen Test. at 38.
[584] West Rebuttal Test. at R11, Figure 2; KPCO_R_KIUC_AG_2_44_Attachment1; KPCO_R_KPSC_PH_2 (to be filed Dec. 9, 2020).
[585] *Id.*
[586] West Rebuttal Test. at R11, Figure 2; KPCO_R_KPSC_PH_2 (to be filed Dec. 9, 2020).
[587] KPCO_R_KIUC_AG_2_44_Attachment1; KPCO_R_KPSC_PH_2 (to be filed Dec. 9, 2020).
[588] West Rebuttal Test. at R11, Figure 2; KPCO_R_KPSC_PH_2 (to be filed Dec. 9, 2020).

of service.[589] Furthermore, the Company excluded all of its apportioned share of line item (4) representing $1,939.46 of charitable contributions.[590] Thus, as supported by the record established in this case, the Company properly excluded its allocated share of EEI dues tied to influencing legislation.

By contrast, although acknowledging that the EEI invoice identifies the percentage of each line item tied to influencing legislation, Mr. Kollen chooses to ignore the plain language of the invoice and, instead, recommend a 45.35% reduction of a 4.02% allocated share of line items (1) and (2).[591] First, as established above, the Company's actual allocated share of the EEI dues is approximately 3.88%.[592] Further, Mr. Kollen provides no evidence demonstrating that his recommended 45.35% reduction to the Company's total allocated share of line items (1) and (2) represents the amount of EEI dues tied to influencing legislation allocated to the Company during the test year. Instead, he bases his recommendation on the records in two 16-year old cases involving two utilities other than the Company.[593] Presumably, Mr. Kollen is reduced to reaching back 16 years into the records in cases involving other utilities because the record here is clear that only 13% of line item (1) and 24% of line item (2) are tied to legislative efforts, which were already properly excluded by the Company.

Further, if the Commission were to accept Mr. Kollen's proposed 45.35% reduction in the EEI dues allocated to the Company, the proposed reduction would inappropriately exclude twice the amount of EEI dues paid by the Company during the test year.[594] Given that Mr. Kollen's recommendation has no basis in this record and would result in the inappropriate

[589] *Id.*
[590] *Id.*
[591] Kollen Test. at 37-38.
[592] West Rebuttal Test. at R11, Figure 2; KPCO_R_KPSC_PH_2 (to be filed Dec. 9, 2020).
[593] Kollen Test. at 37.
[594] West Rebuttal Test. at R11.

exclusion of twice the amount of EEI dues paid by the Company in the test year, his recommendation should be rejected.

Finally, as explained by Company Witness Vaughan at hearing, the EEI dues included in the Company's cost of service are incurred to provide valuable training to Company employees in the form of continuing education and also support continuing education and other activities for other professional organizations such as the National Association Regulatory Utility Commissioners and consumer advocate organizations. These, in turn, support a healthy regulatory environment necessary to provide safe and reliable service to customers.[595] As such, the EEI dues actually included in the Company's cost of service, totaling $88,361.34,[596] are reasonably incurred expenses that should be allowed for ratemaking purposes.

6. The Company's Other Proposed Tariff Additions and Changes are Reasonable, Unopposed, and Should Be Approved.

In addition to the proposals discussed above, Kentucky Power has proposed a number of other new tariff offerings:

<u>Residential Electric Vehicle Charging Provision</u>: The Company proposes to add a provision to the Residential, General Service, and Large General Service tariff that will allow customers through a separately wired TOU meter to take advantage of TOU rates for their EV charging load only.[597] This option encourages customers to charge their vehicles off-peak without having to put their entire household or business usage on a TOU rate offering.[598] 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

---

[595] Tr. Vol. VI at 1483-1484; KPCO_R_KPSC_PH_2 (to be filed Dec. 9, 2020).
[596] West Rebuttal Test. at R11, Figure 2; KPCO_R_KPSC_PH_2 (to be filed Dec. 9, 2020).
[597] Vaughan Direct Test. at 18-19.
[598] *Id.* at 19.

part of the residential tariff offering.[599] 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.[600]

Standard LED Lighting Options: As detailed by Company Witness Vaughan, the Company is proposing to add standard LED lamp offerings to both its outdoor lighting ("OL") and street lighting ("SL") tariffs, as well as to cease new installations of non-LED lamps as of January 1, 2021.[601] Existing OL and SL customers may keep their non-LED lamps, and the Company will continue to maintain them as long as it has replacement lamps and parts in inventory.[602] Customers may also convert to LED for a conversion charge.[603]

Flexible Lighting Option Rate Design: Kentucky Power's proposed flexible lighting option rate design enables OL and SL tariff customers to customize their lighting service within a range of à la carte options, and for the Company to bill the customer for that custom lighting solution in a manner consistent with standard utility lighting service.[604]

Tariff DRS (Demand Response Service): Kentucky Power proposes a new peak shaving demand response tariff, Tariff DRS.[605] In exchange for agreeing to 60 annual hours of interruptions, a participating customer will receive a monthly interruptible demand credit of $5.50/KW-month that will apply to their nominated interruptible demand reservation kW.[606] The Company will use the 60 hours in twenty 3-hour events at its sole discretion to reduce its 1, 5,

---

599 *Id.*
600 *Id.*
601 *Id.* at 19-21.
602 *Id.* at 19-20.
603 *Id.* at 20-21.
604 *Id.* at 21-22.
605 *Id.* at 34-38.
606 *Id.* at 35.

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.

Tariff DRS participation will enable the Company to reduce its peak and lower its generation and transmission costs of service.[607] The Company is requesting that the Commission authorize it to defer the interruptible credits paid to participating Tariff DRS customers and recover the combined amount of DRS and Contract Service – Interruptible Power ("CS-IRP") credits above the test year level of CS-IRP credits in the PPA tariff revenue requirement, as it does currently for CS-IRP interruptible credits.[608] The Company proposes to continue offering Tariff CS-IRP, but to eliminate its expiring special coal provision, which has been difficult to manage and is unnecessary given the shorter contract term available under Tariff DRS.[609]

Kentucky Power also is proposing to close its Non-Utility Generator tariff to new customers as of January 1, 2021, and to eliminate the unused commissioning and startup power provisions of that tariff. [610]

The Company also has proposed several modest revisions to its tariffs, including one to provide customers that desire to take service under Tariff EDR with flexibility to choose when to apply contractual tariff discounts, which are detailed in the Direct Testimony of Company Witness Bishop.[611]

Each of the above tariff proposals is reasonable, appropriate, and unopposed. Accordingly the Commission should approve them as proposed.

---

[607] *Id.* at 38.
[608] *Id.* at 38.
[609] *Id.* at 34-35.
[610] *Id.* at 30.
[611] Bishop Direct Test. at 8-9 (Tariff EDR); *id.* at 5-6 and Ex. SEB-1 (other tariff changes).

V. CONCLUSION

Kentucky Power respectfully requests that the Commission approve its Application as set forth herein.

Respectfully submitted,

____

Mark R. Overstreet
Katie M. Glass
STITES & HARBISON PLLC
421 West Main Street
P.O. Box 634
Frankfort, Kentucky 40602-0634
Telephone: (502) 223-3477
moverstreet@stites.com
kglass@stites.com

Christen M. Blend (*pro hac vice*)
Hector Garcia-Santana (*pro hac vice*)
Tanner S. Wolffram (*pro hac vice*)
American Electric Power Service Corporation
1 Riverside Plaza, 29th Floor
Columbus, Ohio 43215
Telephone: (614) 716-1915 (Blend)
cmblend@aep.com
hgarcia1@aep.com
tswolffram@aep.com

COUNSEL FOR
KENTUCKY POWER COMPANY