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) 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

REBUTTAL TESTIMONY OF

MATTHEW J. SATTERWHITE

ON BEHALF OF KENTUCKY POWER COMPANY

VERIFICATION

The undersigned, Matthew J. Satterwhite, being duly sworn, deposes and says he is the President and COO for Kentucky Power Company that he has personal knowledge of the matters set forth in the forgoing testimony and the information contained therein is true and correct to the best of his information, knowledge and belief

Matthew J. Satterwhite

COMMONWEALTH OF KENTUCKY	)	
	)	2017-00179
COUNTY OF BOYD	)	

Subscribed and sworn to before me, a Notary Public in and before said County and State, by Matthew J. Satterwhite, this 3rd day of November 2017.

Trisha M. Young Blum

Notary Public

Notary ID Number: 530202

My Commission Expires: 3-18-19

TRISHA M. YOUNG
NOTARY ID 530202
COMMISSION EXPIRES 3-18-19

REBUTTAL TESTIMONY OF
MATTHEW J. SATTERWHITE, ON BEHALF OF
KENTUCKY POWER COMPANY
BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY

CASE NO. 2017-00179

TABLE OF CONTENTS

**REBUTTAL TESTIMONY OF
MATTHEW J. SATTERWHITE, ON BEHALF OF
KENTUCKY POWER COMPANY
BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY**

I. INTRODUCTION

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

A. My name is Matthew J. Satterwhite, and I am the President and Chief Operating Officer of Kentucky Power Company ("Kentucky Power" or "Company"). My business address is 855 Central Avenue, Suite 200, Ashland, Kentucky 41101.

Q. ARE YOU THE SAME MATTHEW SATTERWHITE THAT FILED DIRECT TESTIMONY IN THIS CASE?

A. Yes I am.

Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY?

A. The purpose of my rebuttal testimony is to respond to intervenor testimony on four topics:

- the Company's economic development efforts;
- the need for timely recovery of the Company's volatile PJM LSE OATT expense through Tariff P.P.A.;
- KIUC Witness Kollen's proposal to defer costs associated with the Rockport Unit Power Agreement for future recovery; and
- the recovery of costs associated with the Rockport Unit 1 SCR.

II. KENTUCKY POWER'S ECONOMIC DEVELOPMENT EFFORTS

Q. ATTORNEY GENERAL WITNESS DISMUKES RECOMMENDS ELIMINATING THE K-PEGG PROGRAM. HOW DO YOU RESPOND TO HIS RECOMMENDATION?

A. The Commission should adopt the Company's proposed continuation and expansion of the K-PEGG program. Mr. Dismukes' recommendation to reject the program outright would be harmful to economic development efforts in the Company's service territory. As described in more detail by Company Witness Hall, the K-PEGG program allows Kentucky Power to aggregate small contributions from customers through the KEDS, with matching contributions from the Company, to provide much needed economic development assistance grants to municipalities and economic development agencies. These grants bolster the ability of these front-line economic development organizations to position the region to compete for new business and jobs.

Economic development is the best remedy for the Company's declining load and the pressure that decline is placing on rates. It is appropriate that Kentucky Power and its customers be at the forefront of economic development. Kentucky Power's economic development efforts include its economic development grant programs, its Coal Plus tariff program, and its coordination with state and local economic development entities to attract new industry to the service territory. The Company's economic development efforts are gaining momentum, and the K-PEGG program is a key part of these efforts.

Grants issued by the Company through the K-PEGG program have supported economic development agencies in the region by providing them with resources necessary to train their personnel, develop strategic plans, obtain key trade group certifications, and make improvements to industrial park sites. These actions may seem small, compared to the types of tax-incentives and other financial incentives provided directly to companies by the Cabinet for Economic Development, but without these funds the communities in our service territory would struggle even to be a part of the economic development conversation. Now is not the time to derail an important part of economic development in eastern Kentucky by eliminating the K-PEGG Program.

Q. WHAT IS YOUR REACTION TO MR. DISMUKES' ATTACK ON THE K-PEGG PROGRAM?

A. I find it both surprising and disappointing. Beyond providing safe and reliable electric service to its customers, Kentucky Power's organizational focus is on economic development. I have made this a focus for the Company because economic opportunities provide job opportunities for our customers while helping assure an increase in customers in our service territory. Absent job opportunities and additional businesses, the Company's customer totals will continue to shrink. As the number of customers and associated load declines, the fixed costs of providing service is spread out over fewer remaining customers. At its core, the Company's economic development efforts are based on the ultimate goal of increasing the denominator in the rate setting equation – more customers and more load means that the cost of providing service can be spread over more billing units to everyone's benefit.

Mr. Dismukes' objections to economic development and the K-PEGG Program specifically are disappointing to me. I am disappointed because it appears Mr. Dismukes fails to understand the focus of the K-PEGG Program on filling gaps in the region's economic development infrastructure. The K-PEGG

Program is a key component of the Company's economic development plan. Without the support to local economic development agencies that the K-PEGG Program provides, the broader economic development efforts in the region will struggle. It is true that K-PEGG requires a small customer contribution ($3.00/customer/year if the Company's proposed expansion is approved), but the ability of the Company to aggregate these contributions with matching funds from the Company allows the K-PEGG Program to support economic development efforts throughout the service territory. Mr. Dismukes' suggestion to shut the K-PEGG Program down would take away this necessary support.

III. RECOVERY OF PJM LSE OATT EXPENSE

Q. DO YOU AGREE WITH THE RECOMMENDATIONS BY MESSRS. KOLLEN AND SMITH THAT THE COMMISSION REJECT THE COMPANY'S PROPOSAL TO RECOVER OR REFUND CHANGES IN ITS BASE RATE LEVEL OF PJM LSE OATT EXPENSE THOROUGH TARIFF P.P.A.?

A. No. The adjusted test year level of PJM LSE OATT expense included in base rates in this case represents a $20.6[1] million increase in these expenses since the September 30, 2014 test year in Kentucky Power's last rate case. This increase has put considerable downward pressure on the Company's ability to earn its authorized return. The Company projects that in 2018 these expenses will increase by $17.0 million over the amount included in the Company's test year in this case. That is a significant impact on the Company, and absent the requested amendment of Tariff P.P.A. or some measure to recover these expenses,

[1] Company Witness Vaughan Direct Testimony at 29.

Kentucky Power will have to file another base rate case within months of the January 2018 Order in this case.

Q. ARE YOU THREATENING THE COMMISSION WITH ANOTHER RATE CASE FILING IF THE COMPANY'S PROPOSAL IS NOT GRANTED?

A. Absolutely not. I do, however, want to make clear the importance of the issue and what the implications would be and the steps the Company would be forced to take in the event it is unable to recover its incremental PJM LSE OATT. The Commission is charged with setting rates that provide the utility an opportunity to earn a fair return. These PJM LSE OATT expenses are real costs that will impact the Company and immediately upset the balance of any Commission order that authorizes rates to give the Company an opportunity to earn a fair return. Knowing this now allows the Company and the Commission an opportunity to deal with it now. Ignoring it now, just to push it to an immediately subsequent filing, is inefficient.

These PJM charges produce a material financial impact that must be addressed one way or another. The Company proposes to avoid the inefficiency of another rate case immediately on the heels of this one through the Company's proposed changes to Tariff P.P.A. Doing so as proposed by the Company addresses the issue in a manner through which customers pay no more or no less for these PJM LSE OATT expenses.

As stated throughout the case, the volatile nature of these costs that are beyond the Company's control makes the proposed recovery mechanism appropriate. However, the Company must have a path to deal with these expenses that will be charged to the Company regardless of the outcome of the case. Thus, if the Company cannot recover these costs as proposed then the financial impact of the real costs charged to Kentucky Power will require the filing of another rate case shortly after an order is issued in this case to ensure rates provide that fair opportunity.

Q. WHAT IS THE HARM IN KENTUCKY POWER FILING A NEW RATE CASE IN 2018?

A. Rate cases require a significant dedication of resources from the Company, intervenors, and the Commission. The cases can also be expensive. The Company has estimated that the subset of rate case expenses the Company to be recovered in this case will total $1.375 million. This expense includes legal, consulting, and advertising costs. Advertising for the Commission-required notice alone cost approximately $600,000. These Company costs are part of the rate making process and are, accordingly, recovered from the Company's customers. The Company prefers to deal with the impact of these known PJM LSE OATT expenses now and avoid the increased cost of another case. The seven intervenors in this case also undoubtedly have legal and expert witness costs in this case.

Q. ARE FINANCIAL COSTS THE ONLY COSTS IMPOSED BY RATE CASES?

A. Far from it. Rate cases require enormous time and effort by the parties and the Commission. In the case of Kentucky Power, the time and effort required in preparing and litigating a rate case otherwise could be devoted to building on the safe, efficient, and reliable service being provided and to improving its operations. Most importantly, the effort otherwise could be devoted to the Company's customer service and economic development efforts.

With regard to economic development, rate cases produce rate uncertainty for customers evaluating whether to locate within the Company's service territory. The Company's proposal to track incremental PJM LSE OATT costs through Tariff P.P.A. would not produce the same effect on the region's competitiveness since many other utilities in the region, including those in Virginia, West Virginia, Ohio, and Indiana, utilize trackers for OATT costs. Forcing the Company into rate cases to recover these costs would result in a competitive disadvantage as compared to regions where utilities are not subject to the unnecessary rate uncertainty that rate cases bring.

There is also an impact on customers, many of whom are unfamiliar with the regulatory process. Rate cases are never a popular topic, and that is why there is a set regulatory paradigm in the Commonwealth to establish rates to ensure a fair opportunity to earn a fair return for public utilities. Yet failing to provide a regulatory mechanism in this case to address these volatile expenses likely will require Kentucky Power to file a new rate case in 2018. Dealing with the PJM LSE OATT expenses now will help prevent the customer confusion concerning why the Company would need to file a new case immediately, and avoid undermining public trust in the regulatory system.

Q. MANY BASE RATE EXPENSES INCREASE OVER TIME. WHY SHOULD PJM LSE OATT EXPENSE BE RECOVERED AS PROPOSED BY THE COMPANY INSTEAD OF SOLELY THROUGH BASE RATES?

A. There are two principal reasons. First is the magnitude of the estimated increase. Second, is the fact that, unlike many base rate expenses, the increases are largely out of the Company's control.

Q. WHAT IS THE MAGNITUDE OF THE ESTIMATED INCREASE?

A. Kentucky Power estimates that its 2018 PJM LSE OATT expense will be $91.4 million.[2] This is an increase of $17.0 million (22.8%) above the $74.4 million in test year PJM LSE OATT expense. Very few, if any, of the Company's expenses are likely to experience such volatility or increases of this magnitude over a similar period. By avoiding the need to file annual base rate cases, the Company's proposal will allow it to reflect only the actual costs incurred by Kentucky Power without the need to file full rate cases to address the known expenses. These types of changes are consistent with the principles of gradualism.

Q. WHY DO YOU SAY THE AMOUNT OF KENTUCKY POWER'S PJM LSE OATT EXPENSE IS LARGELY OUTSIDE ITS CONTROL?

A. The LSE OATT expense is largely a reflection of Kentucky Power's share of the costs to rebuild the transmission system in the region. These are expenses charged to Kentucky Power regardless of whether the Company has relief for the expenses in its rate structure. Additional detail regarding the nature of the

[2] The increase in anticipated 2018 PJM LSE OATT expense from the $84.4 million presented in the Company's response to KIUC 1-67 is a result of the AEP Companies updated formula rate filing with PJM made on October 31, 2017.

Company's PJM LSE OATT expense is provided in the direct and rebuttal testimonies of Company Witness Vaughan.

Q. SHOULD THERE BE ANY CONCERN THAT THE ESTIMATED $17.0 MILLION INCREASE IN 2018 PJM LSE OATT EXPENSES IS AN ESTIMATE?

A. No. Under the Company's proposal, the adjusted test year amount of PJM LSE OATT charges will remain in base rates and the Company will track for recovery only the annual incremental change in these expenses. The P.P.A. factor will be set at zero for the first year and not adjusted until the end of 2018 based on the actual costs incurred for the year. In addition, as discussed in the direct testimony of Company Witness Vaughan, there is a possibility for adjustments in the rate due to certain proceedings at FERC that could offset some of the costs that would be captured in the tracking of the costs. A tracking mechanism, like the Company's proposed change to Tariff P.P.A., allows those refunds to flow through the mechanism and benefit customers. Ultimately, Kentucky Power's proposed changes to Tariff P.P.A. will ensure that the Company recovers no more and no less than its actual PJM LSE OATT expense.

Q. IS THERE ANY OTHER ASPECT OF MESSRS. KOLLEN AND SMITH'S RECOMMENDATION CONCERNING THE COMPANY'S PROPOSED METHOD FOR TRACKING AND RECOVERING THE MANDATED PJM LSE OATT CHARGES THAT YOU WOULD LIKE TO COMMENT ON?

A. Yes. Fundamental to the establishment of fair, just, and reasonable rates is that the utility be provided the opportunity to earn a reasonable return on equity. The Commission in its Order in this case is charged with establishing a reasonable return on equity. The $17.0 million increase in PSM LSE OATT expense estimated in 2018 means that the failure to provide for recovery of the increase as proposed will reduce the Company's return on equity by 160 basis points and ensure the Company is denied the opportunity to earn its authorized rate return. The Company prefers to deal with the issue now and avoid having to file an entirely new rate case in 2018 for an issue that is currently known.

IV. DEFERRAL OF ROCKPORT UNIT POWER AGREEMENT EXPENSES

Q. CAN YOU DESCRIBE KIUC WITNESS KOLLEN'S PROPOSAL TO DEFER ROCKPORT EXPENSES FOR FUTURE RECOVERY?

A. Yes. Mr. Kollen has proposed for the Company to defer $20.3 million of what he refers to as "Rockport 2 Lease Expense" annually until the end of 2022 and then amortize the deferral amount to expense and recover the amount over the subsequent ten years.

Q WHAT IS THE BASIS FOR MR. KOLLEN'S PROPOSAL?

A. Mr. Kollen argues that because the Company's FERC-approved Unit Power Agreement ("UPA") for capacity and energy expires on December 7, 2022, and because it appears to him unlikely at this point that Kentucky Power will extend the UPA beyond 2022, the Company could defer some of the Rockport UPA costs and recover them after UPA terminates. According to Mr. Kollen, this proposal would allow the Company to implement part of the rate reduction associated with the termination of the Rockport UPA now as method to limit the rate increase in this case.

Q. DO YOU AGREE WITH MR. KOLLEN'S PROPOSED ROCKPORT UPA DEFERRAL?

A. No. While the concept proposed by Mr. Kollen is a creative way of reducing the Company's revenue requirement, the details of the deferral are problematic. The use of a deferral must be carefully considered. While it appears attractive because it lowers bills in the near term, it should not be forgotten that a deferral pushes payment off to a later date.

The risk to the Company is two-fold. First, there is a detriment to its financial statements carrying such a large unrecovered regulatory asset with the promise of future recovery. Details regarding this risk are described in the rebuttal testimony of Company Witness Wohnhas. Second, while the expectation is that a Commission Order that authorizes a deferral will be honored in the future, there are still parties that could seek to deny collection of the deferred amount. In fact, in this case Attorney General Witness Smith testifies that the Commission should consider writing off the unrecovered Big Sandy Retirement regulatory asset. Denying the collection of deferrals on the back end that were agreed upon or ordered to assist with lowering customer bills in the near-term is an undoing of the deal and punishes the Company for participating in the exercise.

V. <u>RECOVERY OF ROCKPORT UNIT 1 SCR COSTS</u>

Q. ON PAGES 59-60 OF HIS TESTIMONY, ATTORNEY GENERAL WITNESS SMITH RECOMMENDS THAT THE COMMISSION

DISALLOW RECOVERY OF THE COSTS ASSOCIATED WITH THE ROCKPORT UNIT 1 SCR. DO YOU AGREE WITH HIS RECOMMENDATION?

A. Absolutely not. Mr. Smith argues that because the Rockport Unit 1 SCR is related to the NSR Consent Decree, Kentucky Power should not be allowed to recover the costs. Company Witness McManus clarifies in his rebuttal testimony, Mr. Smith's misunderstandings about the NSR Consent Decree. The costs associated with the Rockport Unit 1 SCR are part of the required costs to produce capacity and energy at Rockport and, as such, they are costs properly recoverable by Kentucky Power.

Q. DOES THIS CONCLUDE YOUR REBUTTAL TESTIMONY?

A. Yes.

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) An Order Approving Its 2017 Environmental Compliance Plan; (3) An Order Approving Its Tariffs And Riders; And (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

REBUTTAL TESTIMONY OF

ANDREW R. CARLIN

ON BEHALF OF KENTUCKY POWER COMPANY

VERIFICATION

The undersigned, Andrew R. Carlin, being duly sworn, deposes and says he is the Director, Compensation and Executive Benefits for American Electric Power Service Corporation and that he has personal knowledge of the matters set forth in the forgoing testimony and the information contained therein is true and correct to the best of his information, knowledge and belief.

Andrew R. Carlin

STATE OF OHIO)
) Case No. 2017-00179
COUNTY OF FRANKLIN)

Subscribed and sworn to before me, a Notary Public in and before said County and State, by Andrew R. Carlin, this the 2nd day of November 2017.

Notary Public

NOTARIAL SEAL STATE OF OHIO

Cheryl L. Strawser
Notary Public, State of Ohio
My Commission Expires 10-01-2021

My Commission Expires: October 1, 2021

REBUTTAL TESTIMONY OF
ANDREW R. CARLIN
ON BEHALF OF
KENTUCKY POWER COMPANY
BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY

CASE NO. 2017-00179

TABLE OF CONTENTS

REBUTTAL TESTIMONY OF
ANDREW R. CARLIN ON BEHALF OF
KENTUCKY POWER COMPANY
BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY

I. INTRODUCTION

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

A. My name is Andrew R. Carlin. My position is Director of Compensation & Executive Benefits for the American Electric Power Service Corporation ("AEPSC"), a wholly owned subsidiary of American Electric Power Company, Inc. ("AEP"). AEP is the parent company of Kentucky Power Company ("Kentucky Power" or the "Company"). My business address is American Electric Power, 15th Floor, One Riverside Plaza, Columbus, Ohio 43215.

Q. ARE YOU THE SAME ANDREW R. CARLIN WHO OFFERED DIRECT TESTIMONY IN THIS PROCEEDING?

A. Yes.

Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY?

A. The purpose of my rebuttal testimony is to correct mischaracterizations in the testimonies of Attorney General Witness Smith and Kentucky Industrial Utility Customers ("KIUC") Witness Kollen with respect to compensation expenses included in the Company's filing. In particular, I will show that:

- the Company's 2017 wage increases were reasonable;
- the incentive compensation expenses in question provide substantial benefits to customers and, as such, should be included in the revenue requirement without reduction; and
- the requested non-qualified post-retirement plan expenses are reasonable and appropriate costs to be borne by customers.

II. <u>PAYROLL EXPENSE – EMPLOYEE BASE PAY INCREASES</u>

Q. WHAT OPERATING INCOME ADJUSTMENT DOES ATTORNEY GENERAL WITNESS SMITH RECOMMEND WITH RESPECT TO PAYROLL EXPENSE?

A. Mr. Smith recommends reducing the Company's cost of service to reflect only 3.0% merit increases for 2017 for all salaried employees, rather than the 3.5% total increases that the Company has already made and requested be included in its cost of service?

Q. WHAT RATIONALE DOES MR. SMITH PROVIDE FOR HIS RECOMMENDED ADJUSTMENT?

A. Mr. Smith states that the requested increase "is higher than the 2.70% to 3.0% noted for 2009 through 2016 and the 3.0% median salary increase for 2017"[1] based on industry survey data.

Q. DO YOU AGREE?

A. No, I do not agree for several reasons.

Q. PLEASE EXPLAIN THE REASONS YOU DO NOT AGREE.

A. First and foremost, the Company's merit increases lagged the market median practice by a total cumulative deficit of from 1.975% to 3.725% from 2009 through 2016.[2] It would be unreasonable to limit cost recovery for utility wage increases to no more than the market median because this would, at best, only allow wages to keep up with the market and would never allow wages to catch up

[1] Direct testimony of Ralph C. Smith (Smith) on behalf of the Kentucky Office of Attorney General; October 3, 2017; p. 32, lines 3-5.
[2] Direct Testimony of Andrew R. Carlin (Carlin Direct); June 28, 2017; p. 18, Table ARC-2.

to the market, should they ever fall behind market for any reason, as is the Company's situation.

Secondly, the Company's total compensation for these employees is not above the market median on average and it is well within the market competitive range.[3] As such, the Company's compensation is both reasonable and market competitive. In addition, pay compression between the non-salaried and salaried workforces would have been exacerbated if the total increase for salaried workers was reduced to 3.0% given that base wages for the non-salaried workforce were higher as the result of the collective bargaining of wages for union represented employees. This would have reduced the Company's ability to attract employees from its physical workforce to take supervisory and other salaried positions. It also creates employee relations issues when supervisors, who arguably have more responsibility, make the same or less than the employees they are supervising.

Furthermore, the Company's 3.0% merit budget for 2017 was in line with utility and general industry practices. The Company also provided a combined 0.5% budget for line of progression promotions and equity adjustments for a total increase budget of 3.5%. In my experience, other utilities and general industry companies also provide these types of increases. However, these increases are not generally included in the salary increase budget and are instead made outside the salary budget process and funded with vacancy days for open positions or out of other budgets. Changes in the Company's process for salary increases eliminated avenues for out of cycle line of progression promotion and equity adjustment

[3] Carlin direct, Exhibit ARC-4 (Kentucky Power Company Target Total Compensation vs. Market for Technical, Craft and Clerical Jobs)

increases, which led to the need for the Company to create a small separate budget for this purpose.

Line of progression promotions in particular and equity adjustments to a lesser degree are often awarded to the Company's highest performing employees, namely those most deserving of promotion and those whose work performance is comparable to higher paid employees inside and outside the Company. As such, these types of increases are a valuable retention tool.

Finally, the additional 0.5% budget for promotions and equity adjustments is not large enough to drive compensation levels that could be considered excessive by any definition, particularly given that the Company's average compensation is slightly below the market median.

Q. WHAT ARE THE ADDITIONAL REASONS THAT KIUC WITNESS KOLLEN PUTS FORWARD FOR RECOMMENDING A REDUCTION IN THE COMPANY'S REQUESTED LEVEL OF PAYROLL EXPENSE?

A. Mr. Kollen states that these are selective post-test year adjustments that could be offset by other post-test year items that were not proposed.[4] He states that mixing and matching historic and forecast test years is unfair to customers and easily manipulated.[5] In addition, he states that these adjustments simply assume that the Company will not achieve any offsetting cost reductions.[6] However, Mr. Kollen recognizes that if the post-test year increases are denied then the Company would

[4] Direct Testimony of Lane Kollen on behalf of the Kentucky Industrial Utility Customers, Inc. (Kollen), J. Kennedy and Associates, Inc., October 2017, p. 23, lines 18-21.
[5] Kollen, p. 24, lines 3-5.
[6] Kollen, p. 24, lines 6-7.

be forced to reduce other costs or limit other cost increases for its costs to more closely match its revenues.[7]

Q. DO YOU AGREE WITH THESE RATIONALES?

A. No. The post-test year adjustments to payroll expense are for increases that were approved by Company management during or before the test year and have been implemented. As such, they are known and measurable. The criticism about using forecasted and historical information for different data points suggests it would be necessary for the Company to file an entire base rate case on a forecasted test year basis in order to include a small number of known and measurable adjustments in its cost of service. This is obviously not required, and therefore Mr. Kollen's criticism in this regard is without basis.

Including these post-test year items will lead to a revenue requirement that more accurately reflects the Company's costs going forward. This reduces regulatory lag and the frequency of base rate cases. As such, including these post-test year costs is a more fair and reasonable approach for both the Company and its customers.

Furthermore, the Company is not aware of any significant offsetting cost reductions. As Mr. Kollen recognizes, if the post-test year increases are denied, the Company will not be able to earn the rate of return authorized in this case unless it reduces other costs or limits other cost increases.[8]

Q. IF MESSRS. SMITH'S AND KOLLEN'S RECOMMENDED ADJUSTMENTS TO PAYROLL EXPENSE ARE NOT ADOPTED,

---

[7] Kollen, p. 24, lines 11-12.
[8] Kollen, p. 24, lines 9-12.

WOULD THE RECOMMENDED ADJUSTMENTS TO OVERTIME AND PAYROLL TAX APPLY?

A. No. These adjustments are secondary impacts of the payroll adjustments and they would only apply to the extent that the proposed payroll adjustments are adopted. As described above, the adjustments proposed by the Attorney General and KIUC should not be adopted.

III. ANNUAL INCENTIVE COMPENSATION

Q. WHAT ADJUSTMENTS HAVE BEEN PROPOSED WITH RESPECT TO THE COMPANY'S REQUESTED LEVEL OF ANNUAL INCENTIVE COMPENSATION EXPENSE?

A. Attorney General Witness Smith proposes denying cost recovery for 25% of the Company's annual incentive compensation expense while KIUC Witness Kollen proposes denying cost recovery for 75% of this this expense.

Q. WHAT IS MR. SMITH'S RATIONALE FOR HIS RECOMMENDATION TO REMOVE 25% OF ANNUAL INCENTIVE EXPENSE?

A. Mr. Smith cites the following excerpt from Commission's order in the Company's last base rate case:

> While 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. Among the performance measures, only 15% is based on financial performance. Accordingly, the Commission's adjustment removes only 15%, or $442,181, of the cost of $2,947,874 Kentucky Power provided in rebuttal from test-period operating expenses for ratemaking purposes.[9]

Mr. Smith continues and cites an AEP document that states:

[9] Order of the Kentucky Public Service Commission, Case No. 2014-00396, June 22, 2015, pp. 25-26.

> Generally, at least 25% of the total target award for each incentive plan or group should be based on quantitative financial objectives.[10]

Q. DO YOU AGREE WITH MR. SMITH'S ASSERTION THAT ELIMINATING 25% OF THE COMPANY'S REQUESTED ANNUAL INCENTIVE COMPENSATION AS THE RESULT OF THE STATEMENT IN THIS DOCUMENT ABOVE IS IN KEEPING WITH THE COMMISSION'S ORDER IN THE PRIOR CASE?

A. No, for several reasons. First and foremost, "quantitative financial objectives" as used in this document can be and usually are performance measures that unquestionably benefit customers, such as efficiency measures. The Company does not interpret this as requiring an earnings per share ("EPS") or other earnings measure, and it is only the Company's interpretation of its own document that has any impact on incentive compensation. For example, the 2017 annual incentive plan for Kentucky Power distribution and staff employees meets this requirement with a 10% weight on continuous improvement activities, a 5% weight on economic development and a 10% weight on Kentucky Power net income.

The 10% net income measure is the measure that the Commission removed from the Company's cost of service in the prior base rate case. However, the weight for this measure has been reduced from 15% to 10% in the intervening period. The 10% weight on continuous improvement and the 5% weight on economic development both are clearly in customer's interests. Therefore, the net income measure is the only earnings measure in the Company annual incentive plan, other than a portion of the funding measures, which the

[10] AEP Incentive Compensation Guiding Principles and Policies, p. 3.

Commission declined to remove from the cost of service in the Company's last base rate case. Therefore, if the Commission chooses to act in a manner that is consistent with its order in the prior base rate case, it would remove 10% of the Company's annual incentive compensation expense, not 25% as recommend by Mr. Smith.

In addition, this language in the aforementioned company document is outdated and likely to be revised or eliminated. It was written at a time when controlling expenses to budget was a key emphasis of the Company's annual incentive compensation plan. However, the Company's budget, forecasting and management processes have evolved to the point that, to my knowledge, significant expense budget exceedances do not occur without advanced approval from senior management. Therefore, this is no longer an important incentive plan design consideration.

Q. HOW DOES KIUC WITNESS KOLLEN CHARACTERIZE THE COMMISSION'S ORDER IN THE COMPANY'S LAST BASE RATE CASE WITH RESPECT TO ANNUAL AND LONG-TERM INCENTIVE COMPENSATION?

A. Mr. Kollen states that "the Commission specifically disallowed incentive compensation expense incurred to achieve shareholder goals"[11] in support of his recommendation to remove 75% of annual incentive compensation from the Company's cost of service for rate making purposes. However, Mr. Kollen neglects to mention that the Commission found in the previous case "that the amount that should be removed for ratemaking purposes should be based on the

[11] Kollen, p. 21, lines 8-9.

performance measures of the plan, not the funding measures. Among the performance measures, only 15% is based on financial performance."[12] The weight for the net income measure for which cost recovery was denied in the previous case was 10% in this case, not the 75% denial Mr. Kollen recommended, and no new performance measures of this type have been added.

Q. DOES THE COMPANY'S ANNUAL INCENTIVE COMPENSATION, PRIMARILY BENEFIT SHAREHOLDERS?

A. No. The Company's annual incentive compensation, including the portion tied to Company net income, primarily benefits customers. This is because the Company's annual incentive compensation is an integral component of a reasonable and market competitive compensation package that enables the Company to attract and retain employees with the skills and experience needed to efficiently and effectively provide service to customers. As explained in my direct testimony, the overall value of the Company's total compensation package would fall well below market competitive levels without the annual incentive compensation portion of employee pay. This is undisputed thus far in this case.

Furthermore, the customers already receive, and will continue to receive in connection with this filing, the accumulated benefits from past incentive compensation arrangements. Annual incentive compensation is not a limitless productivity engine that generates incremental productivity gains each and every year sufficient to offset the reasonable, prudent and necessary costs associated with it. Denying any portion of this expense would provide all the accumulated benefits to customers without a portion of the corresponding payroll expense that

[12] Order of the Kentucky Public Service Commission, Case No. 2014-00396, June 22, 2015, pp. 25-26.

sustains and builds on these efficiencies over time. Such an approach would be unreasonable and unbalanced.

As such, the expense associated with annual incentive compensation, including the portion associated with the 10% net income measure and the funding measures, provides significant benefits to customers. The annual incentive compensation plan is an integral part of the overall compensation plan of the Company, and the total compensation (the combination of base pay and incentive pay) that eligible employees receive is intended to place that total compensation at or near the market rate for each particular job or salary band. Moreover, improvement in metrics such as safety, efficiency of operations and financial performance can and does lead to savings that eventually benefit the customer when those improvements are captured in a base rate case. 100% of the annual incentive plan costs proposed by the Company for both the Company's employees and employees of AEPSC should be allowed.[13]

The benefit to customers is not diminished by tying a portion of plan funding to AEP's earnings. Because the primary, and often only lever, most employees have in a regulated utility to meet financial objectives is cost efficiency, tying incentive compensation to financial objectives directly benefits customers by providing an incentive that promotes efficiency. Furthermore, the robust nature of this and other rate case proceedings mitigates the risk that employees will be unduly motivated by such earnings measures to pursue rate increases at the expense of rate payers.

[13] See, e.g., Public Service Commission of West Virginia Charleston, Case Nos. 14- 1 152-E-42T and 14- 1 15 1 -E-D, Appalachian Power Company and Wheeling Power Company, Commission Order, May 26, 2015 (WV Commission Order), pp. 75-76. (adopting similar rationale).

Finally, eliminating the financial component of annual incentive compensation is based on the unfounded and inaccurate assumption that the Company's customers have no interest in the Company's financial performance. Earnings that approach the Company's authorized rate of return provide a favorable environment and more capital for discretionary investment, increase the period between rate cases and provide greater rate stability. Companies that provide a clear financial incentive to employees to strive to cut costs, increase efficiency, manage risk, and respond to change likewise are less likely to need to seek rate adjustments.

Q. WOULD THE ELIMINATION OF ANY PORTION OF THE COMPANY'S REQUESTED ANNUAL INCENTIVE COMPENSATION BE IN KEEPING WITH THE COMMISSION'S ORDER IN THE PRIOR CASES?

A. No. The Company's annual incentive compensation, including the portion associated with the funding measures, provides substantial benefits to customers. Without the requested target level of annual incentive compensation, or an equivalent amount of additional base pay, the Company would not be able to attract and retain employees with the skills and experience needed to efficiently and effectively provide service to customers. The Company's annual incentive compensation is also clearly tied to many measures of improvement in service quality. These measures include SAIDI, customer satisfaction, mobile alert penetration, a reliability work plan, a customer experience work plan, a risk mitigation work plan, and emergency restoration planning.

The Company has shown with substantive and sufficient evidence that its incentive compensation program is a critical component of market competitive total compensation that benefits customers by enabling the Company to attract and retain the employees needed to efficiently and effectively provide its service to customers. Neither the need for market competitive total compensation nor the appropriate level of such compensation is contested in the testimony in this case.

Q. IS KIUC'S PROPOSAL TO ELIMINATE 75% OF ANNUAL INCENTIVE EXPENSE BASED ON AN ACCURATE ASSESSMENT OF THE COMPANY'S ANNUAL INCENTIVE PLAN?

A. No. While 75% of the funding measures for the Company's annual incentive compensation was tied to the AEP EPS measure for the test year (only 70% for 2017), this is only a part of the equation. The final award score is the product (z) of three equally weighted components: (w) Kentucky Power Company's overall operating performance score, (x) the overall funding score and (y) the normalizing factor in the equation $w \times x \div y = z$. The normalizing factor (y) is the average operating performance score (AOPS) for all AEP business units. Setting aside the normalizing factor, the funding factor is only half the equation. As such, if the Commission deems it appropriate to make this adjustment, then only half of the 75% weight associated with the AEP EPS measure (37.5%) should be removed from the Company's cost of service.

Q. IS THE COMPANIES' ANNUAL INCENTIVE COMPENSATION WEIGHTED TOWARDS FINANCIAL GOALS?

A. No. Mr. Kollen inappropriately focuses on funding measures while ignoring the operating performance measures in the Company's annual incentive program. The majority of Kentucky Power employees participate in the Kentucky Power Company version of Annual Incentive Compensation Plan for AEP Utilities, which includes the many Kentucky Power specific performance measures. The 2016 Kentucky Power annual incentive compensation performance measures are outlined below.

Infrastructure Development (25%)
Kentucky Power Company Net Income (10%)
Kentucky Power Company / AEP Utilities Economic Development (5%)
Kentucky Power Company Efficiency and Effectiveness Measures (10%)
Kentucky Power Company Cost per ASB (as built) Hour (5%)
Kentucky Power Company ASB Hours per FTE Equivalent (2.5%)
Kentucky Power Company MRO (Meter Revenue Operations) Cost per Order Completed (2.5%)
Customer Experience (40%)
Kentucky Power Company SAIDI (5%)
Kentucky Power Company Reliability Work Plan Execution (5%)
Kentucky Power Company Regulatory Execution (pursuit of customer driven initiatives with regulators that improve the customer experience) (5%)
J.D. Power Residential Overall Customer Satisfaction Index (5%)
Risk Mitigation Work Plan Execution (5%)
Customer Experience Work Plans (10%)
Kentucky Power Company Work Plan Including Mobile Alert
System-Wide Outage Mapping & Data Analytics (5%)
Emergency Restoration Planning / ICS Execution (5%)

<u>Employee Experience (35%)</u>
Kentucky Power Company Employee Culture / Experience Work Plan
Kentucky Power Company DART Rate (10%)
Proactive Employee Safety Measures (20%)
Quality Assurance on Jobsite Observations (5%)
Engage Employees to identify and address top five high-risk activities (5%)
Good Catch Program (5%)
Site Inspection Program (5%)

Only one of the performance measures in these Kentucky Power operating goals, the 10% Net Income measure, is a financial measure.

Q. ARE THERE ANY OTHER REASONS WHY YOU DISAGREE WITH MESSRS. SMITH'S AND KOLLEN'S RECOMMENDATIONS ON INCENTIVE COMPENSATION?

A. Yes. It is not proper for the companies to "charge" employee compensation costs to shareholders when this compensation is a reasonable, prudent and necessary expense for Kentucky Power. It is not accurate to infer that shareholders are the main beneficiaries of the funding pool, when it is simply a mechanism to provide goal oriented variable compensation which directly encourages employees to reduce expense, and operate safely and efficiently to provide reliable service to Kentucky Power customers. Stated another way, objections to the form of the Company's compensation arrangements, but not its reasonableness, is literally a matter of form over substance.

Q. IS MR. KOLLEN'S PROPOSAL TO ELIMINATE 75% OF ANNUAL INCENTIVE EXPENSE CONSISTENT WITH COMPENSATION PRACTICES USED BY INDUSTRIAL EMPLOYERS IN THE UNITED STATES?

A. No. It is common practice among U.S. industrial companies is to heavily utilize annual incentive compensation in the design of their employee compensation programs, and the benefits incentive compensation provides are well-understood.

Q. HOW WOULD THE COMPANY BE AFFECTED BY REDUCING OR ELIMINATING VARIABLE INCENTIVE COMPENSATION FROM ITS COST OF SERVICE FOR RATEMAKING PURPOSES?

A. Denying cost recovery for a portion of the variable component of employee pay would reduce the Company's rate of return to below the level to be set in this rate case, all else being equal. It would also encourage shifting variable incentive compensation into fixed base pay to enable the Company to recover its reasonable payroll costs. The Company would need to continue to offer employees the same target level of total compensation, in one form or another, in order to continue to maintain compensation at the market competitive levels needed to attract and retain employees with the skills and experience needed to efficiently and effectively provide service to customers. Therefore, shifting annual incentive compensation into base pay would not reduce the Company's payroll costs to less than the target level the Company requested be included in its cost of service in this case.

However, transferring variable incentive compensation into fixed base pay would lead to the gradual erosion of the efficiencies, productivity enhancements and operational benefits gained by the proven strategy of linking pay to performance. The loss of these efficiency, productivity and operational benefits, would lead to increased expenses, reduced company performance in many areas and higher rates for customers. Therefore, these proposals offered by KIUC and the Attorney General should be rejected by the Commission.

Furthermore, it is not reasonable to expect that the incremental benefit that annual incentive compensation may produce between rate cases, if any, will be sufficient to cover any significant portion of the Company's annual incentive expense. As a fundamental matter, it is important to recognize that the Company's incentive compensation plan has no incremental cost above the cost of providing market competitive compensation. Annual incentive compensation has encouraged and supported the development of a culture of high performance within the Company over the decades that it has been in place for all employees. The efficiency gains and other benefits that have resulted from incentive compensation and this high performance culture will already be incorporated in rates through this and prior rates case proceedings. It is not known if any further gains will be achieved as a result of the Company's annual incentive program and it is unreasonable to expect that such gains would or even could be sufficient to offset the denial of cost recovery for any significant portion of the Company's annual incentive compensation, let alone the 25% and 75% denials proposed by Messrs. Smith and Kollen, respectively. Because it has been in place for such a long period, only small, incremental benefits, if any, should be expected from incentive compensation going forward. However, even if incentive compensation only produces small incremental benefits or no new benefits going forward, it will still provide a positive net benefit because it has no incremental cost above the cost of providing market competitive compensation through base pay alone and because it helps maintain the efficiency gains and other cost savings that have already been achieved.

Q. WHAT IS YOUR RECOMMENDATION WITH RESPECT TO KIUC'S PROPOSAL TO REDUCE EMPLOYEE COMPENSATION EXPENSE BY ELIMINATING COST RECOVERY FOR 75% OF ANNUAL INCENTIVE EXPENSE?

A. I recommend that the Commission reject KIUC Witness Kollen's proposal to eliminate three quarters of direct employees' and AEPSC employees' annual variable incentive opportunity from cost of service. This is a necessary expense that is properly included as market competitive employee compensation and a reasonable and prudent cost of providing service to our customers.

IV. LONG-TERM INCENTIVE COMPENSATION

Q. WHAT JUSTIFICATIONS ARE CITED BY ATTORNEY GENERAL WITNESS SMITH FOR EXCLUDING 100% OF THE COMPANY'S LONG-TERM COMPENSATION?

A. First Mr. Smith states his position that "ratepayers should not be required to pay executive or management compensation that is based on the performance of the Company's (or its parent company's) stock price, or which has the primary purpose of benefitting the parent company's stockholders and aligning the interests of participants in the stock-based compensation plans with those of such stockholders."[14]

Mr. Smith also points out that stock option expense, which the Company has not had in many years, was at one point many years ago treated as a dilution

[14] Smith, p. 37, lines 5-9.

of shareholder's investment. Despite the fact that this is no longer the case and the fact that the types of stock-based compensation that the Company currently provides have never been accounted for as a dilution of shareholder's investment, Mr. Smith believes that "this does not provide a reason for shifting the cost responsibility for stock-based compensation from shareholders to utility ratepayers."[15]

Q. DO YOU AGREE WITH MR. SMITH?

A. No. There are several mischaracterizations in his testimony and I disagree with both his philosophical view and his recommendation. The first mischaracterization is that the Companies' stock-based compensation is exclusive to executives and management. In the test year the Companies provided stock-based compensation to approximately 1,025 employees, which more than any reasonable definition of executive and management employees. Many participants in this program were, in fact, single contributor professionals.

The expansion of long-term incentive compensation to large numbers of employees at levels that have little, if any, ability to control or influence the value at which it pays out, undermines the view that it provides an incentive for participants to act in shareholder's interests to the detriment of customers. The only incentive or inducement it can possibly have for most participants is simply to control costs because this is the primary and often only lever all but a few participants have available. This cost control directly benefits customers. Eliminating cost recovery of a portion of reasonable and market competitive compensation for a large number of employees, when only a few such employees

[15] Smith, p. 37, lines 19-20.

have any incentive or ability to affect the results is over-reaching and would result in a disallowance that is greatly disproportionate to any concern that this is detrimental to customers beyond the role of the Commission to fully mitigate this concern.

Even if the long-term incentive program was limited to executives and management employees it should not make any difference. The Company needs to provide market competitive compensation to attract and retain executives, management and all other types of employees who participate in it in order to efficiently and effectively provide service to customers. This undeniably benefits customers even with respect to executive and management compensation.

The second mischaracterization is that stock-based compensation is based on the performance of the Company's (or its parent company's) stock price. Unlike stock options, which have no value unless the underlying stock price increases in value, the Companies' stock-based compensation has a substantial value on day one. While the parent Company's stock price is one of several factors that determine the value of this compensation for participants, the amount the Company has requested be included in cost of service is a static value that is unaffected by stock price changes, parent company earnings and all other factors. Shareholders will gladly accept responsibility for any compensation associated with improvements in stock price and earnings provided customers accept responsibility for the cost associated with the static portion of employee compensation, in all forms, that is part of a market competitive compensation package. Furthermore, the impact that Company executives and management may have on a company's stock price is highly attenuated. As such, simply denominating long-term compensation in company shares or stock units does not create a significant incentive for any action whatsoever. This is why some pundits on compensation topics characterize RSUs as "pay for pulse."[16]

Mr. Smith's third mischaracterization is that stock-based compensation provided to officers and other employees that is "beyond their other compensation should be borne by shareholders and not by ratepayers."[17] This implies that the Company's long-term compensation is not a component of reasonable and market competitive compensation for participants but is instead additional to such reasonable and market competitive compensation. I have shown in my direct testimony is not the case.[18]

Lastly, Mr. Smith mischaracterizes the Companies' current stock-based compensation program by associating it with stock options, which the Companies last granted as a regular part of its long-term incentive program in 2013 and last grated at all in 2006. Stock options and the Companies' current forms of stock-based compensation are different instruments, with different accounting, granted in different periods in different volumes to different populations for different reasons. Any comparison between the Company's current stock-based compensation to stock options is unreasonable.

Q. IS ALL OF THE COMPANY'S LONG-TERM COMPENSATION BASED ON THE PERFORMANCE OF AEP STOCK?

---

[16] Equilar Blog, Companies Just Say No to "Pay for Pulse".
[17] Smith, p. 39, lines 6-7.
[18] See, Carlin Direct Testimony, pp. 32-33, lines 14-33 and Exhibit ARC-6 (Target Total Compensation vs. Market for Executive Positions)

A. No, there is a distinction between performance units, the value of which is tied to earnings per share and total shareholder return performance measures, and restricted stock units ("RSUs") that are merely denominated in AEP stock. RSUs, constitute 25% of the initial value of the Company's long-term incentive compensation granted in the test year and are not tied to any performance measures. Instead participants must continue their AEP employment through specified vesting dates in order for RSUs to vest, which is simply a retention incentive.

Q. WHY DOES AEP DENOMINATE LONG-TERM INCENTIVE COMPENSATION IN SHARES OR STOCK UNITS?

A. AEP denominates long-term incentive compensation in AEP shares or stock units for several reasons. First and foremost, long-term incentive compensation provides value to participants in future periods. The time value of money and risk of non-payment is taken into consideration by participants in the same way that investors take it into consideration. If the Company does not tie the value of long-term incentive compensation to a suitable investment vehicle that reflects the time value of money and risk of non-payment to participants, then participants will discount the value of the Company's long-term incentive compensation. Denominating long-term incentive compensation in AEP shares meets this need.

Secondly, the accounting treatment for share-based payments is more favorable than using any other vehicle, including cash. Because company stock is a company's currency and companies generally control the supply of it, compensation that is paid in company stock is basically treated as fully hedged.

As a result, any gain or loss attributable to share price changes and dividends does not have an expense impact. This is the accounting treatment that applies to AEP's RSUs. If the long-term cash awards were issued, then any interest or investment gain applied to it would cause an additional expense.

Furthermore, using stock creates a shared fate between employees and shareholders. It is a false dichotomy that such alignment is not also in customers' interests. The view that this is detrimental to customers ignores the Commission's control over rates through robust regulatory proceedings such as this rate case, which the Commission presumably believes adequately addresses the incentive that any regulated company has to seek higher rates. To the extent that the Company is able to obtain regulatory approval of its rate requests and other initiatives, such approval will customarily require that the Commission finds the rates and other initiatives to be consistent with the interests of customers, or otherwise reasonable and necessary from their perspective. The scrutiny that rate requests undergo inherently encourages Company employees to put together proposals that can be approved as consistent with the public interest, not just the utility's interest, and that are just and reasonable to consumers as well as to the utility. It also ignores the alignment of interests between shareholders and customers with respect to keeping costs low, which is the primary and often only lever most employee-participants have available to improve the value of their long-term incentive compensation.

Q. WHAT JUSTIFICATIONS ARE CITED BY KIUC WITNESS KOLLEN FOR EXCLUDING 100% OF LONG-TERM INCENTIVE COMPENSATION?

A. Mr. Kollen mischaracterizes the Company's long-term incentive compensation in her statement that it "was implemented to incentivize AEP executives and managers to enhance shareholder value."[19] He attributes this statement to the Company's response to KIUC I-30, which provided each of the Company's incentive compensation plans. However, the Company's long-term incentive plan, which was provided in this response, actually states the following:

> **Section 1.03. Purpose of This Plan.** The purposes of the Plan are to: (a) strengthen the alignment of interests between those Employees and Directors of the Company and its Subsidiaries who share responsibility for the success of the business and those of the Company's shareholders, (b) facilitate the use of long-term incentive compensation and the provisions of market competitive total compensation to Employees, (c) increase Employee ownership of shares of the Company's common stock to encourage ownership behaviors, and (d) encourage Plan Participant retention.[20]

Nowhere does in this plan document say that the Company's long-term incentive plan was implemented to enhance shareholder value.

Furthermore, even if the primary objective of long-term incentive compensation was to enhance shareholder value, language in a plan document would not be a good reason to exclude its expense from the Company's cost of service for rate making purposes. Only if it actually enhances shareholder value in a manner that is contrary or inconsistent with providing long-term benefits to customers that are commensurate with its costs, would there be reason to exclude

---

[19] Kollen, p. 19, lines 19-20

[20] Company response to KIUC's First Set of Data Requests, Item 30 (KIUC 1-30), August 14th, 2017, p. 317.

some or all of it from a Company's cost of service. However, any denial of cost recovery in such circumstances should be commensurate with the actual harm to customers, if any.

Q. DOES THE LONG-TERM COMPENSATION PROGRAM PRIMARILY BENEFIT CUSTOMERS OR SHAREHOLDERS?

A. It primarily benefits customers because all of the financial and operational benefits that have accrued as a result are reflected in the Company's cost of service in the test year and will inure to customers through this and prior base rate case proceedings. Very little, if any, additional improvements can be expected going forward. However maintenance the long-term incentive program prevents a gradual backslide with respect to all the cost and operational performance improvements achieved through these many years.

Furthermore, the Company must provide long-term incentive compensation, or an equivalent value of some other type of compensation, in order for its compensation for participants to remain within the market-competitive range. Aside from post-test year base pay adjustments, no party in this case has challenged the reasonableness of the Company's compensation, of which long-term compensation is an integral component. Therefore, long-term incentive compensation benefits customers by enabling the Company to attract, motivate, engage and retain the highly qualified executives, managers and other long-term incentive participants needed to manage its operations efficiently and effectively.

In addition, the increased participant retention that long-term compensation enables benefits customers by fostering management continuity and stability, which leads to better operational performance and lower costs for customers.

Long-term incentive compensation also benefits customers by linking a substantial portion of compensation for participants to longer-term measures of performance. This is prudent because it avoids encouraging short-term performance at the expense of long-term performance, which is analogous to farmers eating their seed corn. Compensating participants with only base pay and short-term incentive compensation would be counter to both shareholder and customer interests because it would discourage executive management from taking on prudent long-term risks that are in the interests of both shareholders and customers. This is because taking on such appropriate and prudent risks, even if they are likely to benefit both shareholders and ratepayers in the longer-term, could otherwise impair short-term performance. This could discourage that achievement of appropriate long-term objectives and performance goals that are beneficial to both customers and the Company.

Q. IS MR. KOLLEN'S ASSERTION TRUE THAT IF PARTICIPANTS ACHIEVE OR EXCEED TOTAL SHAREHOLDER RETURN ("TSR") AND EARNINGS PER SHARE ("EPS") OBJECTIVES, THEY ARE REWARDED WITH ADDITIONAL COMPENSATION?[21]

A. This is only partially true, and it is misleading. While it is true that performance units are tied to TSR and EPS metrics, this is not true with respect to RSUs, which

[21] Kollen, pp. 21-22, lines 20-2

constitute 25% of long term incentive awards granted in the test year. As previously mentioned, RSUs are not tied to any performance measures. It is also misleading to suggest that the Company's long-term incentive compensation "additional," because, as explained in my direct testimony,[22] the target compensation opportunity it provides is an integral component of a reasonable and market competitive compensation for employee-participants.

Q. DO YOU AGREE WITH MR. KOLLEN'S ASSERTION THAT "STOCK PRICE, BY DEFINITION, IS A MEASURE OF AEP'S FINANCIAL PERFORMANCE"?

A. No. As I previously explained, the effect financial performance has on stock price is highly attenuated and the Commission's responsibility for setting the Company's rates mitigates the risk this poses to customers. Mr. Kollen's statement suggest he would prefer that Company management sacrifice the interests of shareholders to those of customers by not seeking to recover the Company's reasonable and appropriate costs of providing service to customers. This would be unbalanced and ultimately detrimental to customers because it would reduce both the dollars available to the Company for investment and the amount of the Company's discretionary investment. The ability to earn an appropriate rate of return on its investment is fundamental to the regulatory compact.

Q. IS THE COMMISSION'S PRACTICE WITH RESPECT TO INCENTIVE COMPENSATION IMMUTABLE?

---

[22] Carlin Direct Testimony, pp. 32-33, lines 14-33 and Exhibit ARC-6 (Target Total Compensation vs. Market for Executive Positions)

A. No. Recommendations in any rate case should stand on the testimony and exhibits in evidence in the particular case. The Commission's practice is based on the view that incentive compensation tied to earnings and similar financial measures of the Company or its parent are detrimental to customers or at least primarily benefit shareholders. This testimony shows, to the contrary, that the Company's long-term incentive compensation, including the performance units that are tied to TSR and EPS measures, primarily benefit customers. Accordingly, the Commission should allow the inclusion of the Company's long-term incentive compensation in its cost of service for rate making purposes in this case.

The Company has shown that its long-term incentive compensation is a critical component of market competitive total compensation that benefits customers by enabling the Companies to attract and retain the employees needed to efficiently and effectively provide its service to customers. Neither the need for market competitive total compensation nor the reasonableness of the Company's total compensation, aside from post-test year adjustments, is contended in pre-filed testimony in this case.

Mr. Kollen portrays a false dichotomy by suggesting that the Companies' long term incentive program incentivizes the achievement of shareholder but not customer goals. 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 needed to efficiently and effectively provide electric service to customers. This fundamental aspect of the plan clearly benefits both customers and the Company. Furthermore, the financial measures included in the performance unit portion of the Companies' long-term incentive compensation (75% of the total) benefit customers by providing an incentive to control costs, which is the primary and often only lever most utility employees have available to improve company financial performance.

The remaining 25% of AEP's long-term incentive program takes the form of RSUs, which are tied primarily to participant retention through vesting requirements and are not tied to any performance measures.

The belief that long-term compensation benefits shareholders to the detriment of customers by encouraging participants to seek unwarranted rate increases, ignores the robust nature of such proceedings and questions the effectiveness of this and other Commissions.

My testimony shows that the Companies' long-term incentive compensation plan provides substantial benefits to customers by enabling the company to attract and retain suitable employees, by encouraging cost control and by encouraging employee retention. These benefits certainly exceed the incremental cost of long-term incentive compensation, which is $0 relative to the cost of providing market competitive compensation through other types of compensation.

Q. ARE THERE ANY OTHER REASONS THAT LONG-TERM INCENTIVE COMPENSATION SHOULD BE INCLUDED IN THE COMPANY'S COST OF SERVICE.

A. Yes, as with annual incentive compensation, each rate case conveys to customers all of the benefits that have accumulated over the many years that the Company's long-term compensation program has been in place. As was the case with annual incentive compensation, Messrs. Smith's and Kollen's proposals would provide customers with all the accumulated benefits of the long-term incentive compensation but none of its costs. This is disproportional to any perceived harm to customers, which in any case is mitigated by the Commission, which is responsible for setting utility rates.

In addition, the Companies' long-term incentive compensation is intended, as the name implies, to encourage participants to consider the long-term impact of their decisions on the Company and all of its stakeholders, including current and future customers. The long-term incentive program also serves as a way of compensating employees for performance that often has significant benefits to customers, for example, by designing new equipment and procedures in-house, and thus avoiding the cost of much more expensive outside contractors and consultants.

Without a market competitive total compensation program that includes either long-term incentive compensation or some other form of compensation of equal value, the Company cannot successfully compete for appropriately skilled and experienced personnel. Therefore, providing market competitive compensation to employees at all levels of the organization is a necessary and a basic cost of providing utility service to our customers. This is particularly true at leadership levels where management continuity is often critical. Simply put, no company of the Companies' size and complexity can function effectively without highly skilled people in a large number of key positions. Including long-term incentive compensation as a component of a reasonable and market compensation package for many of these positions, is the best way to compensate these positions from both shareholder and customer's point of view.

Q. WHAT IS YOUR RECOMMENDATION WITH RESPECT TO INTERVENOR'S PROPOSALS TO ELIMINATE THE STOCK UNIT PORTION OF EMPLOYEE LONG-TERM INCENTIVE COMPENSATION?

A. I recommend that the Commission reject Messrs. Smith's and Kollen's proposals. Long-term incentive compensation simply brings employee compensation to reasonable and market competitive rates and the incentive that it creates provide substantial benefits to customers.

V. <u>SAVINGS PLAN EXPENSE</u>

Q. DID ATTORNEY GENERAL WITNESS SMITH'S ADJUSTMENTS TO PAYROLL EXPENSE, INCENTIVE COMPENSATION EXPENSE AND LONG-TERM INCENTIVE EXPENSE FLOW THROUGH TO SAVINGS PLAN EXPENSE?

A. Yes, although his recommendation goes further than these adjustments. I will address the flow-through adjustments related to compensation and Company Witness Cooper will address Mr. Smith's recommendation for further adjustments.

Q. DO YOU AGREE THAT IF THE ANNUAL OR LONG-TERM INCENTIVE COMPENSATION ADJUSTMENTS ARE ADOPTED THEY SHOULD FLOW THROUGH AND RESULT IN RELATED ADJUSTMENTS TO SAVINGS PLAN EXPENSE?

A. No. The rationale for the adjustments to incentive compensation relate entirely to the form of such compensation and whether customers or shareholders should pay for it. No witness has argued that total compensation is unreasonable or more than is needed to provide market competitive compensation. As such, if the Company chose not to offer incentive compensation, it would still need to provide an equivalent value of base salary and it would still incur the associated savings plan expense. As such, any incentive compensation adjustments should not flow through to cause savings plan adjustments.

VI. NON-QUALIFIED POST-RETIREMENT BENEFITS

Q. PLEASE EXPLAIN THE COMPANIES' POST-RETIREMENT BENEFITS.

A. The Company maintains non-qualified post-retirement benefit plans for its employees to provide benefits that cannot be provided under qualified post retirement plans due to IRS limits imposed on ERISA-qualified plans. These plans are commonly referred to as Supplemental Employee Retirement Plans or "SERPs." The Company utilizes such plans to provide the same retirement benefits to employees as are provided under the ERISA-qualified retirement plans to the extent that such benefits cannot be provided due to the constraints imposed on qualified plans. AEP's non-qualified pension plans use the same benefit formulas as are used under the qualified AEP Retirement Plan for each respective employee, except that the non-qualified benefits are reduced by the amount of qualified benefits. Therefore, the total benefit provided by the Company under both its qualified and non-qualified retirement plans is equal to the benefit that would be produced by the formulas utilized under the qualified retirement plans if these plans were not subject to the benefit limitations imposed on qualified plans.

The Companies' non-qualified defined benefit plans also provide contractual benefits that were negotiated with respect to a few executives, nearly all of whom are now retired. No new contractual benefits have been negotiated in many years.

Q. HOW PREVALENT ARE NON-QUALIFIED DEFINED BENEFIT PENSION PLANS?

A. In my experience, most large companies that provide qualified defined benefit or defined contribution pension plans also provide non-qualified restoration plans that are similar to the Companies' non-qualified pension plans. This is because, to do otherwise, would be to accept arbitrary limits on retirement benefits to the detriment of the highly valuable employees who command compensation that exceeds the limits on qualified retirement plans. By arbitrary, I mean that these qualified plan rules limit the extent of favorable tax treatment, and should not be construed as serving any other purpose, such as designating the maximum acceptable level of retirement benefits that a company should provide or as a limit on amount of utility company benefit expense that customers should bear with respect to a single employee. These plans are more prevalent with larger companies, simply because larger companies are generally more complex and generally need more employees who command compensation in excess of the arbitrary limits on qualified retirement plans. Customers benefit from the economies of scale that larger companies generally provide. As such, they should bear the related cost of the additional compensation and benefits expense associated with managing larger companies.

Q. WHAT TREATMENT OF SERP EXPENSE IS RECOMMENDED BY ATTORNEY GENERAL WITNESS SMITH?

A. Mr. Smith recommends excluding all SERP expense from the Company's cost of service because "the provision of additional retirement compensation to the Company's highest paid executives is not a reasonable expense that should be recovered in rates."[23]

Q. DO YOU AGREE?

A. No, I do not agree. First, the Company's non-qualified post-retirement benefits are not limited to the "Company's highest paid executives."[24] There are several hundred participants in these programs, which goes well beyond any reasonable definition of "highest paid" or "executives."[25]

Second, these programs are not "additional."[26] They are an integral component of a reasonable and market competitive total rewards package. The Company needs employees with specialized experience, knowledge, capabilities and skills to efficiently and effectively provide electric service to customers.

[23] Smith, p. 42, lines 18-19.
[24] Smith, p. 42, lines 18-19.
[25] Smith, p. 42, lines 18-19.
[26] Smith, p. 42, lines 18-19.

Therefore, it is reasonable, prudent and in the customers' interests for the Company to attract and retain such employees. The experience and attributes that such higher paid employees possess makes them scarce and highly sought after, and enables them to command compensation that exceeds IRS-qualified plan compensation limits. Therefore, the cost associated with attracting and retaining such employees is necessary and prudent if the Company is to provide its utility service to customers as efficiently and effectively as possible.

While continuing to provide incremental non-qualified defined benefit pension is a discretionary decision, eliminating this benefit without an offsetting increase in some other form of remuneration would have significant negative consequences on the Companies' ability to attract and retain highly talented employees and this would ultimately have negative impacts on the cost and quality of the service the Company is able to provide to customers.

One of the primary reasons for the existence of the benefit limits on ERISA-qualified plans is the U.S. Federal Government's need for current tax revenue. It is arbitrary to use these tax-driven benefit limits for other purposes, such as setting the maximum level of pension expense that is deemed necessary and prudent for the provision of electric services. Consider, for example, whether it would be reasonable for the Commission to utilize this approach irrespective of substantial changes to these limits (up or down), as have occurred. In fact, utilizing any fixed limit for such a determination is biased against larger companies. Economies of scale enable such companies to be more efficient and, thereby, provide lower cost and higher quality electric service to customers.

However, efficiently and effectively managing larger and more diverse organizations requires more skilled and experienced managers and these managers command higher compensation in the marketplace, which is therefore more likely to exceed any fixed amount established for tax purposes.

The Companies' non-qualified deferred compensation benefits have been designed as part of the market competitive total rewards package, which the Company provides to all employees whose skills and experience command higher pay in the market. It is not an additional benefit above and beyond what is needed to provide market-competitive total rewards to these employees or high quality service to customers. As such, customers benefit from the provision of these benefits as part of a market-competitive total rewards package in the same way as they benefit from the provision of base pay as part of the same market-competitive package.

Q. DOES THIS CONCLUDE YOUR REBUTTAL TESTIMONY?

A. Yes.

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) An Order Approving Its 2017 Environmental Compliance Plan; (3) An Order Approving Its Tariffs And Riders; And (4) An Order Granting All Other Required Approvals And Relief	)))))))	Case No. 2017-00179

REBUTTAL TESTIMONY OF

JASON A. CASH

ON BEHALF OF KENTUCKY POWER COMPANY

VERIFICATION

The undersigned, Jason A Cash, being duly sworn, deposes and says he is employed by American Electric Power as Accountant Policy and Research Staff that he has personal knowledge of the matters set forth in the forgoing testimony and the information contained therein is true and correct to the best of his information, knowledge and belief

Jason A Cash

STATE OF OHIO)
) 2017-00179
COUNTY OF FRANKLIN)

Subscribed and sworn to before me, a Notary Public in and before said County and State, by (Insert Name), this the 2nd day of November 2017.

Notary Public

Notary ID Number: NA

NOTARIAL SEAL
STATE OF OHIO

Amanda E. Owen, Attorney At Law
NOTARY PUBLIC - STATE OF OHIO
My commission has no expiration date
Sec. 147.03 R.C.

My Commission Expires: Never

REBUTTAL TESTIMONY OF
JASON A. CASH
ON BEHALF OF
KENTUCKY POWER COMPANY
BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY

CASE NO. 2017-00179

TABLE OF CONTENTS

REBUTTAL TESTIMONY OF
JASON A. CASH ON BEHALF OF
KENTUCKY POWER COMPANY
BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY

I. INTRODUCTION

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

A. My name is Jason A. Cash. My business address is 1 Riverside Plaza, Columbus, Ohio 43215. My position is Staff Accountant in Accounting Policy and Research for American Electric Power Service Corporation ("AEPSC"), a wholly owned subsidiary of American Electric Power Company, Inc. ("AEP").

Q. ARE YOU THE SAME JASON A. CASH WHO PREVIOUSLY FILED DIRECT TESTIMONY IN THIS PROCEEDING ON BEHALF OF KENTUCKY POWER COMPANY?

A. Yes, I am.

II. PURPOSE OF REBUTTAL TESTIMONY

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

A. My rebuttal testimony responds to depreciation related recommendations made by Lane Kollen on behalf of the Kentucky Industrial Utility Customers, Inc.

Q. PLEASE SUMMARIZE THE ACTIONS YOU PROPOSE THE COMMISSION TAKE IN CONNECTION WITH THE RECOMMENDATIONS, SUGGESTIONS AND PROPOSALS MADE BY INTERVENOR WITNESS KOLLEN?

A. For the reasons I discuss in more detail in this rebuttal testimony, I recommend the Commission:

1. Reject Mr. Kollen's proposal to eliminate terminal net salvage amount when calculating depreciation rates for both Big Sandy Unit 1 and the Company's ownership share of the Mitchell Plant. The Commission should accept the Big Sandy Unit 1 depreciation rates as filed by the Company in this case, and continue to use the deprecation rates approved in Case No. 2014-00396 for the Mitchell Plant for reasons explained in Section III, below.

2. Reject Mr. Kollen's further recommendation to eliminate an inflation rate factor in connection with the calculation of the terminal net salvage amounts used for determining depreciation rates for Big Sandy Unit 1. The Commission should accept the Big Sandy Unit 1 depreciation rates as filed by the Company in this case for reasons explained in Section III, below.

Q. WHAT IS THE TOTAL EFFECT ON DEPRECIATION EXPENSE OF MR. KOLLEN'S PROPOSAL FOR CALCULATING THE BIG SANDY UNIT 1 AND MITCHELL PLANT TERMINAL NET SALVAGE AMOUNTS?

A. Mr. Kollen's adjustment to remove terminal net salvage from depreciation rates reduces depreciation expense by $0.370 million for Big Sandy Unit 1 and $0.567 million for the Mitchell Plant. Mr. Kollen references this depreciation expense change on page 35, lines 4 thru 6 of his testimony and provides a detailed calculation of the adjustment in his Exhibit ___(LK-14).

III. TERMINAL NET SALVAGE

Q. WHAT IS NET SALVAGE AND HOW DOES IT AFFECT DEPRECIATION RATES AND DEPRECIATION EXPENSE?

A. Salvage includes amounts received for depreciable property retired due to sale, reimbursement or reuse of the property. Removal cost is the expenditure incurred in connection with retiring, removing or disposing of property. Net salvage is the difference between salvage and removal cost.

Positive net salvage occurs when salvage exceeds removal cost. Positive net salvage decreases depreciation rates and hence depreciation expense. Negative net salvage occurs when removal cost exceeds salvage. Negative net salvage increases depreciation rates and hence depreciation expense.

Q. WHAT TYPES OF NET SALVAGE ARE TYPICALLY CONSIDERED FOR PRODUCTION PLANT TYPE PROPERTY IN A DEPRECIATION STUDY?

A. A depreciation study for production plant type property typically considers both terminal and interim net salvage.

Q. HOW DOES TERMINAL NET SALVAGE DIFFER FROM INTERIM NET SALVAGE?

A. Terminal net salvage includes the final cost to retire the plant at the end of its useful life less any salvage received from the property retired (net salvage). Interim net salvage represents amounts received (salvage) net of removal cost incurred from retirements from the time a plant is placed in service until its final retirement. Net salvage is included in a depreciation study to recognize that there will be a cost and/or potential salvage value associated with those retirements that needs to be included in the depreciation calculation.

Q. DOES MR. KOLLEN TAKE EXCEPTION TO THE INCLUSION OF TERMINAL OR INTERIM NET SALVAGE IN THE CALCULATION OF BIG SANDY UNIT 1'S AND MITCHELL PLANTS DEPRECIATION RATES AND EXPENSES?

A. Yes. Mr. Kollen takes exception to the inclusion of terminal net salvage in the calculation of Big Sandy Unit 1's and Mitchell Plant's depreciation rates and expenses. In addition, Mr. Kollen takes exception to escalating the terminal net salvage amounts of Big Sandy Unit 1 when calculating its depreciation rates. Mr. Kollen does not take exception to the inclusion of interim net salvage in the calculation of Big Sandy Unit 1's and Mitchell Plant's depreciation rates and expenses.

Q. IS THE COMPANY PROPOSING TO REVISE THE DEPRECIATION RATES FOR ITS SHARE OF THE MITCHELL PLANT DURING THIS PROCEEDING?

A. No. As stated in my direct testimony, Kentucky Power intends to continue to use the depreciation rates for its ownership share of the Mitchell Plant as approved by the Commission in Case No. 2014-00396.

Q. WHAT REASONS DOES MR. KOLLEN GIVE FOR EXCLUDING TERMINAL NET SALVAGE FROM THE CALCULATION OF DEPRECIATION RATES FOR BIG SANDY UNIT 1 AND THE MITCHELL PLANT?

A. Mr. Kollen's explanation is set forth at pages 32 to 34 of his testimony and is premised upon his contention that:

1. The Commission should not attempt to forecast today the scope of any future dismantling activities and site restoration necessary or reasonable when the Company's generating units are retired decades in the future.

2. Including terminal net salvage in the calculation of depreciation rates for Big Sandy Unit 1 will result in double recovery, once in the base revenue requirement and again in the proposed renamed Decommissioning Rider.

Q. DO YOU AGREE WITH MR. KOLLEN THAT THE COMMISSION SHOULD NOT ATTEMPT TO FORECAST ANY FUTURE DISMANTLING ACTIVITIES AND SITE RESTORATION PLANS?

A. No. Mr. Kollen's recommendation to wait until the Company's production plants are retired or are close to retirement, before including the dismantling costs in rates is contrary to generational equity. It forces future ratepayers to pay for the dismantling costs of retired plants in which they receive no benefit. Including terminal net salvage in current depreciation rates allows for current ratepayers to pay for the cost of the production plant for which they receive service.

Q. DO YOU AGREE WITH MR. KOLLEN THAT INCLUDING TERMINAL NET SALVAGE IN CALCULATION OF DEPRECIATION RATES FOR BIG SANDY UNIT 1 WILL RESULT IN DOUBLE RECOVERY?

A. No. The Company is only including costs related to the decommissioning of the coal related assets at Big Sandy in the proposed Decommissioning Rider. The net salvage amount used to calculate depreciation rates for Big Sandy Unit 1 only includes the estimated cost to demolish Big Sandy Unit 1. When the Company retires Big Sandy Unit 1 and begins demolition of the plant a portion will be applied to the Decommissioning Rider and a portion will be applied to the accumulated depreciation accrual for Big Sandy Unit 1. Applying a portion of the cost to each eliminates any type of double recovery.

Q. DOES MR. KOLLEN ALSO CHALLENGE THE MANNER IN WHICH KENTUCKY POWER CALCULATED THE TERMINAL NET SALVAGE AMOUNT?

A. Yes. Mr. Kollen argues at page 34 of his testimony that Kentucky Power erred by including an escalation factor in the calculation of Big Sandy Unit 1's terminal net salvage amount on page 34 of his testimony. His reasons for excluding an escalation factor are:

1. The escalation methodology "front-loads" recovery of an uncertain estimate of future costs in future dollars, which is also uncertain.

2. There will be no changes in the physical dismantling and site restoration approach assumed by Sargent & Lundy, no efficiencies from technology, equipment and disposal advances, and no improvements in productivity, any of which could offset future inflation costs.

3. Use of 2031 dollars for 2017 ratemaking purposes is an inherent mismatch and forces today's customers to subsidize future customers. If the cost estimate escalates in future years, then if the increased cost is reasonable and prudent, those increases can be reflected in future depreciation rates.

Q. HOW DO YOU RESPOND TO MR. KOLLEN'S CRITICISM OF THE COMPANY'S INCLUSION OF AN ESCALATION RATE IN THE CALCULATION OF DEPRECIATION RATES FOR BIG SANDY UNIT 1?

A. Since the terminal net salvage amount represents the net salvage the Company expects to incur when the plant retires and the demolition study used to determine the terminal net salvage was performed in 2013, it is necessary to inflate the 2013 demolition cost estimates to the 2031 estimated retirement date to obtain an accurate estimate of the final demolition cost.

Doing so is consistent with standard and accepted depreciation practices. For example, NARUC's "Public Utility Depreciation Practices" (August 1996), at page 18, lines 9-13 indicates that net salvage positive or negative is to be calculated as of the date of the retirement and not as of the date of the depreciation study:

> Net salvage is expressed as a percentage of plant retired by dividing the dollars of net salvage by the dollars of original cost of plant retired. The goal of accounting for net salvage is to allocate the net cost of an asset to accounting periods, making due allowance for the net salvage positive or negative, **that will be obtained when the asset is retired**. (emphasis added)

The amount that will be obtained when the asset is retired will be the inflated 2031 amount.

In states where other American Electric Power Company, Inc. companies operate, utility commissions have adopted depreciation calculations based on production plant demolition studies comparable to the ones sponsored by KPCo in this proceeding, and have accepted the practice of escalating generating unit retirement costs to the date of retirement. For example, the Indiana Utility Regulatory Commission ruled in a case involving non-AEP affiliate Public Service Company of Indiana, Cause No. 42359 (Order dated May 18, 2004, page 71), that escalation (inflation) should be factored into dismantlement costs. The Indiana commission addressed a depreciation study sponsored by Mr. John Spanos for the utility stating:

> We find Mr. Spanos' approach to be realistic and consistent with past experience. Inflation has been a fact of life in the American economy for many years. Not factoring inflation into dismantlement costs to be incurred in the future would understate those costs, with the result being that future customers would have to pay costs arising from facilities that are not serving them. This result flies in the face of matching rates with costs incurred for service, as sound ratemaking principle followed by this Commission. Moreover, current customers receive a benefit by factoring in inflation, as it may appropriately allow for a reduction in rate base

> because of the increased accumulated reserve for depreciation. **Accordingly**, **this Commission finds that accounting for inflation in determining the dismantlement estimates to be used as part of PSI's depreciation rates is reasonable.** (emphasis added)

Q. HOW DO YOU RESPOND TO MR. KOLLEN'S CRITICISM THAT INCLUSION OF AN ESCALATION RATE "FRONT-LOADS" RECOVERY OF AN UNCERTAIN ESTIMATE OF FUTURE COSTS?

A. Mr. Kollen implies that that the Company will not dismantle Big Sandy Unit 1 after the plant is no longer in use. Based on its historical record, AEP has demonstrated that it demolishes retired generating plants. Since 1955, Appalachian Power Company which is a wholly owned subsidiary of AEP has retired five steam generating plants including Kingsport, Roanoke, Kenova, Logan and Cabin Creek Plants. All five of these plants have been demolished. AEP affiliate Indiana Michigan Power Company ("I&M") completed the demolition of its Breed generating plant in 2006. In 2016, I&M completed the sale of its retired Tanners Creek generating plant site at a cost to I&M. The sale of the Tanners Creek plant site included demolition of the plant and the associated liabilities at the plant site.

The cost associated with dismantling the plant is a cost that the Company will incur after the plant is no longer in use. Straight-line depreciation calculations are designed to produce equal annual depreciation amounts by calculating depreciation rates that allocate the remaining cost of a utility's investment, including net salvage, over the remaining life of the investment. Adding an escalation rate does not "front-load" future costs. It evenly spreads the final cost to dismantle the plant at retirement evenly over the remaining life of the plant.

Q. IS THE COMPANY'S ESTIMATE OF THE FINAL COST TO DISMANTLE THE PLANT REASONABLE?

A. Yes. The company contracted with an independent engineering firm, Sargent & Lundy, to provide an estimate of the cost to dismantle the Big Sandy Plant. That estimate provides a basis for the final costs that will be incurred at the plant site. Mr. Kollen does not provide a different estimate.

Q. **HOW DO YOU RESPOND TO MR. KOLLEN'S ASSERTION THAT S&L FAILS TO FACTOR INTO ITS ESTIMATE FUTURE EFFICIENCIES WHICH COULD OFFSET FUTURE INFLATION COSTS?**

A. Mr. Kollen similarly fails to provide any examples of the type of efficiencies that can be obtained in the future and the effect those efficiencies could have on the estimate provided by Sargent & Lundy.

Q. IS MR. KOLLEN ACCURATE WHEN HE INDICATES THAT USE OF 2031 DOLLARS FOR 2017 RATEMAKING PURPOSES IS AN INHERENT MISMATCH AND FORCES TODAY'S CUSTOMERS TO SUBSIDIZE FUTURE CUSTOMERS?

A. No, in fact the opposite is correct. A central tenant of regulatory practice is generational equity where the cost of electric service is borne by the customers who benefit from that service. Using an escalated 2031 terminal demolition cost for Big Sandy Unit 1 creates a level amount of depreciation expense to be included in rates for current and future customers. Failure to incorporate escalation in the terminal demolition cost estimate would cause future customers to pay continually increasing amounts. The lack of an escalation would also be contrary to straight line depreciation principles.

IV. SUMMARY AND CONCLUSION

Q. PLEASE SUMMARIZE YOUR CONCLUSIONS REGARDING MR. KOLLEN'S RECOMMENDATION TO ELIMINATE THE TERMINAL NET SALVAGE AMOUNTS FOR BOTH BIG SANDY UNIT 1 AND THE MITCHELL PLANT FROM THE CALCULATION OF DEPRECIATION RATES.

A. Mr. Kollen is incorrect in his assumption that terminal net salvage should be excluded when calculating depreciation rates for both Big Sandy Unit 1 and the Mitchell Plant. The Commission should accept the Big Sandy Unit 1 depreciation rates as filed by the Company in this case and continue to use the deprecation rates approved in Case No. 2014-00396 for the Mitchell Plant.

Q. DO YOU HAVE ANY FURTHER COMMENTS REGARDING MR. KOLLEN'S RECOMMENDATIONS AROUND TERMINAL NET SALVAGE?

Yes. Mr. Kollen is also incorrect in his assumption that no escalation should be applied to calculate Big Sandy Unit 1's terminal net salvage cost. As previously mentioned, the Commission should accept the Big Sandy Unit 1 depreciation rates as filed by the Company in this case.

Q. DOES THIS CONCLUDE YOUR REBUTTAL TESTIMONY?

A. Yes.

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) An Order Approving Its 2017 Environmental Compliance Plan; (3) An Order Approving Its Tariffs And Riders; And (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

REBUTTAL TESTIMONY OF

CURT D. COOPER

ON BEHALF OF KENTUCKY POWER COMPANY

VERIFICATION

The undersigned, Curt Cooper, being duly sworn, deposes and says he is the Director of Employee Benefits for American Electric Power, that he has personal knowledge of the matters set forth in the forgoing testimony for which he is the identified witness and that the information contained therein is true and correct to the best of his information, knowledge and belief

Curt Cooper

STATE OF OHIO)
) Case No. 2017-00179
COUNTY OF FRANKLIN)

Subscribed and sworn to before me, a Notary Public in and before said County and State, by Curt Cooper, this the 2nd day of November 2017.

NOTARIAL SEAL
STATE OF OHIO

Cheryl L. Strawser
Notary Public, State of Ohio
My Commission Expires 10-01-2021

Notary Public

My Commission Expires: October 1, 2021

REBUTTAL TESTIMONY OF
CURT D. COOPER
ON BEHALF OF
KENTUCKY POWER COMPANY
BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY

CASE NO. 2017-00179

TABLE OF CONTENTS

REBUTTAL TESTIMONY OF
CURT D. COOPER ON BEHALF OF
KENTUCKY POWER COMPANY
BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME.

A. My name is Curt D. Cooper.

Q. PLEASE PROVIDE YOUR POSITION IN THE COMPANY AND BUSINESS ADDRESS.

A. I am the Director of Employee Benefits with American Electric Power Service Corporation (AEPSC). My business address is American Electric Power, 1 Riverside Plaza, Columbus, Ohio 43215.

Q. WHAT ARE YOUR PRINCIPAL AREAS OF RESPONSIBILITY?

A. I am responsible for implementing and managing the employee benefits offered to the employees and retirees of Kentucky Power Company and its affiliates, including AEPSC. My department manages the third-party vendors used to administer our self-insured benefit plans and negotiates the contracts and fees paid for these services. I serve as the Company's chief privacy officer as required under the federal Health Insurance Portability and Accountability Act.

Q. PLEASE SUMMARIZE YOUR EDUCATIONAL BACKGROUND AND PROFESSIONAL EXPERIENCE.

A. I earned a degree in Business Administration from Ashland College in Ashland, Ohio in 1982 and a Juris Doctorate degree from Ohio State University Moritz College of Law in 1986. I was admitted to the Ohio Bar in 1986. From 1986 until 1990 I was employed as a tax consultant at the accounting firm of Ernst and Young. I have been a Certified Public Accountant since 1989. I began work at AEP in the Benefits Design department in 1990 and assumed my current position as Director of Employee Benefits in 2003.

Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY?

A. The purpose of my testimony is to rebut mischaracterizations in the testimony of Ralph C. Smith on behalf of the Kentucky Attorney General's (AG) office with respect to Kentucky Power's retirement benefit costs included in the Company's Application. I will show that the costs the Company incurs in connection with the retirement benefit component of its employees' compensation is not duplicative, is different from other plans cited by AG Witness Smith, and that to remove these costs from the Company's cost of service as suggested by witness Smith would be without basis, arbitrary, and inconsistent with Commission precedent. The employee retirement benefits contributions paid by the Company were reasonable, are a cost of providing service to Kentucky Power's customers and, as such, should be included in the revenue requirement without reduction.

II. EMPLOYEE BENEFIT EXPENSE

Q. AG WITNESS SMITH MENTIONS SOME SUPPORT IN PAGES 40 AND 41 OF HIS TESTIMONY TO RECOMMEND REDUCTION FOR CERTAIN AMOUNTS RELATED TO EMPLOYEE COMPENSATION AND BENEFITS FROM THE KENTUCKY POWER'S COST OF SERVICE IN CERTAIN COMMISSION ORDERS. DO YOU AGREE WITH HIS INFERENCE?

A. Not at all. The factual situations in the cases Mr. Smith mentioned are not appropriately comparable to Kentucky Power's employee compensation and benefits plans, and therefore do not lend support to his suggestion to arbitrarily remove from the Company's cost of service a portion of the employee compensation costs.

Specifically, the effective plan design and the costs Kentucky Power incurs as part of its employees' compensation is quite different than the plans described for Kentucky Utilities (KU) in Case No. 2016-0370, Louisville Gas and Electric (LGE) in Case No. 2016-00371, and Cumberland Valley Electric, Inc. (Cumberland Valley Electric) in Case No. 2016-00169.

The most significant difference between the Company's benefits plan and the plans disallowed in those three cases is the plans' structure.

First, a common thread among the plans described in the cases noted by AG Witness Smith is that each employer had Defined Benefit Plans in place that had both contribution and distribution attributes. In contrast, Kentucky Power provides two distinct retirement savings plans for its employees. Notably, since 2001 Kentucky Power's defined benefit plan employs a cash balance formula, causing this plan to operate as a defined contribution plan. As a result of this change the contribution percentage in Kentucky Power's plan is substantially below the plans in the noted cases. By way of example, the Cumberland Valley Electric plan's defined benefit contribution had a 30.22% rate. This number is more than three times greater than the upper range of Kentucky Power's defined contribution, and more than ten times greater than the lower range. Kentucky

Power's contribution to employee retirement savings accounts currently ranges between 3% and 8.5%, dependent on employee age and years of service. This difference is illustrated even more clearly by the fact that Kentucky Power's *combined* maximum contribution under its employee defined benefit *and* defined contribution plans is 13%, less than half of Cumberland's *defined benefit alone*.

The differences between the Kentucky Power employee retirement benefit plan and the plans of Kentucky Utilities AG Witness Smith cites, are even more contrasting. Under the Kentucky Utilities plans all employees that were hired prior to January 1, 2006, were eligible to participate in *both* a Pre 2006 defined distribution benefits (DDB) Plan *and* a 401 (k) Plan. Unlike Kentucky Power's, the plan cited by AG Witness Smith from Kentucky Utilities contributed 100% (one hundred percent) of the Pre 2006 DDB Plan costs. In addition to this payment, Kentucky Utilities also contributed to the 401 (k) Plan and additional amount of between 3% to 7% of eligible employee compensation, and another $0.70 per dollar match for employee contributions up to 6 percent of the employee's eligible contribution. The Kentucky Power plans, in contrast, do not provide similar aggregate benefits. AG Witness' Smith characterization that the Company's plans are comparable should be rejected, when (unlike Kentucky Power's plans) the Kentucky Utilities plans referred to by Mr. Smith provided a Kentucky Utilities' employee hired before 2006: 1) a DDB plan contribution funded 100% by the employer and not requiring any employee contribution, *plus* 2) a 401k contribution by Kentucky Utilities of between 3% and 7%, *plus* 3) a

$0.70 per dollar employer match up to 6 percent of the employee's eligible contribution.

The design of Louisville Gas and Electric plan also cited by AG Witness Smith is substantially similar to the Kentucky Utilities' plans described above. They are completely different from the Kentucky Power plans included in the Company's cost of service. Kentucky Power's plans do not provide duplicative benefits as those that Mr. Smith states are "excessive and not reasonable" for LGE and KU. Contrary to Mr. Smith's inference, Kentucky Power's plans do not provide "multiple layers" of retirement programs for their employees. The Company's costs associated with its contribution to employee retirement benefit accounts is simply a component of the employee compensation expenses the Company must incur to be able to provide service to its customers. It follows that all the reported expenses associated with these costs should be allowed.

Q. HOW DOES KENTUCKY POWER'S SAVINGS PLAN BENEFIT COMPARE TO THE EMPLOYEE BENEFITS OFFERED BY ITS INDUSTRY PEERS?

A. The survey results analyzed by the Company demonstrate that as compared to other industry peers the Kentucky Power's Savings Plan Benefit is below average and that reducing this employee benefit would impair Kentucky Power's ability to offer market competitive employee compensation, and therefore would erode its ability to attract and retain qualified employees.

Q. DOES THIS CONCLUDE YOUR REBUTTAL TESTIMONY?

A. Yes.

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) 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

REBUTTAL TESTIMONY OF

BRAD N. HALL

ON BEHALF OF KENTUCKY POWER COMPANY

VERIFICATION

The undersigned, Brad N. Hall, being duly sworn, deposes and says he is the External Affairs Manager for Kentucky Power that he has personal knowledge of the matters set forth in the forgoing testimony and the information contained therein is true and correct to the best of his information, knowledge and belief

Brad N. Hall

Brad N. Hall

COMMONWEALTH OF KENTUCKY)
) CASE NO. 2017-00179
COUNTY OF BOYD)

Subscribed and sworn to before me, a Notary Public in and before said County and State, by Brad N. Hall, this the 2nd day of November 2017.

Trisha M. Young Blum

Notary Public

Notary ID Number: 530202

My Commission Expires: 3-18-19

TRISHA M. YOUNG
NOTARY ID 530202
COMMISSION EXPIRES 3-18-19

REBUTTAL TESTIMONY OF
BRAD N. HALL, ON BEHALF OF
KENTUCKY POWER COMPANY
BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY

CASE NO. 2017-00179

TABLE OF CONTENTS

**REBUTTAL TESTIMONY OF
BRAD N. HALL, ON BEHALF OF
KENTUCKY POWER COMPANY
BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY**

I. INTRODUCTION

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

A. My name is Brad N. Hall, and I am the Manager, External Affairs, for Kentucky Power Company ("Kentucky Power" or "Company"). My business address is 855 Central Avenue, Suite 200, Ashland, Kentucky 41101.

Q. ARE YOU THE SAME BRAD HALL HALL THAT FILED DIRECT TESTIMONY IN THIS CASE?

A. Yes I am.

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

A. The purpose of my rebuttal testimony is to respond to the direct testimony of Attorney General Witness Dismukes. In particular, my rebuttal testimony covers the following specific topics:

- Why the specific and limited purpose of the K-PEGG Program makes Mr. Dismukes' comparisons to other types of economic development programs inappropriate;
- Why abandoning the K-PEGG Program would blunt economic development momentum in eastern Kentucky; and
- Why the Company's proposed expansion of the K-PEGG Program is beneficial to customers.

II. REBUTTAL TESTIMONY

Q. BEFORE RESPONDING TO MR. DISMUKES' TESTIMONY, CAN YOU UPDATE THE COMMISSION ON ADDITIONAL K-PEGG PROGRAM GRANTS ISSUED BY THE COMPANY SINCE THE INCEPTION OF THIS CASE?

A. Happily. As detailed in my direct testimony, Kentucky Power issues K-PEGG Program grants when funds become available. Since the filing of the application in this case, the Company has issued the following seven additional K-PEGG grants totaling $214,230:

DATE	RECIPIENT	PROJECT DESCR.	PROJECT TYPE	AMT.
9/6/2017[1]	One East Kentucky & Ashland Alliance	Aerospace Marketing	EDA Support/Mktg. & Promotion	$60,00
9/6/2017	Ashland Alliance	Braidy Industries Due Diligence Work	Site Development	$50,000
9/6/2017	Ashland Alliance	Wright Concrete Closing Fund	EDA Support	$23,334
9/6/2017	Appalachian Industrial Authority Inc.	Creation UAV Marketing Video	Mktg. & Promotion	$6,000
9/6/2017	Coal Fields Regional Industrial Authority Inc.	Improvement of industrial site appearance	Site Development	$15,000
10/18/2017	Lawrence County Fiscal County	Improvement of industrial site appearance	Site Development	$19,836
10/27/2017	City of Pikeville	Geotechnical	Site Development	$100,000

[1] The six grants dated September 6, 2017 were included in the Company's response to AG 1-390, albeit without disbursement dates. The grants dated October 18 and October 27 were issued after the Company's response to AG 1-390 was filed.

Q. HAVE ANY OF THESE RECENTLY ISSUED K-PEGG GRANTS RESULTED IN NEW ECONOMIC DEVELOPMENT IN THE SERVICE TERRITORY?

A. Yes. Recently, SilverLiner announced that it will construct a new manufacturing facility in Pikeville that will bring 50 employees initially and up to 300 employees eventually. Kentucky Power issued a K-PEGG grant to the City of Pikeville to support geotechnical evaluations at the proposed SilverLiner site. This geotechnical evaluation of the site confirmed that SilverLiner could construct its facility there.

Q. DOES ATTORNEY GENERAL WITNESS DISMUKES MISSTATE THE PURPOSE OF THE K-PEGG PROGRAM?

A. Yes. On pages 39 and 40 of his testimony, Mr. Dismukes identifies the recent economic downturn and the need for promoting economic diversity as the rationales for the Company's K-PEGG Program. In reality, the conditions and needs Mr. Dismukes references are the bases for Kentucky Power's entire economic development efforts. The K-PEGG Program has a far narrower purpose.

Q. WHAT IS THE PURPOSE OF THE K-PEGG PROGRAM?

A. The K-PEGG Program is designed specifically to address the following key gaps in economic development efforts in the Company's service territory:

- a lack of functional and properly trained local or regional economic development organizations;
- limited competitive and marketable industrial parks and buildings;

- insufficient marketing infrastructure for available opportunities; and
- insufficient workforce development and training.

These gaps were identified by InSite in their 2012 gap analysis. The InSite report was attached to my direct testimony as **EXHIBIT BNH-1**.

The K-PEGG program accomplishes its goals by issuing economic development grants to municipalities and economic development organizations to support:

- economic development agency support projects;
- workforce training projects;
- site development projects; and
- marketing and promotional projects.

Unlike the KEAP program, which has similar goals but is narrowly focused on Lawrence County and the contiguous Kentucky counties, the K-PEGG Program provides economic development grants for projects throughout the Company's service territory.

Q. ON PAGE 48 OF HIS TESTIMONY, MR. DISMUKES CRITICIZES THE K-PEGG PROGRAM FOR NOT REQUIRING K-PEGG PROGRAM GRANT RECIPIENTS TO COMMIT TO A MINIMUM LEVEL OF CAPITAL INVESTMENT OR TO REQUIRE GRANT RECIPIENTS TO PAY BACK GRANT FUNDING IF THEY LEAVE THE COMPANY'S SERVICE TERRITORY. IS THIS CRITICISM WARRANTED?

A. No. Mr. Dismukes' criticism ignores the fundamental differences between financial incentives or tax credits issued by the Kentucky Cabinet for Economic Development and grants issued under the K-PEGG Program. First, unlike state financial incentives which are issued directly to a company, K-PEGG Program grants are only issued to municipalities or economic development agencies within the service territory. Second, and perhaps more importantly, state financial incentives are issued directly to a specific company for the purpose of enticing that specific company to locate or expand a business in a specific location. K-PEGG Program grants, on the other hand, are issued to municipalities or economic development agencies for projects that upgrade the economic development infrastructure in the region through improvements to the skill of economic development professionals and to sites available for development.

Comparing state financial incentives with K-PEGG Program grants is an apples-to-oranges comparison. While the scale and company-specific economic development purpose of state incentives make the commitment criteria cited by Mr. Dismukes appropriate, that is not the case for K-PEGG Program grants. K-PEGG Program grants are not issued to specific target companies to incent specific development. The broader goal of the K-PEGG Program – to upgrade the region's economic development infrastructure – makes such criteria impossible.

Q. ON PAGE 48 AND 49 OF HIS TESTIMONY, MR. DISMUKES MAKES SIMILAR COMPARISONS OF THE K-PEGG PROGRAM TO THE COMPANY'S ECONOMIC DEVELOPMENT RATE TARIFF. IS THIS COMPARISON APPROPRIATE?

A. No. Much like the state financial incentives described above, the Company's economic development rate tariff is designed to incent specific companies to locate or expand operations within the Company's service territory. As such, it is fundamentally different than the K-PEGG Program which seeks to improve the economic development infrastructure in the service territory. For the same reasons it is inappropriate to compare the K-PEGG Program to state financial incentives, it is also inappropriate to compare the K-PEGG Program to the Company's economic development rate tariff.

Q. ON PAGES 50 AND 51 OF MR. DISMUKES' TESTIMONY HE IDENTIFIES A FAILURE TO JUSTIFY THE COST EFFECTIVENESS AS EVIDENCE OF INEFFICIENCIES OF THE KEDS. IS MR. DISMUKES CORRECT?

A. No. Once again, Mr. Dismukes conflates the purpose of the K-PEGG Program with the purpose of the Company's economic development efforts as a whole. The purpose of the K-PEGG program is not as Mr. Dismukes claims to "incentivize businesses, such as large commercial and industrial customers to relocate or expand in Kentucky…" Instead, the narrow focus of the K-PEGG Program is to fill the identified gaps in the economic development infrastructure in Company's service territory through support of economic development entities, training, and site development activities. Shoring up this infrastructure is necessary for the region to compete nationally and internationally for economic development opportunities that will bring needed jobs.

Q. DID KENTUCKY POWER'S ECONOMIC DEVELOPMENT GRANT PROGRAMS PLAY A ROLE IN KEEPING THE BRAIDY INDUSTRIES PROJECT IN THE SERVICE TERRITORY?

A. Yes. Braidy Industries announced there was an unacceptable extension of the construction timeline to support the heavy equipment in its planned aluminum mill facility at the original site. Instead of moving outside of the Company's service territory, Braidy Industries has relocated its proposed facility to the EastPark Industrial Site on the Boyd – Greenup County line. Kentucky Power has issued economic development grants to the Northeast Kentucky Regional Industrial Authority, the owner of EastPark, for improvements at the park. The existence of a ready-to-go site allowed the region to keep the planned investment. Without the investment in the EastPark made possible by Kentucky Power economic development grants, the region may have missed out on a transformative economic development opportunity.

Q. ON PAGES 43 AND 44 OF HIS TESTIMONY, MR. DISMUKES ASSERTS THAT THE COMPANY'S REQUEST TO EXPAND THE K-PEGG PROGRAM IS CONTRADICTORY. IS THE COMPANY'S REQUEST CONTRADICTORY?

A. No. Mr. Dismukes argues that because the KEAP Program was undersubscribed in 2016 while the K-PEGG Program was oversubscribed, the Company's request to expand the K-PEGG Program is contradictory. Mr. Dismukes logic is baffling. If anything, the oversubscription of the K-PEGG Program and undersubscription of the KEAP Program is evidence supporting the Company's decision to transition from the dual programs to an expanded K-PEGG Program. The Company's proposed consolidation and expansion removes the geographic barrier in the KEAP Program allowing more economic development grants for the entire service territory. The K-PEGG program is not "unfocused in either regional scope or purpose" as Mr. Dismukes claims. The K-PEGG Program provides needed economic development support to municipalities and economic development entities in the Company's service territory.

Q. WHY IS THE KEDS A NECESSARY COMPONENT OF THE K-PEGG PROGRAM?

A. The KEDS allows the Company to aggregate immaterial contributions from individual customers into material contributions towards improving the economic development infrastructure in the Company's service territory. Under the Company's proposed K-PEGG expansion, the individual customer contribution to this program will increase from a dime and nickel each month to a quarter each month. Annually, the proposed expansions increase the customer's contribution from $1.80 per year to $3.00 per year.

This increase will, when aggregated across all of the Company's customers, add an estimated $200,000 annually to the K-PEGG program. With the dollar-for-dollar Company match, the $1.20 annual increase to individual customers will result in an additional $400,000 in economic development support funds. All told, if the K-PEGG program is expanded, the Company will be able to aggregate annual $3.00 contributions from individual customers with dollar-for-dollar matching funds from the Company to create a K-PEGG Program capable of providing approximately $1.0 million dollars per year in economic development grants.

Q. SHOULD THE COMMISSION APPROVE THE COMPANY'S REQUEST TO EXPAND THE K-PEGG PROGRAM?

A. Absolutely. In the limited time that Kentucky Power has issued economic development grants through the KEAP and K-PEGG Programs, the economic development infrastructure within the Company's service territory has seen remarkable growth. These grants allow municipalities and economic development agencies to invest in human capital through training and professional development of their employees and in upgrading economic development sites to make them ready to go. Expanding the K-PEGG Program at this time capitalizes on the momentum that these economic development grants have created and will put the service territory on more competitive footing for economic development opportunities.

Q. DOES THIS CONCLUDE YOUR REBUTTAL TESTIMONY?

A. Yes.

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) An Order	)	
Approving Its 2017 Environmental Compliance	)	
Plan; (3) An Order Approving Its Tariffs And	)	Case No. 2017-00179
Riders; (4) An Order Approving Accounting	)	
Practices To Establish Regulatory Assets And	)	
Liabilities; And (5) An Order Granting All Other	)	
Required Approvals And Relief	)	

REBUTTAL TESTIMONY OF

ADRIEN M. MCKENZIE, CFA

ON BEHALF OF KENTUCKY POWER COMPANY

VERIFICATION

The undersigned, Adrien M. McKenzie being duly sworn deposes and says he is the Vice President of FINCAP, Inc., and that he has personal knowledge of the matters set forth in the forgoing testimony and the information contained therein is true and correct to the best of his information, knowledge, and belief.

Adrien M .McKenzie

STATE OF TEXAS)
) Case No. 2017-00179
COUNTY OF TRAVIS)

Subscribed and sworn to before me, a Notary Public in and before said County and State, by, Adrien M .McKenzie this 2nd day of November 2017.

Notary Public

ROBERT LEE MARTINEZ
NOTARY PUBLIC STATE OF TEXAS
MY COMM. EXP. 4/17/2019
NOTARY ID 13019391-2

My Commission Expires: 04/17/2019

REBUTTAL TESTIMONY OF

ADRIEN M. MCKENZIE

TABLE OF CONTENTS

I. INTRODUCTION

Q1. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A1. Adrien M. McKenzie, 3907 Red River, Austin, Texas, 78751.

Q2. ARE YOU THE SAME ADRIEN M. MCKENZIE THAT PREVIOUSLY SUBMITTED PREFILED DIRECT TESTIMONY IN THIS CASE?

A2. Yes, I am.

Q3. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY?

A3. My testimony to the Kentucky Public Service Commission ("KPSC" or the "Commission") addresses the testimony of Dr. J. Randall Woolridge, submitted on behalf of the Kentucky Office of Attorney General ("OAG"), Mr. Richard Baudino, on behalf of the Kentucky Industrial Utility Consumers, Inc. ("KIUC"), and Mr. Gregory W. Tillman, on behalf of Wal-Mart Stores East, LP and Sam's East, Inc. ("Wal-Mart"),[1] concerning the fair rate of return on equity ("ROE") that Kentucky Power Company ("Kentucky Power" or "the Company") should be authorized to earn on their investment in providing electric utility service.

Q4. HAVE YOU PREPARED WORKPAPERS SUPPORTING YOUR REBUTTAL TESTIMONY?

A4. Yes. Workpapers including supporting documents referenced in my rebuttal testimony and related exhibits are attached as Appendix A.

A. Summary of Conclusions

Q5. PLEASE SUMMARIZE THE RECOMMENDATIONS OF THE ROE WITNESSES.

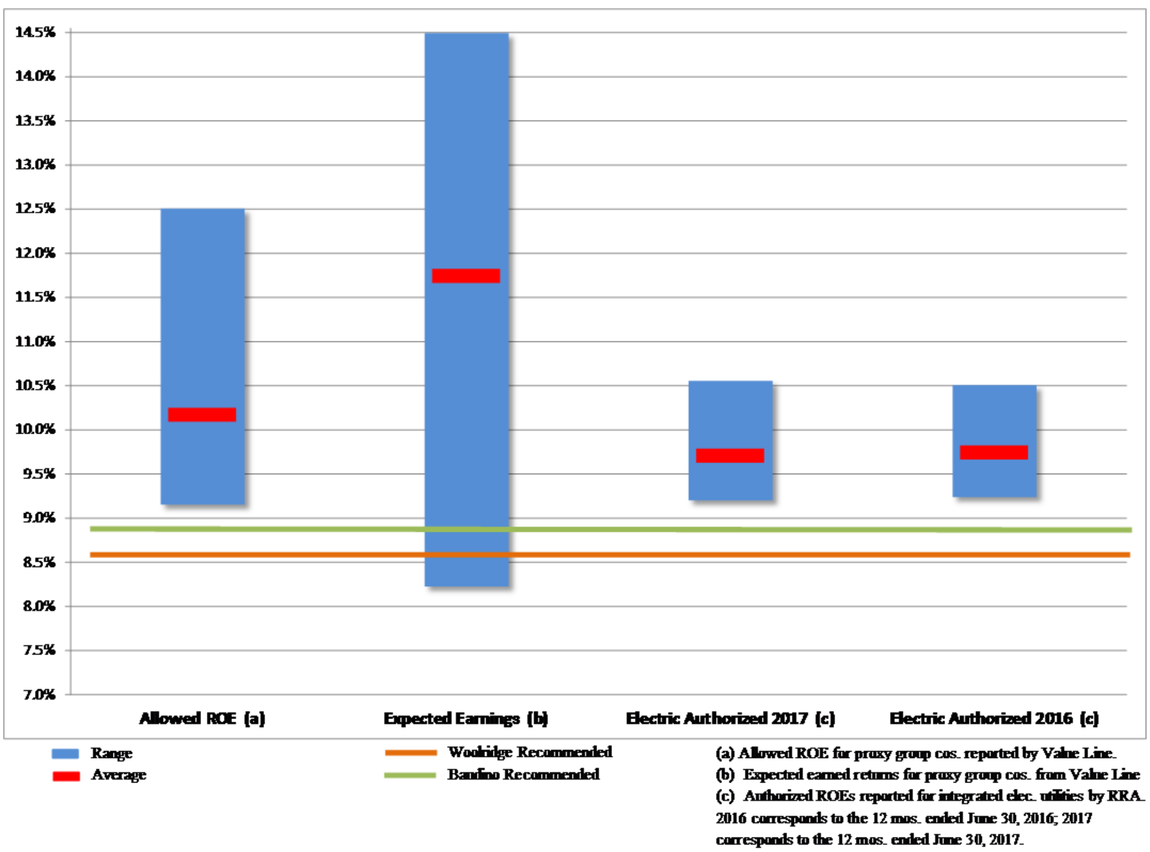
[1] I refer, collectively, to Dr. Woolridge and Mr. Baudino as the "ROE Witnesses" since they made specific ROE recommendations. Mr. Tillman testified generally about the ROE issue without making a specific proposal.

A5. Dr. Woolridge recommends an ROE of 8.60% for the Company, while Mr. Baudino proposes an ROE of 8.85%.

Q6. PLEASE SUMMARIZE YOUR RESPONSE TO THE ROE WITNESSES' TESTIMONY.

A6. Their cost of equity recommendations are simply too low and fail to reflect the risk perceptions and return requirements of real-world investors in the capital markets. The significant shortfall between their recommendations and the ROE benchmarks discussed in my rebuttal testimony are illustrated in the figure below.

FIGURE R-1
COMPARISON OF ROE RECOMMENDATIONS TO BENCHMARKS



Q7. WHAT ARE YOUR PRINCIPAL CONCLUSIONS REGARDING THE RECOMMENDATIONS OF DR. WOOLRIDGE?

A7. I demonstrate that Dr. Woolridge's recommendations should be ignored in their entirety based on the following findings:

- Dr. Woolridge's recommended ROE of 8.60% is an extreme outlier and should be rejected on its face.
- Dr. Woolridge's discussion of current capital market conditions is potentially misleading.
- Dr. Woolridge's focus on market-to-book ratios ("M/B") is misguided and not relevant to the determination of reasonable ROEs in this case.
- The proxy group selected by Dr. Woolridge incorrectly excludes several utilities that should have been considered in his analyses.
- His Discounted Cash Flow ("DCF") analysis contains several flaws, including his reliance on dividend per share and historical data for estimating the DCF growth term, his inclusion of illogical results stemming from unrealistically low growth rates (including numerous negative growth rates), and his reference to growth in gross domestic product ("GDP") as an upper bound on utility company growth rates. As a result, his conclusions are unreliable and should be ignored.
- Dr. Woolridge's application of the DCF model based on the internal, "br" growth rate is flawed and incomplete,
- The Capital Asset Pricing Model ("CAPM") results reported by Dr. Woolridge are based on a hodge-podge of historical data that fail to reflect forward-looking expectations, particularly in light of current conditions in the capital markets.

Furthermore, Dr. Woolridge failed to consider the Empirical CAPM ("ECAPM") and risk premium approaches, which are legitimate ROE methods. His rejection of flotation costs is at odds with the conclusions of recognized financial research and his own admission that these are legitimate expenses that should be recovered. Finally, his criticisms of my size adjustment, market return calculation, expected earnings approach, and non-utility DCF analysis are without merit. Taken as a whole, these shortcomings ensure that Dr. Woolridge's recommended ROE falls well below a fair and reasonable level for the

Company's utility operations. In fact, his recommendation is so far below a reasonable ROE range that it should be rejected on its face.

Q8. WHAT ARE YOUR PRINCIPAL CONCLUSIONS REGARDING THE RECOMMENDATIONS OF MR. BAUDINO?

A8. Mr. Baudino's 8.85% ROE recommendation is also below realistic investor expectations. My rebuttal testimony demonstrates that:

- Mr. Baudino mistakenly excludes legitimate companies from his proxy group, casting doubt on his ROE conclusions.
- Mr. Baudino places too much emphasis on dividend growth and failed to evaluate the reasonableness of individual DCF estimates. As a result, his conclusions are unreliable and should be ignored.
- Mr. Baudino's application of the DCF model based on the internal, "br" growth rate is flawed and incomplete.
- Mr. Baudino's application of the CAPM was compromised by reliance on historical data, while his forward-looking approach was marred by methodological shortcomings and inconsistencies.
- Like Dr. Woolridge, Mr. Baudino's rejection of a flotation cost adjustment contradicts the findings of the financial literature and the economic requirements underlying a fair rate of return on equity.

Finally, my rebuttal testimony demonstrates that Mr. Baudino's criticisms of my alternative applications and conclusions are misguided and should be ignored.

B. Comparison of ROE Recommendations to Accepted Benchmarks

Q9. CAN YOU ILLUSTRATE THE EXTREME NATURE OF THE ROE WITNESSES' RECOMMENDATIONS?

A9. Yes. If adopted, the 8.60% ROE suggested by Dr. Woolridge and the 8.85% value offered by Mr. Baudino would be the lowest ROEs granted to a vertically-integrated electric utility by a state commission in recent history, if not ever.[2] These recommendations are significantly below the 9.70% ROE authorized for Kentucky Utilities Company and Louisville Gas and Electric Company by the Commission in June 2017.[3] These comparisons demonstrate that the recommendations of the ROE Witnesses would not meet the judicial standards underpinning a fair rate of return for Kentucky Power.

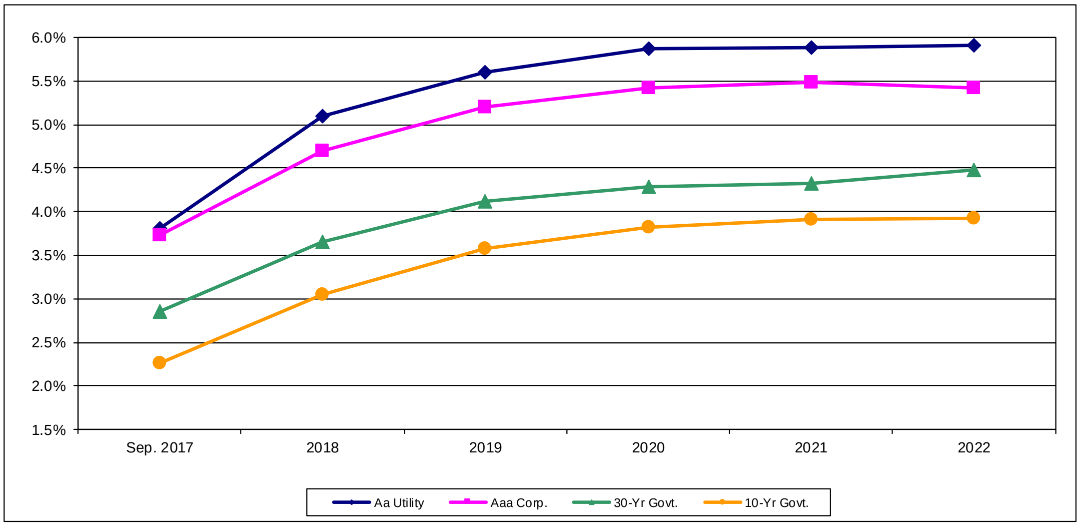
Q10. WHAT IS THE EXPECTED DIRECTION OF INTEREST RATES AND HOW DOES THIS IMPACT THE EVALUATION OF A FAIR ROE IN THIS PROCEEDING?

A10. Interest rates are expected to increase. Below is an update of Figure 3 (Interest Rate Trends) from my Direct Testimony:

[2] Regulatory Research Associated reported that Maui Electric was granted an ROE of 9.0% on May 31, 2013. However, the base ROE determined by the Public Utilities Commission of Hawaii was 9.50%, to which a 50 basis point penalty was applied due to "apparent system inefficiencies which negatively impact MECO's customers." (Docket No. 2011-0092, Decision and Order No. 31288, p, 107). Beyond that, the lowest authorized ROE for a vertically-integrated electric utility was 9.20% authorized for Northern States Power-Minnesota on May 11, 2017. As I discuss later in this testimony, this ROE award was accompanied by a number of risk-reducing regulatory mechanisms not available to the Company.

[3] Case Nos. 2016-00370 (Kentucky Utilities Company) and 2016-00371 (Louisville Gas and Electric Company), Final Order, June 22, 2017.

FIGURE R-2
PROJECTED INTEREST RATE TRENDS



Source:
Value Line Investment Survey, Forecast for the U.S. Economy (Sep. 1, 2017)
IHS Global Insight (Aug. 24, 2017)
Energy Information Administration, Annual Energy Outlook 2017 (Jan. 5, 2017)
Wolters Kluwer, Blue Chip Financial Forecasts, Vol. 36, No. 6 (Jun. 1, 2017)

As the figure shows, investors continue to anticipate that interest rates will increase significantly from present levels. These projections are from forecasting services that are highly regarded and widely referenced, as I discuss in my Direct Testimony (at 20-22). The interest rate increases shown in the figure above are on the order of 150-200 basis points through 2022, which implies higher long-term capital costs over the period when rates established in this proceeding will be in effect.

Q11. DID DR. WOOLRIDGE ACKNOWLEDGE THAT INTEREST RATES ARE EXPECTED TO INCREASE?

A11. Yes. In selecting the risk-free rate for use in his CAPM analysis, Dr. Woolridge states that "[g]iven the recent range of yields <u>and the possibility of higher interest rates</u>, I use the higher end 4.0% as the risk-free rate, or R_f, in my CAPM."[4] Given that the current 30-year U.S. Treasury bond rate (the rate Dr. Woolridge uses as

[4] Woolridge Direct at 50 (emphasis added).

the risk-free rate in his CAPM analysis) is around 2.9%, Dr. Woolridge clearly recognizes that investors anticipate a substantial increase in future interest rates.

Q12. WHAT DO THESE EXPECTATIONS IMPLY WITH RESPECT TO THE ROE FOR THE COMPANY MORE GENERALLY?

A12. Largely because of unprecedented Federal Reserve policies, current capital costs are not representative of what is likely to prevail over the near-term future. As indicated in my Direct Testimony,[5] regulators have recognized the shortcomings of the DCF approach. FERC has reiterated its position that current capital market conditions may undermine the reliability of the DCF model, and for this reason, ROE model results should be evaluated with even more critical judgment and focus:

> As described above, evidence in the record regarding historically low interest rates and Treasury bond yields as well as the Federal Reserve's large and persistent intervention in markets for debt securities are sufficient to find that current capital market conditions are anomalous.[6]
>
> Similarly, while Complainants provide evidence that interest rates have been trending downwards, the current levels may be so low as to cause irregularities in the outputs of the DCF. Despite such yields remaining low for several years, we find that they are anomalous and could distort the results of the DCF model.[7]

Current capital market conditions make the process of setting a fair ROE even more demanding. In this environment, it is imperative that ROE model results be thoroughly tested against accepted benchmarks and compared to other checks of reasonableness.

Q13. IS IT NECESSARY THAT INTEREST RATE FORECASTS, LIKE THOSE MENTIONED ABOVE, BE PERFECTLY ACCURATE IN ORDER TO BE RELIED UPON?

---

[5] McKenzie Direct at 7-8, 22-23.
[6] Opinion No. 551, 156 FERC ¶ 61,234 at P 124 (2016).
[7] *Id.*

A13. Absolutely not. I dealt with this topic in my Direct Testimony (at 37-38) in discussing the validity of analysts' growth forecasts, and the same principle applies here. In estimating investors' required rate of return, what investors expect, not what actually happens, is what matters most. While the projections of various services may be proven optimistic or pessimistic in hindsight, this is irrelevant in assessing expected interest rates and how they might influence the Company's allowed ROE. Any difference in actual rates as compared to analysts' forecasts is beside the point. What is most important is that investors share analysts' views when the forecasts were made and incorporate those views into their decision making process, not the actual rates that ultimately transpire.

Q14. HOW DO THE ROE WITNESSES' RECOMMENDATIONS COMPARE TO RECENTLY-ALLOWED RETURNS FROM OTHER STATE COMMISSIONS?

A14. Allowed ROEs by other state commissions provide a general gauge of reasonableness for the outcome of a cost of equity analysis. In considering utilities with comparable risks, investors will always prefer to provide capital to the opportunity with the highest expected return. If a utility is unable to offer a return similar to that available from other investment opportunities posing equivalent risks, investors will become unwilling to supply the utility with capital on reasonable terms. While the ROEs approved in other jurisdictions do not constrain the Commission's decision-making in this proceeding, it is important to understand that there would be a disincentive for investors to provide equity capital to the Company if the Commission were to apply an unreasonably low ROE, compared to entities of comparable risk.

The recommendations of the ROE Witnesses are significantly below equity returns that have been allowed by other state regulatory commissions around the country. As shown on Exhibit No. 12, over the past 24 months ended

September 30, 2017, the average allowed ROE (excluding adders and penalties) reported by S&P Global (formerly Regulatory Research Associates) for vertically-integrated electric utilities is 9.73%,[8] with the midpoint of the high and low values being 9.88%. Similarly, authorized ROE data reported to investors by The Value Line Investment Survey ("Value Line") for the specific firms in my proxy group also indicate that the recommendations of the ROE Witnesses are insufficient.[9] As shown in Exhibit No. 13, these ROEs average 10.18%, with the midpoint of the lowest and highest values being 10.83%. In other words, allowed returns for the utilities that the ROE Witnesses generally consider comparable to the Company indicate that their recommendations are too low to meet regulatory standards.

Q15. MR. TILLMAN EXCLUSIVELY REFERENCES ROES AWARDED IN RECENT RATE CASES.[10] WOULD IT BE APPROPRIATE TO USE RECENT ALLOWED RETURNS TO ESTABLISH THE COMPANY'S ROE DIRECTLY?

A15. No. As discussed in my direct testimony (pp. 58-63), while allowed ROE data is a valuable "secondary" approach in judging whether an ROE estimate based on the application of accepted financial models makes sense, there is no basis to place undue weight on a single, summary statistic in lieu of comprehensive analyses and a case-specific evidentiary record. Setting a utility's ROE is a very company-specific process, and is a function of investors' perceptions of the risks and prospects for the subject company at a given point in time. As a result, the

[8] For the 12 months ended September 30, 2017, the average is 9.71%; for the 12 months ended September 30, 2016, the average is 9.77%.

[9] Dr. Woolridge relies on my proxy group as one of his two electric groups, after removing Emera, Inc. and Fortis, Inc. due to his unexplained statement (fn. 18) that "they based on Canada" (sic). Likewise, Mr. Baudino starts with my group before removing three companies, AVANGRID, Inc., Emera, Inc., and Fortis, Inc. I address the errors and misconceptions associated with these exclusions at pages 28-29 and 61-64 of my rebuttal testimony.

[10] Tillman Direct at 10-11.

standard practice in regulatory proceedings is to consider the results of numerous approaches that are grounded in current capital market evidence when establishing a utility's ROE. Meanwhile, quarterly allowed ROEs reported by RRA are not necessarily representative or directly comparable to the utility at hand.[11] That is, there may be an "apples and oranges" issue when the RRA data is applied in the current rate setting environment.

Q16. WHAT OTHER BENCHMARKS INDICATE THAT THE ROE WITNESSES' RECOMMENDATIONS ARE TOO LOW TO BE CONSIDERED REASONABLE?

A16. Expected earned rates of return for other utilities provide yet another useful benchmark to gauge the reasonableness of the ROE Witnesses' recommendations. The expected earnings approach is predicated on the comparable earnings test, which developed as a direct result of the Supreme Court decisions in *Bluefield* and *Hope,* as I discuss in my Direct Testimony.[12] This test recognizes that investors compare the allowed ROE with returns available from other alternatives of comparable risk.

Importantly, the expected earnings approach explicitly recognizes that regulators do not set the returns that investors earn in the capital markets. Regulators can only establish the allowed return on the value of a utility's investment, as reflected on its accounting records. As a result, the expected earnings approach provides a direct guide to ensure that the allowed ROE is similar to what other utilities of comparable risk will earn on invested capital.

[11] For example, the lowest ROE granted over the last two-year period was 9.20% to Northern States Power Company ("NSP") in a Minnesota case decided May 11, 2017. This stipulated case resulted in a four-year multiyear rate plan spanning calendar years 2016 through 2019, a 2016 sales-forecast true-up which allowed it to collect nearly $59.99 million due to a one million megawatt-hour sales shortfall in 2016, and extension of full revenue decoupling for residential and small commercial customers through the end of the settlement period. These circumstances are not comparable to those faced by the Company in this proceeding.

[12] McKenzie Direct at 64-66.

This opportunity cost test does not require theoretical models to indirectly infer investors' perceptions from stock prices or other market data. As long as the proxy companies are similar in risk, their expected earned returns on invested capital provide a direct benchmark for investors' opportunity costs that is independent of fluctuating stock prices, market-to-book ratios, debates over DCF growth rates, or the limitations inherent in any theoretical model of investor behavior.

Q17. HAS THE EXPECTED EARNINGS APPROACH BEEN RECOGNIZED AS A VALID ROE BENCHMARK?

A17. Yes. This method predominated before the DCF model became fashionable with academic experts, and it continues to be used around the country.[13] A textbook prepared for the Society of Utility and Regulatory Analysts labels the comparable earnings approach the "granddaddy of cost of equity methods" and points out that the amount of subjective judgment required to implement this method is "minimal," particularly when compared to the DCF and CAPM methods.[14] The *Practitioner's Guide* notes that the comparable earnings test method is "easily understood" and firmly anchored in the regulatory tradition of the *Bluefield* and *Hope* cases,[15] as well as sound regulatory economics. Similarly, *New Regulatory Finance* concluded that, "because the investment base for ratemaking purposes is expressed in book value terms, a rate of return on book value, as is the case with Comparable Earnings, is highly meaningful."[16]

---

[13] For example, the Virginia State Corporation Commission is required by statute (Virginia Code § 56-585.1.A.2.a) to consider the earned returns on book value of electric utilities in its region. Similarly, FERC concluded that, "The returns on book equity that investors expect to receive from a group of companies with risks comparable to those of a particular utility are relevant to determining that utility's market cost of equity." Opinion No. 531-B, 150 FERC ¶ 61,165 at P 128 (2015). Another example is the Idaho Public Utilities Commission, which also references return on book equity evidence. *See, e.g.,* Order No. 29505, Case No. IC-E-03-13 at 38 (Idaho Public Utilities Commission, May 25, 2004).

[14] David C. Parcell, "The Cost of Capital – A Practitioner's Guide," (2010) at 115-116.

[15] *Id.*

[16] Roger A. Morin, "New Regulatory Finance," *Public Utilities Reports, Inc.* (2006) at 395.

Q18. DID MR. BAUDINO RECOGNIZE THE ECONOMIC PREMISE UNDERLYING THE EXPECTED EARNINGS APPROACH?

A18. Yes. The simple, but powerful concept underlying the expected earnings approach is that investors compare each investment alternative with the next best opportunity. As Mr. Baudino recognized, economists refer to the returns that an investor must forgo by not being invested in the next best alternative as "opportunity costs."[17] Mr. Baudino went on to explain that, "investor's opportunity cost is measured by what she or he could have invested in as the next best alternative."[18]

Q19. WHAT ROES ARE IMPLIED BY THE EXPECTED EARNINGS APPROACH FOR THE UTILITY PROXY GROUP?

A19. The year-end returns on common equity projected by Value Line over its forecast horizon for the firms in the utility proxy groups referenced by myself and the ROE Witnesses are shown on Exhibit No. 14. As shown there, once adjusted to mid-year, reference to the expected earnings approach implies an average cost of equity for my proxy group of utilities of 11.8%, while the expected annual average cost of equity for Dr. Woolridge's group and Mr. Baudino's group is 11.9%. These book return estimates are an "apples to apples" comparison to the 8.60% and 8.85% ROE recommendations of the ROE Witnesses.

Q20. PLEASE EXPLAIN THE RATIONALE FOR THE ADJUSTMENT TO CONVERT YEAR-END RETURNS TO AVERAGE RETURNS WHEN APPLYING THIS METHOD.

A20. The adjustment factor incorporated in my evaluation of expected returns is required because Value Line's reported returns are based on end-of-year book values. Since earnings are a flow over the year while book value is determined at

[17] Baudino Direct at 13.
[18] *Id.* at 14.

a given point in time, the measurement of earnings and book value are distinct concepts. It is this fundamental difference between a flow (earnings) and point estimate (book value) that makes it necessary to adjust to mid-year in calculating the ROE. Given that book value will increase or decrease over the year, using year-end book value (as Value Line does) understates or overstates the average investment that corresponds to the flow of earnings. To address this concern, earnings must be matched with a corresponding representative measure of book value, or the resulting ROE will be distorted.

The need for this adjustment has been recognized in the financial literature.[19] Similarly, FERC has also cited the necessity to adjust year-end data from Value Line to reflect average values when computing earned rates of return.[20] In its June 2014 decision establishing new policies regarding ROE and confirmed in its most recent opinion in September 2016, FERC relied directly on the expected earnings approach, which incorporates the exact same adjustment formula used in my Direct Testimony in this proceeding.[21] Similarly, the Virginia State Corporation Commission has determined that it is appropriate to rely on average book equity, rather than year-end equity, when evaluating earned rates of return.[22]

Q21. WHAT OTHER EVIDENCE INDICATES THAT THE RECOMMENDATIONS OF THE ROE WITNESSES FAIL TO MEET REGULATORY STANDARDS?

A21. As discussed in my Direct Testimony, required equity returns for firms in the competitive sector of the economy are also relevant in determining the

[19] Roger A. Morin, "New Regulatory Finance," *Public Utilities Reports, Inc.* (2006) at 305-06.
[20] *Bangor Hydro-Elec. Co.*, 122 FERC ¶ 61,265 (2008).
[21] Opinion No. 531, 147 FERC ¶ 61,234 at P 146 (2014) and Opinion No. 551, 156 FERC ¶ 61,234 at P 239 (2016).
[22] *See, e.g., Case No. PUE-2014-00026,* Final Order at n. 84 (2014).

appropriate return to be allowed for rate-setting purposes.[23] The idea that investors evaluate utilities against the returns available from other investment alternatives – including the low-risk companies in my Non-Utility Group – is a fundamental cornerstone of modern financial theory. Aside from this theoretical underpinning, any casual observer of stock market commentary and the investment media quickly comes to the realization that investors' choices are almost limitless. It follows that utilities must offer a return that can compete with other risk-comparable alternatives, or capital will simply go elsewhere.

In fact, returns in the competitive sector of the economy form the very underpinning for utility ROEs because regulation purports to serve as a substitute for the actions of competitive markets. The Supreme Court has recognized that the degree of risk, not the nature of the business, is relevant in evaluating an allowed ROE for a utility.[24] The cost of capital is based on the returns that investors could realize by putting their money in other alternatives, and the total capital invested in utility stocks is only the tip of the iceberg of total common stock investment.

Q22. DID THE ROE WITNESSES PRESENT ANY OBJECTIVE EVIDENCE THAT WOULD SUPPORT A FINDING THAT YOUR NON-UTILITY PROXY GROUP IS RISKIER THAN THE COMPANIES IN HIS PROXY GROUP?

A22. No. Mr. Baudino, for instance, simply alluded to a general assertion that companies in the non-utility proxy group "face risks that a lower risk electric company like KPC does not face."[25] But my Direct Testimony did not contend that the specific operations or risk consideration of the companies in the Non-

[23] McKenzie Direct at 73-77.
[24] *Fed. Power Comm'n v. Hope Natural Gas Co.*, 320 U.S. 591 (1944).
[25] Baudino Direct at 43.

Utility Group are the same as those for utilities. Clearly, operating a worldwide enterprise in the beverage, pharmaceutical, retail, or food industry involves unique circumstances that are as distinct from one another as they are from an electric utility.

But as the Supreme Court recognized, investors consider the expected returns available from all these opportunities in evaluating where to commit their scarce capital. The simple observation that a firm operates in non-utility businesses says nothing at all about the overall investment risks perceived by investors, which is the very basis for a fair rate of return. So long as the risks associated with the Non-Utility Group are comparable to the Company and other utilities the resulting DCF estimates provide a meaningful benchmark for the cost of equity. As demonstrated in my Direct Testimony, a comparison of objective risk measures demonstrates conclusively that the Non-Utility Group is regarded as less risky than Kentucky Power, making it a conservative benchmark for a fair ROE in this case.[26]

Q23. DR. WOOLRIDGE SAYS THAT ONE REASON YOUR NON-UTILITY ANALYSIS IS FLAWED IS THAT SUCH COMPANIES "DO NOT OPERATE IN A HIGHLY REGULATED ENVIRONMENT."[27] DOES THE FACT THAT UTILITIES ARE REGULATED SOMEHOW INVALIDATE THIS COMPARISON OF OBJECTIVE RISK INDICATORS?

A23. Absolutely not. While I agree that utilities operate under a regulatory regime that differs from firms in the competitive sector, any risk-reducing benefit of regulation is already incorporated in the overall indicators of investment risk presented in Table 7 to my Direct Testimony. The impact of regulation on a

---

[26] McKenzie Direct, Table 7, at 75.
[27] Woolridge Direct at 83.

utility's investment risks is one of the key elements considered by credit rating agencies and investment advisory services, such as Moody's, S&P Global ("S&P"), and Value Line, when establishing corporate credit ratings and other risk measures. As a result, the impact of regulatory protections is already reflected in my risk analysis. Meanwhile, the beta values supported by modern financial theory are premised on stock price volatility relative to the market as a whole, and are not dependent on an assessment of firm-specific considerations. As a result, the impact of regulatory differences on investment risk is accounted for in the published risk indicators relied on by investors and cited in my Direct Testimony.

Q24. WHAT WERE THE RESULTS OF YOUR ROE ANALYSIS FOR THE NON-UTILITY GROUP?

A24. As shown in Exhibit No. 11, page 3, the average ROEs for the Non-Utility group ranged from 10.4% to 10.8%. The midpoint of this range is 10.6%.

Q25. BASED ON YOUR COMPARISON OF THE ROE WITNESSES' RECOMMENDATIONS WITH ACCEPTED BENCHMARKS AND, IN LIGHT OF THE PROSPECT FOR HIGHER INTEREST RATES, WHAT DO YOU CONCLUDE?

A25. Based on these comparisons, the 8.60% and 8.85% ROE recommendations of Dr. Woolridge and Mr. Baudino, respectively, are below any reasonable outcomes. One fundamental standard underlying the regulation of public utilities, as set forth by the Supreme Court's *Bluefield* and *Hope* decisions, requires that the Company must have the opportunity to earn an ROE comparable to contemporaneous returns available from alternative investments of similar risk if it is to maintain its financial flexibility and ability to attract capital. The recommendations of the ROE Witnesses do not provide such an opportunity.

If the utility is unable to offer a return similar to the returns available from other opportunities of comparable risk, investors will become unwilling to supply capital to the utility on reasonable terms. For existing investors, denying the utility an opportunity to earn what is available from other similar risk alternatives prevents them from earning their cost of capital. Both of these outcomes, which would be the result produced by the ROE Witnesses' recommendations, violate regulatory standards.

Q26. WHAT OTHER PITFALLS ARE ASSOCIATED WITH AN ROE THAT FALLS BELOW THOSE AUTHORIZED FOR OTHER COMPARABLE COMPANIES?

A26. Adopting an ROE for the Company that is well below the ROEs for comparable utilities could lead investors to view the Commission's regulatory framework as unsupportive, an outcome that would undermine investors' willingness to support future capital availability for investment in Kentucky. Security analysts study regulatory orders in order to advise investors where to invest their money. Moody's Investors Service ("Moody's) noted that, "[f]undamentally, the regulatory environment is the most important driver of our outlook."[28] Similarly, S&P concluded that "[t]he regulatory framework/regime's influence is of critical importance when assessing regulated utilities' credit risk because it defines the environment in which a utility operates and has a significant bearing on a utility's financial performance."[29] Value Line summarizes these sentiments:

> As we often point out, the most important factor in any utility's success, whether it provides electricity, gas, or water, is the regulatory climate in which it operates. Harsh regulatory

[28] Moody's Investors Service, "Regulation Will Keep Cash Flow Stable As Major Tax Break Ends," *Industry Outlook* (Feb. 19, 2014).
[29] Standard & Poor's Corporation, "Key Credit Factors For The Regulated Utilities Industry," *RatingsDirect* (Nov. 19, 2013).

> conditions can make it nearly impossible for the best run utilities to earn a reasonable return on their investment.[30]

Utilities and their investors must lock up large sums of capital and are exposed to many risks over the long time horizon when they invest in utility infrastructure. At the levels proposed by the ROE Witnesses, the ability of Kentucky utilities to attract and retain capital would be compromised. This would have a long-term, chilling effect on investors' willingness to support capital investment in utility infrastructure, not just for the Company, but for all utilities in the state. On the other hand, if Commission actions instill confidence that the regulatory environment is supportive, investors will provide the necessary capital, which ultimately benefits customers and the service area economy.

II. RESPONSE TO DR. WOOLRIDGE

Q27. WHAT IS THE PURPOSE OF THIS SECTION OF YOUR REBUTTAL TESTIMONY?

A27. My purpose here is to address Dr. Woolridge's mischaracterization of financial market conditions and the failings of his evaluation of a fair ROE for the Company.

A. Capital Market Conditions

Q28. WHAT ARE DR. WOOLRIDGE'S VIEWS REGARDING CURRENT CAPITAL MARKET CONDITIONS?

A28. Dr. Woolridge summarizes his review of current capital market conditions by concluding that "interest rates and capital costs are at low levels and are likely to remain low for some time."[31] He then adds, "[o]n this issue, I show that

[30] Value Line Investment Survey, *Water Utility Industry*, January 13, 2017, p. 1780.
[31] Woolridge Direct at 5.

economists' forecasts of higher interest rates and capital costs, which are used by Mr. McKenzie, have been consistently wrong for a decade."[32]

Q29. HAVE RECENT DECISIONS BY THE FEDERAL RESERVE REINFORCED INVESTOR SENTIMENT THAT INTEREST RATES WILL TREND HIGHER?

A29. Yes. On June 14, 2017 the Federal Reserve increased the target range for the Federal Funds rate by another 25 basis points to 1.00% to 1.25%. This is in addition to similar increases in March 2017, December 2016, and December 2015. More rate hikes by the Federal Reserve are anticipated.

Q30. ARE INTEREST RATE FORECASTERS STILL PROJECTING HIGHER LONG-TERM RATES FOR COMPANIES LIKE KENTUCKY POWER?

A30. Yes. As illustrated in Figure R-2 above, investors continue to anticipate that interest rates will increase significantly from present levels.

Q31. DR. WOOLRIDGE SUGGESTS THAT INTEREST RATE FORECASTS SHOULD BE IGNORED BY THE COMMISSION BECAUSE FORECASTS HAVE BEEN WRONG IN THE PAST. DO YOU AGREE?

A31. Absolutely not. In estimating investors' required rate of return, what investors expect, not what actually happens, is what matters most. Any difference in actual rates as compared to analysts' forecasts is beside the point. What is most important is that investors share analysts' views when the forecasts were made and incorporate those views into their decision making process, not the actual rates that ultimately transpire.

Q32. DR. WOOLRIDGE DISCUSSES THE MARKET-TO-BOOK RATIO AND REACHES SEVERAL BOLD CONCLUSIONS IN THIS AREA. ARE HIS CONCLUSIONS REALISTIC?

---

[32] *Id.*

A32. No. He says that a historical market-to-book ratio greater than one for the utility industry means that "for at least the last decade, returns on common equity have been greater than the cost of capital"[33] and "customers have been paying more than necessary to support an appropriate profit level for regulated utilities."[34]

Dr. Woolridge wants the Commission to sacrifice the Company's financial strength to favor a theoretical ideal of M/B equaling unity. The Commission does not purport to regulate utility stock market prices as Dr. Woolridge urges. Further, and as discussed below, there are many leaps between his economic theory and reality. But if the theory is correct, then Dr. Woolridge is asking the Commission to order an ROE that would almost certainly lead to a capital loss on shareholders' investment in the Company. From an economic perspective, such an action would violate the standards underlying a fair ROE.

Q33. IS THERE A CLEAR LINK BETWEEN M/B FOR UTILITIES AND ALLOWED RATES OF RETURN?

A33. No. Underlying Dr. Woolridge's conclusions is the supposition that regulators should set an ROE to produce a M/B of approximately 1.0. This is fallacious. For example, Regulatory Finance: Utilities Cost of Capital noted that:

> The stock price is set by the market, not by regulators. The market-to-book ratio is the end result of regulation, and not its starting point. The view that regulation should set an allowed rate of return so as to produce a market-to-book of 1.0, presumes that investors are irrational. They commit capital to a utility with a market-to-book in excess of 1.0, knowing full well that they will be inflicted a capital loss by regulators. This is certainly not a realistic or accurate view of regulation.[35]

With M/B for most utilities above 1.0, Dr. Woolridge is suggesting that, unless book value grows rapidly, regulators should establish equity returns that will

---

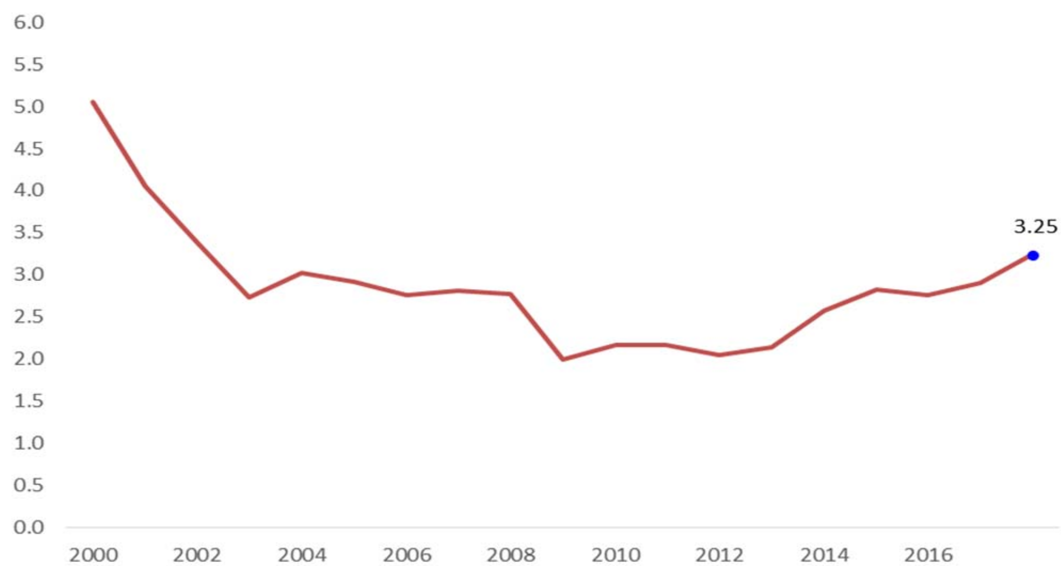
[33] *Id.* at 30.
[34] *Id.*
[35] Roger A. Morin, "New Regulatory Finance," *Public Utilities Reports, Inc.* (2006) at 376.

cause share prices to fall. Given the regulatory imperative of preserving a utility's ability to attract capital, this would be a truly nonsensical result. The M/B is determined by investors in the stock market, and a utility would be foreclosed from attracting capital if regulators were to push market-to-book to 1.0 while other firms command prices well in excess of 1.0 times book value.

Q34. IS THERE ANYTHING UNUSUAL ABOUT A STOCK PRICE EXCEEDING BOOK VALUE?

A34. No. In fact the majority of stocks currently sell substantially above book value. For example, Value Line reports that approximately 1,450 of the roughly 1,700 stocks it follows (including utilities and other industries) sell for prices in excess of book value.[36] In the figure below, I provide the average historical market price-to-book value ratios for the companies in the S&P 500 Composite Index.

FIGURE R-3
S&P 500 PRICE TO BOOK VALUE



Current S&P 500 Price To Book Value: 3.25
Mean: 2.76
Median: 2.74
Min: 1.78 (Mar. 2009)
Max: 5.06 (Mar. 2000)

[36] www.valueline.com (retrieved Oct. 10, 2017).

Current Price To Book Ratio Is Estimated Based On Current Market Price And S&P 500 Book Value As Of March 2017, The Latest Reported By S&P.

Source: Standard & Poor's, www.multpl.com/s-p-500-price-to-book (retrieved Oct. 10, 2017).

For the 500 largest publicly-traded companies in the U.S. economy, stock market prices have averaged almost three times book value. The lowest value occurred at the market bottom in early 2009 during the "great recession," at 1.78 times.

The table below provides a listing of recent market-to-book ratios by industry.

TABLE R-1
MARKET-TO-BOOK RATIO BY SECTOR

Sector	Ratio
Financial	1.67
Energy	1.71
Utilities	1.89
Consumer Discretionary	2.69
Basic Materials	3.04
Conglomerates	3.41
Services	3.77
Healthcare	4.07
Transportation	4.76
Consumer Non-cyclical	5.05
Technology	5.07
Capital Goods	5.35
Retail	6.64

Source: https://csimarket.com/screening/index1.php?s=pb (retrieved Oct. 10, 2017).

The market-to-book ratio for the utilities sector of 1.89 is among the lowest of the industry groups, and it is well below the 2.76 times historical average for the S&P 500. The consistently higher market-to-book relationship for unregulated companies shows that Dr. Woolridge's theoretical 1.0 benchmark is misplaced and that his claims about excessive utility earnings based on this benchmark are incorrect.

Q35. ARE THERE OTHER IMPORTANT FACTORS BEYOND ROE THAT EXPLAIN M/B FOR UTILITIES ABOVE 1.0?

A35. Yes. Although Dr. Woolridge's comparison would make it appear that utility ROEs are the cause for M/B greater than one, this contention entirely ignores accounting issues and other considerations. Consider, for example, the merger and acquisition activity that has significantly affected utility stock market prices in recent years. Investors know that many acquisitions have occurred and that significant premiums and large capital gains have been associated with those transactions. While earnings expectations are a part of market pricing, Dr.

Woolridge's contention about direct causation between ROEs and market-to-book ratios is an extremely narrow view.

Q36. ARE ADJUSTMENTS BASED ON M/B A COMMON FEATURE IN DETERMINING ALLOWED ROES FOR UTILITIES?

A36. No. While arguments regarding the implications of a market-to-book greater than 1.0 are not uncommon, I am not aware of a single instance in recent history where a state regulator has approved a market-to-book adjustment in establishing a fair ROE. Meanwhile, FERC has explicitly recognized the fallacy of relying on market-to-book in evaluating cost of equity estimates. For example, the Presiding Judge in *Orange & Rockland* concluded, and the FERC affirmed that:

> The presumption that a market-to-book ratio greater than 1.0 will destroy the efficacy of the DCF formula disregards the realities of the market place principally because the market-to-book ratio is rarely equal to 1.0.[37]

The Initial Decision found that there was no support in FERC precedent for the use of market-to-book to adjust market derived cost of equity estimates based on the DCF model and concluded that such arguments were to be treated as "academic rhetoric" unworthy of consideration. Similarly, FERC rejected similar arguments from Dr. Woolridge more recently, concluding that "If, all else being equal, the regulator sets a utility's ROE so that the utility does not have the opportunity to earn a return on its book value comparable to the amount that investors expect that other utilities of comparable risk will earn on their book equity, the utility will not be able to provide investors the return they require to invest in that utility."[38]

Q37. IS DR. WOOLRIDGE'S M/B DISCUSSION RELEVANT TO THE SETTING OF THE COMPANY'S ROE IN THIS CASE?

---

[37] *Orange & Rockland Utilities, Inc.*, Initial Decision, 40 FERC ¶ 63,053, 1987 WL 118,352 (F.E.R.C.).
[38] *Martha Coakely, et al.,* Opinion No. 531-B, 150 FERC ¶ 61,165 at P 129 (2015).

A37. No. Even in the unlikely event that the long trail of breadcrumbs between Dr. Woolridge's theoretical postulations on M/B and allowed returns remained unbroken, his conclusion is directed at the wrong hypothesis. The question before the Commission is not what ROE will produce a M/B of 1.0 for utilities; rather, the question is what ROE will allow Kentucky Power to maintain access to capital and grant stockholders the opportunity to earn a fair return on investment vis-à-vis alternatives of comparable risk.

B. Discounted Cash Flow Model

Q38. WHAT ARE THE FUNDAMENTAL PROBLEMS WITH THE DCF ANALYSES CONDUCTED BY DR. WOOLRIDGE (AT 33-48)?

A38. There are numerous problems with the DCF analyses presented by Dr. Woolridge that lead to biased end results:

- One of the proxy groups relied on by Dr. Woolridge is defective due to flaws in the screening criteria and data he used, causing the exclusion of comparable utilities.
- Reliance on dividend growth rates and historical growth measures do not reflect a meaningful guide to investors' expectations.
- Dr. Woolridge discounts reliance on analysts' earnings per share ("EPS") growth forecasts as somehow biased, and fails to sufficiently recognize that it is investors' *perceptions and expectations* that must be considered in applying the DCF model.
- Because Dr. Woolridge failed to test the reasonableness of model inputs, he incorrectly includes data that results in illogical cost of equity estimates.
- Dr. Woolridge's internal growth ("br") rates are downward biased because of computational errors and omissions.
- Rather than looking to the capital markets for guidance as to investors' forward-looking expectations, Dr. Woolridge applies the DCF model based on his own personal views.

As a result of these flaws and omissions, the resulting DCF cost of equity estimates are erroneously downward biased and fail to reflect investors' required rate of return.

Q39. DR. WOOLRIDGE APPLIED HIS ROE ANALYSES TO TWO GROUPS OF ELECTRIC UTILITIES, YOURS AND ONE BASED ON A DIFFERENT SET OF SELECTION CRITERIA. ARE THERE FLAWS IN HIS ELECTRIC PROXY GROUP?

A39. Yes. One of the selection criteria relied on by Dr. Woolridge required that at least 50% of the utility's revenues must come from regulated electric operations as reported by AUS Utility Report ("AUS").[39] There are several problems with this approach.

Q40. DO YOU AGREE WITH DR. WOOLRIDGE THAT THE NATURE OF A UTILITY'S REVENUES IS A VALID CRITERION IN SELECTING A PROXY GROUP FOR THE COMPANY?

A40. No. Dr. Woolridge failed to demonstrate how his subjective 50% revenue criterion translates into differences in the investment risks perceived by investors, while comparisons of objective indicators demonstrate that investment risks for the firms in my proxy groups are relatively homogeneous and comparable to the Company.

Q41. DID DR. WOOLRIDGE DEMONSTRATE ANY NEXUS BETWEEN A SUBJECTIVE CRITERION BASED ON REGULATED REVENUES AND OBJECTIVE MEASURES OF INVESTMENT RISK?

A41. No. Under the regulatory standards established by *Hope* and *Bluefield*, the salient criterion in establishing a meaningful proxy group to estimate investors' required

[39] Woolridge Direct at 23. While Dr. Woolridge testimony references AUS, this report is no longer in publication, with the last monthly edition dated September 2016. It appears that Dr. Woolridge actually relied on information from the 2016 Form 10-K reports for the companies in his proxy groups. *See* "Electric_Utilities_-_Regulated_Revenue_-_2016_10-k.xlsx."

return is relative risk, not the source of the revenue stream or the nature of the asset base. Dr. Woolridge presented no evidence to demonstrate a connection between the subjective revenue criterion that he employed and the views of real-world investors in the capital markets. Nor did Dr. Woolridge provide any evidentiary support for his 50% threshold. Dr. Woolridge's testimony offers no explanation why a revenue cut-off of 50%, rather than, say, 40% or 60%, supposedly impacts a utility's operations sufficiently to justify its exclusion.

Moreover, due to differences in business segment definition and reporting between utilities, it is often impossible to accurately apportion financial measures, such as revenues and total assets, between regulated and non-regulated sources. As a result, even if one were to ignore the fact that there is no clear link between the nature of a utility's revenues or assets and investors' risk perceptions, it is generally not possible to accurately and consistently apply asset or revenue-based criteria. In fact, other regulators have rebuffed these notions, with FERC specifically rejecting arguments that utilities "should be excluded from the proxy group given the risk factors associated with its unregulated, non-utility business operations."[40]

Q42. CAN YOU ILLUSTRATE HOW A SCREEN BASED ON REVENUE COMPOSITION CAN LEAD TO AN ERRONEOUS CONCLUSION?

A42. Yes. Consider Public Service Enterprise Group, Sempra, and Vectren, which Dr. Woolridge omitted because regulated electric revenues were less than 50% of total revenue. However, after further inspection of their revenue composition, a different story is revealed. On page 1 of Exhibit JRW-4, Dr. Woolridge lists not only the level of regulated electric revenue, but also the level of regulated gas revenue. Gas distribution operations are regulated by the states in the same

[40] *Bangor Hydro-Elec. Co.*, 117 FERC ¶ 61,129 at PP 19, 26 (2006).

manner as electric operations, and there is no basis to distinguish between revenues from electric and gas utility operations. When gas revenues are combined with electric revenues, these companies all have regulated revenues that exceed the artificial, 50% threshold.[41]

Q43. DR. WOOLRIDGE ALSO EXCLUDED AVANGRID, ANOTHER COMPANY THAT IS IN YOUR GROUP. IS THERE A LOGICAL BASIS TO EXCLUDE AVANGRID?

A43. No. AVANGRID meets all of Dr. Woolridge's criteria: it is followed by Value Line, it has investment grade bond ratings, it has not cut or omitted any recent dividends, and long-term analyst growth forecasts are available.[42] Moreover, data from in AVANGRID's most recent SEC Form 10-K indicate that regulated operations contributed approximately 84% of total revenues.[43] For these reasons, AVANGRID should properly be included in the proxy group in this case.

Q44. DR. WOOLRIDGE NOTED THAT HE EXCLUDED EMERA INC. ("EMERA") AND FORTIS INC. ("FORTIS") FROM HIS PROXY GROUP BECAUSE THEY ARE BASED IN CANADA.[44] DOES THIS OBSERVATION SUPPORT HIS ELIMINATION OF THESE FIRMS?

A44. No. Other than his simple factual observation, Dr. Woolridge provided no evidence or explanation as to why investors would not regard Emera and Fortis to be comparable opportunities to the other utilities included in his proxy group. Like the other companies included by Dr. Woolridge, Emera is primarily engaged in electricity generation, transmission, and distribution; gas transmission and

[41] From Exhibit JRW-4, page 1, the combined electric and gas revenue percentages are 78% for Sempra, 70% for Public Service Enterprise Group, and 56% for Vectren.
[42] While AVANGRID is not included in the AUS report cited in Dr. Woolridge's testimony, this is more likely to be a function of the cancellation of the publication and the resultant staleness of the data.
[43] AVANGRID reports regulated revenues of $5,030 million, out of total revenues of $6,018 million.
[44] Woolridge Direct at footnote 18.

distribution; and utility energy services, and serves approximately 2.4 million customers. As Value Line reported:

> With the addition of TECO's Florida and New Mexico operations, more than 75 percent of earnings are now generated from rate regulated businesses.[45]

Emera noted that, "With our Florida and New Mexico businesses integrated, more than 90 percent of Emera's earnings now come from our regulated businesses, surpassing our target of 75-85 percent," and that approximately 70% of future adjusted net income will be generated from its US subsidiaries.[46] Similarly, CRFA highlighted Emera's primary focus on electric utility operations, and classified Emera in its "Electric Utilities" industry group.[47] Thus, investors would regard Emera as a comparable investment alternative that is relevant to an evaluation of the required rate of return for Kentucky Power.

Similarly, like the other companies included in Dr. Woolridge's proxy group, Value Line observed that Fortis' "main focus is electricity, hydroelectric, and gas utility operations."[48] With $48 billion in assets, Fortis is one of the leading utility companies in North America, which include the Arizona operations of UNS Energy (including Tucson Electric Power), the New York operations of Central Hudson Gas & Electric, and ITC Holdings, which is the largest independent electricity transmission company in the U.S. There is no support for Dr. Woolridge's exclusion of Emera and Fortis simply because they are headquartered in Canada, and his position on this issue should be ignored.[49]

---

[45] The Value Line Investment Survey (June 23, 2017) at 1218.
[46] Emera, Inc., 2016 Annual Report at 2, 19. In addition to its Florida and New Mexico utility operations, Emera also owns Bangor Hydro-Electric Company, which provides electric utility service in New England.
[47] CRFA, "Emera Incorporated," *Quantitative Stock Report* (June 24, 2017). CRFA, one of the world's largest providers of institutional-grade independent equity research, acquired the equity and fund research arm of S&P in October 2016.
[48] The Value Line Investment Survey (Sep. 15, 2017).
[49] Moreover, Dr. Woolridge is selective on the issue of involvement in foreign operations. His proxy group includes PPL Corporation, which serves 7.8 million electric customers in the United Kingdom.

Q45. DO YOU BELIEVE THAT HISTORICAL TRENDS IN DIVIDENDS PER SHARE ("DPS") PROVIDE A MEANINGFUL GUIDE TO INVESTORS' EXPECTATIONS?

A45. No. As discussed at length in my direct testimony, it is investors' future expectations – and not actual, historical results – that determine the current price they are willing to pay for commons stocks. If past trends in DPS are to be representative of investors' expectations for the future, then the historical conditions giving rise to these growth rates should be expected to continue. That is clearly not the case for utilities, which have experienced declining dividend payouts, earnings pressure, and, in many cases, significant write-offs.

Dr. Woolridge noted the pitfalls associated with historical growth measures. As he correctly observed:

> [T]o best estimate the cost of common equity capital using the conventional DCF model, one must look to long-term growth rate expectations.[50]

As he acknowledged, historical growth rates can differ significantly from the forward-looking growth rate required by the DCF model:

> However, one must use historical growth numbers as measures of investors' expectations with caution. In some cases, past growth may not reflect future growth potential. Also, employing a single growth rate number (for example, for five or ten years), is unlikely to accurately measure investors' expectations due to the sensitivity of a single growth rate figure to fluctuations in individual firm performance as well as overall economic fluctuations (i.e., business cycles).[51]

While past conditions for utilities serve to depress historical DPS growth rates, they are not representative of long-term expectations for the electric utility industry. Moreover, to the extent historical trends for electric utilities are

---

[50] Woolridge Direct at 40.
[51] *Id.*

meaningful, they are also captured in projected growth rates, such as those published by Value Line and Zacks Investment Research ("Zacks"), since securities analysts also routinely examine and assess the impact and continued relevance (if any) of historical trends. Similarly, the Regulatory Commission of Alaska ("RCA") has previously determined that analysts' EPS growth rates provide a superior basis on which to estimate investors' expectations:

> We also find persuasive the testimony . . . that projected EPS returns are more indicative of investor expectations of dividend growth than historical growth data because persons making the forecasts already consider the historical numbers in their analyses.[52]

The RCA has concluded that arguments against exclusive reliance on analysts' EPS growth rates to apply the DCF model "are not convincing."[53] This is consistent with the Commission's conclusions cited in my direct testimony, which noted that, "analysts' projections of growth will be relatively more compelling in forming investors' forward-looking expectations than relying on historical performance, especially given the current state of the economy."[54]

Q46. DR. WOOLRIDGE ARGUES (AT 39) THAT THE GROWTH RATE COMPONENT IN THE DCF MODEL REFLECTS "THE LONG-TERM DIVIDEND GROWTH RATE." DO YOU AGREE THAT THIS IS WHAT INVESTORS ARE MOST LIKELY TO CONSIDER IN DEVELOPING THEIR LONG-TERM GROWTH EXPECTATIONS?

A46. No. Again, implementation of the DCF model is solely concerned with replicating the forward-looking evaluation of real-world investors. In the case of utilities, growth rates in DPS are not likely to provide a meaningful guide to investors' current growth expectations.

---

[52] Regulatory Commission of Alaska, U-07-76(8) at 65, n. 258.
[53] Regulatory Commission of Alaska, U-08-157(10) at 36.
[54] *Kentucky Utilities Co.*, Case No. 2009-00548 (Ky PSC Jul. 30, 2010) at 30-31.

Q47. WHAT ARE INVESTORS MOST LIKELY TO CONSIDER IN DEVELOPING THEIR LONG-TERM GROWTH EXPECTATIONS?

A47. As documented in my direct testimony, future trends in EPS, which provide the source for future dividends and ultimately support share prices, play a pivotal role in determining investors' long-term growth expectations. The continued success of investment services such as IBES,[55] Value Line, and Zacks, and the fact that projected growth rates from such sources are widely referenced, provides strong evidence that investors give considerable weight to analysts' earnings projections in forming their expectations for future growth. The importance of earnings in evaluating investors' expectations and requirements is well accepted in the investment community, and surveys of analytical techniques relied on by professional analysts indicate that growth in EPS is far more influential than trends in DPS. As explained in *New Regulatory Finance*:

> Because of the dominance of institutional investors and their influence on individual investors, analysts' forecasts of long-run growth rates provide a sound basis for estimating required returns. Financial analysts exert a strong influence on the expectations of many investors who do not possess the resources to make their own forecasts, that is, they are a cause of *g* [growth].[56]

The availability of projected EPS growth rates also is key to investors relying upon this measure as compared to future trends in DPS. Apart from Value Line, investment advisory services do not generally publish comprehensive DPS growth projections, and this scarcity of dividend growth rates relative to the abundance of EPS forecasts attests to their relative influence. The fact that analyst EPS growth estimates are routinely referenced in the financial media and

---

[55] Formerly I/B/E/S International, Inc., IBES growth rates are now compiled and published by Thomson Reuters.

[56] Roger A. Morin, "New Regulatory Finance," *Public Utilities Reports, Inc.* (2006) at 298.

in investment advisory publications implies that investors use them as a primary basis for their expectations. As observed in *New Regulatory Finance*:

> The sheer volume of earnings forecasts available from the investment community relative to the scarcity of dividend forecasts attests to their importance. The fact that these investment information providers focus on growth in earnings rather than growth in dividends indicates that the investment community regards earnings growth as a superior indicator of future long-term growth. Surveys of analytical techniques actually used by analysts reveal the dominance of earnings and conclude that earnings are considered far more important than dividends.[57]

While I did not rely solely on EPS projections in applying the DCF model,[58] my evaluation clearly supports greater reliance on EPS growth rate projections than other alternatives. Similarly, my Direct Testimony documented the Commission's preference for relying on analysts' growth forecasts, which is supported by the findings of other regulatory agencies.[59]

Q48. IS DR. WOOLRIDGE CONSISTENT IN HIS INSISTENCE THAT HISTORICAL GROWTH RATES AND TRENDS IN DPS MUST BE CONSIDERED IN APPLYING THE DCF MODEL?

A48. No. In testimony before FERC, Dr. Woolridge has applied the DCF model without any reference to historical trends or growth rates in DPS.[60] In the present case, despite his indictment of analysts' EPS growth projections, this data largely serves as the basis for his own DCF analysis. When selecting the final growth rates for both proxy groups referenced in his testimony, Dr. Woolridge gives "primary weight" to the projected EPS growth rates of Wall Street analysts.[61] So, while Dr. Woolridge complains vociferously about the suitability of analysts' EPS

---

[57] Roger A. Morin, "New Regulatory Finance," *Public Utilities Reports, Inc.* (2006) at 302-303.
[58] As discussed in my direct testimony, I also examined the "br+sv", sustainable growth rates for the companies in my proxy groups.
[59] McKenzie Direct at 38.
[60] *See, e.g.*, *Testimony of J. Randall Woolridge*, Docket No. EL11-66-000, Exhibit SC-100.
[61] Woolridge Direct at 46.

growth projections, he relies primarily on these same projections in reaching his ultimate DCF conclusions. His criticisms of the use of analysts' EPS growth projections ring hollow and are without merit in this light.

Q49. DOES MR. BAUDINO ACKNOWLEDGE THE SUPERIORITY OF FORECASTED DATA, AS OPPOSED TO HISTORICAL DATA, IN THE DCF PROCESS?

A49. Yes. Mr. Baudino concurs that analysts' forecasts are superior:

> Return on equity analysis is a forward-looking process. Five-year or ten-year historical growth rates may not accurately represent investor expectations for dividend growth. Analysts' forecasts for earnings and dividend growth provide better proxies for the expected growth component in the DCF model than historical growth rates. Analysts' forecasts are also widely available to investors and one can reasonably assume that they influence investor expectations.[62]

Q50. IS THE DOWNWARD BIAS IN DR. WOOLRIDGE'S HISTORICAL GROWTH MEASURES SELF EVIDENT?

A50. Yes, it is. As shown on page 3 of Exhibit JRW-10, thirty three of the historical growth rates reported by Dr. Woolridge for his electric proxy companies were 2.0% or less, including sixteen negative values.[63] A negative growth rate implies a cost of equity that falls below the utility's dividend yield which makes no economic sense, since investors could earn higher returns on less-risky utility bonds. These outcomes illustrate the fact that Dr. Woolridge's historical growth measures provide no meaningful information regarding the expectations and requirements of investors.

---

[62] Baudino Direct at 21.

[63] For the McKenzie Proxy Group shown on page 3 of Exhibit JRW-10, fourteen of the historical growth rates reported by Dr. Woolridge were 2.0% or less, including seven negative values.

Q51. DID DR. WOOLRIDGE ALSO INCLUDE LOW AND NEGATIVE GROWTH RATES IN HIS EXAMINATION OF PROJECTED GROWTH RATES?

A51. Yes, as shown on page 4 of Exhibit JRW-10, he included five growth rates at 1.5% or less in his analysis of Value Line projected growth rates for his electric proxy group.[64] Because these growth rates imply cost of equity estimates that are not materially higher than the yields on less risky utility bonds, they are not meaningful and should be excluded from his DCF analysis. On page 5 of Exhibit JRW-10, Dr. Woolridge includes two companies (Entergy Corporation and FirstEnergy Corporation) that have negative analyst projected growth rate estimates.

Q52. DID DR. WOOLRIDGE MAKE ANY EFFORT TO TEST THE REASONABLENESS OF THE INDIVIDUAL GROWTH ESTIMATES HE RELIED ON TO APPLY THE CONSTANT GROWTH DCF MODEL?

A52. No. Despite recognizing that caution is warranted in using historical growth rates, Dr. Woolridge simply calculated the average and median of the individual growth rates with no consideration for the reasonableness of the underlying data. In fact, as indicated above, many of the cost of equity estimates implied by Dr. Woolridge's DCF application are illogical, given the risk-return tradeoff that is fundamental to finance. The table below highlights some of the individual company results that are incorporated into Dr. Woolridge's DCF analysis.

---

[64] For the McKenzie Proxy Group shown on page 4 of Exhibit JRW-10, two of the projected growth rates reported by Dr. Woolridge were 1.5% or less.

TABLE R-2
SAMPLE WOOLRIDGE COST OF EQUITY ESTIMATES

Company	Dividend Yield	Growth	DCF ROE
Entergy Corp.	4.5%	-4.3%	0.2%
First Energy Corp.	4.7%	-2.9%	1.8%
MGE Energy, Inc.	2.0%	4.0%	6.0%
PPL Corporation	4.1%	2.5%	6.5%

Source: Exhibit JRW-10, pages 2 (90 Day Dividend Yield) and 5 (Mean Growth). DCF ROE is sum of dividend yield and growth.

With current triple-B utility interest rates in the 4.4% range, the above results are not reasonable ROE outcomes. And as indicated in my direct testimony[65] and illustrated in Figure R-2 above, it is generally expected that long-term interest rates will rise as the Federal Reserve normalizes its monetary policies. As shown in the table below, the increase in debt yields anticipated by IHS Global Insight and the Energy Information Administration imply an average triple-B bond yield of approximately 6.22% over the period 2018-2022.

[65] McKenzie Direct at 16-23.

TABLE R-3
BOND YIELD FORECAST

	Baa Yield 2018-22
Projected Aa Utility Yield	
IHS Global Insight (a)	5.79%
EIA (b)	5.56%
Average	5.67%
Current Baa - Aa Yield Spread (c)	0.55%
Implied Baa Utility Yield	**6.22%**

(a) IHS Global Insight (Aug. 24, 2017).
(b) Energy Information Administration, Annual Energy Outlook 2017 (Jan. 5, 2017)
(c) Based on monthly average bond yields from Moody's Investors Service for the six-month period Apr. - Sep. 2017.

Equity returns close to, or less than, this threshold are not credible. Yet, Dr. Woolridge factors them into his final conclusions, which biases his results downward.

Q53. WHAT APPROACH SHOULD DR. WOOLRIDGE HAVE USED TO EVALUATE LOW-END DCF ESTIMATES?

A53. It is a basic economic principle that investors can be induced to hold more risky assets only if they expect to earn a return to compensate them for their risk bearing. As a result, the rate of return that investors require from a utility's common stock, the most junior and riskiest of its securities, must be considerably higher than the yield offered by senior, long-term debt. Consistent with this principle, Dr. Woolridge should have evaluated his DCF results to eliminate estimates that are determined to be illogical when compared against the yields available to investors from less risky utility bonds. The practice of eliminating low-end outliers has been affirmed in numerous FERC proceedings. In Opinion

No. 531, FERC concluded that, "The purpose of the low-end outlier test is to exclude from the proxy group those companies whose ROE estimates are below the average bond yield or are above the average bond yield but are sufficiently low that an investor would consider the stock to yield essentially the same return as debt."[66] FERC has used 100 basis points above the six-month average public utility bond yield as an approximation of this threshold, but has also recognized that this is a flexible test.[67]

Q54. DR. WOOLRIDGE ARGUES YOUR ANALYSIS IS FLAWED BECAUSE OF YOUR "ASYMMETRICAL ELIMINATION OF DCF RESULTS."[68] IS THIS A VALID ARGUMENT?

A54. No. As discussed above, low-end outliers were evaluated against the observable returns available from long-term bonds. But the fact that there are numerous results that fail this test of reasonableness says nothing about the validity of estimates at the upper end of the range of results, and there is no basis to discard an equal number of values from the top of the range. While the upper end cost of equity estimate of 14.0% from my Exhibit No. 5 may exceed expectations for most utilities, the remaining low-end estimates in the 7.0% range are assuredly far below investors' required rate of return. Taken together and considered along with the balance of the DCF estimates, these values provides a reasonable basis on which to evaluate investors' required rate of return.

Q55. DR. WOOLRIDGE RELIED ON SUSTAINABLE, "BR" GROWTH RATES (EXHIBIT JRW-10, P. 4). SHOULD THE COMMISSION PLACE ANY WEIGHT ON THESE VALUES?

---

[66] Opinion No. 531 at P 122.
[67] *Id.*
[68] Woolridge Direct at 65.

A55. No. Dr. Woolridge's internal growth rates are downward biased because of computational errors (use of year-end book value) and omissions (failure to incorporate the impact of issuing new shares). Dr. Woolridge based his calculations of the internal, "br" retention growth rate on data from Value Line. If the rate of return, or "r" component of the internal growth rate, is based on end-of-year book values, such as those reported by Value Line, it will understate actual returns because of growth in common equity over the year.

Q56. WHAT OTHER CONSIDERATION LEADS TO A DOWNWARD BIAS IN DR. WOOLRIDGE'S CALCULATION OF INTERNAL, "BR" GROWTH?

A56. Dr. Woolridge ignored the impact of additional issuances of common stock in his analysis of the sustainable growth rate. Under DCF theory, the "sv" factor is a component designed to capture the impact on growth of issuing new common stock at a price above, or below, book value. As noted by Myron J. Gordon in his 1974 study:

> When a new issue is sold at a price per share P = E, the equity of the new shareholders in the firm is equal to the funds they contribute, and the equity of the existing shareholders is not changed. However, if P > E, part of the funds raised accrues to the existing shareholders. Specifically…[v] is the fraction of the funds raised by the sale of stock that increases the book value of the existing shareholders' common equity. Also, "v" is the fraction of earnings and dividends generated by the new funds that accrues to the existing shareholders.[69]

In other words, the "sv" factor recognizes that when new stock is sold at a price above (below) book value, existing shareholders experience equity accretion (dilution). In the case of equity accretion, the increment of proceeds above book value (P > E in Professor Gordon's example) leads to higher growth because it increases the book value of the existing shareholders' equity. In short, the "sv" component is entirely consistent with DCF theory, and the fact that Dr. Woolridge

[69] Myron J. Gordon, "The Cost of Capital to a Public Utility," *MSU Public Utilities Studies* (1974) at 31-32.

failed to consider the incremental impact on growth results in another downward bias to his "internal" growth rates, which should be given no weight.[70]

Q57. DOES DR. WOOLRIDGE'S REFERENCE TO THE MEDIAN (AT 44-45) CORRECT FOR ANY UNDERLYING BIAS IN HIS HISTORICAL GROWTH RATES?

A57. No. The median is simply the observation with an equal number of data values above and below. For odd-numbered samples, the median relies on only a single number, *e.g.*, the fifth number in a nine-number set. Reliance on the median value for a series of illogical values does not correct for the inability of individual cost of equity estimates to pass fundamental tests of economic logic.

Q58. WHAT DO YOU CONCLUDE BASED ON YOUR REVIEW OF DR. WOOLRIDGE'S DCF ANALYSES?

A58. Even a cursory review of pages 3-5 of Exhibit JRW-10 suggests that Dr. Woolridge could basically have arrived at any DCF growth rate that he wanted. These pages are a mishmash of historical and projected growth rates over varying time periods and not just for earnings, but for dividends and book value as well. There are literally hundreds of growth rates to choose from. The averages/medians for the two proxy groups referenced in his analysis range from 3.6% to 6.0%, and almost any DCF result could have been interpreted based on this data. For this reason, his DCF-based ROE recommendations are suspect and should be weighted accordingly.

Furthermore, trends in DPS are impacted by changes in industry financial policies and Dr. Woolridge failed to evaluate the underlying reasonableness of individual growth rates. Finally, the calculations used to arrive at Dr.

[70] In prior testimony before FERC, Dr. Woolridge incorporated an adjustment to correct for the downward bias attributable to end-of-year book values, and recognized the additional growth from new share issues by incorporating the "sv" component. *See, e.g., Testimony of J. Randall Woolridge*, FERC Docket No. EL-66 at Exhibit JRW-8, pp. 3-4 (2011).

Woolridge's internal growth rates are flawed and incomplete because he did not adjust his end-of-year book values for growth in common equity over the year and because he completely left out the "sv" factor designed to capture the impact on growth of issuing new common stock. As a result, his DCF cost of equity estimates are biased downward and fail to reflect investors' required rate of return.

C. Capital Asset Pricing Model

Q59. WHAT IS THE FUNDAMENTAL PROBLEM ASSOCIATED WITH THE APPROACH THAT DR. WOOLRIDGE USED TO APPLY THE CAPM?

A59. The CAPM application presented by Dr. Woolridge was based entirely on *historical* rates of return, not current projections. Like the DCF model, risk premium methods – including the CAPM – are *ex-ante,* or forward-looking models based on expectations of the future. As a result, in order to produce a meaningful estimate of investors' required rate of return, the CAPM approach must be applied using data that reflects the expectations of actual investors in the market. The primacy of current expectations was recognized by Morningstar, one of the sources relied on by Dr. Woolridge to apply the CAPM:

> The cost of capital is always an expectational or forward-looking concept. While the past performance of an investment and other historical information can be good guides and are often used to estimate the required rate of return on capital, the expectations of future events are the only factors that actually determine cost of capital.[71]

By failing to look directly at the returns investors are currently requiring in the capital markets, as I did on Exhibit Nos. 7 and 8 to my direct testimony, the 7.6%

[71] Morningstar, *Ibbotson SBBI, 2013 Valuation Yearbook* at 21.

historical CAPM estimate developed by Dr. Woolridge[72] falls woefully short of investors' current required rate of return.

Q60. DR. WOOLRIDGE (AT 52) CHARACTERIZES HIS RISK PREMIUM AS *EX ANTE.* IS THIS AN ACCURATE ASSESSMENT?

A60. No. In order to be considered a forward-looking, *ex ante* estimate of the current market risk premium, the analysis must be predicated on investors' current expectations. Dr. Woolridge did not attempt to develop a market risk premium using current capital market information. Rather, he simply presented the results of various studies and surveys conducted in the past. Certain of these studies may have attempted to infer the equity risk premium using expected data at the time they were developed, but expectations at some point in the past are not equivalent to investors *ex ante* requirements in capital markets today.

Q61. IS THERE GOOD REASON TO ENTIRELY DISREGARD THE RESULTS OF HISTORICAL CAPM ANALYSES SUCH AS THOSE PRESENTED BY DR. WOOLRIDGE?

A61. Yes. Applying the CAPM is complicated by the impact of the Federal Reserve policies on investors' risk perceptions and required returns. As the Staff of the Florida Public Service Commission concluded regarding historical applications of the CAPM:

> [R]ecognizing the impact the Federal Government's unprecedented intervention in the capital markets has had on the yields on long-term Treasury bonds, staff believes models that relate the investor-required return on equity to the yield on government securities, such as the CAPM approach, produce less reliable estimates of the ROE at this time.[73]

---

[72] Woolridge Direct at 57.
[73] *Staff Recommendation for Docket No. 080677-E1 - Petition for increase in rates by Florida Power & Light Company*, Docket No. 080677-E1, at 280 (Dec. 23, 2009).

Similarly, in *Orange & Rockland Utilities*, FERC determined that CAPM methodologies based on historical data were suspect because whatever historical relationships existed between debt and equity securities may no longer hold.[74] FERC concluded that historical risk premiums are downward biased given recent trends of low yields for Treasury bonds.[75]

As a result, there is every indication that the historical CAPM approach fails to fully reflect the risk perceptions of real-world investors in today's capital markets, which would violate the standards underlying a fair rate of return by failing to provide an opportunity to earn a return commensurate with other investments of comparable risk.

Q62. DID DR. WOOLRIDGE ALSO RECOGNIZE THE FRAILTIES OF HIS HISTORICAL CAPM APPROACHES?

A62. Yes. Dr. Woolridge noted that *ex-post*, historical rates of return "are not the same as *ex ante* expectations," and observed that, "The use of historical returns as market expectations has been criticized in numerous academic studies."[76] Dr. Woolridge admitted that "risk premiums can change over time … such that *ex post* historical returns are poor estimates of *ex ante* expectations."[77] Finally, Dr. Woolridge conceded, that his historical CAPM approach provides "a less reliable indication of equity cost rates for public utilities."[78]

Q63. IS THERE EVIDENCE THAT THE STUDIES REFERENCED BY DR. WOOLRIDGE DO NOT REFLECT INVESTORS' EXPECTATIONS?

A63. Yes. The vast majority of the equity risk premium findings reported by Dr. Woolridge do not make economic sense and contradict his own testimony. For

---

[74] *See Orange & Rockland Utils., Inc.*, 40 FERC ¶ 63,053 at 65,208-09 (1987), *aff'd*, Opinion No. 314, 44 FERC ¶ 61,253 at 65,208 (2008).
[75] *See New York Independent System Operator, Inc.*, 146 FERC ¶ 61,043 at P 105 (2014).
[76] Woolridge Direct at 52-53.
[77] *Id.*
[78] *Id.* at 33.

example, page 5 of Dr. Woolridge's Exhibit JRW-11 reveals that well over half of the historical studies included in Dr. Woolridge's review found market equity risk premiums of approximately 5.0% or below. This was also true for nearly half of the individual risk premium studies that Dr. Woolridge classified as "more recent."[79] But combining a market equity risk premium of 5.0% with Dr. Woolridge's 4.0% risk-free rate results in an indicated cost of equity for the market as a whole of 9.0%, which barely exceeds his ROE recommendation for Kentucky Power in this case.

Meanwhile, after noting that beta is the only relevant measure of investment risk under modern capital market theory, Dr. Woolridge concluded that his comparison of beta values (Exhibit JRW-8) indicates that investors' required return on the market as a whole should exceed the cost of equity for electric utilities.[80] Based on Dr. Woolridge's own logic, it follows that a market rate of return that does not significantly exceed his own downward biased ROE recommendation has no relation to the current expectations of real-world investors. The fact that much of his CAPM "evidence" violates the risk-return tradeoff that is fundamental to financial theory clearly illustrates the frailty of Dr. Woolridge's analyses.

Q64. ARE THERE OTHER SHORTCOMINGS ASSOCIATED WITH THE SOURCES CITED BY DR. WOOLRIDGE?

A64. Yes. For example, the *Fernandez* survey is the result of a mass solicitation to more than 23,000 email addresses, out of which approximately 6,900 responses were received.[81] While many of the responses were undoubtedly from informed

---

[79] Exhibit JRW-11, p. 6.
[80] Woolridge Direct at 31-32.
[81] Pablo Fernandez, Alberto Ortiz, and Isabela Fernandez Acin, "Market Risk Premium used in 71 Countries in 2016: a survey with 6,923 answers," (May 2016) https://papers.ssrn.com/sol3/Delivery.cfm/SSRN_ID2776636_code12696.pdf?abstractid=2776636&mirid=1&type=2 (last visited Oct. 11, 2017).

professionals, there is no ability verify the experience or familiarity of the respondents with the subject matter. In addition, the wording of the surveys is imprecise and open to interpretation. For example, the 2016 survey simply asks, "The Market Risk Premium that I am using in 2016 for USA is _____%,"[82] which is entirely unclear. The respondent has no idea whether he or she is being queried for a risk premium during 2016, or over some other time period; nor is the basis on which the risk premium is calculated even specified.[83]

Meanwhile, the approach used to derive a market risk premium in *Damodaran* forces the growth rate for all competitive firms to a constant long-term rate after five years. In addition, *Damodaran* inexplicably assumes that this long term rate of growth will equal the current yield on U.S. Treasury bonds, or 2.12% in its current rendition.[84] This is significantly below even the GDP growth rate range of 3.0% to 5.0% advocated by Dr. Woolridge.[85] There is no logical link between investors' long-term growth expectations for common stocks and the current Treasury bond yield, and I know of no credible source of investment guidance that is expecting growth for all companies in the economy to collapse to 2.12% over the next five years.

The fundamental problem with Dr. Woolridge's approach is that instead of looking directly at an equity risk premium based on current expectations – which is what is required in order to properly apply the CAPM and is the approach I took – he undertakes an unrelated exercise of compiling selected computations culled from the historical record. In short, while there are many potential definitions of the equity risk premium, the only relevant issue for application of

[82] *Id.*
[83] One respondent to the *Fernandez* survey characterized the imprecision and ambiguity this way: "You don't define exactly what you mean by "Market Risk Premium". Different authorities define it in different ways. Is it expected return over short-term government securities (*e.g.*, 30 or 90 day T-Bills), or longer-term government bonds?" *Id.*
[84] http://www.stern.nyu.edu/~adamodar/pc/implprem/ERPSept17.xls (last visited Oct. 11, 2017).
[85] Woolridge Direct at 72.

the CAPM in a regulatory context is the return investors currently expect to earn on money invested today in the risky market portfolio versus the risk-free U.S. Treasury alternative.

Q65. WAS DR. WOOLRIDGE (EXHIBIT JRW-11, PP. 5-6) JUSTIFIED IN RELYING ON GEOMETRIC MEANS AS A MEASURE OF AVERAGE RATE OF RETURN WHEN APPLYING THE HISTORICAL CAPM?

A65. No. While both the arithmetic and geometric means are legitimate measures of average return, they provide different information. Each may be used correctly, or misused, depending upon the inferences being drawn from the numbers. The geometric mean of a series of returns measures the constant rate of return that would yield the same change in the value of an investment over time. The arithmetic mean measures what the expected return would have to be each period to achieve the realized change in value over time.

In estimating the cost of equity, the goal is to replicate what investors expect going forward, not to measure the average performance of an investment over an assumed holding period. When referencing realized rates of return in the past, investors consider the equity risk premiums in each year independently, with the arithmetic average of these annual results providing the best estimate of what investors might expect in future periods. *New Regulatory Finance* had this to say:

> The best estimate of expected returns over a given future holding period is the arithmetic average. *Only arithmetic means are correct for forecasting purposes and for estimating the cost of capital.* There is no theoretical or empirical justification for the use of geometric mean rates of returns as a measure of the appropriate discount rate in computing the cost of capital or in computing present values.[86]

Similarly, Morningstar concluded that:

---

[86] Roger A. Morin, "New Regulatory Finance" *Public Utilities Reports, Inc.* (2006) at 116-117, (emphasis added).

> For use as the expected equity risk premium in either the CAPM or the building block approach, the arithmetic mean or the simple difference of the arithmetic means of stock market returns and riskless rates is the relevant number. … The geometric average is more appropriate for reporting past performance, since it represents the compound average return.[87]

Q66. WHAT DOES THIS IMPLY WITH RESPECT TO DR. WOOLRIDGE'S CAPM ANALYSES?

A66. For a variable series, such as stock returns, the geometric average will <u>always</u> be less than the arithmetic average. Accordingly, Dr. Woolridge's reference to geometric average rates of return provides yet another element of built-in downward bias.

Q67. DR. WOOLRIDGE REFERENCES CAPITAL MARKET TRENDS.[88] IS IT APPROPRIATE TO CONSIDER ANTICIPATED CAPITAL MARKET CHANGES IN APPLYING THE CAPM?

A67. Yes. As discussed in my direct testimony, there is widespread consensus that interest rates will increase materially as the economy strengthens. Accordingly, in addition to the use of current bond yields, I also applied the CAPM and ECAPM approaches based on the forecasted long-term Treasury bond yields developed based on projections published by Value Line, IHS Global Insight and Blue Chip.

D. Other ROE Issues

Q68. PLEASE RESPOND TO DR. WOOLRIDGE'S ARGUMENT THAT THERE IS NO BASIS TO INCLUDE A FLOTATION COST ADJUSTMENT.

---

[87] Morningstar, *Ibbotson SBBI 2013 Valuation Yearbook* at 56.

[88] Dr. Woolridge cites "the possibility of higher interest rates" as one factor that he considered in selecting the risk-free rate used in his application of the CAPM. Woolridge Direct at 50.

A68. The need for a flotation cost adjustment to compensate for past equity issues is recognized in the financial literature. In a *Public Utilities Fortnightly* article, for example, Brigham, Aberwald, and Gapenski demonstrated that even if no further stock issues are contemplated, a flotation cost adjustment in all future years is required to keep shareholders whole, and that the flotation cost adjustment must consider total equity, including retained earnings.[89] Similarly, *Regulatory Finance: Utilities' Cost of Capital* contains the following discussion:

> Another controversy is whether the underpricing allowance should still be applied when the utility is not contemplating an imminent common stock issue. Some argue that flotation costs are real and should be recognized in calculating the fair rate of return on equity, but only at the time when the expenses are incurred. In other words, the flotation cost allowance should not continue indefinitely, but should be made in the year in which the sale of securities occurs, with no need for continuing compensation in future years. This argument implies that the company has already been compensated for these costs and/or the initial contributed capital was obtained freely, devoid of any flotation costs, which is an unlikely assumption, and certainly not applicable to most utilities. … The flotation cost adjustment cannot be strictly forward-looking unless all past flotation costs associated with past issues have been recovered.[90]

Q69. IS THERE ANY MERIT TO DR. WOOLRIDGE'S ARGUMENT (AT 80) THAT FLOTATION COSTS CAN BE IGNORED BECAUSE THEY CANNOT BE PRECISELY QUANTIFIED?

A69. No. As discussed in my direct testimony,[91] the costs incurred to issue new debt securities are recorded on the financial books of the utility and routinely recovered from customers without controversy. While equity flotation costs are every bit as necessary to supply invested capital, they are not recorded on the utility's books, so there is no precise accounting for these costs. Nevertheless,

[89] E.F. Brigham, D.A. Aberwald, and L.C. Gapenski, "Common Equity Flotation Costs and Rate Making," *Public Utilities Fortnightly*, May, 2, 1985.
[90] Roger A. Morin, "New Regulatory Finance," *Public Utilities Reports, Inc.* (2006) at 335.
[91] McKenzie Direct at 67.

they represent necessary and legitimate expenses incurred to obtain the equity capital invested in utility plant, and unless some provision is made for their recovery, investors will not be offered an opportunity to fully earn their required ROE. The need to consider flotation costs has been documented in the financial literature and Dr. Woolridge's observations provide no basis to ignore issuance costs.

Q70. PLEASE RESPOND TO DR. WOOLRIDGE'S SPECIFIC CRITICISMS OF YOUR FLOTATION COST ADJUSTMENT (AT 80-82).

A70. Flotation cost adjustments are supported by recognized regulatory textbooks and based on research reported in the academic literature, and the lack of a precise accounting of past issuance expenses necessary to raise the common equity capital invested in Kentucky Power provides no basis to ignore a flotation cost adjustment.

Meanwhile, Dr. Woolridge mistakenly claims that a flotation cost adjustment "is necessary to prevent the dilution of the existing shareholders."[92] In fact, a flotation cost adjustment is required in order to allow the utility the opportunity to recover the issuance costs associated with selling common stock. Dr. Woolridge's observation about the level of market-to-book ratios (at 80) may be factually correct, but it has nothing to do with flotation costs. The fact that market prices may be above book value does not alter the fact that a portion of the capital contributed by equity investors is not available to earn a return because it is paid out as flotation costs. Even if the utility is not expected to issue additional common stock, a flotation cost adjustment is necessary to compensate for flotation costs incurred in connection with past issues of common stock.

[92] Woolridge Direct at 80.

Dr. Woolridge's argument (at 81) that flotation costs are not "out-of-pocket expenses" is simply wrong. Dr. Woolridge apparently believes that if investors in past common stock issues had paid the full issuance price directly to the utility and the utility had then paid underwriters' fees by issuing a check to its investment bankers, that flotation cost would be a legitimate expense. Dr. Woolridge's observation merely highlights the absence of an accounting convention to properly accumulate and recover these legitimate and necessary costs.

Q71. HAVE OTHER REGULATORS RECOGNIZED THAT FLOTATION COSTS ARE A LEGITIMATE CONSIDERATION IN ESTABLISHING A FAIR ROE?

A71. Yes. For example, in Docket No. UE-991606 the Washington Utilities and Transportation Commission concluded that a flotation cost adjustment of 25 basis points should be included in the allowed return on equity:

> The Commission also agrees with both Dr. Avera and Dr. Lurito that a 25 basis point markup for flotation costs should be made. This amount compensates the Company for costs incurred from past issues of common stock. Flotation costs incurred in connection with a sale of common stock are not included in a utility's rate base because the portion of gross proceeds that is used to pay these costs is not available to invest in plant and equipment.[93]

Similarly, the South Dakota Public Utilities Commission has recognized the impact of issuance costs, concluding that, "recovery of reasonable flotation costs is appropriate."[94] Another example of a regulator that approves common stock issuance costs is the Mississippi Public Service Commission, which routinely includes a flotation cost adjustment in its Rate Stabilization Adjustment Rider

---

[93] *Third Supplemental Order*, WUTC Docket No. UE-991606, et al., p. 95 (September 2000).
[94] *Northern States Power Co*, EL11-019, Final Decision and Order at P 22 (2012).

formula.[95] The Public Utilities Regulatory Authority of Connecticut[96] and the Minnesota Public Utilities Commission[97] have also recognized that flotation costs are a legitimate expense worthy of consideration in setting a fair ROE.

Q72. IS THERE ANY MERIT TO DR. WOOLRIDGE'S ARGUMENT (AT 75-77) THAT THE SIZE PREMIUM DOES NOT APPLY TO UTILITY COMMON STOCKS?

A72. No. There is no credible basis to conclude that utilities are immune from the well-documented relationship between smaller size and higher realized rates of return. For example, Dr. Woolridge places significant weight on a 1993 study by Annie Wong,[98] but a closer examination of this research reveals that it is largely inconclusive, and inconsistent with the CAPM. In fact, her results demonstrate no material difference between utilities and industrial firms with respect to size premiums, and her study finds no significant relationship between beta and returns, which contradicts modern portfolio theory and the CAPM. A more recent study published in the Quarterly Review of Economics and Finance reconsiders Wong's evidence and concludes that "new information . . . indicates there is a small firm effect in the utility sector."[99]

Q73. DR. WOOLRIDGE CRITICIZES THE MARKET RETURN THAT YOU USE IN YOUR CAPM AND ECAPM ANALYSES CLAIMING THAT "AS INDICATED IN RECENT RESEARCH, THE LONG-TERM EARNINGS GROWTH RATES OF COMPANIES ARE LIMITED TO THE GROWTH RATE IN GDP" (AT 73). WHAT IS YOUR RESPONSE TO THIS CLAIM?

---

[95] *See, e.g.*, Entergy Mississippi, Inc., Formula Rate Plan Rider (Apr. 15, 2015), http://www.entergy-mississippi.com/content/price/tariffs/emi_frp.pdf (last visited Mar. 16, 2017).
[96] *See, e.g.*, Docket No. 14-05-06, Decision (Dec. 17, 2014) at 133-134.
[97] *See, e.g.*, Docket No. E001/GR-10-276, Findings of Fact, Conclusions, and Order at 9.
[98] Woolridge Direct at 75-76.
[99] Thomas M. Zepp, "Utility stocks and the size effect—revisited," Quarterly Review of Economics and Finance, 43 (2003) 578-582.

A73. The use of long-term GDP growth as an upper bound to the DCF growth rate is not justified. There are several reasons why GDP growth is not relevant in applying the DCF model:

- Practical application of the DCF model does not require a long-term growth estimate over a horizon of 25 years and beyond – it requires a growth estimate that matches investors' expectations.
- My evidence supports the conclusion that investors do not reference long-term GDP growth in evaluating expectations for individual common stocks.
- The theoretical proposition that growth rates for all firms converge to overall growth in the economy over the very long horizon does not guide investors' views, and growth rates for utilities can and do exceed GDP growth.

In short, there is no demonstrable evidence that investors look to GDP growth rates in the far distant future in assessing their expectations for common stocks. And while the theoretical assumptions underlying this method contemplate an infinite stream of cash flows, this is simply at odds with the practical circumstances in which real-world investors operate.

Q74. THE DCF MODEL IS BASED ON THE ASSUMPTION OF AN INFINITE STREAM OF CASH FLOWS. WHY WOULDN'T A TRANSITION TO GDP GROWTH MAKE SENSE?

A74. First, this view confuses the theory underlying the DCF model with the practicalities of its application in the real world. While the notion of long-term growth should presumably relate to the specific firm at issue, or at the very least to a particular industry, there are no long-term growth projections available for the companies in electric utility industry, or the broader market, as a whole. By applying the DCF model in a way that is inconsistent with the information that is available to investors and how they use it, the use of GDP growth places the theoretical assumptions of a financial model ahead of investor behavior. The only relevant growth rate is the growth rate used by investors. Investors do not have clarity to see far into the future, and there is little to no evidence to suggest that investors share the view that growth in GDP must be considered a limit on earnings growth over the long-term.

Second, arguments concerning the “sustainability” of any individual growth rate for a single firm in the S&P 500 miss the point. The growth rate underlying the market cost of equity represents a weighted average of the expectations for the dividend paying firms in the S&P 500. Within this large group of firms, growth expectations for some firms may be extremely anemic, while projections for other firms are considerably more optimistic. In addition, growth rates for one company may moderate over time, while for others they may increase. Finally, the composition of the S&P 500 is not static. As a result, formerly successful firms are supplanted by new firms with potential for high growth (*e.g.*, Sears is supplanted by Amazon, or Blockbuster is supplanted by Netflix). On balance, however, the growth rates used in my CAPM study are representative of the consensus expectations for the dividend paying firms in the S&P 500 Index <u>as a whole</u>. This contradicts Dr. Woolridge’s position that investors’ growth expectations should be constrained by a threshold tied to GDP.

Q75. ARE LONG-TERM GDP GROWTH RATES COMMONLY REFERENCED AS A DIRECT GUIDE TO FUTURE EXPECTATIONS FOR SPECIFIC FIRMS?

A75. No. Certainly investors consider broad secular trends in economic activity as one foundation for their expectations for a particular industry or firm. But the idea that investment advisory services view GDP growth as a direct guide to long-term expectations for a particular firm – much less every firm in an entire industry – is not borne out by evidence.

In contrast to this notion, in the financial media one observes many references to three-to-five year EPS growth forecasts for individual companies and very few references to long-term GDP forecasts. Long-term GDP growth rates are simply not discussed within the context of establishing investors' expectations for individual firms. For example, Value Line reports are routinely relied on as an important guide to apply the DCF model.[100] But despite Dr. Woolridge's suggestion that GDP has a fundamental role in shaping investors' growth estimates, Value Line does not even mention trends in GDP in its evaluation of the firms in the electric utility industry, for example. Value Line's singleness of purpose is to inform investors of the pertinent factors that impact future expectations specific to each of the common stocks it covers. If the trajectory of GDP growth out to the year 2040 and beyond had direct relevance in investors' evaluation of common stocks, it would be logical to assume that Value Line or other securities analysts would give at least passing mention to this fact. But they do not.

Q76. HOW MUCH CONFIDENCE WOULD INVESTORS BE LIKELY TO PLACE ON LONG-TERM GDP PROJECTIONS?

A76. Very little. Investors understand the complexities and inherent inaccuracies involved in forecasting, and that such uncertainties are significantly compounded for a long-term time horizon. Consider the example of IHS Global Insight, which is perhaps the world's foremost econometric forecasting service. IHS Global Insight currently publishes GDP projections for the U.S. economy for the next thirty years, but for other important economic variables (*e.g.*, bond yields) their forecast simply holds projected values constant after a five-year horizon.

[100] As noted in *New Regulatory Finance*, "Value Line is the largest and most widely circulated independent investment advisory service, and influences the expectations of a large number of institutional and individual investors." Roger A. Morin, "New Regulatory Finance," *Public Utilities Reports, Inc.* (2006) at 71.

Q77. DID THE FOUNDER OF THE DCF APPROACH SUPPORT THE USE OF A GENERIC LONG-TERM GROWTH RATE, SUCH AS THE GDP GROWTH?

A77. No. Professor Myron J. Gordon, who originated the DCF approach, concluded that reference to a generic long-term growth rate, such as Dr. Woolridge advocates, was unsupported.[101] More specifically, Dr. Gordon concluded that any assumption of a single time horizon for a transition to a generic long-term growth rate was highly questionable and failed to reduce error in DCF estimates. Instead, Dr. Gordon specifically recognized that, "it is the growth that investors expect that should be used" in applying the DCF model, and he concluded:

> A number of considerations suggest that investors may, in fact, use earnings growth as a measure of expected future growth."[102]

Similarly, a recent study reported in the *Journal of Investing* determined that there is no correlation between stock market returns or earnings growth and GDP, suggesting that investors' expectations built into observable share prices are driven by valuation measures, and not expected economic growth.[103]

Q78. PLEASE SUMMARIZE YOUR OBJECTION TO DR. WOOLRIDGE'S REFERENCE TO GDP GROWTH RATES IN YOUR MARKET DCF ANALYSIS?

A78. Dr. Woolridge presents no meaningful information to suggest that earnings growth rates of companies are limited to the growth rate in GDP. There is no link between Dr. Woolridge's GDP growth rate ceiling and the actual expectations of investors in the capital markets, which are the determining factor in any analysis of a fair ROE

---

[101] Myron J. Gordon, "The Cost of Capital to a Public Utility," *MSU Public Utilities Studies* (1974) at 100-01.
[102] *Id.* at 89.
[103] Joachim Klement, "What's Growth Got to Do with It? Equity Returns and Economic Growth," *Journal of Investing,* Vol. 24, No. 2 (Summer 2015): 74:78.

Q79. DR. WOOLRIDGE SAYS THAT YOUR EXPECTED EARNINGS APPROACH IS FLAWED DUE TO UNREGULATED OPERATIONS OF THE PROXY GROUPS AND DUE TO DIFFERENCES IN M/B.[104] DO YOU AGREE WITH THIS ASSESSMENT?

A79. Not at all. The appeal of the expected earnings approach is that it does not require theoretical models to indirectly infer investors' perceptions from stock prices or other market data. As long as the proxy companies are similar in risk, their expected earned returns on invested capital provide a direct benchmark for investors' opportunity costs that is independent of fluctuating stock prices, market-to-book ratios, debates over DCF growth rates, or the limitations inherent in any theoretical model of investor behavior. While companies in the proxy groups may have varying levels of unregulated operations, they have all been judged to be of comparable overall risk and this condition overrides specific differences between them.

Again, market-to-book ratios have no place in applying the expected earnings approach. Traditional applications of the expected earnings approach do not involve a M/B adjustment. Nor is such an adjustment recommended in recognized texts such as *New Regulatory Finance.*[105] FERC has also rejected similar arguments raised by Dr. Woolridge, finding that, "considering market-to-book ratios in an expected earnings study is inconsistent with the purpose of the comparable earnings model."[106]

Q80. DR. WOOLRIDGE CRITICIZES YOUR USE OF A LOW-RISK GROUP OF NON-UTILITY COMPANIES AS AN ROE CHECK OF REASONABLENESS (AT 83). ARE HIS CRITICISMS JUSTIFIED?

---

[104] Woolridge Direct at 82-83.
[105] Roger A. Morin, "New Regulatory Finance," *Public Utilities Reports, Inc.* (2006).
[106] *Martha Coakely, et al.*, Opinion No. 531-B, 150 FERC ¶ 61,165 at P 132 (2015).

A80. Not at all. The implication that an estimate of the required return for firms in the competitive sector of the economy is not useful in determining the appropriate return to be allowed for rate-setting purposes is wrong and inconsistent with reality, investor behavior, and the *Bluefield* and *Hope* decisions. In fact, returns in the competitive sector of the economy form the very underpinning for utility ROEs because regulation purports to serve as a substitute for the actions of competitive markets.

The cost of capital is an opportunity cost based on the returns that investors could realize by putting their money in other alternatives, which include all other securities available in the stock, bond or money markets. Consistent with this view, Dr. Woolridge noted the Supreme Court's economic standards and concluded that the fair rate of return on equity should be "comparable to returns investors expect to earn on other investments of similar risk."[107] Clearly the total capital invested in utility stocks is only the tip of the iceberg of total common stock investment and there are a plethora of other "investments of comparable risk" available to investors beyond those in the utility industry.

True enough, utilities are sheltered from competition, but they undertake other obligations and lose the ability to set their own prices and decide when to exit a market. The Supreme Court has recognized that it is the degree of risk, not the nature of the business, which is relevant in evaluating an allowed ROE for a utility.[108]

Q81. DOES THE MARCH 10, 2015 REPORT FROM MOODY'S CITED BY DR. WOOLRIDGE (AT 62) SUPPORT A DRAMATIC DROP IN THE COMPANY'S ALLOWED RETURN FROM THOSE CURRENTLY BEING AUTHORIZED FOR COMPARABLE UTILITIES?

---

[107] Woolridge Direct at 2-3.
[108] *Fed. Power Comm'n v. Hope Natural Gas Co.*, 320 U.S. 591 (1944).

A81. No. The Moody's report discusses only very generally the impacts of a "slow" decline in utilities' authorized ROEs, and how regulators may lower authorized ROEs without harming utilities' cash flow, such as by "targeting depreciation." The Moody's report does not identify a cost of equity for regulated utilities at all, much less discuss a cost of equity for Kentucky Power, which is not even mentioned in the report. In my view, the Moody's report offers no relevant information about a fair ROE in this proceeding, and it certainly does not support the values recommended by the ROE Witnesses.

Q82. DOES THE MOODY'S REPORT INDICATE THAT EQUITY INVESTORS WOULD NOT BE CONCERNED IF THE COMPANY'S ROE WERE LOWERED TO THE LEVELS RECOMMENDED BY THE ROE WITNESSES?

A82. No. I believe no one can make such an inference based on this report. First, it is important to note that the primary mission of credit rating agencies like Moody's is to provide *debt holders* with an accurate benchmark of the relative risks of default associated with long-term bonds and other debt securities. As the report cited by Dr. Woolridge clearly observes, Moody's evaluation is premised "from the perspective of a probability of a default and expected loss given default."[109]

Bondholders, the constituency represented by Moody's, do not share in a utility's net income or profits. As a result, Moody's focus is on cash flows, which are viewed "as a more important rating driver."[110] On the other hand, *equity investors* are intensely focused on the ability of the utility to generate earnings, dividends and growth. This difference in the characteristics and priorities between debt and equity securities gives rise to the considerable distinction in the

[109] Moody's Investors Service, "Lower Authorized Equity Returns Will Not Hurt Near-Term Credit Profiles," *Sector In-Depth* (March 2015).

[110] *Id.* Moody's further clarified that it defines credit risk "as the risk that an entity will not meet its contractual, financial obligations as they come due and any estimated financial loss in the event of default. Credit ratings do not address any other risk …."

risks faced by debt holders and equity investors. While a moderate and gradual downturn in ROEs may not pose an immediate threat to the cash flow protection underlying the credit ratings on a utility's debt, it would have an immediate, negative impact on returns to common stockholders.

Q83. DR. WOOLRIDGE CLAIMS THAT RECENT TRENDS IN ELECTRIC UTILITY BOND RATING ACTIONS AND HISTORICAL EARNED RETURNS SUPPORT HIS ROE RECOMMENDATION.[111] DO GENERAL TRENDS IN UTILITY CREDIT RATINGS OR HISTORICAL EARNED RETURNS PROVIDE ANY JUSTIFICATION FOR AN 8.6% ROE FOR KENTUCKY POWER IN THIS CASE?

A83. No. The factors that lead to a utility company's bond rating depend on a host of considerations, including the nature of the regulatory environment, diversity and health of the service area economy, availability of supportive recovery mechanisms, weather or geographical challenges, and so on. Thus, there is no direct connection between the general pattern of credit ratings actions for other utilities in the industry and the specific determination of a fair ROE for Kentucky Power in this case. In fact, the wide disparity between Dr. Woolridge's recommendations and the benchmarks discussed earlier in my testimony indicate that an 8.6% ROE would be entirely inconsistent with the factual circumstances leading to the pattern of credit ratings actions displayed in Dr. Woolridge's Figure 6.

Moreover, Dr. Woolridge's analysis of historical earned returns is distorted and provides no useful guidance as to investors' future expectations or requirements. In his analysis, Dr. Woolridge says the "median earned ROE for the year 2016 for the companies in the Electric and McKenzie are 9.3% and 9.4%,

[111] Woolridge Direct at 61.

respectively, as shown in Exhibit JRW-4."[112] A detailed review of Exhibit JRW-4 casts significant doubt on the usefulness of these values, however. Included in the "Return on Equity" column for Dr. Woolridge's Electric Proxy Group are returns of -66.20% (FirstEnergy), -6.73% (Entergy), 3.16% (WEC Energy), and several other values in the 3%-5% range. In the McKenzie Proxy Group panel, there are five "Return on Equity" values in the 2%-5% range. Because these values clearly do not provide a reasonable guide to investors' return requirements, Dr. Woolridge's analysis in this area is not reliable and should be ignored.

III. RESPONSE TO MR. BAUDINO

Q84. HOW DID MR. BAUDINO ARRIVE AT HIS RECOMMENDED COST OF EQUITY?

A84. Mr. Baudino recommended an ROE of 8.85% based exclusively on his application of the constant growth DCF model. He included a CAPM analysis for "additional information" but did not incorporate the results of the CAPM directly in his recommendation.[113] Mr. Baudino applied these methods to the same proxy group I did, but for three utilities that he excluded due to perceived data issues.[114]

Q85. WHAT IS YOUR ASSESSMENT OF MR. BAUDINO'S ROE TESTIMONY AND RECOMMENDATION?

A85. Mr. Baudino's recommendation is not realistic. Several specific factors detract from his analysis. First and foremost, Mr. Baudino fails to apply sufficient checks of reasonableness to test his DCF results. His CAPM approach is significantly flawed and he ignores other accepted benchmarks such as the utility risk premium, expected earnings, and ECAPM methodologies, or a review of non-

---

[112] *Id.*
[113] Baudino Direct at 3.
[114] Mr. Baudino eliminated AVANGRID, Emera, and Fortis.

utility outcomes. Had Mr. Baudino employed these other approaches, he would have seen that his DCF-based result was not reasonable.

A. Discounted Cash Flow Model

Q86. WHAT ARE THE SPECIFIC DEFECTS THAT YOU HAVE IDENTIFIED IN MR. BAUDINO'S DCF ANALYSIS?

A86. While Mr. Baudino's application of the DCF model is fairly straightforward, there are several problems with his approach. First, I do not agree with his decision to eliminate three companies from my proxy group. Second, he repeats the mistakes made by Dr. Woolridge in giving weight to DPS growth rates and in conducting an incomplete "br" growth study. Finally, his DCF results are based on a decision to average all individual growth rates together and compute a single ROE estimate for each growth rate source. This approach masks the presence of extreme data and biases his results downward.

Q87. PLEASE ELABORATE ON YOUR DISAGREEMENT WITH MR. BAUDINO'S PROXY GROUP?

A87. I do not agree with Mr. Baudino's decision to exclude three eligible utilities from my proxy group in forming his sample. He rejects AVANGRID because "there is not enough Value Line information to include this company in the proxy group."[115] AVANGRID is a major utility with a market capitalization of $15 billion. Its subsidiaries are well known to investors and include Central Maine Power, New York State Electric & Gas, Rochester Gas and Electric, and United Illuminating. AVANGRID has a stable dividend policy, and while Value Line may not currently report projected growth rates, this data is available from comparable sources such as Zacks and IBES, which were both relied on by Mr. Baudino. It would have been easy to substitute "No Meaningful Figure" for

---

[115] Baudino Direct at 17-18.

AVANGRID's Value Line growth rate and continue the DCF calculation with the other two growth rate sources. Indeed, this is precisely the approach taken by Mr. Baudino in the case of PPL Corporation which, like AVANGRID, lacked a Value Line projected growth rate. For PPL Corporation, Mr. Baudino input "NMF" for its missing Value Line rate and continued the DCF process with growth rates from Zacks and IBES.[116]

Mr. Baudino excludes Emera, Inc. because, due to its 2016 acquisition of TECO Energy, it "is a different company today from what it was in 2015 and its expected short-term growth in dividends and revenues reflect this."[117] This viewpoint is mistaken on many levels. First, the acquisition of TECO Energy was completed on July 1, 2016, over 15 months ago. All related impacts are fully incorporated in the forecasts and projections of investor information services, including Value Line, Zacks, and IBES. Of course, Emera is not the same company it was prior to the merger but that is not the point; the point is that investors are fully aware of the changes it has undergone and all relevant data, going forward, reflects these impacts. This circumstance is no different than that facing Southern Company, which coincidentally, also completed a merger on July 1, 2016 (with AGL Resources). Southern Company is also not the same company it was in 2015, but exercising a clear double standard, Mr. Baudino left them in his proxy group.[118]

Mr. Baudino cites a sizeable increase in Emera's revenues following the TECO Energy acquisition and implies that this increase is short-term in nature and not reflective of long-term conditions.[119] Again, Mr. Baudino misses the point. Of course, revenues will increase as the new company is added to existing

---

[116] Exhibit RAB-4, page 1.
[117] Baudino Direct at 18.
[118]
[119] *Id.*

operations, but so will expenses and investment. Mr. Baudino's focus on increased revenues is misguided and misleading; the proper focus is on net earnings and, in this light, Emera is clearly not an outlier. The 8.5% earnings growth rate for Emera cited (and excluded) by Mr. Baudino is in line with other rates he considered acceptable: 9.5% for NextEra Energy; 8.5% for Dominion Energy; and 8.5% and 8.0% for Sempra Energy.[120]

Finally, Mr. Baudino eliminates Fortis, Inc. from his proxy group stating that, due to its 2016 acquisition of ITC Holdings, its revenues and total capital will increase significantly.[121] My rebuttal to Mr. Baudino's misleading claims are the same here as above. Simple arithmetic tells us that revenues and investment will increase due to an acquisition, but it is the forward-looking impact on net earnings (after increased expenses and costs are also considered) that is most important to investors. As noted above, the 9.0% projected earnings growth rate for Fortis is not out of line with other rates accepted by Mr. Baudino. In removing AVANGRID, Emera, and Fortis from his proxy group, Mr. Baudino is inconsistent in the application of his selection criteria. His decision appears to be based more on the fact that the rates for the three excluded companies are at the upper end of the growth rate range. Such an approach is capricious and unfair and should be rejected.

Q88. MR. BAUDINO CONSIDERED DIVIDEND DATA IN THE GROWTH RATE PORTION OF HIS DCF ANALYSIS. IS THIS APPROACH LIKELY TO DISTORT HIS DCF RESULTS?

A88. Yes. As discussed earlier in my response to Dr. Woolridge, growth rates in DPS are not likely to provide a meaningful guide to investors' current growth expectations. The importance of earnings in evaluating investors' expectations

---

[120] Exhibit RAB-4.
[121] Baudino Direct at 18.

and requirements is well accepted in the investment community, and surveys of analytical techniques relied on by professional analysts indicate that growth in EPS is far more influential than trends in DPS.

Q89. MR. BAUDINO ALSO PRESENTED SUSTAINABLE, "BR" GROWTH RATES (EXHIBIT RAB-4, P. 1). SHOULD THE KPSC PLACE ANY WEIGHT ON THESE VALUES?

A89. No. In the same way as I explained earlier in my rebuttal to Dr. Woolridge, Mr. Baudino's "br" growth rates are downward biased because he failed to recognize the impact of year-end returns reported by Value Line. Furthermore, like Dr. Woolridge, Mr. Baudino failed to consider the impact of additional issuances of common stock in his analyses of the sustainable growth rate. Because Mr. Baudino ignored these adjustments, his internal, "br" growth rates are distorted and should be ignored. In fact, Mr. Baudino himself did not rely on sustainable "br" growth rates in his final DCF application.[122]

Q90. ARE THERE OTHER PROBLEMS WITH MR. BAUDINO'S DCF ANALYSIS?

A90. Yes. Another flaw in Mr. Baudino's DCF analyses was his decision to average all individual growth rates and then compute a single DCF estimate for each growth rate source. Each growth rate represents a stand-alone estimate of investors' future expectations, and each value should be evaluated on its own merits. The fact that an average of several growth rates might produce a DCF estimate that could be considered reasonable does not absolve the need to evaluate each underlying growth rate separately.

For example, consider a utility with a dividend yield of 3.5% and three hypothetical growth estimates of 0.0%, 6.5%, and 14.0%. Under Mr. Baudino's

[122] Baudino Direct at 21.

method, the DCF estimate would be computed by adding the 6.8% average of the three individual growth rates to the dividend yield, resulting in a cost of equity estimate of 10.3%. The problem with this method is that it disguises the fact that two of the underlying growth rates – 0.0% and 14.0% – do not provide a meaningful guide to investors' expectations. Rather than averaging the good with the bad, each implied cost of equity estimate (in this example, 3.5%, 10.0%, and 17.5%) should be evaluated on a stand-alone basis.[123] Mr. Baudino simply calculated the average of the individual growth rates with no consideration for the reasonableness of the underlying data. Because Mr. Baudino failed to perform this essential step, his DCF analysis included individual growth rates that do not reflect investors' expectations. Therefore, his results are biased downward.

Q91. CAN YOU SHOW THE DOWNWARD BIAS IN MR. BAUDINO'S CONSTANT GROWTH ANALYSIS?

A91. Yes. For example, Mr. Baudino reports a First Call/IBES growth rate of 0.04% for PPL Corporation.[124] Combining this growth rate with PPL's corresponding dividend yield of 4.13% results in a cost of equity estimate of 4.17%. Similarly, combining Public Service Enterprise Group's First Call/IBES growth rate of 0.57% with its dividend yield of 3.86% produces an ROE estimate of 4.43%. These implied costs of equity are less than, or do not sufficiently exceed current and projected yields on public utility bonds. As a result, these illogical growth measures should have been removed from Mr. Baudino's constant growth DCF analysis.

[123] The implied cost of equity estimates are calculated as the sum of the dividend yield (3.5%) and the respective growth rates (0.0%, 6.5%, and 14.0%).
[124] Exhibit RAB-4.

B. Capital Asset Pricing Model

Q92. WHAT IS THE BIGGEST ISSUE YOU HAVE WITH MR. BAUDINO'S CAPM ANALYSIS?

A92. Mr. Baudino's CAPM results are simply so low they should be rejected outright. Results from his current market premium CAPM range from 6.90% to 7.15%; while results from his historic market premium model range from 5.99% to 7.32%.[125] These outcomes are not legitimate ROE estimates.

Q93. CAN YOU IDENTIFY DEFECTS IN MR. BAUDINO'S CAPM METHODOLOGY?

A93. Yes. For instance, Mr. Baudino bases his risk-free rate on 5-year and 20-year Treasury securities when it is more appropriate to rely on the longer-term 30-year Treasury bond. As Dr. Woolridge states:

> The yield on long-term U.S. Treasury bonds has usually been viewed as the risk-free rate of interest in the CAPM. The yield on long-term U.S. Treasury bonds, in turn, has been considered to be the yield on U.S. Treasury bonds with 30-year maturities.[126]

Mr. Baudino's reliance on government debt with shorter maturities serves to unfairly deflate his CAPM results.

Next, Mr. Baudino attempts to develop a forecasted market return, which is a laudable goal. However, instead of simply relying on Value Line earnings forecasts, he introduces book value growth into the process. As I describe above, growth in EPS is the most influential driver of investors' long-term expectations. Adding book value growth only serves to depress his market return estimate, especially given that the earnings growth rate is 10.5% and the book value growth

[125] Baudino Direct, Table 3, at 29.
[126] Woolridge Direct at 49.

rate is 7.5%.[127] If Mr. Baudino had left out the book value component, his market return projection would have been much more reasonable, at 11.37%.[128]

Q94. IS THERE ANOTHER SERIOUS PROBLEM ASSOCIATED WITH CAPM ANALYSIS DEVELOPED BY MR. BAUDINO?

A94. Yes, as I mentioned earlier in my response to Dr. Woolridge, the CAPM is an *ex-ante*, or forward-looking model based on expectations of the future. As a result, in order to produce a meaningful estimate of investors' required rate of return, the CAPM must be applied using data that reflect the expectations of actual investors in the market. Mr. Baudino has recognized that, "There is no real support for the proposition that an unchanging, mechanically applied historical risk premium is representative of current investor expectations and return requirements."[129]

Nevertheless, at least part of Mr. Baudino's application of the CAPM method was based on *historical* – not projected – rates of return (Exhibit RAB-6). Because Mr. Baudino's backward-looking analysis ignores the returns investors are currently requiring in the capital markets, the resulting CAPM estimates fall woefully short of investors' current required rate of return.

Q95. IS THERE ANY MERIT TO MR. BAUDINO'S ARGUMENT (AT 39) THAT YOUR ANALYSIS OF THE MARKET RATE OF RETURN SHOULD NOT HAVE BEEN LIMITED SOLELY TO THE DIVIDEND PAYING FIRMS IN THE S&P 500?

A95. No. As Mr. Baudino recognized (at 15-16), under the constant growth form of the DCF model, investors' required rate of return is computed as the sum of the dividend yield over the coming year plus investors' long-term growth expectations. Because the dividend yield is a key component in applying the DCF

[127] Exhibit RAB-5, page 2.
[128] *Id.* Earnings growth of 10.50% plus the average dividend yield of 0.87% is 11.37%.
[129] *Direct Testimony and Exhibits of Richard A. Baudino*, Case No. 2012-00221 & Case No. 2012-00222, at p. 28 (October 2012).

model, its usefulness is hampered for firms that do not pay common dividends. Accordingly, my DCF analysis of the market rate of return properly focused on the dividend paying firms included in the S&P 500.

Meanwhile, Mr. Baudino (at 25-26) predicated his DCF analysis of the market rate of return on the companies followed by Value Line. Of the U.S. firms in Value Line, amounting to approximately 1,500 companies, approximately 500 do not pay common dividends. In other words, one-third of the companies that underpin Mr. Baudino's DCF analysis do not have the data necessary to implement this approach. Further, many of these firms are relatively small and lack a meaningful operating history. As a result, there is also greater uncertainty associated with estimating the future growth expectations that are central to the application of the DCF method. Taken together, these factors impugn the reliability of Mr. Baudino's market risk premium and confirm my decision to restrict the analysis to the established, dividend paying firms in the S&P 500.

Q96. DO THE ARGUMENTS ADVANCED BY MR. BAUDINO UNDERMINE THE NEED FOR A SIZE ADJUSTMENT AS PART OF THE CAPM AND ECAPM ANALYSES?

A96. No. Mr. Baudino simply observes that the average beta associated with the lower size deciles examined by Duff & Phelps is greater than the average his proxy group.[130] While I do not dispute the observation, it has no relevance whatsoever to the implications of Duff & Phelps' findings regarding the impact of firm size. The fact that the average beta for smaller size deciles is greater than for 1.00 says nothing about the range of individual beta values underlying this average. Moreover, the size premiums are beta adjusted; meaning that the risk impact of beta values (whether higher or lower than Mr. Baudino's proxy group average)

[130] Baudino Direct at 40.

have been removed. While the size premiums reported by Duff & Phelps were not estimated on an industry-by-industry basis, this provides no basis to ignore this relationship in estimating the cost of equity for utilities. Utilities are included in the companies used by Duff & Phelps to quantify the size premium, and firm size has important practical implications with respect to the risks faced by investors in the utility industry. As Duff & Phelps concluded*:*

> Despite many criticisms of the size effect, it continues to be observed in data sources. Further, observation of the size effect is consistent with a modification of the pure CAPM. Studies have shown the limitations of beta as a sole measure of risk. The size premium is an empirically derived correction to the pure CAPM.[131]

C. Other ROE Issues

Q97. DOES MR. BAUDINO ADVANCE ANY CREDIBLE CRITICISM OF YOUR RISK PREMIUM APPROACH?

A97. No. Mr. Baudino's only observation is that the risk premium method is "imprecise."[132] Of course, this "criticism" applies equally to every model of investor behavior that is used to estimate required returns, including the DCF approach that formed the sole basis for Mr. Baudino's recommendation. The DCF method is only one theoretical approach to gain insight into the return investors require, which is unobservable. While the tautology of the DCF model boils this determination down to the familiar dividend yield and growth rate components, this masks the underlying complexities that accompany any attempt to distill every facet of investors' expectations into a single growth estimate. Mr. Baudino's claim that the DCF is "far more reliable and accurate" is unsubstantiated. While the DCF model is a recognized approach to estimating the cost of equity, it is not without shortcomings and does not otherwise eliminate the

---

[131] *Duff & Phelps*, "2016 Valuation Handbook," (2016) at 4-27.
[132] Baudino Direct at 41.

need to examine the results of other methods. As the Indiana Utility Regulatory Commission noted, for example:

> There are three principal reasons for our unwillingness to place a great deal of weight on the results of any DCF analysis. One is . . . the failure of the DCF model to conform to reality. The second is the undeniable fact that rarely if ever do two expert witnesses agree on the terms of a DCF equation for the same utility – for example, as we shall see in more detail below, projections of future dividend cash flow and anticipated price appreciation of the stock can vary widely. And, the third reason is that the unadjusted DCF result is almost always well below what any informed financial analysis would regard as defensible, and therefore require an upward adjustment based largely on the expert witness's judgment. In these circumstances, we find it difficult to regard the results of a DCF computation as any more than suggestive.[133]

Q98. MR. BAUDINO ARGUES THAT THE USE OF FORECASTED INTEREST RATES IN THE ROE ESTIMATION PROCESS IS A PROBLEM BECAUSE THE PROJECTIONS MAY NOT MATERIALIZE.[134] DO YOU AGREE WITH THIS POSITION?

A98. No. As I stated in my Direct Testimony and earlier in this testimony, whether the projections of various services may be proven optimistic or pessimistic in hindsight, is irrelevant in assessing expected interest rates and how they might influence the Company's allowed ROE.

Q99. HOW DO YOU RESPOND TO MR. BAUDINO'S DISCUSSION OF YOUR NON-UTILITY ANALYSIS?

A99. Mr. Baudino makes the statement that utilities "have protected markets, e.g., service territories, and may increase the prices they charge in the face of falling demand or loss of customers."[135] Based on this, Mr. Baudino summarily concluded, "Obviously, the non-utility companies face risks that a lower risk

[133] *Ind. Michigan Power Co.*, Cause No. 38728, 116 PUR4th, 1, 17-18 (IURC 8/24/1990).
[134] Baudino Direct at 32-35.
[135] *Id.* at 43.

electric company like KPC does not face." In fact, however, investors are quite aware that utilities are not guaranteed recovery of reasonable and necessary costs incurred to provide service and that there are many instances in which utilities are unable to increase rates to fully recoup reasonable and necessary costs, resulting in an inability to earn the allowed ROE – and potentially, even bankruptcy. The simple observation that a firm operates in non-utility businesses says nothing at all about the overall investment risks perceived by investors, which is the very basis for a fair rate of return.

Q100. DOES OBJECTIVE EVIDENCE SUPPORT MR. BAUDINO'S RISK ARGUMENTS?

A100. No. My direct testimony noted that the average corporate credit rating for the Non-Utility Group of "A-" is <u>higher</u> than the "BBB+" average for the Utility Group and the Company.[136] This assessment is confirmed by the review of financial strength values and other objective indicators of investment risk presented in Table 7 to my direct testimony, which consider the impact of competition and market share and demonstrated that, if anything, the Non-Utility Group could be considered <u>less</u> risky in the minds of investors than the common stocks of the proxy group of utilities.

In other words, the objective risk measures specifically cited by Mr. Baudino as being relevant indicators of overall investment risks contradict his assertions regarding the relative risk of the Non-Utility Group. Similarly, Mr. Baudino testified that bond ratings reflect a detailed and comprehensive analysis of the key factors contributing to a firm's overall investment risk, concluding, "Bond and credit ratings are tools that investors use to assess the risk comparability of firms."[137]

---

[136] McKenzie Direct, Table 7, at 75.
[137] Baudino Direct at 15.

A101. Contradicting Mr. Baudino's unsupported assertion (at 43) that the companies in my Non-Utility Group "face risks that a lower risk electric company like KPC does not face,"

Q101. MR. BAUDINO SAYS THAT AN ADJUSTMENT TO ACCOUNT FOR FLOTATION COSTS IS NOT NECESSARY SINCE "FLOTATION COSTS ARE ALREADY ACCOUNTED FOR IN CURRENT STOCK PRICES."[138] IS THIS A VALID ASSUMPTION?

A102. No. Mr. Baudino's position is akin to arguing that it is not necessary to reflect the utility's entire reasonable and necessary O&M expense in revenue requirements because such actions would be "accounted for" in the stock price. Flotation costs are legitimate expenses and unless a discrete adjustment is made to recognize them, they will not be recovered in the rate setting process.

IV. RESPONSE TO MR. TILLMAN

Q102. DID MR. TILLMAN CONDUCT AN INDEPENDENT EVALUATION OF A FAIR ROE FOR THE COMPANIES?

A103. No. Mr. Tillman did not conduct any analyses of the cost of equity. His testimony was limited to a presentation of selected data concerning previously authorized ROEs. Based on this limited review, Mr. Tillman expressed his concern that a 10.31% ROE for the Company is "excessive."[139]

Q103. DO YOU AGREE WITH MR. TILLMAN THAT ALLOWED ROES PROVIDE ONE BENCHMARK WORTHY OF CONSIDERATION IN THE COMMISSION'S EVALUATION?

[138] Baudino Direct at 43.
[139] Tillman Direct at 7.

A104. Yes, I do. Importantly, however, such comparisons of allowed ROEs are only one consideration. While this data can be useful in the KPSC's deliberations, it is not a substitute for the detailed analyses presented in my direct testimony.

Q104. DOES THE DATA PRESENTED BY MR. TILLMAN CONFIRM YOUR CONCLUSION THAT DR. WOOLRIDGE'S AND MR. BAUDINO'S RECOMMENDATIONS ARE TOO LOW?

A105. Yes. Mr. Tillman cites an average allowed ROE for vertically integrated utilities of 9.79% for 2014 through the present,[140] which confirms my earlier conclusion that the 8.60% and 8.85% ROE recommendations of the ROE Witnesses fall well below average returns authorized for other utilities, and are insufficient to meet the requirements of regulatory standards.

Q105. FROM YOUR POSITION AS A REGULATORY FINANCIAL ANALYST, WHAT DO YOU MAKE OF MR. TILLMAN'S ADMONITION (AT 7) TO CONSIDER CUSTOMER IMPACTS WHEN ESTABLISHING A FAIR ROE?

A106. First, it is important to note that the determination of the ROE is made by investors in the capital markets, and is not predicated on any notion of costs or savings to customers. The U.S. Supreme Court's regulatory standards embodied in the *Hope* and *Bluefield* decisions represent a balance between the interests of customers and investors, by setting forth the guidelines as to a fair ROE. Meanwhile, Mr. Tillman wrongly suggests that a lower ROE is *per se* in customers' benefit. This is not the case. While a downward-biased ROE may provide the illusion of customer "savings" in the form of a lower revenue requirement in the short-term, the long-term impact of an inadequate ROE can be injurious to customers and the Kentucky economy.

[140] *Id.* at 11.

As discussed earlier, there is a very real connection between the ROE and the availability of capital, and Mr. Tillman ignores the negative impact that an inadequate ROE would have on investment. The ROE is the primary signal to investors, not only with respect to attracting new capital investment, but also in supporting existing utility operations. If the utility is unable to offer a competitive ROE, existing shareholders will suffer a capital loss as investors take advantage of other, more favorable opportunities, and the utility's stock price would fall. Moreover, as investors' confidence is undermined, the ability of utilities to access equity capital markets and expand investment will suffer. While the Company would undoubtedly continue to meet their service obligations to customers, a downward-biased ROE would send an unmistakable signal to the investment community as they consider whether to commit capital in Kentucky, and at what cost.

Q106. DO YOU AGREE WITH MR. TILLMAN'S ASSESSMENT REGARDING THE IMPACT OF CONSTRUCTION WORK IN PROGRESS ("CWIP")?

A107. No. While Mr. Tillman attempts to distinguish the risks of the Company based on the opportunity to include CWIP in rate base, this is hardly novel or unique to the Company and has been widely utilized since the 1970s to address the impact of construction costs on utilities' financial integrity.

Q107. WHAT IS CWIP?

A108. CWIP consists of investment in facilities built to meet service obligations that are not yet physically providing service. For an electric utility, CWIP can be sizeable as a result of the capital intensity of utility infrastructure investment and the extended construction periods involved with these facilities. During the construction phase, the utility must pay capital carrying costs (interest, dividends, etc.) on the investment in new facilities. These capital carrying costs are typically accrued for future recovery in the form of Allowance for Funds Used During

Construction ("AFUDC"), which is included in rate base at the time the facilities are placed in service. Alternatively, regulators may allow CWIP to be included in rate base and thus permit the utility an opportunity to recover these capital costs through current rates.

Q108. WHAT IS THE FINANCIAL IMPACT OF CWIP?

A109. If CWIP is included in rate base, the utility's revenue requirements are increased by the capital costs associated with the new construction. As a result, since customers pay the capital carrying costs of CWIP in current rates, capitalized AFUDC is not added to plant cost. From the utility's standpoint, current cash flow is higher than it would have been otherwise. As a result, including CWIP in rate base improves a utility's cash flow and increases revenue requirements during the construction phase; however, this increase is offset in the future by the lower rate base that results from eliminating capitalized AFUDC.

While the level of a utility's earnings does not differ dramatically depending on whether or not CWIP is included in rate base, the cash flow implications can be significant, especially in the case of a large construction program. To finance the costs of construction, utilities such as the Company must obtain financing in the form of common equity or long-term debt. If CWIP is not included in rate base, no cash is generated from current rates to meet the interest and dividend payments associated with these securities, which in turn must be financed.

The uncertainties that investors associate with cost deferrals and a deterioration in earnings quality are significant and many of the key indicators relied on by securities analysts and bond rating agencies focus on measures of cash flow. As a result, the greater risk associated with higher levels of non-cash earnings (*i.e.*, AFUDC) would ultimately be reflected in higher rates of return required by investors. Investors recognize that including CWIP in rate base is an important tool that supports the utility's financial integrity and attenuates some of the financial risks associated with new infrastructure investment.

Q109. IS THERE ANY MERIT TO MR. TILLMAN'S CONTENTION (AT 9) THAT INCLUDING CWIP IN RATE BASE "SHIFTS RISKS ONTO RATEPAYERS?"

A110. No. Including CWIP in rate base will ease the financial pressure associated with the Company's capital projects by improving cash flow and providing greater regulatory certainty. While instrumental in supporting financial integrity and ability to attract capital, including CWIP will not have a measurable impact on the overall investment risks of the Company or investors' required rate of return. Including CWIP in rate base changes only the timing of cost recovery for projects included in CWIP. Accordingly, CWIP does not shift risks to ratepayers, as alleged by Mr. Tillman.

Q110. HAVE OTHER REGULATORS RECOGNIZED THE POTENTIAL BENEFITS ASSOCIATED WITH INCLUDING CWIP IN RATE BASE?

A111. Yes. Investors recognize that it is not uncommon for regulators to include CWIP in rate base when establishing rates. A study by the Edison Electric Institute observed that:

> The inclusion of CWIP in rate base improves cash flow and reduces future rate shocks. This practice also reduces the losses that a utility experiences making large plant additions under historical test year rates. Monitoring by the Edison Electric Institute has found that states that have recently allowed the inclusion of CWIP in rate base include CO, FL, GA, IN, KS, KY, LA, MI, MO, NC, NM, NV, SD, TN, VA, and WV.[141]

Accordingly, the cost of equity estimates developed for the proxy companies already reflects any impact associated with the opportunity to earn a return on CWIP. FERC has also recognized that including CWIP balances the

[141] Edison Electric Institute, *Forward Test Years for US Electric Utilities* (August 2010).

interest of investors and customers, and the Commission has routinely allowed electric utilities to include CWIP in rate base.[142] FERC noted in *Order No. 679* that including CWIP in rate base provides "up-front regulatory certainty, rate stability and improved cash flow" that encourage investment by "easing the financial pressures" associated with construction programs.[143]

Q111. IS MR. TILLMAN'S POSITION WITH RESPECT TO CWIP CONSISTENT WITH ESTABLISHED PRECEDENT IN KENTUCKY?

A112. No. Mr. Tillman's recommendations conflict with the KPSC's long-established support for including CWIP without any downward adjustment to the Company's ROE. Mr. Tillman has presented no evidence that would suggest the KPSC's longstanding practice no longer benefits customers or would otherwise undermine a constructive regulatory policy that is widespread in the industry. Moreover, while CWIP is supportive of the Company's credit standing, it does not allow recovery of a return on construction expenditures outside of a rate proceeding. As a result, there can be a significant lag between the time that expenditures are incurred and when they are included in CWIP, which is exacerbated for utilities with large capital expenditure programs, such as the Company. Mr. Tillman fails to address these realities, which further disprove his assessment and recommendations.

Q112. DOES THIS CONCLUDE YOUR PRE-FILED REBUTTAL TESTIMONY?

A113. Yes, it does.

[142] *Construction Work in Progress for Public Utilities; Inclusion of Costs in Rate Base*, Order No. 298, FERC Stats. & Regs. ¶ 30,455 (1983), order on reh'g, 25 FERC ¶ 61,023 (1983).

[143] *Order No.679* at P. 115. *See also, Order No. 679-A* at PP. 114-115.

Appendix A

STATE ALLOWED ROEs

RRA INTEGRATED ELECTRIC UTILITIES

(24-Months Ended September 30, 2017)

	Company	State	Date	Allowed ROE	Adder / Penalty	Base ROE
1	Wisconsin Public Service Corp.	WI	11/19/15	10.00%	0.00%	10.00%
2	Consumers Energy Co.	MI	11/19/15	10.30%	0.00%	10.30%
3	Mississippi Power	MS	12/03/15	9.23%	0.00%	9.23%
4	Northern States Power Co - WI	WI	12/03/15	10.00%	0.00%	10.00%
5	DTE Electric Co.	MI	12/11/15	10.30%	0.00%	10.30%
6	Portland General Electric Co.	OR	12/15/15	9.60%	0.00%	9.60%
7	Southwestern Public Service Co	TX	12/17/15	9.70%	0.00%	9.70%
8	Avista Corp.	ID	12/18/15	9.50%	0.00%	9.50%
9	PacifiCorp	WY	12/30/15	9.50%	0.00%	9.50%
10	MDU Resources Group	ND	01/05/16	10.50%	0.00%	10.50%
11	Avista Corp	WA	01/06/16	9.50%	0.00%	9.50%
12	Entergy Arkansas	AR	02/23/16	9.75%	0.00%	9.75%
13	Virginia Electric and Power	VA	(a)	(a)	(a)	9.60%
14	Indianapolis Power & Light Co.	IN	03/16/16	9.85%	-0.15%	10.00%
15	El Paso Electric Co.	NM	06/08/16	9.48%	0.00%	9.48%
16	Virginia Electric and Power	VA	(b)	(b)	(b)	9.60%
17	Northern Indiana Public Service Co.	IN	7/18/2016	9.98%	0.00%	9.98%
18	Kingsport Power Co.	TN	08/09/16	9.85%	0.00%	9.85%
19	UNS Electric	AZ	08/18/16	9.50%	0.00%	9.50%
20	PacifiCorp	WA	09/01/16	9.50%	0.00%	9.50%
21	Upper Peninsula Power	MI	09/08/16	10.00%	0.00%	10.00%
22	Public Service Co. of New Mexico	NM	09/28/16	9.58%	0.00%	9.58%
23	Appalachian Power Co.	VA	10/06/16	9.40%	0.00%	9.40%
24	Madison Gas & Electric Co.	WI	11/09/16	9.80%	0.00%	9.80%
25	Public Service Co. of Oklahoma	OK	11/10/16	9.50%	0.00%	9.50%
26	Wisconsin Power & Light Co.	WI	11/18/16	10.00%	0.00%	10.00%
27	Florida Power & Light Co.	FL	11/29/16	10.55%	0.00%	10.55%
28	Liberty Utilities	CA	12/01/16	10.00%	0.00%	10.00%
29	Duke Energy Progress	SC	12/07/16	10.10%	0.00%	10.10%
30	Black Hills Colorado Electric	CO	12/19/16	9.37%	0.00%	9.37%
31	Sierra Pacific Power Co.	NV	12/22/16	9.60%	0.00%	9.60%
32	Virginia Electric and Power	NC	12/22/16	9.90%	0.00%	9.90%
33	Avista Corporation	ID	12/28/16	9.50%	0.00%	9.50%
34	Appalachian Power Co.	VA	12/30/16	10.00%	0.00%	10.00%
35	MDU Resources Group	WY	01/18/17	9.45%	0.00%	9.45%
36	DTE Electric Co.	MI	01/31/17	10.10%	0.00%	10.10%
37	Tucson Electric Power Co.	AZ	02/24/17	9.75%	0.00%	9.75%
38	Virginia Electric and Power	VA	(c)	(c)	(c)	9.40%
39	Consumers Energy Co.	MI	02/28/17	10.10%	0.00%	10.10%
40	Otter Tail Power Co.	MN	03/02/17	9.41%	0.00%	9.41%
41	Oklahoma Gas and Electric Co.	OK	03/20/17	9.50%	0.00%	9.50%
42	Gulf Power Co.	FL	04/04/17	10.25%	0.00%	10.25%
43	Kansas City Power & Light	MO	05/03/17	9.50%	0.00%	9.50%
44	Northern States Power Co.	MN	05/11/17	9.20%	0.00%	9.20%
45	Oklahoma Gas and Electric Co.	AR	05/18/17	9.50%	0.00%	9.50%
46	Idaho Power Co.	ID	05/31/17	9.50%	0.00%	9.50%
47	Virginia Electric and Power	VA	(d)	(d)	(d)	9.40%
48	MDU Resources Group, Inc.	ND	06/16/17	9.65%	0.00%	9.65%
49	Kentucky Utilities Co.	KY	06/22/17	9.70%	0.00%	9.70%
50	Louisville Gas and Electric Co.	KY	06/22/17	9.70%	0.00%	9.70%
51	Arizona Public Service Co.	AZ	08/15/17	10.00%	0.00%	10.00%
52	Virginia Electric and Power	VA	09/01/17	9.40%	0.00%	9.40%

Range of Reasonableness	**9.20%**	**--**	**10.55%**
Midpoint		**9.88%**	
Average		**9.73%**	

RRA INTEGRATED ELECTRIC UTILITIES

Notes

(a) Adjusted to condense the following duplicative project-specific ROE orders:

	State	Date	Allowed ROE	Adder / Penalty	Base ROE
Virginia Electric and Power	VA	2/29/2016	11.60%	2.00%	9.60%
Virginia Electric and Power	VA	2/29/2016	10.60%	1.00%	9.60%
Virginia Electric and Power	VA	2/29/2016	10.60%	1.00%	9.60%
Virginia Electric and Power	VA	2/29/2016	10.60%	1.00%	9.60%
Virginia Electric and Power	VA	3/29/2016	9.60%	0.00%	9.60%

(b) Adjusted to condense the following duplicative project-specific ROE orders:

	State	Date	Allowed ROE	Adder / Penalty	Base ROE
Virginia Electric and Power	VA	6/30/2016	10.60%	1.00%	9.60%
Virginia Electric and Power	VA	6/30/2016	9.60%	0.00%	9.60%

(c) Adjusted to condense the following duplicative project-specific ROE orders:

	State	Date	Allowed ROE	Adder / Penalty	Base ROE
Virginia Electric and Power	VA	2/27/2017	11.40%	2.00%	9.40%
Virginia Electric and Power	VA	2/27/2017	9.40%	0.00%	9.40%
Virginia Electric and Power	VA	2/27/2017	10.40%	1.00%	9.40%
Virginia Electric and Power	VA	2/27/2017	10.40%	1.00%	9.40%
Virginia Electric and Power	VA	2/27/2017	10.40%	1.00%	9.40%

(d) Adjusted to condense the following duplicative project-specific ROE orders:

	State	Date	Allowed ROE	Adder / Penalty	Base ROE
Virginia Electric and Power	VA	6/1/2017	9.40%	0.00%	9.40%
Virginia Electric and Power	VA	6/30/2017	9.40%	0.00%	9.40%
Virginia Electric and Power	VA	6/30/2017	10.40%	1.00%	9.40%

Source: Regulatory Research Associates, "Major Rate Case Decisions," *Regulatory Focus* (Jan. 14, 2016; Jan. 18, 2017); S&P Global, "Major Rate Case Decisions," *RRA Regulatory Focus* (Oct. 26, 2017).

STATE ALLOWED ROEs

UTILITY GROUP

	Company	(a) Allowed ROE		
1	Alliant Energy	10.50%		
2	Ameren Corp.	9.15%		
3	American Elec Pwr	10.28%		
4	AVANGRID, Inc.	9.23%		
5	CMS Energy Corp.	10.10%		
6	Dominion Energy	10.90%		
7	DTE Energy Co.	10.10%		
8	Duke Energy Corp.	10.31%		
9	Emera Inc.	NA		
10	Eversource Energy	9.52%		
11	Fortis, Inc.	9.31%		
12	NextEra Energy, Inc.	10.60%		
13	PPL Corp.	9.70%		
14	Pub Sv Enterprise Grp.	10.30%		
15	SCANA Corp.	10.07%		
16	Sempra Energy	10.20%		
17	Southern Company	12.50%		
18	Vectren Corp.	10.28%		
	Range of Reasonableness	**9.15%**	--	**12.50%**
	Midpoint	**10.83%**		
	Average	**10.18%**		

(a) The Value Line Investment Survey (Jul. 28, Aug. 18 & Sep. 15, 2017).

EXPECTED EARNINGS APPROACH

UTILITY GROUP

		(a)	(b)	(c)
	Company	**Expected Return on Common Equity**	**Mid-Year Adjustment Factor**	**Adjusted Return on Common Equity**
1	Alliant Energy	13.0%	1.0044	13.1%
2	Ameren Corp.	10.0%	1.0196	10.2%
3	American Elec Pwr	11.0%	1.0208	11.2%
4	AVANGRID, Inc.	5.0%	1.0064	5.0%
5	CMS Energy Corp.	13.5%	1.0356	14.0%
6	Dominion Energy	19.0%	1.0025	19.0%
7	DTE Energy Co.	10.5%	1.0258	10.8%
8	Duke Energy Corp.	8.5%	1.0090	8.6%
9	Emera Inc.	13.0%	1.0183	13.2%
10	Eversource Energy	10.0%	1.0193	10.2%
11	Fortis, Inc.	8.0%	1.0273	8.2%
12	NextEra Energy, Inc.	14.0%	1.0349	14.5%
13	PPL Corp.	13.5%	1.0352	14.0%
14	Pub Sv Enterprise Grp.	11.0%	1.0175	11.2%
15	SCANA Corp.	11.0%	1.0013	11.0%
16	Sempra Energy	13.0%	1.0057	13.1%
17	Southern Company	12.5%	1.0146	12.7%
18	Vectren Corp.	12.0%	1.0119	12.1%
	Average (d)			**11.8%**
	Average-Woolridge Group (d,e)			**11.9%**
	Average-Baudino Group (d,f)			**11.9%**

(a) The Value Line Investment Survey (Jul. 28, Aug. 18 & Sep. 15, 2017).
(b) Computed using the formula 2*(1+5-Yr. Change in Equity)/(2+5 Yr. Change in Equity).
(c) (a) x (b).
(d) Excluding highlighted values.
(e) Excluding Emera and Fortis.
(f) Excluding AVANGRID, Emera, and Fortis.