COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

The Electronic Application of Duke Energy Kentucky, Inc., for: 1) An Adjustment of the Electric Rates; 2) Approval of an Environmental Compliance Plan and Surcharge Mechanism; 3) Approval of New Tariffs; 4) Approval of Accounting Practices to Establish Regulatory Assets and Liabilities; and 5) All Other Required Approvals and Relief.	)	Case No. 2017-00321

REBUTTAL TESTIMONY

OF

JOHN J. SPANOS

ON BEHALF OF

DUKE ENERGY KENTUCKY, INC.

February 14, 2018

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I. <u>INTRODUCTION AND PURPOSE</u>

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is John J. Spanos. My business address is 207 Senate Avenue, Camp Hill, Pennsylvania, 17011.

Q. HAVE YOU PREVIOUSLY SUBMITTED TESTIMONY IN THIS PROCEEDING?

A. Yes. I previously submitted direct testimony on behalf of Duke Energy Kentucky on September 1, 2017.

Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY?

A. The purpose of my rebuttal testimony is to respond to the direct testimony of Kentucky Office of the Attorney General (AG) witness, Mr. Lane Kollen.

Q. WHAT ARE THE SUBJECTS OF YOUR REBUTTAL TESTIMONY?

A. The subjects of my rebuttal testimony relate to the most appropriate depreciation methods for establishing depreciation rates. Specifically, while I have used widely accepted methods and approaches to depreciation, Mr. Kollen has proposed significant changes from the methods currently used for the Company's depreciation rates. The first subject I will address relates to various components of net salvage. The second subject is the utilization of the Equal Life Group (ELG) procedure.

Q. PLEASE SUMMARIZE THESE DEPRECIATION ISSUES.

A. My testimony will respond to the depreciation related proposals of AG witness, Kollen, as mentioned above. There is no opposition to the service lives or probable retirement dates of any asset class. Mr. Kollen did not perform a depreciation study nor did he analyze transactional data. However, he does develop alternative depreciation expense levels which I will address. Specifically, my testimony sets forth the following depreciation issues:

- The Attorney General proposes to defer the recovery of net salvage after the Company's assets have been retired. That is, he proposes to not allow for the recovery of future net salvage prospectively through depreciation rates. In general, his net salvage proposals and overall approach violates the requirements of the Uniform System of Accounts (USOA), is not consistent with widely accepted depreciation practices, and is a significant departure from prior practices of the Company and other Kentucky utilities. Specifically, the Attorney General makes two different, but related, proposals for net salvage:
  - The Attorney General proposes to eliminate the terminal net salvage component for generating facilities. This is inconsistent with current practices for Duke Energy Kentucky and is inconsistent with proper recovery practices set forth in the USOA.
  - For interim net salvage for production plant and for net salvage for all non-production plant accounts, the Attorney General proposes to defer the recovery of net salvage until the Company's assets are retired. This approach is also inconsistent with the USOA, which requires the recovery of net salvage over the service lives of the Company's assets
- The Attorney General has proposed to utilize the Average Life Group (ALG) procedure as compared to the more accurate ELG procedure. The ELG

procedure, which is currently used for the Company's depreciation rates, more accurately matches the recovery of the assets to the utilization of the assets while in service.

II. NET SALVAGE

A. INTRODUCTION

Q. WHAT IS NET SALVAGE?

A. Net salvage, as used in depreciation, is defined as gross salvage less cost of removal. When an asset is retired it may have scrap or reuse value, which is gross salvage. There is also a cost to retire the asset. For example, the retirement of a distribution pole typically requires a multiple person crew and heavy equipment to remove the pole from the ground and cut the pole for disposal. There also may be disposal costs for the pole. All of these costs associated with the retirement are cost of removal.

Most types of utility property typically experience negative net salvage, meaning that cost of removal exceeds gross salvage. Examples may include the cost to remove a pole during a pole replacement project or the cost to decommission a power plant after retirement. These costs need to be recovered over the period of time the assets are in service.

Q. IS NET SALVAGE INCLUDED IN DEPRECIATION?

A. Yes. Net salvage is part of the service value, or overall cost, of an asset. In order to equitably allocate the full cost of an asset over its service life, net salvage must be estimated while the asset is still in service and allocated over the life of the asset. If, instead, the recovery of net salvage costs are deferred until (or after) the asset is retired, then future customers will have to pay the full net salvage cost for an asset that is no longer in service. This is the approach Mr. Kollen has proposed and his approach results in intergenerational inequity by forcing future customers to pay the costs of assets from which they will not receive electric service.

Q. MR. KOLLEN DISCUSSES "THREE APPROACHES" TO NET SALVAGE ON PAGES 36 THROUGH 38 OF HIS TESTIMONY. WHAT ARE THE APPROACHES HE DISCUSSES?

A. Mr. Kollen sets forth three possible approaches for the recovery of net salvage. In summary, these approaches are as follows:

1. Net salvage is recovered through depreciation over the life of an asset;
2. No net salvage is included in depreciation; and
3. Net salvage is amortized over a period of time after the asset is retired.

What Mr. Kollen does not say is that only the first of these approaches is consistent with the USOA, is widely accepted, and results in intergenerational equity. The second and third approaches recover net salvage after an asset has been retired, which is not consistent with the USOA or widely accepted depreciation practices. Mr. Kollen has generally used the third approach.

Q. WHAT DOES THE USOA REQUIRE FOR NET SALVAGE?

A. In General Instruction 22, the USOA requires that

> Utilities must use a method of depreciation that allocates in a systematic and rational manner the service value of depreciable property <u>over the service life</u> of the property. (Emphasis added)

Service value is defined as "the difference between original cost and net salvage value of electric plant."[1] Thus, the USOA is clear that net salvage must be allocated <u>over the service life</u> of utility property. Mr. Kollen's proposals do not meet this requirement. Instead, under his approach net salvage is "deferred" until when or after property is retired and his recommended depreciation rates do not include an estimate of "future net salvage."[2] Mr. Kollen's proposals, therefore, do not comply with the requirements of the USOA.

Q. ARE YOUR NET SALVAGE PROPOSALS FOR THE COMPANY BASED ON WIDELY ACCEPTED DEPRECIATION PRACTICES?

A. Yes.

Q. ARE THE AG'S NET SALVAGE PROPOSALS BASED ON WIDELY ACCEPTED DEPRECIATION PRACTICES?

A. No.

Q. HOW IS NET SALVAGE ESTIMATED IN A DEPRECIATION STUDY?

A. The method of estimating net salvage depends on the type of property. For power plants, the estimate is typically based on a decommissioning study. These costs are typically estimates of the cost to retire a facility today, and therefore need to be adjusted to estimate the cost that will be incurred in the future when the plant is actually retired.

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[1] FERC Uniform System of Accounts, definition 37.
[2] *See* Direct Testimony of Lane Kollen, p. 37, lines 18-21.

For interim net salvage for power plants, and for mass property accounts such as transmission and distribution plant accounts, net salvage estimates are based in part on statistical analyses of historical net salvage data. In this analysis, net salvage (as well as its components of gross salvage and cost of removal) is expressed as a percentage of retirements. This approach, which is widely-accepted in the industry and supported by depreciation textbooks, is referred to as the "traditional method."

Q. ARE YOUR ESTIMATES FOR NET SALVAGE CONSISTENT WITH THE APPROACHES USED FOR THE DEPRECIATION RATES CURRENTLY USED BY THE COMPANY?

A. Yes. The current depreciation rates for production plant incorporate estimates of decommissioning costs which are escalated to the time of retirement, as I have also done in the instant case. The current depreciation rates for mass property accounts are based on the traditional method of estimating net salvage. In both of these instances, the AG has proposed a change from the Commission's current practices for Duke Energy Kentucky's depreciation rates.

Q. HOW WILL YOU ADDRESS THE NET SALVAGE RECOMMENDATIONS OF MR. KOLLEN?

A. As discussed above, Mr. Kollen's proposals are not consistent with widely accepted depreciation concepts. I will discuss these issues in more detail, explain the ratemaking impacts of Mr. Kollen's proposals to defer the recovery of net salvage costs, and also address Mr. Kollen's alternate proposal to exclude the escalation of decommissioning costs to the time of retirement.

B. <u>THE AG'S PROPOSAL IS NOT BASED ON WIDELY ACCEPTED METHODS</u>

Q. IS THE METHOD YOU HAVE USED TO ESTIMATE NET SALVAGE WIDELY ACCEPTED IN THE ELECTRIC INDUSTRY?

A. Yes. The traditional method of recovering net salvage over the life of a Company's assets is used by the vast majority of regulatory commissions in the United States. Specifically:

- The traditional method meets the requirements of the FERC's Uniform System of Accounts, while the AG's method does not;
- The traditional method has been used for many depreciation studies in Kentucky, including for the Company's current depreciation rates;
- The traditional method is widely accepted in the industry in other jurisdictions, whereas the AG's method is not; and
- The traditional method is supported and endorsed by authoritative depreciation texts whereas the AG's method is not.

i. Uniform System of Accounts

Q. WHAT IS THE FERC USOA?

A. The USOA is the standard set of definitions, rules and instructions established by the FERC that provides consistency in accounting for utilities under its jurisdiction. Most jurisdictions, including Kentucky, have adopted the USOA for the utilities they regulate.

Q. DOES THE USOA ADDRESS THE ISSUE OF HOW NET SALVAGE COSTS SHOULD BE ACCOUNTED FOR, AND IF SO, HOW?

A. Yes. The USOA provides that net salvage costs should be accrued over the course of an asset's service life (*i.e.*, recognized in each period in which the asset provides service) in a systematic and rational manner.

Q. PLEASE DISCUSS IN MORE DETAIL THE USOA'S TREATMENT OF DEPRECIATION.

A. The USOA defines depreciation as follows:

> Depreciation, as applied to depreciable electric plant, means the loss in service value not restored by current maintenance, incurred in connection with the consumption or prospective retirement of electric plant in the course of service from causes which are known to be in current operation and against which the utility is not protected by insurance. Among the causes to be given consideration are wear and tear, decay, action of the elements, inadequacy, obsolescence, changes in the art, changes in demand and requirements of public authorities.[3]

Q. IN THE QUOTE ABOVE, THE USOA REFERS TO DEPRECIATION AS THE "LOSS IN SERVICE VALUE." WHAT IS SERVICE VALUE?

A. As discussed previously, service value, as defined in the USOA, is "the difference between original cost and net salvage value of electric plant."[4] Thus, the USOA requires that depreciation include net salvage as well as the original cost of the Company's assets in depreciation.

Q. DOES THE USOA ALSO DEFINE WHAT IT MEANS BY "NET SALVAGE VALUE"?

A. Yes. "'Net salvage value' means the salvage value of property retired less the cost of removal."[5] Net salvage is described as "positive net salvage" if the salvage value

[3] FERC Uniform System of Accounts, definition 12.
[4] FERC Uniform System of Accounts, definition 37.
[5] FERC Uniform System of Accounts, definition 19.

exceeds removal costs, and described as "negative net salvage" (*i.e.*, a net cost) if removal costs exceed the salvage value. These costs are recorded to accumulated depreciation at the cost expended (or received as salvage) at the time they occur, but are included in depreciation expense over the service lives of the assets.

Q. DOES THE USOA PRESCRIBE A METHOD OF DEPRECIATION ACCOUNTING?

A. Yes. The electric USOA includes General Instruction 11, "Accounting to be on accrual basis," which states, "[t]he utility is required to keep its accounts on the accrual basis." Further, as discussed previously, General Instruction 22 in the Electric Uniform System of Accounts, "Depreciation Accounting," states:

> Utilities must use a method of depreciation that allocates in a systematic and rational manner the service value of depreciable property over the service life of the property.

Q. WHAT IS THE ACCRUAL BASIS OF ACCOUNTING?

A. Under the accrual basis of accounting, transactions are counted when the order is made, the item is delivered, or the service occurs, regardless of when any money for such orders, items, or services is actually received or paid. The accrual basis recognizes economic events without regard to when the related cash transaction occurs. Thus, net salvage costs are traditionally recognized when the service is rendered – that is, during each year of an asset's service life - rather than when the actual salvage-related costs are incurred. Any method that recognizes net salvage costs after the costs are incurred would be inconsistent with the concept of accrual accounting, as the costs are recognized as an expense at a time when the asset is no longer rendering service.

Q. DOES THE AG'S METHOD ALLOCATE "IN A SYSTEMATIC AND RATIONAL MANNER THE SERVICE VALUE OF DEPRECIABLE PROPERTY OVER THE SERVICE LIFE OF THE PROPERTY?"

A. No. As I have discussed previously, the AG proposes to recover net salvage concurrent with or after the retirement of the Company's assets. It does not incorporate the future net salvage costs for assets that are currently in service and, therefore, does not allocate the service value of depreciable property over its service life.

ii. The Traditional Method of Net Salvage is Used in Most Jurisdictions, Including Kentucky

Q. WHAT NET SALVAGE METHODS ARE USED IN OTHER JURISDICTIONS?

A. The net salvage approach that I have used (*i.e.*, the first approach described by Mr. Kollen) is the predominate method accepted by the vast majority of jurisdictions in the United States. To my knowledge, the traditional method is accepted by the vast majority of U.S. states (including Kentucky) and by FERC.

Q. HAS MR. KOLLEN PROVIDED ANY EVIDENCE OF ANY U.S. JURISDICTIONS THAT USE HIS PROPOSED NET SALVAGE APPROACH?

A. No.

Q. HAVE THE METHODS YOU HAVE PROPOSED BEEN ACCEPTED PREVIOUSLY IN KENTUCKY?

A. Yes. Again, the current depreciation rates are based on the same methods I have used for net salvage in the instant case.

Q. ARE YOU FAMILIAR WITH ANY STATES THAT HAVE SPECIFICALLY REJECTED ALTERNATIVE PROPOSALS FOR NET SALVAGE, SUCH AS THAT PROPOSED BY THE AG, IN RECENT YEARS?

A. Yes. There are a number of states that have rejected proposals similar to the AG's. I will discuss four of these in my testimony.

Q. PLEASE ADDRESS THE ACCEPTANCE OF NET SALVAGE METHODS IN INDIANA.

A. In a 2004 case for an affiliate Company, PSI Energy (now Duke Energy Indiana), the Indiana Commission addressed the approach to recover net salvage for both mass property and production plant accounts, and also addressed the appropriateness of including future inflation in net salvage. Proposals of intervenors in that case were similar to those of Mr. Kollen for both decommissioning costs and for interim and mass property net salvage. For each of these issues, the Indiana Commission ruled in favor of the methods I have proposed in the instant case and rejected Mr. Kollen's proposals.

The Indiana Commission affirmed that net salvage should be included for production plant accounts, stating:

> The next issue is the timing of the collection of such costs. The parties did not disagree that dismantling costs are a part of the cost of current facilities providing current service. They disagreed as to the timing of the collection of such costs and their amount. This Commission can either find that current customers should pay a share of dismantling costs, which will not be incurred for a number of years, or, in the alternative, conclude that these costs should be passed on to a future generation of customers. This Commission does not believe that the latter alternative constitutes sound regulatory policy, or is based on sound ratemaking principles. Current customers are

> receiving service from PSI's generation facilities. A part of the costs of those facilities is dismantlement upon retirement. Therefore, we do not believe it would be appropriate for the Company to backload the dismantlement costs for future ratepayers to pay when the facilities associated with these costs are providing service to current customers. Rather, we find it is appropriate that these costs be shared by all customers that received service from PSI's generation facilities. Accordingly, this Commission finds that dismantlement costs are properly included in determining the depreciation rates approved in this cause.[6]

The Indiana Commission also affirmed that future net salvage estimates should incorporate future inflation, which supports my proposal to escalate the decommissioning costs to the time of retirement:

> The final issue regarding dismantlement costs is whether inflation should be factored into the dismantlement cost estimates to be utilized in determining PSI's depreciation rates. Mr. Selecky and Mr. Majoros objected to the use of inflation. Mr. Spanos utilized Mr. Wendorfs dismantlement costs which are stated in 2002 dollars, and factored inflation up to the year of the projected dismantlement as a factor in his consideration, along with his analyses of historical or interim retirements. 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. A 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

[6] Order 051804 in Indiana Cause No. 42359, Issued May 18, 2004, page 70.

dismantlement estimates to be used as part of PSI's depreciation rates is reasonable.[7]

Finally, the Indiana Commission ruled against an approach similar to Mr. Kollen's proposal for interim and mass property net salvage. The Indiana Commission first explained the proposals of intervenor parties in that case:

> Turning to the net salvage values for transmission, distribution and general plant, Mr. Selecky and Mr. Majoros urged this Commission to utilize historical average of actual net salvage expense incurred by PSI for determining the net salvage to be utilized for these accounts and then expense these averages as a separate cost of service item. In effect, they are proposing that net salvage values be eliminated from the depreciation rates determination in this proceeding. In contrast, Mr. Spanos took the traditional approach and utilized estimated net salvage values for these accounts based on historical net salvage costs as a percent of the original cost of the retired assets that produced the gross salvage or required costs to remove. Mr. Majoros recognized that Mr. Spanos' approach was not abnormal, but he and Mr. Selecky cited a number of state commissions where an historical average approach had been adopted.[8]

The Indiana Commission rejected proposals of the intervenors in that case:

> We believe that there is a sound basis for the traditional approach on this issue that is utilized by a majority of states. Utilizing historical averages as an item to be expensed to current customers means that these customers will be paying for salvage costs at levels that may not be sufficient. That means that the next generation of customers will be paying for salvage costs related to facilities from which they may never have received service. The use of best estimates of future salvage costs addresses this inequity. Moreover, use of historical averages for dismantling costs does not take into account the current configuration of PSI's system with regard to its production, transmission, distribution and general facilities. Facilities in service 40-50 years ago did not take into account the significantly enhanced customer base that PSI now serves, nor the current configuration of

[7] Order 051804 in Indiana Cause No. 42359, Issued May 18, 2004, page 71.

> PSI's facilities that serve these customers. It seems appropriate to utilize best cost estimates for net salvage values taking into account specific facilities now serving PSI's customers in developing depreciation rates that today's customers should pay. Accordingly, we find that the use of historical averages for net salvage values with regard to transmission, distribution and general plant for the purpose of expensing them outside the context of the depreciation determination should be, and hereby is rejected.[9]

Q. PLEASE EXPLAIN THE ACCEPTANCE OF NET SALVAGE METHODS IN MISSOURI.

A. Missouri provides another example of a party making a net salvage proposal that was similar in concept to what Mr. Kollen has proposed. In the Missouri case, it was the commission staff that made such a proposal. However, the Missouri Public Service Commission (MPSC) rejected its Staff's proposal and affirmed the use of the traditional method that I have proposed in the instant case. The MPSC's Order in that case stated that:

> The Commission finds that Laclede has shown the accrual method to be just and reasonable and that Staff has failed to show that the Commission should adopt Staff's method of accounting for net salvage.[10]

Again, the MPSC Staff's proposal was similar in concept to what Mr. Kollen has proposed in the instant case. In the Laclede case, Laclede's proposal (referred to as the "accrual method" throughout the Laclede order) was the traditional method I have used in the depreciation study in the instant case.

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[8] Order 051804 in Indiana Cause No. 42359, Issued May 18, 2004, page 71.
[9] Order 051804 in Indiana Cause No. 42359, Issued May 18, 2004, pages 71-72.
[10] Missouri Case No. GR-99-315, Third Report and Order issued January 11, 2005, p. 16

The Laclede Order provides a number of important comments on the net salvage issue. First, the MPSC notes that while the utility had the burden of proof in the Laclede case, "Staff is the party advocating a change in the depreciation method used not only by Laclede, but almost all utilities in the country."[11] That is, the MPSC recognized that since the Missouri Staff was advocating a departure from widely accepted and longstanding depreciation practices, the Missouri Staff had an obligation to demonstrate why such a departure was appropriate. In the Laclede case, the Missouri Staff failed to provide justification for such a change, just as Mr. Kollen has failed to do so in the instant case.

Q. WHAT OTHER CONCEPTS DOES THE MPSC DISCUSS IN THE LACLEDE ORDER?

A. The MPSC discusses a number of important comments in its order. The MPSC recognizes that the traditional method is widely accepted, stating that:

> The accrual method has been used by Laclede and the Commission to determine Laclede's depreciation rates since at least the early 1950s. It is undisputed that using the accrual method for this purpose is supported by the overwhelming weight of authority on such matters. In both evidentiary hearings, Laclede and AmerenUE provided evidence showing the widespread support among depreciation professionals and authoritative texts for the traditional, or accrual, method of treating net salvage.
>
> Laclede and AmerenUE also established, and no party disputed, that such a method is consistent with the requirements of the Uniform System of Accounts that this Commission has adopted, and depreciation practices recognized and followed in all but a few regulatory jurisdictions in the United States. In contrast, Staff was unable to cite any depreciation practitioner, outside of other Staff

[11] *Id.* at 7.

> members, or any depreciation treatise that addressed its proposed treatment of net salvage. In addition, Staff was unable to adequately support or explain its reasoning for adopting this new approach.[12]

The MPSC also addressed the fact that net salvage accruals should be expected to be higher than current (or recent) net salvage expenditures. The MPSC stated:

> In criticizing the accrual method for determining net salvage, Staff did show that Laclede is recovering more in depreciation for net salvage than it is currently spending. Ratepayers pay $2.3 million more in depreciation annually under the accrual method than under Staff's proposed expense method.
>
> Laclede explained this result, however, with evidence showing a consistent and significant upward trend over time in both the installation cost of the plant used by Laclede to provide utility service, as well as in the cost to remove such plant from service. In fact, just maintaining the net salvage percentage at its historical rate would result in a higher level of net salvage costs than that currently being realized by the Company, since it applies to an asset base that has grown and continues to grow over time. For example, the evidence shows that in 1950 Laclede's total plant in service was only 6 percent of what it is today.[13]

The MPSC also addressed intergenerational equity, stating:

> Since it is clear from the evidence in this case that the accrual method comes closer to matching the costs to the benefits derived, the Commission finds that intergenerational equity will be promoted by the continued use of the accrual method.[14]

The MPSC also noted the issue of cash flow:

> The Commission also finds that Staff's method significantly decreases the cash flows available to utilities to meet their infrastructure and other public service obligations. This, in turn, has a negative financial impact on both the utility and its customers by

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[12] *Id.* at 8-9. (Emphasis added).
[13] *Id.* at 9-10.
[14] *Id.* at 11-12.

> requiring that such obligations be met with more expensive sources of external financings and by driving up the cost generally of obtaining money in the capital markets. The Commission finds that Staff has not shown that the adoption of its method would justify these increased costs for utility consumers.[15]

Q. HAS ILLINOIS RULED IN FAVOR OF THE TRADITIONAL METHOD?

A. Yes. One example is a case for Ameren's Illinois subsidiaries. The Illinois Commission rejected a method for net salvage that was similar to what Mr. Kollen has proposed in the instant case. The Illinois Commission stated:

> The Commission does not concur with IIEC and the Commercial Group's proposal to depart from the Commission's current treatment of net salvage costs; specifically, using the traditional, accrual method of accounting for net salvage. Although there are some regulatory commissions that have moved away from the methods prescribed for depreciation, this Commission is not inclined to do so as the evidence does not show it is necessary. It has been appropriate to use the traditional method by allocating the cost to each year of the assets' service life rather than when the actual salvage-related costs are incurred. This method of depreciation allocates in a systematic and rational manner the service value of depreciable property over the service life of the property. IIEC's complaint that customers today will pay the same number of dollars as future customers represents a misunderstanding or misrepresentation of the purpose of systematic recovery of depreciation expense, which provides for rate recovery of long-lived assets over their expected useful life. In contrast, the net salvage approach advocated by IIEC and the Commercial Group would improperly push costs into the future that are more appropriately borne by current ratepayers. The Commission understands why such an approach may appear attractive in the short-run, but in the long-term it provides no benefit to ratepayers in aggregate. Further, contrary to the Commercial Group's assertion, the Commission concludes that AIU's reliance on some net salvage estimates from other electric utilities does not result in over-projecting net salvage expense relative to AIU's current net salvage

[15] *Id.* at 14.

> expense. In conclusion, the accrual method for calculating net salvage is consistent with the Commission accounting practices for regulated utilities, has been accepted, deemed appropriate for years, and the Commission remains convinced that it is appropriate in this case.[16]

Q. HAS CALIFORNIA REJECTED PROPOSALS SIMILAR TO THOSE OF MR. KOLLEN?

A. Yes. Proposals similar to those of Mr. Kollen have been proposed and rejected in multiple cases in California.

Q. PLEASE CONTINUE.

A. Various alternative methods for net salvage have been proposed in a number of cases in California. In each case, the non-traditional approaches were rejected.

One such proposal was in Pacific Gas & Electric's (PG&E) 2007 General Rate Case. The Utility Reform Network (TURN) proposed an approach that was very similar to what Mr. Kollen has proposed in the instant case. As the CPUC explained:

> For the previous reasons, TURN recommends that the Commission eliminate inflation from the determination of removal costs. TURN proposes that <u>removal costs for this GRC cycle be based on a rolling three-year or five-year average of PG&E's recorded removal costs</u>. TURN calls this alternative the "normalized net salvage approach." PG&E's revenue requirement for removal costs in 2007 would be $88 million based on a three-year average of historical removal costs or $63 million based on a five-year average.[17]

TURN's proposal in that proceeding to use a 3- or 5-year average of recorded removal costs is based on the same premise as Mr. Kollen's of recovering net salvage

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[16] *See* pages 138 and 139 of the Illinois Commerce Commissions order, dated September 24, 2008, in Docket Nos. 07-0585, 07-0586, 07-0587, 07-0588, 07-0589 and 07-0590.

[17] *See* California D.07-03-044 in A.05-12-002, pp. 226 and 227. (Emphasis added)

concurrent with or after retirement. The CPUC rejected TURN's proposal in PG&E's 2007 GRC. The CPUC explained as follows:

> The issue before us is whether to adopt TURN's proposed "normalized net salvage allowance approach" for setting rates to recover asset removal costs. Under TURN's approach there will be no recovery of removal costs until after assets have retired and the associated removal costs have been incurred. TURN's method is, in effect, a form of cash-basis accounting.
>
> TURN's proposal is a marked departure from the current accrual accounting for removal costs. The purpose of using accrual accounting is to allocate to current ratepayers their pro rata share of the costs that will eventually be incurred to remove those assets that are currently being used to provide utility service. This treatment is in harmony with GAAP, the USOA, and longstanding Commission practice under SP U-4.
>
> Accrual accounting for removal costs is fair to ratepayers because it ensures that ratepayers pay for the removal costs of those assets that serve them, and pay no removal costs for assets that do not serve them. On the other hand, TURN's proposal would require ratepayers to pay for removal costs incurred in prior years for assets that are no longer in service. As a matter of equity, we believe that ratepayers should pay only for those assets that currently serve them. TURN's proposal fails this test.[18]

Q. WERE SIMILAR PROPOSALS REGARDING NET SALVAGE PROPOSED BY TURN AND REJECTED BY THE CPUC FOR OTHER CALIFORNIA UTILITIES?

A. Yes. The language from the original order in the most recent case that addressed the net salvage methodology in California, CPUC Docket No. A.06-12-009, summarizes CPUC policy and explains that alternative net salvage methodologies, including a

[18] *See* California D.07-03-044 in A.05-12-002, pp. 226 and 227.

normalized expense approach, were rejected repeatedly in California. The following language is from this case for Sempra Energy in which TURN had challenged the traditional method. In the original Decision 08-07-046, issued August 1, 2008, the CPUC stated on page 23 (emphasis added):

> The alternative methodology proposed by TURN <u>was not adopted in the most recent Pacific Gas & Electric Company (PG&E) and Southern California Edison Company (SCE) GRCs</u>. We would therefore have denied with prejudice the recommendations of DRA, TURN, and UCAN on depreciation and net salvage in a litigated decision. The purpose of this discussion of our likely denial is to avoid an unnecessary repetition in subsequent proceedings. Any party that raises these issues again should have new analysis and new arguments which may persuade us, unlike the arguments raised here or in other recent rate proceedings.

I present the discussion from Docket No. A.06-12-009 because the CPUC makes clear that it had rejected a normalized expense method multiple times.

Q. A PREMISE OF MR. KOLLEN'S APPROACH IS THAT NET SALVAGE ACCRUALS SHOULD BE BASED ON THE LEVEL OF NET SALVAGE EXPENSE RECORDED IN RECENT YEARS. HAS THE CPUC ADDRESSED THE RELATIONSHIP OF NET SALVAGE ACCRUALS TO NET SALVAGE EXPENSE?

A. Yes. It is important to note that other commissions have recognized that these costs should not be the same (*i.e.*, that net salvage accruals will normally be higher than net salvage expense). In California, the CPUC stated in SCE's 2012 GRC Decision D.12-11-051 (emphasis added):

> We are also not persuaded to retain existing rates just because SCE currently <u>accrues negative net salvage at a level higher than annual</u>

> recorded COR. Even if SCE will have sufficient funds to cover removal or net salvage costs in the foreseeable future, it leaves the question of long-term intergenerational equity versus short-term rate tolerance.

Q. DOES FERC ACCEPT THE TRADITIONAL METHOD YOU HAVE PROPOSED?

A. Yes. In fact, in an ongoing case before FERC for Pacific Gas and Electric Company, an intervenor proposed to estimate net salvage in a similar manner to what Mr. Kollen proposed in the instant case. FERC Trial Staff strongly opposed such an approach, and argued that it was not consistent with the USOA.[19]

iii. Authoritative Depreciation Texts Support That Net Salvage Should Be Included in Depreciation

Q. DO AUTHORITATIVE TEXTS ON DEPRECIATION ADDRESS THE ISSUE OF WHETHER NET SALVAGE SHOULD BE ACCRUED DURING THE LIFE OF THE RELATED PLANT?

A. Yes, they do.

Q. WHAT DO THESE TEXTS PROVIDE?

A. Two widely cited, preeminent depreciation texts are the NARUC Public Utility Depreciation Practices (the NARUC Manual) and Depreciation Systems by Wolf and Fitch (Wolf and Fitch). Each explains that net salvage should be accrued over the life of the related property and should be estimated using the traditional method.

[19] *See* Exhibit S-0001 in FERC Docket No. ER16-2320-000.

Q. DO BOTH OF THESE TEXTS SUPPORT THE TRADITIONAL METHOD THAT YOU HAVE PROPOSED?

A. Yes. Both texts support the traditional method.

Q. PLEASE EXPLAIN.

A. The NARUC Manual states at page 157:

> Historically, most regulatory commissions have required that both gross salvage and cost of removal be reflected in depreciation rates. The theory behind this requirement is that, since most physical plant placed in service will have some residual value at the time of retirement, the original cost recovered through depreciation should be reduced by that amount. Closely associated with this reasoning is the accounting principle that revenues be matched with costs and the regulatory principle that utility customers who benefit from the consumption of plant pay for the cost of that plant, no more, no less. The application of the latter principle also requires that the estimated cost of removal of plant be recovered over its life.

The 1994 edition of Depreciation Systems states at page 7:

> The matching principle specifies that all costs incurred to produce a service should be matched against the revenue produced. Estimated future costs of retiring of an asset currently in service must be accrued and allocated as part of the current expenses.

Thus, both of these texts use mandatory language when describing the traditional approach of accruing "retirement" or "removal" costs over the life of the plant. Further, both also support the method of estimating net salvage I have used.

C. RATEMAKING IMPACTS OF THE ATTORNEY GENERAL'S PROPOSAL

Q. CAN YOU EXPLAIN THE IMPACT OF THE NET SALVAGE METHODS ON CUSTOMER RATES?

A. Yes. Not only will the AG's proposal result in intergenerational inequity, but over time, the AG's proposal is actually more expensive to customers on a total cost of service basis.

Q. PLEASE EXPLAIN THE CONCEPT OF "INTERGENERATIONAL EQUITY."

A. Intergenerational equity is a ratemaking principle in which customers receiving the benefit from the use of an asset (*e.g.*, from electric utility property used to provide electric service) are the same customers who pay for the cost of that asset – no more, no less. Including net salvage in depreciation results in intergenerational equity, as the net salvage costs are part of the cost of an asset and should be recovered over its service life.

Q. DOES MR. KOLLEN'S NET SALVAGE PROPOSALS RESULT IN INTERGENERATIONAL EQUITY?

A. No. Mr. Kollen proposes to recover net salvage costs after the Company's assets are retired. His proposal will, therefore, result in intergenerational inequity because future customers will have to pay the costs of assets that only provided service to previous generations of customers.

Q. IN ADDITION TO THE INTERGENERATIONAL INEQUITY CAUSED BY MR. KOLLEN'S PROPOSAL, IS THERE A LONG-TERM IMPACT ON CUSTOMER RATES THAT WILL RESULT FROM MR. KOLLEN'S PROPOSAL?

A. Yes.

Q. PLEASE EXPLAIN THE IMPACT THAT A DEPRECIATION METHOD HAS ON CUSTOMER RATES, OTHER THAN THE DIRECT IMPACT OF DEPRECIATION EXPENSE.

A. Any method of depreciation has an impact on rate base over the lives of the plant assets as rate base includes original plant cost less accumulated depreciation. By deferring costs to the future, over time the AG's method results in a lower level of accumulated depreciation and a higher rate base than would occur under the traditional method. A higher rate base would mean that customers would have to pay a higher return on rate base. Over time, the rate base impact typically exceeds any reduction to depreciation expense. As a result, while the AG's method may produce a short-term reduction in customer rates, it will result in higher total costs to customers over the lives of the plant assets.

Q. DOES THE RATE BASE IMPACT OF THE AG'S PROPOSAL RESULT IN INTERGENERATIONAL INEQUITY?

A. Yes. The rate base impact compounds the intergenerational inequity inherent in AG's proposal. Not only will future customers pay the costs of retired assets for which they receive no benefits, but they will also have to pay a return on a higher rate base due to the fact that previous generations did not pay the full cost of their service.

D. <u>DECOMMISSIONING COSTS FOR POWER PLANTS</u>

Q. IN SECTION II.A YOU EXPLAINED THAT NET SALVAGE MUST BE BASED ON THE FUTURE COSTS EXPECTED TO BE INCURRED, NOT ON TODAY'S COSTS. DOES THE SAME APPLY FOR DECOMMISSIONING OF POWER PLANTS?

A. Yes. Because net salvage must be based on future costs, decommissioning costs for net salvage must also be estimates of the future cost at the time of decommissioning. For this reason, if decommissioning estimates are developed using the cost to decommission a plant today, then these costs must be escalated to the time period in which they are expected to be incurred.

Q. WHAT DOES THE AG PROPOSE WITH REGARD TO THE DECOMMISSIONING COSTS?

A. The AG proposes to eliminate all decommissioning. Mr. Jeffrey Kopp addresses the issues related to decommissioning costs in his direct testimony. Further, as I have explained in Section II.A, because net salvage must be included in depreciation over the lives of the Company's assets, decommissioning for power plants must also be included in depreciation. Thus, my remaining testimony on net salvage will focus on the issue of escalation raised by Mr. Kollen.[20]

Q. FOR THE COMPANY'S CURRENTLY APPROVED DEPRECIATION RATES, WERE THE DECOMMISSIONING COSTS ESCALATED TO THE DATE OF RETIREMENT?

A. Yes. Although, a different escalation factor was settled upon, the same general process I have used in the instant case is currently approved. The AG's proposal is not consistent with the approach used for the Company's currently approved depreciation rates. Further, as noted in Section II.B.ii, the Indiana Commission affirmed the same approach for an affiliate of the Company.

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[20] Mr. Kollen has proposed that, if his primary proposal to remove all decommissioning from depreciation is rejected, then the Commission should instead remove the escalation component from my proposed depreciation rates.

Q. WILL THE AG'S PROPOSAL PROPERLY ALLOCATE THE COMPANY'S COSTS OVER THE SERVICE LIVES OF THEIR GENERATING FACILITIES?

A. No. The decommissioning study prepared by Mr. Kopp used costs at today's price level. However, many of the Company's plants will not be retired for many years. The net salvage costs need to be escalated so that the correct amounts are allocated over the lives of the plants. Mr. Kollen's proposal to remove escalation from the decommissioning costs is insufficient to recover the Company's costs.

Q. PLEASE PROVIDE AN EXAMPLE THAT ILLUSTRATES WHY COSTS MUST BE ESCALATED TO THE DATE OF RETIREMENT.

A. Consider the following example. Assume a Company has a power plant that cost $1,000,000 to construct, will be in service for 40 years, and the net salvage is negative 10 percent. The negative 10 percent represents the cost at retirement, and so in year 40 it will cost $100,000 to decommission the plant. Additionally, assume that inflation occurs at a rate of 2.5 percent. Using the straight-line method, the resulting depreciation accrual would be $27,500 and a depreciation rate of 2.75 percent. This is the proper amount needed to recover the full $1,100,000 over the 40-year life of the power plant.

If instead decommissioning costs were not escalated to the date of retirement, the resulting depreciation rate would not recover the plant's original cost plus the cost to decommission it upon retirement. Consider the calculation of depreciation at year 1, when the asset is placed in service. The decommissioning cost of $100,000 stated in year 1 dollars is only $37,243. This is the amount that the other parties recommend should be included in depreciation expense for the Company's power plants, and their methodology would produce only $25,931 in depreciation expense and a depreciation rate of 2.59 percent. Using such a method will not recover the full-service value (the plant's original cost + decommissioning costs) that the company should be allowed to recover through depreciation. Instead, the Company will only recover $1,037,243 through depreciation expense and will recover less than 40 percent of the actual net salvage costs for the plant. This represents $62,757 less than the full-service value of the plant that the Company is entitled to recover.

Q. SHOULD NET SALVAGE BE RECOVERED IN TODAY'S COST (*I.E.* THE COST IN TODAY'S DOLLARS)?

A. No. In order to recover the service value of the Company's assets, net salvage must be determined at the cost that will be incurred in the future. When using the straight-line method of depreciation, these costs are recovered ratably, or in equal amounts each year, over the life of the Company's plant.

Q. IS RECOVERING THE FUTURE COST OF NET SALVAGE CONSISTENT WITH THE FERC USOA?

A. Yes. The FERC USOA which is discussed further in Section III.B.i. of my testimony, specifically defines net salvage as follows:

> 19. Net salvage value means the salvage value of property retired less the cost of removal.

Cost of removal is defined as:

> 10. Cost of removal means the cost of demolishing, dismantling, tearing down or otherwise removing electric plant, including the cost of transportation and handling incidental thereto. It does not include the cost of removal activities associated with asset retirement

> obligations that are capitalized as part of the tangible long-lived assets that give rise to the obligation. (See General Instruction 25).

Finally, cost is defined as (emphasis added):

> 9. Cost means the <u>amount of money actually paid</u> for property or services. When the consideration given is other than cash in a purchase and sale transaction, as distinguished from a transaction involving the issuance of common stock in a merger or a pooling of interest, the value of such consideration shall be determined on a cash basis.

Read together, it should be clear from these definitions that the USOA specifies that cost of removal, which as part of net salvage must be recovered through depreciation expense, is the actual amount that is paid at the time of the transaction. Because net salvage will occur in the future, it is an estimate of the future cost that must be included in depreciation rates.

Q. DO GENERALLY ACCEPTED DEPRECIATION CONCEPTS SUPPORT THAT THE NET SALVAGE IN DEPRECIATION SHOULD BE INCLUDED AT THE COST THAT WILL BE INCURRED?

A. Yes. Including the future cost of net salvage for plant accounts is consistent with established depreciation concepts. Depreciation is a cost allocation concept, in which the full cost of an asset (original cost less net salvage) is allocated on a straight-line basis over the period of time an asset will be in service.

Q. DO ANY AUTHORITATIVE DEPRECIATION TEXTS SUPPORT THAT THE NET SALVAGE AMOUNT SHOULD REPRESENT THE FUTURE COST?

A. Yes. I have already explained NARUC's discussion of this issue in Section II.B.iii. I note that NARUC also states the following:

> [U]nder presently accepted concepts, the amount of depreciation to be accrued over the life of an asset is its original cost less net salvage. Net salvage is difference between the gross salvage that will be realized <u>when the asset is disposed of and the cost of retiring it</u>.[21] (Emphasis added)

Wolf and Fitch is another highly regarded, authoritative depreciation text. The authors are clear that net salvage should be included in depreciation and that it should be recognized as a future cost. Wolf and Fitch explain that:

> The matching principle specifies that all cost incurred to produce a service should be matched against the revenue produced. Estimated future costs of retiring an asset currently in service must be accrued and allocated as part of the current expenses.[22]

III. <u>EQUAL LIFE GROUP PROCEDURE</u>

Q. WHAT IS THE ELG PROCEDURE?

A. Under the ELG procedure, a group of property (*e.g.*, a vintage within a property account) is subdivided into groups having equal service lives. The size of these "equal life groups" is based on the estimated survivor characteristics of the account. Depreciation can then be calculated for each equal life group based on the straight line method; that is, an equal amount of the group's service value is recorded as depreciation expense in each year of service. The total depreciation for an account is the summation of the depreciation calculated for each equal life group. In other words, based on the survivor curve estimate for an account, the ELG procedure

[21] NARUC Manual at 18.
[22] Wolf and Fitch, p. 7.

mathematically estimates the life for each unit in the account, and then depreciates each unit over its expected life. For this reason, the procedure is also known as the "unit summation" procedure. By calculating depreciation for each equal life group, the ELG procedure contrasts with the Average Service Life ("ASL", also referred to as "Average Life Group", or "ALG") procedure, which depreciates every asset within an account over the average life of the account.

Q **ARE THE COMPANY'S CURRENT DEPRECIATION RATES BASED ON THE ELG PROCEDURE?**

A. Yes.

Q. **PLEASE EXPLAIN THE ELG PROCEDURE AND ILLUSTRATE HOW IT DIFFERS FROM ALG PROCEDURE.**

A. A simple example employing two units of property of the same vintage in the same property account will show how the ELG procedure more appropriately matches cost recovery through depreciation to consumption or loss in service value than the ASL procedure. For purposes of this example, it is assumed that each unit has an original cost of $1,000. Unit A will be in service for five (5) years and Unit B will be in service for fifteen (15) years. No net salvage will result from the retirement of either unit.

Under the ASL procedure, the average service life for the two units is ten years: (5+15)/2. The annual depreciation rate is 10% (1/10). Thus, for the first five years that both units are in service, the total amount of annual depreciation is $200 ($2,000 x 10%). Therefore, at the end of year five, the total of five annual accruals for the account is $1,000 ($200 x 5). At that time, Unit A is retired, which results in a deduction of $1,000 from accumulated depreciation. (When a unit of property is retired, its original cost is deducted from both the balance of utility plant in service and from accumulated depreciation.)

At the start of year six, Unit B remains in service, and the original cost ($1,000) is offset by the accumulated depreciation of $0. However, at this point, one third of Unit B's service life has, in fact, expired; its accumulated depreciation should, therefore, not be zero.

For the remaining ten years, $100 (10% x $1,000) of annual depreciation expense is charged to accumulated depreciation, for a total of $1,000 of expense over this period. When Unit B is retired, $1,000 is deducted from accumulated depreciation, and both the original cost and accumulated depreciation will equal zero. When Unit B is retired, the Company will have finally recovered the total depreciable cost of both units. However, at the end of year five only one unit remained in service with two-thirds of its life expectancy still to be consumed, but with 100% of the original investment in that unit still to be recovered. As a result, the ALG procedure did a poor job of matching cost recovery to the actual consumption of the service life the asset.

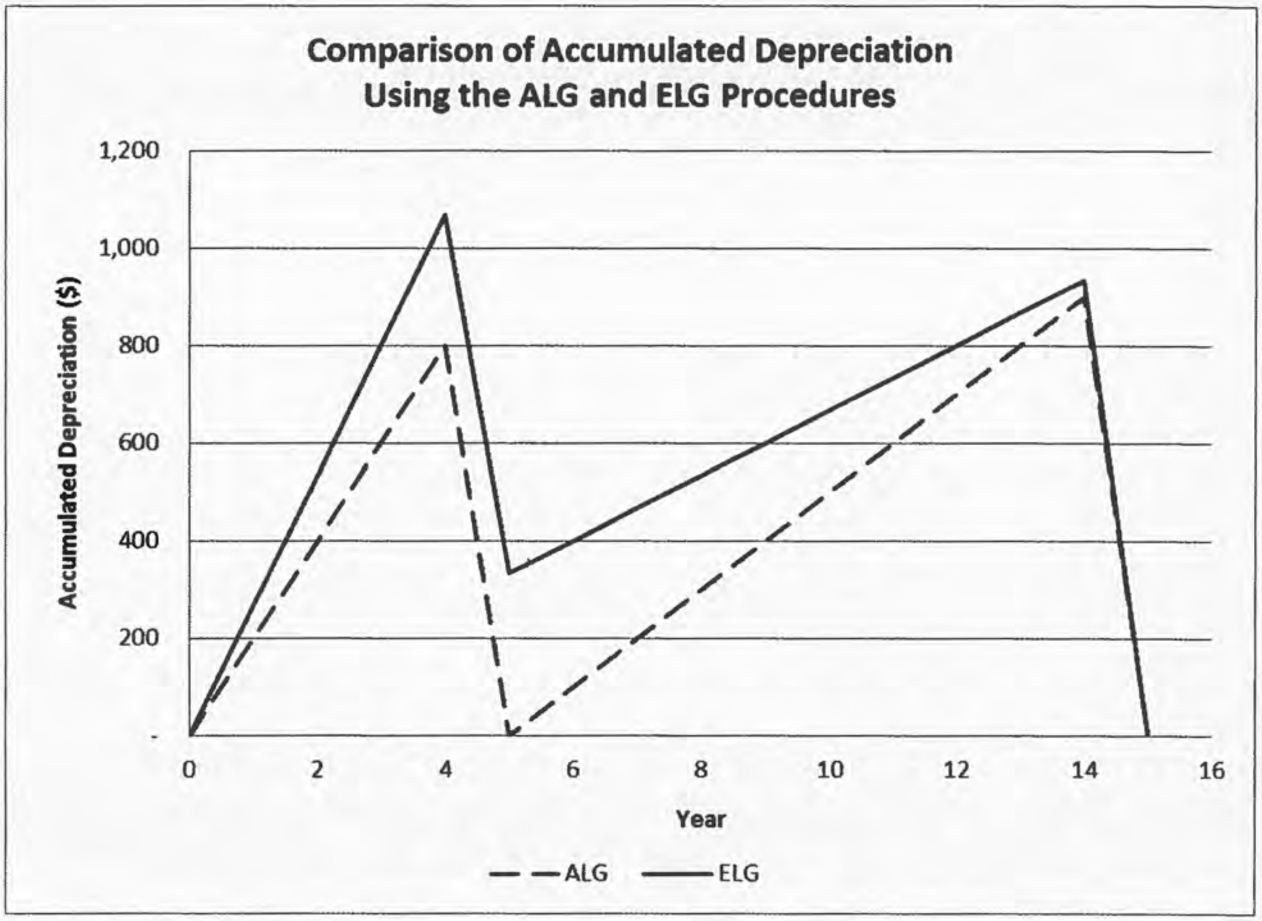
Q. HOW IS DEPRECIATION DETERMINED USING THE ELG PROCEDURE?

A. When depreciation is determined using the ELG procedure, the pattern of cost recovery more accurately matches the actual consumption of property's service value. Using the same two unit example discussed above, the annual depreciation expense under the ELG procedure is calculated by summing the annual expense for each equal life group. In this case, there are two equal life groups – one for Unit A, which has a life of five years, and one for Unit B, which has a life of fifteen years. The annual depreciation rate for Unit A is 20% (1/5) and for Unit B is 6.67% (1/15). Thus, the annual accruals for years one through five will be $200 (20% x $1,000) for the first equal life group (Unit A) summed with $66.67 (6.67% x $1,000) for the second (Unit B), or $266.67. At the end of year 5, when Unit A is retired, the total accruals would be $1,333.33. The retirement of Unit A results in a deduction of $1,000 from accumulated depreciation and, at the start of year 6, the $1,000 original cost of Unit B remains with $333.33 in accumulated depreciation. Thus, with one-third of Unit B's life consumed, accumulated depreciation is exactly one-third of the original cost for this unit.

In the years six through fifteen, the annual depreciation expense is $66.67 or a total of $666.67 over the ten years remaining in the life of Unit B. Thus, when Unit B is retired, the accumulated depreciation goes to $0 ($1,000 is deducted from the total of $1,000 of accruals), and the entire original cost of both units has been recovered.

As the foregoing example shows, the ELG procedure more accurately matches cost recovery for both units with their actual service lives. Figure 1 is a graphic representation of the accumulated depreciation for the same property under both the ELG and ALG procedures. The end of year five provides the best illustration of the difference between the two procedures. Under the ELG procedure, the original cost of Unit A is fully recovered when it is retired at the end of year five; Unit B is one-third through its service life and one-third of its cost has been recovered. For both units, cost recovery matches their service lives. This contrasts with the ALG procedure, in which accumulated depreciation is $0 at the end of year five, despite the fact that one-third of the service life of the only unit remaining in service has been expended.

Figure 1



The area between the two lines on the graph bounded by years five and fifteen represents the additional annual depreciation that would be paid by customers in those years to catch-up for the cost of Unit A that was not recovered when it was providing service. These kinds of inaccuracies can introduce inter-generational inequities, as later generations of customers pay for the recovery of the original cost of plant that was not recovered from customers that received 100% of the service value of that property.

In contrast to the ALG procedure, the ELG procedure assures that cost recovery through annual accruals accurately track the actual service lives for both units of property in my example, which means that cost recovery is properly obtained from the customer who actually receive the service each unit provides.

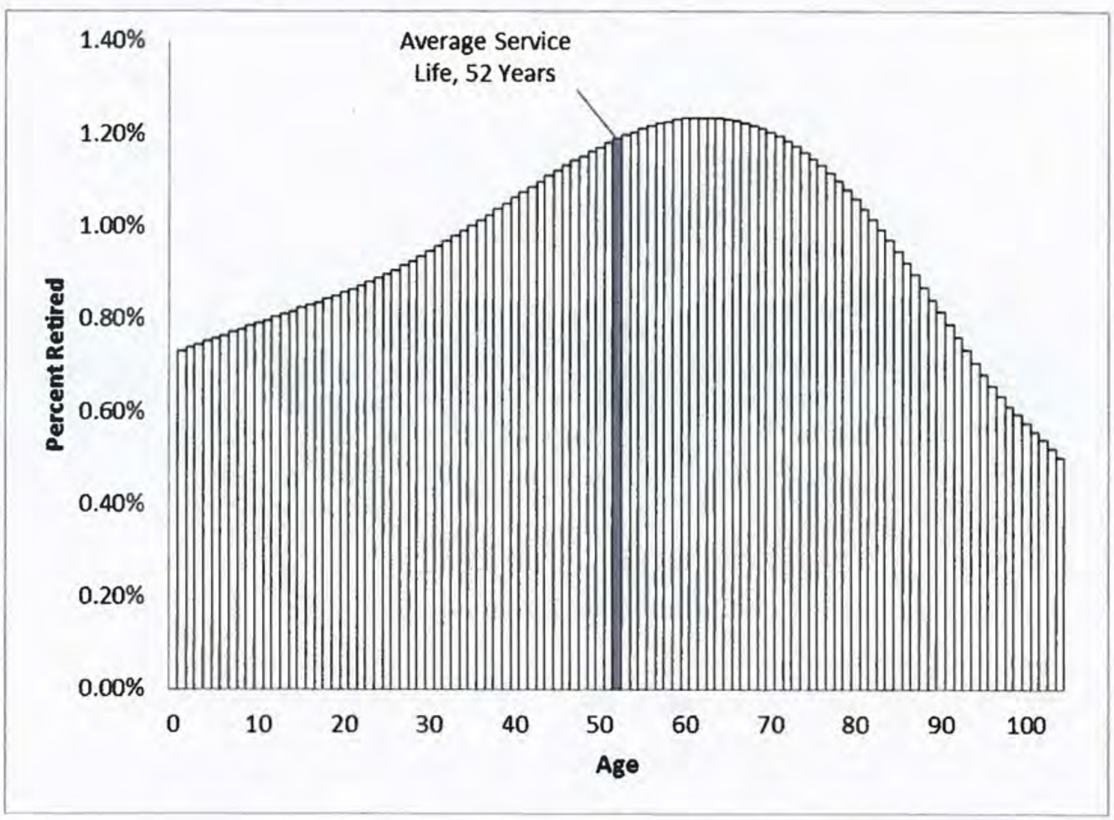
Q. DO THE SAME PRINCIPLES ILLUSTRATED BY THE TWO-UNIT EXAMPLES DISCUSSED ABOVE ALSO APPLY TO LARGER PROPERTY GROUPS THAT CONTAIN MANY MORE UNITS OF PROPERTY?

A. Yes. The same principles apply when the ELG procedure is applied to a large group of property with many units, as is typical of utility property. The survivor curve estimated for each property account can be used to divide an account into equal life groups. The survivor curve allows for the calculation of the percentage of the property account that is in each equal life group, which allows for the calculation of ELG annual depreciation accruals for the entire property group. Under the ALG procedure, the depreciation expense for all property in the account is calculated based on the average service life for the entire group.

The ELG procedure recognizes the reality of "dispersion." Specifically, it recognizes that in actual utility operations only a very small percentage of the dollars of plant investment in an account will actually be retired at the average service life determined for account. Figure 2, below, is a chart of the frequency curve for the 52-R0.5 survivor curve, which I have proposed for Account 364, Poles, Towers and Fixtures, and which no party in this case has challenged. The frequency curve shows the percentage of property in this account that will be retired at each age, based on the estimated survivor curve. This percentage is also the size of each equal life group.

The shaded bar in Figure 2 represents the percentage of property that will have a life of 52 years. In other words, it represents the percentage of property that is expected to be in service a period that corresponds exactly to the average service life for the account. As the chart shows, about 1.2% of the assets will be in service for 52 years; conversely, about 98.8% will have service lives that differ from 52 years. Some poles will be damaged or have to be relocated and, therefore, will be retired much earlier than the average, while others will be in service much longer than the average. Most will fall somewhere between these "tails" of the curve.

Figure 2: Percent Retired by Age Based on 52-R0.5 Survivor Curve



The ELG procedure recognizes dispersion, and allocates costs for each equal life group over the expected life for that group. As a result, the ELG procedure allocates cost in a manner that approximates the result of each asset being depreciated over its actual life. Conversely, the ALG procedure depreciates every unit of property within an account over the same life, that is, the average life of the entire account. As Figure 2 shows, this average life will be incorrect the majority of the time – in this example, the average life will be the wrong life for about 98.8% of the assets.

Thus, just as in the case of the two-unit examples discussed above, the ELG procedure better matches capital recovery with the actual lives that are forecast by the estimated survivor curve.

Q. IS THE ELG PROCEDURE ALSO SUPPORTED BY OTHER DEPRECIATION AUTHORITIES?

A. Yes. ELG is discussed and supported in authoritative depreciation texts and academic literature. One such authority – and a very significant one – is Robley Winfrey, who, as a professor at Iowa State University, developed the Iowa survivor curves that are universally used in estimating service lives based on historical retirement data is generally regarded as the father of utility depreciation practices, referred to the ELG procedure as "the only mathematically correct procedure."[23]

[23] Robley Winfrey, Depreciation of Group Properties, Bulletin 155 (Ames, IA: Iowa State University Press, 1942, reprinted 1969); p. 71

Q. WHAT ARE MR. KOLLEN'S ARGUMENTS AGAINST THE USE OF THE ELG PROCEDURE?

A. Mr. Kollen does not take the merits of ELG head-on. Instead, he just makes the statement that the ELG procedure produces higher depreciation rates and that should be rejected. However, he does not provide justification that ELG is not appropriate, and acknowledged in discovery that both ALG and ELG are straight line and both recover the same amount of expense over the life of the asset.[24]

Q. WHAT DO YOU CONCLUDE REGARDING THE ELG PROCEDURE?

A. The use of the ELG procedure has been utilized for many years in some jurisdictions including Kentucky. Mr. Kollen does not address the ELG procedure other than to disagree with the level of depreciation.

IV. CONCLUSION

Q. DOES THIS CONCLUDE YOUR REBUTTAL TESTIMONY?

A. Yes.

[24] *See* the Attorney General's response to Duke Energy Kentucky's Data Request No. 86.

VERIFICATION

COMMONWEALTH OF PENNSYLVANIA)
) SS:
COUNTY OF CUMBERLAND)

The undersigned, John J. Spanos, Senior Vice President, being duly sworn, deposes and says that he has personal knowledge of the matters set forth in the foregoing rebuttal testimony and that it is true and correct to the best of his knowledge, information and belief.

John J. Spanos

John J. Spanos Affiant

Subscribed and sworn to before me by John J. Spanos on this 2nd day of February, 2018.

NOTARY PUBLIC

My Commission Expires: February 20, 2019

COMMONWEALTH OF PENNSYLVANIA
NOTARIAL SEAL
Cheryl Ann Rutter, Notary Public
East Pennsboro Twp., Cumberland County
My Commission Expires Feb. 20, 2019
MEMBER, PENNSYLVANIA ASSOCIATION OF NOTARIES

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

The Electronic Application of Duke Energy Kentucky, Inc., for: 1) An Adjustment of the Electric Rates; 2) Approval of an Environmental Compliance Plan and Surcharge Mechanism; 3) Approval of New Tariffs; 4) Approval of Accounting Practices to Establish Regulatory Assets and Liabilities; and 5) All Other Required Approvals and Relief.	))))))))))	Case No. 2017-00321

REBUTTAL TESTIMONY OF

WILLIAM DON WATHEN JR.

ON BEHALF OF

DUKE ENERGY KENTUCKY, INC.

February 14, 2018

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I. INTRODUCTION AND PURPOSE

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is William Don Wathen Jr., and my business address is 139 East Fourth Street, Cincinnati, Ohio 45202.

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

A. I am employed by Duke Energy Business Services LLC (DEBS), as Director of Rates and Regulatory Strategy for Ohio and Kentucky. DEBS provides various administrative and other services to Duke Energy Kentucky, Inc., (Duke Energy Kentucky or Company) and other affiliated companies of Duke Energy Corporation (Duke Energy).

Q. ARE YOU THE SAME WILLIAM DON WATHEN JR. THAT SUBMITTED 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 respond to a number of the recommendations made by the Attorney General witnesses Lane Kollen and Richard Baudino. Specifically, I will address Mr. Kollen's recommendations related to:

(1) PJM Ancillary Services Market;

(2) Replacement Power Expense;

(3) AMI Benefit Adjustment;

(4) Normalized Outage Expense for East Bend;

(5) East Bend O&M Expense Regulatory Asset;

(6) Reflect the Impacts of the Tax Cuts and Jobs Act of 2017 (Tax Act);

(7) Capitalization Adjustments;

(8) Transmission Cost Recovery; and

(9) Distribution Capital Investment Rider Recovery.

As noted above, I will address Mr. Kollen's recommendations related to the impact of the Tax Act but, in doing so; I will also address the Company's position in the complaint case filed by the Kentucky Industrial Utility Customers, Inc., (KIUC) as it relates to the Company's electric operations. Although the KIUC complaint was docketed as Case No. 2017-00477, the Commission created a separate docket, Case No 2018-00036, to address the matter as it relates specifically to Duke Energy Kentucky.

With respect to Mr. Baudino, I address his concerns and recommendations about Duke Energy Kentucky's proposed Distribution Capital Investment (Rider DCI) mechanism. Similarly, I address the related concerns by Kroger's witness Mr. Bieber and Northern Kentucky University's witness Mr. Collins.

II. <u>PJM ANCILLARY SERVICE MARKET</u>

Q. PLEASE BRIEFLY SUMMARIZE MR. KOLLEN'S RECOMMENDATION REGARDING THE TREATMENT OF REVENUE FROM PJM'S ANCILLARY MARKET.

A. Mr. Kollen recommended that PJM Make Whole and other revenues from the ancillary service market be factored into the Company's base rates. His recommendation ignored the costs associated with those revenues and the fact that the Company already nets out the revenues and costs of all of the PJM ancillary service market through its off-system sales rider, (Rider PSM) and its fuel adjustment clause (FAC), and is continuing to do so in this case.

Q. HAS MR. KOLLEN CHANGED HIS RECOMMENDATION?

A. Yes. In response to the Company's discovery to the Attorney General, Mr. Kollen states that he no longer supports this adjustment.[1] So, the Commission should disregard his proposed adjustment for this item.

III. REPLACEMENT POWER ADJUSTMENT

Q. PLEASE EXPLAIN MR. KOLLEN'S REPLACEMENT POWER ADJUSTMENT.

A. Mr. Kollen agrees with the Company's proposed deferral mechanism for replacement power expense but disagrees with the Company's forecasted replacement power expense that is included in base rates, calling it "wildly excessive," and refers to it as an unreasonable "increase." Mr. Kollen recommends that, for this test year expense, the Commission use an average of 2015, 2016, and the first ten months 2017.

Q. DOES DUKE ENERGY KENTUCKY AGREE WITH THIS RECOMMENDATION?

A. The Company agrees with the acceptance of the deferral mechanism. However, the Company disagrees with Mr. Kollen's adjustment. First of all, the Company's data response relied upon by Mr. Kollen, AG-1-11, provided actual replacement power costs going all the way back to January 2013. In making his adjustment, Mr. Kollen selectively ignored data for prior periods that showed a higher level of

[1] Attorney General response to Duke Energy Kentucky Question No. 36.

replacement power expense. Through discovery, Mr. Kollen acknowledged that the cost of replacement power is 'volatile.' In question 49 to the AG, the Company asked Mr. Kollen, why he used an historical average of five years of actual data for his adjustment to vegetation management expense but only used three years (it was actually 34 months) of actual data for his adjustment to replacement power costs. In response, he indicated that "[he] used the five years for vegetation management expense because it is not as volatile as the replacement power expense."

Mr. Kollen's apparent rationale is that it is better to use <u>less</u> actual data for volatile expenses and <u>more</u> actual data for non-volatile expenses. Such a justification is irrational and contrary to reason and accepted practice. For one to estimate a future expense that could vary significantly from year to year (*i.e.*, volatile), the common practice is to use more historical data rather than less. For a cost that is not expected to vary significantly from year to year, it is not unreasonable to use less historical data. Mr. Kollen seems confused as to how to estimate volatile and non-volatile expense. One can only assume that his unconventional proposal is to opportunistically reduce the Company's revenue requirement.

Q. WHAT IS YOUR RECOMMENDATION REGARDING THE PROJECTED COST OF REPLACEMENT POWER IN THE COMPANY'S FORECASTED TEST YEAR REVENUE REQUIREMENT?

A. The Company believes its forecasted expense is reasonable. The Company's calculation is based on a probabilistic model using reasonable modeling assumptions and the estimated $5.7 million figure, compared to its historical average for this expense, is reasonable.

Q. IF THE COMMISSION ENTERTAINS MR. KOLLEN'S ADJUSTMENT, SHOULD IT CONSIDER ANY CHANGES TO MR. KOLLEN'S METHODOLOGY?

A. Yes. As Mr. Kollen observes in his response to AG-DR-01-49, replacement power costs are volatile. The timing and duration of forced outages are inherently unpredictable, and the prevailing market prices at the time of a forced outage are also unpredictable. The Company has over ten years of history to estimate the average replacement power costs.

At a minimum, Mr. Kollen should have used at least all of the months of data that were provided to him, January 2013 through October 2017. Instead, he ignored the first two years of data, the very same data that proves his point that this is a volatile expense.

Extending Mr. Kollen's adjustment for all of the months that the Company provided to the Attorney General, in its updated response to AG-01-011(a), the annualized average of ALL of the replacement power expense for Duke Energy Kentucky from January 2013 through October 2017, is $4,748,060.

Q. DID MR. KOLLEN'S METHODOLOGY ACCURATELY REFLECT THE COMPANY'S TRANSITION ASSOCIATED WITH THE RETIREMENT OF MIAMI FORT 6 AND THE ASSOCIATED ACQUISITION OF 100 PERCENT OF EAST BEND?

A. No. Again, Mr. Kollen should have at least used data for all of the years provided. He ignored the data provided for 2013 and 2014, and relied only on data for 2015. Up until June 2015, the Company was still operating Miami Fort Unit 6 and incurred replacement power costs for that unit during those months. Mr. Kollen ignored the 2015 cost for Miami Fort 6 apparently because it retired that year.

If Mr. Kollen's theory is that the costs for Miami Fort 6 should be ignored because it retired, then he should have grossed up the values for East Bend to reflect the full ownership. In other words, the replacement power costs for 2013, 2014, and for the first five months of 2015, should be grossed up to reflect the full ownership of East Bend that Duke Energy Kentucky has now. In Attachment WDW-Rebuttal-1, I provide a calculation to provide a much better representation of the Company's actual experience with replacement power costs for the years provided in Exhibit LK-4.

Recalculating Mr. Kollen's average of replacement power costs for actual experience back to 2013, but reflecting the full value of replacement power for East Bend to reflect full ownership of the station, produces an average cost of $4,107,332.

Q. WHAT IS YOUR RECOMMENDATION FOR THE AMOUNT OF REPLACEMENT POWER COSTS THE COMMISSION SHOULD INCLUDED IN BASE RATES?

A. The Commission should use the Company's forecasted cost of replacement power as it is more representative of the full history of East Bend and is based on a probabilistic model using reasonable assumptions. However, if the Commission chooses to use an historical average, it should reject Mr. Kollen's proposal to use unrepresentative and limited historical data to estimate 'volatile' costs. Just using the complete actual data that was provided to the Attorney General reveals that his methodology "does not pass any rational reasonableness test" and "wildly" understates the Company's overall experience with such costs.[2]

Q. MR. KOLLEN ACKNOWLEDGES THAT THE COST FOR REPLACEMENT POWER IS A 'VOLATILE' EXPENSE. IS THERE ANY REASON TO BELIEVE THAT THIS VOLATILITY WILL INCREASE?

A. As mentioned above and acknowledged by Mr. Kollen in his testimony, the Company's generation portfolio is less diverse now than it was about three years ago. With the retirement of Miami Fort 6 and the Company's acquisition of the full entitlement to East Bend, the Company's generation diversity was reduced and its reliance on East Bend is much greater now than it was previously.

The acquisition of East Bend was a good thing for customers but the increased reliance on East Bend as the main source of supply, increases the volatility the Company can expect for replacement power. Where Miami Fort may have been available in the past to pick up some of the load if East Bend was experiencing an outage, that backup resource is no longer available.

Q. DOES MR. KOLLEN COMMENT ON THE COMPANY'S PROPOSAL TO CREATE A DEFERRAL TO TRACK THE DIFFERENCE BETWEEN ACTUAL FORCED OUTAGE COSTS AND THE AMOUNT IN BASE

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[2] *See* Lane Kollen Direct at 11, lines 12 and 3.

RATES?

A. Yes. Mr. Kollen recommends approval of the deferral mechanism proposed by the Company.

Q. IF THE COMPANY IS ALLOWED TO DEFER THE DIFFERENCE BETWEEN THE ACTUAL FORCED OUTAGE COSTS AND WHATEVER AMOUNT IS INCLUDED IN BASE RATES, DOES IT MATTER WHAT AMOUNT THE COMMISSION APPROVES IN BASE RATES?

A. From the Company's earnings perspective, there is no impact except to the extent a significant balance grows without carrying costs. However, allowing the Company to recover unreasonably low revenue to cover the cost of replacement power means that customers being charged these lower rates will avoid the appropriate costs and future customers will pay for those costs avoided by current customers. It makes more sense to make a reasonable estimate of the costs to be included in current rates rather than lowering cost for current customers at the expense of higher costs to be paid by future customers.

IV. AMI BENEFIT ADJUSTMENT

Q. PLEASE DESCRIBE MR. KOLLEN'S RECOMMENDATION WITH REGARD TO THE EARLY RECOGNITION OF AMI BENEFITS.

A. As provided for in Case No. 2016-00152 (the AMI Case), Duke Energy Kentucky made an adjustment to its test year revenue requirement to bring forward certain benefits it projected would result from the deployment of advanced metering infrastructure (AMI). The Company's adjustment followed the exact same methodology it shared with the intervenors and the Commission in a response to a post hearing data request in the AMI Case[3] estimating the levelized benefit of savings for the five years from the time of a rate case, assumed to be in 2019, in that response.

Because the Company's worksheet included projected savings (and projected costs) through 2034, Mr. Kollen levelized the projected savings for the entire period shown, fourteen years. For whatever reason, Mr. Kollen chose to ignore all of the data for projected incremental costs that was provided by the Company over the entire fourteen-year period although the Company provided all of the projected benefits AND the projected costs in response to AG-DR-01-74(a).

Q. BESIDES YOUR OVERALL OBJECTION TO MR. KOLLEN'S PROPOSAL TO SELECTIVELY INCORPORATE PROJECTIONS OF SAVINGS THROUGH THE YEAR 2032, IS HIS CALCULATION CORRECT?

A. No. Mr. Kollen should not reach so far in the future for his levelization adjustment and certainly should not do so without being balanced and including incremental costs, too. Nevertheless, the calculations underlying his adjustment are also fraught with errors. First, Mr. Kollen indicates in his testimony on page 22, line 19, through page 23, line 3, that he calculated a levelized savings amount over a "15-year benefit period." But, it is clear from the calculation that he actually only used fourteen years for the calculation. Instead of including the data for 2018, as the Company did, Mr. Kollen starts with data for 2019 and includes

[3] Confidential response to AG-DR-02-035(c).

only projected savings through 2032, which would be fourteen years – not fifteen as Mr. Kollen's indicates in his testimony.

Secondly, Mr. Kollen disregarded information provided by the Company to reflect changes in the projected benefits and costs to reflect the delay in implementing the AMI technology. Instead Mr. Kollen relied on a spreadsheet provided by the Company in the AMI Case that assumed an earlier deployment of the program. Mr. Kollen provided no testimony as to why he disregarded the fact that the deployment schedule had changed and, instead, relied on a stale forecast that did not represent the actual timing of the Company's AMI deployment following Commission approval. That Mr. Kollen used the stale forecast is even more remarkable inasmuch as he still relies on the updated data for the savings adjustment. In order words, he recognizes the impact of the delayed deployment for netting the savings but then goes back and uses the projections that did not reflect the deployment for his levelization calculation.

Q. IF THE COMMISSION DOES ACCEPT MR. KOLLEN'S PROPOSAL TO LEVELIZE ONLY THE SAVINGS PROJECTED THROUGH 2032, HAVE YOU CORRECTED MR. KOLLEN'S CALCULATION?

A. Yes. In Attachment WDW-Rebuttal-2 (Confidential), I first substituted the data for 2018 through 2023 from the Company's Schedule D-2-26 in order to reflect the delay in implementation. By not doing so, Mr. Kollen's calculation does not reflect the fact that the deployment was actually delayed as the Company awaited the Commission's approval of the related CPCN. That is a correction that must be done in order to reflect the reality of the actual AMI deployment. I also modified

Mr. Kollen's calculation to do what he apparently intended to do. Mr. Kollen testifies that he intended to levelize the savings over fifteen years but, in fact, his calculation levelized the savings from 2019 through 2032, only fourteen years, completely ignoring 2018. I redid the calculation for all fifteen years and reflected the implications of the delay in the deployment. So, Mr. Kollen's adjustment for AMI savings, when corrected, results in an adjustment to test year revenue requirement of $3,176,520. That figure is higher than the amount included in the Company's application, of $2,321,137, but lower than Mr. Kollen's incorrect calculation of $3,684,481. Therefore, the maximum adjustment the Commission should make to the Company request is $855,383 ($3,176,520 - $2,321,137) rather than Mr. Kollen's adjustment of $1,363,344. For comparison, I included the calculation prepared by Mr. Kollen that ties to the incorrect adjustment he recommended,

Q. IS MR. KOLLEN'S PROPOSAL TO LEVELIZE THE SAVINGS, AND ONLY THE SAVINGS FROM AMI, OVER A FOURTEEN-YEAR PERIOD (OR FIFTEEN YEARS AS HE INTENDED) REASONABLE?

A. No. Mr. Kollen's proposal is flawed in a number of ways. First of all, he opportunistically, only includes the savings for the fourteen projected years and ignores the incremental costs that was also provided in the projections. Just as it would be unfair for the Company to include only the costs of AMI and no benefits, it is equally unfair for Mr. Kollen to include only the incremental savings over a fourteen-year period and ignore all incremental costs. The five-year calculation provided by the Company also only included savings but that was because significant incremental costs were not expected in that time frame. If a longer period was intended to be used for the levelization calculation, it would have been necessary to incorporate incremental costs as well. The Company's filed levelized savings was consistent to what the Company provided in response to the post hearing data request in Case No. 2016-00152, using a five-year period. Customers would receive the balance of savings (and also the actual incremental costs to achieve such savings) reflected in the original cost benefit analysis as part of the Company's next base rate case. At that point all the savings and all of the incremental costs would be embedded in customer rates. Mr. Kollen's adjustment is unfairly seeking to accelerate the benefit in the out-years following deployment, without acknowledgement of the corresponding additional costs.

Q. DO YOU HAVE A RECOMMENDATION TO THE COMMISSION RELATED TO THE AMI BENEFITS ADJUSTMENT?

A. Yes. The Commission should ignore Mr. Kollen's proposal to opportunistically grab fourteen years of savings in this case. His proposal necessarily relies on the unreasonable assumption that it will be at least fourteen years between rate cases and unfairly includes only the savings over that time frame, ignoring all incremental costs the Company also projected in the same document he relies on for his adjustment.

However, if the Commission does accept Mr. Kollen's proposal to levelize only the savings over fifteen years, as Mr. Kollen proposed, it should use the calculation as I have corrected it in Attachment WDW-Rebuttal-2 (Confidential).

V. PLANNED OUTAGES

Q. DESCRIBE MR. KOLLEN'S PROPOSAL REGARDING THE COMPANY'S PROPOSED NORMALIZATION OF PLANNED OUTAGE EXPENSE AND ITS PROPOSED DEFERRAL MECHANISM.

A. Mr. Kollen first recommends a reduction in the Company's proposed test year expense for planned outages at its generating stations, East Bend and Woodsdale. Second, Mr. Kollen opposes the Company's request to create a deferral mechanism to level out the impact of the outage expense on the Company's earnings.

Q. DOES THE COMPANY AGREE WITH MR. KOLLEN'S RECOMMENDATIONS RELATED TO PLANNED OUTAGE EXPENSE?

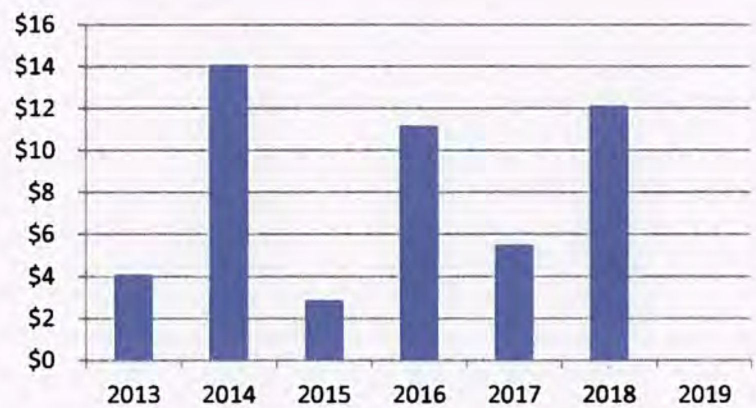
A. No. The Company made a reasonable estimate of its planned outage expense. More importantly, the Company strongly opposes Mr. Kollen's recommendation regarding accounting deferrals for this expense.

Q. WHY DOES THE COMPANY OPPOSE MR. KOLLEN'S RECOMMENDATION REGARDING DEFERRAL ACCOUNTING FOR THE PLANNED OUTAGE EXPENSE?

A. First, and importantly, the Commission has already approved this exact same type of deferral accounting as recently as its June 22, 2017, order approving a stipulation in Case Nos. 2016-00370 and 2016-00371, involving Kentucky Utilities (KU) and Louisville Gas & Electric Company (LG&E), respectively.

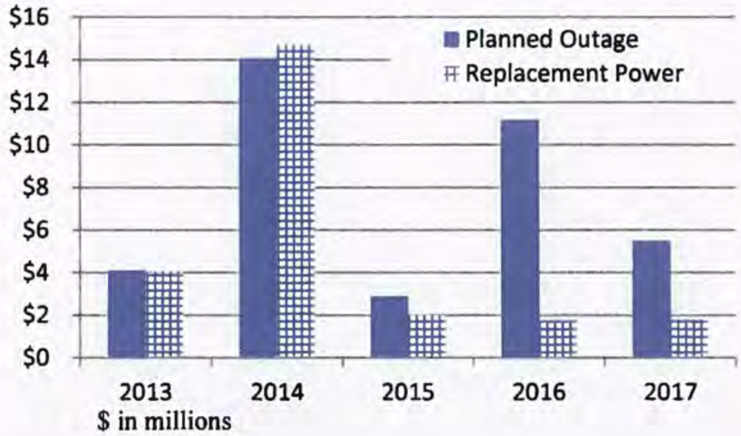
The reason for seeking a deferral is that planned outage costs are volatile. That volatility is evident in data used for his recommended outage expense from

Mr. Kollen's Exhibit LK-8. The chart below is a graph of the planned outage costs used in Mr. Kollen's proposed outage expense. The volatility in this expense should be evident. It is worth mentioning that planned outage expense represents a significant portion of the Company's non-fuel production expense. As shown in the Company's revenue requirement model, Schedule C-2, the forecasted test year expense for non-fuel production is around $48 million per year. The range of planned outage expense from 2013 through projected 2019 is $0 at the low end, for 2019, to over $14 million at the high end.



$ in millions

This volatility is comparable to the volatility the Company has seen in its replacement power costs mentioned earlier and is the primary reason the Company is seeking an accounting deferral. Consistent with the Company's proposal, Mr. Kollen recommends approval of deferral accounting for replacement power costs but against the same treatment for planned outage expense. Consider the following chart comparing the actual planned outage expense for the period 2013 through 2017 and the actual replacement power cost for the same period.



At least for the five years included in this chart it is readily apparent that planned outage expense is at least as volatile as replacement power costs.

Q. WHY IS THERE SO MUCH VOLATILITY IN THE PLANNED OUTAGE EXPENSE FOR DUKE ENERGY KENTUCKY?

A. The primary factor is the Company's size. Duke Energy Kentucky's generation portfolio is made up of one large base-load coal plant and a gas-fired generating station predominantly used for peak load. Planned outages necessarily are only scheduled for periods when the load is not expected to be near its peak, *e.g.*, fall or spring. Typically, major planned outages for East Bend occur every other year (a 24-month cycle). That means that every other year, there will be a significant expense and, for other years, there will be little or no expense.

Because of Duke Energy Kentucky's heavy reliance on the one generating station, East Bend, this cycle necessarily creates volatility in the Company's earnings. Where LG&E and KU have many generating units and can level out the cost of planned outages from year to year, Duke Energy Kentucky does not have that luxury. But even with the benefit of less lumpy planned outage costs, LG&E and KU sought and received approval to use deferral accounting to further level out the earnings impacts of this volatile expense (See Commission's Order in Case Nos. 2016-00370 and 2016-00371, dated June 22, 2017).

Q. IS MR. KOLLEN'S RECOMMENDATION AGAINST DEFERRAL ACCOUNTING RELATED TO THE VOLATILITY OF THIS COST?

A. He does not suggest that the expense is not volatile, rather, he suggests that allowing the Company to use deferral accounting removes the incentive to minimize these costs. Apparently, Mr. Kollen believes that the Commission will abandon its right to review the reasonableness of costs the Company may defer. With or without deferral accounting, the Company has and will continue to use good utility practice to ensure that it can serve its customers safely, efficiently, and reliably. Deferral accounting does not add to or subtract from the Company's incentive to achieve these goals. In this case, the deferral accounting sought by the Company is intended only to mitigate the impact of a volatile expense on the Company's earnings.

Q. ASSUMING THE COMMISSION APPROVES THE DEFERRAL ACCOUNTING FOR PLANNED OUTAGE EXPENSE, WOULD THE COMPANY ACCEPT MR. KOLLEN'S PROPOSED TEST YEAR EXPENSE FOR PLANNED OUTAGES?

A. Yes. The deferral accounting eliminates the earnings impact to the Company of Mr. Kollen's adjustment and ensures that customers only pay for the actual costs. Although the Company believes its proposed test year expense is reasonable and should be approved, Mr. Kollen's number would be acceptable if the Commission allows the Company to defer the difference between actual planned outage expense and the amount included in the test year.

VI. EAST BEND O&M EXPENSE REGULATORY ASSET

Q. DESCRIBE MR. KOLLEN'S PROPOSAL WITH RESPECT TO THE COMPANY'S EAST BEND O&M EXPENSE REGULATORY ASSET?

A. Mr. Kollen recommends a reduction in the Company's regulatory asset to reflect actual deferrals through October 2017 and to revise the forecast for the months of November 2017 through March 2018. The result of Mr. Kollen's adjustment is to reduce the projected regulatory asset balance from the Company's proposed \$39.162 million[4] to \$35.870 million, and reducing the revenue requirement of \$0.406 million related to the amortization of this regulatory asset.

Mr. Kollen provided a spreadsheet in his workpapers showing his calculations. In Attachment WDW-Rebuttal-3, I have provided an updated version of that spreadsheet with additional actual data, and some corrections to Mr. Kollen's spreadsheet for errors in his calculation and to correct errors in the formula from what the Company provided him.

Q. DOES DUKE ENERGY KENTUCKY AGREE WITH THIS RECOMMENDATION?

A. No. While the Company is very willing to accept the use of more contemporary actual data for this component of the revenue requirement, the calculations underlying this adjustment should first be updated for the most contemporary data and the worksheet used to calculate the projected deferral balance needs to be corrected.

Mr. Kollen provides a table with updated actual data on page 30 of his

[4] *See* Direct Testimony of William Don Wathen Jr., page 33.

testimony. He apparently made a clerical error in recording the actual data for July 2017 twice. In Attachment WDW-Rebuttal-3, I have reproduced one of his workpapers, showing the calculation of the projected balance through March 31, 2018. Where Mr. Kollen stopped using actual data and started using projected data between October 2017 and November 2017, we now have actual data through January 31, 2018; so, I substituted an additional three months of actual data for the projected data in Mr. Kollen's spreadsheet. I left Mr. Kollen's estimate of the forecasted deferral amounts unchanged for February and March of 2018.

In Attachment WDW-Rebuttal-3, I also corrected the formulae in some of the cells. Mr. Kollen calculated the carrying charges incorrectly, using the average of the beginning balance for the prior month and the beginning balance for the current month as the basis for the calculation. The formula should calculate carrying charges as the monthly debt rate multiplied by the beginning balance for the current month plus one half of the incremental deferral for the current month. Mr. Kollen's calculation was also undermined by an error in the calculation that came from the Company. Beginning in November 2017, the ending balance of the deferral each month was calculated by adding the cumulative balance for the current month (before carrying charges) to the carrying charges calculated in the next month. Both of these formula errors have been corrected and the actual data has been updated through January 31, 2018.

The net result of the updates and corrections to the spreadsheet is that the projected balance of the deferral at March 31, 2018, to be recovered in base rates is projected to be $36.115 million, up slightly from the number $35.870 million figure Mr. Kollen calculated. Using the same parameters to amortize the deferral, the annual amortization expense is projected to be $4.438 million, just slightly greater than the $4.408 million figure in Mr. Kollen's testimony.

Q. DO YOU HAVE ANY OTHER CONCERNS WITH MR. KOLLEN'S RECOMMENDATIONS RELATED TO THE EAST BEND O&M DEFERRAL?

A. Yes. Mr. Kollen makes an adjustment to capitalization to eliminate the full balance of the deferral being sought in this proceeding. According to Mr. Kollen, "[t]he Company is entitled to only one return on the regulatory asset, not two." The Company agrees that it should not earn a return twice on the regulatory asset, however, Mr. Kollen's adjustment to capitalization assumes that the Company is earning its full weighted-average cost of capital on the regulatory asset.

Inasmuch as Mr. Kollen reproduced the calculation to amortize the balance of the East Bend O&M Deferral using the long-term debt rate, he should be well aware that the only return the Company is earning on this regulatory asset is a return at the long-term debt rate. Mr. Kollen's adjustment to capitalization has the effect of reducing the Company's revenue requirement by far more than the return it is receiving on the regulatory asset.

Q. DO YOU HAVE A RECOMMENDATION AS TO HOW TO CORRECT MR. KOLLEN'S CAPITALIZATION ADJUSTMENT?

A. Yes. Mr. Kollen unnecessarily modifies the Company's capitalization to reflect the concern he raises about return being earned on the East Bend O&M Deferral.

The fact that this regulatory asset is earning a return at the long-term debt rate does not mean that it is not part of the Company's capitalization; so, no adjustment to capitalization was necessary.

A more appropriate way to address the issue raised by Mr. Kollen is to credit the revenue requirement with the return actually expected to be earned on this regulatory asset. As I calculated earlier, the March 31, 2018, balance is now expected to be, $36,114,607. The Company is only allowed to earn a return at the long-term debt rate; so, the overall revenue requirement should be credited with the actual return it can expect to recover through the amortization.

Per Schedule J-1, Forecast, the Company's long-term debt rate is 4.243%. Applying this rate of return that will be earned on the East Bend O&M Deferral by the balance at March 31, 2018, suggests that the Company's will earn a forecasted test year return $1,532,343. Grossing that figure up for bad debt and maintenance fees suggests that the revenue requirement should be reduced by $1,536,562.

Mr. Kollen's proposal implies that the Company is earning a return at its weighted-average cost of capital, which is simply not the case. The Company has not asked for this much return and the Commission did not approve of any more than the long-term debt rate when it approved the deferral in the first place. Consequently, the Commission should ignore Mr. Kollen's proposed $3,449,000 reduction to base rates. The correct method to address this is to include a $1,536,562 offset to the test year revenue requirement.

Q. IS THERE ANOTHER WAY TO CORRECT MR. KOLLEN'S ADJUSTMENT?

A. An alternative would be to accept Mr. Kollen's adjustment to capitalization as is but then to modify the amortization of the regulatory asset to include a return on the unamortized balance at the weighted-average cost of capital rather than the debt rate. This method, albeit at odds with the Commission's approval establishing the deferral, and the one I proposed above maintains the symmetry of the adjustment Mr. Kollen attempted to make.

VII. <u>IMPACTS OF THE TAX ACT</u>

A. Test Year Revenue Requirement

Q. DESCRIBE MR. KOLLEN'S PROPOSAL WITH RESPECT TO THE TAX ACT?

A. Mr. Kollen proposes to modify the Company's revenue requirement to (1) reflect the annualized impact on net income of the change in the federal income tax rate and (2) to flow through excess accumulated deferred income taxes (ADITs) that resulted from the Tax Act.

Q. DOES THE COMPANY AGREE WITH MR. KOLLEN'S RECOMMENDATION RELATED TO REFLECTING THE IMPACT OF THE TAX ACT?

A. As it relates to the impact of the change in the gross revenue conversion factor (GRCF) resulting from the change in the FIT, the Company does agree that this change should be made although the actual dollar amount of the change will be different from Mr. Kollen as the Company has a different recommended level of taxable income than what is being proposed by the Attorney General. Company witness Sarah E. Lawler provides a revised calculation of the Company's overall revenue requirement that includes the impact of the change in the FIT rate on the gross revenue conversion factor.

As it relates to Mr. Kollen's adjustment to reflect an amortization of the excess ADITs, the Company does propose to return the full balance of these excess ADITs as of December 31, 2017; however, following Mr. Kollen's proposal to amortize ALL of this regulatory liability over twenty years would violate normalization rules. Company witness Lisa M. Bellucci provides rebuttal testimony with detailed estimates of the Company's excess ADIT balance as of December 31, 2017. In addition, in Attachment LMB-Rebuttal-1, she segregates these excess ADITs between those that are subject to normalization rules ('protected') and those that are not ('unprotected').

Later in my testimony, I will make a recommendation as to how the Commission should flow these benefits back to customers and some options the Commission may consider.

Q. DID MR. KOLLEN CAPTURE ALL OF THE IMPACTS OF THE TAX ACT IN HIS TESTIMONY?

A. No. Whether intentional or just an oversight, Mr. Kollen neglected to reflect the increases in the Company's rate base and, therefore, its capitalization that will result from the Tax Act.

Q. WHAT COMPONENTS OF THE TAX ACT WILL INCREASE THE COMPANY'S CAPITALIZATION?

A. A significant provision of the Tax Act is that it will eliminate a provision of tax law that existed up through 2017 that has been valuable in reducing customers' rates. Specifically, the Tax Act eliminates bonus depreciation, which allows utilities to provide a significant offset to the capital needs for projects because of the ability to expense, for tax purposes, a very large proportion of investments. For example, with bonus depreciation, a utility may get to deduct, for tax purposes, about fifty percent of the cost of a project in the first year it is in service even for a project that may have a useful life of many years. For a $1 million project[5], expensing fifty-percent of that cost in the first year for tax purposes but only five percent for book purposes, provides a significant offset to the capital needed to finance that project. In this example, $500,000 of the project cost would be deducted for tax purposes and $50,000 would be deducted for book purposes. The difference of $450,000 multiplied by the prevailing tax rate represents cash returned to the Company that offsets the investment. At the new FIT rate, the value of bonus depreciation would have been $94,500 ($450,000 * 0.21). Therefore, as a result of losing the bonus depreciation, the rate base and, therefore, the associated capitalization, of the utility increases and the customers' cost will increase as the return requirement is higher with higher capitalization.

Another factor that will increase capitalization is simply the impact of the change in the FIT on the calculation of deferred taxes. Deferred taxes are calculated as the difference in an expense recorded for tax purposes multiplied by the tax rate. Whatever the difference is between a tax expense and a book expense, the deferred tax will change simply because the FIT changes. In other

[5] For this example, assume that rate base and capitalization are equivalent.

words, for every dollar of difference between tax expense and book expense, 35 cents of deferred taxes would have been generated under the prior FIT rate. At the new FIT rate, only 21 cents of deferred taxes are created in this example. Over the life of any asset, the Company's rate base will be higher simply because of the change in the FIT and, assuming that a dollar of capitalization is required to fund a dollar in rate base, the overall capitalization of the Company will be affected as well.

Q. DOES THE LOSS OF BONUS DEPRECIATION AND THE IMPACT OF THE LOWER FIT RATE ON DEFERRED INCOME TAXES IMPACT THE COMPANY'S REVENUE REQUIREMENT?

A. Yes. The Company's proposed revenue requirement is based on a forecasted test year, namely, April 1, 2018, through March 31, 2019. The forecast includes capital projects that go into service during that time for which the loss of bonus depreciation was not contemplated at the time of the filing. The forecast also includes a projection of deferred income taxes that were based on a 35 percent FIT rate. The projection of deferred income taxes changes because of the change in the FIT rate.

Q. HAS THE COMPANY ESTIMATED THE IMPACT OF THESE CHANGES?

A. Yes. As part of Company witness Bellucci's rebuttal testimony, she has prepared revised accumulated deferred income tax balances through an updated B-6 Schedule. This schedule has been provided to Ms. Lawler. Ms. Lawler's revised revenue requirement summary includes the impact of the adjusted rate base (and to capitalization) to reflect these updated ADIT balances along with other changes from the Tax Act.

Q. AS A RESULT OF THE TAX ACT, DUKE ENERGY KENTUCKY ADJUSTED ITS BALANCE SHEET TO TRANSFER A PORTION OF ITS ACCUMULATED DEFERRED INCOME TAX BALANCE TO A REGULATORY LIABILITY. DOES THIS BALANCE SHEET ADJUSTMENT ALONE CHANGE THE COMPANY'S RATE BASE OR CAPITALIZATION?

A. No. The balances for Accounts 190, 282, and 283 were reduced as a result of the Tax Act as a portion of these accounts were transferred to Account 254. Although Account 254 is not reflected in the Company's filing as an offset to rate base, it will continue to be treated as an offset to rate base. For purposes of establishing the capitalization to be used in this application, the Company is not proposing to reflect the changes in the account balances as the rate base already reflects the full benefit of the offset to rate base for all of the ADITs.

B. Case No. 2018-0036

Q. YOU MENTIONED ABOVE THAT YOU HAD A PROPOSAL FOR HOW TO ENSURE CUSTOMERS GET THE FULL BENEFIT OF THE TAX ACT FROM JANUARY 1, 2018. PLEASE EXPLAIN.

A. As mentioned earlier, the Company has included the lower FIT in its calculation of the revenue requirement which lowers the gross revenue conversion factor and lowers the overall revenue requirement. In addition to the impact of the lower FIT, the Company has included an adjustment to reflect the amortization of the excess ADITs as of December 31, 2017. As discussed above, a significant portion of these excess ADITs can only be amortized pursuant to normalization rules and, thus, can be returned no faster than the law will allow. Based on the Company's analysis, shown in Attachment LMB-Rebuttal-1, to Company witness Bellucci's testimony, the amortization percentages for these "protected" excess ADITs for the forecasted test period of April 1, 2018, through March 31, 2019, is $1,168,705. Because this is an "after-tax" figure, it needs to be grossed up by the GRCF in the case updated for the lower FIT rate. The result is a reduction in revenue requirement of $1,567,218 ($1,168,705 * 1.3409866). For all other excess ADITs, the Company is proposing to use a twenty-year amortization period.

Q. INASMUCH AS THE AMORTIZATION PERIOD FOR UNPROTECTED ADITS IS NOT SUBJECT TO NORMALIZATION RULES, WHY ARE YOU PROPOSING TWENTY YEARS?

A. In the interest of mitigating controversy, the Company is willing to accept the Attorney General's recommended twenty-year amortization period. This twenty-year amortization is also consistent with the Commission's directive in its December 27, 2017 Order in Case No. 2017-0477.

While the Company will agree to a twenty-year amortization for unprotected excess ADITs, it is aware that the Attorney General has reached an agreement with LG&E and KU to amortize the unprotected excess ADITs over fifteen years. If the Commission desires to maintain consistency in the amortization period used for all of the investor-owned utilities, the Company is willing to amortize its excess ADITs over the fifteen-year period; however, the calculation of benefits associated with amortizing the unprotected excess ADITs assumes a twenty-year amortization period.

Again, referring to Ms. Bellucci's Attachment LMB-Rebuttal-1, the annual amortization of the estimated December 31, 2017, balance of unprotected excess ADITs is $1,651,639. Grossing that amount up for taxes at the lower FIT results in an adjustment to revenue requirements of $2,214,826 ($1,651,639 * 1.3409866).

The combined effect of amortizing the excess ADITs is to reduce the Company's test year revenue requirement by $3,782,044.

The difference between this amount and the figure calculated by Mr. Kollen in his testimony is that the Company is compelled to follow normalization rules for about half of the excess ADIT balance, where Mr. Kollen just used twenty years for all of the excess ADIT balance, without considering the potential for normalization violations.

Mr. Kollen's estimate included another error in that his calculation of the excess ADITs assumes that ALL of the balance of ADITs was related to federal income taxes. Because Kentucky has a state income tax rate, a portion of the ADIT balances relied upon by Mr. Kollen included both federal and state taxes. The Tax Act only impacted the federal portion of the ADITs. Mr. Kollen assumed that 40 percent, (35 - 21)/(35), of the entire ADIT balance would be transferred to the excess ADIT liability. His calculation incorrectly transferred 40 percent of all state deferred taxes along with all federal income taxes to the excess ADIT balance.

Another difference is that Mr. Kollen used the Company's forecasted ADITs to compute his estimate of the excess ADITs. It is not apparent why Mr. Kollen chose to use forecasted ADITs for his estimate or why he used an average inasmuch as those ADITs at issue are exclusively those that existed at December 31, 2017. Consequently, his starting point was incorrect. Even if Mr. Kollen had correctly used the December 31, 2017, balance that was shown in the filing, that too was still just an estimate. Since the time Mr. Kollen filed his testimony, the Company has closed its books for December 31, 2017, and has a reasonable estimate of the excess ADIT balance at December 31, 2017. Mr. Kollen's estimate of the excess ADIT balance at issue should be ignored, first because he incorrectly used projected data and, second, because actual data for the date certain balance is now available.

Finally, Mr. Kollen understated the impact by applying a gross up conversion factor that only reflected federal income taxes. By grossing up his proposed amortization of the excess ADIT balance by (1 ÷ (1-0.21)), he understates the revenue impact to customers. Any change in revenue will have a tax effect that includes the state and the federal income taxes. Therefore, Mr. Kollen should have used a gross revenue conversion factor that includes both state and federal income taxes. So, rather than grossing up the benefit of the excess ADIT amortization by 1.2658, as Mr. Kollen did in his workpapers, he should have grossed up the benefit by 1.340966.

Q. DOES THE COMPANY HAVE A RECOMMENDATION AS TO HOW TO CALCULATE AND RETURN ANY TAX BENEFITS IT WILL ACCRUE FROM JANUARY 1, 2018, THROUGH THE EFFECTIVE DATE OF NEW BASE RATES?

A. Yes. Although the Commission has not yet provided direction as to how to calculate that benefit, the Company is aware of the terms of the settlement between the Attorney General, the KIUC, and LG&E and KU, in Case No. 2018-00034. As it relates the benefits owed to customers from the excess ADITs, I described how the Company will address that impact in its revenue requirement. Except for truing-up the balance after the Company's final tax returns are filed for tax year 2017, there is no benefit from January 1, 2018, through the date the actual amortization begins that the Company will benefit from that is not shared with customers as amortization of the excess ADITs will not begin until the Commission approves the base rates with such amortizations as part of this case.

As it relates to the impact of the change in the FIT, the Company proposes to use the methodology agreed to by the Attorney General and the KIUC in Case No. 2018-00034. Following the methodology provided in the testimony of LG&E/KU's witness Kent W. Blake in that proceeding (attached to my testimony as Attachment WDW-Rebuttal-4) that describes the methodology and also includes the stipulation agreed to by the Attorney General and KIUC in that case. I created Attachment WDW-Rebuttal-5, to reflect the same calculation as it would apply to Duke Energy Kentucky's electric operations for the period before new base rates are approved reflecting the full effect of the Tax Act.

Q. WILL YOU GENERALLY DESCRIBE THE CALCULATION?

A. Again, following the methodology agreed to by the Attorney General and the KIUC in Case No. 2018-00034, I start with the capitalization used in the Company's most recently approved base case, which was Case No. 2006-00172. I multiply the capitalization by the pre-tax return used in the rate case to calculate the revenue requirement associated with the cost of debt and equity, grossed up for income taxes, in that case. It should be noted that I assumed 11.0 percent after-tax return on equity (ROE) in that proceeding, although the Commission's order in that case was silent on the approved ROE. The Company has been using the 11.0 percent ROE for purposes of calculating any allowance for funds used during construction (AFUDC) since the time of the last rate case.

The next step in the LG&E/KU model is to calculate the return on the capitalization expected over a forecasted period. For that calculation, I use the capitalization proposed in this case and multiply by the overall return at the ROE from the last rate case but at recognizing the lower costs of debt in the current case. As shown in Attachment WDW-Rebuttal-5, the calculation shows that the annualized impact of the change in FIT using the LG&E/KU model produces a result that shows the Company is overcollecting its federal income tax expense by $2,215,240, on an annualized basis.

For deferrals that the Company is accruing that will be incorporated into base rates (*e.g.*, the East Bend O&M Deferral), it is assumed that new rates begin April 1, 2018; so, the monthly deferrals would end after March 2018. So, for the three months between the effective date of the lower federal income tax rate and the effective date of new rates that reflect those rates, the Company will have overcollected one-fourth (three months of twelve) of the $2,215,240 or $553,810.

The Company recommends that this amount be amortized over five years, similar to some of the regulatory assets being amortized. Therefore, the test year revenue requirement should be reduced by $110,762 to reflect the amortization of the January 2018 through March 2018 effect of the lower FIT.

VIII. CAPITALIZATION VERSUS RATE BASE

Q. MR. KOLLEN MAKES A NUMBER OF ADJUSTMENTS TO THE CAPITALIZATION THE COMPANY PROPOSED IN ITS APPLICATION. DO YOU HAVE ANY CONCERNS WITH HIS CAPITALIZATION ADJUSTMENTS?

A. Yes. Mr. Kollen makes a number of adjustments to reduce the Company's total capitalization allocated to its electric operations. He also makes a few adjustments to increase capitalization. Combined, his adjustments reduce the Company's capitalization by almost $58 million or about 8 percent lower than the $705 million included in the Company's total electric capitalization.

The problem with Mr. Kollen's proposed capitalization is that it produces a result that is not consistent with traditional ratemaking in Kentucky. As the Commission has observed in the past

> "While the Commission has previously found that [Duke Energy Kentucky's] revenue requirements should be determined using capitalization, we are obligated to consider determining revenue requirements using rate base if evidence is present supporting such a finding."[6]

As part of its filing requirements, the Company provides a reconciliation

[6] Commission's Order in Case No. 2001-00092, dated January 31, 2002, at page 28.

of rate base to capitalization. As a general rule, rate base and capitalization should be approximately equal. That is apparent in the Company's application in filing requirement FR 16(6)(f). In that exhibit, the Company demonstrated that its capitalization allocated to electric was $705.1 million while its electric rate base was $700.2 million. Because Duke Energy Kentucky is a combination gas and electric company, with debt and equity that supports both businesses, it is more challenging to develop an accurate estimate of the capitalization allocable to either gas or electric but the calculation of rate base is fairly straightforward. The B-Schedules in the Company's application provide all the details to calculate electric rate base and no allocation between gas and electric is required. However, one arrives at capitalization, it should approximate the Company's rate base.

Mr. Kollen proposes no adjustments to the Company's rate base but proposes to eliminate $57 million of its capitalization. The result is that, after all of Mr. Kollen's adjustments to capitalization, there is now a significant unreconciled difference between rate base and capitalization. Ultimately, Mr. Kollen's recommended capitalization results in a valuation of the Company's electric utility investment that is significantly understated and accepting his recommendation would require the Commission to ignore the statutes for such valuation, namely KRS 278.290.

Q. DO YOU HAVE A RECOMMENDATION FOR THE COMMISSION REGARDING VALUING THE COMPANY'S INVESTMENT IN ELECTRIC UTILITY PROPERTY?

A. While the Commission often relies on capitalization as the basis for establishing utility revenue requirement, it has acknowledged that either capitalization OR rate base can be used to properly establish revenue requirements. Many issues in this proceeding make difficult to accurately value the Company's capitalization allocable to electric service. On the other hand, it is much less difficult to value the rate base. My recommendation is that, if the Commission accepts all of Mr. Kollen's adjustments to capitalization that cause a significant imbalance between capitalization and rate base, the Commission calculate the revenue requirement using rate base instead of capitalization.

Again, no party disputed the valuation of rate base in this proceeding. The end result of the Attorney General's numerous adjustments to capitalization produce an unreasonable result where the capitalization is now significantly lower than rate base. It is well within the rights of the Commission to use rate base instead of capitalization as the appropriate basis for setting rates and, given the many issues in this case, including the impact of the Tax Act on capitalization, the Commission would achieve a fair result if it calculated the Company's electric revenue requirement using rate base.

IX. FERC TRANSMISSION RIDER

Q. DESCRIBE THE INTERVENORS' RECOMMENDATION RELATED TO THE COMPANY'S PROPOSED FERC TRANSMISSION COST RECONCILIATION RIDER.

A. Several intervenors oppose the Company's proposal to implement a rider for the Company to track a cost over which it has little control. For the Attorney General, Mr. Kollen provides of list of reasons why he opposes the Company's FERC

Transmission Cost Reconciliation Rider (Rider FTR). In his view, the rider will essentially allow the Company to track its costs; it will shift cost recovery from base rates to a rider; it will result in 'unending' quarterly updates to rates; it would change the Company's incentive to influence its transmission costs; it would reduce the Company's incentive to reduce other costs to make up for increases in transmission expenses; it would allow the Company to increase rates even if it is earning above its allowed return on equity; and, finally, the Commission already rejected such a proposal in a 2014 case involving Kentucky Power.

Q. HAS MR. KOLLEN RAISED ANY ISSUE THAT WOULD SUGGEST THE COMMISSION SHOULD NOT APPROVE RIDER FTR?

A. No. Taking his concerns in order, every gas and electric utility in the Commonwealth has some rider that allows it to track certain costs, shifting recovery from base rates to a rider. The idea that a utility may not create a rider because it would allow the utility to track costs belies the fact that such riders are commonly approved by the Commission, and that the Commission is fully authorized to approve such a rider.

All riders are updated periodically, some as frequently as monthly and some on an annual basis. The frequency of such updates is no reason to reject the creation of a rider. Also, Mr. Kollen is convinced that the only direction of such riders is upward; however, any cost being tracked could go down. A rider is symmetrical in that way such that customers get the benefit of lower costs and the utility is protected from higher costs.

Duke Energy Kentucky has very little control over its transmission costs.

It is a transmission dependent company relying on the network of other utilities to reliably serve its own retail load. The Company is an active member of PJM but, because of its size, has little influence over the decisions made by the overall PJM entity. The lack of control of such costs is a reason often cited for allowing riders. Mr. Kollen's notion that implementing Rider FTR will reduce the Company's incentive to minimize its transmission costs is misplaced.

Mr. Kollen suggests that allowing the Company to create Rider FTR will reduce its incentive to reduce other costs to make up for costs not included in a rider. This statement is nonsensical. Following Mr. Kollen's logic, allowing electric utilities to track fuel costs through the fuel adjustment clause rider (Rider FAC) disincentivizes electric utilities from controlling other costs. Whether a particular cost is recoverable in a rider or not, does not, in any way, shape, or form reduce the Company's incentive to control its costs. Mr. Kollen's assertion here is simply off the mark.

Mr. Kollen's suggestion that allowing the Company to create Rider FTR will allow it to recover costs even if it is earning above its allowed return on equity is similar to his argument that such a rider would disincentive the utility to control costs. Here again, every electric in the Commonwealth tracks it fuel costs; every electric utility except for Duke Energy Kentucky has a tracker for its environmental costs. These trackers allow for recovery of costs independent of whether the Company's base rates are generating their approved returns on equity. If that possibility was the reason for disallowing riders, then the Commission could not approve any of the many riders that exist for its regulated utilities.

Finally, Mr. Kollen correctly points out that the Commission rejected a similar proposal in a 2014 case involving Kentucky Power. Mr. Kollen's testimony fails to point out that the Commission approved a similar proposal in the most recent Kentucky Power rate case, Case No. 2017-00349. It is understandable that Mr. Kollen omitted any reference to the Commission's approval of the rider for Kentucky Power inasmuch as his testimony was filed before the Commission approved a stipulation that included the rider; however, it is curious that Mr. Kollen neglected to mention that the transmission rider had already been agreed to by a party that he represented in that case. In the most recent Kentucky Power rate case, Mr. Kollen presented testimony on behalf of the Kentucky Industrial Utility Customers, Inc. (KIUC). Although another KIUC witness addresses Kentucky Power's proposal to track transmission costs, the KIUC signed a settlement agreeing to such a rider. That occurred over a month before Mr. Kollen filed his testimony in this instant case. It is inexplicable why Mr. Kollen cited, as precedent, a Commission decision that his own client in the Kentucky Power case agreed to upend. In short, if Mr. Kollen insists on relying on Commission precedent, the most recent precedent is that the Commission has approved a rider similar to the Rider FTR being proposed by Duke Energy Kentucky.

Q. WHAT WERE THE CONCERNS RAISED BY THE OTHER INTERVENORS ABOUT RIDER FTR?

A. Northern Kentucky University's (NKU) witness Brian C. Collins opposes Rider FTR. Mr. Collins' opposition is based on the following in his testimony that the "criteria needed for establishment of a rider are that the cost elements subject to the regulatory mechanism meet the following: (1) must be outside the utility's control; (2) must be volatile and unpredictable; and (3) must be large enough to significantly affect the utility's ability to earn its authorized return." (Collins Direct at page 9).

Q. HOW DO YOU RESPOND TO MR. COLLINS' CONCERNS?

A. Mr. Collins' rationale for opposing the Rider FTR is easily dismissed. First, Duke Energy Kentucky has virtually no control over the costs it incurs for transmission service provided by PJM. Second, the Commission has already determined that such costs are volatile.[7] Inasmuch as the Commission has already made this determination and Duke Energy Kentucky is subject to the same Open Access Transmission Tariff in PJM as Kentucky Power, there does not seem to be a need to re-litigate the question of whether such costs are volatile. Finally, because of Duke Energy Kentucky's relative size, what may seem like relatively small changes in costs does have a material impact on the Company's ability to earn its authorized return. As little as $1 million in incremental costs can reduce the Company's return on equity by 20 basis points.

Essentially, all of the concerns raised by Mr. Collins argue for creation of Rider FTR and do not support his recommendation to reject it.

[7] *See* the Commission's January 18, 2018, Order in Case No. 2017-00179, page 53.

X. DISTRIBUTION CAPITAL INVESTMENT RIDER

Q. DO THE INTERVENORS SUPPORT OR OPPOSE THE COMPANY'S PROPOSED DISTRIBUTION CAPITAL INVESTMENT RIDER?

A. Through its witness Richard Baudino, the Attorney General opposes the creation of the Distribution Capital Investment Rider (Rider DCI). Northern Kentucky University's witness Collins and Kroger's witness Justin Bieber also oppose Rider DCI.

Generally, the objections involve regulatory policy. In particular, some of the concerns mentioned are about single-issue ratemaking, reducing incentives to the utility for managing costs, and the preference for addressing such issues in base rate cases.

Q. HOW DO YOU RESPOND TO THE CONCERNS RAISED BY THE INTERVENORS?

A. In my Direct Testimony I provided an attachment showing that numerous regulators consider the approval of capital-related riders as good policy and many regulators throughout the country have approved such riders. It is difficult to imagine that so many regulators would approve of regulatory models, including those that might be described as "single issue," if they deemed them to be "poor policy." Of course, it is up to the Kentucky Public Service Commission to decide what it believes is good regulatory policy but it is worth noting that the regulatory model being sought by the Company in this case has passed that test with many regulators, including this Commission as many gas utilities have single issue riders for pipeline replacement programs.

Finally, with respect to 'managing costs,' opponents of riders often raise this topic as a reason to oppose just about any rider. That concern is significantly overstated. The Company has numerous stakeholders including customers and shareholders. Managing costs, with or without riders, is an important task for any utility in serving the needs of both of these stakeholders. Furthermore, the Commission itself will always be the judge of whether costs incurred by the Company are reasonable and thus prudently incurred. The existence of a rider does not undermine that authority.

For all these reasons, the Intervenors' bases for opposing Rider DCI is unreasonable and misguided.

XI. <u>CONCLUSION</u>

Q. WHERE ATTACHMENTS WDW-REBUTTAL 1 THROUGH 5 PREPARED BY YOU AND UNDER YOUR DIRECTION AND CONTROL?

A. Yes.

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

A. Yes.

VERIFICATION

STATE OF OHIO)
) **SS:**
COUNTY OF HAMILTON)

The undersigned, William Don Wathen Jr., Director of Rates & Regulatory Strategy, being duly sworn, deposes and says that he has personal knowledge of the matters set forth in the foregoing rebuttal testimony and that it is true and correct to the best of his knowledge, information and belief.

William Don Wathen Jr., Affiant

Subscribed and sworn to before me by William Don Wathen Jr., on this 14TH day of FEBRUARY, 2018.

Adele M. Frisch
NOTARY PUBLIC

ADELE M. FRISCH
Notary Public, State of Ohio
My Commission Expires 01-05-2019

My Commission Expires: 1/5/2019

Duke Energy Kentucky
Case No. 2017-00321
Historical Replacement Power Costs

	Kollen Calc		All F.O. Expense		Replacement Power Cost for EB2		
					DEK Share		Reflect 100%
	(a)		(b)		(c)		(d)
2013	*		$3,677,859		$1,758,978		$2,549,243
2014	*		14,529,278		8,931,876		12,944,748
2015	1,294,461		1,997,737		1,294,461		1,507,240
2016	1,747,687		1,747,687		1,747,687		1,747,687
2017	$1,787,740	(e)	$1,787,740	(e)	$1,787,740	(e)	$1,787,740
	$1,609,963		$4,748,060				$4,107,332

Notes: [(a)] Per Kollen's testimony, page 11, lines 5 through 8.
Mr. Kollen only included replacement power cost provided in AG-DR-01-011(a) for East Bend Station.

[(b)] All of the actual replacement power costs in the data response relied upon by Mr. Kollen. Includes amounts for East Bend 2 and Miami Fort 6.

[(c)] As provided in the Company's response to AG-DR-01-011(a) and included in Kollen's testimony as Attachment LK-4.

[(d)] As Mr. Kollen notes in his testimony, page 11, lines 7 through 8, the Company has owned 100% of East Bend since January 1, 2015, up from 69% in prior years.
Miami Fort 6 was retired after May 2015.

[(e)] Per Mr. Kollen's resposne to the Company's Data Request No. 41 to the Attorney General.

ATTACHMENT WDW-Rebuttal-2
(Confidential)

BEING FILED UNDER SEAL

Duke Energy Kentucky, Inc.
Case No. 2017-00321
East Bend Deferral Analysis

	Actual	Actual	Actual	Actual	Actual	Actual	Actual	Actual	Actual	Actual	Actual	Actual
DEK East Bend Deferral Forecast	Jan-15	Feb-15	Mar-15	Apr-15	May-15	Jun-15	Jul-15	Aug-15	Sep-15	Oct-15	Nov-15	Dec-15
O&M	$1,189,456	$1,415,405	$1,386,209	$1,213,065	$1,099,822	$833,247	$828,586	$815,016	$831,442	$1,036,648	$747,881	$1,274,277
Reagents EB Incremental	$369,911	$318,621	$243,277	$276,276	$328,776	$279,073	$331,357	$274,584	$300,394	$249,432	$287,363	$227,098
Total Incremental	$1,559,367	$1,734,026	$1,629,485	$1,489,341	$1,428,597	$1,112,320	$1,159,943	$1,089,600	$1,131,836	$1,286,079	$1,035,244	$1,501,375
Less MF6 base	($364,590)	($364,590)	($364,590)	($364,590)	($364,590)	($364,590)	($364,590)	($364,590)	($364,590)	($364,590)	($364,590)	($364,590)
Total Deferral	$1,194,778	$1,369,436	$1,264,895	$1,124,751	$1,064,008	$747,730	$795,353	$725,011	$767,246	$921,489	$670,654	$1,136,785
Cumulative Deferral	$1,194,778	$2,569,896	$3,847,014	$4,990,061	$6,077,800	$6,854,435	$7,682,387	$8,443,934	$9,251,338	$10,216,825	$10,936,069	$12,124,864
Carrying Costs (1)	$5,682	$12,222	$18,296	$23,732	$28,905	$32,599	$36,536	$40,158	$43,998	$48,590	$52,010	$57,664
Cumulative Deferral with carrying costs	$1,200,460	$2,582,118	$3,865,309	$5,013,793	$6,106,705	$6,887,034	$7,718,923	$8,484,092	$9,295,336	$10,265,415	$10,988,079	$12,182,528

	Actual	Actual	Actual	Actual	Actual	Actual	Actual	Actual	Actual	Actual	Actual	Actual
	Jan-16	Feb-16	Mar-16	Apr-16	May-16	Jun-16	Jul-16	Aug-16	Sep-16	Oct-16	Nov-16	Dec-16
O&M	$451,395	$915,244	$1,383,284	$3,067,186	$760,341	$828,786	$529,828	$707,425	$676,474	$454,622	$601,413	$1,018,180
Reagents EB Incremental	$284,029	$270,017	$226,066	$7,413	$169,194	$293,808	$304,607	$363,747	$343,535	$354,215	$325,529	$253,949
Total Incremental	$735,424	$1,185,261	$1,609,350	$3,074,599	$929,536	$1,122,595	$834,436	$1,071,172	$1,020,008	$808,837	$926,943	$1,272,129
Less MF6 base	($364,590)	($364,590)	($364,590)	($364,590)	($364,590)	($364,590)	($364,590)	($364,590)	($364,590)	($364,590)	($364,590)	($364,590)
Total Deferral	$370,835	$820,671	$1,244,761	$2,710,009	$564,946	$758,005	$469,846	$706,583	$655,419	$444,247	$562,353	$907,539
Cumulative Deferral	$12,553,362	$13,433,735	$14,742,385	$17,522,506	$18,170,786	$19,015,208	$19,575,487	$20,375,168	$21,127,487	$21,672,214	$22,337,636	$23,351,409
Carrying Costs (1)	$59,702	$63,889	$70,112	$83,334	$86,417	$90,433	$93,098	$96,901	$100,479	$103,069	$106,234	$111,055
Cumulative Deferral with carrying costs	$12,613,064	$13,497,624	$14,812,497	$17,605,840	$18,257,203	$19,105,641	$19,668,585	$20,472,069	$21,227,966	$21,775,283	$22,443,870	$23,462,464

	Updated in Kollen's Testimony										Additional Actual Data	
	Actual	Actual	Actual	Actual	Actual	Actual	Actual	Actual	Actual	Actual	Actual	Actual
	Jan-17	Feb-17	Mar-17	Apr-17	May-17	Jun-17	Jul-17	Aug-17	Sep-17	Oct-17	Nov-17	Dec-17
O&M	$681,758	$725,179	$799,666	$656,943	$1,273,571	$759,832	$812,725	$556,055	$752,834	$749,750	$668,984	$911,123
Reagents EB Incremental	$404,277	$295,316	$429,854	$250,741	$236,575	$278,503	$279,075	$318,951	$360,157	$299,022	$334,635	$318,683
Total Incremental	$1,086,035	$1,020,495	$1,229,520	$907,684	$1,510,146	$1,038,335	$1,091,800	$875,006	$1,112,991	$1,048,772	$1,003,618	$1,229,806
Less MF6 base	($364,590)	($364,590)	($364,590)	($364,590)	($364,590)	($364,590)	($364,590)	($364,590)	($364,590)	($364,590)	($364,590)	($364,590)
Total Deferral	$721,445	$655,905	$864,930	$543,094	$1,145,556	$673,745	$727,210	$510,417	$748,401	$684,182	$639,029	$865,216
Cumulative Deferral	$24,183,909	$24,954,829	$25,938,440	$26,604,893	$27,876,978	$28,683,302	$29,546,925	$30,197,862	$31,089,879	$31,921,920	$32,711,137	$33,730,402
Carrying Costs (1)	$115,015	$118,681	$123,359	$126,528	$132,578	$136,413	$140,520	$143,616	$147,858	$150,188	$154,049	$158,359
Cumulative Deferral with carrying costs	$24,298,924	$25,073,510	$26,061,799	$26,731,422	$28,009,556	$28,819,715	$29,687,445	$30,341,478	$31,237,737	$32,072,108	$32,865,186	$33,888,761

	Last Known Actual	Kollen's Projection	
	Jan-18	Feb-18	Mar-18
O&M	$776,976		
Reagents EB Incremental	$355,996		
Total Incremental	$1,132,973		
Less MF6 base	($364,590)		
Total Deferral	$768,383	$728,732	$728,732
Cumulative Deferral	$34,657,144	$35,385,876	$36,114,607
Carrying Costs (1)	$162,996.45	$167,332	$170,835
Cumulative Deferral with carrying costs	$34,820,141	$35,556,710	$36,114,607

Notes:
(1) Debt Rate assumed through March 2018 5.707%

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

KENTUCKY INDUSTRIAL UTILITY CUSTOMERS, INC.	)	
	)	**CASE NO. 2018-00034**
COMPLAINANT	)	
v.	)	
KENTUCKY UTILITIES COMPANY, AND LOUISVILLE GAS AND ELECTRIC COMPANY	)	
DEFENDANTS	)	

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

Filed: January 29, 2018

INTRODUCTION

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

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

Q. Have you previously testified before this Commission?

A. Yes. I have testified before the Commission on numerous occasions, most recently for KU in its last base rate case, *Application of Kentucky Utilities Company for an Adjustment of its Electric Rates*, Case No. 2016-00370, and for LG&E in its last base rate case, *Application of Louisville Gas and Electric Company for an Adjustment of its Electric and Gas Rates*, Case No. 2016-00371.

Q. What is the purpose of your testimony?

A. Pursuant to the Commission's Order of January 5, 2018 in Case No. 2017-00477, my testimony presents and describes in detail the support for the Offer and Acceptance of Satisfaction which the parties are requesting the Commission approve for the disposition of this case. On January 25, 2018, the Commission issued an Order separating Case No. 2017-00447 into utility-specific proceedings. The Commission established Case No. 2018-00034 for the complaint proceeding against KU and LG&E.

Q. Please briefly describe the recently enacted Tax Cuts and Jobs Act.

A. The Tax Cuts and Jobs Act ("Tax Act") was enacted on December 22, 2017. Despite the adverse consequences on the Companies' cash flows and adverse earnings and cash flow impacts on the Companies' parent company, LG&E and KU and their parent company actively supported the passage of the Tax Act, as it is beneficial to customers and the economy. The Tax Act reduces the maximum federal corporate income tax rate from 35% to 21% effective January 1, 2018. The Tax Act also includes other changes which will currently or ultimately impact the Companies including the elimination of bonus depreciation and the corporate alternative minimum tax ("AMT") provision and the repeal of various other deductions including the Section 199 domestic manufacturing deduction. The Tax Act retains the corporate deduction for state income taxes and the interest deductibility for utilities, and provides modifications for how companies can still utilize net operating losses and existing AMT credit carryforwards.

Q. Please describe the impact of the Tax Act on accumulated deferred income taxes ("ADIT").

A. The Companies and their customers have long benefited from accelerated depreciation deductions for tax purposes where the amount of depreciation deducted on federal income tax returns is greater than the amount of depreciation recorded for book purposes. The accumulated difference reduces the capitalization of the Companies which lowers the revenue requirement for customers. This accumulated difference is reflected on the balance sheet of the Companies as deferred income taxes and, prior to the Tax Act, was based on the 35% federal corporate income tax rate. With a reduction in the federal corporate income tax rate to 21%, the amount that would have ultimately been reversed in favor of the Internal Revenue Service ("IRS") is lowered. The Companies will amortize this excess ADIT and return such amounts to their customers using the Average Rate Assumption Method ("ARAM") for such property-related ADIT as required by the Tax Act.[1] The Companies have reclassified and recorded the excess deferred taxes as a regulatory liability as they closed their books for the year ended December 2017. The Tax Act does not specify a method for the amortization of other non-property-related ADIT, so that matter was negotiated with the parties to this case. Excess deferred taxes for non-property-related ADIT items will also be reclassified to the regulatory liability.

Q. In addition to the regulatory liabilities the Companies established for the excess deferred accumulated taxes, will the Companies create any other regulatory liabilities to reflect the Tax Act?

A. Yes. In addition the regulatory liabilities associated with the excess deferred accumulated taxes, the Companies will also record a regulatory liability for the reduction in the federal corporate income tax rate under the Tax Act as directed by the Commission's December 27, 2017 order.

OFFER AND ACCEPTANCE OF SATISFACTION

Q. Did the Companies tender an Offer of Satisfaction to resolve the issues raised in the KIUC Complaint?

[1] Tax Cuts and Jobs Act § 13001(b)(6)(A), amending § 1561(d)(2) - (d)(3)(B), H.R. 1, Public Law 115-97, 131 Stat. 2054 (Dec. 22, 2017).

A. Yes. On January 8, 2018, LG&E and KU each filed an *Answer and Offer of Satisfaction*. The Companies also filed a joint motion requesting an informal conference to discuss the *Answer and Offer of Satisfaction*. An informal conference for the purpose of discussing the Answers and Offers of Satisfaction and the possibility of settlement took place on January 17, 2018 at the offices of the Commission. The informal conference was extended to and resumed on January 22, 2018. At the informal conference, a number of procedural and substantive issues were discussed, including potential settlement of all issues in the KIUC Complaint related to LG&E and KU. Representatives for the Companies, KIUC, Attorney General, and Commission Staff attended both conferences.

Q. Did the KIUC and the Attorney General accept an offer of satisfaction of KIUC's Complaint from the Companies?

A. Yes. The Companies, KIUC, and the Attorney General reached the Offer and Acceptance of Satisfaction after the conclusion of the informal conferences on January 17 and 22, 2018. The Parties agree that the Offer and Acceptance of Satisfaction is a fair, just, and reasonable resolution of the KIUC Complaint and meets the directives of the Commission's Order dated December 27, 2017 in Case No. 2017-00477. The Offer and Acceptance of Satisfaction is attached to my testimony as Exhibit KWB-1.

Q. Through what means will customers receive the estimated benefits of the Tax Act?

A. The benefit to customers will be provided in two forms. First, the Companies' various rate mechanisms, most notably their Environmental Cost Recovery ("ECR") Surcharges, will be adjusted to reflect the impact of the Tax Act beginning in March based on a January expense month. Second, the Companies will provide a surcredit to provide the base rate benefits of the Tax Act to customers as soon as administratively possible until such times as the Companies' retail rates are reset through base rate cases. The surcredit will be labeled <u>Tax Cuts and Jobs Act Surcredit</u> ("TCJA Surcredit"), and the calculations filed with the Offer and Acceptance of Satisfaction assumes the TCJA Surcredit will appear on customer bills starting in April, 2018. It is important to note that, while the TCJA Surcredit will not appear on customer bills until April, it is based on the benefits of the Tax Act from its inception January 1, 2018, through April 30, 2019, the day before base rates are expected to change following base rate case proceedings. The bill credits identified reflect the estimated 16-month savings returned over a 13-month billing period. The regulatory liabilities I previously described allow the Companies to provide these bill credits over a 13-month billing period for the estimated 16-month savings period.

Q. Please summarize the estimated benefits to be distributed to customers.

A. A summary of the estimated benefits of the Tax Act is included in Article I, Section 1.1 of the Offer and Acceptance of Satisfaction. For KU, the estimated benefits to be distributed to customers are $91,290,656, with $70,180,255 taking the form of the TCJA Surcredit. For LG&E, the estimated benefit for electric customers is $68,934,450, including $48,993,021 from the TCJA Surcredit. For LG&E gas customers, the estimated benefit is $16,663,609, mainly in the form of a TCJA Surcredit estimated at $16,299,321. In total, the Companies will distribute an estimated $176,888,715 to customers for services rendered on and after April 1, 2018 to April 30, 2019, and, as I will discuss, through the ECR mechanisms beginning March 2018.

Q. What is the bill impact for the average residential customer?

A. The Companies estimate the bill impact for the TCJA Surcredit to be a 4.2% reduction for the average KU residential customer, a 4.3% reduction for the average LG&E electric residential customer, and a 3% reduction for the average LG&E gas residential customer.[2] Beginning with March 2018 billings, there will also be an estimated 1.0% and 1.3% reduction in the ECR mechanism billing factor for KU and LG&E residential customers, leading to an estimated total bill reduction of 5.1% for the average KU residential customers and 5.6% for the average LG&E electric residential customer. Exhibit KWB-2 details this calculation.

Q. What is the amount of the TCJA Surcredit?

A. As provided in Article II, Section 2.1 of the Offer and Acceptance of Satisfaction, the Companies will establish monthly energy credits on the electric bills of their Kentucky retail customers as follows:

	Residential Tariff	Non-Residential Tariff
KU	$(0.00415) / kWh	$(0.00323) / kWh
LG&E Electric	$(0.00444) / kWh	$(0.00344) / kWh

LG&E will establish a monthly energy credit on the gas bills of its Kentucky retail customers in the amount of $(0.03384) per Ccf. The monthly energy credits will be applied on Kentucky retail electric and gas customer bills for services rendered on and after April 1, 2018 and continue through April 30, 2019.

Q. Why would the TCJA Surcredit end on April 30, 2019?

[2] The Companies used 1179 kWh for a KU residential customer, 957 kWh for an LG&E electric residential customer, and 55 Ccf for an LG&E gas customer to derive the bill impacts.

A. LG&E and KU expect to file for a change in their base rates no later than September 28, 2018 to address various changes in the supply resources and load of the Companies including the expiration of the Capacity Purchase and Tolling Agreement with Bluegrass Generation, the retirement of Brown Units 1 and 2 and the departure of nine municipal wholesale customers from the KU system. That case would also incorporate the effects of the Tax Act and other changes in revenue requirements. Base rates are expected to be reset effective May 1, 2019 based on a forecasted test year of May 1, 2019 to April 30, 2020. The Companies proposed changes in base rates and the base rates that the Commission approves in those rate cases will fully reflect the impact of the Tax Act. As a result, the base rate credits will no longer be necessary after the next rate case or in the unlikely event that the Companies place the proposed rates into effect subject to refund on May 1, 2019 subject to the Commission's final orders.

Q. Will the monthly energy credit continue beyond April 30, 2019 if new base rates do not take effect on May 1, 2019?

A. Yes, if the Commission has not approved new base rates by May 1, 2019, and the Companies have not placed their proposed base rates into effect subject to refund. As provided in Article III, Section 3.1 of the Offer and Acceptance of Satisfaction, in the event that new base rates for the Companies do not take effect on May 1, 2019, the Companies will continue to impose on the bills of their electric customers the TCJA Surcredit, but in an annualized amount, until such time as new base rates take effect:

	Residential Tariff	Non-Residential Tariff
KU	$(0.00337) / kWh	$(0.00262) / kWh
LG&E Electric	$(0.00360) / kWh	$(0.00280) / kWh

In the event that new base rates for LG&E's gas customers do not take effect on May 1, 2019, LG&E will continue to impose the TCJA Surcredit, but in an annualized amount, until such time as new base rates take effect in the amount of $(0.02750) per Ccf.

The bill credits identified here are lower than those that will be implemented prior to May 1, 2019 because the credits through April 30, 2019 reflect estimated 16-month savings returned over a 13-month billing period. The credits will be reduced May 1, 2019, to reflect an annual savings estimate.

Q. Please describe how the TCJA Surcredit was calculated.

A. Exhibit KWB-3 shows an overall financial summary of the estimated benefits of the Tax Act to be provided to customers through all components of the bill and is consistent with that shown in Section 1.1 of the Offer and Acceptance of Satisfaction. The calculations of the TCJA surcredit for KU, LG&E Electric, and LG&E Gas follow identical calculation processes. The specific calculations for KU, LG&E Electric, and LG&E Gas are attached to my testimony as Exhibits KWB-4, KWB-5 and KWB-6, respectively. I detail the specific calculations in Exhibits KWB-4, KWB-5, and KWB-6 by rows below.

Rows 1-5

Row 1 reflects the adjusted jurisdictional capitalization of each utility from the Companies' most recent rate cases and then brings that forward to the 16-month period for which the impact of the Tax Act is being calculated, that being from its inception on January 1, 2018 until the Companies expect their base rates to be reset on May 1, 2019. The supporting calculations of these amounts are included as pages 2-4 of

Exhibit KWB-4 for KU and pages 2-3 of Exhibits KWB-5 and KWB-6 for LG&E Electric and LG&E Gas. The adjustments are those typically found in base rate cases and include the removal of non-utility capitalization and other rate mechanisms. The jurisdictional factor used to adjust the per books capitalization of KU to the amounts under the Commission's jurisdiction and the jurisdictional factor used to allocate LG&E's per books capitalization to its electric and gas operations are consistent with those used in the Companies' last base rate cases. The increase in KU and LG&E Electric's capitalization and the decrease in LG&E Gas's capitalization include the estimated amounts to be distributed to customers per Exhibit KWB-3 and the estimated increase in cash taxes paid to the IRS under the Tax Act.

Prior to the Tax Act, both KU and LG&E had a tax net operating loss carryforward and thus were not cash taxpayers. With the Tax Act, both KU and LG&E are expected to be cash taxpayers for this period. The estimated amounts to be returned to customers for this period represent an additional cash outlay resulting from the Tax Act that did not exist before. Put simply, the estimated $176.9 million to be returned to customers is a reduction in cash revenues received from customers without a corresponding reduction in cash expenses.

Row 2 reflects the weighted average cost of capital for each of the Companies with the forecasted period of January 1, 2018, through April 30, 2019, adjusted to reflect the new blended federal and state income tax rate of both Companies. The calculation of this amount is also shown on page 2 of Exhibits KWB 4-6. The capital structure and the authorized return on equity used for each of the Companies is that approved in the Companies' most recent rate case. The weighted average cost of short-term and long-term debt were updated to reflect current market interest rates for the forecast period and is detailed for KU on pages 5-6 of Exhibit KWB-4 and pages 4-5 of Exhibits KWB-5 and KWB-6 for LG&E Electric and LG&E Gas, respectively. The calculation of the blended effective tax rate used to incorporate the Tax Act is included on page 7 of Exhibit KWB-4 and page 6 of Exhibits KWB-5 and KWB-6. It reflects the reduction of the corporate federal income tax rate from 35% to 21%, the effect of that on the state income tax deduction benefit and the elimination of the Section 199 deduction.

Row 3 "Required Annual Operating Income" represents the product of Rows 1 and 2 and shows the annual revenue requirement of the Companies before considering excess ADIT. Since Row 3 represents an annual revenue requirement and it is being applied to the 16-month period ending April 30, 2019, it is multiplied by 1.33 on Row 4 (which is 16/12 months) to arrive at the 16-month reduction in the revenue requirement shown on Row 5.

Rows 6-10

Rows 6-10 then add the amortization of excess ADIT to the amount calculated on Row 5. Row 6 represents the amortization of property-related excess ADIT using the ARAM method and the underlying vintage property records of the Companies as required by the Tax Act. Row 7 represents the amortization of non-property-related excess ADIT using a 15-year straight line method. The parties agreed to use a 15-year amortization period because these excess ADIT balances are largely driven by differences in book and tax accounting for pension expense. In Case Nos. 2014-00371 and 2014-00372,[3] amortization of actuarial gains and losses in the Companies' pension expense was set at 15 years and that ratemaking treatment was carried forward in Case Nos. 2016-00370 and 2016-00371. The parties agreed to the use of this amortization period with awareness of the strain that the Tax Act is placing on the credit metrics and ratings of utilities across the country. Row 8 totals the amortization from Rows 6 and 7. All amounts represent 16-months of excess ADIT amortization, and such amounts have been jurisdictionalized. In order to translate this amortization into a revenue requirement impact, it is grossed up for taxes using the post-Tax Act blended federal and state income tax rate on Rows 9 and 10.

Rows 11-13

The revenue requirement reduction due to the Tax Act from Rows 5 and 10 is then summed in Row 11. That amount is divided by the kWh or Ccf annual billing determinants from the Companies' most recent base rate cases multiplied by 13/12 months to reflect the 13-month billing period of April 1, 2018, through April 30, 2019, during which the TCJA Surcredit will be in effect. The resulting per kWh or per Ccf charge is reflected in Row 13.

Q. Please explain the different TCJA Surcredit factors and allocated estimated benefits of the Tax Act for residential and non-residential customers shown on page 1 of Exhibits KWB-4 and KWB-5 for the two electric utilities.

A. The last two columns on each of these pages splits the estimated reduction in revenue requirements between residential and non-residential customer classes proportionately

[3] *In the Matter of: Application of Kentucky Utilities Company for an Adjustment of its Electric Rates*, Case No. 2014-00371, Order at 5 (Ky. PSC June 30, 2015); *In the Matter of: Application of Louisville Gas and Electric Company for an Adjustment of its Electric and Gas Rates*, Case No. 2014-00372, Order at 5 (Ky. PSC June 30, 2015).

using the percentage of revenues provided by each group per the Companies' last base rate cases. Those allocated dollar amounts of benefits are then divided by the annual billing determinants for each group from the Companies' last base rate cases and are adjusted to reflect the 13-month billing period of the TCJA Surcredit to get a different surcredit for each group as shown in the last two columns of Row 13. This allocation methodology was agreed to by all parties to the case and provides a larger share of the estimated benefits of the Tax Act to residential customers since that customer class makes up a larger percentage of revenues than it does kWh consumed given its relative rate design.

Q. Does the Offer and Acceptance of Satisfaction also provide a share of the benefits of the Tax Act with customers through the Companies' rate mechanisms?

A. Yes. As shown in Article IV of the Offer and Acceptance of Satisfaction, customers will also receive credits through the Companies' rate mechanisms, such as the ECR surcharge, Demand Side Management ("DSM") mechanism, and LG&E's Gas Line Tracker ("GLT"). These rate mechanisms have embedded procedural provisions to provide a true-up of actual tax rates and associated rate base amounts. The Companies will employ these procedural mechanisms to return the benefits of the Tax Act associated with the cost of the facilities recovered through the mechanisms to customers.

With regard to the Companies' ECR surcharges, the Commission's December 19, 2017 Orders in Case Nos. 2017-00266 and 2017-00267 approved an overall WACC of 10.33 percent (KU) and 10.34 percent (LG&E) for use in all monthly environmental surcharge filings beginning with the December 2017 expense month. Because the Tax

Act was not enacted at the time the orders were issued, the Orders did not reflect the impact of the lower corporate federal income tax rate. In separate filings, the Companies requested the Commission modify the tax gross-up for the WACC to reflect the changes in the Tax Act effective with the expense month of January 2018 for the ECR surcharge, resulting in an overall grossed-up rate of return of 8.84 percent (KU) and 8.83 percent (LG&E).[4] In Orders dated January 24, 2018, the Commission granted the Companies' motions for reconsideration and determined that the WACC should be adjusted as proposed by the Companies. The Companies will use the WACC, the income tax gross-up factor, and the overall grossed-up rate of return authorized by the Commission's January 24, 2018 orders in Case Nos. 2017-00266 and 2017-00267 effective for the ECR expense month of January 2018 for billings beginning with the March 2018 billing cycle. In addition, in their next ECR review cases, the Companies will propose to modify the ECR Forms to account for the return of the excess deferred taxes.

The Companies also will take timely and comparable actions with respect to the calculation of their other rate mechanisms. With regard to the DSM mechanism, the 2018 tariff filings have already been approved. The Companies will incorporate the Tax Act changes into their 2018 DSM rates when they make their balancing adjustment filings at the end of February 2018 with new rates effective April 1, 2018. For its GLT,

[4] *In the Matter of: An Electronic Examination by the Public Service Commission of the Environmental Surcharge Mechanism of Kentucky Utilities Company for the Two-Year Billing Period Ending April 30, 2017*, Case No. 2017-00266, Order (Ky. PSC Jan. 24, 2018); *In the Matter of: An Electronic Examination by the Public Service Commission of the Environmental Surcharge Mechanism of Louisville Gas and Electric Company for the Two-Year Billing Period Ending April 30, 2017*, Case No. 2017-00267, Order (Ky. PSC Jan. 24, 2018).

LG&E will include the effect of the Tax Act changes in the 2018 annual filing being made at the end of February 2018 with rates effective May 1, 2018.

TCJA Surcredit Tariffs

Q. Are the Companies proposing new rate schedules to reflect the TCJA Surcredit?

A. Yes. Attached as Exhibit KWB-7 are proposed tariff sheets for KU, LG&E Electric and LG&E Gas to implement the TCJA Surcredit adjustment clause. LG&E will also modify the special contract with the Louisville Water Company so that the TCJA Surcredit will apply in the same manner as all tariffed rate schedules.

Q. Is there a need for a "true-up" to either the TCJA Surcredit or other rate mechanisms as it relates to the benefits of the Tax Act?

A. No. The estimated benefits to be provided to customers through the TCJA Surcredit represent a calculation of the impact on the revenue requirement with most provisions of that calculation being tied back to the Companies' last base rate cases. The parties agreed that other changes in adjusted net operating income should not be considered. The most significant and likely change in the ultimate amount of benefits provided by the TCJA Surcredit would be a difference in the actual amounts of energy consumption for the 13-month billing period relative to the assumptions in the Companies' last base rate case. However, all else being equal, a higher or lower amount of energy consumption would raise or lower the taxable income of the Companies. In either case, it is reasonable that the actual amounts provided by the TCJA Surcredit would also be higher or lower as the benefits of the Tax Act would also be higher or lower. With respect to other rate mechanisms, they have established mechanisms for timely trueups for changes in rate base and the weighted average cost of capital, inclusive of the new corporate federal income tax rate.

CONCLUSION AND RECOMMENDATION

Q. What is your conclusion and recommendation to the Commission?

A. I recommend that the Commission accept the Companies' Offer and Acceptance of Satisfaction as the disposition of this case. The Offer and Acceptance of Satisfaction has been accepted by all parties in this case and allows customers to begin to receive the benefits of the Tax Act as quickly as administratively possible. The Companies request the Commission to issue an order approving the Offer and Acceptance of Satisfaction by February 16, 2018. This will allow the Companies the necessary time to program and test their billing system to implement the TCJA Surcredit for service rendered on and after April 1, 2018.

Q. Does this conclude your testimony?

A. Yes, it does.

VERIFICATION

COMMONWEALTH OF KENTUCKY)
) **SS:**
COUNTY OF JEFFERSON)

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

Kent W Blake

KENT W. BLAKE

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 29th day of January 2018.

(SEAL)

Tammy J Elzy
Notary Public

My Commission Expires:

November 9, 2018

APPENDIX A

Kent W. Blake
Chief Financial Officer
Louisville Gas and Electric Company
Kentucky Utilities Company
220 West Main Street
Louisville, Kentucky 40202
Telephone: (502) 627-2573

Previous Positions

LG&E and KU Energy LLC (f/k/a E.ON U.S., LG&E Energy LLC)

Vice President, Corporate Planning and Development	2007-Feb 2012
Vice President, State Regulation and Rates	2003-2007
Director, State Regulation and Rates Director, Regulatory Initiatives	
Director, Business Development	2002-2003
Director, Finance and Business Analysis	

Mirant Corporation (f/k/a Southern Company Energy Marketing) 1998-2002
Senior Director, Applications Development
Director, Systems Integration
Trading Controller

LG&E Energy Corp.
Director, Corporate Accounting and Trading Controls 1997-1998

Arthur Andersen LLP 1988-1997
Manager, Audit and Business Advisory Services
Senior Auditor
Audit Staff

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

Current Professional and Community Affiliations
American Institute of Certified Public Accountants
Kentucky State Society of Certified Public Accountants
Edison Electric Institute
Metro United Way, Board Chair Elect
University of Louisville College of Business, Board of Advisors
Louisville Downtown Development Corporation, Board Member

OFFER AND ACCEPTANCE OF SATISFACTION

This Offer and Acceptance of Satisfaction is entered into this 29th day of January 2018 by and between Kentucky Utilities Company ("KU"); Louisville Gas and Electric Company ("LG&E") (collectively, "the Utilities"); Kentucky Industrial Utility Customers, Inc. ("KIUC" or "Complainant"); and the Attorney General of the Commonwealth of Kentucky, by and through the Office of Rate Intervention ("AG"). (Collectively, the Utilities, KIUC, and AG are the "Parties.")

WITNESSETH:

WHEREAS, on December 21, 2017, KIUC filed with the Kentucky Public Service Commission ("Commission") its *Complaint and Petition for the Establishment of a Regulatory Liability to Provide Customers a Rate Reduction Because of Tax Expense Savings* ("Complaint");

WHEREAS, on December 22, 2017, the legislation known as the Tax Cuts and Jobs Act, H.R. 1, Public Law 115-97, 131 Stat. 2054 (Dec. 22, 2017)("Tax Act") was signed into law and took effect;

WHEREAS, on December 27, 2017, the Commission issued an order with a determination that KIUC's Complaint had established a *prima facie* case and opened Case No. 2017-00477;

WHEREAS, the Commission has granted full intervention in Case No. 2017-00477 to the AG;

WHEREAS, on January 25, 2018, the Commission issued an order separating Case No. 2017-00477 into three separate, utility-specific complaint proceedings. The Commission established a combined complaint case for KU and LG&E and assigned it Case No. 2018-00034 (the "Complaint Proceeding");

WHEREAS, an informal conference for the purpose of discussing the Answers and Offers of Satisfaction filed by Utilities and the possibility of settlement, attended by representatives of the Parties and the Commission Staff, took place on January 17 and 22, 2018, at the offices of the

Commission, and during which a number of procedural and substantive issues were discussed, including potential settlement of all issues pending before the Commission in the Complaint Proceeding;

WHEREAS, the Parties hereto unanimously desire to satisfy all the issues pending before the Commission in the Complaint Proceeding;

WHEREAS, it is understood by all Parties hereto that this Offer and Acceptance of Satisfaction is subject to the approval of the Commission, insofar as it constitutes an agreement by the Parties for satisfying KIUC's Complaint and the Complaint Proceeding, and, absent express agreement stated herein, does not represent agreement on any specific claim, methodology, or theory supporting the appropriateness of any proposed or recommended adjustments to Utilities' rates, terms, or conditions;

WHEREAS, all of the Parties agree that this Offer and Acceptance of Satisfaction, viewed in its entirety, is a fair, just, and reasonable resolution of all the issues in the Complaint Proceeding; and

WHEREAS, the Parties believe sufficient and adequate data and information in the record of this proceeding support this Offer and Acceptance of Satisfaction, and further believe the Commission should approve it and dismiss the Complaint Proceeding as required by 807 KAR 5:001, Section 20(2);

NOW, THEREFORE, for and in consideration of the promises and conditions set forth herein, Utilities make the following offer of satisfaction pursuant to KRS 278.260 and 807 KAR 5:001, Section 20(2), which the KIUC and AG accept:

ARTICLE I. TAX ACT BENEFITS

1.1. From April 1, 2018 to April 30, 2019, the estimated amount of benefits of the Tax Act to be distributed by Utilities as provided in this Offer and Acceptance of Satisfaction are as follows:

LINE NO.	DESCRIPTION	KU	LG&E/ELECTRIC	LG&E/GAS	TOTAL CREDITS
		$	$	$	$
1	BASE RATE CREDIT MECHANISM	(70,180,255)	(48,993,021)	(16,299,321)	(135,472,597)
2	ENVIRONMENTAL SURCHARGE (ECR)	(21,002,921)	(19,852,212)		(40,855,133)
3	GAS LINE TRACKER (GLT)			(364,288)	(364,288)
4	DEMAND SIDE MANAGEMENT (DSM)	(107,480)	(89,217)	-	(196,697)
5	TOTAL CREDITS	(91,290,656)	(68,934,450)	(16,663,609)	(176,888,715)

ARTICLE II. BILL SURCREDITS THROUGH APRIL 30, 2019

2.1. Beginning April 1, 2018 through April 30, 2019, Utilities will establish the following monthly energy credits on the electric bills of their Kentucky retail customers:

	Residential Tariff	Non-Residential Tariff
KU	$(0.00415) / kWh	$(0.00323) / kWh
LG&E Electric	$(0.00444) / kWh	$(0.00344) / kWh

2.2. Beginning April 1, 2018 through April 30, 2019, LG&E will establish a monthly energy credit on the gas bills of its Kentucky retail customers in the amount of $(0.03384) per Ccf.

ARTICLE III. BILL SURCREDITS AFTER APRIL 30, 2019

3.1. Utilities' current base rates took effect July 1, 2017, following orders issued in June 2017 from this Commission in Case Nos 2016-00370 and 2016-00371. Utilities expect to file applications to change base rates with the Commission in 2018. In the event that the current base rates for Utilities do not change on May 1, 2019 (excepting and excluding any adjustments to base rates required by incorporation or "rolled-into" of amounts from the fuel adjustment clause or the environmental surcharge mechanism), Utilities will continue to impose on the bills of their customers the following monthly energy credits, adjusted to reflect estimated annual Tax Act benefits, until such time as new base rates resulting from applications to change base rates take effect:

(A) Beginning May 1, 2019, if the current electric base rates are not changed as a result of a base rate case proceeding, Utilities will establish the following monthly energy credits on the electric bills of their Kentucky retail customers until such time as the base rates are changed:

	Residential Tariff	Non-Residential Tariff
KU	$(0.00337) / kWh	$(0.00262) / kWh
LG&E Electric	$(0.00360) / kWh	$(0.00280) / kWh

(B) Beginning May 1, 2019, if the current gas base rates are not changed as a result of a base rate case proceeding, LG&E will establish the following monthly energy credit on the gas bills of its Kentucky retail customers until such time as the gas base rates are changed: $(0.02750) per Ccf. [1]

[1] The bill surcredits through April 30, 2019 reflect estimated 16-month savings estimates returned over a 13-month billing period. The credits will be reduced May 1, 2019, to reflect an annual savings estimate.

ARTICLE IV. RATE ADJUSTMENT MECHANISMS

4.1. Utilities will employ the procedural mechanisms in their environmental cost recovery surcharge mechanism, demand-side management mechanism and gas line tracker to distribute the Tax Act benefits as follows:

4.2. Utilities will use the weighted average cost of capital, the income tax gross-up factor and the overall grossed-up rate of return authorized by the Commission's January 24, 2018 orders Case Nos. 2017-00266 and 2017-00267 effective for the ECR expense month of January 2018 for billings beginning with the March 2018 billing cycle.

4.3. In the next Commission initiated six-month review proceeding in 2018, Utilities will propose modifications to the ECR monthly forms to allow for the return of the excess deferred taxes.

4.4. With regard to their Demand Side Management mechanisms, Utilities will incorporate the Tax Act changes into the 2018 DSM rates when they make their balancing adjustment filings at the end of February 2018 with new rates effective April 1, 2018.

4.5. For its Gas Line Tracker, LG&E will include the effect of the Tax Act changes in the 2018 annual filing being made at the end of February 2018 with rates effective May 1, 2018.

ARTICLE V. MISCELLANEOUS PROVISIONS

5.1. Except as specifically stated otherwise in this Offer and Acceptance of Satisfaction, entering into this Offer and Acceptance of Satisfaction shall not be deemed in any respect to constitute an admission by any of the Parties that any computation, formula, allegation, assertion, or contention made by any other party in this Complaint Proceeding is true or valid.

5.2. The Parties hereto agree that the foregoing stipulations and agreements represent a fair, just, and reasonable resolution of the issues addressed in KIUC's Complaint and the

Complaint Proceeding, and request the Commission to approve the Offer and Acceptance of Satisfaction.

5.3. Following the execution of this Offer and Acceptance of Satisfaction, the Parties shall cause the Offer and Acceptance of Satisfaction to be filed with the Commission on or about January 29, 2018.

5.4. This Offer and Acceptance of Satisfaction is subject to the acceptance of, and approval by, the Commission. The Parties agree to act in good faith and to use their best efforts to recommend to the Commission that this Offer and Acceptance of Satisfaction be accepted and approved as the complete disposition and resolution of the KIUC Complaint. The Parties commit to notify immediately any other Party of any perceived violation of this provision so the Party may have an opportunity to cure any perceived violation, and all Parties commit to work in good faith to address and remedy promptly any such perceived violation. In all events counsel for all Parties will represent to the Commission that the Offer and Acceptance of Satisfaction is a fair, just, and reasonable means of resolving all issues in the KIUC Complaint relating to the Utilities, and will clearly and definitively ask the Commission to accept and approve the Offer and Acceptance of Satisfaction as such.

5.5. If the Commission issues an order adopting this Offer and Acceptance of Satisfaction in its entirety and without additional conditions, each of the Parties agrees that it shall file neither an application for rehearing with the Commission, nor an appeal to the Franklin Circuit Court with respect to such order.

5.6. If the Commission does not accept and approve this Offer and Acceptance of Satisfaction in its entirety, then any adversely affected Party may withdraw from the Offer and Acceptance of Satisfaction within the statutory periods provided for rehearing and appeal of the

Commission's order by (1) giving notice of withdrawal to all other Parties and (2) timely filing for rehearing or appeal. If any Party timely seeks rehearing of or appeals the Commission's order, all Parties will continue to have the right to withdraw until the conclusion of all rehearings and appeals. Upon the latter of (1) the expiration of the statutory periods provided for rehearing and appeal of the Commission's order and (2) the conclusion of all rehearings and appeals, all Parties that have not withdrawn will continue to be bound by the terms of the Offer and Acceptance of Satisfaction as modified by the Commission's order.

5.7. If the Offer and Acceptance of Satisfaction is voided or vacated for any reason after the Commission has approved the Offer and Acceptance of Satisfaction, none of the Parties will be bound by the Offer and Acceptance of Satisfaction.

5.8. The Offer and Acceptance of Satisfaction shall inure to the benefit of and be binding upon the Parties hereto and their successors and assigns.

5.9. The Offer and Acceptance of Satisfaction constitutes the complete agreement and understanding among the Parties, and any and all oral statements, representations, or agreements made prior hereto or contained contemporaneously herewith shall be null and void and shall be deemed to have been merged into the Offer and Acceptance of Satisfaction.

5.10. The Parties hereto agree that, for the purpose of the Offer and Acceptance of Satisfaction only, the terms are based upon the independent analysis of the Parties to reflect a fair, just, and reasonable resolution of the issues herein and are the product of compromise and negotiation.

5.11. The Parties hereto agree that neither the Offer and Acceptance of Satisfaction nor any of the terms shall be admissible in any court or commission except insofar as such court or commission is addressing litigation arising out of the implementation of the terms herein or the approval of this Offer and Acceptance of Satisfaction. This Offer and Acceptance of Satisfaction shall not have any precedential value in this or any other jurisdiction.

5.12. The signatories hereto warrant that they have appropriately informed, advised, and consulted their respective Parties in regard to the contents and significance of this Offer and Acceptance of Satisfaction and based upon the foregoing are authorized to execute this Offer and Acceptance of Satisfaction on behalf of their respective Parties.

The Parties hereto agree that this Offer and Acceptance of Satisfaction is a product of negotiation among all Parties hereto, and no provision of this Offer and Acceptance of Satisfaction shall be strictly construed in favor of or against any party. Notwithstanding anything contained in the Offer and Acceptance of Satisfaction, the Parties recognize and agree that the effects, if any, of any future events upon the operating income of the Utilities are unknown and this Offer and Acceptance of Satisfaction shall be implemented as written.

IN WITNESS WHEREOF, the Parties have hereunto affixed their signatures.

Kentucky Utilities Company and
Louisville Gas and Electric Company

HAVE SEEN AND AGREED:

By: Kendrick R Riggs
Kendrick R. Riggs

-and-

By: Allyson K. Sturgeon (KRR w/ approval)
Allyson K. Sturgeon

Attorney General for the Commonwealth of Kentucky, by and through the Office of Rate Intervention

HAVE SEEN AND AGREED:

By Rebecca W. Goodman

Rebecca W. Goodman
Kent A. Chandler
Justin M. McNeil
Lawrence W. Cook

Kentucky Industrial Utility Customers, Inc.

HAVE SEEN AND AGREED:

By: ______________________________
Michael L. Kurtz
Kurt J. Boehm
Jody Kyler Cohn

NOTES:
Using February Billing Factors
ECR using December Expense Mo
Using January Base Rates

KU Residential Electric Bill

				Current		March ECR Change		April Tax Act
						Average Usage		
Residential Rate RS				1,179 Kwh				
Customer Charge				$12.25		$12.25		$12.25
All Kwh	kWh	X	0.08795	$103.69		$103.69		$103.69
Fuel/OSS Clause	kWh	X	-0.00157	($1.85)		($1.85)		($1.85)
DSM	kWh	X	0.00230	$2.71		$2.71		$2.71
Tax Act Surcredit	kWh	X		$0.00		$0.00	-0.00415	($4.89)
Subtotal				$116.80		$116.80		$111.91
ECR (X subtotal)			3.87%	$4.52	2.86%	$3.34		$3.20
Subtotal				$121.32		$120.14		$115.11
HEA			0.30	$0.30		$0.30		$0.30
TOTAL				$121.62		$120.44		$115.41
Increase Per Month						($1.18) -1.0%		($5.03) -4.2%
							Total	($6.21)
							Total %	-5.1%

NOTES:
Using February Billing Factors
ECR using December Expense Mo
Using January Base Rates

				March		April		
LG&E Residential Electric Bill				**Current**		**ECR Change**		**Tax Act**
						Average Usage		
Residential Rate RS				957 Kwh				
Customer Charge				$12.25		$12.25		$12.25
All Kwh	kWh	X	0.08865	$84.84		$84.84		$84.84
Fuel/OSS Clause	kWh	X	-0.00076	($0.73)		($0.73)		($0.73)
DSM	kWh	X	0.00248	$2.37		$2.37		$2.37
Tax Act Surcredit	kWh	X		$0.00		$0.00	-0.00444	($4.25)
Subtotal				$98.73		$98.73		$94.48
ECR (X subtotal)			7.74%	$7.64	6.31%	$6.23		$5.96
Subtotal				$106.37		$104.96		$100.44
HEA			0.25	$0.25		$0.25		$0.25
TOTAL				$106.62		$105.21		$100.69
Increase Per Month						($1.41) -1.3%		($4.52) -4.3%
							Total	($5.93)
							Total %	-5.6%

NOTES:
Using February Billing Factors
Using January Base Rates

LG&E Residential Gas Bill				Current		April Tax Act
				Average Usage		
Residential Rate RGS				55 Ccf		
Customer Charge				$16.35		$16.35
All Ccf	Ccf	X	0.36300	$19.97		$19.97
Gas Supply Clause	Ccf	X	0.43432	$23.89		$23.89
DSM	Ccf	X	0.01877	$1.03		$1.03
Tax Act Surcredit	Ccf	X		$0.00	-0.03384	($1.86)
Subtotal				$61.24		$59.38
GLT - per meter			0.71	$0.71		$0.71
GLT - per Ccf	Ccf	X	0.00065	$0.04		$0.04
HEA			0.25	$0.25		$0.25
TOTAL				$62.24		$60.38
Increase Per Month						($1.86) -3.0%

EXHIBIT KWB-3
PAGE 1 OF 1

KENTUCKY UTILITIES COMPANY
LOUISVILLE GAS AND ELECTRIC COMPANY
CASE NO. 2018-00034
SUMMARY OF TAX REDUCTION CREDITS

LINE NO.	DESCRIPTION	KU	LG&E-ELECTRIC	LG&E-GAS	TOTAL CREDITS
		$	$	$	$
1	BASE RATE CREDIT MECHANISM	(70,180,255)	(48,993,021)	(16,299,321)	(135,472,597)
2	ENVIRONMENTAL SURCHARGE (ECR)	(21,002,921)	(19,852,212)		(40,855,133)
3	GAS LINE TRACKER (GLT)			(364,288)	(364,288)
4	DEMAND SIDE MANAGEMENT (DSM)	(107,480)	(89,217)	-	(196,697)
5	TOTAL CREDITS	(91,290,656)	(68,934,450)	(16,663,609)	(176,888,715)

KENTUCKY UTILITIES COMPANY
CASE NO. 2018-00034
OVERALL FINANCIAL SUMMARY

LINE NO.	DESCRIPTION	SUPPORTING SCHEDULE REFERENCE	CASE NO. 2016-00370 FINAL ORDER (7/1/2017 - 6/30/2018)	FORECASTED PERIOD (1/1/2018 - 4/30/2019) REFLECTING CHANGES TO FEDERAL INCOME TAXES	REVENUE REQUIREMENT IMPACT	RESIDENTIAL TARIFF (39% OF TOTAL REVENUES)	OTHER TARIFFS (61% OF TOTAL REVENUES)
			$	$	$	$	$
1	CAPITALIZATION ALLOCATED TO KENTUCKY JURISDICTION	PAGE 2	3,607,984,536	3,696,723,410	88,738,875		
2	REQUIRED RATE OF RETURN ADJUSTED FOR INCOME TAXES	PAGE 2	10.25%	8.92%	-1.33%		
3	REQUIRED ANNUAL OPERATING INCOME BEFORE TAXES (1 x 2)		369,897,726	329,696,019	(40,201,708)		
4	YEARS EQUIVALENT TO 16 MONTHS (16/12)				1.33		
5	TOTAL REDUCTION IN INCOME TAX EXPENSE (3 x 4)				(53,602,277)		
6	AMORTIZATION OF EXCESS ADIT (PROTECTED) - ($309,333,049 USING ARAM)			(11,459,997)			
7	AMORTIZATION OF EXCESS ADIT (UNPROTECTED) - (SL OVER 15 YEARS)			(850,810)			
8	TOTAL AMORTIZATION OF EXCESS ADIT (6 + 7)			(12,310,807)			
9	GROSS-UP FACTOR USING 25.74% EFFECTIVE TAX RATE			1.35			
10	TOTAL REDUCTION IN DEFERRED INCOME TAX EXPENSE (8 x 9)				(16,577,978)		
11	**TOTAL REDUCTION IN REVENUE REQUIREMENTS (5 + 10)**				**(70,180,255)**	**(27,370,299)**	**(42,809,956)**
12	ENERGY BILLING UNITS (TY KWH / 12 MO x 13 MO)				19,857,410,575	6,599,267,393	13,258,143,182
13	ENERGY CREDIT PER KWH (APRIL 1, 2018 - APRIL 30, 2019) (11 / 12)					**(0.00415)**	**(0.00323)**

KENTUCKY UTILITIES COMPANY
CASE NO. 2018-00034
COST OF CAPITAL SUMMARY
SEVENTEEN MONTH AVERAGE
FROM JANUARY 1, 2018 TO APRIL 30, 2019

LINE NO.	CLASS OF CAPITAL	REFERENCE	17 MONTH AVERAGE AMOUNT	ADJUSTMENT AMOUNT	ADJUSTED CAPITAL	JURISDICTIONAL RATE BASE PERCENTAGE	JURISDICTIONAL CAPITAL	JURISDICTIONAL ADJUSTMENTS	JURISDICTIONAL ADJUSTED CAPITAL	PERCENT OF TOTAL	COST RATE	17 MONTH AVERAGE WEIGHTED COST	TAX GROSS-UP	WEIGHTED COST ADJUSTED FOR INCOME TAXES
	(A)	(B)	(C)	(D)	(E=C+D)	(F)	(G=ExF)	(H)	(I=G+H)	(J)	(K)	(L=JxK)	(M) AT 25.74%	(L+M)
			$	$	$		$	$	$		%	%	%	%
1	SHORT-TERM DEBT		132,679,494	(10,583)	132,668,910	89.28%	118,446,803	(27,179,688)	91,267,115	2.47%	2.94%	0.07%		0.07%
2	LONG-TERM DEBT		2,378,495,605	(189,724)	2,378,305,881	89.28%	2,123,351,490	(487,240,098)	1,636,111,392	44.26%	4.28%	1.89%		1.89%
3	COMMON EQUITY		2,863,437,659	(732,473)	2,862,705,187	89.28%	2,555,823,191	(586,478,287)	1,969,344,904	53.27%	9.70%	5.17%	1.79%	6.96%
4	TOTAL CAPITAL		5,374,612,758	(932,780)	5,373,679,978		4,797,621,484	(1,100,898,074)	3,696,723,410	100.00%		7.13%	1.79%	8.92%

NOTES:

(D) "ADJUSTMENT AMOUNTS" REMOVE NON-UTILITY PROPERTY, CONSISTENT WITH CASE NO. 2016-00370. **SEE PAGE 3.**

(F) "JURISDICTIONAL RATE BASE PERCENTAGE IS PER CASE NO. 2016-00370.

(H) "JURISDICTIONAL ADJUSTMENTS" REMOVE RATE BASE OF OTHER RATE MECHANISMS, MAINLY ECR. **SEE PAGE 4.**

(K) SEE CALCULATION OF DEBT COST RATES, **PAGES 5 AND 6.**

(M) SEE CALCULATION OF EFFECTIVE TAX RATE, **PAGE 7**

KENTUCKY UTILITIES COMPANY
CASE NO. 2018-00034
COST OF CAPITAL SUMMARY - ADJUSTMENT AMOUNT
SEVENTEEN MONTH AVERAGE
FROM JANUARY 1, 2018 TO APRIL 30, 2019

LINE NO.	CLASS OF CAPITAL	REFERENCE	17 MONTH AVERAGE AMOUNT	PERCENT OF TOTAL	OTHER COMPREHENSIVE INCOME - EEI	EEI DEFERRED TAXES	INVESTMENT IN OVEC	NET NONUTILITY PROPERTY	ADJUSTMENT AMOUNT
	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I=E+F+G+H)
			$		$	$	$	$	$
1	SHORT-TERM DEBT		132,679,494	2.47%	-	-	(6,172)	(4,412)	(10,583)
2	LONG-TERM DEBT		2,378,495,605	44.25%	-	-	(110,636)	(79,089)	(189,724)
3	COMMON EQUITY		2,863,437,659	53.28%	-	(504,066)	(133,193)	(95,214)	(732,473)
4	TOTAL CAPITAL		5,374,612,758	100.00%	-	(504,066)	(250,000)	(178,714)	(932,780)

KENTUCKY UTILITIES COMPANY
CASE NO. 2018-00034
COST OF CAPITAL SUMMARY - JURISDICTIONAL ADJUSTMENTS
SEVENTEEN MONTH AVERAGE
FROM JANUARY 1, 2018 TO APRIL 30, 2019

LINE NO.	CLASS OF CAPITAL	REFERENCE	JURISDICTIONAL CAPITAL	PERCENT OF TOTAL	ECR RATE BASE	DSM RATE BASE	PROFORMA ADJUSTMENT RATE BASE	JURISDICTIONAL ADJUSTMENTS
	(A)	(B)	(C=PAGE 2 COL G)	(D)	(E)	(F)	(G)	(H=E+F+G)
			$		$	$	$	$
1	SHORT-TERM DEBT		118,446,803	2.47%	(27,043,787)	(135,902)	-	(27,179,689)
2	LONG-TERM DEBT		2,123,351,490	44.26%	(484,803,841)	(2,436,258)	-	(487,240,099)
3	COMMON EQUITY		2,555,823,191	53.27%	(583,545,826)	(2,932,460)	-	(586,478,287)
4	TOTAL CAPITAL		4,797,621,484	100.00%	(1,095,393,455)	(5,504,619)	-	(1,100,898,074)

KENTUCKY UTILITIES COMPANY
CASE NO 2018-00034
EMBEDDED COST OF SHORT-TERM DEBT
SEVENTEEN MONTH AVERAGE
FROM JANUARY 1, 2018 TO APRIL 30, 2019

LINE NO.	ISSUE	AMOUNT OUTSTANDING	INTEREST RATE	INTEREST REQUIREMENT
	(A)	(B)	(C)	(D=BxC)
		$	%	$
	Commercial Paper:			
1	Dec-17	88,757,433	1.500%	1,331,362
2	Jan-18	115,284,207	2.900%	3,343,242
3	Feb-18	80,223,956	2.900%	2,326,495
4	Mar-18	121,132,941	2.900%	3,512,855
5	Apr-18	148,699,047	2.900%	4,312,272
6	May-18	192,732,523	2.900%	5,589,243
7	Jun-18	181,134,637	2.900%	5,252,904
8	Jul-18	171,967,439	2.900%	4,987,056
9	Aug-18	158,153,465	2.900%	4,586,450
10	Sep-18	204,139,312	2.900%	5,920,040
11	Oct-18	234,068,428	2.900%	6,787,984
12	Nov-18	265,582,184	2.900%	7,701,883
13	Dec-18	256,266,518	2.900%	7,431,729
14	Jan-19	232,926,101	3.150%	7,337,172
15	Feb-19	205,950,275	3.150%	6,487,434
16	Mar-19	268,884,001	3.150%	8,469,846
17	Apr-19	296,436,768	3.150%	9,337,758
18	Total	3,222,339,235		94,715,727
19	17 Month Average (D / B)	189,549,367	2.939%	5,571,513
20	Adjustment to Capital Structure - Case No. 2016-00370	(56,869,873)		
21	Adjusted 17 Month Average	132,679,494		
22	Weighted Cost of Short-Term Debt	2.939%		

KENTUCKY UTILITIES COMPANY
CASE NO. 2018-00034
EMBEDDED COST OF LONG-TERM DEBT
SEVENTEEN MONTH AVERAGE
FROM JANUARY 1, 2018 TO APRIL 30, 2019

										ANNUAL COST					
LINE NO.	DEBT ISSUE TYPE	COUPON RATE	DATE ISSUED (DAY/MO/YR)	MATURITY DATE (DAY/MO/YR)	AVERAGE PRINCIPAL AMOUNT	UNAMORT. (DISCOUNT) OR PREMIUM	UNAMORT DEBT EXPENSE	UNAMORT. LOSS ON REACQUIRED DEBT	CARRYING VALUE	INTEREST	AMORT. (DISCOUNT) OR PREMIUM	AMORT. DEBT EXPENSE	AMORT. LOSS ON REACQUIRED DEBT	LETTER OF CREDIT AND OTHER FEES	TOTAL
		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H=D+E-F-G)	(I=AxD)	(J)	(K)	(L)	(M)	(N=I+J+K+L+M)
		%			$	$	$	$	$	$	$	$	$	$	$
1	Kentucky Utilities PCB Variable due Feb 1, 2032	2.20%	5/23/2002	Feb. 1, 2032	20,930,000	-	56,998	487,062	20,385,941	461,245	-	4,018	36,278	20,930	522,470
2	Kentucky Utilities PCB Variable due Feb 1, 2032	2.20%	37399	Feb. 1, 2033	2,400,000	-	39,769	55,759	2,304,471	52,890	-	2,686	4,153	2,400	62,129
3	Kentucky Utilities_PCB Variable due Sep 1, 2042	1.05%	Aug. 25, 2016	Sep. 1, 2042	96,000,000	-	386,266	3,859,412	91,754,322	1,008,000	-	339,626	160,690	-	1,508,316
4	Kentucky Utilities PCB 5.75% due Feb 1, 2026	5.75%	May 24, 2007	Feb. 1, 2026	17,875,000	-	83,626	166,207	17,625,168	1,027,813	-	10,930	22,390	-	1,061,133
5	Kentucky Utilities PCB Variable due Oct 1, 2034	2.00%	Oct. 20, 2004	Oct. 1, 2034	50,000,000	-	165,482	1,526,781	48,307,737	1,001,875	-	9,497	94,880	380,610	1,486,861
6	Kentucky Utilities_PCB Variable due Feb 1, 2032	2.00%	Oct. 17, 2008	Feb. 1, 2032	77,947,405	-	464,221	1,223,866	76,259,318	1,561,871	-	34,369	91,157	593,975	2,281,372
7	Kentucky Utilities PCB Variable due Oct 1, 2034	2.00%	Feb. 23, 2007	Oct. 1, 2034	54,000,000	-	774,680	211,844	53,013,477	1,082,025	-	47,788	13,232	411,491	1,554,537
8	Kentucky Utilities PCB Variable due Feb 1, 2032	2.20%	23-May-02	Feb. 1, 2032	7,400,000	-	44,213	171,124	7,184,663	163,078	-	3,038	12,746	7,400	186,261
9	Kentucky Utilities_PCB Variable due May 1, 2023	2.00%	May 19, 2000	May 1, 2023	12,900,000	-	53,287	167,298	12,679,416	258,484	-	10,884	35,867	97,784	403,019
10	Kentucky Utilities PCB Variable due Feb 1, 2032	2.20%	May 23, 2002	Feb. 1, 2032	2,400,000	-	15,958	173,147	2,210,895	52,890	-	1,108	12,896	2,400	69,294
11	Kentucky Utilities PCB 6.0% due Mar 1, 2037	6.00%	May 24, 2007	Mar. 1, 2037	8,927,000	-	100,273	199,837	8,626,890	535,620	-	5,268	10,797	-	551,685
12	Kentucky Utilities_FMB 3.250% due Nov. 1, 2020	3.25%	Nov. 16, 2010	Nov. 1, 2020	500,000,000	(411,923)	911,733	-	498,676,344	16,250,000	189,623	419,930	-	-	16,859,554
13	Kentucky Utilities FMB 3.300% due Oct. 1, 2025	3.300%	Sep. 28, 2015	Oct. 1,2025	250,000,000	(76,114)	1,427,894	-	248,495,992	8,250,000	10,732	201,425	-	-	8,462,157
14	Kentucky Utilities FMB 4.375% due Oct. 1, 2045	4.38%	Sep. 28, 2015	Oct. 1,2045	250,000,000	(187,345)	2,326,740	-	247,485,915	10,937,500	6,910	85,849	-	-	11,030,259
15	Kentucky Utilities_FMB 4.65% due Nov 15, 2043	4.65%	Nov. 14, 2013	Nov. 15, 2043	250,000,000	(1,512,881)	2,326,721	-	246,160,398	11,625,000	59,958	92,245	-	-	11,777,201
16	Kentucky Utilities_FMB 5.125% due Nov. 1, 2040	5.125%	Nov. 16, 2010	Nov. 1, 2040	750,000,000	(6,023,884)	5,541,478	-	738,434,658	38,437,500	271,424	249,787	-	-	38,958,710
17	Revolving Credit Facility				-	-	1,551,451	101,504	(1,652,955)	-	-	455,063	29,771	-	484,834
18	L of C Facility				-	-	441,737	-	(441,737)	-	-	200,687		-	200,687
19	Called Bonds				-	-	-	129,807	(129,807)	-	-	-	5,821	405,556	411,377
20	2013 30-Year - Swap Hedging FMB - 4.65%									(1,428,467)	-	-	-	-	(1,428,467)
21	2015 10-Year - Swap Hedging FMB -3.30%									1,400,567					1,400,567
22	2015 30-Year - Swap Hedging FMB - 4.375%									982,679					982,679
23	Adjustment to Capital Structure - Case No. 2016-00370								61,114,296						-
24															
25	TOTALS				2,360,779,405	(8,212,128)	18,712,826	8,473,446	2,378,495,805	93,680,588	538,645	2,174,198	530,879	1,922,545	98,826,836
26															
27	EMBEDDED COST OF LONG-TERM DEBT (N / TOTALS H LESS LINE NO. 23)														4.28%

KENTUCKY UTILITIES COMPANY
Calculation of Composite Federal and Kentucky Income Tax Rate
(Based on Law in Effect January 1, 2018)

1. Assume pre-tax income of		100.0000%
2. State income tax (see SIT calc below)		6.0000%
3. Taxable income for Federal income tax before production activities deduction		94.0000%
a. Production Rate	9%	
b. Allocation to Production Income	66.87%	
c. Allocated Production Rate	0.0000%	
4. Less: Production tax deduction (0.0000% of Line 3)		0.0000%
5. Taxable income for Federal income tax (Line 3 - Line 4)		94.0000%
6. Federal income tax at 21% (Line 5 x 21%)		19.7400%
7. Total State and Federal income taxes (Line 2 + Line 6)		25.7400%

State Income Tax Calculation

1. Assume pre-tax income of	100.0000%
2. Less: Production activities deduction @ 0% X 66.87% (1)	0.0000%
3. Taxable income for State income tax	100.0000%
4. State Tax Rate	6.0000%
5. State Income Tax	6.0000%

LOUISVILLE GAS AND ELECTRIC COMPANY
CASE NO. 2018-00034 - ELECTRIC OPERATIONS
OVERALL FINANCIAL SUMMARY

LINE NO.	DESCRIPTION	SUPPORTING SCHEDULE REFERENCE	CASE NO. 2016-00371 FINAL ORDER (7/1/2017 - 6/30/2018)	FORECASTED PERIOD (1/1/2018 - 4/30/2019) REFLECTING CHANGES TO FEDERAL INCOME TAXES	REVENUE REQUIREMENT IMPACT	RESIDENTIAL TARIFF (41% OF TOTAL REVENUES)	OTHER TARIFFS (59% OF TOTAL REVENUES)
			$	$	$	$	$
1	CAPITALIZATION ALLOCATED TO ELECTRIC OPERATIONS	PAGE 2	2,388,355,971	2,442,666,008	54,310,038		
2	REQUIRED RATE OF RETURN ADJUSTED FOR INCOME TAXES	PAGE 2	10.22%	8.86%	-1.35%		
3	REQUIRED ANNUAL OPERATING INCOME BEFORE TAXES (1 x 2)		243,998,420	216,516,693	(27,481,728)		
4	YEARS EQUIVALENT TO 16 MONTHS (16/12)				1.33		
5	TOTAL REDUCTION IN INCOME TAX EXPENSE (3 x 4)				(36,642,304)		
6	AMORTIZATION OF EXCESS ADIT (PROTECTED) - ($207,520,098 USING ARAM)			(7,552,799)			
7	AMORTIZATION OF EXCESS ADIT (UNPROTECTED) - (SL OVER 15 YEARS)			(1,618,844)			
8	TOTAL AMORTIZATION OF EXCESS ADIT (6 + 7)			(9,171,643)			
9	GROSS-UP FACTOR USING 25.74% EFFECTIVE TAX RATE			1.35			
10	TOTAL REDUCTION IN DEFERRED INCOME TAX EXPENSE (8 x 9)				(12,350,717)		
11	**TOTAL REDUCTION IN REVENUE REQUIREMENTS (5 + 10)**				**(48,993,021)**	**(20,087,139)**	**(28,905,882)**
12	ENERGY BILLING UNITS (TY KWH / 12 MO x 13 MO)				12,919,919,682	4,528,429,567	8,391,490,115
13	ENERGY CREDIT PER KWH (APRIL 1, 2018 - APRIL 30, 2019) (11 / 12)					**(0.00444)**	**(0.00344)**

LOUISVILLE GAS AND ELECTRIC COMPANY
CASE NO. 2018-00034
COST OF CAPITAL SUMMARY
SEVENTEEN MONTH AVERAGE
FROM JANUARY 1, 2018 TO APRIL 30, 2019

LINE NO.	CLASS OF CAPITAL	REFERENCE	17 MONTH AVERAGE AMOUNT	JURISDICTIONAL RATE BASE PERCENTAGE	JURISDICTIONAL CAPITAL	JURISDICTIONAL ADJUSTMENTS	JURISDICTIONAL ADJUSTED CAPITAL	PERCENT OF TOTAL	COST RATE	17 MONTH AVERAGE WEIGHTED COST	TAX GROSS-UP	WEIGHTED COST ADJUSTED FOR INCOME TAXES
	(A)	(B)	(C)	(D)	(E=CxD)	(F)	(G=E+F)	(H)	(I)	(J=HxI)	(K) AT 25.74%	(J+K)
			$	%	$	$	$		%	%	%	%
	ELECTRIC:											
1	SHORT-TERM DEBT		164,253,637	82.68%	135,804,907	(42,447,871)	93,357,036	3.82%	2.90%	0.11%		0.11%
2	LONG-TERM DEBT		1,844,220,475	82.68%	1,524,801,489	(476,599,889)	1,048,201,799	42.91%	4.18%	1.80%		1.80%
3	COMMON EQUITY		2,289,185,622	82.68%	1,892,698,672	(591,591,499)	1,301,107,173	53.27%	9.70%	5.17%	1.79%	6.96%
4	TOTAL CAPITAL		4,297,659,734		3,553,305,068	(1,110,639,059)	2,442,666,008	100.00%		7.07%	1.79%	8.86%

NOTES:

(D) "JURISDICTIONAL RATE BASE PERCENTAGE IS PER CASE NO. 2016-00371.

(F) "JURISDICTIONAL ADJUSTMENTS" INCLUDE ITC, AND REMOVE NON-UTILITY PROPERTY, INVENTORIES, AND RATE BASE OF OTHER RATE MECHANISMS, MAINLY ECR. **SEE PAGE 3.**

(I) SEE CALCULATION OF DEBT COST RATES, **PAGES 4 AND 5.**

(K) SEE CALCULATION OF EFFECTIVE TAX RATE. **PAGE 6.**

LOUISVILLE GAS AND ELECTRIC COMPANY
CASE NO. 2018-00034
COST OF CAPITAL SUMMARY - ADJUSTMENT AMOUNT
SEVENTEEN MONTH AVERAGE
FROM JANUARY 1, 2018 TO APRIL 30, 2019

LINE NO.	CLASS OF CAPITAL	REFERENCE	17 MONTH AVERAGE AMOUNT	PERCENT OF TOTAL	ECR RATE BASE	DSM RATE BASE	TRIMBLE COUNTY INVENTORIES	INVESTMENT TAX CREDITS	INVESTMENT IN OVEC	NET NONUTILITY PROPERTY	ADJUSTMENT AMOUNT
	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K=E+F+G+H+I+J)
			$		$	$	$	$	$	$	$
	ELECTRIC:										
1	SHORT-TERM DEBT		164,253,637	3.82%	(43,326,348)	(190,166)	(208,341)	1,321,388	(22,713)	(21,691)	(42,447,871)
2	LONG-TERM DEBT		1,844,220,475	42.91%	(486,463,124)	(2,135,160)	(2,339,230)	14,836,388	(255,021)	(243,542)	(476,599,689)
3	COMMON EQUITY		2,289,185,622	53.27%	(603,834,739)	(2,650,321)	(2,903,629)	18,416,045	(316,552)	(302,303)	(591,591,499)
4	TOTAL CAPITAL		4,297,659,734	100.00%	(1,133,624,211)	(4,975,647)	(5,451,200)	34,573,821	(594,286)	(567,537)	(1,110,639,059)

LOUISVILLE GAS AND ELECTRIC COMPANY
CASE NO. 2018-00034
EMBEDDED COST OF SHORT-TERM DEBT
SEVENTEEN MONTH AVERAGE
FROM JANUARY 1, 2018 TO APRIL 30, 2019

LINE NO.	ISSUE	AMOUNT OUTSTANDING	INTEREST RATE	INTEREST REQUIREMENT
	(A)	(B)	(C)	(D=BxC)
		$	%	$
	Commercial Paper:			
1	Dec-17	196,959,740	1.500%	2,954,396
2	Jan-18	131,235,186	2.900%	3,805,820
3	Feb-18	118,556,027	2.900%	3,438,125
4	Mar-18	139,367,573	2.900%	4,041,660
5	Apr-18	171,756,380	2.900%	4,980,935
6	May-18	207,172,900	2.900%	6,008,014
7	Jun-18	196,247,184	2.900%	5,691,168
8	Jul-18	203,429,539	2.900%	5,899,457
9	Aug-18	204,372,494	2.900%	5,926,802
10	Sep-18	229,620,415	2.900%	6,658,992
11	Oct-18	258,766,473	2.900%	7,504,228
12	Nov-18	284,723,869	2.900%	8,256,992
13	Dec-18	276,215,150	2.900%	8,010,239
14	Jan-19	250,868,543	3.150%	7,902,359
15	Feb-19	231,729,948	3.150%	7,299,493
16	Mar-19	282,780,800	3.150%	8,907,595
17	Apr-19	316,086,292	3.150%	9,956,718
18	Total	3,699,888,513		107,242,994
19	17 Month Average (D / B)	217,640,501	2.899%	6,308,411
20	Adjustment to Capital Structure - Case No. 2016-00371	(53,386,864)		
21	Adjusted 17 Month Average	164,253,637		
22	Weighted Cost of Short-Term Debt	2.899%		

LOUISVILLE GAS AND ELECTRIC COMPANY
CASE NO. 2018-00034
EMBEDDED COST OF LONG-TERM DEBT
SEVENTEEN MONTH AVERAGE
FROM JANUARY 1, 2018 TO APRIL 30, 2019

LINE NO.	DEBT ISSUE TYPE	COUPON RATE	DATE ISSUED (DAY/MO/YR)	MATURITY DATE (DAY/MO/YR)	AVERAGE PRINCIPAL AMOUNT	UNAMORT. (DISCOUNT) OR PREMIUM	UNAMORT. DEBT EXPENSE	UNAMORT LOSS ON REACQUIRED DEBT	CARRYING VALUE	ANNUAL COST: INTEREST	AMORT. (DISCOUNT) OR PREMIUM	AMORT. DEBT EXPENSE	AMORT. LOSS ON REACQUIRED DEBT	LETTER OF CREDIT AND OTHER FEES	TOTAL
		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H=D+E-F-G)	(I=AxD)	(J)	(K)	(L)	(M)	(N=I+J+K+L+M)
		%			$	$	$	$	$	$	$	$	$	$	$
1	LG&E_FMB 5.125% due Nov. 15, 2040	5.13%	Nov. 16, 2010	Nov. 15, 2040	285,000,000	(2,295,474)	2,648,094		280,056,433	14,606,250	103,294	119,144			14,828,688
2	LG&E_FMB 4.65% due Nov 1, 2043	4.65%	Nov. 14, 2013	Nov. 15, 2043	250,000,000	(1,512,288)	2,300,072		246,187,640	11,625,000	59,956	91,179			11,776,136
3	LG&E_FMB 3.30% due Oct 1, 2025	3.30%	Sep. 28, 2015	Oct 1,2025	300,000,000	(91,298)	1,683,360		298,225,343	9,900,000	12,879	237,370			10,150,249
4	LG&E_FMB 4.375% due Oct. 1, 2045	4.38%	Sep. 28, 2015	Oct 1,2045	250,000,000	(187,272)	2,320,493		247,492,236	10,937,500	6,910	85,610			11,030,020
5	LG&E_PCB 3.75% due June 1, 2033	3.75%	Apr. 26, 2007	June 1, 2033	60,000,000		596,457	1,402,980	58,000,563	2,250,000		31,357	95,091	-	2,376,448
6	LG&E_2017 Term Loan $100M	3.36%	Oct. 26, 2017	May 15, 2019	100,000,000		57,143		99,942,857	3,362,500		57,339		-	3,419,839
7	LG&E_2018 Term Loan $100M	3.36%	Jan. 11, 2018	May 15, 2019	100,000,000				94,117,647	3,362,500				-	3,362,500
8	LG&E_PCB Variable due Sep 1, 2026	2.20%	Mar. 6, 2002	Sep 1, 2026	22,500,000		80,047	619,101	21,800,852	495,844		9,675	77,401	22,500	605,419
9	LG&E_PCB Variable due Feb 1, 2035	2.20%	Apr. 13, 2005	Feb 1, 2035	40,000,000		70,034	1,388,359	38,541,606	880,000		75,460	84,562		1,040,022
10	LG&E_PCB Variable due Nov 1, 2027	2.33%	Mar. 22, 2002	Nov 1, 2027	35,000,000		269,501	550,137	34,180,362	816,375		121,064	60,025		997,464
11	LG&E_PCB Variable due Oct 1,2033	1.57%	Nov. 20, 2003	Oct 1,2033	128,000,000		266,992	4,703,554	123,029,454	2,010,800		258,536	313,672		2,583,008
12	LG&E_PCB Variable due June 1, 2033	1.25%	Apr. 26, 2007	June 1, 2033	35,200,000		85,385	484,057	34,630,558	440,000		106,087	32,822		578,908
13	LG&E_PCB Variable due June 1, 2033	1.250%	Apr. 26, 2007	June 1, 2033	31,000,000		79,964	521,328	30,398,707	387,500		99,580	35,349		522,409
14	LG&E_PCB Variable due Nov 1, 2027	2.33%	Mar. 22, 2002	Nov 1, 2027	35,000,000		262,210	548,469	34,189,321	816,375		121,024	59,843		997,242
15	LG&E_PCB Variable due Sep 1, 2026	2.28%	Mar. 6, 2002	Sep 1, 2026	27,500,000		278,167	609,165	26,612,667	628,031		122,829	76,158		827,019
16	LG&E_PCB Variable due Sep 1, 2044	2.204%	Sep. 15, 2016	Sep. 1, 2044	125,000,000		794,668	3,745,363	120,459,970	2,754,668		27,090	143,959	125,000	3,050,737
17	Revolving Credit Facility	0.18%				-	1,714,815	108,563	(1,823,378)	-	-	502,840	31,841	506,944	1,041,726
18	Called Bonds							185,101	(185,101)				21,231		21,231
19	JP Morgan Chase Bank 5.495%			Nov. 1, 2020						2,909,433					2,909,433
20	Morgan Stanley Capital Services 3.657%			Oct. 1, 2033						547,360					547,360
21	Morgan Stanley Capital Services 3.645%			Oct. 1, 2033						543,520					543,520
22	Bank of America 3.695%									557,036					557,036
23	2013 30-Year - Swap Hedging FMB - 4.65%									(1,428,467)					(1,428,467)
24	2015 10-Year - Swap Hedging FMB -3.30%									1,400,587					1,400,587
25	2015 30-Year - Swap Hedging FMB - 4.375%									982,679					982,679
26	Adjustment to Capital Structure - Case No. 2016-00371								58,362,737						
27	TOTALS				1,834,300,000	(4,086,331)	13,507,399	14,886,179	1,844,220,476	70,785,490	183,039	2,068,364	1,031,864	654,444	74,721,192
28															
29	EMBEDDED COST OF LONG-TERM DEBT (N / TOTALS H LESS LINE NO. 26)														4.19%

LOUISVILLE GAS AND ELECTRIC COMPANY
Calculation of Composite Federal and Kentucky
Income Tax Rate
(Based on Law in Effect January 1, 2018)

1. Assume pre-tax income of		100.0000%
2. State income tax (see SIT calc below)		6.0000%
3. Taxable income for Federal income tax before production activities deduction		94.0000%
a. Production Rate	9%	
b. Allocation to Production Income	54.92%	
c. Allocated Production Rate	0.0000%	
4. Less: Production tax deduction (0.0000% of Line 3)		0.0000%
5. Taxable income for Federal income tax (Line 3 - Line 4)		94.0000%
6. Federal income tax at 21% (Line 5 x 21%)		19.7400%
7. Total State and Federal income taxes (Line 2 + Line 6)		25.7400%

State Income Tax Calculation

1. Assume pre-tax income of	100.0000%
2. Less: Production activities deduction @ 0% X 54.92% (1)	0.0000%
3. Taxable income for State income tax	100.0000%
4. State Tax Rate	6.0000%
5. State Income Tax	6.0000%

EXHIBIT KWB-6
PAGE 1 OF 6

LOUISVILLE GAS AND ELECTRIC COMPANY
CASE NO. 2018-00034 - GAS OPERATIONS
OVERALL FINANCIAL SUMMARY

LINE NO.	DESCRIPTION	SUPPORTING SCHEDULE REFERENCE	CASE NO. 2016-00371 FINAL ORDER (7/1/2017 - 6/30/2018)	FORECASTED PERIOD (1/1/2018 - 4/30/2019) REFLECTING CHANGES TO FEDERAL INCOME TAXES	REVENUE REQUIREMENT IMPACT
			$	$	$
1	CAPITALIZATION ALLOCATED TO GAS OPERATIONS	PAGE 2	695,552,077	688,523,750	(7,028,326)
2	REQUIRED RATE OF RETURN ADJUSTED FOR INCOME TAXES	PAGE 2	10.22%	8.86%	-1.35%
3	REQUIRED ANNUAL OPERATING INCOME BEFORE TAXES (1 x 2)		71,058,758	61,030,401	(10,028,357)
4	YEARS EQUIVALENT TO 16 MONTHS (16/12)				1.33
5	TOTAL REDUCTION IN INCOME TAX EXPENSE (3 x 4)				(13,371,143)
6	AMORTIZATION OF EXCESS ADIT (PROTECTED) - ($75,168,977 USING ARAM)			(1,950,880)	
7	AMORTIZATION OF EXCESS ADIT (UNPROTECTED) - (SL OVER 15 YEARS)			(223,585)	
8	TOTAL AMORTIZATION OF EXCESS ADIT (6 + 7)			(2,174,466)	
9	GROSS-UP FACTOR USING 25.74% EFFECTIVE TAX RATE			1.35	
10	TOTAL REDUCTION IN DEFERRED INCOME TAX EXPENSE (8 x 9)				(2,928,179)
11	**TOTAL REDUCTION IN REVENUE REQUIREMENTS (5 + 10)**				**(16,299,321)**
12	GAS BILLING UNITS (TY CCF / 12 MO x 13 MO)				481,601,824
13	GAS CREDIT PER CCF (APRIL 1, 2018 - APRIL 30, 2019) (11 / 12)				**(0.03384)**

LOUISVILLE GAS AND ELECTRIC COMPANY
CASE NO. 2018-00034
COST OF CAPITAL SUMMARY
SEVENTEEN MONTH AVERAGE
FROM JANUARY 1, 2018 TO APRIL 30, 2019

LINE NO.	CLASS OF CAPITAL	REFERENCE	17 MONTH AVERAGE AMOUNT	JURISDICTIONAL RATE BASE PERCENTAGE	JURISDICTIONAL CAPITAL	JURISDICTIONAL ADJUSTMENTS	JURISDICTIONAL ADJUSTED CAPITAL	PERCENT OF TOTAL	COST RATE	17 MONTH AVERAGE WEIGHTED COST	TAX GROSS-UP	WEIGHTED COST ADJUSTED FOR INCOME TAXES
	(A)	(B)	(C)	(D)	(E=CxD)	(F)	(G=E+F)	(H)	(I)	(J=HxI)	(K) AT 25.74%	(J+K)
			$	%	$	$	$		%	%	%	%
	GAS:											
1	SHORT-TERM DEBT		164,253,637	17.32%	28,448,730	(2,133,820)	26,314,910	3.82%	2.90%	0.11%		0.11%
2	LONG-TERM DEBT		1,844,220,475	17.32%	319,418,986	(23,958,276)	295,460,710	42.91%	4.18%	1.80%		1.80%
3	COMMON EQUITY		2,289,185,622	17.32%	396,486,950	(29,738,820)	366,748,130	53.27%	9.70%	5.17%	1.79%	6.96%
4	TOTAL CAPITAL		4,297,659,734		744,354,666	(55,830,916)	688,523,750	100.00%		7.07%	1.79%	8.86%

NOTES:
(D) "JURISDICTIONAL RATE BASE PERCENTAGE IS PER CASE NO. 2016-00371.
(F) "JURISDICTIONAL ADJUSTMENTS" INCLUDE ITC, AND REMOVE RATE BASE OF OTHER RATE MECHANISMS, GLT. SEE PAGE 3.
(I) SEE CALCULATION OF DEBT COST RATES, PAGES 4 AND 5.
(K) SEE CALCULATION OF EFFECTIVE TAX RATE, PAGE 4.

LOUISVILLE GAS AND ELECTRIC COMPANY
CASE NO. 2018-00034
COST OF CAPITAL SUMMARY - ADJUSTMENT AMOUNT
SEVENTEEN MONTH AVERAGE
FROM JANUARY 1, 2018 TO APRIL 30, 2019

LINE NO.	CLASS OF CAPITAL	REFERENCE	17 MONTH AVERAGE AMOUNT	PERCENT OF TOTAL	GLT RATE BASE	DSM RATE BASE		INVESTMENT TAX CREDITS			ADJUSTMENT AMOUNT
	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K=E+F+G+H+I+J)
			$		$	$	$	$	$	$	$
	GAS:										
1	SHORT-TERM DEBT		164,253,637	3.82%	(2,134,565)	-		745			(2,133,820)
2	LONG-TERM DEBT		1,844,220,475	42.91%	(23,966,639)	-		8,363			(23,958,276)
3	COMMON EQUITY		2,289,185,622	53.27%	(29,749,201)	-		10,381			(29,738,820)
4	TOTAL CAPITAL		4,297,659,734	100.00%	(55,850,405)	-		19,489			(55,830,916)

LOUISVILLE GAS AND ELECTRIC COMPANY
CASE NO. 2018-00034
EMBEDDED COST OF SHORT-TERM DEBT
SEVENTEEN MONTH AVERAGE
FROM JANUARY 1, 2018 TO APRIL 30, 2019

LINE NO.	ISSUE	AMOUNT OUTSTANDING	INTEREST RATE	INTEREST REQUIREMENT
	(A)	(B)	(C)	(D=BxC)
		$	%	$
	Commercial Paper:			
1	Dec-17	196,959,740	1.500%	2,954,396
2	Jan-18	131,235,186	2.900%	3,805,820
3	Feb-18	118,556,027	2.900%	3,438,125
4	Mar-18	139,367,573	2.900%	4,041,660
5	Apr-18	171,756,380	2.900%	4,980,935
6	May-18	207,172,900	2.900%	6,008,014
7	Jun-18	196,247,184	2.900%	5,691,168
8	Jul-18	203,429,539	2.900%	5,899,457
9	Aug-18	204,372,494	2.900%	5,926,802
10	Sep-18	229,620,415	2.900%	6,658,992
11	Oct-18	258,766,473	2.900%	7,504,228
12	Nov-18	284,723,869	2.900%	8,256,992
13	Dec-18	276,215,150	2.900%	8,010,239
14	Jan-19	250,868,543	3.150%	7,902,359
15	Feb-19	231,729,948	3.150%	7,299,493
16	Mar-19	282,780,800	3.150%	8,907,595
17	Apr-19	316,086,292	3.150%	9,956,718
18	Total	3,699,888,513		107,242,994
19	17 Month Average (D / B)	217,640,501	2.899%	6,308,411
20	Adjustment to Capital Structure - Case No. 2016-00371	(53,386,864)		
21	Adjusted 17 Month Average	164,253,637		
22	Weighted Cost of Short-Term Debt	2.899%		

LOUISVILLE GAS AND ELECTRIC COMPANY
CASE NO. 2018-00034
EMBEDDED COST OF LONG-TERM DEBT
SEVENTEEN MONTH AVERAGE
FROM JANUARY 1, 2018 TO APRIL 30, 2019

LINE NO.	DEBT ISSUE TYPE	COUPON RATE	DATE ISSUED (DAY/MO/YR)	MATURITY DATE (DAY/MO/YR)	AVERAGE PRINCIPAL AMOUNT	UNAMORT. (DISCOUNT) OR PREMIUM	UNAMORT. DEBT EXPENSE	UNAMORT. LOSS ON REACQUIRED DEBT	CARRYING VALUE	ANNUAL COST: INTEREST	ANNUAL COST: AMORT. (DISCOUNT) OR PREMIUM	ANNUAL COST: AMORT. DEBT EXPENSE	ANNUAL COST: AMORT. LOSS ON REACQUIRED DEBT	ANNUAL COST: LETTER OF CREDIT AND OTHER FEES	ANNUAL COST: TOTAL
		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H=D+E-F-G)	(I=AxD)	(J)	(K)	(L)	(M)	(N=I+J+K+L+M)
		%			$	$	$	$	$	$	$	$	$	$	$
1	LG&E_FMB 5.125% due Nov. 15, 2040	5.13%	Nov. 16, 2010	Nov. 15, 2040	285,000,000	(2,295,474)	2,648,094		280,056,433	14,606,250	103,294	119,144			14,828,688
2	LG&E_FMB 4.65% due Nov 1, 2043	4.65%	Nov. 14, 2013	Nov. 15, 2043	250,000,000	(1,512,288)	2,300,072		246,187,640	11,625,000	59,956	91,179			11,776,135
3	LG&E_FMB 3.30% due Oct 1, 2025	3.30%	Sep. 28, 2015	Oct 1,2025	300,000,000	(91,298)	1,683,360		298,225,343	9,900,000	12,879	237,370			10,150,249
4	LG&E_FMB 4.375% due Oct. 1, 2045	4.38%	Sep. 28, 2015	Oct 1,2045	250,000,000	(187,272)	2,320,493		247,492,235	10,937,500	6,910	85,610			11,030,020
5	LG&E_PCB 3.75% due June 1, 2033	3.75%	Apr. 26, 2007	June 1, 2033	60,000,000		596,457	1,402,980	58,000,563	2,250,000		31,357	95,091	-	2,376,448
6	LG&E_2017 Term Loan $100M	3.36%	Oct. 26, 2017	May 15, 2019	100,000,000		57,143		99,942,857	3,362,500		57,339		-	3,419,839
7	LG&E_2018 Term Loan $100M	3.36%	Jan. 11, 2018	May 15, 2019	100,000,000				94,117,647	3,362,500				-	3,362,500
8	LG&E_PCB Variable due Sep 1, 2026	2.20%	Mar. 6, 2002	Sep 1, 2026	22,500,000		80,047	619,101	21,800,852	495,844		9,675	77,401	22,500	605,419
9	LG&E_PCB Variable due Feb 1, 2035	2.20%	Apr. 13, 2005	Feb 1, 2035	40,000,000		70,034	1,388,359	38,541,606	880,000		75,480	84,562		1,040,022
10	LG&E_PCB Variable due Nov 1, 2027	2.33%	Mar. 22, 2002	Nov 1, 2027	35,000,000		269,501	550,137	34,180,362	816,375		121,064	60,025		997,464
11	LG&E_PCB Variable due Oct 1,2033	1.57%	Nov. 20, 2003	Oct 1,2033	128,000,000		266,992	4,703,554	123,029,454	2,010,800		258,636	313,572		2,583,008
12	LG&E_PCB Variable due June 1, 2033	1.25%	Apr. 26, 2007	June 1, 2033	35,200,000		85,385	484,057	34,630,558	440,000		106,087	32,822		578,908
13	LG&E_PCB Variable due June 1, 2033	1.250%	Apr. 26, 2007	June 1, 2033	31,000,000		79,964	521,328	30,398,707	387,500		99,560	35,349		522,409
14	LG&E_PCB Variable due Nov 1, 2027	2.33%	Mar. 22, 2002	Nov 1, 2027	35,000,000		262,210	548,469	34,189,321	816,375		121,024	59,843		997,242
15	LG&E_PCB Variable due Sep 1, 2026	2.28%	Mar. 6, 2002	Sep 1, 2026	27,500,000		278,167	609,165	26,612,667	626,031		122,829	76,158		827,019
16	LG&E_PCB Variable due Sep 1, 2044	2.204%	Sep. 15, 2016	Sep. 1, 2044	125,000,000		794,666	3,745,363	120,459,970	2,754,688		27,090	143,959	125,000	3,050,737
17	Revolving Credit Facility	0.18%				-	1,714,815	106,563	(1,823,378)	-	-	502,940	31,841	505,944	1,041,728
18	Called Bonds							185,101	(185,101)				21,231		21,231
19	JP Morgan Chase Bank 5.495%			Nov. 1, 2020						2,909,433					2,909,433
20	Morgan Stanley Capital Services 3.657%			Oct. 1, 2033						547,360					547,360
21	Morgan Stanley Capital Services 3.645%			Oct. 1, 2033						543,520					543,520
22	Bank of America 3.885%									587,036					587,036
23	2013 30-Year - Swap Hedging FMB - 4.65%									(1,428,467)					(1,428,467)
24	2015 10-Year - Swap Hedging FMB -3.30%									1,400,587					1,400,587
25	2015 30-Year - Swap Hedging FMB - 4.375%									982,679					982,679
26	Adjustment to Capital Structure - Case No. 2016-00371								58,362,737						
27	TOTALS				1,824,200,000	(4,098,331)	13,507,389	14,868,179	1,844,220,476	70,785,490	183,039	2,058,364	1,031,884	654,444	74,721,182
28															
29	EMBEDDED COST OF LONG-TERM DEBT (N / TOTALS H LESS LINE NO. 26)														4.18%

LOUISVILLE GAS AND ELECTRIC COMPANY
Calculation of Composite Federal and Kentucky
Income Tax Rate
(Based on Law in Effect January 1, 2018)

1. Assume pre-tax income of		100.0000%
2. State income tax (see SIT calc below)		6.0000%
3. Taxable income for Federal income tax before production activities deduction		94.0000%
a. Production Rate	9%	
b. Allocation to Production Income	54.92%	
c. Allocated Production Rate	0.0000%	
4. Less: Production tax deduction (0.0000% of Line 3)		0.0000%
5. Taxable income for Federal income tax (Line 3 - Line 4)		94.0000%
6. Federal income tax at 21% (Line 5 x 21%)		19.7400%
7. Total State and Federal income taxes (Line 2 + Line 6)		25.7400%

State Income Tax Calculation

1. Assume pre-tax income of	100.0000%
2. Less: Production activities deduction @ 0% X 54.92% (1)	0.0000%
3. Taxable income for State income tax	100.0000%
4. State Tax Rate	6.0000%
5. State Income Tax	6.0000%

Kentucky Utilities Company

P.S.C. No. 18, Original Sheet No. 89 N

Adjustment Clause **TCJA**
Tax Cuts and Jobs Act Surcredit

APPLICABLE
In all territory served.

AVAILABILITY OF SERVICE
This schedule is mandatory to all Standard Rate Schedules listed in Sections 1 and 3 of the General Index except PSA and Special Charges.

RATE
The monthly billing amount computed under each of the rate schedules to which this surcredit is applicable shall decrease by the Tax Cuts and Jobs Act (TCJA) Surcredit. The TCJA Surcredit will be distributed to the Company's customers based on the following:

TCJA Surcredit per kWh:

Residential (RS, RTOD-Energy, RTOD-Demand, VFD):	\$0.00415
Non-Residential (all other Rate Schedules):	\$0.00323

TERMS OF DISTRIBUTION
(1) The TCJA Surcredit shall be applied to the customer's bill following the rates and charges for electric service, but before application of the Environmental Cost Recovery Surcharge, Franchise Fee Rider, School Tax, and Home Energy Assistance Program.

(2) The TCJA Surcredit shall be effective April 1, 2018 and continued through April 30, 2019 at the rates specified above.

(3) In the event that the Company's base rates do not change on May 1, 2019, the TCJA Surcredit will continue at the following rates:

TCJA Surcredit per kWh:

Residential (RS, RTOD-Energy, RTOD-Demand, VFD):	\$0.00337
Non-Residential (all other Rate Schedules):	\$0.00262

(4) The TCJA Surcredit shall terminate when base rates are changed following an application requesting a change in base rates.

DATE OF ISSUE: January 29, 2018

DATE EFFECTIVE: April 1, 2018

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Lexington, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2018-00034 dated _____, 2018

Louisville Gas and Electric Company

P.S.C. Electric No. 11, Original Sheet No. 89 N

Adjustment Clause **TCJA**
Tax Cuts and Jobs Act Surcredit

APPLICABLE
In all territory served.

AVAILABILITY OF SERVICE
This schedule is mandatory to all Standard Rate Schedules listed in Sections 1 and 3 of the General Index except PSA and Special Charges.

RATE
The monthly billing amount computed under each of the rate schedules to which this surcredit is applicable shall decrease by the Tax Cuts and Jobs Act (TCJA) Surcredit. The TCJA Surcredit will be distributed to the Company's customers based on the following:

TCJA Surcredit per kWh:

Residential (RS, RTOD-Energy, RTOD-Demand, VFD): $0.00444

Non-Residential (all other Rate Schedules): $0.00344

TERMS OF DISTRIBUTION

(1) The TCJA Surcredit shall be applied to the customer's bill following the rates and charges for electric service, but before application of the Environmental Cost Recovery Surcharge, Franchise Fee Rider, School Tax, and Home Energy Assistance Program.

(2) The TCJA Surcredit shall be effective April 1, 2018 and continued through April 30, 2019 at the rates specified above.

(3) In the event that the Company's base rates do not change on May 1, 2019, the TCJA Surcredit will continue at the following rates:

TCJA Surcredit per kWh:

Residential (RS, RTOD-Energy, RTOD-Demand, VFD): $0.00360

Non-Residential (all other Rate Schedules): $0.00280

(4) The TCJA Surcredit shall terminate when base rates are changed following an application requesting a change in base rates.

DATE OF ISSUE: January 29, 2018

DATE EFFECTIVE: April 1, 2018

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2018-00034 dated _____, 2018

Louisville Gas and Electric Company

P.S.C. Gas No. 11, Original Sheet No. 89 N

Adjustment Clause **TCJA**
Tax Cuts and Jobs Act Surcredit

APPLICABLE
In all territory served.

AVAILABILITY OF SERVICE
This schedule is mandatory to all Standard Rate Schedules listed in Section 1 of the General Index.

RATE
The monthly billing amount computed under each of the rate schedules to which this surcredit is applicable shall decrease by the Tax Cuts and Jobs Act (TCJA) Surcredit. The TCJA Surcredit will be distributed to the Company's customers based on the following:

TCJA Surcredit per 100 cubic feet: $0.03384

TERMS OF DISTRIBUTION
(1) The TCJA Surcredit shall be applied to the customer's bill following the rates and charges for gas service, but before application of the Gas Line Tracker, Franchise Fee Rider, School Tax, and Home Energy Assistance Program.

(2) The TCJA Surcredit shall be effective April 1, 2018 and continued through April 30, 2019 at the rates specified above.

(3) In the event that the Company's base rates do not change on May 1, 2019, the TCJA Surcredit will continue at the following rates:

TCJA Surcredit per 100 cubic feet: $0.02750

(4) The TCJA Surcredit shall terminate when base rates are changed following an application requesting a change in base rates.

DATE OF ISSUE: January 29, 2018

DATE EFFECTIVE: April 1, 2018

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2018-00034 dated _____, 2018

Duke Energy Kentucky
Case No. 2017-00321
Adjustment to Test Year Revenue Requirements

		Case No. 2006-00172 (a)	Forecast Period 4/1/18 - 3/31/19 (b)	Difference (c)	
1	Capitalization Allocated to Electric	$557,080,702	$705,051,140	$147,970,438	Schedule 1, page 2 of 4
2	Pre-Tax Return	12.12%	9.26% *	-2.86%	Schedule 1, page 3 of 4
3	Increase/(Decrease) in Annual Revenue Requirement	$67,500,855	$65,285,615	**($2,215,240)**	(a)(3) - (b)(3)
4	Pro rate deferral for January 1, 2018, through March 31, 2018			**($553,810)**	Line 3 * (3 months ÷ 12 months)
5	Amortize over five years			**($110,762)**	Line 4 ÷ 5 years

Note: * There was no explicitly approved ROE in Case No. 2006-00172. DEK has assumed 11.0% since 2007 for purposes of AFUDC Equity calculations

Duke Energy Kentucky
Case No. 2017-00321
Capitalization (Prior Rate Case and Current)

1	Current Capitalization Allocated to Electric in Base Rates	$557,080,702	Schedule A-1, DEK Application in Case No. 2006-00172
	Calculate Capitalization Allocable to Electric for Forecast Period[a]		
2	Total Capitalization from Pending Electric Rate Case	$705,051,140	Schedule A-1, Line 8, from Case No. 2017-00321

Notes: [a] Forecast period in current rate case is April 1, 2018, through March 31, 2019.

Duke Energy Kentucky
Case No. 2017-00321
Weighted-Average Cost of Capital (Pre-Tax)

	Capitalization from J-1 Forecast in Case No. 2017-00321 (w/ GRCF @ 21% FIT and 10.375% ROE)					
	13-Mo Avg. Bal.	% of Total	Cost	Weighted Cost	GRCF	Pre-Tax ROR
Common Equity	$522,765,867	48.89%	11.000%	5.378%	1.3409866	7.21%
Long-Term Debt	434,934,967	40.68%	4.243%	1.726%	1.0000000	1.73%
Short-Term Debt	111,491,538	10.43%	3.083%	0.321%	1.0000000	0.32%
Total Capital	$1,069,192,372	100.00%		7.426%		9.26%

	Capitalization As Filed in Case No. 2006-00172 (Assume 11.0% ROE)					
	13-Mo Avg. Bal.	% of Total	Cost	Weighted Cost	GRCF	Pre-Tax ROR
Common Equity	$345,393,322	50.88%	11.000% *	5.597%	1.6449687	9.21%
Long-Term Debt	275,774,125	40.63%	6.090%	2.474%	1.0000000	2.47%
Short-Term Debt	57,645,769	8.49%	5.138%	0.436%	1.0000000	0.44%
	$678,813,216	100.00%		8.507%		12.12%

Note: * There was no explicitly approved ROE in Case No. 2006-00172. DEK has assumed 11.0% since 2007 for purposes of AFUDC Equity calculations

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

The Electronic Application of Duke Energy Kentucky, Inc., for: 1) An Adjustment of the Electric Rates; 2) Approval of an Environmental Compliance Plan and Surcharge Mechanism; 3) Approval of New Tariffs; 4) Approval of Accounting Practices to Establish Regulatory Assets and Liabilities; and 5) All Other Required Approvals and Relief.	))))))))))	Case No. 2017-00321

REBUTTAL TESTIMONY OF

ALEXANDER "SASHA" J. WEINTRAUB, PH.D.

ON BEHALF OF

DUKE ENERGY KENTUCKY, INC.

February 14, 2018

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I. INTRODUCTION AND PURPOSE

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Alexander (Sasha) J. Weintraub, and my business address is 400 South Tryon Street, Charlotte, North Carolina 28202.

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

A. I am employed by Duke Energy Progress, LLC (Duke Energy Progress), as Senior Vice President of Customer Solutions. Duke Energy Progress provides various administrative and other services to Duke Energy Kentucky, Inc. (Duke Energy Kentucky), and other affiliated companies of Duke Energy Corporation (Duke Energy).

Q. ARE YOU THE SAME ALEXANDER (SASHA) J. WEINTRAUB THAT SUBMITTED DIRECT TESTIMONY IN THIS PROCEEDING?

A. Yes.

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

A. The purpose of my rebuttal testimony is to rebut the direct testimony of Kentucky School Board Association Mr. Ronald Willhite regarding the need to include The School Energy Managers Project (SEMP) in its DSM Program Portfolio. Additionally, I will rebut the direct testimony of the Kentucky Office of the Attorney General Mr. Glenn A. Watkins on his testimony related to the Company's proposed Fixed Bill Program.

II. DISCUSSION

Q. PLEASE SUMMARIZE MR. WILLHITE'S TESTIMONY REGARDING THE SCHOOL ENERGY MANAGER PROJECT?

A. Mr. Willhite's testimony provides an excellent summary of the history of SEMP in Kentucky. He details how the program which was originally funded through an federal economic stimulus grant, has also received funding from Kentucky's Energy and Environment Cabinet and is currently being funded through money collected from LG&E/KU and Kentucky Power. Mr Willhite also details the energy efficiency achievements that have occurred since 2010, with Kentucky now ranking third nationally in the percentage of its K-12 schools that have achieved Energy Star certification with 35% having reached that certification. Finally, he discusses that Duke Energy Kentucky elected to not participate in SEMP in 2014 and he recommends that the Commission should order the Company to fund SEMP by including it in its DSM Program Portfolio.

Q. DOES MR. WILLHITE PROVIDE ANY JUSTIFICATION FOR HIS RECOMMNEDATION THAT THE COMPANY NEEDS TO PARTICIPATE IN SEMP?

A. No. While Mr. Willhite provides a description of SEMP, how other utilities are funding it, and how Kentucky K-12 schools are becoming more energy efficient and achieving Energy Star certification, he does not claim nor does he demonstrate that the SEMP is the reason for the energy efficiency gains. Even more noticeable and important is the absence of any claim or data showing that

Duke Energy Kentucky's decision to not participate in SEMP has led to schools in its service territory not becoming more energy efficient.

Q. DO YOU BELIEVE THAT THE COMPANY'S DECISION TO NOT INCLUDE SEMP IN ITS DSM PROGRAM PORTFOLIO IN 2014 HAS NEGLECTED K-12 SCHOOLS FROM BENEFITTING FROM THE COMPANY's DSM PROGRAMS?

A. No. I believe that the Company's portfolio of DSM programs has been effective in incentivizing K-12 schools located in its service territory to become more energy efficient. In fact, since 2014, the Company has paid nearly $1 million of DSM incentives to customers associated with energy efficiency projects at K-12 schools.

Q. DO YOU BELIEVE THAT THE COMPANY'S DECISION TO NOT INCLUDE SEMP IN ITS DSM PROGRAM PORTFOLIO HAS NEGATIVELY IMPACTED THE KENTUCKY SCHOOL BOARD ASSOCIATION'S GOAL OF GETTING ITS K-12 SCHOOLS TO BE CERTIFIED ENERGY STAR?

A. No. When reviewing the K-12 schools located in Kentucky and labeled as Energy Star as listed on EnergyStar.Gov, it does not appear that Duke Energy Kentucky's decision to not participate in SEMP has negatively impacted the Kentucky School Boards goal of getting K-12 schools labeled as Energy Star. In fact, approximately 10% of the over 400 Kentucky schools labeled as Energy Star are served by Duke Energy Kentucky.

Q. **WHAT IS THE COMPANY'S POSITION WITH RESPECT TO INCLUDING SEMP IN ITS PORTFOLIO OF DSM PROGRAMS?**

A. The Company believes its current suite of DSM programs provides sufficient incentives and opportunities for the K-12 schools in its service territory. While Duke Energy Kentucky continually evaluates opportunities for cost effective DSM programs for its customers, the Company is also very mindful of the need to control DSM costs and does not believe the addition of SEMP is necessary at this time.

Q. **PLEASE SUMMARIZE MR. WATKINS' TESTIMONY REGARDING THE COMPANY'S PROPOSED FIXED BILL PROGRAM?**

A. Mr. Watkins does not support the Company's proposed voluntary Fixed Bill Program on his beliefs that it will provide "windfall profits" to the Company and that it provides an incentive for customers to use more electricity.

Q. **DO YOU AGREE WITH MR. WATKINS' CONTENTION THAT THE PROGRAM WILL LEAD TO "WINDFALL PROFITS" FOR THE COMPANY?**

A. No, I do not agree with his contention. First and foremost, Mr. Watkins' testimony provides no basis or analysis supporting his assertion that the program will lead to any profits for the Company, let alone "windfall profits." In response to the Attorney General's Data Request, Question 21, Mr. Watkins states, "As a result of the proposed premium, the Company will collect revenues over and above the current authorized residential rates. The traditional rates approved in this case would be designed to recover the Company's total cost of providing service such that the revenue collected from the proposed 'premium' would be over and above the Company's cost of service." Clearly Mr. Watkins does not understand the proposed program, as the premium charged by the Company under its proposed fixed bill program is designed to cover the cost risk that the Company is taking on by guaranteeing a customer's bill regardless of energy usage for a period of time. If customer usage is higher than the expected weather normal usage for a customer, the Company will bear the costs. Given Mr. Watkins unsubstantiated belief that customers on the proposed Fixed Bill will increase their consumption, it is hard to believe that he would believe that the Company's proposed program will generate windfall profits for the Company.

Q. DO YOU AGREE WITH MR. WATKINS CONTENTION THAT THE PROPOSED FIXED BILL PROGRAM WOULD PROVIDE PARTICPATING CUSTOMERS AN INCENTIVE TO USE MORE ELECTRICITY?

A. No, I do not agree. Mr. Watkins' testimony provides no analysis or factual basis for his contention. Beyond, a lack of explanation for his belief, it appears that Mr Watkins does not understand the Company's proposal. Under the proposed fixed bill program, a participant's monthly bill is fixed and they pay the same amount regardless of whether or not they use more or less, so it is very hard to understand how Mr. Watkins believes that Duke Energy Kentucky would be providing the customer an incentive to use more.

Q. DO YOU AGREE WITH MR. WATKINS PREMISE THAT DUE TO THE LACK OF A PRICE SIGNAL, CUSTOMERS ON THE FIXED BILL PROGRAM WILL NOT WANT TO CONSERVE ENERGY OR BECOME ENERGY EFFIECIENT AND HENCE WILL USE MORE ENERGY?

A. No. Again Mr. Watkins provides no evidence or analysis underlying his opinion. In fact, as I discussed in my direct testimony, data from a survey of Duke Energy Indiana customers indicates that Fixed Bill participants may have a higher interest in energy efficiency. The survey data showed that Fixed Bill participants had a higher rate of participation in three of the four residential energy efficiency programs that they were asked about than the non-participants surveyed.

Q. DO YOU AGREE WITH MR. WATKINS' CONTENTION THAT UNDER THE COMPANY'S PROPOSED PROGRAM THAT THE DIFFERENCE BETWEEN BUDGET BILL AND FIXED BILL IS THAT FIXED BILL CUSTOMERS NEVER SEE THE IMPACT OF INEFFICIENTLY INCREASING CONSUMPTION?

A. No. Mr. Watkins' contention is incorrect. A customer inefficiently increasing consumption will see the impacts of that decision in two ways. First, assuming the program is structured like the Duke Energy Indiana Fixed Bill, in an extreme case that a Fixed Bill customer inefficiently increases their consumption by more than 15 percent of the expected weather normal usage, after being warned, the customer would either have their fixed bill repriced or be terminated from the program. Secondly, in a more moderate case of increased usage, a customer's Fixed Bill amount for the next year would be higher, as the increase in consumption would be factored into the calculation of their expected bill the following year. The only real difference for a fixed bill and budget bill customer, is that the budget bill customer's bill for the next year includes a true-up of the prior year; a fixed bill customer does not.

Q. **DO YOU AGREE WITH MR WATKINS' CONCLUSION THAT THE COMPANY'S PROPOSED FIXED BILL PROGRAM SHOULD BE REJECTED?**

A. No. For a large segment of Duke Energy Kentucky's customers bill certainty is extremely important and the Company's proposed Fixed Bill Program meets their needs. While its customers currently have access to the Budget Billing Program, which does provide a level of certainty around a customer's monthly bill, however, many customer opt not to participate in this program because of concerns of a potentially large true-up associated with usage increasing due to extreme weather or other reasons. Duke Energy Indiana's program has proven to be very successful in meeting this need for bill certainty and has seen high satisfaction and retention among participants. Given that this proposed program is completely voluntary and all of the costs and risk associated with changes in customer consumption are borne by the program participants and Duke Energy Kentucky, not non-participating customers, I believe the Commission should approve the Company's proposed Fixed Bill program subject to their review and acceptance of the Company's compliance tariff.

Q. IF THE COMMISSION DOES NOT APPROVE THE FIXED BILL PROGRAM, WILL THAT IMPACT THE COMPANY'S REVENUE REQUIREMENT IN THIS CASE?

A Yes. As part of the Company's revenue requirement, the Company assumed the fixed bill would be approved and imputed revenue for the program within its forecasted test year. If Fixed Bill is not approved, then the revenue assumed will not occur, and is understated. Therefore, if the Commission denies Fixed Bill, the Company's revenue requirement in this case will have to increase by approximately $122,230.

IV. <u>CONCLUSION</u>

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

A. Yes.

VERIFICATION

STATE OF NORTH CAROLINA	)	
	)	**SS:**
COUNTY OF MECKLENBURG	)	

The undersigned, Alexander (Sasha) J. Weintraub, Senior Vice President of Customer Solutions, being duly sworn, deposes and says that he has personal knowledge of the matters set forth in the foregoing rebuttal testimony and that it is true and correct to the best of his knowledge, information and belief.

Alexander (Sasha) J. Weintraub Affiant

Subscribed and sworn to before me by Alexander (Sasha) J. Weintraub on this 7 day of February 2018.

Carla Sechrest
NOTARY PUBLIC

CARLA SECHREST
Notary Public
Rowan County
NORTH CAROLINA

My Commission Expires: 7/27/2019