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 New Tariffs; 3) Approval of Accounting Practices to Establish Regulatory Assets and Liabilities; and 4) All Other Required Approvals and Relief.	)	Case No. 2022-00372

PETITION OF DUKE ENERGY KENTUCKY, INC. FOR CONFIDENTIAL TREATMENT OF INFORMATION CONTAINED IN THE REBUTTAL TESTIMONY OF CHRISTOPHER R. BAUER

Duke Energy Kentucky, Inc. (Duke Energy Kentucky or the Company), by counsel, pursuant to 807 KAR 5:001, Section 13, KRS 61.878(1)(c)(1), and other applicable law respectfully requests the Public Service Commission of Kentucky (Commission) issue an Order granting confidential treatment to two attachments to the Rebuttal Testimony of Christopher R. Bauer, respectfully stating as follows:

1. The information for which Duke Energy Kentucky seeks confidential treatment is contained in Confidential Attachments to the Rebuttal Testimony of Christopher R. Bauer (CRB-Rebuttal-2 and CRB-Rebuttal-3). Collectively, these documents are referred to herein as the "Confidential Information" and are reports and articles created by third-party vendors that are provided the Company through a paid subscription that prohibits public disclosure.

2. Confidential Attachment CRB-Rebuttal-2, Duke Energy Kentucky is Moody's Investors Service January 23, 2023 Credit Opinion of the Company. This document provides a summary of Duke Energy Kentucky's credit profile.

3. Confidential Attachment CRB-Rebuttal-3, Duke Energy Kentucky is Moody's Investors Service November 3, 2022, Sector In-Depth article.

4. The foregoing Confidential Attachments CRB-Rebuttal-2 and CRB-Rebuttal-3 are reports and articles that are provided to Duke Energy from a third-party vendor, Moody's Investors Service (Moody's) who provide services to the Company under a paid subscription service. Moody's takes reasonable steps to protect their confidential information by only releasing such information to paid subscribers subject to confidentiality agreements. Duke Energy Kentucky is contractually bound to maintain Moody's reports and articles as confidential.

5. Administrative Regulation 807 KAR 5:110, Section 5 sets forth the procedure by which certain information filed with the Commission shall be treated as confidential. Specifically, the party seeking confidential treatment must establish "each basis upon which the petitioner believes the material should be classified as confidential" in accordance with the Kentucky Open Records Act, KRS 61.878. *See* 807 KAR 5:110 Section 5(2)(a)(1).

6. The Kentucky Open Records Act exempts certain records from the requirement of public inspection. See KRS 61.878. In particular, KRS 61.878(1)(c)(1) excludes from the Open Records Act:

> Records confidentially disclosed to an agency or required by an agency to be disclosed to it, generally recognized as confidential or proprietary, which if openly disclosed would permit an unfair commercial advantage to competitors of the entity that disclosed the records.

7. KRS 61.878(1)(c)(1) requires the Commission to consider three criteria in determining confidentiality: (1) whether the record is confidentially disclosed to an agency or required by an agency to be disclosed to it; (2) whether the record is generally recognized as confidential or proprietary; and (3) whether the record, if openly disclosed, would present an unfair commercial advantage to competitors of the entity that disclosed the records.

8. The two attachments, Confidential Attachment CRB-Rebuttal-2 and Confidential Attachment CRB-Rebuttal-3, are not publicly available, thus satisfying the first element of the statutory standard for confidentiality of a proprietary record. These two attachments satisfy the second element, as they are articles and reports generated by a third-party vendor for a fee that derives value from not being publicly available and constitutes a "trade secret" under KRS 365.880(4). The third element is satisfied, as disclosure of these documents could violate the Company's agreement with this third-party vendor to maintain the confidentiality of these articles and reports and result in a commercial disadvantage as Duke Energy Kentucky may be barred from obtaining future reports and articles from this vendor. Access to this type of information is integral to Duke Energy Kentucky's effective execution of business decisions.

9. The Company requests that these attachments be afforded confidential treatment pursuant to KRS 61.878(1)(c)(1), and additionally requests that these attachments be treated as confidential in their entirety pursuant to 807 KAR 5:001E, Section 13(2)(a)(3)(b).

10. Duke Energy Kentucky does not object to limited disclosure of the Confidential Information described herein, pursuant to an acceptable protective agreement entered into with any intervenors with a legitimate interest in reviewing the same for the sole purpose of participating in this case.

11. In accordance with the provisions of 807 KAR 5:001, Section 13(2)(e), the Company is filing one copy of the Confidential Information separately under seal, and the appropriate number of copies with the Confidential Information redacted.

12. Duke Energy Kentucky respectfully requests that the Confidential Information be withheld from public disclosure for a period of ten years. This will assure that the Confidential

Information—if disclosed after that time—will no longer be commercially sensitive so as to likely impair the interests of the Company or its employees if publicly disclosed.

13. To the extent the Confidential Information becomes generally available to the public, whether through filings required by other agencies or otherwise, Duke Energy Kentucky will notify the Commission and have its confidential status removed, pursuant to 807 KAR 5:001 Section 13(10)(a).

WHEREFORE, Duke Energy Kentucky, Inc., respectfully requests that the Commission classify and protect as confidential the specific information described herein.

Respectfully submitted,

DUKE ENERGY KENTUCKY, INC.

/s/Rocco D'Ascenzo

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CERTIFICATE OF SERVICE

This is to certify that the foregoing electronic filing is a true and accurate copy of the document in paper medium; that the electronic filing was transmitted to the Commission on April 14, 2023; that there are currently no parties that the Commission has excused from participation by electronic means in this proceeding; and that submitting the original filing to the Commission in paper medium is no longer required as it has been granted a permanent deviation.[1]

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/s/Rocco D'Ascenzo
Counsel for Duke Energy Kentucky, Inc.

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[1] *In the Matter of Electronic Emergency Docket Related to the Novel Coronavirus COVID-19,* Order, Case No. 2020-00085 (Ky. P.S.C. July 22, 2021).

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

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REBUTTAL TESTIMONY OF

BRUCE L. SAILERS

ON BEHALF OF

DUKE ENERGY KENTUCKY, INC.

April 14, 2023

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PAGE

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Bruce L. Sailers, 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, Jurisdictional Rate Administration for Duke Energy Kentucky, Inc., (Duke Energy Kentucky or the Company) and Duke Energy Ohio, Inc. DEBS provides various administrative and other services to Duke Energy Kentucky and other affiliated companies of Duke Energy Corporation (Duke Energy).

Q. ARE YOU THE SAME BRUCE L. SAILERS 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 address the comments and recommendations by several intervening parties in this proceeding. Specifically, I address the comments by Ms. Sarah Shenstone-Harris on behalf of the Sierra Club as it relates to the impact of the Company's rate design on electric vehicle (EV) charging. I then discuss the recommendations and comments raised by Ms. Patricia D. Kravtin on behalf of the Kentucky Broadband and Cable Association (KBCA) as it relates to the Company's proposed adjustments to its Pole Attachment tariff. Finally, I respond to the recommendation and comments by Mr. Steve W. Chriss on behalf of Walmart as it relates to The Company's Rate DT.

II. IMPACTS OF RATE DESIGN ON ELECTRIC VEHICLE CHARGING

A. GENERAL COMMENTS

Q. PLEASE BRIEFLY SUMMARIZE MS. SHENSTONE-HARRIS'S COMMENTS REGARDING THE COMPANY'S PROPOSED RATE RS-TOU-CPP AND REVISIONS TO RATE DT AND RIDER LM.

A. Ms. Shenstone-Harris expressed concerns with what she describes as the efficiency and fairness of rates for customers who adopt EVs and who take service under either the Company's proposed and optional residential time of use rate with critical peak pricing (Rate RS-TOU-CPP), Time of Day Rate for Distribution Voltage (Rate DT), or under the Load Management Rider (Rider LM). Her concerns relate to whether the Company's rate design proposals result in 1) EV customers paying more than their fair share of costs for off-peak charging; 2) reduced incentives to shift load to off peak hours, resulting in less efficient use of the grid; and 3) hindering EV adoption by increasing costs of charging EVs. She believes several modifications to the Company's commercial rates would increase the cost of EV adoption by increasing demand charges while reducing incentives to charge during off-peak hours. Where specific objections to specific proposals are identified, these objections are addressed below.

Specifically, as it relates to Rate RS-TOU-CPP, she believes that the Company's design is unlikely to attract widespread enrollment in the rate as it offers only a modest reduction in off-peak and super-off-peak prices. [The Company notes that the on-peak price is 50 percent higher than the off-peak price while the super off-peak rate is 20 percent lower than the off-peak price.] She recommends the Company strengthen the on-peak to off-peak differential but provides no recommendation or metric on which to do so.

As it relates to Rate DT, Ms. Shenstone-Harris believes that non-coincident demand charges poorly reflect cost causation and result in customers paying too much for off-peak charging and that non-coincident demand charges substantially increase costs for public direct current fast charging (DCFC) and fleet customers. She recommends that the Commission require the Company to maintain the use of the current time-varying volumetric rate design for the recovery of distribution costs.

Finally, as it relates to Rider LM, Ms. Shenstone-Harris argues that including off-peak hours in the tariff results in customers paying too much for charging during off-peak hours, resulting in lower EV adoption and inefficient use of the system. She recommends that the Commission reject the Company's proposed modifications to Rider LM and to maintain the application of demand charges to on-peak hours only.

Q. DO YOU HAVE GENERAL COMMENTS REGARDING THESE TOPICS FROM MS. SHENSTONE-HARRIS?

A. Yes. In general, Ms. Shenstone-Harris focuses narrowly on EV charging and the impact to only EV charging load. I'll comment on this narrow focus below but note here that none of the rate designs proposed are narrowly focused on serving only EV load. Rate RS-TOU-CPP is a whole account rate. Rate DT and Rider LM are for the customer's entire account load. The Commission has a current investigation, Case No. 2022-00369, regarding electric vehicle adoption and specific rates for only EV charging load might be one item resulting from this investigation or addressed because of the investigation.

B. RATE RS-TOU-CPP

Q. DO YOU AGREE WITH MS. SHENSTONE-HARRIS' RECOMMENDATION REGARDING RATE RS-TOU-CPP?

A. No. The Company has already strengthened the on-peak and critical-peak charges as Ms. Shenstone-Harris recommends. Absent a specific metric or recommendation for the Company to evaluate, there is no apparent justification for altering the charges proposed by the Company.

Q. MS. SHENSTONE-HARRIS PROVIDES AN ASSESSMENT OF SAVINGS A CUSTOMER COULD OBTAIN FROM PARTICIPATION IN RATE RS-TOU-CPP. DO YOU AGREE WITH HER ASSESSMENT? PLEASE EXPLAIN.

A. No, for several reasons. First, Ms. Shenstone-Harris recognizes that Rate RS-TOU-CPP is a whole house rate as stated in her testimony on page 57. Her savings estimates are based only on EV charging load. While she opines that some customers' existing load may result in higher bills under Rate RS-TOU-CPP as compared to Rate RS, she ignores the fact that other customers may experience lower bills on Rate RS-TOU-CPP as compared to Rate RS. She limits her analysis to only EV charging assumptions which is not consistent with the rate's design. Depending on when a customer chooses to charge their EV, customers can use Rate RS-TOU-CPP as a tool to save money on their total electric bill if they choose to charge their vehicles at off peak or super off-peak times.

Second, Ms. Shenstone-Harris appears to suggest that the purpose of Rate RS-TOU-CPP is to encourage EV adoption. While the rate may encourage such action by customers, this is not the intention of the rate. The Company has not proposed rates specifically and independently for EV charging load. Rate RS-TOU-CPP is a robust critical peak pricing rate, revenue neutral to Rate RS, with time-of-use periods based on researched load periods resulting in a rate structure that is more reflective of the cost to serve customers as compared to Rate RS. This rate can be leveraged by customers for technologies they will or already have adopted including but not limited to rooftop solar, EVs, and smart thermostats. The rate is optional for customers to consider.

Third, Ms. Shenstone-Harris does not consider all the Company's proposed programs. The Company's proposed Make Ready Credit (MRC) and Electric Vehicle Supply Equipment (EVSE) programs clearly provide benefits for customers who wish to adopt EVs. Participation in Rate RS-TOU-CPP can present additional benefit for the customer if the customer so chooses. These programs do not include non-Company related EV benefits such as tax credits and operational savings that EV adoption may provide.

Finally, Ms. Shenstone-Harris states on page 58 that the Company ignores distribution system benefits related to off-peak charging. This is not true. Rate RS-TOU-CPP is not a disaggregated rate. The Company has used Locational Marginal Price (LMP) differentials for guidance and then adjusted those ratios. In fact, the Company has proposed ratios similar to the LMP structure and applied that structure to generation, transmission, and distribution thus providing those structural benefits to all three categories. The Company acknowledges that this simplification is proposed and believes it to be a good proxy for use with the rate structure. The Sierra Club does not offer any other metric-based solution as an alternative consideration but simply disparages what the Company is proposing. The Commission should ignore her recommendations and approve Rate RS-TOU-CPP as proposed by the Company in order to provide customers optionality.

C. RATE DT

Q. DO YOU BELIEVE THE COMPANY'S RATE DESIGN PROPOSAL FOR RATE DT WILL RESULT IN EV CUSTOMERS PAYING MORE THAN THEIR FAIR SHARE OF COSTS?

A. No. Contrary to Ms. Shenstone-Harris' comments, non-coincident demand charges are commonly used across many utilities and are an appropriate charge for non-residential customer rates. As Ms. Shenstone-Harris notes, non-coincident class demand charges are used in the Company's cost of service study along with other demand concepts including the sum of individual customer non-coincident demands. But once the appropriate revenue requirement is allocated to the Rate DT customer class, the rate design for Rate DT determines how the class revenue requirement is collected from customers in the class.

Q. DO NON-COINCIDENT DEMANDS FAIRLY REFLECT USE OF THE DISTRIBUTION SYSTEM?

A. Yes. Non-coincident demand reflects a customer's maximum use of the distribution system and is a commonly used and reasonable methodology to spread the collection of the distribution demand revenue requirement among the customers in a non-residential class.

Q. DO YOU HAVE ANY COMMENTS ON MS. SHENSTONE-HARRIS' DISCUSSION ABOUT COINCIDENT DEMAND?

A. Yes. For distribution, coincident demand can be a difficult concept on which to bill customers throughout the year and over billing cycles. The coincident demand hour for a month may not be known at the time customers are billed due to billing cycles. This concept also leads to discussions surrounding locational concepts for customers on the same feeder and served through the same substation.

Q. DO YOU HAVE ANY COMMENTS ON MS. SHENSTONE-HARRIS BILL IMPACT REVIEW?

A. Yes. Much like the review presented for Rate RS-TOU-CPP, Ms. Shenstone-Harris singles out EV charging load. This is not appropriate for most customers on Rate DT. Most Rate DT customers have existing non-EV load and have maximum demand during the on-peak period. Under the current rate design, EV load can be added off-peak with no additional demand charge bill impact until the customer's off-peak demand exceeds the customer's current maximum demand; typically set on-peak. The Company believes the proposed distribution demand charge is a more reasonable and equitable charge for the collection of the distribution demand revenue requirement among class customers.

Q. DO YOU HAVE ANY COMMENTS ON MS. SHENSTONE-HARRIS' REFERENCES TO DCFC STATIONS?

A. Yes. For DCFC stations which are low load factor, demand charges can be a customer concern. This is an identified industry issue for these customers and the Commission has a pending proceeding reviewing such issues. Unlike smaller customers on the Company's Rates DS and DP where there are low load factor protections in place, larger, more sophisticated Rate DT customers do not have similar low load factor protection mechanisms. The Company has not proposed alternatives for such customers in this proceeding. It is also uncertain whether such customers would be able to control their demand and limiting it to off-peak charging given the nature of public charging stations that serve customers at any time they arrive to charge their vehicles. Potential rate design alternatives for these customers may be discussed in the future pending additional investigation. However, in the interim, DCFC station customers remain encouraged through the Rate DT design proposed to charge off-peak for significant bill savings.

D. RIDER LM

Q. DO YOU AGREE WITH MS. SHENSTONE-HARRIS'S CRITICISMS OF THE COMPANY'S PROPOSED CHANGES TO RIDER LM?

A. No.

Q. PLEASE EXPLAIN.

A. Ms. Shenstone-Harris focuses her comments on EV charging off-peak demand and estimates how EV charging customers will face an inequitable increase in their bills for off-peak demand increases. However, she again erroneously singles out EV charging load independent of all other customer load.

Q. BRIEFLY EXPLAIN THE DEMAND CHARGES FOR RATES DS AND DP.

A. Rates DS and DP both contain a demand charge component based on the customer's maximum 15-minute demand during the billing period. A customer has the option to participate in Rider LM which changes the determination of the demand billing determinant from the maximum 15-minute demand during the billing period to the maximum 15-minute demand during the on-peak hours of the billing period. Combining values for Rates DS and DP and using the values provided in the test period Schedule M, approximately 1 percent of customer bills participate in Rider LM.

Q. HOW DOES EV CHARGING CHANGE THE NATURE OF THE INTERACTION OF RIDER LM WITH RATES DS AND DP?

A. EV charging is a relatively new load source that potentially is very flexible in terms of when a customer charges; especially non-residential customers adopting EV fleet vehicles. Currently, without the changes the Company is proposing in this proceeding to Rider LM, the interaction of Rider LM with Rates DS and DP allows customers to potentially add unlimited off-peak charging load with no impact to the customer's demand charges. This is inconsistent with the Rate DS and DP rate design for the 99 percent of customers who do not participate in Rider LM which applies demand charges consistent with a customer's maximum use of the system.

Q. DOES THE COMPANY CONTINUE TO ENCOURAGE OFF-PEAK LOAD?

A. Yes. The Company has simply added a provision to Rider LM to limit the increase in off-peak load that is not subject to a demand charge. Through Rider LM, Rate DS and DP customers can increase their off-peak demand to an amount double their on-peak demand before realizing any impact to their demand charge bill component.

Q. DO YOU HAVE ANY COMMENTS ON MS. SHENSTONE-HARRIS BILL IMPACT REVIEW?

A. Yes. Much like the reviews presented for Rate RS-TOU-CPP and Rate DT, Ms. Shenstone-Harris singles out EV charging load and ignores the existing load of customers. Doing so results in an analysis that provides at best misleading and incomplete results and potentially exaggerates bill impacts for customers. Even assuming a customer on either Rate DS or DP with only off-peak EV charging load, participation in the proposed Rider LM lowers the customer's bill as compared to Rate DS or DP without Rider LM participation. Ms. Shenstone-Harris' analysis also fails to recognize the other provisions of Rate DS or Rate DP specifically the cap rates. The emphasis being that both Rates DS and DP contain long-standing, Commission approved low load factor provisions in the form of cap rates that limit the impacts of demand charges on smaller non-residential customer bills and establish a maximum $/kWh charge (i.e., after adding the energy and demand charges together and dividing by the kWh) for a customer.

Q. DO YOU AGREE WITH MS. SHENSTONE-HARRIS'S RECOMMENDATIONS REGARDING RIDER LM?

A. No. Ms. Shenstone-Harris recommends that the Commission reject the proposed change to Rider LM in favor of the current unlimited off-peak demand charge provision. Ms. Shenstone-Harris' recommendation should be rejected. To further support the Company's proposal and its impact to small commercial customers, the Company counted the number of bills over a 12-month period where the customer's on-peak demand was greater than 50 percent of the customer's off-peak demand. Ninety-four percent (94 percent) of Rate DS customer bills had on-peak demand > 50 percent of off-peak demand indicating that most customers could add off-peak demand under the Company's proposed change to Rider LM without impact to the customer's demand charges.

III. POLE ATTACHMENT TARIFF CHARGES

Q. PLEASE BRIEFLY SUMMARIZE THE DIRECT TESTIMONMY OF MS. KRAVTIN ON BEHALF OF KBCA.

A. Ms. Kravtin's testimony focuses on two issues that she has with the Company's pole attachment rates reflected in its Rate DPA proposed in this proceeding. Specifically, Ms. Kravtin states that the Company failed to include the number of non-unitized poles it had identified, but not yet finalized in its pole count used in the rate calculation. Ms. Kravtin recommends that if the rate is adjusted to account for all non-unitized poles, the pole attachment rate drops to $9.62 for two user poles and $7.96 for three-user poles.

Secondly, Ms. Kravtin argues that Duke Energy Kentucky's distinction between two and three-user poles does not accurately reflect the actual distribution of attachments on the Company's 35, 40 and 45-foot poles. She also claims that the Company's calculation does not consider the attachments on 50-foot poles. Ms. Kravtin recommends that the Commission direct Duke Energy Kentucky to amend its pole attachment rate in one of two ways: 1) to charge the three user rate ($7.96 including all non-unitized pole counts) on the basis of an average of 42.5 foot pole height for all attachments instead of the current mix of two-user (calculated based upon a lower average of 37.5 foot pole height and three user rates based upon the higher average 42.5 feet; or 2) recalculate the two-user and three-user rates to reflect the actual distribution of poles used for attachments including the use of 50 foot poles in the computation of the three-user rates.

Q. DO YOU AGREE WITH MS. KRAVTIN'S CRITICISMS AND RECOMMENDATIONS REGARGING THE COMPANY'S POLE ATTACHMENT RATES?

A. As to the first issue regarding non-unitized poles, the Company agrees that at this time, those values are available and can be included in the calculation. However, the Company notes that Ms. Kravtin's calculation is incorrect. As to the second issue regarding changes to the Commission's order in Administrative Case No. 251, the Commission states on page 19 of Administrative Case No. 251 that "(5) The Commission will allow deviations from the mathematical elements found reasonable herein only when a major discrepancy exists between the contested element and the average characteristics of the utility, and the burden of proof should be upon the party asserting the need for such deviation;". Ms. Kravtin has not demonstrated that the current calculation results in a poor estimate for pole attachment rates. Simply stating that the Company now uses more 50-foot poles does not determine that a major discrepancy exists.

Q. PLEASE EXPLAIN THE ISSUE REGARDING THE INCLUSION OF ALL NON-UNITIZED POLES AND WHETHER THEY SHOULD BE INCLUDED IN THE RATE DPA CALCULATION.

A. Although the number of non-unitized poles may not be available when a pole attachment charge increase is requested, in this case, those values are now available. Establishing a criterion requiring the Company to know the number of non-unitized poles in each height category before filing for an increase in pole attachment charges is unreasonable. However, in this case, the number of non-unitized poles at the end of 2021 that were unitized in 2022 are now known and can be included to revise the calculation in witness Sailers' Attachment BLS-7.

Q. WHAT ARE THE REVISED TWO-USER AND THREE-USER POLE ATTACHMENT CHARGES INCLUDING THE NON-UNITIZED POLE COUNTS?

A. Attachment BLS-Rebuttal-1 provides the revised pole attachment charges and upon Commission order approving the revised values, the Company will implement the charges of $9.99 for two-user poles and $8.62 for three-user poles. However, given the immaterial change to these charges (i.e., original proposal of

$9.99 and $8.61 respectively), the Company recommends the approval of the original Company proposed charges.

Note that the additional pole counts added to the previous pole counts are 22, 9, and 40 for 35-, 40-, and 45-foot poles respectively for a total of 71 poles. These are the number of poles of the specified lengths that were unitized during the year 2022 but were not unitized as of 12/31/2021.

Q. DO YOU AGREE WITH MS. KRAVTIN'S CALCULATION OF THE POLE ATTACHMENT RATE THAT SHE CLAIMS INCORPORATES ALL NON-UNITIZED POLES? PLEASE EXPLAIN.

A. No. Ms. Kravtin recommends the addition of 2,464 poles but these poles are not unitized and do not represent only 35-, 40-, and 45-foot heights. Of the non-unitized poles as of 12/31/2021, the correct number of poles for these heights that were not unitized as of 12/31/2021 but were unitized during the year 2022 are 71 as provided above.

Q. IS THERE ANOTHER REASON WHY MS. KRAVTIN'S CALCULATION IN EXHIBIT 7 IS INCORRECT?

A. Yes. Ms. Kravtin adds additional poles to the 35-, 40-, and 45-foot pole counts but neglects to add the corresponding investment associated with those poles. The Company adds $15,727.20, $15,325.25, and $74,647.88 to the pole investment for 35-, 40-, and 45-foot poles respectively.

Q. ARE THERE ADDITIONAL 35-, 40-, and 45-FOOT POLES IN THE REMAINING NON-UNITIZED POLE COUNT AS OF 12/31/2021?

A. There could be. The Company does not have these counts available. An allocated number of poles could be assumed and added to the pole counts but a corresponding investment in those poles must then be added to the investment amounts. The Company does not believe these allocated additions will materially change the two- and three-user pole attachment charges similar to the adjustments the Company makes above.

Q. IF THE COMMISSION AGREES WITH A RECOMMENDATION THAT REVISES THE POLE ATTACHMENT CHARGES, WHAT IMPACT DOES THAT HAVE ON THE TOTAL REVENUE REQUIRMENT BEING REQUESTED IN THIS CASE?

A. There is no impact on the total revenue requirement but there is an impact on where the revenue requirement is allocated. If the Commission orders the Company to update the pole attachment rates from the proposed rates, an adjustment needs to be made to the revenue requirement collected from base rate charges. The pole attachment revenues reduce the portion of the revenue requirement collected through base rate charges and therefore appropriate adjustment is required. If the Commission approves pole attachment charges other than the Company's proposal, the total pole attachment revenues included in miscellaneous revenues in the test period in this proceeding will change and an off-setting adjustment would be appropriate to the revenue requirement collected through base rate charges.

Q. PLEASE EXPLAIN THE ISSUE MS. KRAVTIN RAISES WITH REGARD TO POLE HEIGHTS AND WHETHER OR NOT ATTACHMENTS ON 50-FOOT POLES SHOULD BE INCLUDED IN THE CALCULATION.

A. Ms. Kravtin proposes to change the Commission directed calculation as specified in Administrative Case No. 251 to either eliminate the difference in the charges between two- and three-user poles or to include 50-foot poles in the calculation.

Q. DO YOU AGREE WITH MS. KRAVTIN'S RECOMMENDATION? PLEASE EXPLAIN.

A. No. The order in Administrative Case No. 251 does not define the term "major discrepancy" and the Company does not agree with Ms. Kravtin that a major discrepancy exists. Therefore, the Company does not deviate from the calculation assumptions specified by the Commission's order in Administrative Case No. 251. This long-standing order could have potentially been evaluated in the Commission's review of pole attachments in Case number 2022-00105. However, the Company is not aware of any revisions from Case No. 2022-00105 impacting the calculations specified by the Commission in Administrative Case No. 251. Given that the Commission did not review the pole attachment calculations in Case No. 2022-00105, the Company maintains the calculations specified in Administrative Case No. 251. Ms. Kravtin's request is to change the Commission's specified calculations for pole attachment charges due to an increased use of 50-foot poles. However, Ms. Kravtin does not show why this is a major discrepancy. There are assumptions established in Administrative Case No. 251 such as usable space on two- and three-user poles that do not include an evaluation encompassing 50-foot poles. The Company suggests that it is not appropriate to perform a Company-specific calculation deviating from the Commission's order in the absence of a review of assumptions established in Administrative Case No. 251. More specifically, to include 50-foot poles in the calculation, the Company would need to perform a study to calculate the usable space assumption for 50-foot poles, which has not been done, rather than accepting the unsupported assumptions provided by Ms. Kravtin.

IV. WALMART SUPPORT OF REVISIONS TO RATE DT

Q. PLEASE DESCRIBE MR. CHRISS' TESTIMONY AS IT RELATES TO THE COMPANY'S PROPOSED CHANGE TO RATE DT.

A. Mr. Chriss supports the Company's proposed change, noting that the Company's proposal aligns with how distribution costs are incurred and transparently presents them in the tariff. The Company welcomes support from a customer who may have locations taking service under Rate DT.

Q. DO YOU AGREE WITH MR. CHRISS' ASSESSMENT OF RATE DT?

A. Yes.

V. CONCLUSION

Q. WAS REBUTTAL ATTACHMENT BLS-1 PREPARED BY YOU OR UNDER YOUR SUPERVISION?

A. Yes.

Q. IS THE INFORMATION CONTAINED IN REBUTTAL ATTACHMENT BLS-1 ACCURATE TO THE BEST OF YOUR KNOWLEDGE AND BELIEF?

A. Yes.

Q. DOES THIS CONCLUDE YOUR REBUTTAL TESTIMONY?

A. Yes.

VERIFICATION

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

The undersigned, Bruce Sailers, Director Jurisdictional Rate Administration, 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.

Bruce L. Sailers

Bruce Sailers Affiant

Subscribed and sworn to before me by Bruce Sailers on this 11TH day of APRIL, 2023.

NOTARIAL SEAL STATE OF OHIO

ADELE M. FRISCH
Notary Public, State of Ohio
My Commission Expires 01-05-2024

Adele M. Frisch

NOTARY PUBLIC

My Commission Expires: 1/5/2024

Duke Energy Kentucky
Case No. 2022-00372
Revised CATV Pole Attachment Formula - Adminstrative Case No. 251
For Use of Electric Utility Poles Including Adjustment for Non-Unitized Pole Counts
BASED UPON 2021 FERC FORM 1 DATA

	FCC Pole Attachment Rate Formula	Amount 35'	40'	45'	Two User	Three User	Reference/Source
1	Gross Pole Investment	$5,079,623	$16,776,621	$19,328,392	$21,856,244	$36,105,013	A Below
2	Pole Depreciation Reserve	$1,904,141	$6,288,862	$7,245,415	$8,193,003	$13,534,277	B1 below
3	Appurtenance Factor	$382,158	$1,262,164	$1,454,143	$1,644,322	$2,716,307	(1 - 2 + R1) * 15%
4	Accumulated Deferred Taxes (Poles)	($627,763)	($2,073,330)	($2,388,690)	($2,701,093)	($4,462,020)	R1 Below
5	Net Pole Investment	$2,547,719	$8,414,429	$9,694,287	$10,962,148	$18,108,716	1 - 2 + R1
6	Number of Poles	6,606	16,716	10,976	23,322	27,692	D Below
7	Net Investment Per Bare Pole	$327.82	$427.87	$750.74	$399.53	$555.84	(5 - 3) / 6
8	Pole Maintenance						
	A. Maintenance of Overhead Lines	$6,352,091	$6,352,091	$6,352,091	$6,352,091	$6,352,091	E Below
	B. Total Investment in Poles, Conductors, Services	$248,780,121	$248,780,121	$248,780,121	$248,780,121	$248,780,121	A + F + G
	C. Depreciation Reserve	$72,815,839	$72,815,839	$72,815,839	$72,815,839	$72,815,839	B1+B2+B3
	D. Accumulated Deferred Taxes	($30,735,651)	($30,735,651)	($30,735,651)	($30,735,651)	($30,735,651)	R1+R2+R3
	E. Total Investment in Poles - Net	$145,228,631	$145,228,631	$145,228,631	$145,228,631	$145,228,631	8B - 8C + 8D
	F. Pole Maintenance Ratio	4.37%	4.37%	4.37%	4.37%	4.37%	8A / 8E
9	Depreciation	4.17%	4.17%	4.17%	4.17%	4.17%	(1 / (1 - 2 + R1)) * H.
10	Administration	2.19%	2.19%	2.19%	2.19%	2.19%	I / (J - K + R)
11	Taxes (Normalized)	2.16%	2.16%	2.16%	2.16%	2.16%	(L + M + N + O + P + Q) / (J - K + R)
12	Rate of Return	7.530%	7.530%	7.530%	7.530%	7.530%	S Below
13	Total Carrying Charge	20.42%	20.42%	20.42%	20.42%	20.42%	8F + 9 + 10 + 11 + 12
14	Allocated Space				12.24%	7.59%	T / U
15	Maximum Rate Per Attachment				**$9.99**	**$8.62**	7 * 13 * 14

Input Data

		35'	40'	45'	Two User	Three User	Reference/Source
A.	Poles, Towers, & Fixtures (Acctg.364)	$74,482,036	$74,482,036	$74,482,036	$74,482,036	$74,482,036	FERC Form 1, Page 207, Line 64, Column g
B.	Accum. Depr. - Distribution Plant	$150,530,889	$150,530,889	$150,530,889	$150,530,889	$150,530,889	FERC Form 1, Page 219, Line 26, Column c.
	1. Accum Depr. for FERC Acctg 364	$27,920,237	$27,920,237	$27,920,237	$27,920,237	$27,920,237	Provided by Plant Accounting
	2. Accum Depr. for FERC Acctg 365	$34,254,142	$34,254,142	$34,254,142	$34,254,142	$34,254,142	Provided by Plant Accounting
	3. Accum Depr. for FERC Acctg 369	$10,641,460	$10,641,460	$10,641,460	$10,641,460	$10,641,460	Provided by Plant Accounting
C.	Gross Investment - Distribution Plant	$622,687,366	$622,687,366	$622,687,366	$622,687,366	$622,687,366	FERC Form 1, Page 207, Line 75, Column g
D.	Number of Distribution Poles	41,110	41,110	41,110	41,110	41,110	Provided by Cost Accounting
E.	Mtce of Overhead Lines (Acctg. 593)	$6,352,091	$6,352,091	$6,352,091	$6,352,091	$6,352,091	FERC Form 1, Page 322, Line 149, Column b.
F.	Overhead Conductors & Devices (Acctg. 365)	$152,067,838	$152,067,838	$152,067,838	$152,067,838	$152,067,838	FERC Form 1, Page 207, Line 65, Column g.
G.	Services (Acctg. 369)	$22,230,247	$22,230,247	$22,230,247	$22,230,247	$22,230,247	FERC Form 1, Page 207, Line 69, Column g.
H.	Depreciation Rate - Distribution Property	2.09%	2.09%	2.09%	2.09%	2.09%	Provided by Plant Accounting
I.	Admin. & Gen. Exps. (Acctgs. 920-935)	$22,907,236	$22,907,236	$22,907,236	$22,907,236	$22,907,236	FERC Form 1, Page 323, Line 197, Column b.
J.	Utility Plant in Service	$2,149,668,551	$2,149,668,551	$2,149,668,551	$2,149,668,551	$2,149,668,551	FERC Form 1, Page 200, Line 8, Column c.
K.	Accum. Depr. - Utility Plant in Service	$840,267,458	$840,267,458	$840,267,458	$840,267,458	$840,267,458	FERC Form 1, Page 200, Line 22, Column c.
	1. ADIT - Accelerated Amort. Property (Acctg. 281)	$0	$0	$0	$0	$0	FERC Form 1, Page 273, Line 8, Column k.
	2. ADIT - Other Property (Acctg. 282)	$227,752,649	$227,752,649	$227,752,649	$227,752,649	$227,752,649	FERC Form 1, Page 275, Line 2, Column k.
	3. ADIT - Other (Acctg. 283)	$31,279,406	$31,279,406	$31,279,406	$31,279,406	$31,279,406	FERC Form 1, Page 277, Line 9, Column k.
L.	Taxes Other Than Income Taxes (Acctg. 408.1)	$15,842,108	$15,842,108	$15,842,108	$15,842,108	$15,842,108	FERC Form 1, Page 115, Line 14, Column g.
M.	Income Taxes - Federal (Acctg. 409.1)	($8,317,550)	($8,317,550)	($8,317,550)	($8,317,550)	($8,317,550)	FERC Form 1, Page 115, Line 15, Column g.
N.	Income Taxes - Other (Acctg. 409.1)	($2,533,237)	($2,533,237)	($2,533,237)	($2,533,237)	($2,533,237)	FERC Form 1, Page 115, Line 16, Column g.
O.	Prov. for Deferred Inc. Taxes (Acctg 410.1)	$47,582,356	$47,582,356	$47,582,356	$47,582,356	$47,582,356	FERC Form 1, Page 115, Line 17, Column g.
P.	(Less) Prov. for Def. Inc. Taxes - Cr. (Acctg 411.1)	($30,003,029)	($30,003,029)	($30,003,029)	($30,003,029)	($30,003,029)	FERC Form 1, Page 115, Line 18, Column g.
Q.	Investment Tax Credit Adj. - Net (Acctg 411.4)	($428)	($428)	($428)	($428)	($428)	FERC Form 1, Page 115, Line 19, Column g.
R.	Accumulated Deferred Inc. Taxes (Acct 190, 281, 282, 283)	($264,506,468)	($264,506,468)	($264,506,468)	($264,506,468)	($264,506,468)	Deferred Tax Calculation Worksheet
	1. ADIT for Poles (Acct 364)	($9,204,825)	($9,204,825)	($9,204,825)	($9,204,825)	($9,204,825)	Deferred Tax Calculation Worksheet
	2. ADIT for Overhead Conductor (Acct 365)	($18,779,959)	($18,779,959)	($18,779,959)	($18,779,959)	($18,779,959)	Deferred Tax Calculation Worksheet
	3. ADIT for Services (Acct 369)	($2,750,867)	($2,750,867)	($2,750,867)	($2,750,867)	($2,750,867)	Deferred Tax Calculation Worksheet
S.	Rate of Return	7.53%	7.53%	7.53%	7.53%	7.53%	Proposed in KYPSC Case No. 2022-00372
T.	Space Occupied (feet)	1.00	1.00	1.00	1.00	1.00	Administrative Case No. 251
U.	Usable Space (feet) - Two Users				8.17	8.17	Administrative Case No. 251
V.	Usable Space (feet) - Three Users				13.17	13.17	Administrative Case No. 251
W.	Pole Height (feet) - Two Users				37.5	37.5	Administrative Case No. 251
X.	Pole Height (feet) - Three Users				42.5	42.5	Administrative Case No. 251

Cost	# of Poles		Source
$5,079,623	6,606	35'	Asset Accounting
$16,776,621	16,716	40'	Asset Accounting
$19,328,392	10,976	45'	Asset Accounting
$41,184,636	34,298	Sum	
$74,482,036		Poles, Tov FF1	
0.068199307		35' % of Total	
0.225243862		40' % of Total	
0.259504075		45' % of Total	
0.552947243			

Case No. 2022-00372
Duke Energy Kentucky
Allocation of Accumulated Deferred Tax Balances (Acct. 190)
To Plant Accounts 364, 365 and 369
Twelve Months Ended December 31, 2021

Poles			Allocated ADIT Amounts ($)	FERC Form No. 1 Source
Accumulated Deferred Taxes (Acct. 190)			$53,751,239	Pg 234, line 8, column c
ADIT - Accelerated Amort. Property (Acctg. 281)			$0	Pg 272, Line 8, Column k.
ADIT - Other Property (Acctg. 282)			($227,752,649)	Pg 274, Line 2, Column k.
ADIT - Other (Acctg. 283)			(31,279,406)	Pg 276, Line 9, Column k.
ADIT - Tax Reform Act (Acctg. 254)			(59,225,652)	Attachment H-22A of Rate Case (Protected + Unprotected)
Accumulated Deferred Taxes for Electric			($264,506,468)	
		% of Total		
Electric Plant in Service	($)		($)	
Total Plant	$2,141,261,295	100.00%		Pg 207, line 104, column g
Poles (Acct. 364)	$74,482,036	3.48%	($9,204,825)	FERC Form 1, Page 207, Line 64, Column g
Overhead Conductor (Acct. 365)	$152,067,838	7.10%	(18,779,959)	FERC Form 1, Page 207, Line 65, Column g.
Services (Acct. 369)	$22,230,247	1.04%	(2,750,867)	FERC Form 1, Page 207, Line 69, Column g.
Total Accts 364, 365 and 369			($30,735,651)	

Source: Duke Energy Kentucky 2021 FERC Form No. 1

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 New Tariffs; 3) Approval of Accounting Practices to Establish Regulatory Assets and Liabilities; and 4) All Other Required Approvals and Relief.	)	Case No. 2022-00372

REBUTTAL TESTIMONY OF

CHRISTOPHER R. BAUER

ON BEHALF OF

DUKE ENERGY KENTUCKY, INC.

April 14, 2023

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I. INTRODUCTION AND PURPOSE

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Christopher R. Bauer and my business address is 525 South Tryon Street, Charlotte, North Carolina 28202.

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

A. I am employed by Duke Energy Business Services LLC (DEBS) as Director, Corporate Finance and Assistant Treasurer. 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 CHRISTOPHER R. BAUER THAT SUBMITTED DIRECT TESTIMONY IN THIS PROCEEDING?

A. Yes.

Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY IN THESE PROCEEDINGS?

A. My rebuttal testimony responds to the recommendations by Messer's Richard Baudino and Randy A. Futral on behalf of the Kentucky Attorney General as it relates to the Company's proposed capital structure for the test year in this proceeding. In doing so, I first discuss changes that have occurred to the Company's forecasted capital structure since it filed its application in this proceeding.

II. DISCUSSION

Q. HAVE THERE BEEN ANY CHANGES TO THE COMPANY'S FORECASTED TEST PERIOD CAPITAL STRUCTURE?

A. Yes. The Company's most recent financial model run reflects an average equity ratio over the 13-month forecast period, ending June 30, 2024, of 52.145percent. Please refer to Attachment CRB-Rebuttal-1. This financial model run includes 2022 actuals and is more reflective of where the Company's capital structure is projected to be over the 13-month forecast period. The Company recommends that the Commission adopt the capital structure as shown in Attachment CRB-Rebuttal-1.

Q. PLEASE BRIEFLY SUMMARIZE THE RECOMMENDATIONS OF MR. BAUDINO AND MR. FUTRAL AS IT RELATES TO THE COMPANY'S CAPITAL STRUCTURE PROPOSED IN THIS PROCEEDING?

A. Mr. Baudino supports the Company's proposed costs of short-term and long-term debt. However, Mr. Baudino disagrees with the Company's proposed capital structure of 52.505 percent equity. He recommends that the Commission adopt a capital structure with a common equity ratio of 50 percent and a short-term debt ratio of 6.287 percent. Mr. Futral, in turn, takes Mr. Baudino's recommendation and calculates reduction to the Company's requested revenue requirement of $2.483 million.

Q. DOES MR. BAUDINO PROVIDE ANY JUSTIFICATION FOR HIS RECOMMENDED REDUCTION IN THE COMPANY'S EQUITY RATIO?

A. Mr. Baudino's recommendation is based upon the Company's historical capitalization ratios from the period of January 2020 through November 2022. Mr. Baudino argues that the Company's actual equity ratios during this period were between 46.44 percent and 50.19 percent. He argues that the Company was able to maintain its strong credit rating with an equity ratio that was not above 50 percent, and thus concludes that the Company's proposed 52.505 percent forecasted ration is not necessary.[1]

Q. DOES MR. BAUDINO PROVIDE ANY SPECIFIC JUSTIFICATION FOR REDUCING THE COMPANY'S PERCENTAGE OF SHORT-TERM DEBT?

A. No. The percentage of short-term debt in the capital structure as suggested by Mr. Baudino was plugged to arrive at a 50/50 split between debt and equity.

Q. DO YOU AGREE WITH MR. BAUDINO'S RECOMMENDATION THAT THE COMMISSION ADOPT A 50 PERCENT EQUITY RATIO FOR THE COMPANY'S CAPITAL STRUCTURE IN THIS PROCEEDING?

A. No.

Q. PLEASE EXPLAIN.

A. Maintaining strong, investment-grade credit ratings, which is underpinned by the Company's allowed return on equity (ROE) and authorized capital structure, is of paramount importance as the Company faces elevated capital expenditures and market uncertainty. As the Company continues to make significant capital investments to provide energy to its customers, its ability to efficiently finance those investments to the benefit of customers is dependent upon Duke Energy Kentucky's high credit quality. Capital structure should not be viewed in isolation; it is part of an overall framework that considers capital structure, allowed ROE, and the various mechanisms used to recover costs. The Company's revised requested 52.145 percent equity ratio and requested 10.35 percent ROE strikes the appropriate

[1] Baudino pp. 31-33.

balance in keeping rates affordable for Duke Energy Kentucky's customers, while allowing for the necessary level of leverage and cash flows to maintain Duke Energy Kentucky's current credit ratings.

Market conditions have vastly changed since Duke Energy Kentucky's last electric base rate case proceeding as volatility, benchmark US Treasury rates, and credit spreads have all increased significantly. Duke Energy Kentucky's strong balance sheet and credit quality give the Company the flexibility to access the market during various market conditions and not be forced to pick only favorable issuance windows to raise capital. This flexibility is imperative to ensure Duke Energy Kentucky can continue funding its operations at the most economical terms possible.

Recently, there was a disruption in the capital markets created by headlines coming out of the banking sector, that effectively closed the primary market for a period of time. Duke Energy needed access to capital during this time to maintain adequate liquidity and was in a position to effectively re-open the primary market with an operating company due to its strong credit quality. Utilities of lower credit quality were unable to access the capital markets during that window. This was a testament to the importance of maintaining strong credit, especially during times of volatility and market uncertainty.

As evidenced in the direct testimony of Company Witness Joshua C. Nowak, Duke Energy Kentucky's requested capital structure is very much in line with the capital structures of a proxy group of companies with comparable business and financial risks. It is appropriate to compare the financial capital structures of the proxy group companies to the financial capital structure proposed by the Company in order to assess whether the Company's capital structure is reasonable and consistent with industry standards for companies with commensurate risk. In witness Nowak's testimony, he calculated the weighted average capital structures for each of the proxy group operating companies for the eight quarters ended Q2 2022. Attachment JCN-10 shows that the Company's proposed common equity ratio of 52.145 percent is within the range of actual common equity ratios of 45.62 percent to 60.35 percent for the operating companies held by the proxy group over this period. Further, Duke Energy Kentucky's proposed common equity ratio is somewhat below the proxy group average actual common equity ratio of 53.06 percent. Additionally, in the Company's recent natural gas base rate case, the Commission adopted an equity ratio of 51.344 percent, which is higher and more credit-supportive than the 50 percent proposed by Mr. Baudino.

Q. WHY IS MR. BAUDINO'S RELIANCE UPON THE COMPANY'S CAPITAL STRUCTURE BETWEEN 2020 THROUGH NOVEMBER 2022 AS A PROXY FOR ITS FORECASTED CAPITAL STRUCTURE UNREASONABLE?

A. As noted in Moody's 2023 Duke Energy Kentucky credit opinion, included as Confidential Attachment CRB-Rebuttal-2, Duke Energy Kentucky's capital spending has been elevated in recent years. Annual capital expenditures grew from roughly $100 million in 2016 to over $200 million on average between the 2017-2022 timeframe. The higher capital spending led to a significantly higher debt burden for the Company during this period, which contributed to a deterioration in the Funds from Operations (FFO)/Debt metric. Duke Energy Kentucky faces substantial capital needs over the next several years to satisfy debt maturities, upgrade aging infrastructure, and to further invest in energy infrastructure upgrades. The Company's capital requirement for the regulated business of Duke Energy Kentucky is projected to be approximately $885 million during the period – 2023-2025. This amount consists of approximately $715 million in projected capital expenditures and approximately $170 million in debt maturities. The Company must be able to operate and maintain its business without interruption and refinance maturing debt on time, regardless of financial market conditions. Strong investment-grade credit ratings provide the Company greater assurance of continued access to the capital markets on reasonable terms during periods of elevated volatility.

A credit strength of Duke Energy Kentucky, as described in Moody's January 2023 credit opinion, is a generally credit-supportive regulatory climate in Kentucky. Moody's specifically notes that Kentucky permits the use of a forward test year. The forward test year allows the Company to look ahead and proactively address credit concerns, as opposed to being reactive and waiting to address these concerns until it's too late. While the 50 percent (or below) equity percentage has been adequate in maintaining Duke Energy Kentucky's credit quality over the past several years, the Company now faces significant capital needs amid rising interest rates, elevated inflation and heightened market uncertainty and volatility. The revised 52.145 percent equity percent takes these factors into consideration, and it more appropriately reflects an equity percent needed to support Kentucky's current credit rating.

Q. IS THERE ANY EXTERNAL SUPPORT FOR THE PREMISE THAT REGULATORY SUPPORT IS NEEDED FOR UTILITIES TO MEET FINANCING NEEDS?

A. In Moody's November 3, 2022, Sector In-Depth article, Confidential Attachment CRB-Rebuttal-3, they explain that, for the utility sector in general, regulatory support will be essential as utilities will need to fund unprecedented levels of capital spending. Further, utilities in jurisdictions with forward-looking test years are better positioned to improve cash flow in line with debt because they have shorter regulatory lag. Over the last three years, growth in utility cash flow has lagged growth in leverage, resulting in deteriorating credit metrics. Moody's describes an environment where cash flow growth will need to exceed historical levels if utilities are to maintain credit quality over the next several years.

Q. PLEASE RESPOND TO MR. BAUDINO'S CLAIM THAT THE COMPANY HAS BEEN ABLE TO MAINTAIN STRONG CREDIT RATINGS DESPITE HAVING A CAPITAL STRUCTURE WITH AN EQUITY RATIO AT OR SLIGHTLY BELOW 50 PERCENT.

A. In Moody's January 2023 credit opinion, three factors are listed that could lead to a downgrade for Duke Energy Kentucky: FFO/Debt remaining below 17 percent, higher capital expenditures resulting in a material increase in debt levels, and a decline in the credit supportiveness of the regulatory environment in Kentucky. From 2012 through 2018, Duke Energy Kentucky's cash flow and key financial metrics had been historically strong for its credit profile. The Company's FFO/ Debt generally remained above 20 percent. Beginning in 2018, Duke Energy Kentucky's credit metrics have been negatively impacted, primarily by increased debt funding for capital expenditures. As of September 2022, the ratio of FFO to Debt for Duke Energy Kentucky was 16.8 percent, which is below the 17 percent downgrade threshold. Duke Energy Kentucky's FFO to Debt metric has remained below 17 percent since 2019. This demonstrates how quickly credit metrics can erode during periods of elevated capital spending, how difficult it can be to improve a Company's credit metrics, and how important it is for a Company to be proactive in addressing credit metrics and credit quality.

The Company's elevated capital plan will continue to place pressure on credit quality. The Company has not paid a dividend to its parent since 2016, and measures like this will continue to be taken to support its credit quality. While the argument can be made that Duke Energy Kentucky has been able to maintain its strong credit quality over the past several years, that is not an indication of whether or not Duke Energy Kentucky will be able to maintain its credit quality going forward, especially in light of the significant capital requirements the Company faces over the next three years and the volatile economic climate that we're currently in.

Duke Energy Kentucky remains below the downgrade threshold for its FFO/Debt metric, and any unforeseen credit-negative event could result in further deterioration of the Company's metrics and result in a potential ratings downgrade. Moody's clearly signals that they expect the Company's FFO/Debt metric to rebound and stabilize in the 17 percent-18 percent range over the next two years. A capital structure reflective of 52.145 percent equity would better align the Company with this target. The use of a forecasted test period capital structure, which takes future capital needs into consideration and more appropriately reflects the current and forecasted economic backdrop, is more appropriate than the use of a historical capital structure in which we've witnessed a deterioration of Duke Energy Kentucky's credit metrics over the past several years.

The January 2023 Moody's credit opinion generally views the Kentucky regulatory environment as credit supportive, permitting the use of a forward test year when determining rate treatment. However, if the Commission were to adopt a historical capital structure in a forecasted test year proceeding, it could bring into question the supportive regulatory environment in Kentucky, which is currently viewed as a credit strength of the Company by the ratings agencies as it reduces regulatory lag. If there is a decline in the credit supportiveness of the regulatory environment, such as delays in recovery of prudently incurred costs through the absence of rider mechanisms or a reduced ROE and equity layer, it could lead to weaker financial credit metrics and could result in a credit downgrade. Such an event could, in turn, negatively impact the Company's ability to access the financial markets on reasonable terms, and ultimately, increase the Company's costs to borrow funds. This would result in increased costs to customers.

Approval of the proposed capital structure will help Duke Energy Kentucky maintain its credit quality to meet its ongoing business objectives, while approval of Mr. Baudino's recommendation would reduce the Company's cash flows and increase the likelihood of a ratings downgrade.

An equity ratio of 52.145 percent is also more supportive of the Company's current credit ratings. High credit quality improves financial flexibility by providing more readily available access to the capital markets on reasonable terms, and ultimately lower debt financing costs. Duke Energy Kentucky's equity component, as supported in these proceedings, enables it to maintain current credit ratings and financial strength and flexibility. This level of equity enables the Company to operate through different business cycles. The Company's current and future capital expenditures require the need for a strong equity component of the Company's capital structure in order to maintain access to capital funding at reasonable terms.

Q. PLEASE RESPOND TO MR. BAUDINO'S ADJUSTMENT TO THE COMPANY'S SHORT-TERM DEBT RATIO.

A. As previously noted, Mr. Baudino plugged the short-term debt ratio to arrive at a 50/50 split between debt and equity. There is no support provided for the 6.287 percent in which Mr. Baudino is recommending, and therefore this recommendation should be ignored. Schedule J-1, as filed in the rate case, reflecting a short-term debt ratio of 3.782 percent, and Attachment CRB-Rebuttal-1, reflecting a short-term debt ratio of 3.780 percent are based on the Company's financial models, and are more appropriate to use than a percentage that was arbitrarily plugged to arrive at a 50/50 split between debt and equity.

Q. WHAT IS YOUR RECOMMENDATION REGARDING MR. BAUDINO'S TESTIMONY TO REDUCE THE COMPANY'S FORECASTED EQUITY RATIO TO 50 PERCENT AND TO INCREASE ITS COST OF SHORT-TERM DEBT TO 6.287 PERCENT?

A. For the reasons I described above, and in my Direct Testimony, the Commission should adopt an equity ratio of 52.145 percent. The Commission should disregard Mr.

Baudino's recommendations, along with that of Mr. Futral, to arbitrarily reduce the Company's proposed equity ratio, short-term debt ratio and correspondingly, the Company's requested revenue requirement.

III. CONCLUSION

Q. DOES THIS CONCLUDE YOUR REBUTTAL TESTIMONY?

A. Yes.

VERIFICATION

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

The undersigned, Christopher Bauer, Director Corporate Finance – Asset Treasurer, 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.

Christopher Bauer Affiant

Subscribed and sworn to before me by Christopher Bauer on this 12th day of April, 2023.

VIRGINIA M. ADAMS
My Comm. Expires
NOTARY PUBLIC
October 2, 2026
MECKLENBURG COUNTY, NC

Virginia M. Adams
NOTARY PUBLIC

My Commission Expires: 10/2/26

DUKE ENERGY KENTUCKY, INC.
CASE NO. 2022-00xxx
COST OF CAPITAL SUMMARY
THIRTEEN MONTH AVERAGE BALANCE ENDING JUNE 30, 2024

DATA: BASE PERIOD "X" FORECASTED PERIOD
DATE OF CAPITAL STRUCTURE: END OF FORECASTED PERIOD
TYPE OF FILING: "X" ORIGINAL UPDATED REVISED
WORK PAPER REFERENCE NO(S).: See Below

ATTACHMENT CRB-REBUTTAL-1
PAGE 1 OF 1
WITNESS RESPONSIBLE:
C. R. BAUER

LINE NO.	CLASS OF CAPITAL	13 MONTH AVG. BALANCE	% OF TOTAL	COST %	WEIGHTED COST %
1	Common Equity	$ 951,750,195	52.145%	10.350%	5.397%
2	Long-Term Debt	804,442,968	44.075%	4.377%	1.929%
3	Short-Term Debt	68,990,481	3.780%	4.739%	0.179%
4					
5	Total Capital	$ 1,825,183,644	100.000%		7.505%

DE Kentucky Consolidated
Capital Structure - Forecast Period

	Jun 2023	Jul 2023	Aug 2023	Sep 2023	Oct 2023	Nov 2023	Dec 2023	Jan 2024
Short Term Debt - Forecasted Balances:								
Intercompany Notes Payable	45,521,063	49,937,187	52,692,837	(0)	13,446,693	8,974,584	10,521,701	9,848,253
Sale of Accounts Receivable	35,000,000	35,000,000	35,000,000	35,000,000	35,000,000	35,000,000	35,000,000	35,000,000
Current Maturities of LT Debt	74,990,937	74,992,781	74,994,626	24,996,470	(2,607)	(2,607)	(2,607)	(2,607)
Total ST Debt	155,511,999	159,929,969	162,687,463	59,996,470	48,444,085	43,971,977	45,519,094	44,845,645
Long Term Debt - Forecasted Balances:								
Long Term Debt	679,319,435	679,343,229	679,367,023	809,390,817	809,414,611	809,438,405	809,462,199	809,485,993
Intercompany Long Term Debt	25,000,000	25,000,000	25,000,000	25,000,000	25,000,000	25,000,000	25,000,000	25,000,000
Total LT Debt	704,319,435	704,343,229	704,367,023	834,390,817	834,414,611	834,438,405	834,462,199	834,485,993
Common Equity - Forecasted Balances:								
Common Equity	1,083,430,700	1,089,563,292	1,096,373,516	1,099,479,025	1,102,630,883	1,108,802,444	1,122,149,894	1,134,900,692
Exclude: Goodwill	(173,032,325)	(173,032,325)	(173,032,325)	(173,032,325)	(173,032,325)	(173,032,325)	(173,032,325)	(173,032,325)
Exclude: DEK Purchase Accounting	(249,245)	(249,245)	(249,245)	(249,245)	(249,245)	(249,245)	(249,245)	(249,245)
Total Regulatory Equity	910,149,130	916,281,722	923,091,946	926,197,455	929,349,313	935,520,874	948,868,324	961,619,122

Feb 2024	Mar 2024	Apr 2024	May 2024	Jun 2024	13 mth Avg
982,586	0	0	0	0	
35,000,000	35,000,000	35,000,000	35,000,000	35,000,000	
(2,607)	(2,607)	(2,607)	(2,607)	(2,607)	
35,979,978	34,997,393	34,997,393	34,997,393	34,997,393	68,990,481
809,459,787	809,483,581	809,507,375	809,531,169	809,554,963	
25,000,000	25,000,000	25,000,000	25,000,000	25,000,000	
834,459,787	834,483,581	834,507,375	834,531,169	834,554,963	804,442,968
1,146,943,126	1,153,895,277	1,158,252,602	1,161,664,434	1,167,327,063	
(173,032,325)	(173,032,325)	(173,032,325)	(173,032,325)	(173,032,325)	
(249,245)	(249,245)	(249,245)	(249,245)	(249,245)	
973,661,556	980,613,708	984,971,032	988,382,864	994,045,493	951,750,195

CONFIDENTIAL PROPRIETARY TRADE SECRET

ATTACHMENT CRB-REBUTTAL-2 CONFIDENTIAL ATTACHMENT

FILED UNDER SEAL

CONFIDENTIAL PROPRIETARY TRADE SECRET

ATTACHMENT CRB-REBUTTAL-3 CONFIDENTIAL ATTACHMENT

FILED UNDER SEAL

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 New Tariffs; 3) Approval of Accounting Practices to Establish Regulatory Assets and Liabilities; and 4) All Other Required Approvals and Relief.	)))))))	Case No. 2022-00372

REBUTTAL TESTIMONY OF

CORMACK C. GORDON

ON BEHALF OF

DUKE ENERGY KENTUCKY, INC.

April 14, 2023

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I. INTRODUCTION AND PURPOSE

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Cormack C. Gordon and my business address is 1000 East Main Street, Plainfield, Indiana 46168.

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

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

Q. ARE YOU THE SAME CORMACK C. GORDON 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 the recommendations made by Steve W. Chriss on behalf of Walmart, Inc., (Walmart) and Lane Kollen on behalf of the Kentucky Attorney General.

II. DISCUSSION

A. RECOMMENDATIONS BY MR. CHRISS ON BEHALF OF WALMART

Q. PLEASE BRIEFLY SUMMARIZE THE COMPANY'S PROPOSALS FOR TWO NEW EV TARIFFS IN THIS PROCEEDING.

A. As I more fully described in my Direct Testimony, the Company proposed two EV programs and associated tariffs in this proceeding: (1) the Make Ready Credit

(MRC) program and (2) the Electric Vehicle Supply Equipment (EVSE) program.

The MRC program will be available on a voluntary basis to residential and non-residential customers at their premise/places of business that require improvements (make ready infrastructure) to prepare for installation of a Level 2 or higher EV charger that is customer-owned or third-party owned. The Company will not own the make ready infrastructure. The credit is designed to defray installation costs associated with EV chargers to encourage mutually beneficial EV adoption.

The EVSE Program will be available on a voluntary basis and provides customers, both residential and non-residential, with the ability to choose a Level 2 or higher EVSE to have installed at their home or business. Once installed the customer would pay a flat rate each month for that charger for the life of the contract with the Company. Included in the monthly rate amount is the charger, installation, maintenance, and warranty work for the charger for the duration of the contract. Duke Energy Kentucky will own the charging equipment, but customers will operate it on a day-to-day basis as per their unique needs. Participating customers will be responsible for any energy use (to be billed at standard, approved rates) as well as any make ready work that would be needed prior to installation.

Q. PLEASE SUMMARIZE THE RECOMMENDATIONS OF MR. CHRISS AS IT RELATES TO THE COMPANY'S EV PROPOSALS.

A. Mr. Chriss only speaks to the Company's proposed MRC program. In his testimony, Mr. Chriss states that Walmart generally supports approval of the Company's program, but with a recommended modification to the as-filed tariff. Mr. Chriss states it is unclear what is required by way of a customer submitting a "completed customer usage profile" and that it raises a concern because it could potentially expose proprietary and confidential customer EV charging business operations data to the Company or competitors if they gain access through the regulatory process. Mr. Chriss recommends that the Commission require additional language to the proposed Rate MRC tariff and application conditions that would require mutual agreement between the Company and participating customers on data privacy and security parameters.[1]

Q. WHAT IS DUKE ENERGY KENTUCKY'S RESPONSE TO MR. CHRISS'S CONCERN REGARDING DATA PRIVACY?

A. Mr. Chriss' concerns are reasonable and can be resolved with clarification of the program's processes and application requirements, without modification.. The Company agrees with the importance of data protection and privacy. Customer data from the MRC program will never be used for competitive reasons. Instead, data may be used, for example, to 1) provide anonymized program reporting to monitor program performance; 2) ensure that credit payment amounts, which are based on revenues, are adjusted over time to reflect changes in actual consumption for given segments; and 3) help structure future load management programs that benefit all Duke Energy Kentucky customers. The Company will not use metering and load research devices to expose proprietary and confidential customer EV charging data to competitors.

Applications for MRC non-residential customers require submittal of a customer usage profile form that encompasses information that is no different than

[1] Mr. Chriss Testimony pp.26-27.

what is requested when a new service or existing service upgrade is requested. The MRC customer usage profile and the Commercial/Industrial Service Information forms request the following identical information: 1) Type of service requested- new service or upgrade from existing service; 2) the type of business the EV charger will serve and expected hours of operation; 3) Level of EV chargers; and 4) Quantities of EV chargers and total kW demand. For further context, MRC's customer usage profile form is provided in Attachment CCG-1.

Similar to the long-standing examples of the Company's energy efficiency programs, the MRC program Terms and Conditions provide specifics as to how the Company may or may not use program data. For example, the terms and conditions detail that information provided in the application may be used internally by the Company for purposes other than processing the application. A key example is reporting to the Public Service Commission. It also stipulates that all personal information will be handled in accordance with applicable laws and regulations. Most importantly, the Company will not expose proprietary and confidential customer information to competitors.

B. RECOMMENDATIONS BY MR. KOLLEN ON BEHALF OF THE ATTORNEY GENERAL

Q. PLEASE SUMMARIZE THE RECOMMENDATIONS OF MR. KOLLEN AS IT RELATES TO THE COMPANY'S EV PROPOSALS.

A. Mr. Kollen does not oppose the two proposed programs. However, he notes an absence of legal mandate for the programs. Additionally, he is unconvinced that the MRC program leverages the Line Extension Policy (LEP) because under the LEP, new customers are required to pay a portion of the costs of service and the Company owns the assets. Mr. Kollen also does not agree that the cost of the Company's proposed MRC program should be socialized and recovered in a future proceeding.

He instead recommends that the MRC program be subsumed into the EVSE program such that the costs of the combined program be recovered exclusively from participating customers. Further, Mr. Kollen recommends that if the Commission does approve the MRC as a stand-alone program, that the Company be required to recover the costs exclusively from participating customers. He recommends the Commission deny the Company's request for deferral authority for the MRC program. Ms. Lawler addresses this deferral issue in her rebuttal testimony.

Q. WHAT IS DUKE ENERGY KENTUCKY'S RESPONSE TO MR. KOLLEN'S STATEMENT THAT THERE IS NO LEGAL MANDATE FOR THE COMPANY TO PROVIDE INCENTIVES TO EXPAND USE OF EVS OR THE DEVELOPMENT OF EV INFRASTRUCTURE?

A. Absence of a legal mandate does not equate to lack of a compelling reason to deploy a program that simplifies adoption for customers that wish to take part in EV adoption but are prevented from doing so due to lack of capital or discomfort with electrical installations. As designed, the Make Ready Credit will encourage residential and non-residential customers to invest in working upgrades to existing structures while also delivering a conduit to benefit to all utility customers through future programs that put downward pressure on the per unit cost of electricity.

Mr. Kollen overlooks the significance of this potential benefit. Increased EV adoption coupled with advancement in EV infrastructure in Kentucky can result in statewide benefits for all Kentuckians, regardless of whether or not they choose to personally drive an EV. Although owners of EVs benefit directly from reduced fuel and maintenance costs, greater EV adoption will lead to increased EV charging. This increase in flexible load will benefit all customers by establishing a broader base to spread utility system costs and put mitigating upward pressure on rates.

Q. WHAT IS DUKE ENERGY KENTUCKY'S RESPONSE TO MR. KOLLEN'S OPINION THAT THE MAKE READY CREDIT PROGRAM DOES NOT LEVERAGE THE CONCEPTS OF THE LINE EXTENSTION POLICY?

A. The Company does not contend that the MRC is identical to or an extension of the LEP. They are separate. However, the MRC program provides credits based on increased revenue from EV charging for the first three years after an installation, just as the LEP provides a revenue-based credit over the same time frame enabling a customer to join the system. As such, MRC plainly leverages the concepts of LEP.

Contrary to Mr. Kollen's assertions, the MRC program is also structured so that it can support not only expansion of service, but also new installations at a reduced credit amount. Further, there are simple mechanisms in place to ensure that, like the LEP, credits have upper limits and participating customers bear any costs above those limits.

Q. WHAT IS DUKE ENERGY KENTUCKY'S RESPONSE TO MR. KOLLEN'S RECOMMENDATION TO COMBINE THE TWO EV PROGRAMS INTO ONE SINGLE PROGRAM?

A. The Company has designed complementary, beneficial programs that work together but were not intended to be one in the same. Thus, subsummation is not a trivial matter. Notably, the Attorney General offers no detailed suggestion as to program structure or, importantly, how a combined program would operate and deliver benefits effectively. When asked in discovery, Mr. Kollen merely hypothesizes, without any support, explanation or detail, that the programs could be combined with separate charges within a single tariff.[2] Adding a make ready component to the EVSE program would significantly complicate delivery of that program.

If EVSE were to subsume MRC, this would require the Company to participate in the market in ways that limit consumer choice. Most notably, the MRC residential Customer Option, Non-Residential and Homebuilder options could not exist as designed, thus limiting MRC customer autonomy when participating. Given the limited customer choice, MRC would ultimately become negligible and provide little benefit.

Subsummation would also require a contractor option, in which a Company-sourced electrician installs make ready infrastructure, for non-residential customers. While the Company would consider this non-residential option for the MRC program in the future, simplifying and efficient programmatic structure is not

[2] Attorney General's Response to Commission Data Request No. 1.

in place today. Implementing this modification to the MRC program without thorough planning would add complications and likely add significant costs.

Q. WHAT IS THE COMPANY'S RESPONSE TO MR. KOLLEN'S RECOMMENDATION THAT IF THE COMMISSION DOES APPROVE THE MRC AS A STAND-ALONE PROGRAM, THAT THE COMPANY BE REQUIRED TO RECOVER THE COSTS EXCLUSIVELY FROM PARTICIPATING CUSTOMERS?

A. Firstly, it is notable that in concluding that the MRC program costs should be recovered by participants alone, Mr. Kollen disregards that the program was deliberately conceived with the cost offset of future EV charging revenues and that the program sets the stage for downward rate pressure benefit to all ratepayers. Further, Mr. Kollen provides only a cursory proposal for how such recovery can be accomplished.

It is implausible to recover costs only from program participants while maintaining the benefits of the program. Insomuch as the Company appreciates the appeal of recovery from participants alone, MRC is not a rate wherein associated charges or fees are assessed to participants. Additionally, the Company does not propose to offer a simple a financing mechanism.

Q. DO YOU HAVE ADDITIONAL COMMENTS REGARDING MR. KOLLEN'S TESTIMONY?

A. Yes. The Company understands the importance of cost socialization and has not created the MRC program without consideration of why the proposed cost recovery is both necessary and appropriate. As stated, the program has been designed to minimize socialization through the offset of future EV charging revenues. MRC also sets a foundation for future downward rate pressure, particularly through programs that Duke Energy Kentucky intends to pursue in the near future.

MRC provides a durable foundation for future of EV programs regardless of how the industry and cost structures may change over time. If the costs of make ready infrastructure installations decline over time, this would in turn cap the revenue credits. If a particular charging station ownership model takes hold, the make ready infrastructure program is there to provide support.

The MRC Program aims to simplify EV adoption for Kentucky customers by mitigating barriers to EV ownership, especially for lower income customers or those who desire to adopt electric vehicles but are hesitant due to lack of confidence in safe EVSE installation.

Q. DO ANY OF DUKE ENERGY KENTUCKY'S NEIGHBORING UTILITIES HAVE SIMILAR PROGRAMS?

A. Duke Energy Kentucky is aware of the current programs offered by Louisville Gas and Electric and the Kentucky Utilities. However, there are currently no utility programs in Kentucky that include ownership model agnostic funding for customers to install EV charging infrastructure as is provided by the MRC program. Further, while the Company is aware of many examples of cost-based rebates throughout the country, only Duke Energy Kentucky's sister utility in North Carolina currently offers funding based on the revenue that make-ready investments bring to the utility system. As a result, Kentucky is in a position to be an early adopter of an innovative, value-based program.

III. CONCLUSION

Q. DOES THIS CONCLUDE YOUR REBUTTAL TESTIMONY?

A. Yes.

VERIFICATION

STATE OF INDIANA)
) SS:
COUNTY OF)

The undersigned, Cormack C. Gordon, Director Transportation Electrification, 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.

Cormack C. Gordon Affiant

Subscribed and sworn to before me by Cormack C. Gordon on this 5TH day of APRIL, 2023.

State of Indiana
County of: Hendricks

NOTARY PUBLIC

Commissioned in Hamilton County

My Commission Expires: 1/26/2031

SARAH A. SMITH
Hamilton County
NOTARY PUBLIC
Commission Number
NP0746411
NOTARY SEAL
My Commission Expires 1/26/2031
STATE OF INDIANA

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 New Tariffs; 3) Approval of Accounting Practices to Establish Regulatory Assets and Liabilities; and 4) All Other Required Approvals and Relief.	)))))))	Case No. 2022-00372

REBUTTAL TESTIMONY OF

JAMES J. MCCLAY

ON BEHALF OF

DUKE ENERGY KENTUCKY, INC.

April 14, 2023

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PAGE

I. INTRODUCTION AND PURPOSE

Q. STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is James J. McClay, III, and my business address is 526 South Church Street, Charlotte, North Carolina 28202.

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

A. I am employed as Managing Director of Natural Gas Trading for Progress Energy Carolinas a utility affiliate of Duke Energy Kentucky, Inc. (Duke Energy Kentucky or the Company).

Q. ARE YOU THE SAME JAMES J. MCCLAY 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 the recommendations made by Mr. Lane Kollen on behalf of the Kentucky Attorney General (KYAG) related to the Company's proposal for a comprehensive hedging program designed to mitigate market volatility for customers in the Fuel Adjustment Clause (FAC), optimize the market dispatch of the Company's fossil-fueled generation in PJM Interconnection LLC (PJM), and in the procurement of replacement power.

II. DISCUSSION

Q. PLEASE PROVIDE A BRIEF SUMMARY OF MR. KOLLEN'S RECOMMENDATIONS REGARDING THE COMPANY'S HEDGING PLAN PROPOSAL.

A. Mr. Kollen recommends that the Commission should require the Company to file a separate case concerning its backup power supply plan and a comprehensive hedging program with further evaluation and long-term effectiveness analysis.

Q. PLEASE SUMMARIZE MR. KOLLEN'S CONCERNS WITH THE COMPANY'S PROPOSAL IN THIS CASE?

A. Mr. Kollen claims the Company has not provided a detailed description of its hedging proposal and only generally describes it. Mr. Kollen also criticizes the Company's proposal for not listing the products in the PJM AD financial forward power markets to mitigate market volatility. The AD HUB is the aggregation of selected busses at the AEP/Dayton Interface within the PJM Control Area that provides a common point for commercial energy trading for Duke Energy Kentucky's power plants. Finally, Mr. Kollen states that the Company did not provide a long-term cost effectiveness analysis of its back up power supply plan or its proposed hedging plan program.

Q. WHAT IS THE COMPANY'S RESPONSE TO MR. KOLLEN'S STATEMENT THAT THE COMPANY HAS NOT PROVIDED A DETAILED DESCRIPTION OF ITS HEDGING PROPOSAL?

A. The description provided in my testimony regarding the proposed hedging plan was both detailed and informative. The plan included the scope of the hedging proposal, hedge methodology, hedging horizon limit, and hedge products that would be used to mitigate volatility and provide price certainty to protect customers. The comprehensive hedging proposal described applies to hedging scheduled outages, derates and forced outages periods to provide price certainty and limit customer exposure to spot price volatility. In addition, the ability to purchase fixed price power when the market price was more economical than running Duke Energy Kentucky-owned generation resulting in lower customer costs is prudent and in the customers' best interest.

Q. WHAT IS THE COMPANY'S RESPONSE TO MR. KOLLEN'S CLAIM THAT THE COMPANY DID NOT LIST THE PRODUCTS IN THE PJM AD FINANCIAL FORWARD POWER MARKETS THAT COULD BE USED TO MITIGATE MARKET VOLATILITY?

A. The Company didn't list all the PJM AD products that could be used to mitigate market volatility in order to keep the direct testimony concise and not overly burdened by technical details. There are a number of PJM AD Hub forward or futures products available for monthly, weekly, and daily terms and the information is publicly available. A link to the PJM AD hub financial futures products on InterContinental Exchange (ICE) is found here: https://www.ice.com/site-search?q=PJM+AEP+DAyton&page=1

These products can be used as hedging tools for different time periods and peak types. For example, PJM AEP Dayton Hub Day-Ahead Peak Fixed Price Future (contract symbol ADB) is defined by ICE as A monthly cash settled Exchange Futures Contract based upon the mathematical average of daily prices calculated by averaging the peak hourly electricity prices published by PJM for the location specified in Reference Price A.

As of March 28, 2023, June 2023 ADB future contract was quoted as $40.60 bid at $41.50 offer on ICE. If the Company agreed to buy 50MW at the $41.50 offer price, it would have locked in fixed price for 50MW of expected on-peak purchased power in June 2023. If average on-peak PJM AD Hub prices settled at $45/MWh for June 2023, the hedge would realize a gain of $3.5/MWh ($45-$41.50=$3.5). On the other hand, if average on-peak June 2023 settled at $40/MWh, the hedge would have a loss of $1.50/MWh ($40-$41.50=-$1.5).

Q. WHAT IS THE COMPANY'S RESPONSE TO MR. KOLLEN'S CRITICISM THAT THE COMPANY DID NOT PERFORM A LONG-TERM COST EFFECTIVENESS ANALYSIS OF ITS BACK-UP POWER SUPPLY PLAN OR ITS HEDGING PROPOSAL?

A. Since its first Back-up Power Supply Plan filed with the Commission, over the years, before filing each Back-up Supply Plan, the Company consistently evaluated various hedging strategies, including fixed price financial forwards and futures, daily PJM market purchases, daily call options, heat rate call options, outage contingent call options, and forced outage insurance policies. An economic decision was made each time to balance cost and customers' exposure to market price risk. It turned out obtaining back-up power through the PJM daily energy market during forced outages and using fixed forward contract purchases during scheduled outages was the most appropriate choice for the customers. This strategy mitigates the risk of price spikes during scheduled outages because the price for back-up power would be fixed.

Although a hedging program shouldn't be evaluated by the profits and losses from hedging activities alone because its goal is to smooth out the market price impact on the customers, the Company did go back to 2006 and calculated monthly hedge profits and losses all the way up to May 2022. As depicted in Attachment JJM-Rebuttal-1, Overall results for the 16-year time period was approximately $4.07 million for the customers. There were some relatively big swings in the monthly results. As designed, hedges realized gains when market prices were high and lost value when market prices were low. The goal of the hedging program is not to make a profit, rather it works to smooth out market price impact to customers.

Q. WHAT IS THE COMPANY'S RESPONSE TO MR. KOLLEN'S RECOMMEDATION THE COMPANY SHOULD FILE ITS HEDGING PROGRAM PROPOSAL IN A SEPARATE PROCEEDING?

A. As mentioned in my direct testimony, the goal of the hedging program is to manage the market price impact for purchased power and mitigate volatility in customers cost. Power hedging and economic power purchases have a direct impact on how much customers pay for power usage. Therefore, the Company believes it should be a part of this rate case proceeding. Waiting for a separate case only serves to lengthen the customer's exposure to volatility in the energy markets.

Q. PLEASE EXPLAIN WHY THE COMMISSION SHOULD APPROVE THE COMPANY'S HEDGING PROPOSAL NOW?

A. Commencing a proactive comprehensive power financial hedging program and enabling economic purchases when the market price is less than the cost of generating power provides immediate benefits to customers given the number of risk factors that can impact prices and trends. Underlying commodity markets are driven by complicated US and global dynamics which can result in substantial or frequent changes in prices, contributing to the volatility of spot and forward markets. The power markets are dependent and driven by the underlying interrelated fuel markets. Duke Energy Kentucky believes a comprehensive hedge program that includes flexibility to hedge forced and scheduled outage/derate periods provides price certainty and limits customer exposure to spot price volatility. In addition, the ability to purchase more economical financial power resulting in lower customer costs is prudent and, in the customers' best interest.

III. CONCLUSION

Q. DOES THIS CONCLUDE YOUR REBUTTAL TESTIMONY?

A. Yes.

VERIFICATION

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

The undersigned, James McClay, Managing Director Natural Gas, 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.

James McClay Affiant

Subscribed and sworn to before me by James McClay on this 5 day of April, 2023.

NOTARY PUBLIC

My Commission Expires:

SHAMELL M WILSON
My Comm. Expires
NOTARY PUBLIC
July 06, 2026
MECKLENBURG COUNTY, NC

Year	DEK Native Hedging P/L
2006	$98,516
2007	$1,684,674
2008	($446,211)
2009	($1,284,699)
2010	($71,916)
2011	($66,446)
2012	($34,496)
2013	($18,276)
2014	$61,203
2015	($119,201)
2016	($8,272)
2017	($56,763)
2018	$2,981,573
2019	($169,226)
2020	($1,052,402)
2021	$1,710,683
2022	$866,245
2023	($2,100)
Total	**$4,072,884**

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 New Tariffs; 3) Approval of Accounting Practices to Establish Regulatory Assets and Liabilities; and 4) All Other Required Approvals and Relief.	)))))))	Case No. 2022-00372

REBUTTAL TESTIMONY OF

JAMES E. ZIOLKOWSKI

ON BEHALF OF

DUKE ENERGY KENTUCKY, INC.

April 14, 2023

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I. INTRODUCTION AND PURPOSE

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is James E. Ziolkowski, 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, Rates & Regulatory Planning. DEBS 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 JAMES E. ZIOLKOWSKI 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 the recommendations of Justin D. Bieber, on behalf of the Kroger Company as it relates to cost allocation and revenue distribution. I also respond to his advocacy for a multi-site rate aggregation/ conjunctive billing program.

II. DISCUSSION

Q. PLEASE FURTHER EXPLAIN MR. BIEBER'S RECOMMENDATIONS REGARDING COST ALLOCATION AND REVENUE DISTRIBUTION?

A. Mr. Bieber recommends the Commission approve the Company's requested and continued use of a class cost of service that utilizes a 12 Coincident Peak (12 CP) methodology to allocate production costs. He further recommends that if the

Commission decides to deviate from the 12 CP methodology, that the Commission should use the Average & Excess methodology. Mr. Bieber recommends that the Commission not adopt the Production Stacking Methodology. Finally, Mr. Bieber implies that if the Commission approves a lower overall revenue requirement for the Company, the proposed revenue distribution could be adjusted to eliminate more of the interclass subsidies.

Q. DOES DUKE ENERGY KENTUCKY AGREE WITH MR. BIEBER'S RECOMMENDATIONS WITH RESPECT TO COST ALLOCATION AND REVENUE DISTRIBUTION?

A. Duke Energy Kentucky agrees that the Commission should approve the 12 CP allocation methodology and that there was no compelling reason to adopt a different methodology as I stated in my Direct Testimony. As it relates to the revenue distribution, the Company believes it proposed a reasonable distribution taking into consideration the impacts across all rate classes. The Company would be open to a different distribution if the Commission deems it reasonable.

Q. PLEASE DESCRIBE MR. BIEBER'S RECOMMENDATION FOR A MULTI-SITE AGGREGATED DEMAND RATE PROGRAM.

A. Mr. Bieber recommends that a multi-site commercial rate aggregation program would allow eligible customers with multiple service locations to aggregate their demands for purposes of production and transmission billing. For a multi-site aggregation program, the billing demand is measured as the highest hourly demand occurring simultaneously across each of a customer's participating locations, thereby measuring billing demand for the totality of the customer's participating sites as if it were a single load for billing purposes. This is described as conjunctive demand billing and should only apply to a customer's generation and transmission service. The distribution portion of the bill should be calculated using demand billing determinants established separately at each location.

Q. PLEASE DISCUSS DUKE ENERGY KENTUCKY'S CURRENT DEMAND CHARGE RATE STRUCTURE.

A. Non-residential customers who take service under Rate DS, Rate DP, Rate DT, or Rate TT incur per-kW (i.e., demand) charges as part of their monthly electric bills. The demand charge rate is applied to the highest fifteen-minute kW demand that occurs at the customer facility during the billing month, with some possible adjustments for power factor, demand ratchet, and Rider LM (Load Management Rider) if applicable.

Q. WHAT IS THE COMPANY'S RESPONSE TO THIS RECOMMENDATION.

A. The Company opposes this recommendation and requests that it be denied.

Q. PLEASE EXPLAIN WHY DUKE ENERGY KENTUCKY OPPOSES A CONJUNCTIVE BILLING PROGRAM.

A. The Company opposes a conjunctive billing program for the following reasons:

- The proposal shifts costs to customers that have only one facility.
- Complexity of billing.
- Duke Energy Kentucky's tariff rates are based on individual accounts and not groups of accounts.
- Individual stores come and go – some close, some are opened, some are

sold etc. Someone would need to keep track of which accounts belong to which customer. This can be a time-consuming process and can result in frequent re-billing issues.

Q. PLEASE EXPLAIN HOW CONJUNCTIVE BILLING SHIFTS COSTS TO OTHER CUSTOMERS.

A. Mr. Bieber's proposal violates the principles of fairness and nondiscriminatory rates by creating a sub-set of customers that will be advantaged based on their ability to combine separate individual accounts to take advantage of conjunctive demand billing for generation and transmission charges. Mr. Bieber's proposal would, implicitly, shift costs to other customers. That is why he is making the proposal. If the annual generation and transmission revenue requirement is known, and if Kroger pays less than they would under the current billing methodology, other customers will pay more. Specifically, as more customers take advantage of the ability to aggregate their accounts such that more are being billed under the conjunctive bill process, it will require additional costs to be recovered from the many non-residential customers that have only one facility in the Duke Energy Kentucky service territory. It should be noted that many customers in addition to Kroger have multiple facilities including other national retailers, food service stores, and gas station chains. Conjunctive billing would be reallocating and spreading millions of dollars of costs across rate classes resulting in those single-account, "mom and pop" businesses paying more.

Q. PLEASE DISCUSS THE BILLING PROBLEMS AND COMPLEXITIES ASSOCIATED WITH CONJUNCTIVE BILLING.

A. Mr. Bieber's proposal would result in many billing problems:

- Duke Energy Kentucky's electric retail rates are currently designed as bundled rates. To implement the proposal, the retail electric rates would need to be unbundled into distribution, transmission, and generation functions.
- The generation and transmission charges on the bills would be based on different kW billing determinants from the kW used to bill the distribution charges. The Company's billing system is not designed to handle this, and substantial programming would be required to implement the program.
- As discussed below, the Company would need to manually intervene to ensure that the account list associated with customers with multiple sites is completely accurate each month. If not, numerous accounts would require subsequent rebilling.
- All accounts associated with the customer would need to be placed on the same monthly billing cycle. To determine the generation / transmission billing demand, the Company would need to aggregate the hourly demands for each account, determine when the aggregated peak occurred, and apply the individual account demands for that hour to each account. A meter failure or any interruption of service at any one of the individual accounts would affect the determination of the billing demands for all other accounts for that customer. Depending on how this issue is handled,

this could result in held bills or re-billing of many accounts associated with that customer.

Q. PLEASE DISCUSS HOW DUKE ENERGY KENTUCKY'S DEMAND RATES ARE CURRENTLY DESIGNED.

A. As previously discussed, non-residential customers who take service under Rate DS, Rate DP, Rate DT, or Rate TT incur per-kW (i.e., demand) charges as part of their monthly electric bills. The demand charge rate is applied to the highest fifteen-minute kW demand that occurs at the customer facility during the billing month, with some possible adjustments for power factor, demand ratchet, and Rider LM (Load Management Rider) if applicable. The demand charge rates were designed in the previous rate case under the assumption that this billing process would be used upon approval of the new demand charges. The charges in the Company's electric tariff have not been designed for conjunctive electric billing.

Q. PLEASE DISCUSS THE PROBLEMS ASSOCIATED WITH FACILITIES AND STORES OPENING, CLOSING, AND CHANGING OWNERSHIP.

A. Large grocery chains such as Kroger and other retailers such as gas stations often open, close, sell, or purchase new facilities. Activities such as this could render the previously billed generation and transmission demand charges as incorrect if the Company was not notified about the changes well ahead of time. This could result in numerous cancellations and rebilling of many accounts, and it would likely require frequent time-consuming manual interventions by Company employees.

Q. IS THERE ANY VALUE TO STUDYING THE MERITS OF SUCH A PROGRAM?

A. There is always value in studying programs across the country, but I recommend against implementing a pilot program. Pilot programs tend to take on a "life of their own", and they are easier to begin than to terminate. Additionally because of the many issues I have noted with such a program, I believe these issues far outweigh any value in performing such a study. The costs for implementing this type of pilot would likely be significant. Not only would it require billing and customer information system program changes, but additional personnel would also need to be hired or allocated and trained to manage this type of program. As I indicated previously, this is not a "set-it and forget" type of program. To do this effectively, would require many employees verifying accounts monthly and reviewing the billing to make sure that it is capturing the world of sites for a particular customer. As I mentioned, the number of customers that would take advantage of this would include every chain grocery, restaurant, gas station, and business that has multiple sites within the Company's service territory.

Q. DO MULTI-SITE CUSTOMERS HAVE ALTERNATIVES AVAILABLE FOR DEMAND AGGREGATION IN THE COMPANY'S CURRENT TARIFFS?

A. Multi-site customers do not have alternatives for demand aggregation, but they have many opportunities to reduce the demand charge costs on their bills. Specifically, they can:

- Install energy efficiency measures at their facilities to reduce kWh and kW

- usage and associated electric costs.

- Participate in Duke Energy Kentucky's Rider LM (Load Management Rider) if they take service under Rate DS or Rate DP. Under Rider LM, participating customers can lower their billing demands by shifting load from on-peak to off-peak periods.
- Larger customers who take service under the non-residential time-of-day rates, Rate DT and Rate TT, can reduce their electric bills by shifting demand from on-peak to off-peak periods.

These three items can substantially reduce customers' bills and they do not require conjunctive billing.

III. CONCLUSION

Q. DOES THIS CONCLUDE YOUR REBUTTAL TESTIMONY?

A. Yes.

VERIFICATION

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

The undersigned, James E. Ziolkowski, Director, Rates & Regulatory Planning, 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.

James E. Ziolkowski Affiant

Subscribed and sworn to before me by James E. Ziolkowski on this 13th day of April, 2023.

NOTARY PUBLIC

My Commission Expires: July 8, 2027

NOTARY PUBLIC STATE OF OHIO
EMILIE SUNDERMAN
Notary Public
State of Ohio
My Comm. Expires
July 8, 2027

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 New Tariffs; 3) Approval of Accounting Practices to Establish Regulatory Assets and Liabilities; and 4) All Other Required Approvals and Relief.	)))))))	Case No. 2022-00372

REBUTTAL TESTIMONY OF

JEFFREY T. KOPP

ON BEHALF OF

DUKE ENERGY KENTUCKY, INC

April 14, 2023

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I. INTRODUCTION AND PURPOSE

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Jeffrey (Jeff) T. Kopp, and my business address is 9400 Ward Parkway, Kansas City, Missouri 64114.

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

A. I am employed by 1898 & Company (1898 & Co), which is part of Burns and McDonnel Engineering Company (BMcD) as Senior Managing Director the Utility Consulting Department.

Q. ARE YOU THE SAME JEFFREY T. KOPP THAT SUBMITTED DIRECT TESTIMONY IN THIS PROCEEDING?

A. Yes.

Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY?

A. The purpose of my testimony is respond to the recommendation of Mr. Lane Kollen on behalf of the Kentucky Attorney General as it relates to the inclusion of spare parts inventory in the decommissioning study.

II. DISCUSSION

Q. PLEASE BRIEFLY SUMMARIZE MR. KOLLEN'S TESTIMONY AS IT RELATES TO THE INCLUSION OF MATERIALS AND SUPPLIES INVENTORIES, INCLUDING SPARE PARTS INVENTORY IN DECOMMISSIONING COSTS RECOVERED THROUGH DEPRECIATION EXPENSE.

A. Mr. Kollen recommends that the Commission remove end of life materials and supplies from decommissioning cost estimates and instead allow any future recovery of these costs through the Company's proposal for a separate rider to recover any remaining net book value of its generating assets at the time of the unit's retirement.

Q. WHAT IS MR. KOLLEN'S JUSTIFICATION FOR REMOVING THESE COSTS FROM DECOMMISSIONING COSTS IN DEPRECIATION RATES?

A. Mr. Kollen does not provide any specific reasoning to remove these costs, other than to suggest there is "no need to estimate such end-of-life inventory amounts at this time or to recover the estimated amounts prior to the retirement of the generating units."[1]

Q. DOES MR. KOLLEN ARGUE THAT THE COMPANY SHOULD NOT BE ABLE TO RECOVER THESE COSTS?

A. No. He doesn't. In fact, he acknowledges that these costs exist and should be recoverable, net of salvage. He is merely advocating that the Commission arbitrarily reduce the Company's depreciation expense, essentially kicking the can down the road where future customers would bear the burden of these costs when the unit is retired, instead of amortizing a level of these costs now to mitigate that impact in the future.

[1] Kollen Testimony, pg. 38.

Q. IS IT REASONABLE TO INCLUDE THESE MATERIALS AND SUPPLIES INVENTORIES AS PART OF DECOMMISSIONING COSTS RECOVERED THROUGH DEPRECIATION EXPENSE?

A. Yes. Disposing of remaining inventory is just as much a part of decommissioning a station as disposing of other equipment and plant components. It must be safely sold, moved to other locations, or scrapped. In fact, the warehouse, or other portions of the plant where the supplies are held cannot be demolished until the inventory is safely removed.

A level of inventory is required to be maintained at each site in order to achieve appropriate reliability of the plants and to facilitate routine maintenance on the facilities. The value of this inventory that cannot be reclaimed through sale or scrap of the inventory is directly related to the retirement of the facility. If the facility were to remain in service, this inventory would retain its value to the plant. However, when the plant is retired, the value of this inventory is reduced to the value it has as salvage or scrap. This reduction in value of the inventory is a cost associated with net salvage rates associated with retirement and demolition of the facility.

Q. HAVE YOU INCLUDED MATERIALS AND SUPPLIES INVENTORIES AS PART OF DECOMMISSIONING COSTS RECOVERED THROUGH DEPRECIATION EXPENSE IN OTHER STUDIES?

A. Yes. I have included materials and supplies inventories as in the decommissioning costs for Duke Energy operating companies in Indiana, North Carolina, South Carolina, and Florida as well as for FPL in Florida.

Q. DO YOU AGREE WITH MR. KOLLEN'S RECOMMENDATION TO REMOVE END OF LIFE MATERIALS AND SUPPLIES FROM DECOMMISSIONING COST ESTIMATES?

A. No.

Q. PLEASE EXPLAIN WHY THE COMMISSION SHOULD REJECT MR. KOLLEN'S RECOMMENDATION?

A. Mr. Kollen does not provide any specific reasoning to remove these costs, but instead actually acknowledges that these costs exist and should be recoverable, net of salvage. His recommendation would not eliminate these costs from being recovered but would push the cost off to future rate payers, creating intergenerational inequity issues.

III. <u>CONCLUSION</u>

Q. DOES THIS CONCLUDE YOUR REBUTTAL TESTIMONY?

A. Yes.

VERIFICATION

STATE OF Missouri)
) **SS:**
COUNTY OF Jackson)

The undersigned, Jeffrey Kopp, Managing Director the Business Consulting Department, 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.

Jeffrey Kopp
Jeffrey Kopp Affiant

Subscribed and sworn to before me by Jeffrey Kopp on this 7 day of April, 2023.

Linda R. Olvera
NOTARY PUBLIC

My Commission Expires: 10/11/2024

Linda R. Olvera
Notary Public-Notary Seal
STATE OF MISSOURI
Commissioned for Jackson County
My Commission Expires: 10/11/2024
ID. #12403570

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 New Tariffs; 3) Approval of Accounting Practices to Establish Regulatory Assets and Liabilities; and 4) All Other Required Approvals and Relief.	)))))))	Case No. 2022-00372

REBUTTAL TESTIMONY OF

JOHN R. PANIZZA

ON BEHALF OF

DUKE ENERGY KENTUCKY, INC.

April 14, 2023

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ATTACHMENTS:

Attachment JRP-Rebuttal-1

Response to Duke Energy Kentucky's First Set of Discovery to the Attorney General, Request No. 33

Attachment JRP-Rebuttal-2

Response to Duke Energy Kentucky's First Set of Discovery to the Attorney General, Request No. 37

I. INTRODUCTION AND PURPOSE

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is John R. Panizza and my business address is 525 South Tryon Street, Charlotte, North Carolina 28202.

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

A. I am employed by Duke Energy Business Services LLC (DEBS) as Director, Tax Operations. 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 JOHN R. PANIZZA 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 the recommendations of Mr. Randy Futral on behalf of the Kentucky Attorney General (KYAG) as it relates to his proposed adjustments to the Company's property tax expense included in its application in this proceeding.

II. DISCUSSION

Q. PLEASE SUMMARIZE MR. FUTRAL'S RECOMMENDATIONS REGARDING THE COMPANY'S PROPERTY TAX EXPENSE.

A. Mr. Futral makes two adjustments to the Company's property tax expense. First, he recommends that the property tax expense related to four capital projects that are currently in the Company's Environmental Surcharge Mechanism (ESM) remain in the ESM instead of "rolling" into base rates. Company witness Ms. Lisa Steinkuhl addresses that issue in her Rebuttal Testimony. Second, Mr. Futral recommends that the Commission reduce the Company's projected property tax expense to reflect the Company's 2022 actual expense escalated through the end of the test year for increases in electric net plant by using the Company's 2.0 percent per year property tax rate increase.

Q. PLEASE EXPLAIN HOW THE COMPANY ACCOUNTS FOR PROPERTY TAX EXPENSE FOR ACCOUNTING PURPOSES.

A. The Company accounts for property tax based on Kentucky's property tax year cycle. For example, Kentucky property tax year 2021 is related to the Company's financial statements year ending December 31, 2020. The Kentucky Department of Revenue (DOR) issues tax year 2021 assessments in calendar year 2021, but tax bills are issued and paid in calendar year 2022. The Company must accrue tax year 2021 in calendar year 2021 for accounting purposes. Other activity in account 408 during Kentucky property calendar year 2021 can take place such as tax year 2020 payments and other various true-ups to account for other tax years. For example, any resolution tax appeals for prior years can impact the current accounting year. Therefore, utilizing book expense for 2021 out of account 408 to estimate the potential property tax for the test period would not achieve an accurate result.

In response to the Company's Discovery request, Mr. Futral concedes that he is not aware that the $14.498 million of book expense he cites to on page 16 of his testimony includes prior period accounting adjustments. The fact that this number includes prior period adjustments supports that Mr. Futral's figure should not be included in estimating the Company's future tax expense.[1] To further demonstrate the inaccuracy of Mr. Futral's recommendation, as indicated in his response to the Company's First Set of Discovery to the Attorney General, No. 37, Mr. Futral explains that he compared two different tax years, the Company's tax year 2021, $15.653 million to the Company's book expense balance for tax year 2022.[2] Mr. Futral's reasoning is fault. These two different years are not comparable because the 2021 amount reflects actual taxes for the tax year versus the 2022 amount which reflects accounting activity for multiple tax years including adjustment for successful appeals.

Q. IS MR. FUTRAL'S CALCULATION OF AN EFFECTIVE TAX RATE CORRECT? IF NO, PLEASE EXPLAIN.

A. No. Mr. Futral's starting property tax estimate of $14.498 million includes book adjusting entries for multiple property tax years and one time property tax reductions that do not accurately reflect a single year's likely property tax expense. One-time adjustments such as property tax reductions achieved by successfully appealing to the DOR are not always successful. Therefore, one-time reductions should not be included in the property tax estimate's starting point. Also, each tax year should be independently analyzed and then allocated to the test period. Since the test period is a fiscal year that covers Kentucky property tax

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[1] *See* Duke Energy Ohio's First Set of Discovery to the Attorney General, Question No. 33. Attached as JRP-Rebuttal-1.

[2] *See* Duke Energy Ohio's First Set of Discovery to the Attorney General, Question No. 37. Attached as JRP-Rebuttal-2.

years 2023 and 2024, one should calculate property tax expense for each year and then allocate 50% of each year to the test period.

Q. WHAT STARTING POINT IS NECESSARY TO ACCURATELY ESTIMATE PROPERTY TAXES FOR THE TEST PERIOD.

A. The starting point for each year's tax estimate should utilize the most current information available as it relates to an individual tax year. Typically, one would use information from actual tax bills or an assessment notice from the DOR depending on which is more current. For the filing, the Company utilized the tax estimate in the 2021 notice of value from DOR and escalated it by growth factors to estimate property tax expense for the test period. Growth factors are included to account for potential changes in tax rates, projected capital investments, and projected net operating income growth. The resulting tax estimate utilizing this information for the 2021 tax year is $15.653 million and reduces the realized tax savings to what is potentially achievable.

Q. PLEASE EXPLAIN MR. FUTRAL'S RECOMMENDED ESCALATED EFFECTIVE TAX RATE.

A. Mr. Futral uses projected net plant increases and grows the local tax rate to escalate the effective tax rate for each tax year. He calculates the effective tax rate be dividing estimated tax expense by net book value. He insists that this is the "best" and possibly the only approach to account for increases in assets.

Q. DOES THE COMPANY AGREE WITH MR. FUTRAL'S METHOD OF ESCALATING THE EFFECTIVE TAX RATE? IF NO, PLEASE EXPLAIN.

A. No. While the Company utilized total capital cost increases to escalate an effective tax rate that was calculated by dividing property tax estimate by total capital cost, the Company's approach would not yield a material difference with Mr. Futral's approach to estimating the future growth of assets. However, Mr. Futral only considers net plant growth and tax rate increases in his escalation factor and he appears to ignore potential net operating income increases in his testimony unlike the Company which incorporated potential increases in net operating income in its escalation.

Q. PLEASE EXPLAIN WHY THE TAX ESTIMATE WOULD BE INACCURATE WITHOUT CONSIDERING THE INCOME COMPONENT UTILIZED BY THE DOR TO VALUE THE COMPANY.

A. DOR utilizes the unit value method to calculate the assessed value of the Company's property. The unit value method includes analyzing both the Company's costs and net operating income. Historically, the DOR has relied 100% on the income component of the overall unit value analysis. Therefore, any property tax estimate that relies solely on the cost component of the unit value method could not possibly calculate an accurate estimate of property tax in any year.

Q. DOES THE COMPANY AGREE WITH MR. FUTRAL'S RECOMMENDED ADJUSTMENTS TO THE COMPANY'S TAX EXPENSE? IF NO, PLEASE EXPLAIN WHY MR. FUTRAL'S RECOMMENDATION IS UNREASONABLE.

A. No. Mr. Futral's recommended expense is unreasonable because his calculation starts with an incorrect starting point that includes activity that may not occur during the test period, and he fails to incorporate potential changes in net operating income in his escalation of an effective tax rate.

Q. WHAT IS YOUR RECOMMENDATION REGARDING MR. FUTRAL'S ADJUSTMENTS?

A. The Company recommends that the Commission reject Mr. Futral's recommendations, and instead, utilize the property tax expense submitted by the Company in its filing. The filing reflects utilizing tax year 2021 property tax expense of $15.653 million and escalating using factors that rely on net operating income growth as well as local tax rate growth and other potential adjustments such as tax appeal results to ultimately estimate a property tax expense of $19.741 million for the test period. This is before any adjustment Ms. Steinkuhl discusses regarding the property taxes associated with the four capital projects that are currently in the Company's Environmental Surcharge Mechanism (ESM).

III. CONCLUSION

Q. ARE ATTACHMENTS JRP-REBUTTAL-1 AND 2 ACCURATE COPIES OF THE ATTORNEY GENERAL'S RESPONSES TO DATA REQUESTS AND WHERE THOSE ATTACHMENTS PREPARED BY YOU AND AT YOUR DIRECTION AND UNDER YOUR CONTROL?

A. Yes.

Q. DOES THIS CONCLUDE YOUR REBUTTAL TESTIMONY?

A. Yes.

VERIFICATION

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

The undersigned, John R. Panizza, Director, Tax Operations, 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 R. Panizza

John R. Panizza Affiant

Subscribed and sworn to before me by John R. Panizza on this 23 day of March, 2023.

VIRGINIA M. ADAMS
My Comm. Expires
NOTARY PUBLIC
October 2, 2026
MECKLENBURG COUNTY, NC

Virginia M Adams

NOTARY PUBLIC

My Commission Expires: 10/2/26

WITNESS RESPONSIBLE:
RANDY A. FUTRAL

QUESTION NO. 33
Page 1 of 1

Referencing Page 16 of Mr. Futral's testimony, is Mr. Futral aware that the $14.498M includes any prior period adjustments for other Kentucky property tax years? If yes, please provide the calculation separating the $14.498M between property tax years 2021 and 2020.

RESPONSE:

Mr. Futral does not have access to the Company's general ledger detail applicable to each jurisdiction or the Company's allocations of property tax expenses between electric and gas in order to determine whether the recorded property tax expense of $14.498 million included any prior period adjustments.

WITNESS RESPONSIBLE:
RANDY A. FUTRAL

QUESTION NO. 37
Page 1 of 1

Why does Mr. Futral believe that the 2022 property tax book expense of $15.510M is comparable to the estimated property tax year expense that utilizes the assessing authorities' 2021 valuation notices and tax year 2021 estimated tax rate?

RESPONSE:

Refer to Mr. Futral's Direct Testimony at 17. The actual property tax book expense for 2022 was $15.510 million. This amount almost matches the estimated property tax assessment amount of $15.653 million applicable to 2021 included in the Company's workpapers to project 2021 costs.

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 New Tariffs; 3) Approval of Accounting Practices to Establish Regulatory Assets and Liabilities; and 4) All Other Required Approvals and Relief.	)))))))	Case No. 2022-00372

REBUTTAL TESTIMONY

OF

JOHN J. SPANOS

ON BEHALF OF

DUKE ENERGY KENTUCKY, INC.

April 14, 2023

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PAGE

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND 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 December 1, 2022.

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, Lane Kollen and Sierra Club witness, Sarah Shenstone-Harris as it relates to the Company's depreciation rates proposed in this proceeding.

Q. WHAT ARE THE SUBJECTS OF YOUR REBUTTAL TESTIMONY?

A. My rebuttal testimony relates to depreciation issues, specifically the appropriate recovery methodology for generating facilities which includes the life span for the East Bend facility and the standard practice of recording decommissioning costs as a component of the depreciation rate.

II. LIFE SPAN OF THE EAST BEND GENERATING FACILITY

Q. HAS MR. KOLLEN PROPOSED A DIFFERENT RETIREMENT DATE FOR THE EAST BEND GENERATING FACILITY THAN WHAT WAS RECOMMENDED IN THE DEPRECIATION STUDY?

A. Yes. He has proposed using a probable retirement date of 2041 for East Bend instead of 2035 as recommended in the depreciation study.

Q. DOES MR. KOLLEN'S RECOMMENDED PROBABLE RETIREMENT DATE PROPERLY CONSIDER THE APPROPRIATE LIFE CYCLE OF THE EAST BEND GENERATING FACILITY?

A. No. The purpose of a probable retirement date and the impact on depreciation is to estimate the life cycle of each asset class and to recover the investment over the same time period that the asset will render service. Mr. Kollen chose to ignore this fundamental concept of depreciation (that is, matching recovery to usage) in his proposal by suggesting that, if necessary, it is appropriate to recover the remaining net book value of East Bend 2 "from the generation of customers that will be served by the new capacity."[1] He reasons that, "future customers should bear the remaining cost of the East Bend 2 in exchange for the benefits they will achieve from an earlier transition to lower cost replacement capacity."[2] Not only is this an arbitrary proposal, but more importantly, it is at odds with a fundamental concept of depreciation which is matching recovery to the usage of assets.

Further, Mr. Kollen provides no basis for his proposal of a 2041 retirement date, aside from it being the previously estimated date for this facility. The proposal

[1] Direct Testimony of Lane Kollen, page 30, lines 6-7.
[2] Direct Testimony of Lane Kollen, page 30, lines 11-13.

of the 2035 date is supported by the Company's informed judgement of East Bend 2 based on evaluation of various economic considerations. The Company has clearly identified that 2041 is no longer a realistic expectation for the life span of this facility as expressed by various witnesses in this case.

Q. DOES SIERRA CLUB WITNESS SARAH SHENSTONE-HARRIS HAVE THE SAME POSITION AS MR. KOLLEN?

A. No. Ms. Shenstone-Harris recommends retiring East Bend by 2030. Her primary support is the Company's projections and plans for future costs required to operate and maintain the facility. This is key information in the determination of an estimated retirement date, and she is correct in concluding that a retirement date of no later than 2035 is appropriate.[3]

Q. DOES THAT MEAN YOU AGREE WITH MS. SHENSTONE-HARRIS THAT 2030 IS THE BEST DATE TO RETIRE EAST BEND?

A. No. Every year there are costs to operate and maintain a power plant and some years are higher than others. In the case of East Bend, the Company has evaluated these costs compared to the costs related to new and alternative generation. This evaluation process takes time. Additionally, it should be emphasized that the operation and maintenance costs currently incurred must be replaced by the cost of new generation which can cost as much or more, so proper decisions need to be evaluated for the best alternative.

[3] Direct Testimony of Sarah Shenstone-Harris, page 12, line 1.

Q. WHAT TREND HAVE YOU EXPERIENCED IN THE RETIREMENT OF COAL FIRED GENERATING FACILITIES?

A. In my experience of over 30 years working within the electric industry, I have conducted depreciation studies of hundreds of electric utilities throughout the United States, and I see trends within the industry firsthand. In recent years, there is clearly a trend of increased coal generation retirement, and most, if not all, of the retired facilities are being taken out of service earlier than their estimated retirement dates. Prior to 2015, the most common range of life spans for coal fired generating facilities was between 55 and 65 years. Since 2015, the average age of coal fired generating facilities has been well below 50 years. East Bend will have a life span of 54 years if retired in 2035.

Q. ARE THE OPERATIONAL AND MAINTENANCE COSTS INCURRED EACH YEAR IN MANY CASES REPLACING CAPITAL IMPROVEMENTS?

A. Yes. In most years there are decisions that are required to be made as to whether to spend funds to maintain existing assets or to replace with new assets. As assets age when they near the end of life, the operating and maintenance expense amounts are overall a better option than replacement. This is particularly common as assets near end of life and the replacement of new assets would be more expensive and require major changes to the functionality of the facility.

Q. ARE DECISIONS RELATED TO O&M EXPENSE VERSUS CAPITAL COSTS THE ONLY FACTOR FOR GENERATING FACILITIES?

A. No. The O&M versus capital decision must also be reviewed at the same time discussions are made related to generation capacity, such as how will the closure of a generating facility capacity be replaced when retired.

III. TERMINAL NET SALVAGE FOR PRODUCTION

Q. WHAT ARE MR. KOLLEN'S OBJECTIONS TO THE TERMINAL NET SALVAGE ESTIMATES FOR THE EAST BEND GENERATING FACILITY?

A. Mr. Kollen has two primary objections to the development of terminal net salvage estimates in this case. First, he claims decommissioning, or terminal net salvage, should be excluded from the depreciation rate and be a standalone expense. Second, he asserts that the escalation of decommissioning costs to the date of retirement should be reduced to just the test year. Neither of these claims are correct, and Mr. Kollen provides no evidence to support their merit.

Q. DO THE COMPANY'S CURRENT DEPRECIATION RATES, APPROVED BY THE COMMISSION, INCLUDE ESCALATION?

A. Yes. In the Company's previous depreciation studies, the terminal net salvage estimates include escalation to the date of retirement and were developed in the same manner as in the instant case. The Commission approved the Company's proposals with regard to terminal net salvage:

> The Commission finds Dukes Kentucky's recommendation on the treatment of terminal net salvage value in the computing the

> depreciation rates for generating units is reasonable in order to avoid intergenerational inequity and should be approved.[4]

Q. WILL MR. KOLLEN'S PROPOSAL TO ELIMINATE ESCALATION PROPERLY ALLOCATE THE COMPANY'S COSTS OVER THE SERVICE LIVES OF THEIR GENERATING FACILITIES?

A. No. The decommissioning study prepared by 1898 & Co. (previously known as Burns and McDonnell) uses costs at current price level. However, 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 to the date of retirement from the decommissioning costs would result in insufficient recovery of the Company's actual costs.

Q. ARE MR. KOLLEN'S NET SALVAGE PROPOSALS BASED ON ACCEPTED DEPRECIATION PRACTICES?

A. No. It is widely accepted that depreciation should include future net salvage costs, which are recovered on a straight-line basis and that those costs should be based on the expected cost to retire the Company's assets at the time of retirement or removal. This applies not only to decommissioning costs but to the costs of all plant assets.

[4] Order in Case No. 2017-00321, p. 27

Q. SHOULD NET SALVAGE BE BASED ON THE FUTURE COSTS EXPECTED TO BE INCURRED, NOT ON TODAY'S COSTS?

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 to achieve adequate recovery.

Q. SHOULD NET SALVAGE BE RECOVERED IN TODAY'S COST (THAT IS, 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 FEDRAL ENERGY REGULATORY COMMISSION'S UNIFORM SYSTEM OF ACCOUNTS (FERC USOA)?

A. Yes. The FERC USOA 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 cost of removal, as part of net salvage, must be recovered through depreciation expense and is the actual amount 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. Two preeminent depreciation texts are the National Association of Regulatory Utility Commissioners' Public Utility Depreciation Practices (typically referred to as "NARUC") and *Depreciation Systems* by Wolf and Fitch (Wolf and Fitch). Both texts are clear that net salvage should be included in depreciation as a future cost. NARUC 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>.[5] (Emphasis added)

> NARUC also explains that:

> The goal of accounting for net salvage is to allocate the net cost of an asset to accounting periods, <u>making due allowance for the net salvage, positive or negative, that will be obtained when the asset is retired.</u> This concept carries with it the premise that property ownership includes the responsibility for the property's ultimate abandonment or removal. Hence, <u>if users benefit from its use, they should pay their pro rata share of the costs involved in the abandonment or removal of the property and also receive their pro rata share of the benefits of the proceeds received</u>.[6] (Emphasis added)

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.[7]

Q. CAN YOU FURTHER DISCUSS WHY MR. KOLLEN'S CALCULATIONS FOR CREATING A STANDALONE TERMINAL NET SALVAGE COMPONENT ARE INAPPROPRIATE FOR ALL THE GENERATING FACILITIES?

A. Yes. First, as mentioned above, the terminal net salvage should be included in the depreciation rate based on all authoritative guidance. Second, the development of

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[5] NARUC Manual at 18.
[6] NARUC Manual at 18.
[7] Wolf and Fitch, p. 7.

the weighted net salvage includes both interim and terminal net salvage which is based on the plant in service forecasted to be in place up to the date of retirement. Therefore, the amount that is equitably included in the depreciation rate is determined based on both the interim survivor curve and the decommissioning cost as a percentage of the assets in service each year up to the date of retirement. Thus, it is both expected and appropriate that the decommissioning costs will increase if the original cost increases. Mr. Kollen's proposal to segregate the decommissioning expense and base it on a calculation performed at a single point in time (in this case, December 31, 2021) would significantly underestimate the full cost of decommissioning at the end of the facility's life. Not only does Mr. Kollen's proposed method of segregating decommissioning from the calculation of depreciation deviate from industry practice, but it can also lead to a departure from the matching principle that is a fundamental depreciation concept.

Q. PLEASE BRIEFLY DISCUSS THE CONCEPT OF GROUP DEPRECIATION AND HOW IT RELATES TO THE COMPANY'S RECOVERY OF RETIREMENT COSTS FOR MIAMI FORT UNIT 6.

A. Group depreciation is the practice of recording or assembling similar fixed assets into a single group or property account, which is used in aggregate as the cost base for depreciation calculations. Assets should be assembled into a group if they share similar characteristics and have been identified by the Uniform System of Accounts to be a property unit within the account. In group depreciation, all the assets should have their full service value recovered over the overall life cycle of all the assets in the account.

As it relates to Duke Energy Kentucky's Miami Fort Unit 6, a coal-fired generating unit, the unit was retired several years ago but the full service value was not recovered at the time of retirement. In conformance with the concept of group depreciation, Miami Fort Unit 6 was depreciated in the same steam production accounts as East Bend which is another coal-fired unit. Therefore, upon its retirement, the undepreciated remaining net book value of Miami Fort Unit 6, consistent with the principle of group depreciation, continued to depreciate along the useful life of the remaining assets in that account, in this instance, East Bend.

Q. PLEASE EXPLAIN WHY THE RETIREMENT OF EAST BEND WILL BE TREATED DIFFERENTLY FROM A GROUP DEPRECIATOIN PERSPECTIVE AS IT RELATES TO ANY UNDEPRECIATED REMAINING PLANT AT ITS RETIREMENT.

A. East Bend is the only remaining steam-production plant remaining in that account. The Company's Woodsdale and solar units are in different accounts in accordance with the FERC Uniform System of Accounts (USoA). It is highly unlikely that Duke Energy Kentucky will replace East Bend with another coal-fired generating unit or that any new unit would be added that would be classified in steam production plant per the USoA used for East Bend generating facility. Therefore, there would be no related account or assets that any remaining undepreciated plant for East Bend could be assigned upon East Bend's retirement. A separate regulatory asset would need to be created or else the Company would be facing an enormous and financially damaging write-off.

IV. CONCLUSION

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes.

VERIFICATION

COMMONWEALTH OF PENNSYLVANIA)
) SS:
COUNTY OF CUMBERLAND)

The undersigned, John J. Spanos, President of Gannett Fleming Valuation and Rate Consultants, LLC, 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 27th day of March, 2023.

NOTARY PUBLIC

My Commission Expires: February 20, 2027

Commonwealth of Pennsylvania - Notary Seal
Cheryl Ann Rutter, Notary Public
Cumberland County
My commission expires February 20, 2027
Commission number 1143028
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 New Tariffs; 3) Approval of Accounting Practices to Establish Regulatory Assets and Liabilities; and 4) All Other Required Approvals and Relief.	)))))))	Case No. 2022-00372

REBUTTAL TESTIMONY OF

JOHN D. SWEZ

ON BEHALF OF

DUKE ENERGY KENTUCKY, INC.

April 14, 2023

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PAGE

I. INTRODUCTION AND PURPOSE

Q. STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is John D. Swez and my business address is 526 S. Church Street, Charlotte, North Carolina 28202.

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

A. I am employed as Managing Director, Trading and Dispatch, by Duke Energy Carolinas, LLC, a utility affiliate of Duke Energy Kentucky, Inc. (Duke Energy Kentucky or Company).

Q. ARE YOU THE SAME JOHN D. SWEZ THAT SUBMITTED DIRECT TESTIMONY IN THIS PROCEEDING?

A. Yes.

Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY IN THESE PROCEEDINGS?

A. My rebuttal testimony responds to the recommendations by Mr. Lane Kollen on behalf of the Kentucky Attorney General as it relates to the Company's recovery of deferred forced outage expenses.

II. DISCUSSION

Q. PLEASE BRIEFLY SUMMARIZE MR. KOLLEN AS IT RELATES TO THE COMPANY'S FORCED OUTAGE EXPENSE?

A. Mr. Kollen argues that the Company did not demonstrate that the forced outage deferrals were prudent, reasonable, and necessary. He also argues that the Company has no ratemaking incentive to minimize forced outages or related expenses if it can simply defer and recover without any justification.

Q. PLEASE EXPLAIN HOW THE COMPANY MANAGES FORCED OUTAGES AND FORCED DERATES IN THE WHOLESALE ENERGY MARKETS?

A. First, as explained by Company Witness Mr. William Luke, the Company conducts planned and maintenance outages to minimize the number of forced outages and derates on its generators. However, if forced outages or derates do occur, when possible, the Company calculates the impact of the trade-off between a return of the unit to full availability versus the impact from additional purchase energy expense and potential capacity performance risk in the PJM Interconnection LLC (PJM) energy market, and/or capacity market impact from the PJM capacity market.

As an example, assume that a unit has a forced outage and must be brought off-line. If different repair options are available, the station and generation dispatch departments will discuss those options, including the scope for the repair, the length of repair under each option, and the incremental expense associated with the different options. If PJM energy prices are forecast to be equal to or less than the variable and startup cost of the generating unit in question and if the potential for a PJM capacity performance event is low, it may make economic sense to choose a lesser cost, but longer in duration repair alternative, than a more expensive and quicker solution to return the unit to service. Conversely, if PJM energy prices are forecast to be greater than the variable and startup cost of the generating unit in question, or if the potential for a PJM capacity performance event is high, it will likely make economic sense to spend additional costs to return the unit to service quicker. Note that under both scenarios, the risk of a potential change to the forecasted market prices may need to be additionally considered.

Finally, although less common due to the relatively short length of most forced outages and the corresponding impact on the units Equivalent Forced Outage Rate (EFOR) and Unforced Capacity (UCAP) value, the same trade-off can be completed when examining impacts in the PJM capacity market. For all these analyses, communication between power plant and generation dispatch is critical and a primary reason why the Company has daily regularly scheduled standing meetings with station and dispatch personnel with additional communication occurring as needed.

Q. ARE THE COMPANY'S GENERATING ASSETS RELIABLE?

A. Yes. As a testament to this fact, according to the 2022 PJM State of the Market Report, the average PJM generating unit EFORd in 2022 was 7.6 percent and 7.0 percent in 2021. In comparison, the Company's 60-month East Bend and Woodsdale 1-6 weighted rolling average XEFORd is 6.49 percent.[1] Finally, as shown in the testimony of Mr. Luke, East Bend has outperformed the NERC average EFOR for units of similar size in six of the past seven years.

[1] https://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2022/2022-som-pjm-vol2.pdf; XEFORD is measure of the probability that a generating unit will not be available due to forced outages or forced deratings when there is demand on the unit to generate which is the same as EFORd, but excludes events that are designated as outside management's control.

Q. FOR THE PAST FOUR FULL YEARS PLUS YEAR-TO-DATE 2023, PLEASE DETAIL THE AMOUNT OF FORCED OUTAGE AND FORCED DERATES OF THE COMPANIES GENERATORS AS WELL AS THE AMOUNT OF EXPENSE EXCLUDED FROM FAC RECOVERY DUE TO THESE OUTAGES AND DERATES?

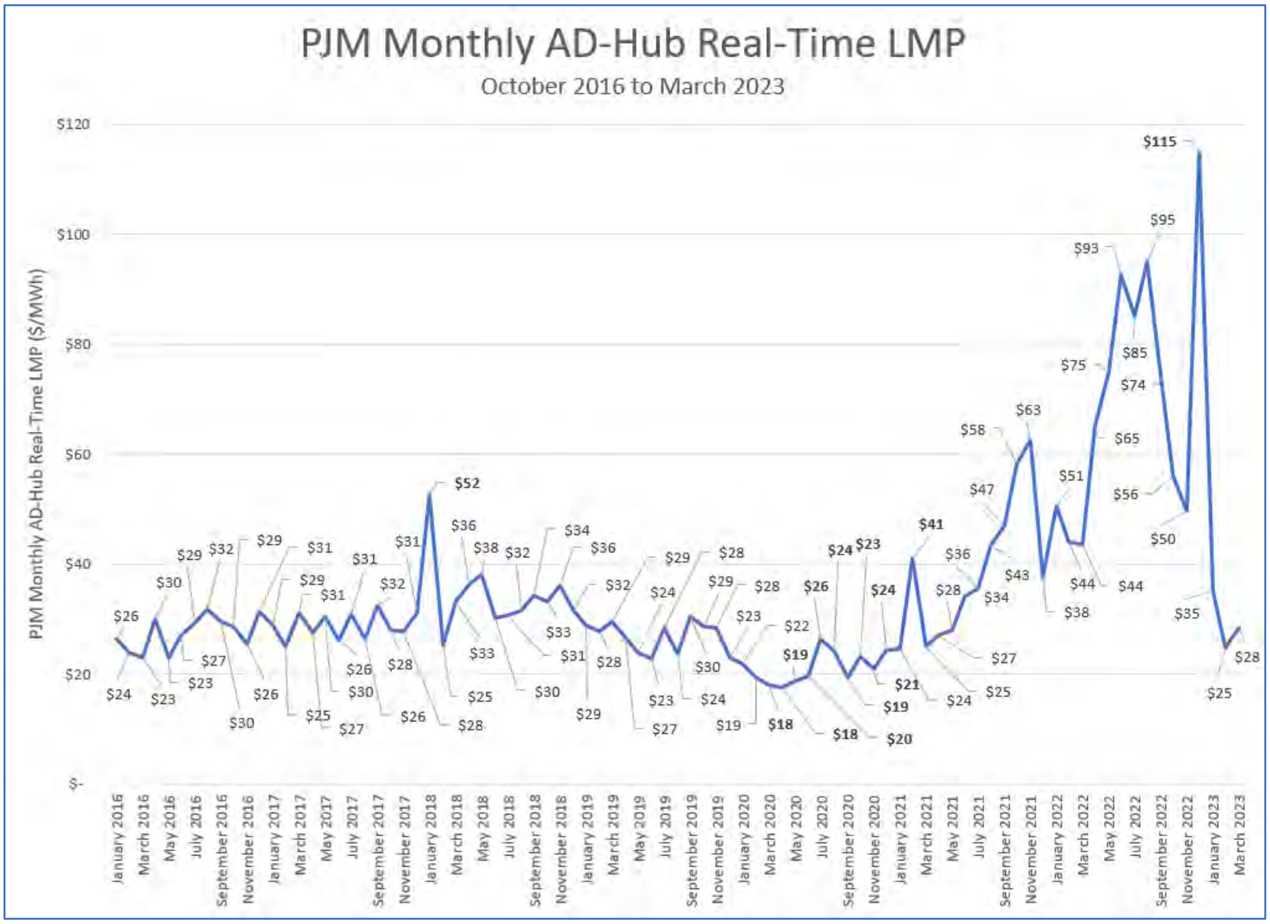
A. For 2019 through the current month of 2023, the table below shows the Company's Forced Outage & Derate Generation Amount (MWh), Cost of Replacement Power from PJM due to Forced Outages and Derates ($), the Prior Month Generating Unit Average Cost ($/MWh), the FAC Recovery Limit ($), and the amount of the Replacement Power Cost Excluded from FAC recovery ($). As an example of the volatility of the replacement power cost due to forced outages, the forced outage and derate (MWh) amount in 2021 was approximately double the amount in 2022. However, the amount excluded from FAC recovery was approximately double in 2022 than in 2021. Although the amount of forced outage/derate generation amount (MWh) was obviously a factor contributing to the $7,231,522 amount of replacement power cost excluded from FAC recovery in 2022, the biggest impact was the significantly higher PJM purchase price of $82/MWh in 2022, a factor very much out of the Company control.

	Forced Outage & Derate Generation Amount (MWh)	Cost of Replacement Power from PJM Due to Forced Outages & Derates ($)	Cost of Replacement Power from PJM Due to Forced Outages & Derates ($/MWh)	FAC Recovery Limit Using Prior Month Generating Unit Average Cost ($)	Prior Month Generating Unit Average Cost ($/MWh)	Amount of Replacement Power Cost Excluded from FAC Recovery ($)
2019	72,600	$ 2,549,995	$ 35	$ 1,544,378	$ 21	$ 1,013,826
2020	56,143	$ 1,157,375	$ 21	$ 1,172,654	$ 21	$ 16,448
2021	257,400	$ 8,264,605	$ 32	$ 4,674,065	$ 18	$ 3,590,540
2022	130,369	$ 10,678,256	$ 82	$ 3,446,733	$ 26	$ 7,231,522
2023	26,095	$ 764,023	$ 29	$ 969,362	$ 37	$ -

Q. PLEASE EXPLAIN THE DRIVER FOR THE INCREASES IN FORCED OUTAGE REPLACEMENT POWER COST EXPERIENCED SINCE THE COMPANY'S LAST RATE CASE?

A. The primary driver for the increase in replacement power costs is the volatility in the PJM market itself. As shown above, each month as part of the Company's FAC, the total PJM replacement power cost minus the calculated generation cost that would have occurred absent these forced outages and derates is excluded from FAC recovery. The amount of forced outage and derate generation (MWh) has varied some, but the financial impact of these forced outages and derates is far more volatile, from a low of $16,448 in 2020 to a high of $7,231,522 in 2022. Since the actual cost of the Company's predominant source of energy, East Bend Station, has a relatively consistent cost, especially in comparison to PJM LMP, the volatility in this unrecovered forced outage and derate expense is primarily due to the varying nature of PJM LMP's. This LMP volatility can be further seen by a plot of monthly Real-Time PJM LMP's at the AD-Hub Zone, shown below. Notice that LMP's remained relatively consistent from 2016 to 2019 ($23/MWh to $38/MWh range), with one outlier due to the Winter Storm in January 2018 ($52/MWh).

Starting 2020 there is a dip in power prices due to lower demand from the impact of the COVID epidemic ($18/MWh to $26/MWh range), followed by a spike in prices from Winter Storm Uri in February 2021 ($41MWh). However, starting in mid-2021 and continuing throughout 2022, PJM power prices started a steady price upward that peaked in December 2022 ($115/MWh) with the impact of Winter Storm Elliott among other factors. Since this time, for the first three months of 2023, PJM power prices have dropped and realized significantly lower prices. In fact, PJM prices over the first three months of 2023 have averaged $29.44/MWh compared to the 2022 yearly average of $70.45/MWh, a 58% reduction. Clearly PJM, PJM power prices have shown significant volatility, especially since 2020.

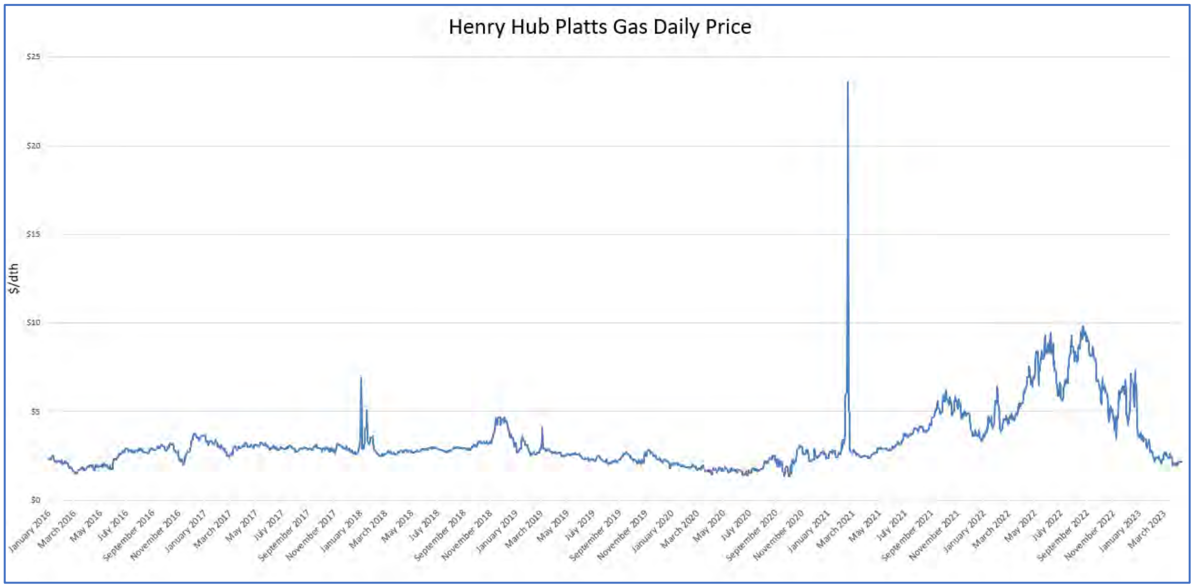


Q. WHAT IS THE DRIVER OF THIS INCREASE IN POWER PRICES?

A. During mid-2021 and through 2022, coal and natural gas markets exhibited higher prices and volatility that resulted in higher PJM LMP's. The coal supply chain experienced increasing challenges throughout 2021 and 2022 as historically low utility stockpiles—combined with rapidly increasing demand for coal, both domestically and internationally—made procuring additional coal supply increasingly challenging. Additional factors impacting the coal supply chain included: (1) deteriorating financial health of coal suppliers which impacted the ability of producers to respond to changes in demand; (2) continued labor and resource constraints due to structural changes in the coal industry further limiting suppliers' operational flexibility, and (3) the on-going threat of a rail strike in Fourth Quarter, 2022. These factors combined to drive both domestic and export coal prices in 2021 and 2022 to record levels.

As natural gas is frequently the marginal fuel within PJM, it has a strong correlation to PJM power prices. Although the nation's natural gas supply has grown significantly over the last several years as producers enhanced production techniques and efficiencies, and lowered production costs, natural gas prices are reflective of the dynamics between supply and demand factors. In 2021 and 2022, such dynamics were influenced primarily by growth in export demand, stable production, lower than average storage inventory balances and seasonal weather demand. Gas production's slow response to rising prices placed continued stress on gas storage replenishment through much of 2022, keeping upward pressure on gas prices into the latter half of 2022.

The chart below reflects the Platts Gas Daily spot Henry Hub natural gas price.



Q. WHAT ACTIONS DOES THE COMPANY TAKE TO MINIMIZE AND MITIGATE THE RISK OF FORCED OUTAGES?

A. In addition to the process described between plant and dispatch personnel, and in addition to planned outages that support reliability as explained by Company Mr. Luke, the Company takes further action to minimize potential forced outages and derates by conducting proactive maintenance outages. As the name implies, if station personnel have a reason to believe a particular piece of equipment is nearing a failure, a maintenance outage is typically scheduled to reduce the likelihood of a forced outage occurring in the future.

Scheduling a maintenance outage typically results in a better outcome than a forced outage for many reasons: (1) the potential for higher LMPs occur during a forced outage due to the randomness of these outages compared to a maintenance outage that is scheduled during typically a period of lower LMP such as over a weekend; (2) waiting for a component to fail typically results in additional damage to the unit, resulting in more costly repairs; (3) a capacity performance event is less likely to occur during a planned maintenance outage since these are again scheduled over lower demand time periods and typically result in a shorter outage duration; and (4) capacity performance charges are not assessed to units on planned or maintenance outages, but are for forced outages. This is because PJM grants permission to take maintenance outages in the first place, therefore, capacity performance events are less likely or expected to occur. Finally, a reduction in a unit's PJM capacity value can occur if the Company waits until a failure due to the additional EFORd impact of a forced outage.

Q. CAN YOU PROVIDE ANY RECENT EXAMPLES REGARDING HOW THE COMPANY'S ACTIONS HAVE REDUCED FORCED OUTAGE AND CAPACITY PERFORMANCE RISKS?

A. One needs to look no further than the December 2022 Winter Storm Elliott event and specifically the PJM Capacity Performance event on December 23rd and 24th, 2022, as an example of the Company's actions in mitigating regarding forced outage and derate performance and the resulting positive benefits to its customers. Although the latest information is that PJM will issue $1,817,695,727 in market-wide Capacity Performance non-performance charges, before interest, Duke Energy Kentucky is expected to be net <u>receiver</u> of Capacity Performance payments of approximately $1,000,000 with only a minimal 1.2 MW additional capacity requirement in its next Fixed Resource Requirement (FRR) plan. Note that in some cases the results are still being calculated by PJM. As a comparison, since Duke Energy Kentucky represents approximately 0.63 percent of all generation capacity in PJM (1,164 MW combined Winter installed capacity vs. PJM total installed capacity of 183,385 MW on 12-31-

2022)[2] and using the $1,817,695,727 in market-wide Capacity Performance penalties, on average one would have expected a charge to Duke Energy Kentucky of approximately $11M, not a net positive payment to the Company as is expected.

Q. DO YOU AGREE WITH MR. KOLLEN'S STATEMENT THAT THE COMPANY DOES NOT HAVE ANY INCENTIVE TO MINIMIZE FORCED OUTAGES?

A. No. It's in the Company's best interests to minimize forced outages for the following reasons. The Company has a financial incentive to increase unit availability through the PSM sharing mechanism where it shares 90 percent of off-system margins with customers and conversely keeps 10 percent of off-system margins. Finally, it should be noted especially after Winter Storm Elliott that perhaps the largest example of risk related to forced outages/derates is from PJM capacity performance penalties and to the extent that these occur, assessments are recovered in the PSM where the Company similarly bears 10 percent of this exposure, creating a financial incentive to reduce forced outages and derates as possible.

[2] *Id.* Pg. 301 of the PJM State of the Market Report.

Q. WHAT IS YOUR RECOMMENDATION AS IT RELATES TO MR. KOLLEN'S PROPOSAL TO DENY THE COMPANY'S REQUEST TO RECOVER ITS DEFERRED INCREMENTAL FORCED OUTAGE EXPENSES?

A. I recommend rejecting Mr. Kollen's proposal for the reasons I've identified. As I explained above, the Company acts prudently in managing its generation portfolio to mitigate the risk of forced outages. The increased costs in forced outage expense is due primarily to the volatility in the PJM markets and not due to any action or inaction on behalf of the Company.

III. CONCLUSION

Q. DOES THIS CONCLUDE YOUR REBUTTAL TESTIMONY?

A. Yes.

VERIFICATION

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

The undersigned, John Swez, Managing Director Trading & Dispatch, 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 Swez Affiant

Subscribed and sworn to before me by John Swez on this 13th day of April, 2023.

AMY E. LINZEY NOTARY PUBLIC MECKLENBURG COUNTY, N.C.

NOTARY PUBLIC

My Commission Expires: 11-16-27

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 New Tariffs; 3) Approval of Accounting Practices to Establish Regulatory Assets and Liabilities; and 4) All Other Required Approvals and Relief.	)))))))	Case No. 2022-00372

REBUTTAL TESTIMONY OF

JOSHUA C. NOWAK

ON BEHALF OF

DUKE ENERGY KENTUCKY, INC.

April 14, 2023

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ATTACHMENTS:

I. INTRODUCTION

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

A. My name is Joshua C. Nowak. I am employed by Concentric Energy Advisors, Inc. (Concentric) as a Vice President. My business address is 293 Boston Post Road West, Suite 500, Marlborough, Massachusetts 01752.

Q. DID YOU PREVIOUSLY FILE TESTIMONY IN THIS PROCEEDING?

A. Yes. I submitted Direct Testimony on behalf of Duke Energy Kentucky, Inc. (Duke Energy Kentucky or the Company) on December 1, 2022.

Q. ARE YOU SPONSORING ANY REBUTTAL ATTACHMENTS IN THIS PROCEEDING?

A. Yes. My analyses and recommendations are supported by the data presented in Rebuttal Attachments JCN-R1 through JCN-R6, which have been prepared by me or under my direction. I sponsor the following Attachments:

- JCN-R1 – Comprehensive Summary of ROE Results
- JCN-R2 – Constant Growth Discounted Cash Flow (DCF) Analysis
- JCN-R3 – Market Risk Premium (MRP)
- JCN-R4 – Capital Asset Pricing Model (CAPM) Analysis
- JCN-R5 – Bond Yield Plus Risk Premium Analysis
- JCN-R6 – Expected Earnings Analysis

Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY?

A. The purpose of this Rebuttal Testimony is to respond to the Direct Testimony of Mr. Richard A. Baudino on behalf of Office of the Attorney General of the

Commonwealth of Kentucky (OAG) and the Direct Testimony of Mr. Steve W. Chriss on behalf of Walmart Inc. (Walmart) as it relates to the appropriate return on equity (ROE) or "cost of equity" and capital structure for Duke Energy Kentucky. In response to Mr. Baudino's analysis incorporating market data through February 2023, I have updated my cost of capital analysis, incorporating changes in market data and forecasts through the end of March 2023.

Q. HOW IS THE REMAINDER OF YOUR REBUTTAL TESTIMONY ORGANIZED?

A. The remainder of this Rebuttal Testimony is organized as follows. Section II provides a summary of my testimony and the analytical results of Mr. Baudino's recommendations. Section III presents the results of my updated ROE analyses based on market data through March 31, 2023. Section IV discusses economic and capital market conditions and how those conditions are affecting the various models used to estimate the cost of equity for Duke Energy Kentucky. In Section V, I respond to Mr. Baudino's testimony and discuss the proper application of the various cost of capital models and the appropriate inputs to the ROE analyses. Section VI contains my response to Mr. Chriss. Section VII summarizes my key conclusions and recommendations.[1]

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[1] The fact that I may not have responded to any particular argument or statement made by Mr. Baudino or Mr. Chriss does not indicate my agreement with that argument or statement.

II. <u>EXECUTIVE SUMMARY</u>

Q. WHAT ARE YOUR KEY CONCLUSIONS REGARDING MR. BAUDINO'S RECOMMENDATIONS ON DUKE ENERGY KENTUCKY'S COST OF CAPITAL?

A. My key conclusions are as follows:

(1) Mr. Baudino's analysis contains flaws and inconsistencies that produce results that are below the average authorized ROEs over vertically integrated electric utilities since 2022.

(2) While Mr. Baudino's ROE recommendation is unreasonably low and below the average ROEs authorized for other vertically integrated electric utilities, he fails to demonstrate that Duke Energy Kentucky's risk profile is lower than the average utility to support a departure from the returns available to other utilities.

(3) The cost of equity for regulated utility companies is affected by several key factors in the current and prospective capital markets, including the interest rate environment and central bank monetary policy, as well as current inflationary pressure and the longer-term outlook for inflation. Inflation has escalated to levels not seen since the early 1980s, interest rates across the yield spectrum have increased, and capital market volatility is at an elevated state. These circumstances also reinforce the importance of considering the results of multiple models, as I have with the CAPM, DCF, Risk Premium, and Expected Earnings approaches. Mr. Baudino effectively disregards the results of his CAPM analysis and relies exclusively on his DCF analysis in determining the range of reasonableness. Given the recent changes in

financial markets, and the fact that the CAPM directly accounts for changes in interest rates (i.e., risk-free rate) and the relative performance of utilities relative to the broader equity market (i.e., Beta), it is necessary to give weight to an appropriately specified CAPM in determining the ROE for the Company.

(4) Based on my updated DCF, CAPM, Risk Premium, and Expected Earnings analyses and considering the Company's risk profile, I continue to recommend an ROE of 10.35 percent. In addition, I support Duke Energy Kentucky's updated financial capital structure of 52.145 percent common equity, 44.075 percent long-term debt, and 3.780 percent short-term debt as reasonable.

Q. PLEASE SUMMARIZE MR. BAUDINO'S COST OF CAPITAL RECOMMENDATION.

A. Mr. Baudino recommends an ROE of 9.55 percent based on a range of analytical results from 8.30 percent to 12.48 percent. Mr. Baudino's range of reasonableness coincides with the average of his two DCF methodologies – 9.48 percent to 9.58 percent, and acknowledges his recommended ROE of 9.55 percent it "near the midpoint of the range."[2] Mr. Baudino's proposed capital structure includes 50.00

[2] Direct Testimony of Richard A. Baudino, at 30.

percent common equity, 43.713 percent long-term debt, and 6.287 percent short-term debt.[3]

Q. PLEASE DESCRIBE THE LEGAL STANDARDS THAT MUST BE MET TO ESTABLISH THE AUTHORIZED ROE FOR A REGULATED PUBLIC UTILITY SUCH AS DUKE ENERGY KENTUCKY.

A. As discussed in my Direct Testimony, the standards for a just and reasonable return established by the United States Supreme Court in the *Hope* and *Bluefield* cases are:

(1) Financial Integrity: the return must be adequate to ensure the company's financial soundness and support credit quality;

(2) Capital Attraction: the return must be sufficient to enable the company to attract capital on reasonable terms and conditions; and

(3) Comparable Return: the return must be comparable to those available to investors in firms with commensurate risk.

Q. MR. CHRISS REFERS TO AUTHORIZED ROES IN OTHER JURISDICTIONS. DO YOU AGREE WITH HIS REPRESENTATION OF AUTHORIZED ROES AND ITS RELEVANCE TO DUKE ENERGY KENTUCKY'S COST OF EQUITY?

A. No, I do not. National average returns must be placed in the proper context in order to be useful. First, market conditions at the time the authorized returns were established are different from conditions going forward. For example, equity

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[3] *Id.*, at 32.

returns set when interest rates were lower in 2020 and 2021 are not a reasonable basis of comparison for evaluating the authorized ROE for Duke Energy Kentucky when bond yields have increased and are projected to continue to increase as the Federal Reserve continues its tighter monetary policy. After the decline in interest rates in 2020-2021 driven by the Federal Reserve's unprecedented actions to respond to the COVID-19 pandemic, interest rates have now increased by 186 to 256 basis points since Duke Energy Kentucky's last ROE authorization of 9.25 percent in April 2020.[4]

Although state utility commissions mitigated ROE reductions in 2020-2021 due to the knowledge that interest rates were being artificially suppressed due to the Federal Reserve's actions,[5] the use of prior decisions during that time period

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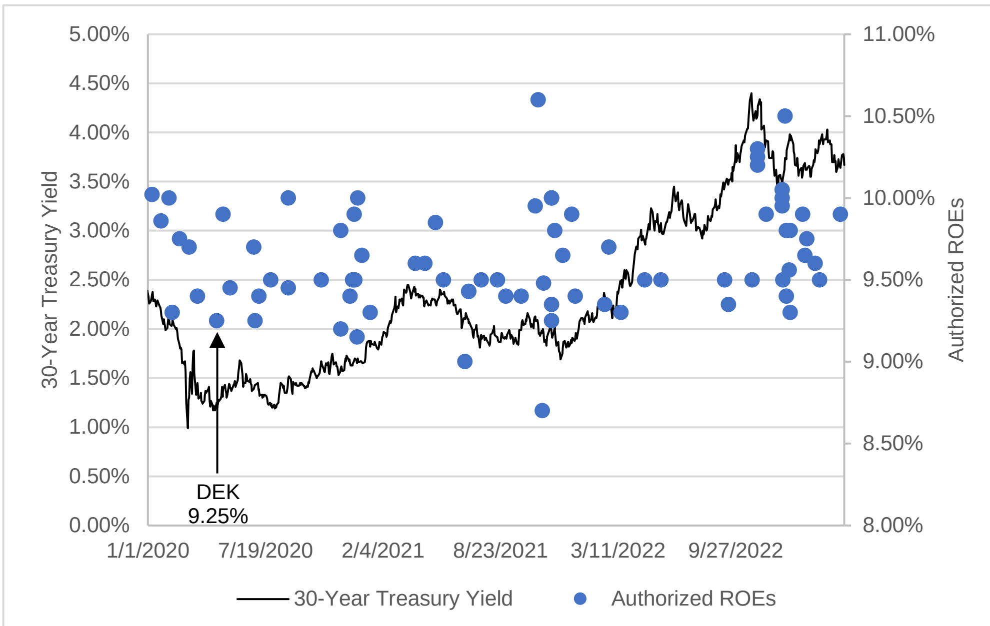
[4] The 30-year Treasury bond yield was 1.95 percent when Duke Energy Kentucky filed its case on September 3, 2019, and 1.25 percent when the final order was issued on April 27, 2020. The 30-day average 30-year Treasury bond yield was 3.81 percent on March 31, 2023.

[5] S&P, The Big Picture: 2022 Electric, Natural Gas and Water Utilities Outlook (Oct 2021) at 5 (finding that the spread between authorized ROE and interest rates increased because state utility commissions "recognized that long-term bond yields have been artificially suppressed due to the Fed[eral] Reserve's unprecedent intervention in the capital markets."; *see also* RRA, Major Energy Rate Case Decisions in the US—January-June 2022 (July 27, 2022) at 6 ("the gap between authorized ROEs and interest rates widened somewhat over this period, largely as a result of regulators' often-unstated understanding that the drop in interest rates caused by Federal Reserve intervention was unusual.").

which set ROEs under previously lower levels understates the forward-looking cost of equity and rising interest rate environment that we are now experiencing.[6]

Figure 1: Authorized ROEs for Vertically Integrated Electric Utilities and Interest Rates[7]



Q. HOW DOES MR. BAUDINO'S RECOMMENEDED ROE COMPARE TO RECENTLY AUTHORIZED ROES?

A. Mr. Baudino's recommended ROE is below the average authorized ROE for vertically integrated electric utilities each year since 2020 despite the fact that interest rates reached record lows in 2020 and 2021. =To support such a departure from the returns available to other vertically integrated electric utilities, Mr.

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[6] RRA, Major Energy Rate Case Decisions in the US—January-June 2022 (July 27, 2022) at 7 (with interest rates on the rise "the average authorized returns for full year 2022 and 2023 may edge higher"); *accord id.* at 4 ("Authorized returns may edge slightly higher going forward as the U.S. Federal Reserve continues efforts to tamp down soaring inflation via a series of interest rate hikes, the first of which was announced in March").

[7] Sources: S&P Capital IQ Pro, Regulatory Research Associates and Bloomberg Professional. Excludes rate cases for formula-rate plans.

Baudino would have to demonstrate that Duke Energy Kentucky's risk profile is meaningfully lower than the average utility. However, Mr. Baudino has not demonstrated that Duke Energy Kentucky's risk profile is lower than the average vertically integrated electric utility. As discussed in my Direct Testimony, there is no basis to conclude that Duke Energy Kentucky is less risky than its peers.[8] In fact, the Company's generation portfolio suggests a higher level of risk as compared to other vertically integrated electric utilities.[9] Given the recent increase in interest rates and the fact that Duke Energy Kentucky's risk profile is, if anything, somewhat higher than the average vertically integrated utility, there is no basis to conclude that the Company's cost of equity is lower than the national average authorized ROE as Mr. Baudino's recommendation suggests.

III. UPDATED ROE ANALYSES

Q. PLEASE DESCRIBE THE DATE APPLIED IN DR. MR. BAUDINO'S ROE ANALYSES AND YOUR UPDATED ROE ANALYSES.

A. In my Direct Testimony, filed in December 2022, I used market data updated through October 31, 2022. Mr. Baudino has relied on market data updated through February 2023. To put our analyses on more comparable bases, I have updated the results of the financial models used to estimate the cost of equity for Duke Energy Kentucky in my Direct Testimony to include market data through March 31, 2023. I have used the same proxy group and my updated analyses contain the same fourteen companies Mr. Baudino relied upon in his ROE analyses. The results of

[8] Direct Testimony of Joshua C. Nowak, at 46-47.
[9] *Id.*, at 45-46.

my updated analyses are shown in Figure 2 and Rebuttal Attachments JCN-R1 through JCN-R6.

Figure 2: Summary of Results

	Average	**Median**
Primary Analyses		
DCF Result	9.92%	9.59%
CAPM Result[10]	10.86%	10.79%
Risk Premium	10.29%	10.29%
Average	**10.36%**	**10.22%**
Other Benchmark Analyses		
Expected Earnings	11.61%	11.31%

IV. ECONOMIC AND CAPITAL MARKET CONDITIONS

Q. HAVE THE ECONOMIC AND FINANCIAL MARKET CONDITIONS CHANGED OVER THE PAST MONTHS SINCE YOU SUBMITTED YOUR DIRECT TESTIMONY?

A. Yes, since December 2022 several changes have occurred, some of which were signaled earlier, and others emerging. It is important to consider current and expected conditions in the general economy and financial markets because the authorized ROE for a public utility should allow the utility to attract investor capital at a reasonable cost under a variety of economic and financial market conditions.

[10] Consistent with the approach in my Direct Testimony, this result is derived by applying the more conservative FERC approach to the MRP, including only a subset of S&P 500 companies with growth rates that are between 0 percent and 20 percent.

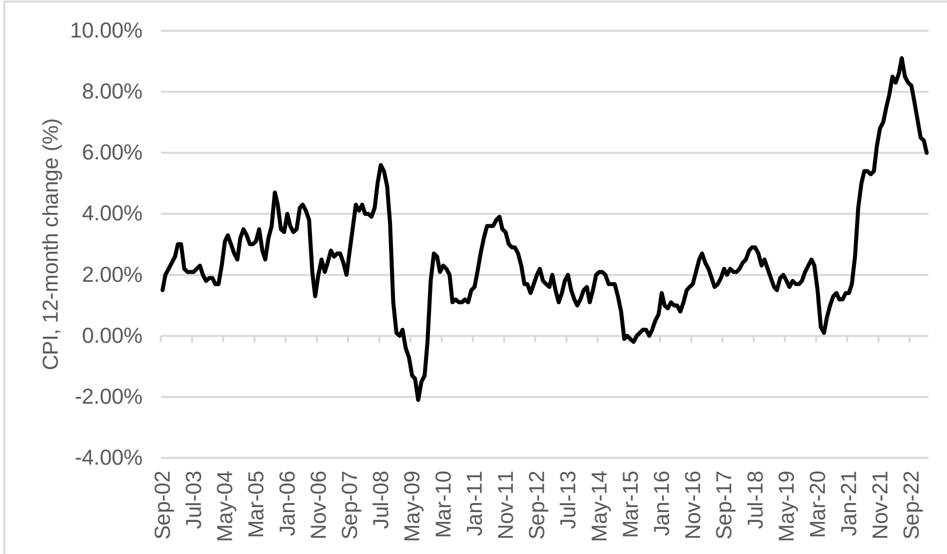
Q. WHAT CHANGES HAVE OCCURRED IN RECENT MONTHS?

A. There are three primary changes: (1) inflation has moderated but continues to persist at levels above the Federal Reserve's target; (2) interest rates have moderated since late 2022 but remain higher than levels not seen since 2014; and (3) equity market volatility remains above its historical average.

Q. PLEASE DESCRIBE THE RECENT CHANGES IN INFLATION.

A. As illustrated in Figure 3, inflation spiked in June 2022 at 9.2 percent. Even though the Consumer Price Index receded to 6.0 percent in February 2023, this level remains well above the Federal Reserve's target inflation threshold of around 2.0 percent which has been in place since the mid-1990s. The relationship between recession and lower inflation rates, also reflected in the chart, pinpoints the delicate balancing act the Federal Reserve faces as it raises interest rates to rein in inflation. By deliberately slowing economic growth with higher interest rates, inflation will ease, but with a risk of recession.

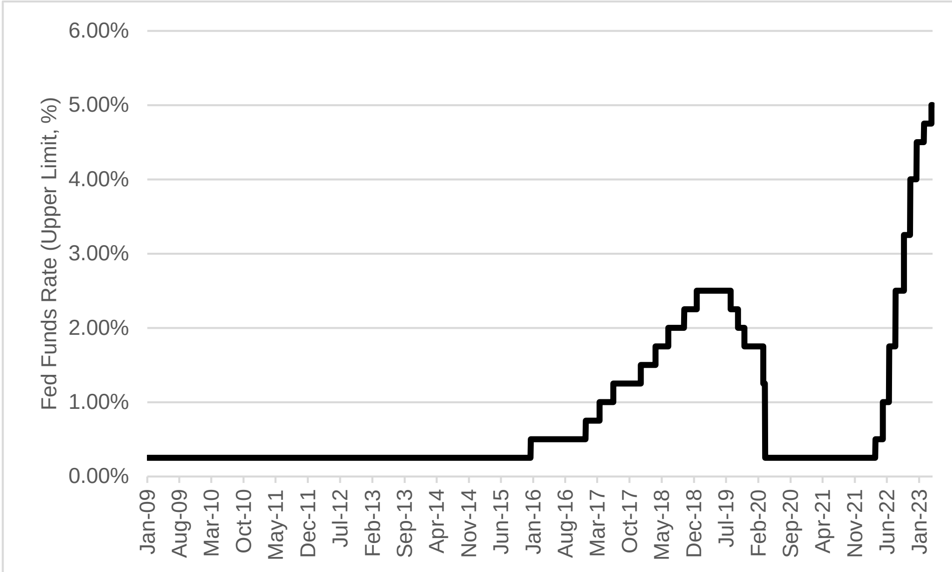
Figure 3: Consumer Price Index, 12-month Percentage Change[11]



As a result of these substantially higher inflation rates, the Federal Reserve has been left little choice but to pull back on its COVID-related monetary policies and apply tighter monetary policy with higher interest rates. In 2022, the Federal Reserve increased the target rate seven times, and in 2023 another two times, as illustrated in Figure 4.

[11] Bureau of Labor Statistics, 12-Month Percentage Change, Consumer Price Index, Selected Categories, https://www.bls.gov/charts/consumer-price-index/consumer-price-index-by-category-line-chart.htm, (not seasonally adjusted).

Figure 4: Federal Funds Rate, Target Range, Upper Limit[12]



This demonstrates the level of Federal Reserve action necessary to reel in inflation. The Federal Reserve is willing to risk substantially higher interest rates and a slowdown in the economy, and it is clear that the era of record low interest rates and moderate inflation has closed. In addition, the Federal Reserve is executing its plan to reduce the size of its balance sheet by selling $95 billion in bonds each month, which will further tighten financial markets. In its most recent policy statement, the Federal Reserve confirmed its commitment to a 2 percent inflation target, stating:

[12] Source: Federal Reserve Bank of St. Louis, FRED Economic Data, https://fred.stlouisfed.org/series/DFEDTARU .

> The [Federal Open Market] Committee will closely monitor incoming information and assess the implications for monetary policy. The Committee anticipates that some additional policy firming may be appropriate in order to attain a stance of monetary policy that is sufficiently restrictive to return inflation to 2 percent over time. In determining the extent of future increases in the target range, the Committee will take into account the cumulative tightening of monetary policy, the lags with which monetary policy affects economic activity and inflation, and economic and financial developments. In addition, the Committee will continue reducing its holdings of Treasury securities and agency debt and agency mortgage-backed securities, as described in its previously announced plans. The Committee is strongly committed to returning inflation to its 2 percent objective.[13]

This is significant because the costs of all forms of capital are impacted by the Federal Reserve's actions, even though it only sets the short-term rate for federal funds. Long-term interest rates have similarly increased as the Fed has increased its policy rate. The 30-day average yield on 30-year Treasury bonds has increased by nearly two percentage points, from 1.87 percent as of December 31, 2021, to 3.81 percent as of March 31, 2023. Higher government bond yields place pressure on the valuations of utility companies, many of which have declined substantially since late August 2022. As the share prices of the companies in my utility proxy group decline, the dividend yields used in the DCF analysis for these companies increase.

Q. HAVE YOU FACTORED THESE CIRCUMSTANCES INTO YOUR UPDATED COST OF EQUITY ESTIMATES FOR DUKE ENERGY KENTUCKY, AND, IF SO, WHAT CONCLUSIONS DO YOU DRAW?

A. Yes. I have relied on the most recent market data and forecasts available to me in my updated analysis. Long-term interest rates have increased substantially since the

[13] Press Release, Federal Reserve Board, FOMC statement, (Mar. 22, 2023).

historical lows of 2020 and are expected to continue to remain above pre-COVID-19 levels. This supports the use of both current and forecast bond yields in the CAPM. In addition, these circumstances also reinforce the importance of considering the results of multiple models, as I have with the CAPM, DCF Risk Premium, and Expected Earnings approaches. My updated results have not, however, changed materially since I prepared my Direct Testimony, and I do not change my recommendation.

V. RESPONSE TO MR. BAUDINO'S RECOMMENDATIONS

Q. PLEASE SUMMARIZE MR. BAUDINO'S COST OF CAPITAL RECOMMENDATIONS.

A. Mr. Baudino recommends an authorized ROE for the Company of 9.55 percent based primarily on the approximate average results of his Constant Growth DCF analyses for a proxy group of fourteen vertically-integrated electric utility companies (the same proxy group I use in my analyses), but also observes his recommendation is consistent with his CAPM that produces estimates of 8.30 percent and 10.02 percent when excluding his CAPM of 12.48 percent based on a forward-looking market return.[14] As to the capital structure, Mr. Baudino recommends a capital structure consisting of 50.00 percent common equity, 43.713 percent long-term debt, and 6.287 percent short-term debt.[15]

[14] Direct Testimony of Richard A. Baudino, at 3, 28-30.
[15] *Id.*, at 30-31.

Q. WHAT ARE THE PRINCIPAL DIFFERENCES BETWEEN YOUR ANALYSIS AND MR. BAUDINO'S?

The principal differences are: (1) Mr. Baudino's exclusive reliance on the DCF model in developing his range of reasonableness, (2) Mr. Baudino's application of dividend growth rates in his DCF model, (3) the inputs and assumptions used in the CAPM analysis, (4) the relevance of the Bond Yield Plus Risk Premium analysis, (5) the relevance of the Expected Earnings analysis, and (6) the capital structure recommendation. I discuss each of these issues in my Rebuttal Testimony.

Approaches Used to Estimate the Cost of Equity

Q. PLEASE EXPLAIN THE IMPORTANCE OF USING MULTIPLE MODELS IN ESTIMATING THE COST OF EQUITY?

A. The determination of the cost of equity is not an exact science and no one model precisely quantifies the investor required return in all market environments. When faced with the task of estimating the cost of equity, it is imperative to gather and evaluate as much relevant data (both quantitative and qualitative) as can be reasonably obtained. As such, it is essential to consider multiple approaches. Mr. Baudino points to "increased volatility, higher bond yields, and uncertainty inherent in financial markets at this time,"[16] but he fails to consider how such conditions may affect the DCF model as compared to alternative approaches. Recent equity market volatility, historic levels of inflation, and significant increase in interest

[16] *Id.*, at 30.

rates, reinforce the importance of considering multiple models when estimating the cost of equity.

Q. DID MR. BAUDINO CONSIDER ANY ALTERNATIVE ANALYSES BEYOND THE DCF APPROACH?

While Mr. Baudino presented a CAPM analysis, he merely observes that his recommended ROE falls within the range of his CAPM results.[17] However, Mr. Baudino's CAPM results produce a broad range, from 8.30 percent to 12.48 percent. Mr. Baudino did not present a Risk Premium analysis, Expected Earnings analysis, or any other approaches apart from the DCF and CAPM. As such, Mr. Baudino's range is ultimately based on results from a single model – the DCF. Given the volatility and higher bond yields that Mr. Baudino acknowledges in the current financial markets, and the fact that other models, such as the CAPM, directly account for changes in bond yields (i.e., risk-free rate) and the relative volatility of utilities (i.e., Beta), the CAPM and other models are an important consideration in determining the ROE for Duke Energy Kentucky.

Application of the DCF Model

Q. PLEASE SUMMARIZE MR. BAUDINO'S APPLICATION OF THE DCF MODEL.

A. Mr. Baudino develops eight DCF-based ROE estimates ranging from 8.89 percent to 10.51 percent. He calculates the dividend yield using the current annualized dividend divided by a six-month average stock price for each of the proxy

[17] *Ibid.*

companies.[18] His proxy group average dividend yield is 3.56 percent. For the growth rate component, Mr. Baudino reviews the projected dividend growth rate from Value Line, and projected earnings growth rates from Value Line, Yahoo! Finance, and Zacks for each of the proxy companies. For his "Method 1", Mr. Baudino uses the proxy group average of each of the four growth rates, while he uses the proxy group median growth rate for his "Method 2".[19]

Q. ARE THERE AREAS OF THE DCF ANALYSIS WITH WHICH YOU AND MR. BAUDINO AGREE?

A. Yes. Mr. Baudino and I both agree that analysts' growth rate projections are the most appropriate proxy for expected growth in the DCF model.[20] Additionally, Mr. Baudino and I both rely on growth rates from Value Line, Yahoo! Finance, and Zacks. Lastly, we both calculate the expected dividend yield by applying one half of the expected growth rate to the current dividend yield.[21] However, I disagree with Mr. Baudino's reliance on Value Line's projected dividend growth rate.

Q. DO YOU AGREE WITH MR. BAUDINO THAT YOU SHOULD HAVE CONSIDERED VALUE LINE'S DIVIDEND GROWTH RATE PROJECTION IN YOUR DCF ANALYSIS?[22]

A. No, I do not. As explained in my Direct Testimony, projected earnings growth is superior to other growth rate estimates. First, growth in dividends occurs primarily

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[18] *Id.*, at 16.

[19] Direct Testimony of Richard A. Baudino, at 18-19; Exhibit RAB-3.

[20] Direct Testimony of Richard A. Baudino, at 17-18; Direct Testimony of Joshua C. Nowak, at 32.

[21] Direct Testimony of Richard A. Baudino, at 18-19; Direct Testimony of Joshua C. Nowak, at 31.

[22] Direct Testimony of Richard A Baudino, at 34-35.

as a result of growth in earnings.[23] Further, several academic studies indicate that investors base their investment decisions on analysts' expectations of growth in earnings.[24] Lastly there are no sources of which I am aware that publish consensus estimates of projected dividend growth; Value Line's estimates are not considered to reflect a consensus of a variety of analysts' projections, as Yahoo! and Zacks are. If there were a demand for consensus dividend growth projections from the financial community, there would likely be several widely available sources publishing dividend growth rate projections. Because that is not the case, it supports the position that earnings growth is the most meaningful measure of growth among the investment community.[25]

Application of the CAPM

Q. PLEASE SUMMARIZE MR. BAUDINO'S CAPM ANALYSIS AND RESULTS.

A. Mr. Baudino's CAPM results apply a risk-free rate of 3.79 percent based on the most recent "normalized" risk-free rate from Kroll (formerly Duff & Phelps), Value Line betas for the companies in his proxy group (average of 0.88), and several estimates of the market risk premium (MRP) ranging from 5.14 percent to 9.89 percent.[26] Using these assumptions and inputs, Mr. Baudino derives CAPM results ranging from 8.30 percent to 12.48 percent.[27] However, Mr. Baudino asserts that

[23] Direct Testimony of Joshua C. Nowak, at 32.

[24] *Id.*, at 33.

[25] *Ibid.*.

[26] Exhibit RAB-4.

[27] Direct Testimony of Richard A. Baudino, at 29; Exhibit RAB-4.

his forward-looking CAPM ROE of 12.48 percent is “implausibly high” and recommends the Commission ignore that result, and instead consider his CAPM estimates ranging from 8.30 percent to 10.02 percent.[28]

Q. DO YOU HAVE ANY HIGH-LEVEL PERSPECTIVES ON MR. BAUDINO’S CAPM ANALYSES?

A. Yes, I do. While he suggests the Commission disregard his forward-looking CAPM estimate of 12.48 percent as being “implausibly high”, Mr. Baudino does not appear to consider whether any of his estimates are “implausibly low”. If Mr. Baudino believes his estimates should be assessed for reasonableness on the high side, he should also acknowledge where his results are unreasonably low. In particular, Mr. Baudino’s CAPM estimates as low as 8.30 percent are well below returns recently authorized for vertically-integrated electric utilities.

Q. WHAT MRP ESTIMATES DOES MR. BAUDINO USE IN HIS CAPM ANALYSIS?

A. Mr. Baudino applies five estimates of the market risk premiums in his CAPM analysis: (1) a forward-looking “ex-ante” market risk premium, (2) a historical market risk premium derived by an arithmetic average of returns, (3) a historical risk premium based on a Kroll’s study that removes the effects of growth in the Price/Earnings (P/E) ratio from the historical risk premium, (4) Kroll’s current “recommended” MRP of 6.00 percent, and (5) the average (5.14 percent) of Dr.

[28] Direct Testimony of Richard A. Baudino, 30.

Damodaran's February 2023 range of implied equity premium estimates of 4.50 percent to 5.14 percent.

Q. ARE THERE ANY INCONSISTENCIES WITH MR. BAUDINO'S MRP ESTIMATES AND OTHER ASSUMPTIONS IN HIS ROE ANALYSES?

A. Yes, there are. Mr. Baudino argues that it is appropriate to consider the "supply side" MRP based on the expectation that recent high P/E ratios are not expected to continue indefinitely,[29] he does not consider how a "normalization" of P/E ratios would affect his DCF analysis. A decline in P/E ratios would increase the dividend yield component of the DCF model, thus suggesting that his DCF results (and mine for that matter) are understated.

Q. WHAT IS YOUR RESPONSE TO MR. BAUDINO'S POSITION THAT YOUR FORWARD-LOOKING MARKET RISK PREMIUM IS OVERSTATED?[30]

A. I disagree. The S&P 500 is a widely referenced measure of market returns representative of the broader diversified equity market and is appropriate for the determination of investor expectations for equity returns. More importantly, for consistency, the market index employed should closely correspond to the market index used to derive beta, which is either the NYSE index in the case of Value Line or S&P 500 index in the case of Bloomberg.[31] Additionally, my forward-looking market return estimate is highly consistent with actual returns over the last 96 years. As shown in Figure 5 below, since 1926, a forward-looking market return estimate

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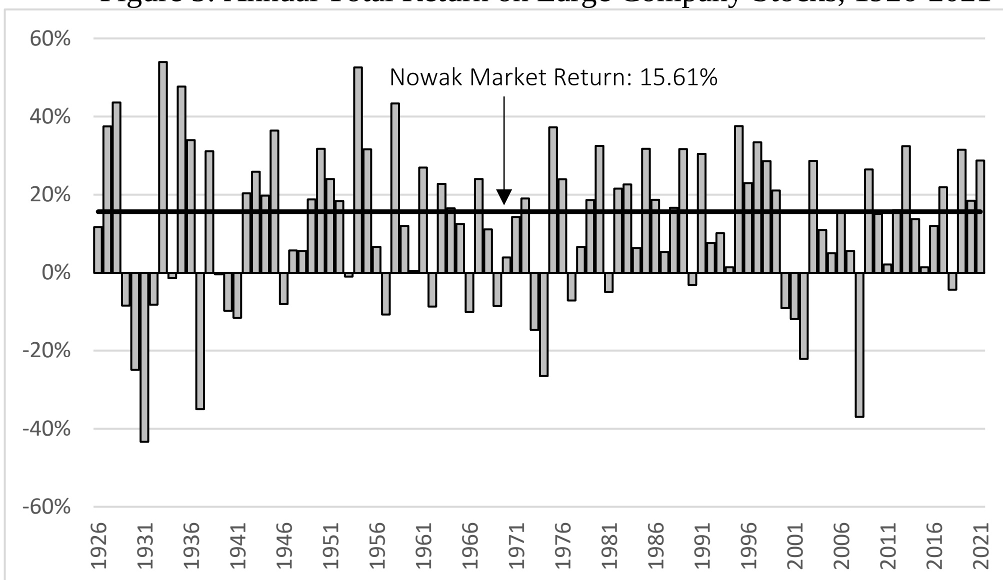
[29] *Id.*, at 24-25.

[30] *Id.*, at 36-38.

[31] Roger A. Morin, PhD., *New Regulatory Finance*, Public Utilities Reports, Inc. (2006) at 159-160.

of 15.61 percent, or higher, has occurred quite frequently. In fact, a market return of at least 15.61 percent has occurred in 47 of the last 96 years, or nearly half the time. From that perspective, my “ex ante” market return is not overstated.

Figure 5: Annual Total Return on Large Company Stocks, 1926-2021[32]



Q. MR. BAUDINO ALSO ASSERTS YOUR FORWARD-LOOKING MARKET RETURN IS OVERSTATED BECAUSE IT IS BASED ON GROWTH RATES THAT EXCEED THE LONG-TERM HISTORICAL RATE OF CAPITAL APPRECIATION AND HISTORICAL AND PROJECTED GDP GROWTH RATES. WHAT IS YOUR RESPONSE?

A. I disagree. In Opinion No. 531-B, the FERC specifically endorsed the method I have used to calculate the forward-looking market risk premium (i.e., applying a Constant Growth DCF analysis to the S&P 500). Regarding whether using a single-

[32] Source: Kroll, <u>2022 SBBI Yearbook</u>, at Appendix A-1.

stage DCF analysis of the S&P 500 to calculate the market risk premium for the CAPM analysis produces sustainable results, the FERC found:

> The rationale for incorporating a long-term growth rate estimate in conducting a two-step DCF analysis of a specific group of utilities does not necessarily apply when conducting a DCF study of the companies in the S&P 500. That is because the S&P 500 is regularly updated to include only companies with high market capitalization. While an individual company cannot be expected to sustain high short-term growth rates in perpetuity, the same cannot be said for a stock index like the S&P 500 that is regularly updated to contain only companies with high market capitalization, and the record in this proceeding does not indicate that the growth rate of the S&P 500 stock index is unsustainable.[33]

The use of the S&P 500 is the accepted basis for calculating a forward-looking market risk premium by the FERC as it has continued to rely on the same methodology in its subsequent Opinions including Opinion Nos. 569 and 569-A. Dr. Morin, the author of the often-cited regulatory treatise, *New Regulatory Finance*, explains the derivation of the projected market risk premium as follows:

> A second approach to estimate the MRP is prospective in nature and consists of applying the DCF model to a representative market index, such as the Standard & Poor's 500 Index, Value Line Composite Index, or the New York Stock Exchange Index.[34]

Q. HAVE OTHER REGULATORS ACCEPTED THE APPROACH OF DERIVING THE MARKET RISK PREMIUM FROM THE ESTIMATED FORWARD-LOOKING MARKET RETURN?

A. Yes. In New York, the Commission Staff relies on a similar approach that derives the market risk premium by subtracting the risk-free rate from Merrill Lynch's two forward-looking returns on the market, a required return and an implied return. The

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[33] Federal Energy Regulatory Commission, Opinion No. 531-B, March 3, 2015, at paragraph 113.

[34] Roger A. Morin, PhD., *New Regulatory Finance*, Public Utilities Reports, Inc. (2006) at 159.

Commission has consistently applied and implemented that risk premium methodology since 1996. In a 2016 rate case decision for Corning Natural Gas, Commission Staff justified its approach for using a forward-looking MRP by stating:

> …the application of the historical market risk premium method is problematic because ex-post MRPs are based on the faulty premise that past performance is a valid proxy for expectations regarding future results. In addition, the historical approach is highly sensitive to the actual time period selected to calculate the premium. [35]

The Commission went on to affirm its preference for relying on forward-looking MRP analyses as opposed to ex-post analyses, where it stated that its approach goes back to Case 95-G-1034, where the Commission stated "…the Judge's market return calculation based on Merrill Lynch data is a reasonable method of deriving a risk premium; and it avoids the problem of stale data in the Ibbotson estimate."[36]

Relevance of Bond Yield Plus Risk Premium Analysis

Q. HAS MR. BAUDINO PRESENTED A BOND YIELD PLUS RISK PREMIUM ANALYSIS?

A. No, he has not. According to Mr. Baudino, the Bond Yield Plus Risk Premium approach is imprecise and can only provide very general guidance on the current authorized ROE for a regulated utility. He states that risk premiums can change substantially over time, and that this approach is a "blunt instrument" for estimating the ROE in regulatory proceedings. Lastly, he argues that a properly formulated DCF model using current stock prices and growth forecasts is far more reliable and

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[35] New York State Public Service Commission, In the Matter of Corning Natural Gas Corporation Case 16-G-0369 (October 2016) at 68-70.

[36] *Id.*

accurate than the bond yield plus risk premium approach, which relies on a historical risk premium analysis over a certain time period.[37]

Q. DO YOU AGREE WITH MR. BAUDINO'S CONCERNS WITH THE BOND YIELD PLUS RISK PREMIUM APPROACH?

A. No, I do not. As shown in Attachment JCN-R5, my Bond Yield Plus Risk Premium analysis is supported by a regression equation that evaluates the relationship between bond yields and the equity risk premium over time. The regression equation has an adjusted R^2 of 0.83, meaning that the regression equation can be reliably used to predict the equity risk premium at different levels of interest rates. My Bond Yield Plus Risk Premium analysis is designed to do exactly what Mr. Baudino suggests it cannot – that is, use the historical relationship between bond yields and equity risk premia to predict how investors will react to changes in interest rates as a result of monetary policy and economic conditions.

Q. WHY IS IT IMPORTANT FOR THE COMMISSION TO CONSIDER THE RISK PREMIUM RESULTS?

A. It is a widely accepted principle in regulatory finance, that the estimation of a just and reasonable return on equity requires the application of multiple methodologies, such that weaknesses in one methodology might be offset by the strengths of another. No methodology is perfect and when one places exclusive reliance on one methodology, the risk of estimation error increases. Dr. Morin, in *New Regulatory*

[37] Direct Testimony of Richard A. Baudino, at 39-40.

Finance, provides the following explanation for the importance of using multiple methods for estimating the required equity return for a regulated utility.

> [T]here are no specific rules of infallible models for determining a fair rate of return. It is dangerous and inappropriate to rely on only one methodology in determining the cost of equity. The results from only one method are likely to contain a high degree of measurement error. The regulator's hands should not be bound to one methodology of estimating equity costs, nor should the regulator ignore relevant evidence and back itself into a corner. For instance, by relying solely on the DCF model at a time when the fundamental assumptions underlying the DCF model are tenuous, a regulatory body greatly limits its flexibility and increases the risk of authorizing unreasonable rates of return. The same is true for any one specific model.
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> When measuring equity costs, which essentially deals with the measurement of investor expectations, no one single methodology provides a foolproof panacea. Each methodology requires the exercise of considerable judgment on the reasonableness of the assumption underlying the methodology and on the reasonableness of the proxies used to validate the theory. It follows that more than one methodology should be employed in arriving at a judgment on the cost of equity and that these methodologies should be applied across a series of comparable risk companies.[38]

The Bond Yield Plus Risk Premium analysis provides another perspective on investors' required return. As shown in my Bond Yield Plus Risk Premium analysis, there is a well-established inverse relationship between equity risk premiums and prevailing risk-free rates. Equity investors tend to require higher risk premiums during periods of lower interest rates. Thus, the low interest rate environment caused by the Federal Reserve's monetary policy intervention is not a reliable long-term indicator of investment risk or the cost of capital in equity

[38] Roger A. Morin, PhD., New Regulatory Finance, Public Utilities Reports, Inc. (2006) at 26.

markets. Mr. Baudino fails to recognize this inverse relationship between interest rates and the equity risk premium in his analysis.

Q. HAVE OTHER STATE REGULATORY AGENCIES GIVEN WEIGHT TO THE RISK PREMIUM MODEL IN ESTABLISHING THE ALLOWED ROE FOR REGULATED UTILITIES UNDER THEIR JURISDICTION?

A. Yes. I researched the methodologies that other state regulatory agencies have used to establish the authorized ROE for regulated electric and gas utilities. Based on that research, I found seven states that explicitly indicate in the rate case decision that they have given weight to Risk Premium methodologies. These include: Georgia (Atmos Energy); Indiana (Indianapolis Power and Light); Iowa (Interstate Power and Light); Maryland (Baltimore Gas and Electric); Missouri (Kansas City Power and Light); Nevada (Nevada Power); New Hampshire (Liberty Utilities Energy North); and Utah (Questar Gas).

For example, the Indiana Utility Regulatory Commission uses the midpoint of a range derived using several methodologies, including the Risk Premium analysis. The Commission states that "the use of multiple methods is desirable because no single method will produce the most reasonable results under all conditions and circumstances."[39] Similarly, the Maryland Public Service Commission states:

[39] Indiana Utility Regulatory Commission, Docket No. Ca-44576, Indianapolis Power and Light, March 16, 2016, at 41.

> Witnesses for BGE, Staff and OPC provided similar analytical methods for evaluating a just and reasonable ROE for the Company. For example, all the parties employed the DCF analysis and ECAPM methodology. Additionally, BGE used the utility risk premium analysis. Staff used a combination of the CAPM and ECAPM methodology and Build-Up method. OPC used additionally the two-step DCF analysis and risk premium analysis. We find all of these analytical tools helpful and will not rely on anyone to the exclusion of the others in making our decision.[40]

FERC also uses the Risk Premium as one of its three methods for determining ROEs for public utilities.

In summary, the Risk Premium analysis, based on authorized returns for electric and gas utilities spanning three decades of varying capital markets and economic cycles, has been accepted in many states and the FERC and is particularly relevant during periods of irregular capital market conditions, such as the current period. I have observed over time that the Risk Premium approach provides stability to CAPM and DCF results, which can vary widely based on market conditions and user specified assumptions.

Relevance of Expected Earnings Analysis

Q. WHAT IS MR. BAUDINO'S CONCERN REGARDING YOUR EXPECTED EARNINGS ANALYSIS?

A. Mr. Baudino contends that forecasted returns from Value Line are not "as reliable or as accurate as a properly specified DCF analysis using current stock prices."[41] He further contends that my analysis "overstates" the expected return by adjusting

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[40] Maryland Public Service Commission, Docket No. C-9326, Baltimore Gas and Electric Company, December 13, 2013, at 75-76.

[41] Direct Testimony of Richard A. Baudino, at 41.

shares outstanding to reflect the average number of shares during the forecast period, rather than the end of the period.[42]

Q. WHAT IS YOUR RESPONSE TO MR. BAUDINO'S ARGUMENTS?

A. Mr. Baudino provides no evidence to support his position that Value Line's expected returns are not "as reliable or as accurate" as the DCF model. As a practical matter, it is not possible to test the "reliability" or "accuracy" of each model relative to another. As explained in my Direct Testimony, the determination of the cost of equity is not an exact science and no one model precisely quantifies the investor required return in all market environments.[43] Whereas Mr. Baudino suggests that the Expected Earnings approach is inferior to a market-based approach like the DCF model, he fails to appreciate that a book-based approach like the Expected Earnings analysis provides another perspective to the market-based models and is uniquely suited to estimating the expected return for regulated utilities. This is because the standard revenue requirements formula applied by regulatory commissions measures capital structures based on book value, rather than market value, thereby explicitly reinforcing the validity of the book value of equity. In that sense, the Expected Earnings approach provides a direct measure of the book-based return comparable-risk utilities are expected to earn, consistent with the *Hope* and *Bluefield* "comparable return" standard.

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[42] *Id.*, at 41-42.

[43] Direct Testimony of Joshua C. Nowak, at 24-25.

Q. WHAT ABOUT MR. BAUDINO'S ASSERTION THAT YOU HAVE OVERSTATED FORECASTED RETURNS FROM VALUE LINE IN YOUR EXPECTED EARNINGS ANALYSIS?

A. Mr. Baudino's critique is not well founded. Value Line projects shares on a year-end basis. My adjustment is simply to convert the year-end shares to the average shares for the year, in recognition that the shareholder earns a return on the average number of shares during the year. A higher year-end number of shares would diminish the earnings, and therefore needs to be adjusted.

Capital Structure

Q. MR. BAUDINO ARGUES THAT THE COMPANY'S REQUESTED EQUITY RATIO IS UNREASONABLE BASED ON THE COMPANY'S HISTORICAL CAPITALIZATION STRUCTURE.[44] WHAT IS YOUR RESPONSE?

A. Mr. Baudino recommends a common equity ratio of 50.00 percent based on his review of Duke Energy Kentucky's historical capital structure.[45] This recommendation fails to consider that: (1) the Company's requested capital structure is well below the proxy group mean of 53.06 percent; and (2) the change in capital market conditions affecting the Company's financial circumstances. While Mr. Baudino states that the Company's credit ratings remained stable in the historical period he analyzed, [46]he has not provided any analysis demonstrating the

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[44] Direct Testimony of Richard A. Baudino, at 32.

[45] *Ibid*.

[46] *Id.*, at 31-32.

effect of reducing the Duke Energy Kentucky's equity ratio to 50.00 percent on the Company's credit profile.

My capital structure analysis presented in my Direct Testimony Attachment JCN-10 calculates the capital structures used to finance the regulated vertically-integrated electric utility operations of the proxy companies. As shown in Attachment JCN-10 of my Direct Testimony, the Company's requested equity ratio of 52.145 percent is conservative relative to the proxy group three-year average at the operating company level, demonstrating its requested common equity ratio is reasonable and well supported.

Q. IS THE COMPANY'S REQUESTED CAPITAL STRUCTURE CONSISTENT WITH OTHER AUTHORIZATIONS FOR VERTICALLY INTEGRATED ELETRIC ULTILITES?

A. Yes, it is. The average authorized equity ratio for vertically integrated electric utilities since 2022 has been 52.46 percent.[47] Therefore, the Company's requested equity ratio of 52.145 percent is highly consistent with equity ratios for other vertically integrated utilities and with industry standards for companies with commensurate risk. Sufficient equity in the capital structure is an important factor for maintaining Duke Energy Kentucky's financial integrity and investment grade credit rating and it is an essential component of Duke Energy Kentucky's financial policies enabling access to capital on favorable terms in a variety of market circumstances.

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[47] Source: Regulatory Research Associates. Rate cases in Arkansas, Florida, Indiana, and Michigan have been excluded from the analysis since the authorized capital structure approved in the cases includes deferred taxes and other credits as non-investor supplied capital.

VI. RESPONSE TO MR. CHRISS

Q. PLEASE SUMMARIZE MR. CHRISS' TESTIMONY AS IT RELATES TO THE COST OF EQUITY.

A. Mr. Chriss does not conduct an ROE analysis and does not provide a specific ROE recommendation for Duke Energy Kentucky in this proceeding. Rather, Mr. Chriss urges the Commission to consider the impact of the proposed ROE on the Company's revenue requirement and customer rates. In support of his conclusions, Mr. Chriss provides data from Regulatory Research Associates on authorized returns for electric utilities in other jurisdictions from 2019-2023. The comparable return data provided by Mr. Chriss is consistent with data I used to create Figure 1. Mr. Chriss notes that the proposed ROE of 10.35 percent for Duke Energy Kentucky, which is within the range of ROEs authorized nationally, exceeds the ROEs awarded by this Commission since 2019.

Q. WHAT IS YOUR RESPONSE TO MR. CHRISS' TESTIMONY?

A. While I agree with Mr. Chriss that recently authorized ROEs are a useful benchmark that investors use to develop their return requirements, I also believe that current and expected economic and capital market conditions need to be considered to understand investors' required return on a forward-looking basis. As shown in Figure 1, the returns authorized from early-2020 through mid-2022 were determined at a time when interest rates were at historically low levels. This includes Duke Energy Kentucky's currently authorized ROE. Since August 2022 interest rates have increased considerably. Looking forward, the Federal Reserve is considering additional interest rate increases that will place additional upward pressure on the cost of capital. Further, projections suggest that interest rates are expected to remain above pre-COVID-19 levels suggesting that the capital market conditions are considerably different from the majority of the period Mr. Chriss' reviewed in his analysis of authorized returns.

VII. CONCLUSION

Q. WHAT IS YOUR CONCLUSION REGARDING A FAIR ROE FOR DUKE ENERGY KENTUCKY?

A. Based on the quantitative analyses provided in my Rebuttal Testimony, I have established a range of ROE results shown previously in Figure 1 (also see Rebuttal Attachment JCN-R1). The DCF, CAPM, and Bond Yield Risk Premium, analysis produce a range of estimates of the Company's cost of equity of 9.92 percent to 10.86 percent. Based on these analyses, I consider an ROE range of 9.85 percent to 10.85 percent to be reasonable. From within that range, and considering the Company's risk profile, I continue to recommend an ROE of 10.35 percent.

Q. WHAT IS YOUR RECOMMENDATION WITH REGARD TO THE CAPITAL STRUCTURE FOR DUKE ENERGY KENTUCKY IN THIS PROCEEDING?

A. I support Duke Energy Kentucky's actual capital structure of 52.145 percent common equity, 44.075 percent long-term debt, and 3.780 percent short-term debt as reasonable relative to the range of capital structures for the operating companies held by the proxy group companies.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes, it does.

VERIFICATION

COMMONWEALTH OF MASSACHUSETTS)
)
) **SS:**
COUNTY OF MIDDLESEX)

The undersigned, Joshua C. Nowak, 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.

Joshua C. Nowak Affiant

Subscribed and sworn to before me by Joshua Nowak on this 11 day of April, 2023.

NOTARY PUBLIC

My Commission Expires:

REGINA A. KOLB
Notary Public
COMMONWEALTH OF MASSACHUSETTS
My Commission Expires On
November 27, 2026

SUMMARY OF RESULTS

Company	Ticker	*Primary Analyses*															*Benchmark Analysis*	Average of DCF, CAPM, and Risk Premium
		DCF				**CAPM**							**Risk Premium (Average)**					
						Value Line Beta			Bloomberg Beta									
		30-Day Average	90-Day Average	180-Day Average	*Average*	Current Yield	Near-Term Projected Yield	Long-Term Projected Yield	Current Yield	Near-Term Projected Yield	Long-Term Projected Yield	*Average*	Current Yield	Near-Term Projected Yield	Long-Term Projected Yield	*Average*	**Expected Earnings**	
ALLETE, Inc.	ALE	11.85%	11.77%	11.98%	11.86%	11.36%	11.36%	11.37%	10.78%	10.78%	10.80%	11.07%	10.28%	10.26%	10.32%	10.29%	9.18%	11.07%
Alliant Energy Corporation	LNT	9.63%	9.51%	9.41%	9.52%	10.94%	10.94%	10.95%	10.50%	10.50%	10.52%	10.72%	10.28%	10.26%	10.32%	10.29%	12.32%	10.18%
Ameren Corporation	AEE	9.80%	9.71%	9.70%	9.73%	10.94%	10.94%	10.95%	10.22%	10.21%	10.24%	10.58%	10.28%	10.26%	10.32%	10.29%	10.30%	10.20%
American Electric Power Company, Inc.	AEP	9.77%	9.64%	9.60%	9.67%	10.10%	10.09%	10.12%	10.22%	10.21%	10.24%	10.16%	10.28%	10.26%	10.32%	10.29%	11.32%	10.04%
Edison International	EIX	13.22%	13.28%	13.39%	13.29%	11.78%	11.78%	11.78%	10.89%	10.88%	10.90%	11.34%	10.28%	10.26%	10.32%	10.29%	13.44%	11.64%
Entergy Corporation	ETR	8.55%	8.39%	8.34%	8.42%	11.78%	11.78%	11.78%	10.98%	10.98%	10.99%	11.38%	10.28%	10.26%	10.32%	10.29%	9.26%	10.03%
Evergy, Inc.	EVRG	9.34%	9.25%	9.13%	9.24%	11.36%	11.36%	11.37%	10.42%	10.41%	10.44%	10.89%	10.28%	10.26%	10.32%	10.29%	10.14%	10.14%
Hawaiian Electric Industries, Inc.	HE	6.73%	6.56%	6.64%	6.65%	10.94%	10.94%	10.95%	9.81%	9.80%	9.83%	10.38%	10.28%	10.26%	10.32%	10.29%	12.76%	9.10%
IDACORP, Inc.	IDA	6.58%	6.54%	6.54%	6.55%	10.52%	10.51%	10.54%	10.53%	10.53%	10.55%	10.53%	10.28%	10.26%	10.32%	10.29%	9.73%	9.12%
NextEra Energy, Inc.	NEE	12.64%	12.48%	12.43%	12.52%	11.78%	11.78%	11.78%	10.69%	10.68%	10.71%	11.24%	10.28%	10.26%	10.32%	10.29%	15.15%	11.35%
OGE Energy Corp.	OGE	13.13%	12.86%	12.82%	12.93%	12.20%	12.20%	12.20%	11.53%	11.53%	11.54%	11.86%	10.28%	10.26%	10.32%	10.29%	13.12%	11.70%
Portland General Electric Company	POR	8.99%	8.96%	8.93%	8.96%	10.94%	10.94%	10.95%	10.42%	10.42%	10.44%	10.68%	10.28%	10.26%	10.32%	10.29%	9.80%	9.98%
Southern Company	SO	10.17%	10.06%	9.94%	10.05%	11.36%	11.36%	11.37%	10.34%	10.33%	10.36%	10.85%	10.28%	10.26%	10.32%	10.29%	14.76%	10.40%
Xcel Energy Inc.	XEL	9.61%	9.48%	9.45%	9.51%	10.52%	10.51%	10.54%	10.09%	10.09%	10.12%	10.31%	10.28%	10.26%	10.32%	10.29%	11.31%	10.04%
Low		6.58%	6.54%	6.54%	6.55%	10.10%	10.09%	10.12%	9.81%	9.80%	9.83%	10.16%					9.18%	
Median		9.70%	9.57%	9.52%	9.59%	11.15%	11.15%	11.16%	10.46%	10.46%	10.48%	10.79%	10.28%	10.26%	10.32%	10.29%	11.31%	10.22%
Mean		10.00%	9.89%	9.88%	9.92%	11.18%	11.18%	11.19%	10.53%	10.52%	10.55%	10.86%	10.28%	10.26%	10.32%	10.29%	11.61%	10.36%
High		13.22%	13.28%	13.39%	13.29%	12.20%	12.20%	12.20%	11.53%	11.53%	11.54%	11.86%					15.15%	

30-DAY CONSTANT GROWTH DCF

Company	Ticker	[1] Annualized Dividend	[2] Stock Price	[3] Dividend Yield	[4] Expected Dividend Yield	[5] Value Line Earnings Growth	[6] Yahoo! Finance Earnings Growth	[7] Zacks Earnings Growth	[8] Average Growth	[9] Low DCF ROE	[10] Mean DCF ROE	[11] High DCF ROE
ALLETE, Inc.	ALE	$2.71	$62.25	4.35%	4.51%	6.00%	8.70%	7.30%	7.33%	10.48%	11.85%	13.24%
Alliant Energy Corporation	LNT	$1.81	$52.10	3.47%	3.58%	6.50%	5.55%	6.10%	6.05%	9.12%	9.63%	10.09%
Ameren Corporation	AEE	$2.52	$84.06	3.00%	3.10%	6.50%	6.70%	6.90%	6.70%	9.60%	9.80%	10.00%
American Electric Power Company, Inc.	AEP	$3.32	$89.54	3.71%	3.82%	6.00%	5.76%	6.10%	5.95%	9.57%	9.77%	9.92%
Edison International	EIX	$2.95	$67.66	4.36%	4.55%	16.00%	7.00%	3.00%	8.67%	7.43%	13.22%	20.71%
Entergy Corporation	ETR	$4.28	$104.65	4.09%	4.18%	0.50%	6.60%	6.00%	4.37%	4.60%	8.55%	10.82%
Evergy, Inc.	EVRG	$2.45	$59.54	4.11%	4.22%	7.50%	2.67%	5.20%	5.12%	6.84%	9.34%	11.77%
Hawaiian Electric Industries, Inc.	HE	$1.44	$38.81	3.71%	3.77%	4.50%	1.30%	3.10%	2.97%	5.03%	6.73%	8.29%
IDACORP, Inc.	IDA	$3.16	$104.52	3.02%	3.08%	4.50%	3.00%	3.00%	3.50%	6.07%	6.58%	7.59%
NextEra Energy, Inc.	NEE	$1.87	$74.26	2.52%	2.64%	10.00%	11.00%	9.00%	10.00%	11.63%	12.64%	13.66%
OGE Energy Corp.	OGE	$1.66	$36.08	4.59%	4.78%	6.50%	Negative	10.20%	8.35%	11.24%	13.13%	15.02%
Portland General Electric Company	POR	$1.81	$47.64	3.80%	3.90%	5.00%	4.18%	6.10%	5.09%	8.06%	8.99%	10.02%
Southern Company	SO	$2.72	$66.16	4.11%	4.23%	6.50%	7.30%	4.00%	5.93%	8.19%	10.17%	11.56%
Xcel Energy Inc.	XEL	$2.08	$65.56	3.17%	3.27%	6.00%	6.40%	6.60%	6.33%	9.27%	9.61%	9.88%
PROXY GROUP MEAN				3.72%	3.83%	6.57%	5.86%	5.90%	6.17%	8.37%	10.00%	11.61%

Notes
[1] Source: Bloomberg Professional
[2] Source: Bloomberg Professional, equals 30-day average as of March 31, 2023
[3] Equals [1] / [2]
[4] Equals [3] x (1 + 0.50 x [8])
[5] Source: Value Line
[6] Source: Yahoo! Finance
[7] Source: Zacks
[8] Equals Average ([5], [6], [7])
[9] Equals [3] x (1 + 0.50 x Minimum ([5], [6], [7]) + Minimum ([5], [6], [7])
[10] Equals [4] + [8]
[11] Equals [3] x (1 + 0.50 x Maximum ([5], [6], [7]) + Maximum ([5], [6], [7])

90-DAY CONSTANT GROWTH DCF

Company		[1] Annualized Dividend	[2] Stock Price	[3] Dividend Yield	[4] Expected Dividend Yield	[5] Value Line Earnings Growth	[6] Yahoo! Finance Earnings Growth	[7] Zacks Earnings Growth	[8] Average Growth	[9] Low DCF ROE	[10] Mean DCF ROE	[11] High DCF ROE
ALLETE, Inc.	ALE	$2.71	$63.36	4.28%	4.43%	6.00%	8.70%	7.30%	7.33%	10.41%	11.77%	13.16%
Alliant Energy Corporation	LNT	$1.81	$53.88	3.36%	3.46%	6.50%	5.55%	6.10%	6.05%	9.00%	9.51%	9.97%
Ameren Corporation	AEE	$2.52	$86.49	2.91%	3.01%	6.50%	6.70%	6.90%	6.70%	9.51%	9.71%	9.91%
American Electric Power Company, Inc.	AEP	$3.32	$92.78	3.58%	3.68%	6.00%	5.76%	6.10%	5.95%	9.44%	9.64%	9.79%
Edison International	EIX	$2.95	$66.78	4.42%	4.61%	16.00%	7.00%	3.00%	8.67%	7.48%	13.28%	20.77%
Entergy Corporation	ETR	$4.28	$108.83	3.93%	4.02%	0.50%	6.60%	6.00%	4.37%	4.44%	8.39%	10.66%
Evergy, Inc.	EVRG	$2.45	$60.89	4.02%	4.13%	7.50%	2.67%	5.20%	5.12%	6.75%	9.25%	11.67%
Hawaiian Electric Industries, Inc.	HE	$1.44	$40.65	3.54%	3.59%	4.50%	1.30%	3.10%	2.97%	4.87%	6.56%	8.12%
IDACORP, Inc.	IDA	$3.16	$105.87	2.98%	3.04%	4.50%	3.00%	3.00%	3.50%	6.03%	6.54%	7.55%
NextEra Energy, Inc.	NEE	$1.87	$79.31	2.36%	2.48%	10.00%	11.00%	9.00%	10.00%	11.46%	12.48%	13.49%
OGE Energy Corp.	OGE	$1.66	$38.29	4.33%	4.51%	6.50%	Negative	10.20%	8.35%	10.97%	12.86%	14.75%
Portland General Electric Company	POR	$1.81	$48.04	3.77%	3.86%	5.00%	4.18%	6.10%	5.09%	8.03%	8.96%	9.98%
Southern Company	SO	$2.72	$67.86	4.01%	4.13%	6.50%	7.30%	4.00%	5.93%	8.09%	10.06%	11.45%
Xcel Energy Inc.	XEL	$2.08	$68.26	3.05%	3.14%	6.00%	6.40%	6.60%	6.33%	9.14%	9.48%	9.75%
PROXY GROUP MEAN				3.61%	3.72%	6.57%	5.86%	5.90%	6.17%	8.26%	9.89%	11.50%

Notes

[1] Source: Bloomberg Professional
[2] Source: Bloomberg Professional, equals 90-day average as of March 31, 2023
[3] Equals [1] / [2]
[4] Equals [3] x (1 + 0.50 x [8])
[5] Source: Value Line
[6] Source: Yahoo! Finance
[7] Source: Zacks
[8] Equals Average ([5], [6], [7])
[9] Equals [3] x (1 + 0.50 x Minimum ([5], [6], [7]) + Minimum ([5], [6], [7])
[10] Equals [4] + [8]
[11] Equals [3] x (1 + 0.50 x Maximum ([5], [6], [7]) + Maximum ([5], [6], [7])

180-DAY CONSTANT GROWTH DCF

Company		[1] Annualized Dividend	[2] Stock Price	[3] Dividend Yield	[4] Expected Dividend Yield	[5] Value Line Earnings Growth	[6] Yahoo! Finance Earnings Growth	[7] Zacks Earnings Growth	[8] Average Growth	[9] Low DCF ROE	[10] Mean DCF ROE	[11] High DCF ROE
ALLETE, Inc.	ALE	$2.71	$60.52	4.48%	4.64%	6.00%	8.70%	7.30%	7.33%	10.61%	11.98%	13.37%
Alliant Energy Corporation	LNT	$1.81	$55.56	3.26%	3.36%	6.50%	5.55%	6.10%	6.05%	8.90%	9.41%	9.86%
Ameren Corporation	AEE	$2.52	$86.94	2.90%	3.00%	6.50%	6.70%	6.90%	6.70%	9.49%	9.70%	9.90%
American Electric Power Company, Inc.	AEP	$3.32	$93.78	3.54%	3.65%	6.00%	5.76%	6.10%	5.95%	9.40%	9.60%	9.75%
Edison International	EIX	$2.95	$65.16	4.53%	4.72%	16.00%	7.00%	3.00%	8.67%	7.60%	13.39%	20.89%
Entergy Corporation	ETR	$4.28	$110.17	3.88%	3.97%	0.50%	6.60%	6.00%	4.37%	4.39%	8.34%	10.61%
Evergy, Inc.	EVRG	$2.45	$62.65	3.91%	4.01%	7.50%	2.67%	5.20%	5.12%	6.63%	9.13%	11.56%
Hawaiian Electric Industries, Inc.	HE	$1.44	$39.76	3.62%	3.68%	4.50%	1.30%	3.10%	2.97%	4.95%	6.64%	8.20%
IDACORP, Inc.	IDA	$3.16	$105.90	2.98%	3.04%	4.50%	3.00%	3.00%	3.50%	6.03%	6.54%	7.55%
NextEra Energy, Inc.	NEE	$1.87	$80.92	2.31%	2.43%	10.00%	11.00%	9.00%	10.00%	11.41%	12.43%	13.44%
OGE Energy Corp.	OGE	$1.66	$38.64	4.29%	4.47%	6.50%	Negative	10.20%	8.35%	10.93%	12.82%	14.71%
Portland General Electric Company	POR	$1.81	$48.41	3.74%	3.83%	5.00%	4.18%	6.10%	5.09%	8.00%	8.93%	9.95%
Southern Company	SO	$2.72	$69.95	3.89%	4.00%	6.50%	7.30%	4.00%	5.93%	7.97%	9.94%	11.33%
Xcel Energy Inc.	XEL	$2.08	$68.91	3.02%	3.11%	6.00%	6.40%	6.60%	6.33%	9.11%	9.45%	9.72%
PROXY GROUP MEAN				3.60%	3.71%	6.57%	5.86%	5.90%	6.17%	8.24%	9.88%	11.49%

Notes

[1] Source: Bloomberg Professional
[2] Source: Bloomberg Professional, equals 180-day average as of March 31, 2023
[3] Equals [1] / [2]
[4] Equals [3] x (1 + 0.50 x [8])
[5] Source: Value Line
[6] Source: Yahoo! Finance
[7] Source: Zacks
[8] Equals Average ([5], [6], [7])
[9] Equals [3] x (1 + 0.50 x Minimum ([5], [6], [7]) + Minimum ([5], [6], [7])
[10] Equals [4] + [8]
[11] Equals [3] x (1 + 0.50 x Maximum ([5], [6], [7]) + Maximum ([5], [6], [7])

MARKET RISK PREMIUM DERIVED FROM S&P 500 - ALL COMPANIES

[1] Cap. Weighted Estimate of the S&P 500 Dividend Yield	1.66%
[2] Cap. Weighted Estimate of the S&P 500 Growth Rate	12.90%
[3] Cap. Weighted S&P 500 Estimated Required Market Return	14.67%

Notes:
[1] Source: Bloomberg Professional, as of March 31, 2023
[2] Source: Value Line, as of March 31, 2023
[3] Equals ([1] x (1 + (0.5 x [2]))) + [2]

Name	Ticker	Shares Outst'g	Price	Dividend Yield	Value Line Long-Term Growth Estimate	Market Cap Excl. n/a Growth	% of Total Market Cap.	Cap. Weighted Div. Yield	Cap. Weighted Long-Term Growth
LyondellBasell Industries NV	LYB	325.99	93.89	5.07	3.00	30,607.39	0.09%	0.47%	0.28%
American Express Co	AXP	744.07	164.95	1.45	10.00	122,733.69	0.37%	0.54%	3.73%
Verizon Communications Inc	VZ	4200.00	38.89	6.71	2.50	163,338.00	0.50%	3.33%	1.24%
Broadcom Inc	AVGO	416.92	641.54	2.87	30.00	267,473.42	0.81%	2.33%	24.38%
Boeing Co/The	BA	599.18	212.43	n/a		Excl.	Excl.		
Caterpillar Inc	CAT	516.35	228.84	2.10	10.50	118,160.39	0.36%	0.75%	3.77%
JPMorgan Chase & Co	JPM	2943.36	130.31	3.07	5.00	383,548.59	1.17%	3.58%	5.83%
Chevron Corp	CVX	1906.67	163.16	3.70	45.00	311,092.93	0.95%	3.50%	42.54%
Coca-Cola Co/The	KO	4326.31	62.03	2.97	8.00	268,360.76	0.82%	2.42%	6.52%
AbbVie Inc	ABBV	1769.40	159.37	3.71	2.00	281,989.28	0.86%	3.18%	1.71%
Walt Disney Co/The	DIS	1826.83	100.13	n/a	86.00	182,919.99	0.56%		47.80%
FleetCor Technologies Inc	FLT	73.49	210.85	n/a	10.50	15,495.79	0.05%		0.49%
Extra Space Storage Inc	EXR	134.99	162.93	3.98	6.50	21,993.11	0.07%	0.27%	0.43%
Exxon Mobil Corp	XOM	4070.99	109.66	3.32		Excl.	Excl.		
Phillips 66	PSX	460.91	101.38	4.14		Excl.	Excl.		
General Electric Co	GE	1090.28	95.60	0.33	21.00	104,231.05	0.32%	0.11%	6.65%
HP Inc	HPQ	985.33	29.35	3.58	12.50	28,919.38	0.09%	0.31%	1.10%
Home Depot Inc/The	HD	1014.96	295.12	2.83	9.00	299,533.81	0.91%	2.58%	8.19%
Monolithic Power Systems Inc	MPWR	47.31	500.54	0.80	21.00	23,678.04	0.07%	0.06%	1.51%
International Business Machines Corp	IBM	907.11	131.09	5.03	3.00	118,912.53	0.36%	1.82%	1.08%
Johnson & Johnson	JNJ	2604.29	155.00	2.92	8.00	403,664.33	1.23%	3.58%	9.81%
McDonald's Corp	MCD	731.50	279.61	2.17	9.00	204,533.88	0.62%	1.35%	5.59%
Merck & Co Inc	MRK	2538.59	106.39	2.74	8.50	270,080.80	0.82%	2.25%	6.98%
3M Co	MMM	551.47	105.11	5.71	7.50	57,964.91	0.18%	1.01%	1.32%
American Water Works Co Inc	AWK	194.64	146.49	1.79	3.00	28,513.25	0.09%	0.15%	0.26%
Bank of America Corp	BAC	8003.84	28.60	3.08	8.50	228,909.80	0.70%	2.14%	5.91%
Pfizer Inc	PFE	5644.40	40.80	4.02	2.00	230,291.60	0.70%	2.81%	1.40%
Procter & Gamble Co/The	PG	2359.14	148.69	2.46	5.50	350,781.12	1.07%	2.62%	5.86%
AT&T Inc	T	7129.87	19.25	5.77	1.00	137,250.00	0.42%	2.40%	0.42%
Travelers Cos Inc/The	TRV	232.09	171.41	2.17	7.50	39,783.23	0.12%	0.26%	0.91%
Raytheon Technologies Corp	RTX	1463.21	97.93	2.25	14.00	143,291.96	0.44%	0.98%	6.10%
Analog Devices Inc	ADI	505.85	197.22	1.74	11.50	99,764.13	0.30%	0.53%	3.49%
Walmart Inc	WMT	2695.66	147.45	1.55	7.50	397,474.48	1.21%	1.87%	9.06%
Cisco Systems Inc	CSCO	4095.82	52.28	2.98	8.50	214,109.15	0.65%	1.94%	5.53%
Intel Corp	INTC	4137.00	32.67	1.53		Excl.	Excl.		
General Motors Co	GM	1394.64	36.68	0.98	8.50	51,155.29	0.16%	0.15%	1.32%
Microsoft Corp	MSFT	7443.80	288.30	0.94	15.00	2,146,048.69	6.52%	6.15%	97.82%
Dollar General Corp	DG	219.11	210.46	1.12	10.00	46,113.47	0.14%	0.16%	1.40%
Cigna Group/The	CI	297.03	255.53	1.93	10.00	75,900.84	0.23%	0.44%	2.31%
Kinder Morgan Inc	KMI	2248.00	17.51	6.34	18.50	39,362.53	0.12%	0.76%	2.21%
Citigroup Inc	C	1946.47	46.89	4.35	3.50	91,269.74	0.28%	1.21%	0.97%
American International Group Inc	AIG	733.67	50.36	2.54	6.50	36,947.52	0.11%	0.29%	0.73%
Altria Group Inc	MO	1785.56	44.62	8.43	6.00	79,671.87	0.24%	2.04%	1.45%
HCA Healthcare Inc	HCA	277.26	263.68	0.91	12.50	73,106.60	0.22%	0.20%	2.78%
International Paper Co	IP	349.37	36.06	5.13	9.50	12,598.14	0.04%	0.20%	0.36%
Hewlett Packard Enterprise Co	HPE	1295.87	15.93	3.01	7.50	20643.19	0.06%	0.19%	0.47%
Abbott Laboratories	ABT	1737.95	101.26	2.01	6.50	175,984.41	0.53%	1.08%	3.48%
Aflac Inc	AFL	611.71	64.52	2.60	8.00	39,467.40	0.12%	0.31%	0.96%
Air Products and Chemicals Inc	APD	222.08	287.21	2.44	11.50	63,784.46	0.19%	0.47%	2.23%
Royal Caribbean Cruises Ltd	RCL	255.35	65.30	n/a		Excl.	Excl.		
Hess Corp	HES	306.18	132.34	1.32		Excl.	Excl.		
Archer-Daniels-Midland Co	ADM	546.45	79.66	2.26	13.00	43,529.81	0.13%	0.30%	1.72%
Automatic Data Processing Inc	ADP	414.35	222.63	2.25	10.00	92,247.19	0.28%	0.63%	2.80%
Verisk Analytics Inc	VRSK	154.70	191.86	0.71	13.00	29,679.97	0.09%	0.06%	1.17%
AutoZone Inc	AZO	18.40	2458.15	n/a	14.50	45,225.04	0.14%		1.99%
Avery Dennison Corp	AVY	81.11	178.93	1.68	9.50	14,512.83	0.04%	0.07%	0.42%
Enphase Energy Inc	ENPH	136.50	210.28	n/a	24.50	28,702.59	0.09%		2.14%
MSCI Inc	MSCI	80.06	559.69	0.99	12.50	44,810.46	0.14%	0.13%	1.70%
Ball Corp	BALL	314.40	55.11	1.45	21.50	17,326.31	0.05%	0.08%	1.13%
Ceridian HCM Holding Inc	CDAY	152.70	73.22	n/a		Excl.	Excl.		
Carrier Global Corp	CARR	834.95	45.75	1.62		Excl.	Excl.		
Bank of New York Mellon Corp/The	BK	808.45	45.44	3.26	6.00	36,735.74	0.11%	0.36%	0.67%
Otis Worldwide Corp	OTIS	414.87	84.40	1.37		Excl.	Excl.		
Baxter International Inc	BAX	505.52	40.56	2.86	7.00	20,504.01	0.06%	0.18%	0.44%
Becton Dickinson & Co	BDX	283.90	247.54	1.47	4.50	70,277.10	0.21%	0.31%	0.96%
Berkshire Hathaway Inc	BRK/B	1298.19	308.77	n/a		Excl.	Excl.		
Best Buy Co Inc	BBY	218.05	78.27	4.70	4.00	17,066.46	0.05%	0.24%	0.21%
Boston Scientific Corp	BSX	1437.33	50.03	n/a	15.50	71,909.52	0.22%		3.39%
Bristol-Myers Squibb Co	BMY	2098.78	69.31	3.29		Excl.	Excl.		
Brown-Forman Corp	BF/B	310.00	64.27	1.28		Excl.	Excl.		
Coterra Energy Inc	CTRA	765.50	24.54	9.29		Excl.	Excl.		

Name	Ticker	Shares Outst'g	Price	Dividend Yield	Value Line Long-Term Growth Estimate	Market Cap Excl. n/a Growth	% of Total Market Cap.	Cap. Weighted Div. Yield	Cap. Weighted Long-Term Growth
Campbell Soup Co	CPB	299.48	54.98	2.69	5.00	16,465.19	0.05%	0.13%	0.25%
Hilton Worldwide Holdings Inc	HLT	266.45	140.87	0.43		Excl.	Excl.		
Carnival Corp	CCL	1113.48	10.15	n/a		Excl.	Excl.		
Qorvo Inc	QRVO	99.89	101.57	n/a	14.50	10,145.73	0.03%		0.45%
UDR Inc	UDR	329.17	41.06	4.09	17.00	13,515.56	0.04%	0.17%	0.70%
Clorox Co/The	CLX	123.53	158.24	2.98	7.00	19,546.60	0.06%	0.18%	0.42%
Paycom Software Inc	PAYC	60.31	304.01	n/a	21.00	18,333.63	0.06%		1.17%
CMS Energy Corp	CMS	291.26	61.38	3.18	6.50	17,877.78	0.05%	0.17%	0.35%
Newell Brands Inc	NWL	413.60	12.44	7.40		Excl.	Excl.		
Colgate-Palmolive Co	CL	832.14	75.15	2.55	6.00	62,535.17	0.19%	0.49%	1.14%
EPAM Systems Inc	EPAM	57.68	299.00	n/a	20.50	17,245.72	0.05%		1.07%
Comerica Inc	CMA	131.51	43.42	6.54	8.50	5,710.34	0.02%	0.11%	0.15%
Conagra Brands Inc	CAG	476.62	37.56	3.51	3.50	17,901.96	0.05%	0.19%	0.19%
Consolidated Edison Inc	ED	355.05	95.67	3.39	4.50	33,967.16	0.10%	0.35%	0.46%
Corning Inc	GLW	847.23	35.28	3.17	17.50	29,890.34	0.09%	0.29%	1.59%
Cummins Inc	CMI	141.54	238.88	2.63	8.50	33,811.08	0.10%	0.27%	0.87%
Caesars Entertainment Inc	CZR	215.18	48.81	n/a		Excl.	Excl.		
Danaher Corp	DHR	728.58	252.04	0.43	16.00	183,630.55	0.56%	0.24%	8.93%
Target Corp	TGT	460.36	165.63	2.61	12.00	76,250.09	0.23%	0.60%	2.78%
Deere & Co	DE	296.32	412.88	1.21	12.50	122,345.43	0.37%	0.45%	4.65%
Dominion Energy Inc	D	835.25	55.91	4.78	4.00	46,698.88	0.14%	0.68%	0.57%
Dover Corp	DOV	139.77	151.94	1.33	9.00	21,236.81	0.06%	0.09%	0.58%
Alliant Energy Corp	LNT	251.14	53.40	3.39	6.00	13,410.77	0.04%	0.14%	0.24%
Steel Dynamics Inc	STLD	171.58	113.06	1.50	2.00	19,398.61	0.06%	0.09%	0.12%
Duke Energy Corp	DUK	770.65	96.47	4.17	5.00	74,344.41	0.23%	0.94%	1.13%
Regency Centers Corp	REG	171.31	61.18	4.25	10.50	10,480.62	0.03%	0.14%	0.33%
Eaton Corp PLC	ETN	398.00	171.34	2.01	12.00	68,193.32	0.21%	0.42%	2.49%
Ecolab Inc	ECL	284.67	165.53	1.28	6.00	47,121.26	0.14%	0.18%	0.86%
PerkinElmer Inc	PKI	126.41	133.26	0.21	4.00	16,845.66	0.05%	0.01%	0.20%
Emerson Electric Co	EMR	571.40	87.14	2.39	6.50	49,791.80	0.15%	0.36%	0.98%
EOG Resources Inc	EOG	587.72	114.63	2.88	26.00	67,370.80	0.20%	0.59%	5.32%
Aon PLC	AON	205.14	315.29	0.71	7.50	64,679.22	0.20%	0.14%	1.47%
Entergy Corp	ETR	212.09	107.74	3.97	0.50	22,850.68	0.07%	0.28%	0.03%
Equifax Inc	EFX	123.23	202.84	0.77	7.00	24,995.36	0.08%	0.06%	0.53%
EQT Corp	EQT	360.36	31.91	1.88		Excl.	Excl.		
IQVIA Holdings Inc	IQV	186.14	198.89	n/a	14.50	37,021.58	0.11%		1.63%
Gartner Inc	IT	79.06	325.77	n/a	17.50	25,755.70	0.08%		1.37%
FedEx Corp	FDX	251.35	228.49	2.01	9.00	57,431.42	0.17%	0.35%	1.57%
FMC Corp	FMC	125.14	122.13	1.90	10.50	15,283.59	0.05%	0.09%	0.49%
Brown & Brown Inc	BRO	283.70	57.42	0.80	8.00	16,289.94	0.05%	0.04%	0.40%
Ford Motor Co	F	3915.33	12.60	4.76	27.50	49,333.16	0.15%	0.71%	4.12%
NextEra Energy Inc	NEE	1987.50	77.08	2.43	10.00	153,196.11	0.47%	1.13%	4.66%
Franklin Resources Inc	BEN	500.36	26.94	4.45	3.50	13,479.64	0.04%	0.18%	0.14%
Garmin Ltd	GRMN	191.36	100.92	2.89	5.00	19,311.95	0.06%	0.17%	0.29%
Freeport-McMoRan Inc	FCX	1430.69	40.91	1.47	18.50	58,529.69	0.18%	0.26%	3.29%
Dexcom Inc	DXCM	386.41	116.18	n/a		Excl.	Excl.		
General Dynamics Corp	GD	274.71	228.21	2.31	9.50	62,692.48	0.19%	0.44%	1.81%
General Mills Inc	GIS	587.35	85.46	2.53	4.00	50,195.27	0.15%	0.39%	0.61%
Genuine Parts Co	GPC	140.81	167.31	2.27	10.50	23,558.75	0.07%	0.16%	0.75%
Atmos Energy Corp	ATO	143.16	112.36	2.63	7.00	16,085.79	0.05%	0.13%	0.34%
WW Grainger Inc	GWW	50.26	688.81	1.00	9.00	34,621.66	0.11%	0.11%	0.95%
Halliburton Co	HAL	904.08	31.64	2.02	32.50	28,605.12	0.09%	0.18%	2.83%
L3Harris Technologies Inc	LHX	189.96	196.24	2.32	17.00	37,277.16	0.11%	0.26%	1.93%
Healthpeak Properties Inc	PEAK	546.99	21.97	5.46	14.50	12,017.44	0.04%	0.20%	0.53%
Insulet Corp	PODD	69.54	318.96	n/a		Excl.	Excl.		
Catalent Inc	CTLT	180.09	65.71	n/a	21.00	11,833.71	0.04%		0.76%
Fortive Corp	FTV	353.20	68.17	0.41	12.00	24,077.58	0.07%	0.03%	0.88%
Hershey Co/The	HSY	146.92	254.41	1.63	9.00	37,378.43	0.11%	0.19%	1.02%
Synchrony Financial	SYF	437.04	29.08	3.16	9.50	12,708.98	0.04%	0.12%	0.37%
Hormel Foods Corp	HRL	546.53	39.88	2.76	7.50	21,795.74	0.07%	0.18%	0.50%
Arthur J Gallagher & Co	AJG	214.08	191.31	1.15	18.50	40,954.69	0.12%	0.14%	2.30%
Mondelez International Inc	MDLZ	1363.31	69.72	2.21	7.50	95,049.76	0.29%	0.64%	2.17%
CenterPoint Energy Inc	CNP	629.43	29.46	2.58	6.50	18,543.07	0.06%	0.15%	0.37%
Humana Inc	HUM	124.98	485.46	0.73	12.50	60,670.36	0.18%	0.13%	2.30%
Willis Towers Watson PLC	WTW	106.58	232.38	1.45	8.50	24,766.60	0.08%	0.11%	0.64%
Illinois Tool Works Inc	ITW	304.82	243.45	2.15	11.00	74,208.67	0.23%	0.49%	2.48%
CDW Corp/DE	CDW	135.59	194.89	1.21	8.50	26,425.52	0.08%	0.10%	0.68%
Trane Technologies PLC	TT	229.08	183.98	1.63		Excl.	Excl.		
Interpublic Group of Cos Inc/The	IPG	385.11	37.24	3.33	10.00	14,341.42	0.04%	0.15%	0.44%
International Flavors & Fragrances Inc	IFF	255.07	91.96	3.52	6.00	23,455.96	0.07%	0.25%	0.43%
Generac Holdings Inc	GNRC	61.89	108.01	n/a	19.00	6,684.41	0.02%		0.39%
NXP Semiconductors NV	NXPI	259.52	186.48	2.18	11.00	48,393.81	0.15%	0.32%	1.62%
Kellogg Co	K	342.67	66.96	3.52	3.50	22,945.05	0.07%	0.25%	0.24%
Broadridge Financial Solutions Inc	BR	117.69	146.57	1.98	8.50	17,250.26	0.05%	0.10%	0.45%
Kimberly-Clark Corp	KMB	337.45	134.22	3.52	7.00	45,293.08	0.14%	0.48%	0.96%
Kimco Realty Corp	KIM	618.46	19.53	4.71	11.00	12,078.54	0.04%	0.17%	0.40%
Oracle Corp	ORCL	2699.80	92.92	1.72	10.00	250,865.60	0.76%	1.31%	7.62%
Kroger Co/The	KR	717.47	49.37	2.11	6.50	35,421.40	0.11%	0.23%	0.70%
Lennar Corp	LEN	252.47	105.11	1.43	8.50	26,536.70	0.08%	0.12%	0.69%
Eli Lilly & Co	LLY	950.30	343.42	1.32	11.50	326,350.65	0.99%	1.31%	11.40%
Bath & Body Works Inc	BBWI	228.77	36.58	2.19	26.50	8,368.26	0.03%	0.06%	0.67%
Charter Communications Inc	CHTR	152.65	357.61	n/a	15.50	54,589.52	0.17%		2.57%
Lincoln National Corp	LNC	169.22	22.47	8.01	30.50	3,802.40	0.01%	0.09%	0.35%
Loews Corp	L	230.88	58.02	0.43	18.50	13,395.43	0.04%	0.02%	0.75%
Lowe's Cos Inc	LOW	596.36	199.97	2.10	11.00	119,253.31	0.36%	0.76%	3.99%
IDEX Corp	IEX	75.52	231.03	1.04	11.00	17,446.92	0.05%	0.06%	0.58%
Marsh & McLennan Cos Inc	MMC	494.57	166.55	1.42	11.00	82,370.80	0.25%	0.35%	2.75%
Masco Corp	MAS	225.20	49.72	2.29	8.00	11,197.09	0.03%	0.08%	0.27%

Name	Ticker	Shares Outst'g	Price	Dividend Yield	Value Line Long-Term Growth Estimate	Market Cap Excl. n/a Growth	% of Total Market Cap.	Cap. Weighted Div. Yield	Cap. Weighted Long-Term Growth
S&P Global Inc	SPGI	327.95	344.77	1.04	6.50	113,066.29	0.34%	0.36%	2.23%
Medtronic PLC	MDT	1330.42	80.62	3.37	7.50	107,258.78	0.33%	1.10%	2.44%
Viatris Inc	VTRS	1196.81	9.62	4.99		Excl.	Excl.		
CVS Health Corp	CVS	1284.11	74.31	3.26	6.00	95,422.36	0.29%	0.94%	1.74%
DuPont de Nemours Inc	DD	458.34	71.77	2.01	10.00	32,894.92	0.10%	0.20%	1.00%
Micron Technology Inc	MU	1094.39	60.34	0.76	9.50	66,035.73	0.20%	0.15%	1.91%
Motorola Solutions Inc	MSI	167.47	286.13	1.23	10.50	47,917.33	0.15%	0.18%	1.53%
Cboe Global Markets Inc	CBOE	105.74	134.24	1.49	10.00	14,194.94	0.04%	0.06%	0.43%
Laboratory Corp of America Holdings	LH	88.50	229.42	1.26	1.50	20,303.90	0.06%	0.08%	0.09%
Newmont Corp	NEM	794.51	49.02	3.26	8.00	38,946.83	0.12%	0.39%	0.95%
NIKE Inc	NKE	1245.67	122.64	1.11	24.00	152,768.48	0.46%	0.51%	11.14%
NiSource Inc	NI	412.51	27.96	3.58	9.50	11,533.72	0.04%	0.13%	0.33%
Norfolk Southern Corp	NSC	227.78	212.00	2.55	10.00	48,289.78	0.15%	0.37%	1.47%
Principal Financial Group Inc	PFG	243.10	74.32	3.44	6.50	18,067.49	0.05%	0.19%	0.36%
Eversource Energy	ES	348.67	78.26	3.45	6.50	27,287.15	0.08%	0.29%	0.54%
Northrop Grumman Corp	NOC	152.09	461.72	1.50	9.50	70,221.61	0.21%	0.32%	2.03%
Wells Fargo & Co	WFC	3777.09	37.38	3.21	12.00	141,187.55	0.43%	1.38%	5.15%
Nucor Corp	NUE	251.93	154.47	1.32	9.50	38,915.47	0.12%	0.16%	1.12%
Occidental Petroleum Corp	OXY	898.12	62.43	1.15		Excl.	Excl.		
Omnicom Group Inc	OMC	201.41	94.34	2.97	6.50	19,000.93	0.06%	0.17%	0.38%
ONEOK Inc	OKE	447.22	63.54	6.01	11.50	28,416.42	0.09%	0.52%	0.99%
Raymond James Financial Inc	RJF	215.35	93.27	1.80	15.00	20,085.88	0.06%	0.11%	0.92%
PG&E Corp	PCG	1988.47	16.17	n/a	7.50	32,153.48	0.10%		0.73%
Parker-Hannifin Corp	PH	128.27	336.11	1.58	15.50	43,111.49	0.13%	0.21%	2.03%
Rollins Inc	ROL	492.74	37.53	1.39	10.50	18,492.68	0.06%	0.08%	0.59%
PPL Corp	PPL	736.68	27.79	3.45	3.50	20,472.28	0.06%	0.21%	0.22%
ConocoPhillips	COP	1217.38	99.21	0.60	20.00	120,776.57	0.37%	0.22%	7.34%
PulteGroup Inc	PHM	224.31	58.28	1.10	7.00	13,072.85	0.04%	0.04%	0.28%
Pinnacle West Capital Corp	PNW	113.18	79.24	4.37	0.50	8,968.07	0.03%	0.12%	0.01%
PNC Financial Services Group Inc/The	PNC	399.75	127.10	4.72	12.00	50,808.61	0.15%	0.73%	1.85%
PPG Industries Inc	PPG	235.36	133.58	1.86	4.00	31,439.12	0.10%	0.18%	0.38%
Progressive Corp/The	PGR	585.37	143.06	0.28	6.50	83,742.46	0.25%	0.07%	1.65%
Public Service Enterprise Group Inc	PEG	498.77	62.45	3.65	4.50	31,148.19	0.09%	0.35%	0.43%
Robert Half International Inc	RHI	107.70	80.57	2.38	9.50	8,677.23	0.03%	0.06%	0.25%
Edison International	EIX	382.63	70.59	4.18	16.00	27,009.64	0.08%	0.34%	1.31%
Schlumberger NV	SLB	1427.60	49.10	2.04	28.50	70,095.26	0.21%	0.43%	6.07%
Charles Schwab Corp/The	SCHW	1791.45	52.38	1.91	9.00	93,836.05	0.29%	0.54%	2.57%
Sherwin-Williams Co/The	SHW	258.44	224.77	1.08	7.00	58,090.01	0.18%	0.19%	1.24%
West Pharmaceutical Services Inc	WST	74.14	346.47	0.22	17.00	25,685.90	0.08%	0.02%	1.33%
J M Smucker Co/The	SJM	106.64	157.37	2.59	4.00	16,781.31	0.05%	0.13%	0.20%
Snap-on Inc	SNA	53.13	246.89	2.62	4.50	13,117.02	0.04%	0.10%	0.18%
AMETEK Inc	AME	230.09	145.33	0.69	10.00	33,439.56	0.10%	0.07%	1.02%
Southern Co/The	SO	1088.67	69.58	3.91	6.50	75,749.87	0.23%	0.90%	1.50%
Truist Financial Corp	TFC	1328.14	34.10	6.10	5.50	45,289.57	0.14%	0.84%	0.76%
Southwest Airlines Co	LUV	594.29	32.54	2.21		Excl.	Excl.		
W R Berkley Corp	WRB	263.45	62.26	0.64	17.50	16,402.15	0.05%	0.03%	0.87%
Stanley Black & Decker Inc	SWK	153.06	80.58	3.97	6.00	12,333.17	0.04%	0.15%	0.22%
Public Storage	PSA	175.80	302.14	3.97	7.50	53,114.70	0.16%	0.64%	1.21%
Arista Networks Inc	ANET	306.40	167.86	n/a	10.00	51,431.46	0.16%		1.56%
Sysco Corp	SYY	507.60	77.23	2.54	21.50	39,202.26	0.12%	0.30%	2.56%
Corteva Inc	CTVA	712.61	60.31	0.99	15.50	42,977.21	0.13%	0.13%	2.02%
Texas Instruments Inc	TXN	907.34	186.01	2.67	4.50	168,774.69	0.51%	1.37%	2.31%
Textron Inc	TXT	203.66	70.63	0.11	10.50	14,384.51	0.04%	0.00%	0.46%
Thermo Fisher Scientific Inc	TMO	385.43	576.37	0.24	11.00	222,150.29	0.68%	0.16%	7.43%
TJX Cos Inc/The	TJX	1152.57	78.36	1.70	17.00	90,315.31	0.27%	0.47%	4.67%
Globe Life Inc	GL	96.52	110.02	0.82	8.50	10,619.24	0.03%	0.03%	0.27%
Johnson Controls International plc	JCI	687.21	60.22	2.39	12.50	41,384.03	0.13%	0.30%	1.57%
Ulta Beauty Inc	ULTA	50.20	545.67	n/a	16.50	27,389.91	0.08%		1.37%
Union Pacific Corp	UNP	611.87	201.26	2.58	9.50	123,145.56	0.37%	0.97%	3.56%
Keysight Technologies Inc	KEYS	178.14	161.48	n/a	13.00	28,765.89	0.09%		1.14%
UnitedHealth Group Inc	UNH	932.85	472.59	1.40	12.00	440,854.16	1.34%	1.87%	16.08%
Marathon Oil Corp	MRO	629.65	23.96	1.67		Excl.	Excl.		
Bio-Rad Laboratories Inc	BIO	24.52	479.02	n/a	11.50	11,746.53	0.04%		0.41%
Ventas Inc	VTR	399.99	43.35	4.15	23.50	17,339.74	0.05%	0.22%	1.24%
VF Corp	VFC	388.66	22.91	5.24	9.00	8,904.13	0.03%	0.14%	0.24%
Vulcan Materials Co	VMC	133.06	171.56	1.00	9.00	22,827.26	0.07%	0.07%	0.62%
Weyerhaeuser Co	WY	732.89	30.13	2.52	5.00	22,082.04	0.07%	0.17%	0.34%
Whirlpool Corp	WHR	54.50	132.02	5.30	6.00	7,195.35	0.02%	0.12%	0.13%
Williams Cos Inc/The	WMB	1218.81	29.86	5.99	11.00	36,393.73	0.11%	0.66%	1.22%
Constellation Energy Corp	CEG	326.66	78.50	1.44		Excl.	Excl.		
WEC Energy Group Inc	WEC	315.44	94.79	3.29	6.00	29,900.08	0.09%	0.30%	0.55%
Adobe Inc	ADBE	458.70	385.37	n/a	13.00	176,769.22	0.54%		6.98%
AES Corp/The	AES	669.03	24.08	2.76	14.00	16,110.27	0.05%	0.13%	0.69%
Amgen Inc	AMGN	533.98	241.75	3.52	5.50	129,088.70	0.39%	1.38%	2.16%
Apple Inc	AAPL	15821.95	164.90	0.56	10.50	2,609,038.90	7.93%	4.42%	83.25%
Autodesk Inc	ADSK	214.78	208.16	n/a	14.00	44,709.23	0.14%		1.90%
Cintas Corp	CTAS	101.67	462.68	0.99	14.00	47,041.60	0.14%	0.14%	2.00%
Comcast Corp	CMCSA	4206.61	37.91	3.06	8.50	159,472.66	0.48%	1.48%	4.12%
Molson Coors Beverage Co	TAP	200.03	51.68	3.17	49.50	10,337.40	0.03%	0.10%	1.55%
KLA Corp	KLAC	138.48	399.17	1.30	20.00	55,277.06	0.17%	0.22%	3.36%
Marriott International Inc/MD	MAR	308.88	166.04	0.96	17.50	51,287.10	0.16%	0.15%	2.73%
McCormick & Co Inc/MD	MKC	250.84	83.21	1.87	4.50	20,872.23	0.06%	0.12%	0.29%
PACCAR Inc	PCAR	522.56	73.20	1.37	5.00	38,251.03	0.12%	0.16%	0.58%
Costco Wholesale Corp	COST	443.48	496.87	0.72	10.50	220,353.40	0.67%	0.49%	7.03%
First Republic Bank/CA	FRC	186.22	13.99	n/a	11.50	2,605.20	0.01%		0.09%
Stryker Corp	SYK	378.83	285.47	1.05	6.50	108,144.89	0.33%	0.35%	2.14%
Tyson Foods Inc	TSN	285.62	59.32	3.24	6.00	16,942.74	0.05%	0.17%	0.31%
Lamb Weston Holdings Inc	LW	147.82	104.52	1.07	11.50	15,450.46	0.05%	0.05%	0.54%

Name	Ticker	Shares Outst'g	Price	Dividend Yield	Value Line Long-Term Growth Estimate	Market Cap Excl. n/a Growth	% of Total Market Cap.	Cap. Weighted Div. Yield	Cap. Weighted Long-Term Growth
Applied Materials Inc	AMAT	845.12	122.83	1.04	10.50	103,805.84	0.32%	0.33%	3.31%
American Airlines Group Inc	AAL	652.82	14.75	n/a		Excl.	Excl.		
Cardinal Health Inc	CAH	257.64	75.50	2.63	5.00	19,451.74	0.06%	0.16%	0.30%
Cincinnati Financial Corp	CINF	157.18	112.08	2.68	9.00	17,616.29	0.05%	0.14%	0.48%
Paramount Global	PARA	609.81	22.31	4.30	4.50	13,604.91	0.04%	0.18%	0.19%
DR Horton Inc	DHI	343.39	97.69	1.02	1.00	33,546.06	0.10%	0.10%	0.10%
Electronic Arts Inc	EA	274.23	120.45	0.63	13.00	33,030.76	0.10%	0.06%	1.30%
Fair Isaac Corp	FICO	25.16	702.69	n/a	16.00	17,676.17	0.05%		0.86%
Expeditors International of Washington Inc	EXPD	154.40	110.12	1.22	10.00	17,002.31	0.05%	0.06%	0.52%
Fastenal Co	FAST	570.96	53.94	2.60	6.50	30,797.64	0.09%	0.24%	0.61%
M&T Bank Corp	MTB	168.04	119.57	4.35	9.00	20,093.02	0.06%	0.27%	0.55%
Xcel Energy Inc	XEL	549.85	67.44	3.08	6.00	37,081.68	0.11%	0.35%	0.68%
Fiserv Inc	FISV	628.13	113.03	n/a	11.00	70,997.08	0.22%		2.37%
Fifth Third Bancorp	FITB	681.05	26.64	4.95	10.00	18,143.28	0.06%	0.27%	0.55%
Gilead Sciences Inc	GILD	1248.82	82.97	3.62	12.00	103,614.26	0.31%	1.14%	3.78%
Hasbro Inc	HAS	138.22	53.69	5.22	7.50	7,421.03	0.02%	0.12%	0.17%
Huntington Bancshares Inc/OH	HBAN	1449.64	11.20	5.54	12.50	16,235.93	0.05%	0.27%	0.62%
Welltower Inc	WELL	490.64	71.69	3.40	12.00	35,174.27	0.11%	0.36%	1.28%
Biogen Inc	BIIB	144.49	278.03	n/a	-10.50	40,171.44	0.12%		-1.28%
Northern Trust Corp	NTRS	207.75	88.13	3.40	8.00	18,309.10	0.06%	0.19%	0.45%
Packaging Corp of America	PKG	89.88	138.83	3.60	11.00	12,478.60	0.04%	0.14%	0.42%
Paychex Inc	PAYX	360.51	114.59	2.76	10.50	41,310.73	0.13%	0.35%	1.32%
QUALCOMM Inc	QCOM	1115.00	127.58	2.35	9.50	142,251.70	0.43%	1.02%	4.11%
Roper Technologies Inc	ROP	106.24	440.69	0.62	3.50	46,820.23	0.14%	0.09%	0.50%
Ross Stores Inc	ROST	342.05	106.13	1.26	14.00	36,301.55	0.11%	0.14%	1.54%
IDEXX Laboratories Inc	IDXX	82.90	500.08	n/a	11.50	41,458.13	0.13%		1.45%
Starbucks Corp	SBUX	1149.30	104.13	2.04	16.00	119,676.61	0.36%	0.74%	5.82%
KeyCorp	KEY	924.86	12.52	6.55	7.50	11,579.23	0.04%	0.23%	0.26%
Fox Corp	FOXA	296.92	34.05	1.47	12.00	10,110.02	0.03%	0.05%	0.37%
Fox Corp	FOX	237.64	31.31	1.60		Excl.	Excl.		
State Street Corp	STT	344.48	75.69	3.33	8.50	26,073.62	0.08%	0.26%	0.67%
Norwegian Cruise Line Holdings Ltd	NCLH	421.93	13.45	n/a		Excl.	Excl.		
US Bancorp	USB	1531.12	36.05	5.33	7.00	55,196.88	0.17%	0.89%	1.17%
A O Smith Corp	AOS	125.01	69.15	1.74	11.50	8,644.44	0.03%	0.05%	0.30%
Gen Digital Inc	GEN	639.13	17.16	2.91	10.50	10,967.45	0.03%	0.10%	0.35%
T Rowe Price Group Inc	TROW	224.51	112.90	4.32	4.50	25,347.63	0.08%	0.33%	0.35%
Waste Management Inc	WM	406.77	163.17	1.72	6.50	66,372.17	0.20%	0.35%	1.31%
Constellation Brands Inc	STZ	184.50	225.89	1.42	6.00	41,676.25	0.13%	0.18%	0.76%
DENTSPLY SIRONA Inc	XRAY	215.36	39.28	1.43	12.00	8,459.42	0.03%	0.04%	0.31%
Zions Bancorp NA	ZION	148.10	29.93	5.48	6.50	4,432.60	0.01%	0.07%	0.09%
Alaska Air Group Inc	ALK	127.47	41.96	n/a		Excl.	Excl.		
Invesco Ltd	IVZ	454.72	16.40	4.57	10.00	7,457.47	0.02%	0.10%	0.23%
Intuit Inc	INTU	280.55	445.83	0.70	16.50	125,075.82	0.38%	0.27%	6.27%
Morgan Stanley	MS	1681.94	87.80	3.53	8.50	147,674.33	0.45%	1.58%	3.81%
Microchip Technology Inc	MCHP	547.80	83.78	1.71	10.00	45,894.35	0.14%	0.24%	1.39%
Chubb Ltd	CB	413.51	194.18	1.71	14.50	80,294.60	0.24%	0.42%	3.54%
Hologic Inc	HOLX	246.55	80.70	n/a	25.00	19,896.67	0.06%		1.51%
Citizens Financial Group Inc	CFG	484.31	30.37	5.53	8.00	14,708.46	0.04%	0.25%	0.36%
O'Reilly Automotive Inc	ORLY	61.57	848.98	n/a	13.00	52,269.15	0.16%		2.06%
Allstate Corp/The	ALL	263.33	110.81	3.21	2.50	29,179.60	0.09%	0.28%	0.22%
Equity Residential	EQR	378.60	60.00	4.42	-5.00	22,716.18	0.07%	0.30%	-0.35%
BorgWarner Inc	BWA	233.79	49.11	1.38	9.50	11,481.18	0.03%	0.05%	0.33%
Keurig Dr Pepper Inc	KDP	1406.45	35.28	2.27	11.50	49,619.45	0.15%	0.34%	1.73%
Organon & Co	OGN	254.38	23.52	4.76		Excl.	Excl.		
Host Hotels & Resorts Inc	HST	713.48	16.49	2.91	51.00	11,765.27	0.04%	0.10%	1.82%
Incyte Corp	INCY	222.97	72.27	n/a	27.00	16,113.68	0.05%		1.32%
Simon Property Group Inc	SPG	326.73	111.97	6.43	3.50	36,584.18	0.11%	0.71%	0.39%
Eastman Chemical Co	EMN	119.14	84.34	3.75	7.00	10,048.10	0.03%	0.11%	0.21%
AvalonBay Communities Inc	AVB	139.92	168.06	3.93	7.00	23,514.96	0.07%	0.28%	0.50%
Prudential Financial Inc	PRU	366.97	82.74	6.04	3.00	30,363.43	0.09%	0.56%	0.28%
United Parcel Service Inc	UPS	723.30	193.99	3.34	7.50	140,312.77	0.43%	1.42%	3.20%
Walgreens Boots Alliance Inc	WBA	862.80	34.58	5.55	3.00	29,835.49	0.09%	0.50%	0.27%
STERIS PLC	STE	99.28	191.28	0.98	10.00	18,991.04	0.06%	0.06%	0.58%
McKesson Corp	MCK	136.94	356.05	0.61	10.00	48,757.13	0.15%	0.09%	1.48%
Lockheed Martin Corp	LMT	254.52	472.73	2.54	7.00	120,318.77	0.37%	0.93%	2.56%
AmerisourceBergen Corp	ABC	202.26	160.11	1.21	8.50	32,383.53	0.10%	0.12%	0.84%
Capital One Financial Corp	COF	381.08	96.16	2.50		Excl.	Excl.		
Waters Corp	WAT	58.94	309.63	n/a	6.00	18,250.83	0.06%		0.33%
Nordson Corp	NDSN	57.26	222.26	1.17	12.00	12,726.83	0.04%	0.05%	0.46%
Dollar Tree Inc	DLTR	221.23	143.55	n/a	12.00	31,757.28	0.10%		1.16%
Darden Restaurants Inc	DRI	121.71	155.16	3.12	17.50	18,883.75	0.06%	0.18%	1.00%
Evergy Inc	EVRG	229.58	61.12	4.01	7.50	14,032.11	0.04%	0.17%	0.32%
Match Group Inc	MTCH	279.32	38.39	n/a	21.00	10,723.25	0.03%		0.68%
Domino's Pizza Inc	DPZ	35.42	329.87	1.47	13.00	11,683.34	0.04%	0.05%	0.46%
NVR Inc	NVR	3.25	5572.19	n/a	5.50	18,104.05	0.06%		0.30%
NetApp Inc	NTAP	213.91	63.85	3.13	8.50	13,657.83	0.04%	0.13%	0.35%
DXC Technology Co	DXC	227.68	25.56	n/a	12.00	5,819.55	0.02%		0.21%
Old Dominion Freight Line Inc	ODFL	110.03	340.84	0.47	12.50	37,501.26	0.11%	0.05%	1.42%
DaVita Inc	DVA	90.40	81.11	n/a	7.50	7,332.34	0.02%		0.17%
Hartford Financial Services Group Inc/The	HIG	313.06	69.69	2.44	6.50	21,816.94	0.07%	0.16%	0.43%
Iron Mountain Inc	IRM	291.57	52.91	4.68	10.00	15,427.18	0.05%	0.22%	0.47%
Estee Lauder Cos Inc/The	EL	231.68	246.46	1.07	14.00	57,099.36	0.17%	0.19%	2.43%
Cadence Design Systems Inc	CDNS	272.94	210.09	n/a	12.00	57,341.96	0.17%		2.09%
Tyler Technologies Inc	TYL	41.82	354.64	n/a	12.00	14,830.69	0.05%		0.54%
Universal Health Services Inc	UHS	63.42	127.10	0.63	5.50	8,060.30	0.02%	0.02%	0.13%
Skyworks Solutions Inc	SWKS	159.15	117.98	2.10	9.00	18,776.87	0.06%	0.12%	0.51%
Quest Diagnostics Inc	DGX	111.32	141.48	2.01	5.00	15,749.98	0.05%	0.10%	0.24%
Activision Blizzard Inc	ATVI	784.27	85.59	0.55	11.50	67,126.01	0.20%	0.11%	2.35%

Name	Ticker	Shares Outst'g	Price	Dividend Yield	Value Line Long-Term Growth Estimate	Market Cap Excl. n/a Growth	% of Total Market Cap.	Cap. Weighted Div. Yield	Cap. Weighted Long-Term Growth
Rockwell Automation Inc	ROK	114.78	293.45	1.61	9.50	33,682.78	0.10%	0.16%	0.97%
Kraft Heinz Co/The	KHC	1227.00	38.67	4.14	6.50	47,448.05	0.14%	0.60%	0.94%
American Tower Corp	AMT	465.65	204.34	3.05	6.00	95,150.10	0.29%	0.88%	1.73%
Regeneron Pharmaceuticals Inc	REGN	107.51	821.67	n/a	5.00	88,335.28	0.27%		1.34%
Amazon.com Inc	AMZN	10247.26	103.29	n/a	26.50	1,058,439.49	3.22%		85.23%
Jack Henry & Associates Inc	JKHY	72.99	150.72	1.38	8.50	11,001.20	0.03%	0.05%	0.28%
Ralph Lauren Corp	RL	41.10	116.67	2.57	12.00	4,794.90	0.01%	0.04%	0.17%
Boston Properties Inc	BXP	156.82	54.12	7.24	-1.00	8,487.26	0.03%	0.19%	-0.03%
Amphenol Corp	APH	594.61	81.72	1.03	12.50	48,591.12	0.15%	0.15%	1.85%
Howmet Aerospace Inc	HWM	411.80	42.37	0.38	14.00	17,448.14	0.05%	0.02%	0.74%
Pioneer Natural Resources Co	PXD	235.00	204.24	10.93	21.00	47,997.22	0.15%	1.59%	3.06%
Valero Energy Corp	VLO	367.84	139.60	2.92	29.50	51,350.46	0.16%	0.46%	4.60%
Synopsys Inc	SNPS	152.30	386.25	n/a	12.50	58,826.65	0.18%		2.23%
Etsy Inc	ETSY	124.65	111.33	n/a	24.50	13,877.17	0.04%		1.03%
CH Robinson Worldwide Inc	CHRW	114.89	99.37	2.46	8.50	11,416.52	0.03%	0.09%	0.29%
Accenture PLC	ACN	662.60	285.81	1.57	12.50	189,376.56	0.58%	0.90%	7.19%
TransDigm Group Inc	TDG	54.60	737.05	n/a	20.00	40,241.46	0.12%		2.45%
Yum! Brands Inc	YUM	280.11	132.08	1.83	10.50	36,996.66	0.11%	0.21%	1.18%
Prologis Inc	PLD	923.45	124.77	2.79	2.50	115,218.86	0.35%	0.98%	0.88%
FirstEnergy Corp	FE	572.25	40.06	3.89	3.00	22,924.13	0.07%	0.27%	0.21%
VeriSign Inc	VRSN	104.88	211.33	n/a	11.00	22,164.08	0.07%		0.74%
Quanta Services Inc	PWR	144.00	166.64	0.19	15.50	23,996.33	0.07%	0.01%	1.13%
Henry Schein Inc	HSIC	131.28	81.54	n/a	6.00	10,704.90	0.03%		0.20%
Ameren Corp	AEE	262.48	86.39	2.92	6.50	22,675.22	0.07%	0.20%	0.45%
ANSYS Inc	ANSS	87.09	332.80	n/a	8.50	28,982.22	0.09%		0.75%
FactSet Research Systems Inc	FDS	38.25	415.09	0.86	10.50	15,878.02	0.05%	0.04%	0.51%
NVIDIA Corp	NVDA	2470.00	277.77	0.06	23.00	686,091.90	2.08%	0.12%	47.95%
Sealed Air Corp	SEE	143.96	45.91	1.74	9.00	6,609.30	0.02%	0.03%	0.18%
Cognizant Technology Solutions Corp	CTSH	509.30	60.93	1.90	8.00	31,031.34	0.09%	0.18%	0.75%
Intuitive Surgical Inc	ISRG	350.26	255.47	n/a	10.00	89,480.16	0.27%		2.72%
Take-Two Interactive Software Inc	TTWO	168.68	119.30	n/a	3.00	20,122.93	0.06%		0.18%
Republic Services Inc	RSG	316.24	135.22	1.46	12.50	42,762.51	0.13%	0.19%	1.62%
eBay Inc	EBAY	536.88	44.37	2.25	12.50	23,821.37	0.07%	0.16%	0.90%
Goldman Sachs Group Inc/The	GS	333.80	327.11	3.06	5.00	109,187.68	0.33%	1.01%	1.66%
SBA Communications Corp	SBAC	108.04	261.07	1.30	35.50	28,205.74	0.09%	0.11%	3.04%
Sempra Energy	SRE	314.65	151.16	3.15	7.50	47,562.49	0.14%	0.46%	1.08%
Moody's Corp	MCO	183.20	306.02	1.01	4.00	56,062.86	0.17%	0.17%	0.68%
ON Semiconductor Corp	ON	431.97	82.32	n/a	18.50	35,559.61	0.11%		2.00%
Booking Holdings Inc	BKNG	37.65	2652.41	n/a	22.00	99,857.93	0.30%		6.68%
F5 Inc	FFIV	55.07	145.69	n/a	10.00	8,023.44	0.02%		0.24%
Akamai Technologies Inc	AKAM	156.30	78.30	n/a	5.50	12,238.60	0.04%		0.20%
Charles River Laboratories International Inc	CRL	50.99	201.82	n/a	12.00	10,289.99	0.03%		0.38%
MarketAxess Holdings Inc	MKTX	37.61	391.29	0.74	10.00	14,716.03	0.04%	0.03%	0.45%
Devon Energy Corp	DVN	654.00	50.61	7.03	27.50	33,098.94	0.10%	0.71%	2.77%
Bio-Techne Corp	TECH	157.28	74.19	0.43	13.00	11,668.23	0.04%	0.02%	0.46%
Alphabet Inc	GOOGL	5956.00	103.73	n/a		Excl.	Excl.		
Teleflex Inc	TFX	46.94	253.31	0.54	10.00	11,891.38	0.04%	0.02%	0.36%
Bunge Ltd	BG	149.93	95.52	2.62	2.50	14,320.93	0.04%	0.11%	0.11%
Netflix Inc	NFLX	445.35	345.48	n/a	14.50	153,858.48	0.47%		6.78%
Allegion plc	ALLE	87.87	106.73	1.69	11.00	9,378.04	0.03%	0.05%	0.31%
Agilent Technologies Inc	A	295.70	138.34	0.65	12.00	40,907.41	0.12%	0.08%	1.49%
Warner Bros Discovery Inc	WBD	2435.60	15.10	n/a		Excl.	Excl.		
Elevance Health Inc	ELV	237.46	459.81	1.29	12.50	109,185.56	0.33%	0.43%	4.15%
Trimble Inc	TRMB	246.95	52.42	n/a	7.00	12,945.22	0.04%		0.28%
CME Group Inc	CME	359.74	191.52	2.30	8.50	68,897.40	0.21%	0.48%	1.78%
Juniper Networks Inc	JNPR	321.34	34.42	2.56	11.00	11,060.66	0.03%	0.09%	0.37%
BlackRock Inc	BLK	150.24	669.12	2.99	8.50	100,525.91	0.31%	0.91%	2.60%
DTE Energy Co	DTE	206.11	109.54	3.48	4.50	22,577.07	0.07%	0.24%	0.31%
Nasdaq Inc	NDAQ	489.00	54.67	1.46	8.50	26,733.79	0.08%	0.12%	0.69%
Celanese Corp	CE	110.83	108.89	2.57	7.50	12,067.73	0.04%	0.09%	0.28%
Philip Morris International Inc	PM	1552.15	97.25	5.22	5.00	150,946.39	0.46%	2.40%	2.29%
Salesforce Inc	CRM	1000.00	199.78	n/a	19.50	199,780.00	0.61%		11.84%
Ingersoll Rand Inc	IR	404.96	58.18	0.14		Excl.	Excl.		
Huntington Ingalls Industries Inc	HII	39.93	207.02	2.40	10.00	8,265.48	0.03%	0.06%	0.25%
MetLife Inc	MET	774.36	57.94	3.45	7.50	44,866.53	0.14%	0.47%	1.02%
Tapestry Inc	TPR	236.08	43.11	2.78	13.50	10,177.24	0.03%	0.09%	0.42%
CSX Corp	CSX	2048.43	29.94	1.47	10.50	61,330.05	0.19%	0.27%	1.96%
Edwards Lifesciences Corp	EW	606.10	82.73	n/a	11.00	50,142.65	0.15%		1.68%
Ameriprise Financial Inc	AMP	105.15	306.50	1.63	13.50	32,227.86	0.10%	0.16%	1.32%
Zebra Technologies Corp	ZBRA	51.41	318.00	n/a	11.50	16,346.79	0.05%		0.57%
Zimmer Biomet Holdings Inc	ZBH	210.06	129.20	0.74	4.50	27,140.27	0.08%	0.06%	0.37%
CBRE Group Inc	CBRE	309.89	72.81	n/a	8.50	22,563.24	0.07%		0.58%
Camden Property Trust	CPT	106.76	104.84	3.82	-4.00	11,193.03	0.03%	0.13%	-0.14%
Mastercard Inc	MA	945.72	363.41	0.63	18.50	343,685.20	1.04%	0.66%	19.32%
CarMax Inc	KMX	158.02	64.28	n/a	-3.00	10,157.72	0.03%		-0.09%
Intercontinental Exchange Inc	ICE	558.85	104.29	1.61	7.00	58,282.57	0.18%	0.29%	1.24%
Fidelity National Information Services Inc	FIS	591.94	54.33	3.83	52.00	32,159.83	0.10%	0.37%	5.08%
Chipotle Mexican Grill Inc	CMG	27.62	1708.29	n/a	20.00	47,186.39	0.14%		2.87%
Wynn Resorts Ltd	WYNN	113.68	111.91	n/a	27.00	12,722.15	0.04%		1.04%
Live Nation Entertainment Inc	LYV	231.59	70.00	n/a		Excl.	Excl.		
Assurant Inc	AIZ	52.92	120.07	2.33	15.50	6,354.22	0.02%	0.05%	0.30%
NRG Energy Inc	NRG	232.27	34.29	4.40	-2.50	7,964.54	0.02%	0.11%	-0.06%
Regions Financial Corp	RF	934.56	18.56	4.31	11.50	17,345.47	0.05%	0.23%	0.61%
Monster Beverage Corp	MNST	1044.82	54.01	n/a	10.50	56,430.67	0.17%		1.80%
Mosaic Co/The	MOS	336.49	45.88	1.74	7.50	15,438.02	0.05%	0.08%	0.35%
Baker Hughes Co	BKR	1011.22	28.86	2.63		Excl.	Excl.		
Expedia Group Inc	EXPE	147.83	97.03	n/a		Excl.	Excl.		
CF Industries Holdings Inc	CF	195.77	72.49	2.21	11.00	14,191.22	0.04%	0.10%	0.47%

Name	Ticker	Shares Outst'g	Price	Dividend Yield	Value Line Long-Term Growth Estimate	Market Cap Excl. n/a Growth	% of Total Market Cap.	Cap. Weighted Div. Yield	Cap. Weighted Long-Term Growth
Leidos Holdings Inc	LDOS	137.19	92.06	1.56	8.00	12,629.99	0.04%	0.06%	0.31%
APA Corp	APA	310.95	36.06	2.77		Excl.	Excl.		
Alphabet Inc	GOOG	5968.00	104.00	n/a	18.50	620,672.00	1.89%		34.89%
First Solar Inc	FSLR	106.82	217.50	n/a	24.50	23,234.00	0.07%		1.73%
TE Connectivity Ltd	TEL	316.46	131.15	1.80	10.50	41,503.34	0.13%	0.23%	1.32%
Cooper Cos Inc/The	COO	49.46	373.36	0.02	12.00	18,464.89	0.06%	0.00%	0.67%
Discover Financial Services	DFS	259.36	98.84	2.43	8.50	25,635.24	0.08%	0.19%	0.66%
Linde PLC	LIN	490.77	355.44	1.43	10.00	174,438.22	0.53%	0.76%	5.30%
Visa Inc	V	1624.95	225.46	0.80	13.50	366,362.13	1.11%	0.89%	15.03%
Mid-America Apartment Communities Inc	MAA	116.60	151.04	3.71	-12.50	17,611.11	0.05%	0.20%	-0.67%
Xylem Inc/NY	XYL	180.28	104.70	1.26	9.00	18,875.11	0.06%	0.07%	0.52%
Marathon Petroleum Corp	MPC	441.63	134.83	2.23		Excl.	Excl.		
Tractor Supply Co	TSCO	110.07	235.04	1.75	13.50	25,871.56	0.08%	0.14%	1.06%
Advanced Micro Devices Inc	AMD	1611.39	98.01	n/a	25.50	157,932.14	0.48%		12.24%
ResMed Inc	RMD	146.91	218.99	0.80	8.50	32,171.60	0.10%	0.08%	0.83%
Mettler-Toledo International Inc	MTD	22.07	1530.21	n/a	13.50	33,771.73	0.10%		1.39%
Jacobs Solutions Inc	J	126.71	117.51	0.89	12.00	14,890.16	0.05%	0.04%	0.54%
Copart Inc	CPRT	476.59	75.21	n/a	7.00	35,844.56	0.11%		0.76%
VICI Properties Inc	VICI	1004.21	32.62	4.78	7.00	32,757.17	0.10%	0.48%	0.70%
Albemarle Corp	ALB	117.30	221.04	0.72	21.50	25,927.77	0.08%	0.06%	1.69%
Fortinet Inc	FTNT	784.07	66.46	n/a	21.50	52,109.03	0.16%		3.40%
Moderna Inc	MRNA	385.68	153.58	n/a	-2.50	59,232.43	0.18%		-0.45%
Essex Property Trust Inc	ESS	64.46	209.14	4.42	-3.00	13,482.00	0.04%	0.18%	-0.12%
CoStar Group Inc	CSGP	406.77	68.85	n/a	13.00	28,006.25	0.09%		1.11%
Realty Income Corp	O	660.52	63.32	4.83	5.50	41,824.19	0.13%	0.61%	0.70%
Westrock Co	WRK	254.65	30.47	3.61	10.00	7,759.25	0.02%	0.09%	0.24%
Westinghouse Air Brake Technologies Corp	WAB	180.35	101.06	0.67	9.50	18,226.37	0.06%	0.04%	0.53%
Pool Corp	POOL	39.10	342.44	1.17	14.00	13,389.75	0.04%	0.05%	0.57%
Western Digital Corp	WDC	319.32	37.67	n/a	4.00	12,028.86	0.04%		0.15%
PepsiCo Inc	PEP	1377.32	182.30	2.52	6.50	251,084.52	0.76%	1.93%	4.96%
Diamondback Energy Inc	FANG	183.59	135.17	8.73		Excl.	Excl.		
ServiceNow Inc	NOW	203.00	464.72	n/a	45.50	94,338.16	0.29%		13.04%
Church & Dwight Co Inc	CHD	244.04	88.41	1.23	6.00	21,575.66	0.07%	0.08%	0.39%
Federal Realty Investment Trust	FRT	81.35	98.83	4.37	2.50	8,040.12	0.02%	0.11%	0.06%
MGM Resorts International	MGM	372.89	44.42	n/a	25.00	16,563.86	0.05%		1.26%
American Electric Power Co Inc	AEP	514.41	90.99	3.65	6.00	46,805.89	0.14%	0.52%	0.85%
SolarEdge Technologies Inc	SEDG	56.15	303.95	n/a	27.00	17,065.88	0.05%		1.40%
Invitation Homes Inc	INVH	611.41	31.23	3.33		Excl.	Excl.		
PTC Inc	PTC	118.26	128.23	n/a	29.00	15,164.86	0.05%		1.34%
JB Hunt Transport Services Inc	JBHT	103.77	175.46	0.96	10.00	18,207.48	0.06%	0.05%	0.55%
Lam Research Corp	LRCX	134.94	530.12	1.30	14.00	71,532.27	0.22%	0.28%	3.04%
Mohawk Industries Inc	MHK	63.54	100.22	n/a	10.00	6,367.98	0.02%		0.19%
GE HealthCare Technologies Inc	GEHC	453.93	82.03	n/a		Excl.	Excl.		
Pentair PLC	PNR	164.94	55.27	1.59	12.00	9,116.23	0.03%	0.04%	0.33%
Vertex Pharmaceuticals Inc	VRTX	257.09	315.07	n/a	13.50	81,001.66	0.25%		3.32%
Amcor PLC	AMCR	1485.78	11.38	4.31	14.50	16,908.18	0.05%	0.22%	0.75%
Meta Platforms Inc	META	2225.76	211.94	n/a	11.00	471,728.21	1.43%		15.77%
T-Mobile US Inc	TMUS	1219.38	144.84	n/a	16.00	176,615.43	0.54%		8.59%
United Rentals Inc	URI	69.36	395.76	1.50	18.00	27,449.91	0.08%	0.12%	1.50%
Honeywell International Inc	HON	668.14	191.12	2.16	12.00	127,694.92	0.39%	0.84%	4.66%
Alexandria Real Estate Equities Inc	ARE	173.09	125.59	3.85	11.00	21,738.00	0.07%	0.25%	0.73%
Delta Air Lines Inc	DAL	641.24	34.92	n/a		Excl.	Excl.		
Seagate Technology Holdings PLC	STX	206.48	66.12	4.23	12.00	13,652.72	0.04%	0.18%	0.50%
United Airlines Holdings Inc	UAL	326.73	44.25	n/a		Excl.	Excl.		
News Corp	NWS	193.24	17.43	1.15		Excl.	Excl.		
Centene Corp	CNC	550.70	63.21	n/a	9.00	34,809.75	0.11%		0.95%
Martin Marietta Materials Inc	MLM	62.10	355.06	0.74	4.50	22,050.65	0.07%	0.05%	0.30%
Teradyne Inc	TER	156.05	107.51	0.41	19.00	16,776.72	0.05%	0.02%	0.97%
PayPal Holdings Inc	PYPL	1131.37	75.94	n/a	12.00	85,916.47	0.26%		3.13%
Tesla Inc	TSLA	3164.10	207.46	n/a	21.50	656,424.81	1.99%		42.89%
Arch Capital Group Ltd	ACGL	371.20	67.87	n/a	21.50	25,193.14	0.08%		1.65%
DISH Network Corp	DISH	292.72	9.33	n/a	-4.00	2,731.05	0.01%		-0.03%
Dow Inc	DOW	707.99	54.82	5.11	8.50	38,811.96	0.12%	0.60%	1.00%
Everest Re Group Ltd	RE	39.16	358.02	1.84	9.50	14,018.99	0.04%	0.08%	0.40%
Teledyne Technologies Inc	TDY	47.00	447.36	n/a	9.50	21,023.68	0.06%		0.61%
News Corp	NWSA	382.36	17.27	1.16		Excl.	Excl.		
Exelon Corp	EXC	994.30	41.89	3.44		Excl.	Excl.		
Global Payments Inc	GPN	263.78	105.24	0.95	17.00	27,760.63	0.08%	0.08%	1.43%
Crown Castle Inc	CCI	433.67	133.84	4.68	13.50	58,042.26	0.18%	0.82%	2.38%
Aptiv PLC	APTV	270.95	112.19	n/a	30.00	30,397.88	0.09%		2.77%
Advance Auto Parts Inc	AAP	59.27	121.61	4.93	12.00	7,208.31	0.02%	0.11%	0.26%
Align Technology Inc	ALGN	76.74	334.14	n/a	17.00	25,641.57	0.08%		1.32%
Illumina Inc	ILMN	158.00	232.55	n/a	6.50	36,742.90	0.11%		0.73%
Targa Resources Corp	TRGP	226.28	72.95	1.92		Excl.	Excl.		
LKQ Corp	LKQ	267.29	56.76	1.94	13.00	15,171.38	0.05%	0.09%	0.60%
Zoetis Inc	ZTS	462.95	166.44	0.90	9.00	77,052.57	0.23%	0.21%	2.11%
Equinix Inc	EQIX	92.75	721.04	1.89	15.00	66,872.85	0.20%	0.38%	3.05%
Digital Realty Trust Inc	DLR	291.30	98.31	4.96	-1.00	28,637.31	0.09%	0.43%	-0.09%
Molina Healthcare Inc	MOH	58.27	267.49	n/a	12.50	15,586.37	0.05%		0.59%
Las Vegas Sands Corp	LVS	764.27	57.45	n/a		Excl.	Excl.		

MARKET RISK PREMIUM DERIVED FROM S&P 500 - FERC METHODOLOGY

[4] Cap. Weighted Estimate of the S&P 500 Dividend Yield	1.79%
[5] Cap. Weighted Estimate of the S&P 500 Growth Rate	10.32%
[6] Cap. Weighted S&P 500 Estimated Required Market Return	12.20%

Notes:
[4] Source: Bloomberg Professional, as of March 31, 2023
[5] Source: Value Line, as of March 31, 2023
[3] Equals ([4] x (1 + (0.5 x [5]))) + [5]

Name	Ticker	Shares Outst'g	Price	Dividend Yield	Value Line Long-Term Growth Estimate	Market Cap Excl. n/a Growth	% of Total Market Cap.	Cap. Weighted Div. Yield	Cap. Weighted Long-Term Growth
LyondellBasell Industries NV	LYB	325.99	93.89	5.07	3.00	30,607.39	0.11%	0.55%	0.33%
American Express Co	AXP	744.07	164.95	1.45	10.00	122,733.69	0.44%	0.64%	4.38%
Verizon Communications Inc	VZ	4200.00	38.89	6.71	2.50	163,338.00	0.58%	3.91%	1.46%
Broadcom Inc	AVGO	416.92	641.54	2.87	30.00	Excl.	Excl.		
Boeing Co/The	BA	599.18	212.43	n/a		Excl.	Excl.		
Caterpillar Inc	CAT	516.35	228.84	2.10	10.50	118,160.39	0.42%	0.88%	4.43%
JPMorgan Chase & Co	JPM	2943.36	130.31	3.07	5.00	383,548.59	1.37%	4.20%	6.84%
Chevron Corp	CVX	1906.67	163.16	3.70	45.00	Excl.	Excl.		
Coca-Cola Co/The	KO	4326.31	62.03	2.97	8.00	268,360.76	0.96%	2.84%	7.66%
AbbVie Inc	ABBV	1769.40	159.37	3.71	2.00	281,989.28	1.01%	3.74%	2.01%
Walt Disney Co/The	DIS	1826.83	100.13	n/a	86.00	Excl.	Excl.		
FleetCor Technologies Inc	FLT	73.49	210.85	n/a	10.50	15,495.79	0.06%		0.58%
Extra Space Storage Inc	EXR	134.99	162.93	3.98	6.50	21,993.11	0.08%	0.31%	0.51%
Exxon Mobil Corp	XOM	4070.99	109.66	3.32		Excl.	Excl.		
Phillips 66	PSX	460.91	101.38	4.14		Excl.	Excl.		
General Electric Co	GE	1090.28	95.60	0.33	21.00	Excl.	Excl.		
HP Inc	HPQ	985.33	29.35	3.58	12.50	28,919.38	0.10%	0.37%	1.29%
Home Depot Inc/The	HD	1014.96	295.12	2.83	9.00	299,533.81	1.07%	3.03%	9.62%
Monolithic Power Systems Inc	MPWR	47.31	500.54	0.80	21.00	Excl.	Excl.		
International Business Machines Corp	IBM	907.11	131.09	5.03	3.00	118,912.53	0.42%	2.14%	1.27%
Johnson & Johnson	JNJ	2604.29	155.00	2.92	8.00	403,664.33	1.44%	4.20%	11.53%
McDonald's Corp	MCD	731.50	279.61	2.17	9.00	204,533.88	0.73%	1.59%	6.57%
Merck & Co Inc	MRK	2538.59	106.39	2.74	8.50	270,080.80	0.96%	2.65%	8.19%
3M Co	MMM	551.47	105.11	5.71	7.50	57,964.91	0.21%	1.18%	1.55%
American Water Works Co Inc	AWK	194.64	146.49	1.79	3.00	28,513.25	0.10%	0.18%	0.31%
Bank of America Corp	BAC	8003.84	28.60	3.08	8.50	228,909.80	0.82%	2.51%	6.94%
Pfizer Inc	PFE	5644.40	40.80	4.02	2.00	230,291.60	0.82%	3.30%	1.64%
Procter & Gamble Co/The	PG	2359.14	148.69	2.46	5.50	350,781.12	1.25%	3.08%	6.89%
AT&T Inc	T	7129.87	19.25	5.77	1.00	137,250.00	0.49%	2.82%	0.49%
Travelers Cos Inc/The	TRV	232.09	171.41	2.17	7.50	39,783.23	0.14%	0.31%	1.06%
Raytheon Technologies Corp	RTX	1463.21	97.93	2.25	14.00	143,291.96	0.51%	1.15%	7.16%
Analog Devices Inc	ADI	505.85	197.22	1.74	11.50	99,764.13	0.36%	0.62%	4.09%
Walmart Inc	WMT	2695.66	147.45	1.55	7.50	397,474.48	1.42%	2.19%	10.64%
Cisco Systems Inc	CSCO	4095.82	52.28	2.98	8.50	214,109.15	0.76%	2.28%	6.50%
Intel Corp	INTC	4137.00	32.67	1.53		Excl.	Excl.		
General Motors Co	GM	1394.64	36.68	0.98	8.50	51,155.29	0.18%	0.18%	1.55%
Microsoft Corp	MSFT	7443.80	288.30	0.94	15.00	2,146,048.69	7.66%	7.23%	114.89%
Dollar General Corp	DG	219.11	210.46	1.12	10.00	46,113.47	0.16%	0.18%	1.65%
Cigna Group/The	CI	297.03	255.53	1.93	10.00	75,900.84	0.27%	0.52%	2.71%
Kinder Morgan Inc	KMI	2248.00	17.51	6.34	18.50	39,362.53	0.14%	0.89%	2.60%
Citigroup Inc	C	1946.47	46.89	4.35	3.50	91,269.74	0.33%	1.42%	1.14%
American International Group Inc	AIG	733.67	50.36	2.54	6.50	36,947.52	0.13%	0.34%	0.86%
Altria Group Inc	MO	1785.56	44.62	8.43	6.00	79,671.87	0.28%	2.40%	1.71%
HCA Healthcare Inc	HCA	277.26	263.68	0.91	12.50	73,106.60	0.26%	0.24%	3.26%
International Paper Co	IP	349.37	36.06	5.13	9.50	12,598.14	0.04%	0.23%	0.43%
Hewlett Packard Enterprise Co	HPE	1295.87	15.93	3.01	7.50	20,643.19	0.07%	0.22%	0.55%
Abbott Laboratories	ABT	1737.95	101.26	2.01	6.50	175,984.41	0.63%	1.27%	4.08%
Aflac Inc	AFL	611.71	64.52	2.60	8.00	39,467.40	0.14%	0.37%	1.13%
Air Products and Chemicals Inc	APD	222.08	287.21	2.44	11.50	63,784.46	0.23%	0.55%	2.62%
Royal Caribbean Cruises Ltd	RCL	255.35	65.30	n/a		Excl.	Excl.		
Hess Corp	HES	306.18	132.34	1.32		Excl.	Excl.		
Archer-Daniels-Midland Co	ADM	546.45	79.66	2.26	13.00	43,529.81	0.16%	0.35%	2.02%
Automatic Data Processing Inc	ADP	414.35	222.63	2.25	10.00	92,247.19	0.33%	0.74%	3.29%
Verisk Analytics Inc	VRSK	154.70	191.86	0.71	13.00	29,679.97	0.11%	0.08%	1.38%
AutoZone Inc	AZO	18.40	2458.15	n/a	14.50	45,225.04	0.16%		2.34%
Avery Dennison Corp	AVY	81.11	178.93	1.68	9.50	14,512.83	0.05%	0.09%	0.49%
Enphase Energy Inc	ENPH	136.50	210.28	n/a	24.50	Excl.	Excl.		
MSCI Inc	MSCI	80.06	559.69	0.99	12.50	44,810.46	0.16%	0.16%	2.00%
Ball Corp	BALL	314.40	55.11	1.45	21.50	Excl.	Excl.		
Ceridian HCM Holding Inc	CDAY	152.70	73.22	n/a		Excl.	Excl.		
Carrier Global Corp	CARR	834.95	45.75	1.62		Excl.	Excl.		
Bank of New York Mellon Corp/The	BK	808.45	45.44	3.26	6.00	36,735.74	0.13%	0.43%	0.79%
Otis Worldwide Corp	OTIS	414.87	84.40	1.37		Excl.	Excl.		
Baxter International Inc	BAX	505.52	40.56	2.86	7.00	20,504.01	0.07%	0.21%	0.51%
Becton Dickinson & Co	BDX	283.90	247.54	1.47	4.50	70,277.10	0.25%	0.37%	1.13%
Berkshire Hathaway Inc	BRK/B	1298.19	308.77	n/a		Excl.	Excl.		
Best Buy Co Inc	BBY	218.05	78.27	4.70	4.00	17,066.46	0.06%	0.29%	0.24%
Boston Scientific Corp	BSX	1437.33	50.03	n/a	15.50	71,909.52	0.26%		3.98%
Bristol-Myers Squibb Co	BMY	2098.78	69.31	3.29		Excl.	Excl.		
Brown-Forman Corp	BF/B	310.00	64.27	1.28		Excl.	Excl.		
Coterra Energy Inc	CTRA	765.50	24.54	9.29		Excl.	Excl.		

Name	Ticker	Shares Outst'g	Price	Dividend Yield	Value Line Long-Term Growth Estimate	Market Cap Excl. n/a Growth	% of Total Market Cap.	Cap. Weighted Div. Yield	Cap. Weighted Long-Term Growth
Campbell Soup Co	CPB	299.48	54.98	2.69	5.00	16,465.19	0.06%	0.16%	0.29%
Hilton Worldwide Holdings Inc	HLT	266.45	140.87	0.43		Excl.	Excl.		
Carnival Corp	CCL	1113.48	10.15	n/a		Excl.	Excl.		
Qorvo Inc	QRVO	99.89	101.57	n/a	14.50	10,145.73	0.04%		0.53%
UDR Inc	UDR	329.17	41.06	4.09	17.00	13,515.56	0.05%	0.20%	0.82%
Clorox Co/The	CLX	123.53	158.24	2.98	7.00	19,546.60	0.07%	0.21%	0.49%
Paycom Software Inc	PAYC	60.31	304.01	n/a	21.00	Excl.	Excl.		
CMS Energy Corp	CMS	291.26	61.38	3.18	6.50	17,877.78	0.06%	0.20%	0.41%
Newell Brands Inc	NWL	413.60	12.44	7.40		Excl.	Excl.		
Colgate-Palmolive Co	CL	832.14	75.15	2.55	6.00	62,535.17	0.22%	0.57%	1.34%
EPAM Systems Inc	EPAM	57.68	299.00	n/a	20.50	Excl.	Excl.		
Comerica Inc	CMA	131.51	43.42	6.54	8.50	5,710.34	0.02%	0.13%	0.17%
Conagra Brands Inc	CAG	476.62	37.56	3.51	3.50	17,901.96	0.06%	0.22%	0.22%
Consolidated Edison Inc	ED	355.05	95.67	3.39	4.50	33,967.16	0.12%	0.41%	0.55%
Corning Inc	GLW	847.23	35.28	3.17	17.50	29,890.34	0.11%	0.34%	1.87%
Cummins Inc	CMI	141.54	238.88	2.63	8.50	33,811.08	0.12%	0.32%	1.03%
Caesars Entertainment Inc	CZR	215.18	48.81	n/a		Excl.	Excl.		
Danaher Corp	DHR	728.58	252.04	0.43	16.00	183,630.55	0.66%	0.28%	10.49%
Target Corp	TGT	460.36	165.63	2.61	12.00	76,250.09	0.27%	0.71%	3.27%
Deere & Co	DE	296.32	412.88	1.21	12.50	122,345.43	0.44%	0.53%	5.46%
Dominion Energy Inc	D	835.25	55.91	4.78	4.00	46,698.88	0.17%	0.80%	0.67%
Dover Corp	DOV	139.77	151.94	1.33	9.00	21,236.81	0.08%	0.10%	0.68%
Alliant Energy Corp	LNT	251.14	53.40	3.39	6.00	13,410.77	0.05%	0.16%	0.29%
Steel Dynamics Inc	STLD	171.58	113.06	1.50	2.00	19,398.61	0.07%	0.10%	0.14%
Duke Energy Corp	DUK	770.65	96.47	4.17	5.00	74,344.41	0.27%	1.11%	1.33%
Regency Centers Corp	REG	171.31	61.18	4.25	10.50	10,480.62	0.04%	0.16%	0.39%
Eaton Corp PLC	ETN	398.00	171.34	2.01	12.00	68,193.32	0.24%	0.49%	2.92%
Ecolab Inc	ECL	284.67	165.53	1.28	6.00	47,121.26	0.17%	0.22%	1.01%
PerkinElmer Inc	PKI	126.41	133.26	0.21	4.00	16,845.66	0.06%	0.01%	0.24%
Emerson Electric Co	EMR	571.40	87.14	2.39	6.50	49,791.80	0.18%	0.42%	1.16%
EOG Resources Inc	EOG	587.72	114.63	2.88	26.00	Excl.	Excl.		
Aon PLC	AON	205.14	315.29	0.71	7.50	64,679.22	0.23%	0.16%	1.73%
Entergy Corp	ETR	212.09	107.74	3.97	0.50	22,850.68	0.08%	0.32%	0.04%
Equifax Inc	EFX	123.23	202.84	0.77	7.00	24,995.36	0.09%	0.07%	0.62%
EQT Corp	EQT	360.36	31.91	1.88		Excl.	Excl.		
IQVIA Holdings Inc	IQV	186.14	198.89	n/a	14.50	37,021.58	0.13%		1.92%
Gartner Inc	IT	79.06	325.77	n/a	17.50	25,755.70	0.09%		1.61%
FedEx Corp	FDX	251.35	228.49	2.01	9.00	57,431.42	0.20%	0.41%	1.84%
FMC Corp	FMC	125.14	122.13	1.90	10.50	15,283.59	0.05%	0.10%	0.57%
Brown & Brown Inc	BRO	283.70	57.42	0.80	8.00	16,289.94	0.06%	0.05%	0.47%
Ford Motor Co	F	3915.33	12.60	4.76	27.50	Excl.	Excl.		
NextEra Energy Inc	NEE	1987.50	77.08	2.43	10.00	153,196.11	0.55%	1.33%	5.47%
Franklin Resources Inc	BEN	500.36	26.94	4.45	3.50	13,479.64	0.05%	0.21%	0.17%
Garmin Ltd	GRMN	191.36	100.92	2.89	5.00	19,311.95	0.07%	0.20%	0.34%
Freeport-McMoRan Inc	FCX	1430.69	40.91	1.47	18.50	58,529.69	0.21%	0.31%	3.86%
Dexcom Inc	DXCM	386.41	116.18	n/a		Excl.	Excl.		
General Dynamics Corp	GD	274.71	228.21	2.31	9.50	62,692.48	0.22%	0.52%	2.13%
General Mills Inc	GIS	587.35	85.46	2.53	4.00	50,195.27	0.18%	0.45%	0.72%
Genuine Parts Co	GPC	140.81	167.31	2.27	10.50	23,558.75	0.08%	0.19%	0.88%
Atmos Energy Corp	ATO	143.16	112.36	2.63	7.00	16,085.79	0.06%	0.15%	0.40%
WW Grainger Inc	GWW	50.26	688.81	1.00	9.00	34,621.66	0.12%	0.12%	1.11%
Halliburton Co	HAL	904.08	31.64	2.02	32.50	Excl.	Excl.		
L3Harris Technologies Inc	LHX	189.96	196.24	2.32	17.00	37,277.16	0.13%	0.31%	2.26%
Healthpeak Properties Inc	PEAK	546.99	21.97	5.46	14.50	12,017.44	0.04%	0.23%	0.62%
Insulet Corp	PODD	69.54	318.96	n/a		Excl.	Excl.		
Catalent Inc	CTLT	180.09	65.71	n/a	21.00	Excl.	Excl.		
Fortive Corp	FTV	353.20	68.17	0.41	12.00	24,077.58	0.09%	0.04%	1.03%
Hershey Co/The	HSY	146.92	254.41	1.63	9.00	37,378.43	0.13%	0.22%	1.20%
Synchrony Financial	SYF	437.04	29.08	3.16	9.50	12,708.98	0.05%	0.14%	0.43%
Hormel Foods Corp	HRL	546.53	39.88	2.76	7.50	21,795.74	0.08%	0.21%	0.58%
Arthur J Gallagher & Co	AJG	214.08	191.31	1.15	18.50	40,954.69	0.15%	0.17%	2.70%
Mondelez International Inc	MDLZ	1363.31	69.72	2.21	7.50	95,049.76	0.34%	0.75%	2.54%
CenterPoint Energy Inc	CNP	629.43	29.46	2.58	6.50	18,543.07	0.07%	0.17%	0.43%
Humana Inc	HUM	124.98	485.46	0.73	12.50	60,670.36	0.22%	0.16%	2.71%
Willis Towers Watson PLC	WTW	106.58	232.38	1.45	8.50	24,766.60	0.09%	0.13%	0.75%
Illinois Tool Works Inc	ITW	304.82	243.45	2.15	11.00	74,208.67	0.26%	0.57%	2.91%
CDW Corp/DE	CDW	135.59	194.89	1.21	8.50	26,425.52	0.09%	0.11%	0.80%
Trane Technologies PLC	TT	229.08	183.98	1.63		Excl.	Excl.		
Interpublic Group of Cos Inc/The	IPG	385.11	37.24	3.33	10.00	14,341.42	0.05%	0.17%	0.51%
International Flavors & Fragrances Inc	IFF	255.07	91.96	3.52	6.00	23,455.96	0.08%	0.29%	0.50%
Generac Holdings Inc	GNRC	61.89	108.01	n/a	19.00	6,684.41	0.02%		0.45%
NXP Semiconductors NV	NXPI	259.52	186.48	2.18	11.00	48,393.81	0.17%	0.38%	1.90%
Kellogg Co	K	342.67	66.96	3.52	3.50	22,945.05	0.08%	0.29%	0.29%
Broadridge Financial Solutions Inc	BR	117.69	146.57	1.98	8.50	17,250.26	0.06%	0.12%	0.52%
Kimberly-Clark Corp	KMB	337.45	134.22	3.52	7.00	45,293.08	0.16%	0.57%	1.13%
Kimco Realty Corp	KIM	618.46	19.53	4.71	11.00	12,078.54	0.04%	0.20%	0.47%
Oracle Corp	ORCL	2699.80	92.92	1.72	10.00	250,865.60	0.90%	1.54%	8.95%
Kroger Co/The	KR	717.47	49.37	2.11	6.50	35,421.40	0.13%	0.27%	0.82%
Lennar Corp	LEN	252.47	105.11	1.43	8.50	26,536.70	0.09%	0.14%	0.81%
Eli Lilly & Co	LLY	950.30	343.42	1.32	11.50	326,350.65	1.16%	1.53%	13.39%
Bath & Body Works Inc	BBWI	228.77	36.58	2.19	26.50	Excl.	Excl.		
Charter Communications Inc	CHTR	152.65	357.61	n/a	15.50	54,589.52	0.19%		3.02%
Lincoln National Corp	LNC	169.22	22.47	8.01	30.50	Excl.	Excl.		
Loews Corp	L	230.88	58.02	0.43	18.50	13,395.43	0.05%	0.02%	0.88%
Lowe's Cos Inc	LOW	596.36	199.97	2.10	11.00	119,253.31	0.43%	0.89%	4.68%
IDEX Corp	IEX	75.52	231.03	1.04	11.00	17,446.92	0.06%	0.06%	0.68%
Marsh & McLennan Cos Inc	MMC	494.57	166.55	1.42	11.00	82,370.80	0.29%	0.42%	3.23%
Masco Corp	MAS	225.20	49.72	2.29	8.00	11,197.09	0.04%	0.09%	0.32%

Name	Ticker	Shares Outst'g	Price	Dividend Yield	Value Line Long-Term Growth Estimate	Market Cap Excl. n/a Growth	% of Total Market Cap.	Cap. Weighted Div. Yield	Cap. Weighted Long-Term Growth
S&P Global Inc	SPGI	327.95	344.77	1.04	6.50	113,066.29	0.40%	0.42%	2.62%
Medtronic PLC	MDT	1330.42	80.62	3.37	7.50	107,258.78	0.38%	1.29%	2.87%
Viatris Inc	VTRS	1196.81	9.62	4.99		Excl.	Excl.		
CVS Health Corp	CVS	1284.11	74.31	3.26	6.00	95,422.36	0.34%	1.11%	2.04%
DuPont de Nemours Inc	DD	458.34	71.77	2.01	10.00	32,894.92	0.12%	0.24%	1.17%
Micron Technology Inc	MU	1094.39	60.34	0.76	9.50	66,035.73	0.24%	0.18%	2.24%
Motorola Solutions Inc	MSI	167.47	286.13	1.23	10.50	47,917.33	0.17%	0.21%	1.80%
Cboe Global Markets Inc	CBOE	105.74	134.24	1.49	10.00	14,194.94	0.05%	0.08%	0.51%
Laboratory Corp of America Holdings	LH	88.50	229.42	1.26	1.50	20,303.90	0.07%	0.09%	0.11%
Newmont Corp	NEM	794.51	49.02	3.26	8.00	38,946.83	0.14%	0.45%	1.11%
NIKE Inc	NKE	1245.67	122.64	1.11	24.00	Excl.	Excl.		
NiSource Inc	NI	412.51	27.96	3.58	9.50	11,533.72	0.04%	0.15%	0.39%
Norfolk Southern Corp	NSC	227.78	212.00	2.55	10.00	48,289.78	0.17%	0.44%	1.72%
Principal Financial Group Inc	PFG	243.10	74.32	3.44	6.50	18,067.49	0.06%	0.22%	0.42%
Eversource Energy	ES	348.67	78.26	3.45	6.50	27,287.15	0.10%	0.34%	0.63%
Northrop Grumman Corp	NOC	152.09	461.72	1.50	9.50	70,221.61	0.25%	0.38%	2.38%
Wells Fargo & Co	WFC	3777.09	37.38	3.21	12.00	141,187.55	0.50%	1.62%	6.05%
Nucor Corp	NUE	251.93	154.47	1.32	9.50	38,915.47	0.14%	0.18%	1.32%
Occidental Petroleum Corp	OXY	898.12	62.43	1.15		Excl.	Excl.		
Omnicom Group Inc	OMC	201.41	94.34	2.97	6.50	19,000.93	0.07%	0.20%	0.44%
ONEOK Inc	OKE	447.22	63.54	6.01	11.50	28,416.42	0.10%	0.61%	1.17%
Raymond James Financial Inc	RJF	215.35	93.27	1.80	15.00	20,085.88	0.07%	0.13%	1.08%
PG&E Corp	PCG	1988.47	16.17	n/a	7.50	32,153.48	0.11%		0.86%
Parker-Hannifin Corp	PH	128.27	336.11	1.58	15.50	43,111.49	0.15%	0.24%	2.38%
Rollins Inc	ROL	492.74	37.53	1.39	10.50	18,492.68	0.07%	0.09%	0.69%
PPL Corp	PPL	736.68	27.79	3.45	3.50	20,472.28	0.07%	0.25%	0.26%
ConocoPhillips	COP	1217.38	99.21	0.60	20.00	120,776.57	0.43%	0.26%	8.62%
PulteGroup Inc	PHM	224.31	58.28	1.10	7.00	13,072.85	0.05%	0.05%	0.33%
Pinnacle West Capital Corp	PNW	113.18	79.24	4.37	0.50	8,968.07	0.03%	0.14%	0.02%
PNC Financial Services Group Inc/The	PNC	399.75	127.10	4.72	12.00	50,808.61	0.18%	0.86%	2.18%
PPG Industries Inc	PPG	235.36	133.58	1.86	4.00	31,439.12	0.11%	0.21%	0.45%
Progressive Corp/The	PGR	585.37	143.06	0.28	6.50	83,742.46	0.30%	0.08%	1.94%
Public Service Enterprise Group Inc	PEG	498.77	62.45	3.65	4.50	31,148.19	0.11%	0.41%	0.50%
Robert Half International Inc	RHI	107.70	80.57	2.38	9.50	8,677.23	0.03%	0.07%	0.29%
Edison International	EIX	382.63	70.59	4.18	16.00	27,009.64	0.10%	0.40%	1.54%
Schlumberger NV	SLB	1427.60	49.10	2.04	28.50	Excl.	Excl.		
Charles Schwab Corp/The	SCHW	1791.45	52.38	1.91	9.00	93,836.05	0.33%	0.64%	3.01%
Sherwin-Williams Co/The	SHW	258.44	224.77	1.08	7.00	58,090.01	0.21%	0.22%	1.45%
West Pharmaceutical Services Inc	WST	74.14	346.47	0.22	17.00	25,685.90	0.09%	0.02%	1.56%
J M Smucker Co/The	SJM	106.64	157.37	2.59	4.00	16,781.31	0.06%	0.16%	0.24%
Snap-on Inc	SNA	53.13	246.89	2.62	4.50	13,117.02	0.05%	0.12%	0.21%
AMETEK Inc	AME	230.09	145.33	0.69	10.00	33,439.56	0.12%	0.08%	1.19%
Southern Co/The	SO	1088.67	69.58	3.91	6.50	75,749.87	0.27%	1.06%	1.76%
Truist Financial Corp	TFC	1328.14	34.10	6.10	5.50	45,289.57	0.16%	0.99%	0.89%
Southwest Airlines Co	LUV	594.29	32.54	2.21		Excl.	Excl.		
W R Berkley Corp	WRB	263.45	62.26	0.64	17.50	16,402.15	0.06%	0.04%	1.02%
Stanley Black & Decker Inc	SWK	153.06	80.58	3.97	6.00	12,333.17	0.04%	0.17%	0.26%
Public Storage	PSA	175.80	302.14	3.97	7.50	53,114.70	0.19%	0.75%	1.42%
Arista Networks Inc	ANET	306.40	167.86	n/a	10.00	51,431.46	0.18%		1.84%
Sysco Corp	SYY	507.60	77.23	2.54	21.50	Excl.	Excl.		
Corteva Inc	CTVA	712.61	60.31	0.99	15.50	42,977.21	0.15%	0.15%	2.38%
Texas Instruments Inc	TXN	907.34	186.01	2.67	4.50	168,774.69	0.60%	1.61%	2.71%
Textron Inc	TXT	203.66	70.63	0.11	10.50	14,384.51	0.05%	0.01%	0.54%
Thermo Fisher Scientific Inc	TMO	385.43	576.37	0.24	11.00	222,150.29	0.79%	0.19%	8.72%
TJX Cos Inc/The	TJX	1152.57	78.36	1.70	17.00	90,315.31	0.32%	0.55%	5.48%
Globe Life Inc	GL	96.52	110.02	0.82	8.50	10,619.24	0.04%	0.03%	0.32%
Johnson Controls International plc	JCI	687.21	60.22	2.39	12.50	41,384.03	0.15%	0.35%	1.85%
Ulta Beauty Inc	ULTA	50.20	545.67	n/a	16.50	27,389.91	0.10%		1.61%
Union Pacific Corp	UNP	611.87	201.26	2.58	9.50	123,145.56	0.44%	1.14%	4.18%
Keysight Technologies Inc	KEYS	178.14	161.48	n/a	13.00	28,765.89	0.10%		1.33%
UnitedHealth Group Inc	UNH	932.85	472.59	1.40	12.00	440,854.16	1.57%	2.20%	18.88%
Marathon Oil Corp	MRO	629.65	23.96	1.67		Excl.	Excl.		
Bio-Rad Laboratories Inc	BIO	24.52	479.02	n/a	11.50	11,746.53	0.04%		0.48%
Ventas Inc	VTR	399.99	43.35	4.15	23.50	Excl.	Excl.		
VF Corp	VFC	388.66	22.91	5.24	9.00	8,904.13	0.03%	0.17%	0.29%
Vulcan Materials Co	VMC	133.06	171.56	1.00	9.00	22,827.26	0.08%	0.08%	0.73%
Weyerhaeuser Co	WY	732.89	30.13	2.52	5.00	22,082.04	0.08%	0.20%	0.39%
Whirlpool Corp	WHR	54.50	132.02	5.30	6.00	7,195.35	0.03%	0.14%	0.15%
Williams Cos Inc/The	WMB	1218.81	29.86	5.99	11.00	36,393.73	0.13%	0.78%	1.43%
Constellation Energy Corp	CEG	326.66	78.50	1.44		Excl.	Excl.		
WEC Energy Group Inc	WEC	315.44	94.79	3.29	6.00	29,900.08	0.11%	0.35%	0.64%
Adobe Inc	ADBE	458.70	385.37	n/a	13.00	176,769.22	0.63%		8.20%
AES Corp/The	AES	669.03	24.08	2.76	14.00	16,110.27	0.06%	0.16%	0.80%
Amgen Inc	AMGN	533.98	241.75	3.52	5.50	129,088.70	0.46%	1.62%	2.53%
Apple Inc	AAPL	15821.95	164.90	0.56	10.50	2,609,038.90	9.31%	5.20%	97.77%
Autodesk Inc	ADSK	214.78	208.16	n/a	14.00	44,709.23	0.16%		2.23%
Cintas Corp	CTAS	101.67	462.68	0.99	14.00	47,041.60	0.17%	0.17%	2.35%
Comcast Corp	CMCSA	4206.61	37.91	3.06	8.50	159,472.66	0.57%	1.74%	4.84%
Molson Coors Beverage Co	TAP	200.03	51.68	3.17	49.50	Excl.	Excl.		
KLA Corp	KLAC	138.48	399.17	1.30	20.00	55,277.06	0.20%	0.26%	3.95%
Marriott International Inc/MD	MAR	308.88	166.04	0.96	17.50	51,287.10	0.18%	0.18%	3.20%
McCormick & Co Inc/MD	MKC	250.84	83.21	1.87	4.50	20,872.23	0.07%	0.14%	0.34%
PACCAR Inc	PCAR	522.56	73.20	1.37	5.00	38,251.03	0.14%	0.19%	0.68%
Costco Wholesale Corp	COST	443.48	496.87	0.72	10.50	220,353.40	0.79%	0.57%	8.26%
First Republic Bank/CA	FRC	186.22	13.99	n/a	11.50	2,605.20	0.01%		0.11%
Stryker Corp	SYK	378.83	285.47	1.05	6.50	108,144.89	0.39%	0.41%	2.51%
Tyson Foods Inc	TSN	285.62	59.32	3.24	6.00	16,942.74	0.06%	0.20%	0.36%
Lamb Weston Holdings Inc	LW	147.82	104.52	1.07	11.50	15,450.46	0.06%	0.06%	0.63%

Name	Ticker	Shares Outst'g	Price	Dividend Yield	Value Line Long-Term Growth Estimate	Market Cap Excl. n/a Growth	% of Total Market Cap.	Cap. Weighted Div. Yield	Cap. Weighted Long-Term Growth
Applied Materials Inc	AMAT	845.12	122.83	1.04	10.50	103,805.84	0.37%	0.39%	3.89%
American Airlines Group Inc	AAL	652.82	14.75	n/a		Excl.	Excl.		
Cardinal Health Inc	CAH	257.64	75.50	2.63	5.00	19,451.74	0.07%	0.18%	0.35%
Cincinnati Financial Corp	CINF	157.18	112.08	2.68	9.00	17,616.29	0.06%	0.17%	0.57%
Paramount Global	PARA	609.81	22.31	4.30	4.50	13,604.91	0.05%	0.21%	0.22%
DR Horton Inc	DHI	343.39	97.69	1.02	1.00	33,546.06	0.12%	0.12%	0.12%
Electronic Arts Inc	EA	274.23	120.45	0.63	13.00	33,030.76	0.12%	0.07%	1.53%
Fair Isaac Corp	FICO	25.16	702.69	n/a	16.00	17,676.17	0.06%		1.01%
Expeditors International of Washington Inc	EXPD	154.40	110.12	1.22	10.00	17,002.31	0.06%	0.07%	0.61%
Fastenal Co	FAST	570.96	53.94	2.60	6.50	30,797.64	0.11%	0.29%	0.71%
M&T Bank Corp	MTB	168.04	119.57	4.35	9.00	20,093.02	0.07%	0.31%	0.65%
Xcel Energy Inc	XEL	549.85	67.44	3.08	6.00	37,081.68	0.13%	0.41%	0.79%
Fiserv Inc	FISV	628.13	113.03	n/a	11.00	70,997.08	0.25%		2.79%
Fifth Third Bancorp	FITB	681.05	26.64	4.95	10.00	18,143.28	0.06%	0.32%	0.65%
Gilead Sciences Inc	GILD	1248.82	82.97	3.62	12.00	103,614.26	0.37%	1.34%	4.44%
Hasbro Inc	HAS	138.22	53.69	5.22	7.50	7,421.03	0.03%	0.14%	0.20%
Huntington Bancshares Inc/OH	HBAN	1449.64	11.20	5.54	12.50	16,235.93	0.06%	0.32%	0.72%
Welltower Inc	WELL	490.64	71.69	3.40	12.00	35,174.27	0.13%	0.43%	1.51%
Biogen Inc	BIIB	144.49	278.03	n/a	-10.50	Excl.	Excl.		
Northern Trust Corp	NTRS	207.75	88.13	3.40	8.00	18,309.10	0.07%	0.22%	0.52%
Packaging Corp of America	PKG	89.88	138.83	3.60	11.00	12,478.60	0.04%	0.16%	0.49%
Paychex Inc	PAYX	360.51	114.59	2.76	10.50	41,310.73	0.15%	0.41%	1.55%
QUALCOMM Inc	QCOM	1115.00	127.58	2.35	9.50	142,251.70	0.51%	1.19%	4.82%
Roper Technologies Inc	ROP	106.24	440.69	0.62	3.50	46,820.23	0.17%	0.10%	0.58%
Ross Stores Inc	ROST	342.05	106.13	1.26	14.00	36,301.55	0.13%	0.16%	1.81%
IDEXX Laboratories Inc	IDXX	82.90	500.08	n/a	11.50	41,458.13	0.15%		1.70%
Starbucks Corp	SBUX	1149.30	104.13	2.04	16.00	119,676.61	0.43%	0.87%	6.83%
KeyCorp	KEY	924.86	12.52	6.55	7.50	11,579.23	0.04%	0.27%	0.31%
Fox Corp	FOXA	296.92	34.05	1.47	12.00	10,110.02	0.04%	0.05%	0.43%
Fox Corp	FOX	237.64	31.31	1.60		Excl.	Excl.		
State Street Corp	STT	344.48	75.69	3.33	8.50	26,073.62	0.09%	0.31%	0.79%
Norwegian Cruise Line Holdings Ltd	NCLH	421.93	13.45	n/a		Excl.	Excl.		
US Bancorp	USB	1531.12	36.05	5.33	7.00	55,196.88	0.20%	1.05%	1.38%
A O Smith Corp	AOS	125.01	69.15	1.74	11.50	8,644.44	0.03%	0.05%	0.35%
Gen Digital Inc	GEN	639.13	17.16	2.91	10.50	10,967.45	0.04%	0.11%	0.41%
T Rowe Price Group Inc	TROW	224.51	112.90	4.32	4.50	25,347.63	0.09%	0.39%	0.41%
Waste Management Inc	WM	406.77	163.17	1.72	6.50	66,372.17	0.24%	0.41%	1.54%
Constellation Brands Inc	STZ	184.50	225.89	1.42	6.00	41,676.25	0.15%	0.21%	0.89%
DENTSPLY SIRONA Inc	XRAY	215.36	39.28	1.43	12.00	8,459.42	0.03%	0.04%	0.36%
Zions Bancorp NA	ZION	148.10	29.93	5.48	6.50	4,432.60	0.02%	0.09%	0.10%
Alaska Air Group Inc	ALK	127.47	41.96	n/a		Excl.	Excl.		
Invesco Ltd	IVZ	454.72	16.40	4.57	10.00	7,457.47	0.03%	0.12%	0.27%
Intuit Inc	INTU	280.55	445.83	0.70	16.50	125,075.82	0.45%	0.31%	7.37%
Morgan Stanley	MS	1681.94	87.80	3.53	8.50	147,674.33	0.53%	1.86%	4.48%
Microchip Technology Inc	MCHP	547.80	83.78	1.71	10.00	45,894.35	0.16%	0.28%	1.64%
Chubb Ltd	CB	413.51	194.18	1.71	14.50	80,294.60	0.29%	0.49%	4.16%
Hologic Inc	HOLX	246.55	80.70	n/a	25.00	Excl.	Excl.		
Citizens Financial Group Inc	CFG	484.31	30.37	5.53	8.00	14,708.46	0.05%	0.29%	0.42%
O'Reilly Automotive Inc	ORLY	61.57	848.98	n/a	13.00	52,269.15	0.19%		2.43%
Allstate Corp/The	ALL	263.33	110.81	3.21	2.50	29,179.60	0.10%	0.33%	0.26%
Equity Residential	EQR	378.60	60.00	4.42	-5.00	Excl.	Excl.		
BorgWarner Inc	BWA	233.79	49.11	1.38	9.50	11,481.18	0.04%	0.06%	0.39%
Keurig Dr Pepper Inc	KDP	1406.45	35.28	2.27	11.50	49,619.45	0.18%	0.40%	2.04%
Organon & Co	OGN	254.38	23.52	4.76		Excl.	Excl.		
Host Hotels & Resorts Inc	HST	713.48	16.49	2.91	51.00	Excl.	Excl.		
Incyte Corp	INCY	222.97	72.27	n/a	27.00	Excl.	Excl.		
Simon Property Group Inc	SPG	326.73	111.97	6.43	3.50	36,584.18	0.13%	0.84%	0.46%
Eastman Chemical Co	EMN	119.14	84.34	3.75	7.00	10,048.10	0.04%	0.13%	0.25%
AvalonBay Communities Inc	AVB	139.92	168.06	3.93	7.00	23,514.96	0.08%	0.33%	0.59%
Prudential Financial Inc	PRU	366.97	82.74	6.04	3.00	30,363.43	0.11%	0.65%	0.33%
United Parcel Service Inc	UPS	723.30	193.99	3.34	7.50	140,312.77	0.50%	1.67%	3.76%
Walgreens Boots Alliance Inc	WBA	862.80	34.58	5.55	3.00	29,835.49	0.11%	0.59%	0.32%
STERIS PLC	STE	99.28	191.28	0.98	10.00	18,991.04	0.07%	0.07%	0.68%
McKesson Corp	MCK	136.94	356.05	0.61	10.00	48,757.13	0.17%	0.11%	1.74%
Lockheed Martin Corp	LMT	254.52	472.73	2.54	7.00	120,318.77	0.43%	1.09%	3.01%
AmerisourceBergen Corp	ABC	202.26	160.11	1.21	8.50	32,383.53	0.12%	0.14%	0.98%
Capital One Financial Corp	COF	381.08	96.16	2.50		Excl.	Excl.		
Waters Corp	WAT	58.94	309.63	n/a	6.00	18,250.83	0.07%		0.39%
Nordson Corp	NDSN	57.26	222.26	1.17	12.00	12,726.83	0.05%	0.05%	0.55%
Dollar Tree Inc	DLTR	221.23	143.55	n/a	12.00	31,757.28	0.11%		1.36%
Darden Restaurants Inc	DRI	121.71	155.16	3.12	17.50	18,883.75	0.07%	0.21%	1.18%
Evergy Inc	EVRG	229.58	61.12	4.01	7.50	14,032.11	0.05%	0.20%	0.38%
Match Group Inc	MTCH	279.32	38.39	n/a	21.00	Excl.	Excl.		
Domino's Pizza Inc	DPZ	35.42	329.87	1.47	13.00	11,683.34	0.04%	0.06%	0.54%
NVR Inc	NVR	3.25	5572.19	n/a	5.50	18,104.05	0.06%		0.36%
NetApp Inc	NTAP	213.91	63.85	3.13	8.50	13,657.83	0.05%	0.15%	0.41%
DXC Technology Co	DXC	227.68	25.56	n/a	12.00	5,819.55	0.02%		0.25%
Old Dominion Freight Line Inc	ODFL	110.03	340.84	0.47	12.50	37,501.26	0.13%	0.06%	1.67%
DaVita Inc	DVA	90.40	81.11	n/a	7.50	7,332.34	0.03%		0.20%
Hartford Financial Services Group Inc/The	HIG	313.06	69.69	2.44	6.50	21,816.94	0.08%	0.19%	0.51%
Iron Mountain Inc	IRM	291.57	52.91	4.68	10.00	15,427.18	0.06%	0.26%	0.55%
Estee Lauder Cos Inc/The	EL	231.68	246.46	1.07	14.00	57,099.36	0.20%	0.22%	2.85%
Cadence Design Systems Inc	CDNS	272.94	210.09	n/a	12.00	57,341.96	0.20%		2.46%
Tyler Technologies Inc	TYL	41.82	354.64	n/a	12.00	14,830.69	0.05%		0.64%
Universal Health Services Inc	UHS	63.42	127.10	0.63	5.50	8,060.30	0.03%	0.02%	0.16%
Skyworks Solutions Inc	SWKS	159.15	117.98	2.10	9.00	18,776.87	0.07%	0.14%	0.60%
Quest Diagnostics Inc	DGX	111.32	141.48	2.01	5.00	15,749.98	0.06%	0.11%	0.28%
Activision Blizzard Inc	ATVI	784.27	85.59	0.55	11.50	67,126.01	0.24%	0.13%	2.76%

Name	Ticker	Shares Outst'g	Price	Dividend Yield	Value Line Long-Term Growth Estimate	Market Cap Excl. n/a Growth	% of Total Market Cap.	Cap. Weighted Div. Yield	Cap. Weighted Long-Term Growth
Rockwell Automation Inc	ROK	114.78	293.45	1.61	9.50	33,682.78	0.12%	0.19%	1.14%
Kraft Heinz Co/The	KHC	1227.00	38.67	4.14	6.50	47,448.05	0.17%	0.70%	1.10%
American Tower Corp	AMT	465.65	204.34	3.05	6.00	95,150.10	0.34%	1.04%	2.04%
Regeneron Pharmaceuticals Inc	REGN	107.51	821.67	n/a	5.00	88,335.28	0.32%		1.58%
Amazon.com Inc	AMZN	10247.26	103.29	n/a	26.50	Excl.	Excl.		
Jack Henry & Associates Inc	JKHY	72.99	150.72	1.38	8.50	11,001.20	0.04%	0.05%	0.33%
Ralph Lauren Corp	RL	41.10	116.67	2.57	12.00	4,794.90	0.02%	0.04%	0.21%
Boston Properties Inc	BXP	156.82	54.12	7.24	-1.00	Excl.	Excl.		
Amphenol Corp	APH	594.61	81.72	1.03	12.50	48,591.12	0.17%	0.18%	2.17%
Howmet Aerospace Inc	HWM	411.80	42.37	0.38	14.00	17,448.14	0.06%	0.02%	0.87%
Pioneer Natural Resources Co	PXD	235.00	204.24	10.93	21.00	Excl.	Excl.		
Valero Energy Corp	VLO	367.84	139.60	2.92	29.50	Excl.	Excl.		
Synopsys Inc	SNPS	152.30	386.25	n/a	12.50	58,826.65	0.21%		2.62%
Etsy Inc	ETSY	124.65	111.33	n/a	24.50	Excl.	Excl.		
CH Robinson Worldwide Inc	CHRW	114.89	99.37	2.46	8.50	11,416.52	0.04%	0.10%	0.35%
Accenture PLC	ACN	662.60	285.81	1.57	12.50	189,376.56	0.68%	1.06%	8.45%
TransDigm Group Inc	TDG	54.60	737.05	n/a	20.00	40,241.46	0.14%		2.87%
Yum! Brands Inc	YUM	280.11	132.08	1.83	10.50	36,996.66	0.13%	0.24%	1.39%
Prologis Inc	PLD	923.45	124.77	2.79	2.50	115,218.86	0.41%	1.15%	1.03%
FirstEnergy Corp	FE	572.25	40.06	3.89	3.00	22,924.13	0.08%	0.32%	0.25%
VeriSign Inc	VRSN	104.88	211.33	n/a	11.00	22,164.08	0.08%		0.87%
Quanta Services Inc	PWR	144.00	166.64	0.19	15.50	23,996.33	0.09%	0.02%	1.33%
Henry Schein Inc	HSIC	131.28	81.54	n/a	6.00	10,704.90	0.04%		0.23%
Ameren Corp	AEE	262.48	86.39	2.92	6.50	22,675.22	0.08%	0.24%	0.53%
ANSYS Inc	ANSS	87.09	332.80	n/a	8.50	28,982.22	0.10%		0.88%
FactSet Research Systems Inc	FDS	38.25	415.09	0.86	10.50	15,878.02	0.06%	0.05%	0.60%
NVIDIA Corp	NVDA	2470.00	277.77	0.06	23.00	Excl.	Excl.		
Sealed Air Corp	SEE	143.96	45.91	1.74	9.00	6,609.30	0.02%	0.04%	0.21%
Cognizant Technology Solutions Corp	CTSH	509.30	60.93	1.90	8.00	31,031.34	0.11%	0.21%	0.89%
Intuitive Surgical Inc	ISRG	350.26	255.47	n/a	10.00	89,480.16	0.32%		3.19%
Take-Two Interactive Software Inc	TTWO	168.68	119.30	n/a	3.00	20,122.93	0.07%		0.22%
Republic Services Inc	RSG	316.24	135.22	1.46	12.50	42,762.51	0.15%	0.22%	1.91%
eBay Inc	EBAY	536.88	44.37	2.25	12.50	23,821.37	0.09%	0.19%	1.06%
Goldman Sachs Group Inc/The	GS	333.80	327.11	3.06	5.00	109,187.68	0.39%	1.19%	1.95%
SBA Communications Corp	SBAC	108.04	261.07	1.30	35.50	Excl.	Excl.		
Sempra Energy	SRE	314.65	151.16	3.15	7.50	47,562.49	0.17%	0.53%	1.27%
Moody's Corp	MCO	183.20	306.02	1.01	4.00	56,062.86	0.20%	0.20%	0.80%
ON Semiconductor Corp	ON	431.97	82.32	n/a	18.50	35,559.61	0.13%		2.35%
Booking Holdings Inc	BKNG	37.65	2652.41	n/a	22.00	Excl.	Excl.		
F5 Inc	FFIV	55.07	145.69	n/a	10.00	8,023.44	0.03%		0.29%
Akamai Technologies Inc	AKAM	156.30	78.30	n/a	5.50	12,238.60	0.04%		0.24%
Charles River Laboratories International Inc	CRL	50.99	201.82	n/a	12.00	10,289.99	0.04%		0.44%
MarketAxess Holdings Inc	MKTX	37.61	391.29	0.74	10.00	14,716.03	0.05%	0.04%	0.53%
Devon Energy Corp	DVN	654.00	50.61	7.03	27.50	Excl.	Excl.		
Bio-Techne Corp	TECH	157.28	74.19	0.43	13.00	11,668.23	0.04%	0.02%	0.54%
Alphabet Inc	GOOGL	5956.00	103.73	n/a		Excl.	Excl.		
Teleflex Inc	TFX	46.94	253.31	0.54	10.00	11,891.38	0.04%	0.02%	0.42%
Bunge Ltd	BG	149.93	95.52	2.62	2.50	14,320.93	0.05%	0.13%	0.13%
Netflix Inc	NFLX	445.35	345.48	n/a	14.50	153,858.48	0.55%		7.96%
Allegion plc	ALLE	87.87	106.73	1.69	11.00	9,378.04	0.03%	0.06%	0.37%
Agilent Technologies Inc	A	295.70	138.34	0.65	12.00	40,907.41	0.15%	0.09%	1.75%
Warner Bros Discovery Inc	WBD	2435.60	15.10	n/a		Excl.	Excl.		
Elevance Health Inc	ELV	237.46	459.81	1.29	12.50	109,185.56	0.39%	0.50%	4.87%
Trimble Inc	TRMB	246.95	52.42	n/a	7.00	12,945.22	0.05%		0.32%
CME Group Inc	CME	359.74	191.52	2.30	8.50	68,897.40	0.25%	0.56%	2.09%
Juniper Networks Inc	JNPR	321.34	34.42	2.56	11.00	11,060.66	0.04%	0.10%	0.43%
BlackRock Inc	BLK	150.24	669.12	2.99	8.50	100,525.91	0.36%	1.07%	3.05%
DTE Energy Co	DTE	206.11	109.54	3.48	4.50	22,577.07	0.08%	0.28%	0.36%
Nasdaq Inc	NDAQ	489.00	54.67	1.46	8.50	26,733.79	0.10%	0.14%	0.81%
Celanese Corp	CE	110.83	108.89	2.57	7.50	12,067.73	0.04%	0.11%	0.32%
Philip Morris International Inc	PM	1552.15	97.25	5.22	5.00	150,946.39	0.54%	2.81%	2.69%
Salesforce Inc	CRM	1000.00	199.78	n/a	19.50	199,780.00	0.71%		13.90%
Ingersoll Rand Inc	IR	404.96	58.18	0.14		Excl.	Excl.		
Huntington Ingalls Industries Inc	HII	39.93	207.02	2.40	10.00	8,265.48	0.03%	0.07%	0.30%
MetLife Inc	MET	774.36	57.94	3.45	7.50	44,866.53	0.16%	0.55%	1.20%
Tapestry Inc	TPR	236.08	43.11	2.78	13.50	10,177.24	0.04%	0.10%	0.49%
CSX Corp	CSX	2048.43	29.94	1.47	10.50	61,330.05	0.22%	0.32%	2.30%
Edwards Lifesciences Corp	EW	606.10	82.73	n/a	11.00	50,142.65	0.18%		1.97%
Ameriprise Financial Inc	AMP	105.15	306.50	1.63	13.50	32,227.86	0.12%	0.19%	1.55%
Zebra Technologies Corp	ZBRA	51.41	318.00	n/a	11.50	16,346.79	0.06%		0.67%
Zimmer Biomet Holdings Inc	ZBH	210.06	129.20	0.74	4.50	27,140.27	0.10%	0.07%	0.44%
CBRE Group Inc	CBRE	309.89	72.81	n/a	8.50	22,563.24	0.08%		0.68%
Camden Property Trust	CPT	106.76	104.84	3.82	-4.00	Excl.	Excl.		
Mastercard Inc	MA	945.72	363.41	0.63	18.50	343,685.20	1.23%	0.77%	22.69%
CarMax Inc	KMX	158.02	64.28	n/a	-3.00	Excl.	Excl.		
Intercontinental Exchange Inc	ICE	558.85	104.29	1.61	7.00	58,282.57	0.21%	0.34%	1.46%
Fidelity National Information Services Inc	FIS	591.94	54.33	3.83	52.00	Excl.	Excl.		
Chipotle Mexican Grill Inc	CMG	27.62	1708.29	n/a	20.00	47,186.39	0.17%		3.37%
Wynn Resorts Ltd	WYNN	113.68	111.91	n/a	27.00	Excl.	Excl.		
Live Nation Entertainment Inc	LYV	231.59	70.00	n/a		Excl.	Excl.		
Assurant Inc	AIZ	52.92	120.07	2.33	15.50	6,354.22	0.02%	0.05%	0.35%
NRG Energy Inc	NRG	232.27	34.29	4.40	-2.50	Excl.	Excl.		
Regions Financial Corp	RF	934.56	18.56	4.31	11.50	17,345.47	0.06%	0.27%	0.71%
Monster Beverage Corp	MNST	1044.82	54.01	n/a	10.50	56,430.67	0.20%		2.11%
Mosaic Co/The	MOS	336.49	45.88	1.74	7.50	15,438.02	0.06%	0.10%	0.41%
Baker Hughes Co	BKR	1011.22	28.86	2.63		Excl.	Excl.		
Expedia Group Inc	EXPE	147.83	97.03	n/a		Excl.	Excl.		
CF Industries Holdings Inc	CF	195.77	72.49	2.21	11.00	14,191.22	0.05%	0.11%	0.56%

Name	Ticker	Shares Outst'g	Price	Dividend Yield	Value Line Long-Term Growth Estimate	Market Cap Excl. n/a Growth	% of Total Market Cap.	Cap. Weighted Div. Yield	Cap. Weighted Long-Term Growth
Leidos Holdings Inc	LDOS	137.19	92.06	1.56	8.00	12,629.99	0.05%	0.07%	0.36%
APA Corp	APA	310.95	36.06	2.77		Excl.	Excl.		
Alphabet Inc	GOOG	5968.00	104.00	n/a	18.50	620,672.00	2.22%		40.98%
First Solar Inc	FSLR	106.82	217.50	n/a	24.50	Excl.	Excl.		
TE Connectivity Ltd	TEL	316.46	131.15	1.80	10.50	41,503.34	0.15%	0.27%	1.56%
Cooper Cos Inc/The	COO	49.46	373.36	0.02	12.00	18,464.89	0.07%	0.00%	0.79%
Discover Financial Services	DFS	259.36	98.84	2.43	8.50	25,635.24	0.09%	0.22%	0.78%
Linde PLC	LIN	490.77	355.44	1.43	10.00	174,438.22	0.62%	0.89%	6.23%
Visa Inc	V	1624.95	225.46	0.80	13.50	366,362.13	1.31%	1.04%	17.65%
Mid-America Apartment Communities Inc	MAA	116.60	151.04	3.71	-12.50	Excl.	Excl.		
Xylem Inc/NY	XYL	180.28	104.70	1.26	9.00	18,875.11	0.07%	0.08%	0.61%
Marathon Petroleum Corp	MPC	441.63	134.83	2.23		Excl.	Excl.		
Tractor Supply Co	TSCO	110.07	235.04	1.75	13.50	25,871.56	0.09%	0.16%	1.25%
Advanced Micro Devices Inc	AMD	1611.39	98.01	n/a	25.50	Excl.	Excl.		
ResMed Inc	RMD	146.91	218.99	0.80	8.50	32,171.60	0.11%	0.09%	0.98%
Mettler-Toledo International Inc	MTD	22.07	1530.21	n/a	13.50	33,771.73	0.12%		1.63%
Jacobs Solutions Inc	J	126.71	117.51	0.89	12.00	14,890.16	0.05%	0.05%	0.64%
Copart Inc	CPRT	476.59	75.21	n/a	7.00	35,844.56	0.13%		0.90%
VICI Properties Inc	VICI	1004.21	32.62	4.78	7.00	32,757.17	0.12%	0.56%	0.82%
Albemarle Corp	ALB	117.30	221.04	0.72	21.50	Excl.	Excl.		
Fortinet Inc	FTNT	784.07	66.46	n/a	21.50	Excl.	Excl.		
Moderna Inc	MRNA	385.68	153.58	n/a	-2.50	Excl.	Excl.		
Essex Property Trust Inc	ESS	64.46	209.14	4.42	-3.00	Excl.	Excl.		
CoStar Group Inc	CSGP	406.77	68.85	n/a	13.00	28,006.25	0.10%		1.30%
Realty Income Corp	O	660.52	63.32	4.83	5.50	41,824.19	0.15%	0.72%	0.82%
Westrock Co	WRK	254.65	30.47	3.61	10.00	7,759.25	0.03%	0.10%	0.28%
Westinghouse Air Brake Technologies Corp	WAB	180.35	101.06	0.67	9.50	18,226.37	0.07%	0.04%	0.62%
Pool Corp	POOL	39.10	342.44	1.17	14.00	13,389.75	0.05%	0.06%	0.67%
Western Digital Corp	WDC	319.32	37.67	n/a	4.00	12,028.86	0.04%		0.17%
PepsiCo Inc	PEP	1377.32	182.30	2.52	6.50	251,084.52	0.90%	2.26%	5.82%
Diamondback Energy Inc	FANG	183.59	135.17	8.73		Excl.	Excl.		
ServiceNow Inc	NOW	203.00	464.72	n/a	45.50	Excl.	Excl.		
Church & Dwight Co Inc	CHD	244.04	88.41	1.23	6.00	21,575.66	0.08%	0.09%	0.46%
Federal Realty Investment Trust	FRT	81.35	98.83	4.37	2.50	8,040.12	0.03%	0.13%	0.07%
MGM Resorts International	MGM	372.89	44.42	n/a	25.00	Excl.	Excl.		
American Electric Power Co Inc	AEP	514.41	90.99	3.65	6.00	46,805.89	0.17%	0.61%	1.00%
SolarEdge Technologies Inc	SEDG	56.15	303.95	n/a	27.00	Excl.	Excl.		
Invitation Homes Inc	INVH	611.41	31.23	3.33		Excl.	Excl.		
PTC Inc	PTC	118.26	128.23	n/a	29.00	Excl.	Excl.		
JB Hunt Transport Services Inc	JBHT	103.77	175.46	0.96	10.00	18,207.48	0.06%	0.06%	0.65%
Lam Research Corp	LRCX	134.94	530.12	1.30	14.00	71,532.27	0.26%	0.33%	3.57%
Mohawk Industries Inc	MHK	63.54	100.22	n/a	10.00	6,367.98	0.02%		0.23%
GE HealthCare Technologies Inc	GEHC	453.93	82.03	n/a		Excl.	Excl.		
Pentair PLC	PNR	164.94	55.27	1.59	12.00	9,116.23	0.03%	0.05%	0.39%
Vertex Pharmaceuticals Inc	VRTX	257.09	315.07	n/a	13.50	81,001.66	0.29%		3.90%
Amcor PLC	AMCR	1485.78	11.38	4.31	14.50	16,908.18	0.06%	0.26%	0.88%
Meta Platforms Inc	META	2225.76	211.94	n/a	11.00	471,728.21	1.68%		18.52%
T-Mobile US Inc	TMUS	1219.38	144.84	n/a	16.00	176,615.43	0.63%		10.09%
United Rentals Inc	URI	69.36	395.76	1.50	18.00	27,449.91	0.10%	0.15%	1.76%
Honeywell International Inc	HON	668.14	191.12	2.16	12.00	127,694.92	0.46%	0.98%	5.47%
Alexandria Real Estate Equities Inc	ARE	173.09	125.59	3.85	11.00	21,738.00	0.08%	0.30%	0.85%
Delta Air Lines Inc	DAL	641.24	34.92	n/a		Excl.	Excl.		
Seagate Technology Holdings PLC	STX	206.48	66.12	4.23	12.00	13,652.72	0.05%	0.21%	0.58%
United Airlines Holdings Inc	UAL	326.73	44.25	n/a		Excl.	Excl.		
News Corp	NWS	193.24	17.43	1.15		Excl.	Excl.		
Centene Corp	CNC	550.70	63.21	n/a	9.00	34,809.75	0.12%		1.12%
Martin Marietta Materials Inc	MLM	62.10	355.06	0.74	4.50	22,050.65	0.08%	0.06%	0.35%
Teradyne Inc	TER	156.05	107.51	0.41	19.00	16,776.72	0.06%	0.02%	1.14%
PayPal Holdings Inc	PYPL	1131.37	75.94	n/a	12.00	85,916.47	0.31%		3.68%
Tesla Inc	TSLA	3164.10	207.46	n/a	21.50	Excl.	Excl.		
Arch Capital Group Ltd	ACGL	371.20	67.87	n/a	21.50	Excl.	Excl.		
DISH Network Corp	DISH	292.72	9.33	n/a	-4.00	Excl.	Excl.		
Dow Inc	DOW	707.99	54.82	5.11	8.50	38,811.96	0.14%	0.71%	1.18%
Everest Re Group Ltd	RE	39.16	358.02	1.84	9.50	14,018.99	0.05%	0.09%	0.48%
Teledyne Technologies Inc	TDY	47.00	447.36	n/a	9.50	21,023.68	0.08%		0.71%
News Corp	NWSA	382.36	17.27	1.16		Excl.	Excl.		
Exelon Corp	EXC	994.30	41.89	3.44		Excl.	Excl.		
Global Payments Inc	GPN	263.78	105.24	0.95	17.00	27,760.63	0.10%	0.09%	1.68%
Crown Castle Inc	CCI	433.67	133.84	4.68	13.50	58,042.26	0.21%	0.97%	2.80%
Aptiv PLC	APTV	270.95	112.19	n/a	30.00	Excl.	Excl.		
Advance Auto Parts Inc	AAP	59.27	121.61	4.93	12.00	7,208.31	0.03%	0.13%	0.31%
Align Technology Inc	ALGN	76.74	334.14	n/a	17.00	25,641.57	0.09%		1.56%
Illumina Inc	ILMN	158.00	232.55	n/a	6.50	36,742.90	0.13%		0.85%
Targa Resources Corp	TRGP	226.28	72.95	1.92		Excl.	Excl.		
LKQ Corp	LKQ	267.29	56.76	1.94	13.00	15,171.38	0.05%	0.10%	0.70%
Zoetis Inc	ZTS	462.95	166.44	0.90	9.00	77,052.57	0.28%	0.25%	2.48%
Equinix Inc	EQIX	92.75	721.04	1.89	15.00	66,872.85	0.24%	0.45%	3.58%
Digital Realty Trust Inc	DLR	291.30	98.31	4.96	-1.00	Excl.	Excl.		
Molina Healthcare Inc	MOH	58.27	267.49	n/a	12.50	15,586.37	0.06%		0.70%
Las Vegas Sands Corp	LVS	764.27	57.45	n/a		Excl.	Excl.		

CAPITAL ASSET PRICING MODEL -- LONG-TERM PROJECTED RISK-FREE RATE & VL BETA
MARKET RISK PREMIUM DERIVED FROM S&P 500 - ALL COMPANIES
K = Rf + β (Rm − Rf)

		[1]	[2]	[3]	[4]	[5]
Company	Ticker	Current 30-year Treasury bond yield (30-day average)	Beta (β)	Market Return (Rm)	Market Risk Premium (Rm − Rf)	ROE (K)
ALLETE, Inc.	ALE	3.81%	0.90	14.67%	10.86%	13.58%
Alliant Energy Corporation	LNT	3.81%	0.85	14.67%	10.86%	13.04%
Ameren Corporation	AEE	3.81%	0.85	14.67%	10.86%	13.04%
American Electric Power Company, Inc.	AEP	3.81%	0.75	14.67%	10.86%	11.95%
Edison International	EIX	3.81%	0.95	14.67%	10.86%	14.12%
Entergy Corporation	ETR	3.81%	0.95	14.67%	10.86%	14.12%
Evergy, Inc.	EVRG	3.81%	0.90	14.67%	10.86%	13.58%
Hawaiian Electric Industries, Inc.	HE	3.81%	0.85	14.67%	10.86%	13.04%
IDACORP, Inc.	IDA	3.81%	0.80	14.67%	10.86%	12.50%
NextEra Energy, Inc.	NEE	3.81%	0.95	14.67%	10.86%	14.12%
OGE Energy Corporation	OGE	3.81%	1.00	14.67%	10.86%	14.67%
Portland General Electric Company	POR	3.81%	0.85	14.67%	10.86%	13.04%
Southern Company	SO	3.81%	0.90	14.67%	10.86%	13.58%
Xcel Energy Inc.	XEL	3.81%	0.80	14.67%	10.86%	12.50%
Mean			0.88			13.35%

Notes:
[1] Bloomberg Professional as of March 31, 2023
[2] Source: Value Line, as of March 31, 2023
[3] Source: Average expected market return calculated in Rebuttal Attachment JCN-R3, page 1
[4] Equals [3] - [1]
[5] Equals [1] + [2] x [4]

CAPITAL ASSET PRICING MODEL -- CURRENT RISK-FREE RATE & VL BETA
MARKET RISK PREMIUM DERIVED FROM S&P 500 - ALL COMPANIES
K = Rf + β (Rm − Rf)

		[1]	[2]	[3]	[4]	[5]
Company	Ticker	Near-term projected 30-year U.S. Treasury bond yield (Q2 2023 - Q2 2024)	Beta (β)	Market Return (Rm)	Market Risk Premium (Rm − Rf)	ROE (K)
ALLETE, Inc.	ALE	3.78%	0.90	14.67%	10.89%	13.58%
Alliant Energy Corporation	LNT	3.78%	0.85	14.67%	10.89%	13.03%
Ameren Corporation	AEE	3.78%	0.85	14.67%	10.89%	13.03%
American Electric Power Company, Inc.	AEP	3.78%	0.75	14.67%	10.89%	11.95%
Edison International	EIX	3.78%	0.95	14.67%	10.89%	14.12%
Entergy Corporation	ETR	3.78%	0.95	14.67%	10.89%	14.12%
Evergy, Inc.	EVRG	3.78%	0.90	14.67%	10.89%	13.58%
Hawaiian Electric Industries, Inc.	HE	3.78%	0.85	14.67%	10.89%	13.03%
IDACORP, Inc.	IDA	3.78%	0.80	14.67%	10.89%	12.49%
NextEra Energy, Inc.	NEE	3.78%	0.95	14.67%	10.89%	14.12%
OGE Energy Corporation	OGE	3.78%	1.00	14.67%	10.89%	14.67%
Portland General Electric Company	POR	3.78%	0.85	14.67%	10.89%	13.03%
Southern Company	SO	3.78%	0.90	14.67%	10.89%	13.58%
Xcel Energy Inc.	XEL	3.78%	0.80	14.67%	10.89%	12.49%
Mean			0.88			13.35%

Notes:
[1] Source: Blue Chip Financial Forecasts, Vol. 42, No. 4, April 1, 2023 at 2
[2] Source: Value Line, as of March 31, 2023
[3] Source: Average expected market return calculated in Rebuttal Attachment JCN-R3, page 1
[4] Equals [3] - [1]
[5] Equals [1] + [2] x [4]

CAPITAL ASSET PRICING MODEL -- CURRENT RISK-FREE RATE & VL BETA
MARKET RISK PREMIUM DERIVED FROM S&P 500 - ALL COMPANIES
K = Rf + β (Rm − Rf)

		[1]	[2]	[3]	[4]	[5]
Company	Ticker	Projected 30-year U.S. Treasury bond yield (2024 - 2028)	Beta (β)	Market Return (Rm)	Market Risk Premium (Rm − Rf)	ROE (K)
ALLETE, Inc.	ALE	3.90%	0.90	14.67%	10.77%	13.59%
Alliant Energy Corporation	LNT	3.90%	0.85	14.67%	10.77%	13.05%
Ameren Corporation	AEE	3.90%	0.85	14.67%	10.77%	13.05%
American Electric Power Company, Inc.	AEP	3.90%	0.75	14.67%	10.77%	11.98%
Edison International	EIX	3.90%	0.95	14.67%	10.77%	14.13%
Entergy Corporation	ETR	3.90%	0.95	14.67%	10.77%	14.13%
Evergy, Inc.	EVRG	3.90%	0.90	14.67%	10.77%	13.59%
Hawaiian Electric Industries, Inc.	HE	3.90%	0.85	14.67%	10.77%	13.05%
IDACORP, Inc.	IDA	3.90%	0.80	14.67%	10.77%	12.51%
NextEra Energy, Inc.	NEE	3.90%	0.95	14.67%	10.77%	14.13%
OGE Energy Corporation	OGE	3.90%	1.00	14.67%	10.77%	14.67%
Portland General Electric Company	POR	3.90%	0.85	14.67%	10.77%	13.05%
Southern Company	SO	3.90%	0.90	14.67%	10.77%	13.59%
Xcel Energy Inc.	XEL	3.90%	0.80	14.67%	10.77%	12.51%
Mean			0.88			13.36%

Notes:
[1] Source: Blue Chip Financial Forecasts, Vol. 41, No. 12, December 1, 2022 at 14
[2] Source: Value Line, as of March 31, 2023
[3] Source: Average expected market return calculated in Rebuttal Attachment JCN-R3, page 1
[4] Equals [3] - [1]
[5] Equals [1] + [2] x [4]

CAPITAL ASSET PRICING MODEL -- LONG-TERM PROJECTED RISK-FREE RATE & BLOOMBERG BETA
MARKET RISK PREMIUM DERIVED FROM S&P 500 - ALL COMPANIES
K = Rf + β (Rm − Rf)

		[1]	[2]	[3]	[4]	[5]
Company	Ticker	Current 30-year Treasury bond yield (30-day average)	Beta (β)	Market Return (Rm)	Market Risk Premium (Rm − Rf)	ROE (K)
ALLETE, Inc.	ALE	3.81%	0.83	14.67%	10.86%	12.83%
Alliant Energy Corporation	LNT	3.81%	0.80	14.67%	10.86%	12.47%
Ameren Corporation	AEE	3.81%	0.76	14.67%	10.86%	12.10%
American Electric Power Company, Inc.	AEP	3.81%	0.76	14.67%	10.86%	12.10%
Edison International	EIX	3.81%	0.84	14.67%	10.86%	12.97%
Entergy Corporation	ETR	3.81%	0.85	14.67%	10.86%	13.09%
Evergy, Inc.	EVRG	3.81%	0.79	14.67%	10.86%	12.36%
Hawaiian Electric Industries, Inc.	HE	3.81%	0.72	14.67%	10.86%	11.57%
IDACORP, Inc.	IDA	3.81%	0.80	14.67%	10.86%	12.51%
NextEra Energy, Inc.	NEE	3.81%	0.82	14.67%	10.86%	12.72%
OGE Energy Corporation	OGE	3.81%	0.92	14.67%	10.86%	13.80%
Portland General Electric Company	POR	3.81%	0.79	14.67%	10.86%	12.37%
Southern Company	SO	3.81%	0.78	14.67%	10.86%	12.26%
Xcel Energy Inc.	XEL	3.81%	0.75	14.67%	10.86%	11.94%
Mean			0.801			12.51%

Notes:
[1] Bloomberg Professional as of March 31, 2023
[2] Source: Bloomberg Professional, calculated based on five years of weekly returns, as of March 31, 2023
[3] Source: Average expected market return calculated in Rebuttal Attachment JCN-R3, page 1
[4] Equals [3] - [1]
[5] Equals [1] + [2] x [4]

CAPITAL ASSET PRICING MODEL -- CURRENT RISK-FREE RATE & BLOOMBERG BETA
MARKET RISK PREMIUM DERIVED FROM S&P 500 - ALL COMPANIES
K = Rf + β (Rm − Rf)

		[1]	[2]	[3]	[4]	[5]
Company	Ticker	Near-term projected 30-year U.S. Treasury bond yield (Q2 2023 - Q2 2024)	Beta (β)	Market Return (Rm)	Market Risk Premium (Rm − Rf)	ROE (K)
ALLETE, Inc.	ALE	3.78%	0.83	14.67%	10.89%	12.83%
Alliant Energy Corporation	LNT	3.78%	0.80	14.67%	10.89%	12.47%
Ameren Corporation	AEE	3.78%	0.76	14.67%	10.89%	12.10%
American Electric Power Company, Inc.	AEP	3.78%	0.76	14.67%	10.89%	12.10%
Edison International	EIX	3.78%	0.84	14.67%	10.89%	12.97%
Entergy Corporation	ETR	3.78%	0.85	14.67%	10.89%	13.09%
Evergy, Inc.	EVRG	3.78%	0.79	14.67%	10.89%	12.36%
Hawaiian Electric Industries, Inc.	HE	3.78%	0.72	14.67%	10.89%	11.57%
IDACORP, Inc.	IDA	3.78%	0.80	14.67%	10.89%	12.51%
NextEra Energy, Inc.	NEE	3.78%	0.82	14.67%	10.89%	12.71%
OGE Energy Corporation	OGE	3.78%	0.92	14.67%	10.89%	13.80%
Portland General Electric Company	POR	3.78%	0.79	14.67%	10.89%	12.36%
Southern Company	SO	3.78%	0.78	14.67%	10.89%	12.25%
Xcel Energy Inc.	XEL	3.78%	0.75	14.67%	10.89%	11.94%
Mean			0.801			12.50%

Notes:
[1] Source: Blue Chip Financial Forecasts, Vol. 42, No. 4, April 1, 2023 at 2
[2] Source: Bloomberg Professional, calculated based on five years of weekly returns, as of March 31, 2023
[3] Source: Average expected market return calculated in Rebuttal Attachment JCN-R3, page 1
[4] Equals [3] - [1]
[5] Equals [1] + [2] x [4]

CAPITAL ASSET PRICING MODEL -- CURRENT RISK-FREE RATE & BLOOMBERG BETA
MARKET RISK PREMIUM DERIVED FROM S&P 500 - ALL COMPANIES
K = Rf + β (Rm − Rf)

		[1]	[2]	[3]	[4]	[5]
Company	Ticker	Projected 30-year U.S. Treasury bond yield (2024 - 2028)	Beta (β)	Market Return (Rm)	Market Risk Premium (Rm − Rf)	ROE (K)
ALLETE, Inc.	ALE	3.90%	0.83	14.67%	10.77%	12.85%
Alliant Energy Corporation	LNT	3.90%	0.80	14.67%	10.77%	12.49%
Ameren Corporation	AEE	3.90%	0.76	14.67%	10.77%	12.12%
American Electric Power Company, Inc.	AEP	3.90%	0.76	14.67%	10.77%	12.12%
Edison International	EIX	3.90%	0.84	14.67%	10.77%	12.98%
Entergy Corporation	ETR	3.90%	0.85	14.67%	10.77%	13.10%
Evergy, Inc.	EVRG	3.90%	0.79	14.67%	10.77%	12.38%
Hawaiian Electric Industries, Inc.	HE	3.90%	0.72	14.67%	10.77%	11.60%
IDACORP, Inc.	IDA	3.90%	0.80	14.67%	10.77%	12.53%
NextEra Energy, Inc.	NEE	3.90%	0.82	14.67%	10.77%	12.73%
OGE Energy Corporation	OGE	3.90%	0.92	14.67%	10.77%	13.81%
Portland General Electric Company	POR	3.90%	0.79	14.67%	10.77%	12.39%
Southern Company	SO	3.90%	0.78	14.67%	10.77%	12.28%
Xcel Energy Inc.	XEL	3.90%	0.75	14.67%	10.77%	11.97%
Mean			0.801			12.53%

Notes:
[1] Source: Blue Chip Financial Forecasts, Vol. 41, No. 12, December 1, 2022 at 14
[2] Source: Bloomberg Professional, calculated based on five years of weekly returns, as of March 31, 2023
[3] Source: Average expected market return calculated in Rebuttal Attachment JCN-R3, page 1
[4] Equals [3] - [1]
[5] Equals [1] + [2] x [4]

CAPITAL ASSET PRICING MODEL -- LONG-TERM PROJECTED RISK-FREE RATE & VL BETA
MARKET RISK PREMIUM DERIVED FROM S&P 500 - FERC METHODOLOGY
$K = Rf + \beta (Rm - Rf)$

Company	Ticker	[1] Current 30-year Treasury bond yield (30-day average)	[2] Beta (β)	[3] Market Return (Rm)	[4] Market Risk Premium (Rm − Rf)	[5] ROE (K)
ALLETE, Inc.	ALE	3.81%	0.90	12.20%	8.39%	11.36%
Alliant Energy Corporation	LNT	3.81%	0.85	12.20%	8.39%	10.94%
Ameren Corporation	AEE	3.81%	0.85	12.20%	8.39%	10.94%
American Electric Power Company, Inc.	AEP	3.81%	0.75	12.20%	8.39%	10.10%
Edison International	EIX	3.81%	0.95	12.20%	8.39%	11.78%
Entergy Corporation	ETR	3.81%	0.95	12.20%	8.39%	11.78%
Evergy, Inc.	EVRG	3.81%	0.90	12.20%	8.39%	11.36%
Hawaiian Electric Industries, Inc.	HE	3.81%	0.85	12.20%	8.39%	10.94%
IDACORP, Inc.	IDA	3.81%	0.80	12.20%	8.39%	10.52%
NextEra Energy, Inc.	NEE	3.81%	0.95	12.20%	8.39%	11.78%
OGE Energy Corporation	OGE	3.81%	1.00	12.20%	8.39%	12.20%
Portland General Electric Company	POR	3.81%	0.85	12.20%	8.39%	10.94%
Southern Company	SO	3.81%	0.90	12.20%	8.39%	11.36%
Xcel Energy Inc.	XEL	3.81%	0.80	12.20%	8.39%	10.52%
Mean			0.88			11.18%

Notes:
[1] Bloomberg Professional as of March 31, 2023
[2] Source: Value Line, as of March 31, 2023
[3] Source: Average expected market return calculated in Rebuttal Attachment JCN-R3, page 7
[4] Equals [3] - [1]
[5] Equals [1] + [2] x [4]

CAPITAL ASSET PRICING MODEL -- CURRENT RISK-FREE RATE & VL BETA
MARKET RISK PREMIUM DERIVED FROM S&P 500 - FERC METHODOLOGY
$K = Rf + \beta (Rm - Rf)$

Company	Ticker	[1] Near-term projected 30-year U.S. Treasury bond yield (Q2 2023 - Q2 2024)	[2] Beta (β)	[3] Market Return (Rm)	[4] Market Risk Premium (Rm − Rf)	[5] ROE (K)
ALLETE, Inc.	ALE	3.78%	0.90	12.20%	8.42%	11.36%
Alliant Energy Corporation	LNT	3.78%	0.85	12.20%	8.42%	10.94%
Ameren Corporation	AEE	3.78%	0.85	12.20%	8.42%	10.94%
American Electric Power Company, Inc.	AEP	3.78%	0.75	12.20%	8.42%	10.09%
Edison International	EIX	3.78%	0.95	12.20%	8.42%	11.78%
Entergy Corporation	ETR	3.78%	0.95	12.20%	8.42%	11.78%
Evergy, Inc.	EVRG	3.78%	0.90	12.20%	8.42%	11.36%
Hawaiian Electric Industries, Inc.	HE	3.78%	0.85	12.20%	8.42%	10.94%
IDACORP, Inc.	IDA	3.78%	0.80	12.20%	8.42%	10.51%
NextEra Energy, Inc.	NEE	3.78%	0.95	12.20%	8.42%	11.78%
OGE Energy Corporation	OGE	3.78%	1.00	12.20%	8.42%	12.20%
Portland General Electric Company	POR	3.78%	0.85	12.20%	8.42%	10.94%
Southern Company	SO	3.78%	0.90	12.20%	8.42%	11.36%
Xcel Energy Inc.	XEL	3.78%	0.80	12.20%	8.42%	10.51%
Mean			0.88			11.18%

Notes:
[1] Source: Blue Chip Financial Forecasts, Vol. 42, No. 4, April 1, 2023 at 2
[2] Source: Value Line, as of March 31, 2023
[3] Source: Average expected market return calculated in Rebuttal Attachment JCN-R3, page 7
[4] Equals [3] - [1]
[5] Equals [1] + [2] x [4]

CAPITAL ASSET PRICING MODEL -- CURRENT RISK-FREE RATE & VL BETA
MARKET RISK PREMIUM DERIVED FROM S&P 500 - FERC METHODOLOGY
$K = Rf + \beta (Rm - Rf)$

Company	Ticker	[1] Projected 30-year U.S. Treasury bond yield (2024 - 2028)	[2] Beta (β)	[3] Market Return (Rm)	[4] Market Risk Premium (Rm − Rf)	[5] ROE (K)
ALLETE, Inc.	ALE	3.90%	0.90	12.20%	8.30%	11.37%
Alliant Energy Corporation	LNT	3.90%	0.85	12.20%	8.30%	10.95%
Ameren Corporation	AEE	3.90%	0.85	12.20%	8.30%	10.95%
American Electric Power Company, Inc.	AEP	3.90%	0.75	12.20%	8.30%	10.12%
Edison International	EIX	3.90%	0.95	12.20%	8.30%	11.78%
Entergy Corporation	ETR	3.90%	0.95	12.20%	8.30%	11.78%
Evergy, Inc.	EVRG	3.90%	0.90	12.20%	8.30%	11.37%
Hawaiian Electric Industries, Inc.	HE	3.90%	0.85	12.20%	8.30%	10.95%
IDACORP, Inc.	IDA	3.90%	0.80	12.20%	8.30%	10.54%
NextEra Energy, Inc.	NEE	3.90%	0.95	12.20%	8.30%	11.78%
OGE Energy Corporation	OGE	3.90%	1.00	12.20%	8.30%	12.20%
Portland General Electric Company	POR	3.90%	0.85	12.20%	8.30%	10.95%
Southern Company	SO	3.90%	0.90	12.20%	8.30%	11.37%
Xcel Energy Inc.	XEL	3.90%	0.80	12.20%	8.30%	10.54%
Mean			0.88			11.19%

Notes:
[1] Source: Blue Chip Financial Forecasts, Vol. 41, No. 12, December 1, 2022 at 14
[2] Source: Value Line, as of March 31, 2023
[3] Source: Average expected market return calculated in Rebuttal Attachment JCN-R3, page 7
[4] Equals [3] - [1]
[5] Equals [1] + [2] x [4]

CAPITAL ASSET PRICING MODEL -- LONG-TERM PROJECTED RISK-FREE RATE & BLOOMBERG BETA
MARKET RISK PREMIUM DERIVED FROM S&P 500 - FERC METHODOLOGY
K = Rf + β (Rm − Rf)

Company	Ticker	[1] Current 30-year Treasury bond yield (30-day average)	[2] Beta (β)	[3] Market Return (Rm)	[4] Market Risk Premium (Rm − Rf)	[5] ROE (K)
ALLETE, Inc.	ALE	3.81%	0.83	12.20%	8.39%	10.78%
Alliant Energy Corporation	LNT	3.81%	0.80	12.20%	8.39%	10.50%
Ameren Corporation	AEE	3.81%	0.76	12.20%	8.39%	10.22%
American Electric Power Company, Inc.	AEP	3.81%	0.76	12.20%	8.39%	10.22%
Edison International	EIX	3.81%	0.84	12.20%	8.39%	10.89%
Entergy Corporation	ETR	3.81%	0.85	12.20%	8.39%	10.98%
Evergy, Inc.	EVRG	3.81%	0.79	12.20%	8.39%	10.42%
Hawaiian Electric Industries, Inc.	HE	3.81%	0.72	12.20%	8.39%	9.81%
IDACORP, Inc.	IDA	3.81%	0.80	12.20%	8.39%	10.53%
NextEra Energy, Inc.	NEE	3.81%	0.82	12.20%	8.39%	10.69%
OGE Energy Corporation	OGE	3.81%	0.92	12.20%	8.39%	11.53%
Portland General Electric Company	POR	3.81%	0.79	12.20%	8.39%	10.42%
Southern Company	SO	3.81%	0.78	12.20%	8.39%	10.34%
Xcel Energy Inc.	XEL	3.81%	0.75	12.20%	8.39%	10.09%
Mean			0.801			10.53%

Notes:
[1] Bloomberg Professional as of March 31, 2023
[2] Source: Bloomberg Professional, calculated based on five years of weekly returns, as of March 31, 2023
[3] Source: Average expected market return calculated in Rebuttal Attachment JCN-R3, page 7
[4] Equals [3] - [1]
[5] Equals [1] + [2] x [4]

CAPITAL ASSET PRICING MODEL -- CURRENT RISK-FREE RATE & BLOOMBERG BETA
MARKET RISK PREMIUM DERIVED FROM S&P 500 - FERC METHODOLOGY
K = Rf + β (Rm − Rf)

Company	Ticker	[1] Near-term projected 30-year U.S. Treasury bond yield (Q2 2023 - Q2 2024)	[2] Beta (β)	[3] Market Return (Rm)	[4] Market Risk Premium (Rm − Rf)	[5] ROE (K)
ALLETE, Inc.	ALE	3.78%	0.83	12.20%	8.42%	10.78%
Alliant Energy Corporation	LNT	3.78%	0.80	12.20%	8.42%	10.50%
Ameren Corporation	AEE	3.78%	0.76	12.20%	8.42%	10.21%
American Electric Power Company, Inc.	AEP	3.78%	0.76	12.20%	8.42%	10.21%
Edison International	EIX	3.78%	0.84	12.20%	8.42%	10.88%
Entergy Corporation	ETR	3.78%	0.85	12.20%	8.42%	10.98%
Evergy, Inc.	EVRG	3.78%	0.79	12.20%	8.42%	10.41%
Hawaiian Electric Industries, Inc.	HE	3.78%	0.72	12.20%	8.42%	9.80%
IDACORP, Inc.	IDA	3.78%	0.80	12.20%	8.42%	10.53%
NextEra Energy, Inc.	NEE	3.78%	0.82	12.20%	8.42%	10.68%
OGE Energy Corporation	OGE	3.78%	0.92	12.20%	8.42%	11.53%
Portland General Electric Company	POR	3.78%	0.79	12.20%	8.42%	10.42%
Southern Company	SO	3.78%	0.78	12.20%	8.42%	10.33%
Xcel Energy Inc.	XEL	3.78%	0.75	12.20%	8.42%	10.09%
Mean			0.801			10.52%

Notes:
[1] Source: Blue Chip Financial Forecasts, Vol. 42, No. 4, April 1, 2023 at 2
[2] Source: Bloomberg Professional, calculated based on five years of weekly returns, as of March 31, 2023
[3] Source: Average expected market return calculated in Rebuttal Attachment JCN-R3, page 7
[4] Equals [3] - [1]
[5] Equals [1] + [2] x [4]

CAPITAL ASSET PRICING MODEL -- CURRENT RISK-FREE RATE & BLOOMBERG BETA
MARKET RISK PREMIUM DERIVED FROM S&P 500 - FERC METHODOLOGY
K = Rf + β (Rm − Rf)

Company	Ticker	[1] Projected 30-year U.S. Treasury bond yield (2024 - 2028)	[2] Beta (β)	[3] Market Return (Rm)	[4] Market Risk Premium (Rm − Rf)	[5] ROE (K)
ALLETE, Inc.	ALE	3.90%	0.83	12.20%	8.30%	10.80%
Alliant Energy Corporation	LNT	3.90%	0.80	12.20%	8.30%	10.52%
Ameren Corporation	AEE	3.90%	0.76	12.20%	8.30%	10.24%
American Electric Power Company, Inc.	AEP	3.90%	0.76	12.20%	8.30%	10.24%
Edison International	EIX	3.90%	0.84	12.20%	8.30%	10.90%
Entergy Corporation	ETR	3.90%	0.85	12.20%	8.30%	10.99%
Evergy, Inc.	EVRG	3.90%	0.79	12.20%	8.30%	10.44%
Hawaiian Electric Industries, Inc.	HE	3.90%	0.72	12.20%	8.30%	9.83%
IDACORP, Inc.	IDA	3.90%	0.80	12.20%	8.30%	10.55%
NextEra Energy, Inc.	NEE	3.90%	0.82	12.20%	8.30%	10.71%
OGE Energy Corporation	OGE	3.90%	0.92	12.20%	8.30%	11.54%
Portland General Electric Company	POR	3.90%	0.79	12.20%	8.30%	10.44%
Southern Company	SO	3.90%	0.78	12.20%	8.30%	10.36%
Xcel Energy Inc.	XEL	3.90%	0.75	12.20%	8.30%	10.12%
Mean			0.801			10.55%

Notes:
[1] Source: Blue Chip Financial Forecasts, Vol. 41, No. 12, December 1, 2022 at 14
[2] Source: Bloomberg Professional, calculated based on five years of weekly returns, as of March 31, 2023
[3] Source: Average expected market return calculated in Rebuttal Attachment JCN-R3, page 7
[4] Equals [3] - [1]
[5] Equals [1] + [2] x [4]

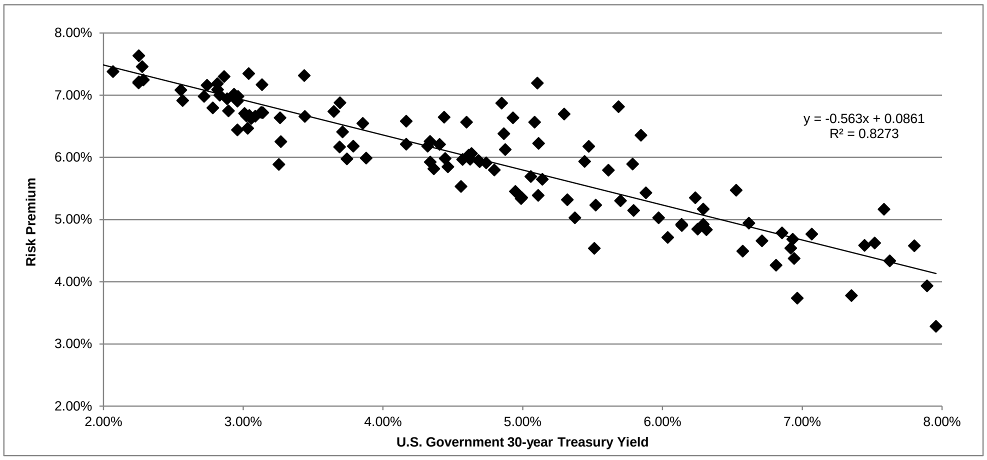
BOND YIELD PLUS RISK PREMIUM ANALYSIS
Vertically Integrated Electric Utilities

	[1]	[2]	[3]
	Average Authorized Electric ROE	U.S. Govt. 30-year Treasury	Risk Premium
1992.1	12.38%	7.80%	4.58%
1992.2	11.83%	7.89%	3.93%
1992.3	12.03%	7.45%	4.59%
1992.4	12.14%	7.52%	4.62%
1993.1	11.84%	7.07%	4.77%
1993.2	11.64%	6.86%	4.79%
1993.3	11.15%	6.31%	4.84%
1993.4	11.04%	6.14%	4.90%
1994.1	11.07%	6.57%	4.49%
1994.2	11.13%	7.35%	3.78%
1994.3	12.75%	7.58%	5.17%
1994.4	11.24%	7.96%	3.28%
1995.1	11.96%	7.63%	4.34%
1995.2	11.32%	6.94%	4.37%
1995.3	11.37%	6.71%	4.66%
1995.4	11.58%	6.23%	5.35%
1996.1	11.46%	6.29%	5.17%
1996.2	11.46%	6.92%	4.54%
1996.3	10.70%	6.96%	3.74%
1996.4	11.56%	6.62%	4.94%
1997.1	11.08%	6.81%	4.27%
1997.2	11.62%	6.93%	4.68%
1997.3	12.00%	6.53%	5.47%
1997.4	11.06%	6.14%	4.92%
1998.1	11.31%	5.88%	5.43%
1998.2	12.20%	5.85%	6.35%
1998.3	11.65%	5.47%	6.18%
1998.4	12.30%	5.10%	7.20%
1999.1	10.40%	5.37%	5.03%
1999.2	10.94%	5.79%	5.15%
1999.3	10.75%	6.04%	4.71%
1999.4	11.10%	6.25%	4.85%
2000.1	11.21%	6.29%	4.92%
2000.2	11.00%	5.97%	5.03%
2000.3	11.68%	5.79%	5.89%
2000.4	12.50%	5.69%	6.81%
2001.1	11.38%	5.44%	5.93%
2001.2	11.00%	5.70%	5.30%
2001.3	10.76%	5.52%	5.23%
2001.4	11.99%	5.30%	6.70%
2002.1	10.05%	5.51%	4.54%
2002.2	11.41%	5.61%	5.79%
2002.3	11.65%	5.08%	6.57%
2002.4	11.57%	4.93%	6.64%
2003.1	11.72%	4.85%	6.87%
2003.2	11.16%	4.60%	6.56%
2003.3	10.50%	5.11%	5.39%
2003.4	11.34%	5.11%	6.23%
2004.1	11.00%	4.88%	6.12%
2004.2	10.64%	5.32%	5.32%
2004.3	10.75%	5.06%	5.69%
2004.4	11.24%	4.86%	6.38%
2005.1	10.63%	4.69%	5.93%
2005.2	10.31%	4.47%	5.85%
2005.3	11.08%	4.44%	6.65%
2005.4	10.63%	4.68%	5.95%
2006.1	10.70%	4.63%	6.06%
2006.2	10.79%	5.14%	5.65%
2006.3	10.35%	4.99%	5.35%
2006.4	10.65%	4.74%	5.91%
2007.1	10.59%	4.80%	5.80%
2007.2	10.33%	4.99%	5.34%
2007.3	10.40%	4.95%	5.45%
2007.4	10.65%	4.61%	6.04%
2008.1	10.62%	4.41%	6.21%
2008.2	10.54%	4.57%	5.97%
2008.3	10.43%	4.44%	5.98%
2008.4	10.39%	3.65%	6.74%
2009.1	10.75%	3.44%	7.31%
2009.2	10.75%	4.17%	6.58%
2009.3	10.50%	4.32%	6.18%
2009.4	10.59%	4.34%	6.26%
2010.1	10.59%	4.62%	5.97%
2010.2	10.18%	4.36%	5.82%
2010.3	10.40%	3.86%	6.55%
2010.4	10.38%	4.17%	6.21%
2011.1	10.09%	4.56%	5.53%
2011.2	10.26%	4.34%	5.92%
2011.3	10.57%	3.69%	6.88%

BOND YIELD PLUS RISK PREMIUM ANALYSIS
Vertically Integrated Electric Utilities

	[1]	[2]	[3]
	Average Authorized Electric ROE	U.S. Govt. 30-year Treasury	Risk Premium
2011.4	10.39%	3.04%	7.35%
2012.1	10.30%	3.14%	7.17%
2012.2	9.95%	2.93%	7.02%
2012.3	9.90%	2.74%	7.16%
2012.4	10.16%	2.86%	7.30%
2013.1	9.85%	3.13%	6.72%
2013.2	9.86%	3.14%	6.72%
2013.3	10.12%	3.71%	6.41%
2013.4	9.97%	3.79%	6.18%
2014.1	9.86%	3.69%	6.17%
2014.2	10.10%	3.44%	6.66%
2014.3	9.90%	3.26%	6.64%
2014.4	9.94%	2.96%	6.98%
2015.1	9.64%	2.55%	7.08%
2015.2	9.83%	2.88%	6.94%
2015.3	9.40%	2.96%	6.44%
2015.4	9.86%	2.96%	6.90%
2016.1	9.70%	2.72%	6.98%
2016.2	9.48%	2.57%	6.91%
2016.3	9.74%	2.28%	7.46%
2016.4	9.83%	2.83%	7.00%
2017.1	9.72%	3.04%	6.67%
2017.2	9.64%	2.90%	6.75%
2017.3	10.00%	2.82%	7.18%
2017.4	9.91%	2.82%	7.09%
2018.1	9.69%	3.02%	6.66%
2018.2	9.75%	3.09%	6.66%
2018.3	9.69%	3.06%	6.63%
2018.4	9.52%	3.27%	6.25%
2019.1	9.72%	3.01%	6.71%
2019.2	9.58%	2.78%	6.79%
2019.3	9.53%	2.29%	7.24%
2019.4	9.89%	2.25%	7.63%
2020.1	9.72%	1.89%	7.83%
2020.2	9.58%	1.38%	8.20%
2020.3	9.30%	1.37%	7.93%
2020.4	9.56%	1.62%	7.94%
2021.1	9.45%	2.07%	7.38%
2021.2	9.47%	2.25%	7.21%
2021.3	9.27%	1.93%	7.34%
2021.4	9.67%	1.94%	7.73%
2022.1	9.45%	2.25%	7.20%
2022.2	9.50%	3.03%	6.47%
2022.3	9.14%	3.26%	5.88%
2022.4	9.87%	3.88%	5.99%
2023.1	9.72%	3.74%	5.97%
AVERAGE	10.60%	4.55%	6.05%
MEDIAN	10.57%	4.60%	6.18%

BOND YIELD PLUS RISK PREMIUM ANALYSIS
Vertically Integrated Electric Utilities



SUMMARY OUTPUT

Regression Statistics	
Multiple R	0.909548491
R Square	0.827278458
Adjusted R Square	0.825874218
Standard Error	0.004267272
Observations	125

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	0.010727809	0.010727809	589.1288895	9.84842E-49
Residual	123	0.002239782	1.82096E-05		
Total	124	0.012967591			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
Intercept	0.086118953	0.001121285	76.80381645	8.6376E-106	0.083899439	0.08833847	0.083899439	0.088338468
X Variable 1	-0.562953142	0.023193543	-24.27197745	9.84842E-49	-0.608863337	-0.5170429	-0.60886334	-0.51704295

	[7]	[8]	[9]
	U.S. Govt. 30-year Treasury	Risk Premium	ROE
Current 30-day average of 30-year U.S. Treasury bond yield [4]	3.81%	6.47%	10.28%
Blue Chip Near-Term Projected Forecast (Q2 2023 - Q2 2024) [5]	3.78%	6.48%	10.26%
Blue Chip Long-Term Projected Forecast (2024-2028) [6]	3.90%	6.42%	10.32%
AVERAGE			10.29%

Notes:
[1] Source: Regulatory Research Associates, rate cases through March 31, 2023
[2] Source: Bloomberg Professional, quarterly bond yields are the average of each trading day in the quarter
[3] Equals Column [1] − Column [2]
[4] Source: Bloomberg Professional, 30-day average as of March 31, 2023
[5] Source: Blue Chip Financial Forecasts, Vol. 42, No. 4, April 1, 2023 at 2
[6] Source: Blue Chip Financial Forecasts, Vol. 41, No. 12, December 1, 2022 at 14
[7] See notes [4], [5] & [6]
[8] Equals 0.086119 + (-0.562953 x Column [6])
[9] Equals Column [7] + Column [8]

EXPECTED EARNINGS ANALYSIS

Company	Ticker	[1] Value Line ROE Projection Years 4-6	[2] Value Line Total Capital ($mill) MRY	[3] Value Line Common Equity Ratio MRY	[4] Total Equity MRY	[5] Value Line Total Capital ($mill) Projection Years 4-6	[6] Value Line Common Equity Ratio Projection Years 4-6	[7] Total Equity ($mill) Projection Years 4-6	[8] Compound Annual Growth Rate	[9] Adjustment Factor	[10] Adjusted Return on Common Equity
ALLETE, Inc.	ALE	9.00%	4,465	60.50%	2,701	5,550	59.50%	3,302	4.10%	1.020	9.18%
Alliant Energy Corporation	LNT	12.00%	13,944	45.00%	6,275	17,070	48.00%	8,194	5.48%	1.027	12.32%
Ameren Corporation	AEE	10.00%	24,193	44.00%	10,645	29,500	48.50%	14,308	6.09%	1.030	10.30%
American Electric Power Company, Inc.	AEP	11.00%	57,520	42.00%	24,158	75,900	42.50%	32,258	5.95%	1.029	11.32%
Edison International	EIX	13.00%	41,959	33.20%	13,930	61,000	32.00%	19,520	6.98%	1.034	13.44%
Entergy Corporation	ETR	9.00%	36,810	35.20%	12,957	52,410	33.00%	17,295	5.95%	1.029	9.26%
Evergy, Inc.	EVRG	10.00%	19,675	48.00%	9,444	23,400	46.50%	10,881	2.87%	1.014	10.14%
Hawaiian Electric Industries, Inc.	HE	12.50%	4,524	52.80%	2,389	5,950	49.50%	2,945	4.28%	1.021	12.76%
IDACORP, Inc.	IDA	9.50%	4,669	57.20%	2,671	6,775	50.00%	3,388	4.87%	1.024	9.73%
NextEra Energy, Inc.	NEE	14.50%	94,485	41.50%	39,211	153,100	40.00%	61,240	9.33%	1.045	15.15%
OGE Energy Corp.	OGE	13.00%	8,962	53.00%	4,750	10,400	50.00%	5,200	1.83%	1.009	13.12%
Portland General Electric Company	POR	9.50%	6,265	43.20%	2,706	8,250	45.00%	3,713	6.53%	1.032	9.80%
Southern Company	SO	14.50%	80,550	36.00%	28,998	93,500	37.00%	34,595	3.59%	1.018	14.76%
Xcel Energy Inc.	XEL	11.00%	37,391	41.80%	15,629	49,200	42.00%	20,664	5.74%	1.028	11.31%
Mean											11.61%
Median											11.31%

Notes:
[1] Source: Value Line
[2] Source: Value Line
[3] Source: Value Line
[4] Equals [2] x [3]
[5] Source: Value Line
[6] Source: Value Line
[7] Equals [5] x [6]
[8] Equals ([7] / [4]) ^ (1/5) - 1
[9] Equals 2 x (1 + [8]) / (2 + [8])
[10] Equals [1] x [9]

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 New Tariffs; 3) Approval of Accounting Practices to Establish Regulatory Assets and Liabilities; and 4) All Other Required Approvals and Relief.	)))))))	Case No. 2022-00372

REBUTTAL TESTIMONY OF

LISA D. STEINKUHL

ON BEHALF OF

DUKE ENERGY KENTUCKY, INC.

April 14, 2023

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I. INTRODUCTION AND PURPOSE

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Lisa D. Steinkuhl 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 Rates & Regulatory Planning. 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 LISA D. STEINKUHL 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's witnesses Randy Futral and Lane Kollen. Specifically, I will address Mr. Futral's and Mr. Kollen's recommendations related to:

(1) the effects on the revenue requirement of the reversal of the Company's proposal to roll-in to base rates certain portions of the Companies Environmental Surcharge Mechanism (Rider ESM);

(2) the effects on the revenue requirement of the AG's witnesses' proposals to adjust rate base for various adjustments to net plant and accumulated

deferred income taxes (ADIT) associated with the retirement date of East Bend and the treatment of decommissioning expenses;

(3) the AG witnesses' proposal to either not amortize or adjust amortization expense timing for certain regulatory assets in this proceeding as well as in the Company's Rider ESM; and

First, I will also address adjustments proposed by Mr. Futral and Mr. Kollen that the Company does not oppose, some of which were identified by the Company through discovery and the resulting revised revenue requirement increase being requested by the Company.

II. REVISED REVENUE REQUIREMENT

Q. HAS THE ATTORNEY GENERAL MADE REVENUE REQUIREMENT ADJUSTMENT RECOMMENDATIONS THAT THE COMPANY ACCEPTS?

A. Yes. There are three adjustments that Mr. Futral is recommending which the Company is willing to accept. These adjustments were identified by the Company through the course of answering discovery. Mr. Kollen also makes two recommendations that the Company is not opposing.

Mr. Baudino also makes a recommendation as it relates to the Company's proposed capital structure. While Company witness Chris Bauer explains in his rebuttal testimony why Duke Energy Kentucky disagrees with Mr. Baudino's recommendation, Mr. Bauer does revise the Company's proposed capital structure. I address the impacts of that revised capital structure on the Company's total proposed revenue requirement.

Q. PLEASE EXPLAIN MR. FUTRAL'S ADJUSTMENTS THAT THE COMPANY IS WILLING TO ACCEPT.

A. First, as the Company noted in response to discovery question AG-DR-01-112, the Company discovered an error in the calculation of the forecasted 13-month average plant in-service balances. In AG-DR-02-042, the Company quantified the impact of the error to be an understatement of the total accumulated depreciation and amortization reserve for total electric plant including allocated common was $0.121 million. The error did not impact ADIT amounts in the projected test year. The impact to the Company's requested revenue requirement is a reduction of $0.011 million and the Company agrees to adjust its requested revenue requirement accordingly.

Secondly, the Company discovered an error in the lead/lag calculation for collection lag days. Per response to AG-DR-01-096, it was determined that two changes needed to be made to the collection lag days calculation. The first change relates to using total revenues and total receivables in the calculation instead of incorrectly using a combination of electric only and total. The receivable balances had been stated on a combined electric and gas operations basis, while the revenue amounts had been stated on an electric-only basis. The second change was to remove the effect of both unbilled gas and electric revenues since the unbilled amounts are not accounted for in the accounts receivable balances. The corrections reduce the cash working capital by $4.919 million. The impact to the Company's requested revenue requirement is a reduction of $0.460 million and the Company agrees to adjust its requested revenue requirement accordingly.

Thirdly, the Company did not include the amortization for DEBS EDIT amortization approved in Case No. 2019-00271. The Commission's Order stated $0.214 million of DEBS EDITs allocated to Duke Energy Kentucky electric should be amortized over 5-years for a revenue reduction of $0.043 million. This was included in rates effective on May 1, 2020. The unamortized balance on June 30, 2023, will be $0.082 million. The 5-year amortization of the June 30, 2023 balance is $0.016 million. This adjustment has the effect of reducing the Company's proposed revenue requirement increase by $0.016 million and the Company agrees to adjust its requested revenue requirement accordingly.

Q. PLEASE DESCRIBE MR. KOLLEN'S PROPOSAL AS IT RELATES TO THE COMPANY'S REQUEST TO ROLL-IN TO BASE RATES CERTAIN PORTIONS OF RIDER ESM.

A. Mr. Kollen recommends the Commission deny the Company's request to transfer recovery of the return on four capital projects and the related depreciation expense and property tax expense from Rider ESM revenues to base revenues. As a result, he recommends the revenue requirement be reduced by $12.076 million.

Q. DOES THE COMPANY AGREE WITH MR. KOLLEN'S PROPOSAL?

A. The Company is not opposed to Mr. Kollen's recommendation to deny the Company's request to transfer the recovery of the return on and of four capital projects from Rider ESM revenues to base revenues.

Q. DOES THE COMPANY AGREE WITH MR. KOLLEN'S CALCUATION OF THE REVENUE REQUIREMENT IMAPCT OF HIS PROPOSAL?

A. No.

Q. PLEASE EXPLAIN.

A. Mr. Kollen's reduction to the revenue requirement of $12.076 million for the roll-in of certain portions of the ESM rider was provided by the Company through discovery.[1] The Company supplemented the responses to correct the calculation for various errors in the original calculation. The correct amount of revenue requirement related to certain portions of Rider ESM being rolled-in to base rates is $9.939 million. The Company is willing to remove this amount from the revenue requirement and keep the return on and of the four capital projects in question in the Rider ESM.

Q. PLEASE DESCRIBE MR. KOLLEN'S PROPOSAL AS IT RELATES TO THE COMPANY'S REQUEST TO ZERO COST VENDOR FINANCING.

A. Fuel and limestone inventories are additions to rate base as other working capital. Mr. Kollen is recommending that these balances in rate base be reduced by zero-cost vendor financing in the related accounts payable amounts.

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[1] *See* Staff DR-03-021 Supplemental and AG-DR-02-040 Supplemental.

Q. PLEASE EXPLAIN THE CONCEPT OF ZERO COST VENDOR FINANCING.

A. The Company does not actually finance its purchases of fuel and lime from the date it purchases the fuel and lime from its vendors until it actually pays the vendors. The vendor actually finances the purchase for this short period of time. Mr. Kollen calls this zero-cost vendor financing.

Q. DOES MR. KOLLEN PROVIDE ANY SUPPORT OR PRECEDENT FOR THIS TYPE OF ADJUSTMENT?

A. Yes, in the Kentucky Power Company Case No. 2020-00174 the Commission subtracted construction accounts payable and prepayments accounts payable from rate base and in the Atmos Energy Corporation Case No. 2021-00214 construction accounts payable were deducted. In the Atmos final Order, the Commission stated the following:

> In a number of recent base rate cases where the revenue requirement is determined using rate base, the Commission has accepted adjustments to remove accounts payable from working capital amounts because the utility does not finance these amounts. The same reasoning exists here. Therefore, the Commission finds that this adjustment is reasonable and is accepted.

Q. DOES THE COMPANY AGREE WITH MR. KOLLEN'S PROPOSAL?

A. Based on the Commission precedent sited above, the Company does not oppose Mr. Kollen's recommendation that the balances in rate base be reduced by the related accounts payable amounts for fuel and limestone inventory accounts. As a result, the Company has reduced rate base by $6.459 million. This reduces the revenue requirement being requested by the Company by $0.604 million.

Q DOES THE COMPANY AGREE WITH MR. BAUDINO'S RECOMMENDATIONS AS IT RELATES TO THE COMPANY'S PROPOSED CAPITAL STRUCTURE?

A. No. Company witness Bauer explains why the Company disagrees with this recommendation. However, in his testimony Mr. Bauer does propose a revised capital structure. As a result of this change in capital structure, the revenue requirement being requested by the Company is reduced by $0.370.

Q. PLEASE SUMMARIZE THE COMPANY'S REVISED REVENUE REQUIREMENT BASED ON THE CHANGES DISCUSSED IN YOUR REBUTTAL TESTIMONY.

A. The following table reflects the Company's revised revenue requirement increase based on my rebuttal testimony.

Line No.	Summary	Impact to Revenue Requirement
1	**Duke Energy Kentucky Initial Request**	$ 75,176,922
2	Accumulated Depreciation	(11,272)
3	Cash Working Capital	(459,678)
4	DEBS EDIT Amortization	(16,435)
5	ESM Roll-in	(9,938,525)
6	Fuel & Lime Inventory	(603,620)
7	Capital Structure	(369,966)
8	**Total Adjustments to Company's Proposed Revenue Requirement**	$(11,399,496)
9	**Duke Energy Kentucky Revised Revenue Requirement Request**	$ 63,777,426

III. EAST BEND RETIREMENT DATE

Q. PLEASE DESCRIBE MR. KOLLEN'S PROPOSAL AS IT RELATES TO THE RETIREMENT DATE OF EAST BEND.

A. Mr. Kollen recommends that the Commission reject the Company's request to accelerate East Bend's depreciation to align with a likely retirement in 2035. He makes various recommendations to the revenue requirement as a result.

Q. DOES THE COMPANY AGREE WITH MR. KOLLEN'S PROPOSAL?

A. No. Company witnesses John Spanos, Bill Luke, Sarah Lawler, and Scott Park discuss in their rebuttal testimony why the Company disagrees with Mr. Kollen's proposal and believes that the depreciable life through 2035 is the most appropriate date to include in this proceeding. I discuss how rejecting this proposal impacts the revenue requirement.

Q. PLEASE EXPLAIN THE IMPACT OF REJECTING MR. KOLLEN'S PROPOSAL ON THE COMPANY'S REVENUE REQUIREMENT.

A. The Company recommends that the Commission reject Mr. Kollen's proposal to maintain East Bend's depreciable life through 2041. Instead, for the reasons explained by Ms. Lawler, Mr. Spanos, Mr. Park, and Mr. Luke, the Commission should instead align the depreciation expense with a likely retirement date of 2035. Mr. Kollen's recommendation results in a decrease in depreciation expense of $10.435 million and the decrease in accumulated depreciation, net of ADIT effects, of $2.616 million. The corresponding revenue impact of $10.208 million shown on Table 1 of Mr. Futral's testimony should also be rejected. This is comprised of a reduction of $10.452 million for the decrease in depreciation expense and an increase of $0.245 million for the decrease in accumulated depreciation net of ADIT impacts.

IV. DECOMMISSIONING COSTS

Q. PLEASE DESCRIBE MR. KOLLEN'S PROPOSAL AS IT RELATES TO DECOMMISSIONING COSTS.

A. Mr. Kollen recommends the decommissioning expense for the Company's generating units be included in the revenue requirement as a separate and standalone expense instead of including it as a component of the depreciation rates and expense. He also recommends that the Commission limit the escalation of the decommissioning cost and resulting expense to the test year and removing the estimated end of life materials and supplies from the decommissioning cost estimate. He makes various recommendations to the revenue requirement as a result of these changes.

Q. DOES THE COMPANY AGREE WITH MR. KOLLEN'S PROPOSAL?

A. No. Company witnesses John Spanos and Jeff Kopp discuss in their rebuttal testimony why the Company disagrees with Mr. Kollen's proposal and believes that the decommissioning costs should be (1) a component of the depreciation rates, (2) escalated through the probable retirement date, and (3) include the estimated end of life materials and supplies. I discuss how rejecting these proposals impact the revenue requirement.

Q. PLEASE EXPLAIN THE REVENUE REQUIREMENT IMPACT OF THE COMPANY'S POSITION AS IT RELATES TO MR. KOLLEN'S RECOMMENDATION TO TREAT DECOMMISSIONING COSTS AS A STANDALONE EXPENSE.

A. As outlined in the rebuttal testimony of the Company witnesses noted above, the Company recommends the Commission reject Mr. Kollen's proposal to treat the decommissioning costs as a separate and standalone expense in the revenue requirement. This recommendation reduced depreciation expense by $5.765 million and was offset by an increase in depreciation expense for the decommissioning costs of $4.908 million for a net reduction in depreciation expense of $0.857 million. The corresponding revenue requirement decrease of $0.859 million shown on Table 1 of Mr. Futral's testimony should be rejected.

This recommendation also decreased accumulated depreciation, net of ADIT effects, by $1.446 million and increased accumulated depreciation, net of ADIT effects, by $1.231 million for a net increase in accumulated depreciation, net of ADIT effects, of $0.215 million. This results in a recommended increase to the revenue requirement of $0.020 million. The Commission should also reject this adjustment.

Q. PLEASE EXPLAIN THE REVENUE REQUIREMENT IMPACT OF THE COMPANY'S POSITION AS IT RELATES TO THE ESCALATION OF DECOMMISSIONING COSTS.

A. As outlined in the rebuttal testimony of the Company witnesses noted above, the Company recommends the Commission reject Mr. Kollen's proposal to escalate the decommissioning costs and resulting expense only through the test year and not through the estimated retirement date. This recommendation reduced decommissioning costs in the test year by $1.563 million. The corresponding revenue requirement decrease of $1.566 million shown on Table 1 of Mr. Futral's testimony should be rejected.

This recommendation also decreased accumulated depreciation, net of ADIT effects, of $0.392 million. This results in a recommended increase to the revenue requirement of $0.037 million. The Commission should also reject this adjustment.

Q. PLEASE EXPLAIN THE REVENUE REQUIREMENT IMPACT OF THE COMPANY'S POSITION AS IT RELATES TO THE ESTIMATED END OF LIFE MATERIALS AND SUPPLIES.

A. As outlined in the rebuttal testimony of the Company witnesses noted above, the Company recommends the Commission reject Mr. Kollen's proposal to remove the estimated end of life materials and supplies from the decommissioning cost estimate. This recommendation reduced decommissioning costs in the test year by $0.757 million. The corresponding revenue requirement decrease of $0.758 million shown on Table 1 of Mr. Futral's testimony should be rejected.

This recommendation also decreased accumulated depreciation, net of ADIT effects, of $0.190 million. This results in a recommended increase to the revenue requirement of $0.018 million. The Commission should also reject this adjustment.

V. PLANNED OUTAGE O&M EXPENSE REGULATORY ASSET AMORTIZATION

Q. PLEASE DESCRIBE MR. KOLLEN'S PROPOSAL AS IT RELATES TO THE AMORTIZATION OF THE PLANNED OUTAGE O&M DEFERRAL.

A. Mr. Kollen recommends the amortization for the planned maintenance outage O&M deferrals be denied in this proceeding. Mr. Kollen argues that the Company has not met its burden to demonstrate that the expenses incurred were prudent, reasonable, and necessary.

Q. DOES THE COMPANY AGREE WITH MR. KOLLEN'S PROPOSAL?

A. No.

Q. PLEASE EXPLAIN.

A. Mr. Luke explains in his rebuttal testimony why the Company disagrees with this argument. Mr. Luke outlined in his direct testimony details around the Company's planned outages. Additionally, the Company responded to discovery Mr. Kollen asked on this exact matter.[2] Mr. Kollen failed to prove why that direct testimony and responses to discovery doesn't demonstrate that the expenses incurred were prudent, reasonable, and necessary.

[2] *See* Response to AG-DR-01-100(c), Attachment 1.

Q. IF THE COMMISSION RULES IN FAVOR OF MR. KOLLEN'S RECOMMENDATION, DOES THE COMPANY HAVE ANY ADDITIONAL RECOMMENDATION?

A. Yes. If the Commission does not allow the Company to begin amortizing these costs in rates, the Commission should approve that the balance of the regulatory asset or liability should accrue a carrying cost at the Company's long-term debt rate approved in this proceeding. The carrying costs should apply to any credit balance (*i.e.*, amounts owed to customers) or to any debit balance (*i.e.*, amounts owed to the Company) to maintain the symmetry and ensure that neither customer nor Company is deprived of the time value of money.

Q. DOES MR. KOLLEN HAVE ANY OTHER RECOMMENDATIONS REGARDING THE AMORTIZATION OF THE PLANNED OUTAGE O&M DEFERRAL?

A. Yes. Mr. Kollen recommends that if the Commission does grant amortization, that it set the amortization period to ten years instead of the five years the Company is requesting.

Q. DO YOU AGREE WITH THIS RECOMMENDATION?

A. No. The Company believes the five-year amortization period is the most appropriate period for the Company to recover its costs. At a minimum, if the Commission orders the Company to amortize the costs over ten years, it should allow the Company to accrue carrying costs at the Company's long-term debt rate.

VI. FORCED OUTAGE PURCHASED POWER EXPENSE REGULATORY ASSET AMORTIZATION

Q. PLEASE DESCRIBE MR. KOLLEN'S PROPOSAL AS IT RELATES TO THE AMORTIZATION OF THE FORCED OUTAGE PURCHASED POWER DEFERRAL.

A. Mr. Kollen recommends the amortization for the forced outage purchased power deferrals be denied in this proceeding. He makes a similar argument as he did for the planned outage O&M deferral that the Company has not met its burden of proof to demonstrate that the expenses incurred were prudent, reasonable, and necessary.

Q. DOES THE COMPANY AGREE WITH MR. KOLLEN'S PROPOSAL?

A. No.

Q. PLEASE EXPLAIN.

A. Mr. Swez explains in his rebuttal testimony why the Company disagrees with this argument. The Company responded to discovery questions Mr. Kollen asked on this describing the nature of the forced outages.[3] Mr. Kollen failed to prove why the responses to the discovery did not demonstrate that the expenses incurred were prudent, reasonable, and necessary.

[3] *See* response to AG-DR-01-100(f), Attachment 1.

Q. IF THE COMMISSION RULES IN FAVOR OF MR. KOLLEN'S RECOMMENDATION, DOES THE COMPANY HAVE ANY ADDITIONAL RECOMMENDATON?

A. Yes. The Commission should approve that the balance of the regulatory asset or liability should accrue a carrying cost at the Company's long-term debt rate approved in this proceeding. The carrying costs should apply to any credit balance (*i.e.*, amounts owed to customers) or to any debit balance (*i.e.*, amounts owed to the Company) to maintain the symmetry and ensure that neither customer nor Company is deprived of the time value of money.

Q. DOES MR. KOLLEN HAVE ANY OTHER RECOMMENDATIONS REGARDING THE AMORTIZATION OF THE FORCED OUTAGE PURCHASED POWER DEFERRAL?

A. Yes. Mr. Kollen recommends that if the Commission does grant amortization, that it set the amortization period to ten years instead of the five years the Company is requesting.

Q. DO YOU AGREE WITH THIS RECOMMENDATION?

A. No. The Company believes the five-year amortization period is the most appropriate period for the Company to recover its costs. At a minimum, if the Commission orders the Company to amortize the costs over ten years, it should allow the Company to accrue carrying costs at the Company's long-term debt rate.

Q. WHAT ELSE DOES MR. KOLLEN HAVE TO SAY ABOUT THE AMORTIZATION OF THIS DEFERRAL?

A. Mr. Kollen also argues that the Commission should not allow the amortization until it has completed its investigation in Case 2022-0190.

Q. DO YOU AGREE WITH THIS ARGUMENT?

A. No. I do not. First, although I am not an attorney, by experience in regulatory matters before the Commission leads me to conclude that the Commission has the ability to decide these sorts of issues within a base rate proceeding. Moreover, Mr. Kollen's argument in this regard is inconsistent with other positions he is taking in this proceeding. For example, Mr. Kollen argues in favor of the Company's recommendation to eliminate volatility in Rider FAC by introducing a twelve-month rolling average calculation to the clause. The volatility of fuel expense and how to address it is also being discussed and considered by the Commission in another proceeding, administrative Case 2022-00190. It makes no sense that the Commission can rule on one issue in this case but not the other, simply because a particular issue is being considered in another proceeding. The Commission has the experience, expertise, and authority to address these important issues now, and the Company submits that the Commission should do so in this case, rather than delaying.

VII. EAST BEND DEFERRED O&M AMORTIZATION

Q. PLEASE DESCRIBE MR. KOLLEN'S PROPOSAL AS IT RELATES TO THE AMORTIZATION OF THE EAST BEND O&M EXPENSE DEFERRAL RELATED TO THE ACQUISITION OF THE REMAINING OWNERSHIP OF THE GENERATING UNIT.

A. Mr. Kollen recommends the Commission extend the amortization period and recalculate the levelized recovery to reflect a probable retirement date of mid-year 2041.

Q. DOES THE COMPANY AGREE WITH MR. KOLLEN'S PROPOSAL?

A. No.

Q. PLEASE EXPLAIN.

A. The Commission approved the ten-year amortization period of this regulatory asset in Case No. 2017-00321.[4] Mr. Kollen was a witness in that proceeding and did not object to the ten-year amortization period that the Company proposed, and the Commission adopted. In fact, in that case, Mr. Kollen recommended an adjustment to the regulatory asset balance and recommended that that balance be amortized over ten years. The Commission's order found that the "10-year period is reasonable and should be approved." Mr. Kollen's recommendation is an untimely request for the Commission to reconsider its prior decision. The Commission should not be second guessed in this proceeding.

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[4] *See 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; 30 Approval of New Tariffs; 4) Approval of Accounting Practices to Establish Regulatory Assets; and 5) All Other Required Approvals and Relief;* Case No 2017-00321 pp. 11 and 75 (Ky.P.S.C. Apr. 13, 2018).

VIII. COAL ASH ARO AMORTIZATION

Q. PLEASE DESCRIBE MR. KOLLEN'S PROPOSAL AS IT RELATES TO THE AMORTIZATION OF THE COAL ASH ARO IN RIDER ESM.

A. Mr. Kollen recommends the Commission extend the amortization period and recalculate the levelized recovery to reflect a probable retirement date of mid-year 2041.

Q. DOES THE COMPANY AGREE WITH MR. KOLLEN'S PROPOSAL?

A. No.

Q. PLEASE EXPLAIN.

A. No. As I explained above as it relates to the amortization of East Bend's O&M expense, the Commission has already addressed this issue in a fully-litigated case, and approved the ten-year amortization period of this regulatory asset in Case No. 2017-00321.[5] Specifically, in that proceeding, the Commission found that the Company should "amortize only the actual balance of the East Bend Coal Ash ARO regulatory asset over 10 years and recover additional costs associated with the settlement of the East Bend Coal Ash ARO in the second month after they are incurred." That is the methodology the Company has been employing ever since. Mr. Kollen's recommendation is an untimely request for the Commission to reconsider its prior decision. The Commission should not be second guessed in this proceeding and should hold true to its prior determination on this issue.

[5] *Id.*

IX. CONCLUSION

Q. DOES THIS CONCLUDE YOUR REBUTTAL TESTIMONY?

A. Yes.

VERIFICATION

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

The undersigned, Lisa Steinkuhl, Director Rates & Regulatory Planning, being duly sworn, deposes and says that she has personal knowledge of the matters set forth in the foregoing rebuttal testimony and that it is true and correct to the best of her knowledge, information and belief.

Lisa D Steinkuhl
Lisa Steinkuhl Affiant

Subscribed and sworn to before me by Lisa Steinkuhl on this 11TH day of APRIL, 2023.

Adele M. Frisch
NOTARY PUBLIC

NOTARIAL SEAL
STATE OF OHIO

ADELE M. FRISCH
Notary Public, State of Ohio
My Commission Expires 01-05-2024

My Commission Expires: 1/5/2024

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

The Electronic Application of Duke Energy Kentucky, Inc., for: 1) An Adjustment of the Electric Rates; 2) Approval of New Tariffs; 3) Approval of Accounting Practices to Establish Regulatory Assets and Liabilities; and 4) All Other Required Approvals and Relief.	)))))))	Case No. 2022-00372

REBUTTAL TESTIMONY OF

PAUL L. HALSTEAD

ON BEHALF OF

DUKE ENERGY KENTUCKY, INC.

April 14, 2023

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PAGE

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Paul L. Halstead and my business address is 526 South Church Street, Charlotte NC, 28202.

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

A. I am employed by Duke Energy Business Services LLC (DEBS), as Director Jurisdictional Rate Administration. DEBS provide 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 PAUL L. HALSTEAD THAT SUBMITTED DIRECT TESTIMONY IN THIS PROCEEDING?

A. Yes.

Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY?

A. My rebuttal testimony responds to the direct testimonies of Messer's Chriss and Kollen on behalf of Walmart, Inc., (Walmart) and the Kentucky Attorney General, respectively, related to the Company's Clean Energy Connection (CEC) Program proposal.

II. DISCUSSION

Q. PLEASE BRIEFLY SUMMARIZE MR. CHRISS'S TESTIMONY REGARDING THE CEC PROGRAM PROPOSAL.

A. Mr. Chriss is supportive of the Company's CEC proposal as designed.

Q. DO YOU HAVE ANY COMMENTS REGARDING MR. CHRISS'S TESTIMONY ON BEHALF OF WALMART?

A. The Company finds similar customer interest as noted in Mr. Chriss' testimony where he states "…Walmart seeks renewable energy resources that deliver industry-leading cost, including renewable and project specific attributes such as RECs, within structures where the value proposition allows the customer to receive any potential benefits brought about by taking on the risk of being served by that resource…". Walmart's interests in CEC are not unique and this program provides a reasonable strategy to meet these customers where they are, and potentially attract more similarly situated job-providing companies interested in renewable opportunities.

Q. PLEASE BRIEFLY SUMMARIZE MR. KOLLEN'S RECOMMENDATION REGARDING THE COMPANY'S CLEAN ENERGY CONNECTION PROPOSAL.

A. Mr. Kollen recommends the Commission deny the Company's proposal at this time. He suggests the Company should provide a revised and more developed CEC program at the time it files an application for a Certificate of Public Convenience and Necessity (CPCN) for a new solar facility.

Q. DOES MR. KOLLEN OFFER ANY EXPLANATION WHY THE COMMISSION SHOULD NOT APPROVE THE CEC PROGRAM AT THIS TIME?

A. Yes. Mr. Kollen's criticism of the CEC Program is twofold:

1) The proposed CEC tariff does not set forth or describe the calculations of the subscription fees charged on a $/kW-month basis and bill credits on a cents/kWh basis;[1]

2) The proposed CEC tariff does not include any procedural provisions and it isn't clear whether there will be separate tariff rates for participants in separate projects or a single tariff for all participants in all projects.

Q. WHAT IS THE COMPANY'S RESPONSE TO MR. KOLLEN'S CRITICISM.

A. Regarding Mr. Kollen's concern the program calculations are not described, I stated in my testimony the subscription charge would be the NPV of 105 percent of the CEC Program cost less 75 percent of the capital deferral and capacity benefits associated with the underlying assets.[2] Regarding the program's credit, the Company proposes that the bill credit will be sufficient to, and capped at, the amount to generate the forecasted participant payback with all excess provide to non-participating customers.[3] The calculations noted above provide the framework to ensure non-participating customers are not harmed as well as provide sufficient information for customers interested in renewables to make an informed participation decision. When the CPCN is filed the calculations noted above will be updated to reflect the actual cost.

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[1] Kollen Testimony pg. 65-66.
[2] *See* Direct Testimony of Paul L. Halstead, page 12, line 6 to line 10.
[3] *Id.*, line 11 to line 14.

Q. WHAT IS THE COMPANY'S RESPONSE TO MR. KOLLEN'S CRITICISM REGARDING THE PROCEDURAL PROVISIONS AND TARIFF CHARGES FOR PARTICIPANTS.

A. The Company has proposed a single tariff concept in this application. With the exception of the low-income carve-out which is included in the single tariff all customer classes are treated equally and charged the same subscription cost and will receive the same bill credit value. Therefore, one tariff is sufficient.

Q. DOES THE COMPANY AGREE WITH MR. KOLLEN'S RECOMMENDATION THAT THE COMPANY SHOULD FILE AN UPDATED CEC PROPOSAL WITH A CPCN FOR A SOLAR FACILITY IN THE FUTURE?

A. No.

Q. PLEASE EXPLAIN WHY THIS IS NOT A REASONABLE AND WORKABLE SOLUTION.

A. The Company requested the CEC framework in this case so it can use that tariff as an opportunity to attract interest and engage with customers. Having a tariff and a structure approved now provides certainty to customers who are interested in this type of offering. Having a tariff offering allows the Company to engage directly with customers regarding their renewable strategies with a tool that can assist their desire to have real renewable power satisfying their load requirements. And this will allow the Company to plan for future installations if the interest is there. The Commission will have the authority/ability to approve or not approve the value streams when the final values are provided as part of the CPCN filing. In addition, by proceeding with the program as filed, the Company will be able to meet the immediate needs of our customers which is having confidence that the Company has renewable program options coming to help with their sustainability goals along with knowing the specific CEC framework. This is critical to ensuring customers not only stay in Kentucky but are able to consider Kentucky in locating or expanding their business in Kentucky.

Q. DO YOU BELIEVE THE CEC PROGRAM WILL ATTRACT BUSINESSES TO LOCATE TO KENTUCKY?

A. Existing and potential customers continue to note the need for renewable options for them to even consider expanding or locating their operations within the Company's jurisdiction. Programs such as CEC provides an important tool for the Company to keep Kentucky attractive and competitive to existing and prospective customers.

Q. HAS THE CEC PROGRAM IN OTHER DUKE ENERGY JURISDICTIONS PROVIDED BENEFITS TO CUSTOMERS?

A. Yes. The Company's approved CEC program in Florida has been received well by customers and continue to prove to be successful in meeting customer's needs for renewable energy. The Duke Energy Florida based version of the Clean Energy Connection program started billing in August 2022. The program was pre-registered at 75% with Large Customers and Local Governments opting to enroll their account in the program at the start. The overwhelming response to the program required a reduction of 30% and 60% of Large Customer and Local Governments original subscription request, respectively. As solar centers go online throughout the program's first 3 years, Large Customers and Local Government's subscription are being phased-in due to their size.

Residential and Small Medium Businesses (SMB) are treated as one carveout with initial subscription levels at approximately 45% based on online capacity at program start or 8% based on total program capacity (10 solar centers). Income qualified participation started at 14% for online capacity or 3% based on total program capacity. As Duke Energy Florida's CEC moved into its current, ninth month of billing, Residential and SMB enrollment has grown to 63% based on online capacity or 13% based on total program capacity. Income qualified has grown to 89% based on online capacity or 18% based on total program capacity. Ongoing marketing and customer education activities have assisted with customer enrollment. These activities continue along with community engagement opportunities to further grow enrollment.

III. CONCLUSION

Q. DOES THIS CONCLUDE YOUR REBUTTAL TESTIMONY?

A. Yes.

VERIFICATION

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

The undersigned, Paul Halstead, Director Jurisdictional Rate Administration, 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.

Paul Halstead Affiant

Subscribed and sworn to before me by Paul Halstead on this 29 day of March, 2023.

NOTARY PUBLIC

LAUREN A PADILLA
NOTARY
PUBLIC
CABARRUS COUNTY, NC

My Commission Expires: 3/3/27

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 New Tariffs; 3) Approval of Accounting Practices to Establish Regulatory Assets and Liabilities; and 4) All Other Required Approvals and Relief.	)))))))	Case No. 2022-00372

REBUTTAL TESTIMONY OF

PAUL M. NORMAND

ON BEHALF OF

DUKE ENERGY KENTUCKY, INC.

April 14, 2023

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I. INTRODUCTION AND PURPOSE

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

A. My name is Paul M. Normand. I am a Principal with the firm of Management Applications Consulting, Inc. (MAC), 1103 Rocky Drive, Suite 201, Reading, PA 19609.

Q. PLEASE DESCRIBE MAC.

A. MAC is a management consulting firm that provides rate and regulatory assistance including lead lag studies, allocated cost of service studies, and depreciation services for electric, gas and water utilities.

Q. ARE YOU THE SAME PAUL M. NORMAND 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 the recommendations of Mr. Lane Kollen on behalf of the Kentucky Attorney General as it relates to the Company's cash-working capital requirements, and specifically, the lead-lag study that I performed and submitted in this proceeding.

II. DISCUSSION

Q. PLEASE SUMMARIZE MR. KOLLEN'S RECOMMENDATIONS AS IT RELATES TO THE COMPANY'S CASH WORKING CAPITAL REQUIREMENT AND THE LEAD-LAG STUDY.

A. Mr. Kollen recommends that the Commission reflect a factor of 1.46 in collection lag days in the collection component of the revenue lag days in the calculation of cash working capital included in rate base using the lead/lag approach. The result of Mr. Kollen's recommendations are a reduction of $17.945 in the Company's rate base and a $1.677 million reduction in the base revenue requirement and requested base rate increase.

Q. PLEASE SUMMARIZE MR. KOLLEN'S POSITION REGARDING HIS RECOMMENDED USE OF THE FACTOR 1.46 FOR THE COLLECTION LAG DAYS USED IN THE LEAD LAG STUDY.

A. Mr. Kollen's testimony is claiming that "CRC is an affiliated special purpose financing entity used to accelerate the Company's conversion of receivables into cash on a daily basis rather than waiting until customers actually pay their bills".[1] Mr. Kollen's testimony further states, "The Company actually sells its receivables to CRC daily for cash. The Company actually collects cash from its customers to remit to CRC daily. However, it only remits or collects the net of these two daily and recurring cash flows to CRC on a monthly basis.[2] Concerning the flow of cash, Mr. Kollen further states, "the reality is that there is an increasing cycle of cash flowing in from the sales of the receivables to CRC and cash ebbing out when the cash received from customers is remitted to CRC on a recurring daily basis".[3] Using these arguments above, Kollen calculates that "the Company accelerates the conversion of the receivables to cash and waits an average of only 1.46 days from the date of customer billing to the date when it receives cash for service".[4]

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[1] Case No. 2022-00372, Direct Testimony and Exhibits of Lane Kollen, Page 11, 13 to 16.
[2] Case No. 2022-00372, Direct Testimony and Exhibits of Lane Kollen, Page 12, 11 to 14.
[3] Case No. 2022-00372, Direct Testimony and Exhibits of Lane Kollen, Page 13, 1 to 4.
[4] Case No. 2022-00372, Direct Testimony and Exhibits of Lane Kollen, Page 13, 14 to 16.

Duke's lead lag study shows that Duke waits an average of 27.02 days from the date of customer billing to the date when it receives cash payment for service. This difference in the collection lag from 27.02 days to 1.46 days results in a reduction of cash working capital included in rate base in the amount of $17.945 million.

Q. DO YOU AGREE WITH MR. KOLLEN'S POSITION REGARDING THE USE OF 1.46 AS THE LAG-DAY COMPONENT FOR THE LEAD LAG STUDY? PLEASE EXPLAIN.

A. No. As discussed by Duke Energy Kentucky witness, Mr. Heath, Mr. Kollen completely misstates the relationship between CRC and Duke Energy Kentucky and misstates facts as to how cash flows between CRC and Duke Energy Kentucky. As a result, Mr. Kollen's reasoning for using 1.46 days is flawed and should be rejected. Mr. Heath explains that the program between Duke Energy Kentucky and CRC is a securitization financing of the accounts receivable not a factoring of accounts receivables. Mr. Kollen's 1.46 lag day calculation is based on Duke Energy Kentucky receiving cash for its receivables the day after they are billed which is how a factoring of receivables program works. This is not the case with CRC. Duke Energy Kentucky only receives cash for its receivables after the customer remits payment. Mr. Heath's testimony explains in detail how the securitization financing program between CRC and Duke Energy Kentucky works.

Q. WHAT IS YOUR RECOMMENDATION REGARDING MR. KOLLEN'S ADJUSTMENTS TO THE LEAD LAG STUDY?

A. Mr. Kollen's claim that CRC is paying Duke Energy Kentucky cash for receivables on a daily basis is not supported by what is <u>actually happening</u> between Duke

Energy Kentucky and CRC. No cash is ever received by Duke Energy Kentucky from CRC immediately upon the customer billing as explained by Mr. Heath.

Kollen's support for the 1.46-day lag on receivables is faulty insofar as it is based upon his erroneous conclusion that Duke Energy Kentucky receives cash for the receivables on the next working day from CRC. This is simply not the case. The lead lag study presented in this case calculates the average lag in days from when a customer is billed and the receipt of cash from the customer by Duke Energy Kentucky as 27.02 days. The use of the 27.02 days lag on receivable properly reflects the average number of days cash is available to Duke Energy Kentucky after customer billings and not the 1.46 days in Kollen's testimony which is not based on actual cash flows.

III. CONCLUSION

Q. DOES THIS CONCLUDE YOUR REBUTTAL TESTIMONY?

A. Yes, it does.

VERIFICATION

COMMONWEALTH OF PENNSYLVANIA	**)**	
	)	**SS:**
COUNTY OF BERKS	**)**	

The undersigned, Paul Normand, Principal, 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.

Paul Normand Affiant

Subscribed and sworn to before me by Paul Normand on this 27 day of March, 2023.

NOTARY PUBLIC

My Commission Expires: June 18, 2026

Commonwealth of Pennsylvania - Notary Seal
Stephen A. Parzanese, Notary Public
Berks County
My commission expires June 18, 2026
Commission number 1125901
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 New Tariffs; 3) Approval of Accounting Practices to Establish Regulatory Assets and Liabilities; and 4) All Other Required Approvals and Relief.	)))))))	Case No. 2022-00372

REBUTTAL TESTIMONY OF

SARAH E. LAWLER

ON BEHALF OF

DUKE ENERGY KENTUCKY, INC.

April 14, 2023

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I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Sarah E. Lawler 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 Vice President, 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 SARAH E. LAWLER WHO 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's witness Lane Kollen and the Sierra Club's witness, Sarah Shenstone-Harris. Specifically, I address the concerns with the witnesses' recommendations related to the probable remaining lives of the Company's fossil fuel-fired generation and the alignment of depreciation expense with those probable remaining lives. I also discuss the Company's proposed Generation Asset True-Up Mechanism (Rider GTM). In doing so, I address relevant legislative changes that have occurred since the Company's filing of its application in this proceeding. Further, I discuss Mr. Kollen's recommendations related to the

Company's proposed Incremental Local Investment Rider (Rider ILIC). Finally, I address his recommendation related to the Company's request to defer the costs of the Make Ready Credit Program (Rider MRC).

II. FOSSIL FUEL-FIRED GENERATION ISSUES AND THE COMPANY'S RIDER GTM

A. OVERVIEW

Q. PLEASE BRIEFLY SUMMARIZE THE COMPANY'S PROPOSALS RELATED TO ITS FOSSIL FUEL-FIRED GENERATION IN THIS PROCEEDING.

A. Duke Energy Kentucky has three proposals related to its fossil fuel-fired generation in this proceeding. The first is the Company's proposal to adopt a rolling twelve-month average to its Fuel-Adjustment Clause (FAC) to mitigate volatility in fuel expense for customers. No intervenor in this proceeding has offered testimony opposing this proposal; in fact, the Attorney General's witness recommends the Commission approve this proposal.

Second, the Company is proposing to align its depreciation expense for its East Bend and Woodsdale Generating stations with the revised useful lives for these plants. In this regard, the Company's proposal is consistent with the Commission's long-standing policy and sound rate-making principles of recovering the costs of assets over their useful lives. As supported by Company witness, Mr. Scott Park, based upon the Company's most recent Integrated Resource Plan (IRP) analysis, the likely retirement date for East Bend is projected to be 2035. Consequently, depreciation rates need to be adjusted to reflect this revised probable useful life. Additionally, based upon plant performance, the Company is proposing that its

Woodsdale depreciation rates should be adjusted to reflect a revised estimated useful life of 2040, instead of the previously projected 2032.

Finally, the Company proposed the creation of Rider GTM, as a placeholder, to recover any over/under collection of the remaining costs of these assets as of the date of their retirements.

B. Recent Legislative Changes Impacting the Company's Application

Q. PLEASE IDENTIFY THE RECENT LEGISLATIVE ACTION REGARDING FOSSIL FUEL-FIRED GENERATION THAT IMPACTS THE COMPANY'S PROPOSALS IN THIS PROCEEDING.

A. In late March 2023, Senate Bill (SB) 4 became law without the Governor's signature. As this was well after the Company submitted its application and supporting testimony in this proceeding, the Company's filings could not have been informed by this newly enacted law. However, it is now the law and thus warrants discussion.

Although I am not an attorney, as part of my job responsibilities as Vice President of Rates and Regulatory Strategy, I regularly review Kentucky statutes and regulations to stay abreast of requirements relating to the Company's regulated operations in the Commonwealth of Kentucky. Accordingly, I have reviewed SB 4 and am familiar with it.

The purpose of SB 4 was to create new sections of Chapter 278 of the Kentucky Revised Statutes to "prohibit the Kentucky Public Service Commission from approving a request by a utility to retire a coal-fired electric generator unless the utility demonstrates the retirement will not have a negative impact on the reliability or the resilience of the electric grid or the affordability of the customers electric rate”[1] and requires the Commission to submit an annual report on retirements of electric generating units annually. In its final form, SB 4 does the following:

1) grants the Commission authority to approve or deny the retirement of any electric generating unit owned by a utility;

2) requires a utility to file an application with the Commission requesting authorization before it can retire any electric generating unit;

3) creates a rebuttable presumption against retirement of a fossil fuel-fired generating unit; and

4) prohibits the Commission from approving the retirement, authorizing a surcharge for decommissioning of a unit, or taking any action that authorizes or allows for the recovery of costs for the retirement of an electric generating unit, including any stranded asset recovery, unless the presumption against retirement is rebutted.

Importantly, SB 4 defines an “electric generating unit” as being limited to a fossil fuel-fired source and “retirement” as “the closure or the complete and permanent cessation of operations at an electric generating unit.”

In order to rebut the presumption against retiring an electric generating unit, a utility must demonstrate that:

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[1] *See* Summary of the Bill, available *at:* https://apps.legislature.ky.gov/record/23rs/sb4.html

1) The utility will replace the retired generating unit with new electric generating capacity that:

a) is dispatchable by either the utility or the regional transmission organization or independent system operator responsible for balancing load within the utility's service area;

b) maintains or improves the reliability and resilience of the electric transmission grid; and

c) maintains the minimum reserve capacity requirement established by the utility's reliability coordinator;

2) The retirement will not harm the utility's ratepayers by causing the utility to incur any net incremental costs to be recovered from ratepayers that could be avoided by continuing to operate the electric generating unit proposed for retirement in compliance with applicable law; and

3) The decision to retire the fossil fuel-fired electric generating unit is not the result of any financial incentives or benefits offered by any federal agency.

Q. HOW DOES SB 4 IMPACT THE COMPANY'S PROPOSED RIDER GTM?

A. Although I am not an attorney and am not offering a legal opinion, I have expertise in rate regulation and I can read the plain language of a statute and its stated purpose. I am thus qualified to discuss the effect of SB 4 on the Company's proposed Rider GTM.

As set forth above, SB 4 established a three-part test that must be satisfied before the Commission could authorize either the retirement of a fossil fuel-fired generating unit, a decommissioning surcharge, or the recovery of retirement costs. As discussed in the application and my direct testimony, both of which were filed on December 1, 2022, the intended purpose of Rider GTM is to allow Duke Energy Kentucky to recover any remaining undepreciated amounts for both East Bend and Woodsdale upon their respective retirements. In light of its stated purpose, Rider GTM is, in my opinion, subject to SB 4. And as the Company's application did not – and could not – address the presumption created in SB 4, Rider GTM cannot be approved in this proceeding.

Q. THE ATTORNEY GENERAL'S WITNESS, LANE KOLLEN, SUPPORTS RIDER GTM, WITH MODIFICATIONS, IN HIS MARCH 10, 2023, TESTIMONY. DOES HIS SUPPORT OF RIDER GTM CONTRADICT SB 4?

A. Like the Company's application in this proceeding, Mr. Kollen's testimony was filed prior to the enactment of SB 4 and I am not criticizing him for supporting Rider GTM. However, should the Commission find that it is authorized to act on Rider GTM, I do take exception to several of Mr. Kollen's proposed modifications. I discuss these proposals below, as well as Mr. Kollen's misguided attempt to redefine depreciation expense as a transition cost.

Q. HOW DOES SB 4 IMPACT THE COMPANY'S PROPOSAL IN THIS PROCEEDING TO ADJUST THE DEPRECIABLE LIVES OF EAST BEND AND WOODSDALE?

A. Again, I am not an attorney, and thus am not able to offer a legal opinion. But I can read the plain language of the statute and its stated purpose and can apply my expertise in utility rates and regulation.

As a foundational matter, it is indisputable that a law cannot be enacted in such a manner that compliance with it is impossible. If the Commission does not approve the Company's request to align the depreciation rates with East Bend's and Woodsdale's new estimated useful lives, this decision would make it impossible for the Company to comply with SB 4. Here, SB 4 did not create an absolute ban against the retirement of a fossil fuel-fired generating unit. Rather, it created a rebuttable presumption against retirement – a presumption that can be overcome with the required evidence. One such element of this evidence is that, upon the proposed retirement date – or as defined by SB 4, complete and permanent cessation of operations – the utility's customers would not be exposed to net incremental costs. If the Commission does not approve the Company's request to align depreciation rates of the units with their new estimated lives, the utility's customers ***will be*** exposed to net incremental costs.

Here, the Company is merely seeking to align its depreciation rates with the probable life of the assets so to mitigate the potential for the creation of stranded costs. If the Company cannot align the depreciation rate of East Bend with its anticipated retirement date, it will have significant undepreciated balances upon that unit's retirement; balances that would have been artificially and arbitrarily created. And, in that instance, the Company could not possibly pass the three-part test under SB 4 once the Company does seek to retire East Bend. It is apparent, therefore, that SB 4 directs the Commission to consistently – and timely – align depreciation rates with probable remaining useful lives so as to enable compliance with the law.

Q. IS THE COMPANY SEEKING, IN THIS PROCEEDING, COMMISSION APPROVAL TO RETIRE EITHER EAST BEND OR WOODSDALE?

A. No. Again, the Company's request is to simply align the depreciation rates with the estimated useful lives of those assets.

Q. DO THE COMPANY'S CURRENT DEPRECIATION RATES FULLY DEPRECIATE EAST BEND EVEN BY 2041?

A. No. In the Company's last electric rate case, filed in 2019, the Commission rejected the Company's request to adjust depreciation rates. A consequence of that decision is that the current depreciation rates do not fully depreciate the station by 2041 and, assuming no capital investment in East Bend through December 31, 2041, the remaining net book value (NBV) of East Bend would be $107 million. If the Commission does not align depreciation rates with East Bend's substantiated and now probable end of useful life in 2035, and again assuming no additional capital investment in East Bend, the NBV of the plant at the end of 2035 would be $134 million. Admittedly these numbers are understated because Duke Energy Kentucky must continue to invest in East Bend to maintain safe operations and dispatch the plant. But what these numbers demonstrate is that it is critical to correctly align depreciation rates.

And SB 4 compels such an outcome. As I noted above, the Company is not proposing to close or permanently cease operations at either East Bend or Woodsdale; rather, those plants are expected to continue operating until 2035 and 2040, respectively. But if the Commission fails to adjust depreciation rates, the NBV of East Bend upon its likely 2035 retirement will be larger than it should otherwise be – making it impossible for the Company to credibly advance a request under SB 4 for retirement, a decommissioning surcharge, or recovery of costs for a retirement. Simply put, depreciation rates must align with the expected end of an asset's useful life; otherwise, it will be impossible for a utility to comply with SB 4.

C. <u>Generation Issues Raised by the Sierra Club</u>

Q. PLEASE BRIEFLY SUMMARIZE THE TESTIMONY OF WITNESS SHENSTONE-HARRIS ON BEHALF OF THE SIERRA CLUB, AS IT RELATES TO THE COMPANY'S REQUEST TO ADJUST DEPRECIATION RATES.

A. Ms. Shenstone-Harris' testimony is limited to East Bend and she advocates for an even earlier retirement of that unit. Indeed, Ms. Shenstone-Harris recommends that the Company commit to retire East Bend by 2030. She surmises that the Company's forecasted ongoing capital and operations and maintenance (O&M) expense for East Bend are too conservative, and the Company's forecasted capacity factors for the unit are too optimistic. She also suggests the Commission consider securitization as a strategy to mitigate rate shock to customers upon generation unit retirement.

Q. WHAT IS YOUR RESPONSE TO MS. SHENSTONE-HARRIS'S RECOMMENDATION THAT EAST BEND RETIRE NO LATER THAN 2030?

A. The Company disagrees with this recommendation and believes the Commission should reject it at this time. As stated by Company witness Mr. Park, the current IRP supports a 2035 retirement as the most likely outcome. As explained by Company witness Mr. Luke, in order for East Bend to continue to be considered dispatchable into PJM, the Company must continue to invest capital and incur O&M expense for the plant until its retirement. This will serve to increase the NBV for the plant and will impact the economics of the unit in the market.

Q. PLEASE BRIEFLY ADDRESS MS. SHENSTONE-HARRIS'S RECOMMENDATIONS REGARDING SECURITIZATION.

A. Company witness Mr. Thomas Heath addresses this directly in his testimony. I would only add that Ms. Shenstone-Harris's discussion of securitization is premature and, for that reason alone, should be rejected by the Commission. Moreover, as explained further by Mr. Heath, securitization itself is not without challenges.

D. <u>Generation Issues Raised by the Kentucky Attorney General</u>

Q. PLEASE BRIEFLY SUMMARIZE THE TESTIMONY OF WITNESS KOLLEN ON BEHALF OF THE KENTUCKY ATTORNEY GENERAL, AS IT RELATES TO THE COMPANY'S GENERATION-RELATED PROPOSALS.

A. Mr. Kollen recommends that the Commission reject the Company's proposal to adjust depreciation expense to align with a 2035 retirement date for East Bend, but he does not object to the Company's proposal to adjust the expense to align with a later retirement date for Woodsdale of 2040. The effect of his recommendation is that the Company's entire fossil fuel-fired generation fleet would be retiring in roughly a twelve-month period. Mr. Kollen also recommends the Commission approve the Company's Rider GTM proposal, with some modifications.

Q. DID MR. KOLLEN PROVIDE ANY ANALYSIS OR JUSTIFICATION SUPPORTING HIS RECOMMENDATION NOT TO ALIGN THE DEPRECIATION RATE OF EAST BEND WITH ITS REVISED PROJECTED USEFUL LIFE OF 2035?

A. Mr. Kollen did not provide any analysis. He merely states it is not certain that East Bend is, or will be, uneconomic compared to other capacity resources by 2035 and that it is uncertain that the Company will retire the unit by that date. He also merely dismisses the Company's IRP data and modeling. Mr. Kollen argues that the Company will eventually file a CPCN to replace East Bend with new capacity and in that proceeding, the Commission will decide whether it is economic to retire East Bend prior to 2041.

Ironically, for all of his criticisms regarding the Company's IRP projecting East Bend's retirement by 2035, Mr. Kollen blindly accepts the Company's proposal to extend Woodsdale's remaining life for depreciation purposes.

It is the Company's view that the passage of SB 4 necessitates that the depreciation schedule align with the projected retirement date, based on the most likely outcome of the modeling. Otherwise, because of remaining undepreciated costs, it may be impossible to meet the burden imposed by SB 4 to prove unit retirement and replacement is cost effective, and as a result, customers will also be forced to otherwise unnecessarily pay O&M and ongoing capital investment, for a generating asset that is sitting idle because it is no longer economically dispatchable in the energy market. Further, keeping an uneconomic unit operational would expose customers to costs incurred relating to complying with any new environmental rules that apply to active generating assets that may not apply to retired assets.

Q. DO YOU AGREE WITH MR. KOLLEN'S POSITION THAT THE COMMISSION SHOULD JUST WAIT TO ADDRESS EAST BEND'S RETIRMENT DATE WHEN THE COMPANY EVENTUALLY FILES A CPCN TO REPLACE EAST BEND?

A. No, not from a depreciation perspective. By that time, it may be too late for the Commission to take meaningful action to mitigate costs for customers regarding the remaining undepreciated NBV of the unit. Again, the Company believes that it is in the best interests of customers to spread the recovery of the net plant associated with East Bend over its life as we now know it and not take a "wait and see" approach. Data and analysis show that the unit is more likely than not going to retire by 2035. Under SB 4, the wait and see approach is no longer a prudent option for the Commission.

Q. WHAT IS LIKELY TO HAPPEN IN TERMS OF RATES TO CUSTOMERS IF THE COMMISSION DOES NOT ALIGN EAST BEND'S DEPRECIATION EXPENSE WITH ITS NEW ESTIMATED LIFE?

A. If the Commission does not align East Bend's depreciation expense with its new estimated life, current customers will enjoy a benefit in their rates at the expense of future customers. If the Commission only approves depreciation rates to align with a 2041 retirement date, the remaining NBV of the East Bend generation asset will be approximately $134 million at the end of 2035, before adding any new needed capital for maintenance between now and then. This balance will be borne by future customers and will serve as an impediment to the prudent retirement of the asset. The issue compounds itself as the generating asset will require further investment once the prudent retirement date passes further prolonging the issue at the customer's expense.

Q. IF THE COMPANY IS COMMITTING TO COME TO THE COMMISSION WITH A SPECIFIC APPLICATION TO RETIRE AND REPLACE EAST BEND IN THE FUTURE, WHY SHOULD THE COMMISSION ADJUST DEPRECIATION RATES TO AN ANTICIPATED USEFUL LIFE OF 2035 NOW?

A. There are several fundamental tenants of rate making that this Commission, and other regulatory commissions, tend to follow. One of the most basic tenants is the recovery of the costs of an asset (including depreciation expense) over the life of an asset. The lives of an asset can and do change based upon investments, changes in technology, obsolescence, and other factors. The Commission routinely examines useful lives in the context of base rate proceedings and establishes appropriate depreciation expense. That is what the Company is requesting here.

A second acknowledged tenant of ratemaking policy, which supports the prior tenant, is to design rates in accordance with the principle of cost causation. That is, the customers on whom a cost is incurred, or benefit is accrued, should in turn, pay for such costs. This avoids intergenerational cost subsidies whereby a future group of customers is paying for benefits that were accrued to customers in the present. This is precisely what the Company is proposing to avoid here. Customers should pay an appropriate level of depreciation expense over the likely remaining life of the asset so to attempt to recover its costs over the life of the asset. Adjusting rates now will adjust the rates to reflect what customers should be paying today.

If rates are not adjusted now, future customers will be paying some level of costs they should not be paying. Adjusting rates now ensures there will be less remaining NBV of the plant for customers to pay for when it retires by 2035. In a perfect ratemaking scenario, customers will be able to cease paying for East Bend at the time the unit is replaced and the new resource gets folded into rates.

Finally, the third rate-making tenant is to design rates in an attempt to avoid rate shock to customers. Rate shock is a sudden or a significant rate increase for customers. I would pose that the Commission should not myopically consider the impact of rate shock in isolation to customers today but consider how to mitigate the impact to customers in the future. With depreciation, the Commission can do just that. By aligning depreciation expense to the most likely useful life of the generation station, it will mitigate the amount that would need to be addressed in rates in the future, when customers are also having to pay for the replacement generation.

Q. IS MR. KOLLEN'S RECOMMENDATION TO NOT ADJUST EAST BEND'S DEPRECIATION IS IN THE BEST INTEREST OF CUSTOMERS?

A. No. Mr. Kollen ignores all of the fundamental rate-making tenants I described and simply decides that "future customers should bear the remaining cost of the East Bend 2 in exchange for the benefits they will achieve from an earlier transition to lower cost replacement capacity."[2] Not only is this an arbitrary proposal, but more importantly it is at odds with the fundamental depreciation concept of matching recovery to the usage of assets. It ignores principles of cost causation, creates intergenerational cross subsidization, and has the potential to create rate shock for the future customers who under Kollen's recommendation will have to pay for future generation and these remaining costs of East Bend.

Moreover, as explained by Mr. Spanos, attributing the East Bend retirement costs to the same FERC accounts as that of the replacement generation would not be consistent with the Uniform System of Accounts, unless the Company were to replace East Bend 2 with another coal-fired unit. The practicality of such a scenario is near implausible. Under group accounting, there would be no related account or

[2] Direct Testimony of Lane Kollen, page 30, lines 11-13.

assets that any remaining undepreciated plant for East Bend could be assigned upon East Bend's retirement. A separate regulatory asset would need to be created or else the Company would be facing an enormous and financially damaging write-off.

Q. PLEASE EXPLAIN MR. KOLLEN'S RECOMMENDATIONS REGARDING RIDER GTM.

A. Mr. Kollen recommends that the Commission adopt the Company's proposed Rider GTM, but only if it adopts his recommendations to modify the rider to ensure that the Company recovers the actual costs of the retired generating units, no more and no less. He recommends the following modifications:

1) Mr. Kollen recommends modifications to the rider that are necessary to ensure that the Company does not recover the undepreciated remaining costs of the generating units twice, once through base rates and a second time through Rider GTM. He recommends modifications to the rider to ensure the timely reduction in rates coincident with the reduction in non-fuel and non-depreciation operating expenses.

2) He also recommends that the rider be modified to ensure that what he perceives as other calculation errors and other flaws in the proposed rider GTM language are corrected.

Q. DOES DUKE ENERGY KENTUCKY AGREE WITH HIS RECOMMENDATIONS?

A. With the passage of SB 4, the Company no longer believes that the Commission can consider Rider GTM in this case. This makes it all the more imperative that depreciation rates are set at appropriate levels to align with the probable retirement dates of the assets.

However, if the Commission disagrees with the Company's interpretation of SB 4 and approves Rider GTM, there are certain of Mr. Kollen's recommendations the Company does not agree with. As a general premise, the Company's intention is to recover only the actual costs of the retired generating units, no more and no less, as Mr. Kollen recommends. I will address each one of his proposed modifications further below.

Q. EXPLAIN IN MORE DETAIL MR. KOLLEN'S RECOMMENDATION TO MODIFY THE PROPOSED RIDER GTM TO ENSURE THAT THE COMPANY DOES NOT RECOVER THE UNDEPRECIATED REMAINING COSTS OF THE GENERATING UNITS TWICE.

A. Mr. Kollen states that the Rider GTM does not address the ongoing recovery of the costs of the retired generating units through base rates until base rates are reset. He recommends that the Rider GTM revenue requirement for the generating unit that is retired be reduced by the base revenues that recover the non-fuel costs of that generating unit. He proposes that this credit would remain in effect until base rates are reset and exclude all costs of the retired generating unit.

Q. DO YOU AGREE WITH HIS RECOMMENDATION?

A. Yes. As noted in response to discovery, the Company agrees that at the time that Rider GTM is put into rates, to the extent there are any revenues included in base rates associated with these assets, the Rider GTM would reflect a credit for those revenues to ensure no double recovery. The Company also noted in response to discovery that it would make necessary calculations in that proceeding to ensure that it does not over or double recover the remaining NBV of the assets in base rates.

Q. DOES MR. KOLLEN ACKNOWLEDGE THE COMPANY'S AGREEMENT IN HIS DIRECT TESTIMONY?

A. Yes. However, Mr. Kollen claims that the Company did not go far enough to address all of the costs that should be credited in Rider GTM. He states that the Company failed to acknowledge in discovery any non-fuel operating expenses other than depreciation expense related to gross plant and income tax related to the return on equity. He argues that the Company failed to address non-fuel O&M expenses, administrative and general expenses, including employee benefit/welfare expense, payroll tax expense, and property tax expense. He also notes that the Company did not address the methodology that will be used to calculate the recovery through base revenues.

Q. HOW DO YOU RESPOND TO THESE CLAIMS?

A. Again, the Company no longer believes the Commission can authorize Rider GTM. However, if the Commission concludes otherwise, as I have already noted, as a general premise, the Company's intention in asking the Commission to authorize

Rider GTM, as a placeholder rider, was to ensure customers pay no more or no less than the actual costs incurred. I would also reiterate that the Company's application merely sought a placeholder rider. We were not proposing to populate the Rider GTM with any dollars at this time. I have already noted in my direct testimony that the Company proposed to upon approval of the placeholder tariff and mechanism in this proceeding, and in advance of the retirement date of either East Bend, Woodsdale, or both, file a separate application to set and implement Rider GTM. This application would be subject to Commission determination of reasonableness. Rider GTM charges or credits would not appear on a customer's bill until such applications are approved by the Commission. Further, the Company would put forth a filing at that time that ensures that all necessary costs included in the revenue requirement in base rates are reflected as a credit in this rider proceeding. The Commission would determine the reasonableness and appropriateness of the Company's proposal at that time. To the extent that there are other non-fuel expenses associated with the retired assets included in the Company's base rates at the time Rider GTM would be implemented in customer rates, the Company would want to ensure those costs were appropriately credited but also ensure that operating expenses included in base rates were still set at appropriate levels to support the replacement generation. All of this could be determined in the detailed filing to implement Rider GTM.

Q. WHAT CALCULATION ISSUES DOES MR. KOLLEN POINT OUT NEED TO BE ADDRESSED BY THE COMMISSION IN THIS PROCEEDING?

A. Mr. Kollen recommends that the calculation of the credit in Rider GTM follow the "base/current method" used for the Company's environmental surcharge mechanism. He notes that the Company's "environmental surcharge mechanism calculates the revenue requirement for the allowed costs and then subtracts the base revenues that recover some or all of the allowed costs." The Company is not completely clear on what Mr. Kollen means by the "base/current method" and does not believe it "calculates a revenue requirement for allowed costs and then subtracts the base revenues that recover some or all of the allowed costs." However, if Mr. Kollen means that the Company should include an over/under recovery provision associated with the imperfection of estimating billing determinants like it includes in its environmental surcharge mechanism, then the Company agrees. However, this should be applied to the total revenue requirement of the rider, not just the credit. The Company also notes that its proposed tariff contemplates this in paragraph 3 of the tariff.

Q. WHAT FLAW DOES MR. KOLLEN POINT OUT IN HIS DIRECT TESTIMONY AS IT RELATES TO ACCUMULATED DEFERRED INCOME TAXES?

A. Mr. Kollen states that the Company proposes to only subtract accumulated deferred income taxes (ADIT) associated with the plant in-service and that this does not entirely reflect the ADIT related to the generating unit after it is retired. He states that it does not include the effects of the Company's deduction from taxable income for the remaining tax basis of that asset.

Q. DO YOU AGREE WITH MR. KOLLEN?

A. Yes. The Company agrees that the ADIT should be the total of the ADIT associated with the deduction for the remaining tax basis of that asset when the unit is retired (calculated by multiplying the regulatory asset times the combined federal and state income tax rate).

Q. WHAT DOES MR. KOLLEN RECOMMEND AS IT RELATES TO THE AMORTIZATION PERIOD THE COMPANY PROPOSED FOR THE RIDER GTM?

A. Mr. Kollen disagrees with the Company's proposal to recover the remaining NBV of each generating unit over ten years. He recommends the Commission adopt a twenty-year amortization.

Q. DO YOU AGREE WITH HIS RECOMMENDATION?

A. No. One of the basic premises of ratemaking is cost causation. Just as the Company is proposing a depreciable life of East Bend to align with a retirement date of 2035 in order to limit intergenerational cross subsidization, so was it attempting to limit that intergenerational cross subsidization here. The Company believes ten years is reasonable in this instance and anything longer would just further exacerbate that intergenerational cross subsidization unnecessarily.

Q. WHAT CONCERNS DOES MR. KOLLEN HAVE WITH THE PROPOSED RIDER GTM TARIFF LANGUAGE?

A. Mr. Kollen argues that the Rider GTM tariff language is not limited to the East Bend 2 and Woodsdale generating units. He states that the tariff would apply to the East Bend 1 and Miami Fort 6 generating units already retired, the costs of which are presently recovered in base rates.

Q. DO YOU AGREE WITH MR. KOLLEN?

A. I do agree that the Rider GTM tariff language is not limited to East Bend 2 and Woodsdale. However, I do not agree that the tariff would apply to East Bend 1. As noted in response to discovery, there are no costs for East Bend 1as it was never built. As it relates to Miami Fort 6, group accounting requires that a retired asset's NBV remain in that group and continue to be depreciated at that group depreciation rate. Company witness Mr. Spanos explains more in his rebuttal testimony that when there are no more assets left in a group, as would be the case if East Bend 2 were retired and moved to a regulatory asset for recovery in Rider GTM, the assets associated with those retired assets must be written off or moved to a regulatory asset. The Company's intention would be to move any remaining NBV to a regulatory asset associated with Miami Fort 6 at the time the costs associated with East Bend 2 were also move to that regulatory asset. Consequently, the Company does not agree with Mr. Kollen that the tariff language needs to be changed.

Q. DOES MR. KOLLEN HAVE OTHER CONCERNS WITH THE PROPOSED RIDER GTM LANGUAGE?

A. Yes. He argues that the tariff language does not incorporate the procedural aspects of the Company's proposal. He also argues that the tariff does not address or define the test year that will be used to calculate the Rider GTM revenue requirement.

Q. DOES THE COMPANY AGREE WITH MR. KOLLEN?

A. No. The tariff is appropriate as written. These are aspects that would be unique to each rider filing under the Rider GTM and should be spelled out in the Company's application to populate the rider.

Q. DOES MR. KOLLEN HAVE ANY OTHER RECOMMENDATIONS RELATED TO THE RIDER GTM?

A. Yes. He recommends the Company include two true-up provisions in the calculation. One for the true-up of forecast revenue requirement to the actual revenue requirement and the other for the true-up of actual revenues to the actual revenue requirement.

Q. DO YOU AGREE?

A. To the extent the Company's application to populate Rider GTM included a revenue requirement based on a forecasted test period, the Company would include a provision for a true-up of forecasted revenue requirement to the actual revenue requirement. If the Company's application to populate Rider GTM was based on an historical test period, then this will not be necessary.

The Company had planned to include a true-up of actual revenues to the actual revenue requirement.

III. <u>RIDER ILIC</u>

Q. PLEASE BRIEFLY SUMMARIZE THE COMPANY'S RIDER ILIC PROPOSAL.

A. Duke Energy Kentucky is proposing Rider ILIC to recover the costs of incremental processes and system investments required pursuant to a local ordinance or franchise, such as undergrounding of electric facilities or other relocations or system improvements and upgrades that are either requested or required by local regulation that are outside the Company's regular system-wide construction plans. This rider is necessary to ensure appropriate cost recovery from customers if a city passes an ordinance that imposes such incremental processes and associated costs upon the utility specific to that city, which are outside the normal system needs of the Company.

Q. PLEASE BREIFLY SUMMARIZE MR. KOLLEN'S RECOMMENDATION REGARDING RIDER ILIC.

A. Mr. Kollen recommends the Commission reject the Company's Rider ILIC proposal. His chief criticism is that it introduces a new alternative form of regulation, calling it a self-regulation, that allows the Company through an "agreement" with a local governmental authority to implement a charge not only within the boundaries of the local authority, but potentially system wide. Mr. Kollen opposes the Rider ILIC because:

1) the Company has not proposed an objective process by which the Commission can ensure that the scope and/or cost of any such projects would or should be included in the Company's regulatory system-wide construction plans;

2) the proposal does not require the Company to file and obtain Commission approval of the "agreement" between the Company and the local governmental authority before construction commences or rates are implemented; and

3) the ratemaking recovery is based upon estimated installed costs of assets before such cost are incurred and construction is completed, and that the use of a fixed charge provides a levelized form of ratemaking recovery where the Company will incur costs on a declining cost basis.

Q. PLEASE RESPOND TO MR. KOLLEN'S CRITICISM THAT THE RIDER ILIC IS AN ALTERNATIVE FORM OF REGULATION AND SELF REGULATION.

A. The Company is simply proposing a mechanism to ensure that it can timely recover its costs to serve customers. The Company is proposing the Commission would have to approve any rider applications before the Company could establish rates. This is a similar process to that of pipeline replacement mechanisms, and amendments to Environmental Surcharge Mechanisms. I'm not sure how this constitutes self-regulation. Mr. Kollen himself provides no explanation as to how it constitutes self-regulation. He simply makes the statement in the middle of his recommendation to deny the mechanism.

Q. PLEASE RESPOND TO MR. KOLLEN'S CRITICISM THAT THE COMPANY HAS NOT PROPOSED AN OBJECTIVE PROCESS FOR THE COMMISSION TO ENSURE THAT THE SCOPE AND/OR COST OF ILIC-PROJECTS WOULD BE OR SHOULD BE INCLUDED IN THE COMPANY'S SYSTEM-WIDE CONSTRUCTION PLANS.

A. The Company disagrees. The Company is proposing to establish this tariff and mechanism in this proceeding. As outlined in my direct testimony, upon approval, Duke Energy Kentucky will file a separate application to implement Rider ILIC as necessary in response to a local government mandate such as an ordinance or franchise. This application would be filed prior to the Company commencing work on the mandated project and subject to Commission determination of reasonableness. Rider ILIC charges will not appear on a customer's bill until such applications are *approved by the Commission*. Going forward, the Company will make annual applications with the Commission to update Rider ILIC, reflecting any new proposed capital projects and the depreciation of previously approved capital projects as well as any other necessary data input changes supporting the rider calculation. This process provides even greater transparency than what currently exists with franchise fees, which appear as separate line-items on customer bills in each municipality that has such a fee.

Q. PLEASE RESPOND TO MR. KOLLEN'S CRITICISM THAT THE RIDER ILIC PROPOSAL DOES NOT REQUIRE THE COMPANY TO FILE AND OBTAIN COMMISSION APPROVAL OF THE "AGREEMENT" BETWEEN THE COMPANY AND THE LOCAL GOVERNMENTAL AUTHORITY BEFORE CONSTRUCTION COMMENCES OR RATES ARE IMPLEMENTED.

A. The Company would file the contract or agreement with the Commission for its review and approval along with the application to implement the rider. Again, this Rider ILIC proposal is no different than how franchise fees are dealt with today. The Commission has absolute authority over how the rates and charges are calculated. However, and unfortunately, the Commission does not have control over whether or not a governmental entity exercises its statutory authority to require the utility to take specific action regarding its provision of service within those political boundaries, like undergrounding an entire distribution system within the city's borders. The Company's only response to such a directive by a local governmental authority is to say there is a potential that such costs could be recovered in a manner akin to franchise fees, from those citizens benefitting directly.

Q. IS THIS JUST A HYPOTHETICAL SITUATION?

A. No. As shown in Attachment ABS-5 to Ms. Spiller's testimony, this is a real issue facing the Company. While to date the city who has drafted that ordinance has not enacted this specific franchise ordinance, it continues to threaten to do so. If such an ordinance is passed, and absent an ILIC process, this places the Company in the untenable position of having to 1) either comply with the local ordinance and incur significant costs that will need to be recovered from all customers; 2) engage in expensive and time-consuming legal challenges seeking a potential stay; or 3) risk fines and penalties for non-compliance with a municipal ordinance. If one city is successful in forcing the Company to relocate its entire existing distribution system, others will follow.

Q. PLEASE RESPOND TO MR. KOLLEN'S CRITICISMS REGARDING THE RATE DESIGN OF RIDER ILIC THAT 1) RECOVERY IS BASED UPON ESTIMATED INSTALLED COSTS OF ASSETS BEFORE SUCH COST ARE INCURRED AND CONSTRUCTION IS COMPLETED, AND 2) THAT THE USE OF A FIXED CHARGE PROVIDES A LEVELIZED FORM OF RATEMAKING RECOVERY WHEREAS THE COMPANY WILL INCUR COSTS ON A DECLINING COST BASIS.

A. The Company is not opposed to the Commission determining a different rate design; however, the Company continues to believe that a levelized fixed charge is the most straightforward way of recovering these costs. All Rider ILIC charges would be approved by the Commission and at the Commission's determination, a Rider ILIC charge may or may not be implemented in full or in part before the completion of construction. In addition, Rider ILIC establishes an annual review of the ILIC charge where remaining depreciation expense, remaining depreciable life, property insurance rates, the weighted average cost of capital, and other inputs can be reviewed to keep the ILIC project's charge in line with the project's remaining depreciable investment. Annual adjustments are subject to Commission review and approval.

IV. RIDER MRC

Q. PLEASE BREIFLY SUMMARIZE MR. KOLLEN'S RECOMMENDATION REGARDING RIDER MRC.

A. Mr. Kollen does not oppose the program. However, he states that there is no compelling reason why the cost or risk of the MRC program should be socialized and imposed on all ratepayers in a future rate proceeding. He recommends that the program be subsumed into the EVSE program, that all the costs of the combined program be recovered exclusively from participating customers and that none of the revenues and none of the costs be included in the base revenue requirement. If the Commission approves the MRC program as a standalone program, he recommends it require the Company to recover the costs exclusively from participating customers. In any event, he recommends that the Commission deny the Company's request for authority to defer the costs of the MRC program for future ratemaking recovery.

Q. PLEASE RESPOND TO MR. KOLLEN'S CRITICISMS REGARDING RIDER MRC.

A. Company witness Cory Gordon's rebuttal testimony addresses Mr. Kollen's recommendation to subsume Rider MRC into the EVSE program. I respond to his recommendation to not allow recovery of Rider MRC costs if the Commission approves the program as a standalone program.

Q. DOES MR. KOLLEN PROVIDE ANY RATIONALE AS TO WHY HE RECOMMENDS THE COMMISSION DENY RECOVERY OF THESE COSTS?

A. No, he simply states at the end of his recommendation that the Commission deny the Company's deferral request of these costs.

Q. WHY SHOULD THE COMMISSION APPROVE DEFERRAL AUTHORITY FOR THESE COSTS?

A. As a standalone program, the Company requests approval to defer the costs of the MRC program for future ratemaking recovery. Mr. Kollen gave no substantive reason as to why this treatment should be denied. The Company is simply requesting to be made whole for these expenses.

Additionally, Company witness Danielle L. Weatherston explained in detail in her direct testimony why the Commission should approve deferral authority for these costs. As she has already stated, the Commission has exercised its discretion to approve regulatory assets where a utility has incurred: (1) an extraordinary, nonrecurring expense which could not have reasonably been anticipated or included in the utility's planning; (2) an expense resulting from a statutory or administrative directive; (3) an expense in relation to an industry sponsored initiative; or (4) an extraordinary or nonrecurring expense that over time will result in a saving that fully offsets the costs.

The costs for which the Company is seeking to create this regulatory deferral constitute an expense in relation to an industry-sponsored initiative in support of a statutory directive to expand the electrification of vehicles across the country. Company witness Cormack C. Gordon discusses the need for this program as it relates to the Infrastructure Investment & Jobs Act (IIJA).

V. <u>CONCLUSION</u>

Q. DOES THIS CONCLUDE YOUR REBUTTAL TESTIMONY?

A. Yes.

VERIFICATION

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

The undersigned, Sarah E. Lawler, VP Rates & Regulatory Strategy OH/KY, being duly sworn, deposes and says that she has personal knowledge of the matters set forth in the foregoing rebuttal testimony and that it is true and correct to the best of her knowledge, information and belief.

Sarah E. Lawler Affiant

Subscribed and sworn to before me by Sarah E. Lawler on this 27TH day of MARCH, 2023.

NOTARIAL SEAL STATE OF OHIO

ADELE M. FRISCH
Notary Public, State of Ohio
My Commission Expires 01-05-2024

Adele M. Frisch

NOTARY PUBLIC

My Commission Expires: 1/5/2024

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

The Electronic Application of Duke Energy Kentucky, Inc., for: 1) An Adjustment of the Electric Rates; 2) Approval of New Tariffs; 3) Approval of Accounting Practices to Establish Regulatory Assets and Liabilities; and 4) All Other Required Approvals and Relief.	)))))))	Case No. 2022-00372

REBUTTAL TESTIMONY OF

SCOTT PARK

ON BEHALF OF

DUKE ENERGY KENTUCKY, INC.

April 14, 2023

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PAGE

I. INTRODUCTION AND PURPOSE

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Scott Park, and my business address is 526 South Church Street, Charlotte, North Carolina.

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

A. I am employed by Duke Energy Business Services LLC, a service company affiliate of Duke Energy Kentucky, Inc., (Duke Energy Kentucky or Company), as Managing Director IRP and Analytics.

Q. ARE YOU THE SAME SCOTT PARK THAT SUBMITTED DIRECT TESTIMONY IN THIS PROCEEDING?

A. Yes.

Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY?

A. My Rebuttal Testimony is provided to respond to certain claims and recommendations by Ms. Sarah Shenstone-Harris on behalf of the Sierra Club, Mr. Lane Kollen, on behalf of the Kentucky Attorney General and Mr. Justin Bieber on behalf of the Kroger Company as it relates to the timing, analysis, and support for the Company's estimated useful live of its fossil-fueled generating portfolio.

II. DISCUSSION

A. RESPONSE TO THE SIERRA CLUB

Q. ARE YOU FAMILIAR WITH THE INTEGRATED RESOURCE PLANNING PROCESS FOR DUKE ENERGY KENTUCKY?

A. Yes, I oversaw the development of the 2021 Duke Energy Kentucky IRP.

Q. PLEASE EXPLAIN THE DRIVERS FOR THE ANTICIPATED EARLIER RETIREMENT DATE OF EAST BEND IN 2035 IN THE COMPANY'S INTEGRATED RESOURCE PLAN (IRP).

A. Higher coal prices have and are expected to drive down the capacity factor of the East Bend 2 unit, which lessens the value that the station provides to customers. Additionally, with less generation coming from Company resources, the remaining energy will come from greater market purchases. Operating a unit that runs so infrequently makes a unit less reliable to start up successfully which can increase capacity performance risk. Infrequent operations can create other operational issues such as increased cycling and equipment failures as well as staffing the station. In addition, Federal policy is likely going to continue to negatively impact the service life of East Bend. For example, the recently passed Inflation Reduction Act (IRA) initiative, which, among other things, provides subsidies for low and zero-emitting generating resources, has an indirect impact on the viability of coal-fired resources. As these subsidized zero emitting resources come online, power prices will be pushed down, and existing higher-cost assets will be less economic. Any further actions to either directly support renewable or zero emitting resources or to directly tax fossil-fueled resources will impact the dispatchability and economics of resources like East Bend.

Q. PLEASE BRIEFLY SUMMARIZE MS. SHENSTONE-HARRIS'S TESTIMONY AS IT RELATES TO THE COMPANY'S FOSSIL GENERATING PORTFOLIO.

A. As it relates to the Company's generating portfolio, Ms. Shenstone-Harris concludes the following: 1) Duke Energy has incurred costs in excess of its market energy revenue and capacity value that have been passed to customers; 2) The Company has not demonstrated the prudence of continuing to invest in and operate East Bend through its current retirement date and that the plant should retire by 2030; 3) customers can avoid capital and operations and maintenance (O&M) costs and mitigate risks with coal generation with an earlier retirement; 4) Duke Energy Kentucky's estimated costs to operate and maintain East Bend are too low; 5) Duke Energy Kentucky's analysis supporting the ongoing operation of East Bend is stale and does not reflect the IRA and current market conditions; and 6) the Commission should consider alternative financing mechanisms to allow Duke Energy Kentucky to recover the value of East Bend and avoid rate shock.

She then makes four recommendations related to the Company's generating portfolio: 1) Duke Energy Kentucky should commit to retiring East Bend by 2030; 2) the Commission should require the Company to conduct more appropriate and accurate electricity system modeling and forecasting of East Bend's economic and operational performance before any future rate cases, fuel dockets, or other regulatory proceedings involving the Company's generating portfolio; 3) the

Commission should require the Company to provide more clear and consistent accounting of historical and projected future costs associated with operating East Bend; and 4) the Commission should order the Company as part of its next IRP, to evaluate the economics of retiring the plant early and using securitization to finance the remaining balance.

Q. ON PAGE 13 OF MS. SHENSTONE-HARRIS'S TESTIMONY, SHE CLAIMS THAT ALTHOUGH DUKE ENERGY KENTUCKY'S 2021 IRP "SET" EAST BEND'S RETIREMENT AT 2035, THE IRP ANALYSIS DOES NOT SUGGEST IT AS A SPECIFIC RETIREMENT DATE, AND THAT ITS ANALYSIS SUGGESTS 2027 AS THE MOST ECONOMIC RETIREMENT DATE. PLEASE EXPLAIN THIS.

A. Ms. Shenstone-Harris's claim the Company's IRP shows 2027 is the most economic retirement date is not supported by the analysis and ignores the other possible futures where East Bend 2 is economically retired in the model. This does not mean that 2027 could not be the most economic date as we progress through time but recognizes that the window for the most economic retirement date is relatively wide. When one considers the possibility of futures that do not include carbon regulation, the supply chain issues that delay the executability of replacement capacity, higher fuel prices or greater recognition that the amount of reliable generation is reduced, it is reasonable to conclude that reliability can suffer. Any one of those factors could drive the best retirement date for East Bend 2 to be later than 2027 or 2030, the date that Ms. Shenstone-Harris asserts.

Q. ON PAGE 14 OF HER TESTIMONY, MS. SHENSTONE HARRIS CLAIMS THERE HAVE BEEN MANY CHANGES SINCE THE COMPANY'S 2021 IRP, INCLUDING THE IRA, GREATER GAS VOLATILITY AND HIGHER COAL PRICES DUE TO THE WAR IN UKRAINE, AND INFLATION AND SUPPLY CHAIN CHALLENGES. PLEASE RESPOND TO THESE CHANGES AS IT RELATES TO THE COMPANY'S MOST RECENT IRP ANALYSIS AND ANTICIPATED ECONOMICS OF ITS GENERATION PORTFOLIO.

A. While it is true that a number of changes have happened since submission of the 2021 IRP, the impact of these factors is reasonably contained within the breadth of the scenario analysis that was presented in the IRP. These factors are dynamic in nature and although they would impact the IRP analysis in isolation, when one considers them holistically, the existing IRP analysis, with varying scenarios for retirement remains directionally correct, and the 2035 likely retirement date holds true.

For example, although the IRP did not consider the impacts of the IRA since the law hadn't passed at the time of the IRP preparation, the IRP nonetheless did include a scenario that included a tax on carbon emissions. While the IRA clearly benefits zero carbon emitting resources in favor over carbon emitting resources, the expected impact of the IRA is directionally consistent with the IRP analysis related to a carbon emission tax. That is, due to the IRA's directly supporting zero-emitting resources, that variable alone would mean that East Bend 2 would retire sooner than the analyzed IRP portfolio optimized for a scenario without a carbon tax, but later than the portfolio optimized for the scenario that included a carbon tax.

Likewise, greater gas market volatility highlights the value of coal resources, and as a result, in a silo, would likely support a later economic retirement of coal generation. However, while coal prices did increase in 2022, it is also true that coal prices have come down considerably since then. In general higher coal prices would move up the economic retirement of coal generation. Supply chain issues would have a greater impact on the cost and ability to construct new generation which would make the economics of keeping existing generation around longer, all else being equal.

In summary, while there have been a number of changes, when considered in whole - some accelerate coal retirements and some delay coal retirements. The IRP, and the likelihood of a 2035 retirement is still prudent given the changes cited in the question.

Q. MS. SHENSTONE HARRIS ALSO CLAIMS THAT THE COMPANY HAS NOT PRESENTED EVIDENCE THAT KEEPING EAST BEND ONLINE BEYOND 2030 IS THE LOWEST COST OPTION FOR CUSTOMERS. PLEASE RESPOND TO THIS CLAIM.

A. For reasons stated before, there are a number of scenarios that suggest that continuing to operate East Bend 2 past 2030 makes sense for customers. Given that the economic retirement date for East Bend 2 is subject to a number of variables, the salient question today is whether it makes sense to prepare for the substantial likelihood that East Bend 2 is going to retire earlier than 2041, and most likely by

2035 based upon our most current IRP modeling. In the Company's view, yes, it does. The Company believes that the recovery of costs, particularly depreciation expense, should be aligned to that date to protect future customers and provide the Company with the opportunity to timely recovery its costs for investing in assets to provide service. The decision about a specific retirement and replacement asset is still an emerging issue that the Company monitors, and as I understand, due to a recent change in Kentucky law, will be determined in a subsequent case filed before the Commission.

The Company believes, that based upon current modeling, and the recent legislative changes in Kentucky, retiring East Bend 2 **before 2030**, would be challenging from an execution standpoint, and as we sit today, not in the best interest of customers from a long-term cost perspective due to the remaining undepreciated book value of the East Bend 2 asset. As explained by Ms. Lawler in her rebuttal testimony meeting the retirement thresholds for fossil-fueled generation under the new Kentucky legislation will be a challenge as one considers the remaining undepreciated plant of an existing asset, and factors in the time, costs, and lead-time for gaining approval and construction of a replacement asset. Unless the costs of the existing asset are reasonably and timely recovered in base rates, the ability to justify the retirement will be difficult. This would likely result in customers paying for an asset that is not generating and paying for the Company to purchase power in the market and this being subject to volatility in the energy market, and not having a dedicated asset that is actually running and providing a hedge for power.

Q. ON PAGE 17 OF HER TESTIMONY, MS. SHENSTONE-HARRIS CLAIMS THAT DUKE ENERGY KENTUCKY HAS INCURRED COSTS IN EXCESS OF ITS MARKET ENERGY AND CAPACITY VALUE BETWEEN 2018 TO 2020 AND BROKE EVEN IN 2021. PLEASE RESPOND.

A. Ms. Shenstone-Harris claim is predicated on the capacity values that she assigns to the unit and are not applicable for Duke Energy Kentucky as a Fixed Resource Requirement(FRR) entity in PJM Interconnection LLC (PJM). Even then, Ms. Shenstone-Harris shows that based on her calculations, that East Bend 2 provided over $100 million of value in 2022 with each year in Figure 1 of her testimony increasing in value.

Q. ON PAGE 19 OF HER TESTIMONY, MS. SHENSTONE-HARRIS ANALYZES THE HISTORIC PERFORMANCE OF EAST BEND. DO YOU HAVE ANY CONCERNS WITH THIS ANALYSIS?

A. Ms. Shenstone-Harris correctly points out that her assumption for cost of capacity (PJM's Base Residual Auction) is not an option for Duke Energy Kentucky since Duke Energy Kentucky is a FRR entity. To make a true and fair comparison, one would have to assign the cost of an actual generator, the energy margins provided by that generator, the impact on reliability as well as any transmission impacts. Ms. Shenstone-Harris fails to do that, which undermines the relevance of her analysis.

Q. BEGINNING ON PAGE 20 OF HER TESTIMONY, MS. SHENSTONE-HARRIS MAKES THE CLAIM THAT HER ANALYSIS SHOWS THAT EAST BEND IS NOT EXPECTED TO BE ECONOMIC GOING FORWARD UNDER WHAT SHE DESCRIBES AS "REASONABLE ASSUMPTIONS ABOUT THE FUTURE." DO YOU AGREE WITH THIS ANALYSIS? PLEASE EXPLAIN.

A. Similar to my response to the previous question, Ms. Shenstone-Harris is mixing apples and oranges in her assumptions in that she is including the O&M and fixed costs of a coal unit, but only valuing the capacity at the Base Residual Auction price of the Cost of New Entrant. As a FRR entity, the assumptions for the cost categories need to be consistent with the costs of the generator in question, whether that be an existing unit or a new unit.

Q. MS. SHENSTONE-HARRIS CLAIMS THAT EAST BEND'S UTILIZATION RATES ARE PROJECTED TO DECLINE AND SHE PROJECTS THE STATION TO INCUR NET LOSSES OF $123 MILLION (ON AN NPV BASIS) FROM 2023 THROUGH 2034 BASED UPON VALUING CAPACITY BASED ON PJM AUCTION CAPACITY PRICES. DO YOU AGREE WITH HER ANALYSIS?

A. This is a very narrow analysis that paints a one-sided picture of East Bend 2's future operations. In Figure 3 of her testimony, she shows three lines of the capacity factors for East Bend 2: historical (2018-2022), projected assuming no carbon regulation (2023-2034) and the one that she chooses to use which is a projection assuming carbon regulation. The historical data varies between 40 percent and 60 percent, the projected with CO_2 regulation increases for two years and then decreases to near zero in the 2030s. In the case that does not include a carbon tax, the capacity factors actually increase overtime and stabilize around 80 percent. While either one of those futures is possible, as well as other outcomes, making a significant decision based on a single possibility is not sound decision making. Planning based on only one view of the future does not make sense and is the very reason that the Company's analysis considers several plausible futures to ensure a more robust analysis that supports sound decision making that is in the best interest in the customer. The Company's recommended life for East Bend to retire by 2035 is based upon more rigorous and comprehensive analysis, and considers multiple factors to produce a most-likely outcome.

Q. PLEASE EXPLAIN WHAT A CAPACITY FACTOR IS AND WHY IT IS AN IMPORTANT METRIC.

A. A capacity factor is the amount of energy a generator produces divided by the product of the capacity of the unit and the number of hours in a year. Another term that is sometimes used is utilization factor. For example, a unit with a capacity factor of 50 percent generated half of the output it could have generated had it run at full output for the entire year.

Capacity factor is informative as to the generating unit's reliability or its cost effectiveness in the market in terms of dispatch. But it does not consider the costs of the unit or the value that a unit provides in terms of capacity or grid support. It is possible that a unit could have a low-capacity factor, but the value of the energy margin and capacity can mean the unit is still economic. Conversely, a unit can run at a higher capacity factor and the energy margin and capacity value are still not sufficient to mean that the unit is economic.

In the case of East Bend, our IRP analysis is based on economics which is a far better measure of the value that a unit provides to a system. This analysis shows and supports that, given the multiple scenarios that are possible, the most likely result is a retirement by 2035.

Q. UNDER CURRENT FORECASTS, DO YOU SEE EAST BEND'S UTILIZATION RATES (*e.g.*, CAPACITY FACTORS) IMPROVING IN THE FUTURE?

A. While there are a number of scenarios in our most recent IRP where the capacity factor of East Bend 2 could increase into the future, there are many others that show it continuing to decline. While the future is not certain, there are enough plausible scenarios to say that retiring East Bend 2 in the 2020s is premature, retiring in the mid 2030's is most likely, and retiring later than 2035 is less likely.

Q. ON PAGES 26 THROUGH 27 OF HER TESTIMONY, MS. SHENSTONE-HARRIS CLAIMS THAT DUKE ENERGY KENTUCKY'S ESTIMATED FIXED COSTS FOR OPERATING EAST BEND ARE SIGNIFICANTLY BELOW HISTORICAL SPENDING AND INDUSTRY AVERAGES, CONCLUDING THE STATION WILL INCURE NET LOSSES OF $261 MILLION ON A NPV BASIS OVER ITS LIFETIME. DO YOU AGREE WITH HER ANALYSIS?

A. No, Ms. Shenstone-Harris makes a number of questionable assumptions in that she applies generic assumptions about the cost of operating a coal unit rather than the specific costs used by the Company. She also uses the PJM Base Residual Auction as a proxy for capacity value which, as I previously explained, is not applicable for an FRR entity like Duke Energy Kentucky under current PJM rules. Thus, her conclusion is flawed.

Q. PLEASE RESPOND TO MS. SHENSTONE-HARRIS'S CLAIMS BEGINNING ON PG 28 AND 29 OF HER TESTIMONY THAT THE COMPANY'S NO CARBON MODELING ASSUMPTIONS REGARDING CAPACITY PRICES ARE FLAWED.

A. Ms. Shenstone-Harris continues to make inaccurate assumptions in her analysis by relying too heavily upon historical performance and concluding it will persist into the future. This is overly simplistic and is the reason that we forecast the market price of power, use fuel forecast from industry experts, and model the cost of East Bend 2 relative to alternate resources.

Additionally, I would also point to another misleading element of her testimony in her characterization of the Company's position with respect to a future with a carbon price. While the Company believes that carbon regulation is likely, we do not know the form that it will take or its impact on the electrical system. The inclusion of a carbon tax in our IRP modeling provides a scenario for analysis as a proxy for other forms of regulation that may or may not be an actual carbon tax. As I mentioned previously, the IRA is one such scenario that has come to fruition. While the IRA doesn't directly tax a carbon-emitting resource, but by creating subsidies for zero emitting resource, it has an indirect effect on the future economics of a carbon-emitting resource.

Q. DO YOU AGREE WITH MS. SHENSTONE-HARRIS'S CLAIMS REGARDING MARKET DYNAMICS IMPACTING EAST BEND'S UTILIZATION RATES, PARTICULARLY AS IT RELATES TO WIND AND SOLAR DISPLACING FOSSIL GENERATION?

A. I agree in part with her claim in that the addition of solar and wind resources will pull down power prices when they are operating. It is also reasonable to expect capacity factors for fossil-generation to fall with higher penetration levels of wind and solar resources. However, one should not then conclude that renewables represent a silver bullet to meeting customer load requirements. Having a base-load asset that is not intermittent is in the best interests of customers from an overall system planning perspective.

While it is reasonable to expect that in hours when solar and wind resources are not generating, the energy margins at a base-load resource like East Bend 2 could be greater, it would also be reasonable to expect that East Bend 2 will run less in the future as more zero-emitting resources come online, particularly if wholesale energy prices remain rather low and coal prices high. This makes sense for customers insofar as when market power prices are low, it benefits customers to buy low price market power, but when market prices are high, it makes sense to run East Bend 2 if it is "in the money." This is one example of the value of a generating portfolio system having a resource that is dispatchable in all hours of the year; another example to consider are those winter mornings when it is cloudy and still. Without a dispatchable resource on those winter mornings, where intermittent renewables cannot perform, customers are subject to potentially higher prices and reliability could suffer. The question ultimately becomes whether or not it is in a customer's best interests to continue to pay for, and a utility to continue to invest in, a base-load, coal-fired asset that is only dispatching into the market a fraction of the total hours in a year, and customers are exposed to market energy prices more than 90 percent of the time because it is cheaper to do so. That is the most likely scenario in 2035 under the Company's IRP.

Q. PLEASE RESPOND TO MS. SHENSTONE-HARRIS'S CRITICISMS ON PAGES 31 THROUGH 36 REGARDING THE COMPANY'S ASSUMPTIONS REGARDING ENERGY MARKETS, LOCATIONAL MARGINAL PRICING (LMPs), AND CAPACITY IN ITS IRP MODELING.

A. I agree with Ms. Shenstone-Harris's claims that power prices are expected to remain relatively flat through 2027 but disagree with her assertion that the Company is assuming that power prices remaining flat throughout the IRP's study period. Moderating fuel prices are expected to keep rates relatively flat through 2027, but after that fuel and power prices are expected to increase.

Ms. Shenstone's use of the Base Residual Auction and Cost of New Entrant prices as a reasonable proxy for wholesale market prices is still not relevant for FRR entities such as Duke Energy Kentucky under current PJM rules. Her recommendation would be suitable for an entity that participates in the Base Residual Auction, purchases all of its power from the RTO and who's customers would wear all of the risk of such a strategy.

Q. BEGINNING ON PAGE 36 OF HER TESTIMONY, MS. SHENSTONE-HARRIS CLAIMS THAT THERE ARE AVOIDABLE COSTS AND RISKS (*e.g.,* FUEL, ENVIRONMENTAL COMPLIANCE, O&M, SUPPLY AND TRANSPORTATION, RELIABILTY, FORCED OUTAGES, *etc.,)*[1] WITH RETIRING EAST BEND EARLY. PLEASE RESPOND TO THESE CLAIMS.

A. While it might be true that there are avoidable costs if East Bend 2 is retired by 2030, as she recommends, it would also be true that the benefits such as energy production value, grid support and dispatchable capacity of East Bend 2 would also not be there for customers during those years. Highlighting the risks but ignoring the benefits does not constitute a complete analysis. This also ignores the cost and risk associated with the replacement resource.

Duke Energy Kentucky's IRP, however, does factor in costs and risks associated with a replacement resource. This is reflected in the assumption that East Bend 2 would be replaced with a "firm dispatchable resource." In other words, the Company would economically retire East Bend 2 and replace it with another base-load asset. The costs used in the IRP for this firm dispatchable resource are based upon a Combined Cycle natural gas turbine, as that is the technology that would exist if that decision were made today. The IRP leaves open the possibility for a different technology if one becomes more cost effective at the actual time of replacement, currently estimated to occur by 2035.

[1] Shenstone-Harris Testimony at pg. 38.

Q. MS. SHENSTONE-HARRIS ARGUES THAT DUKE ENERGY KENTUCKY SHOULD START BUILDING REPLACEMENT RESOURCES FOR EAST BEND 2 SOONER RATHER THAN LATER, AND THAT THE COMPANY SHOULD FOCUS ON SOLAR AND WIND PAIRED WITH BATTERIES TO MITIGATE THE RISKS OF THERMAL PLANTS. PLEASE RESPOND.

A. Retiring East Bend 2 and replacing it with solar, wind and battery resources fits Ms. Shenstone-Harris' narrative, but fails to reflect the long-term cost, feasibility issues, and rate impact to construct that many resources. In order to provide sufficient capacity to replace the 600 MW East Bend 2 unit, one would need to add well over 1,000 MW of renewable resources and that would still leave customers subject to undue market exposure and reliability concerns. PJM credits solar with approximately 50 percent of its capacity value, which suggests that 1,200 MW of solar would need to be added to replace East Bend 2 during the summer peak. During a winter peak, solar provides very little output which means that the shortfall would need to come from wind and batteries. PJM credits wind with 13 percent capacity value in the summer; wind typically blows more in the wintertime and would produce more, but if a 25 percent capacity value is assumed that would suggest 2,400 MW of wind. Lastly, storage receives approximately 80 percent capacity value which would suggest replacement of East Bend 2 with 750 MW of 4-hour storage. The 1,200 MW of solar, 2,400 MW of wind and 750 MW of storage are to some degree complimentary, and the amounts could be reduced. If that total of 4,350 MW could be cut in half and cost a very optimistic $1,000/kw to build, that will still cost over $2 billion. To be fair, the solar and wind resources, but not the storage, would not have a fuel cost and would represent a significant benefit, but when the Company evaluates those resources, it does not make economic sense to replace East Bend 2 solely with a mix of solar, storage and wind.

Moreover, Ms. Shenstone-Harris does not even attempt to address the feasibility of constructing such a large portfolio of renewable resources in Duke Energy Kentucky's territory or even in its delivery zone in PJM. The Company's PJM delivery zone has separated on multiple occasions from the rest of PJM, creating generation import constraints into the zone during those periods. To avoid finding itself in a situation where the Company cannot import generation into its zone, the Company should attempt to construct its replacement generation within that zone. Constructing more than 2,000 MWs of renewables in the Company's territory is simply not feasible or practical.

Q. FROM AN IRP PLANNING PERSPECTIVE, WHAT IS AN OPTIMAL TIMING FOR DETERMING WHEN A UTILITY SHOULD RETIRE A PLANT AND IDENTIFY WHAT ITS REPLACEMENT SHOULD BE?

A. The timing of an asset's retirement is based on several factors in addition to the modeled economics. For example, the risk of that decision, the impact on the transmission system, fuel security issues, rate making issues and timing of the replacement resources all need to be considered when a plant is ultimately retired.

B. RESPONSE TO THE ATTORNEY GENERAL

Q. PLEASE BRIEFLY SUMMARIZE MR. KOLLEN'S TESTIMONY AS IT RELATES TO THE COMPANY'S FOSSIL GENERATING PORTFOLIO THAT YOU ARE ADDRESSING IN YOUR REBUTTAL TESTIMONY.

A. Mr. Kollen recommends that the Commission reject the Company's request to accelerate the East Bend 2 probable retirement date and shorten the remaining service life of East Bend 2. He argues that the Commission will have an opportunity in a future Certificate of Public Convenience and Necessity (CPCN) proceeding to determine whether new capacity is more economic than continuing to operate East Bend 2 until 2041.

He also makes several recommendations related to the Company's rates, and future recovery of costs related the Company's generation portfolio, that will be addressed by other Company witnesses. Those issues addressed by other Company witnesses include: 1) inclusion of decommissioning expense for generating units as a separate and standalone expense in base revenue requirement instead of as a component of depreciation rates and expense; 2) limiting the escalation of the decommissioning cost and the resulting expense to the test year and reject the Company's request to escalate the cost through the probable retirement dates; and 3) removal the estimated end of life materials and supplies from decommissioning costs and instead allow the cost recovery through the proposed new Rider GTM.

Q. DID MR. KOLLEN PERFORM ANY ANALYSIS REGARDING THE REMAINING USEFUL OR DEPRECIABLE LIFE OF EAST BEND?

A. No. He just argues that the Company has "failed to demonstrate that it is or will be uneconomic to continue to operate East Bend 2 after 2035 or that it will actually retire the facility in 2035 or some other date prior to 2041."

Q. DO YOU AGREE WITH MR. KOLLEN'S STATEMENT? PLEASE EXPLAIN.

A. I do not agree with Mr. Kollen's statement as he has not performed economic analysis, nor has he performed a risk analysis of his recommendation. A prudent decision needs to include risk-informed economic analysis. Since the future is uncertain, a prudent decision needs to be informed by what the Company thinks is most likely to happen, based upon robust modeling and analysis. Our most recent IRP is such an analysis.

Q. DID THE COMPANY PROVIDE ITS IRP IN THIS PROCEEDING?

A. Yes. In discovery, the Company was asked to provide its most recent IRP in response to Sierra Club DR-01-03.

Q. DOES THIS IRP INCLUDE ANALYSIS REGARDING THE CONTINUED OPERATION OF EAST BEND, ITS ECONOMICS, AND PROBABLE RETIREMENT DATE AND SERVICE LIFE?

A. Yes.

Q. PLEASE BRIEFLY SUMMARIZE THAT ANALYSIS.

A. Recognizing that the future is uncertain, the Company considered six different plausible futures where we vary the drivers that have the biggest influence on the economics of the generating portfolio - carbon regulation and gas prices which affect power prices.

Those six scenarios represent the six combinations of whether or not a carbon tax is enacted and high, low, and base gas forecasts. In some scenarios, East Bend 2 retires in the 2020's, whereas in other scenarios the unit retires in the mid 2030's or beyond the planning window. The actual retirement decision for East Bend 2 does not need to be made today, but preparing for the eventuality and the probability of such timing as it relates to recovery of asset costs is prudent and imperative.

Consider the impact of adopting Mr. Kollen's recommendation to not align the book life of the unit with its currently modeled and most likely retirement date of 2035, and alas, the unit retires in 2035 as the Company predicts. The result would be that there would be a significant undepreciated amount in rate base in addition to the cost of the replacement generation that must be addressed. The combination of those factors would cause a more abrupt and significant increase in rates for customers.

Now consider the impact of aligning the book life of the unit with its currently modeled and most likely retirement date of 2035, but due to some factors, it doesn't retire until a date after 2035. In such a case, the depreciation expense for the unit through 2035 would be higher than current expense, but after 2035 rates would drop considerably, and then increase once a new resource is added. Customers would also benefit.

The economics and the risk profile of the decisions about East Bend support aligning the book life of the unit with its probably retirement date of 2035 so that customers and the utility are better prepared to adapt to an uncertain future.

Q. ON PAGE 30 OF HIS TESTIMONY, MR. KOLLEN ARGUES THAT IF IT IS ECONOMIC FOR THE COMPANY TO REPLACE EAST BEND IN 2035 RATHER THAN 2041, THEN THE RECOVERY OF ANY REMAINING NET BOOK VALUE OF EAST BEND SHOULD BE CONSIDERED A COST OF TRANSITIONING TO THE NEW CAPACITY AND RECOVERED BY THE CUSTOMERS THAT WILL BE SERVED BY THE NEW CAPACITY. DO YOU AGREE WITH THIS STATEMENT?

A. No, I do not agree with Mr. Kollen's statement. The cost of East Bend 2 is attributable to the decision over forty years ago to build the unit, and the decision approximately twenty-years ago for Duke Energy Kentucky to purchase it from Duke Energy Ohio. And Duke Energy Kentucky's customers have and will enjoy the benefits of the unit until it retires. Allocating East Bend 2 remaining costs to the new replacement generation is not appropriate as those costs are not providing any benefit to customers after East Bend 2 retires and when the replacement generator is operating. Moreover, as explained by Mr. Spanos, attributing the East Bend retirement costs to the same FERC accounts as that of the replacement generation would not be consistent with the Uniform System of Accounts, unless the Company were to replace East Bend 2 with another coal-fired unit. The practicality of such a scenario is near implausible.

For reasons of intergenerational equity and prudent risk management, following a glide path where the book life and operable life are as close as possible makes the most sense. Mr. Spanos and Ms. Lawler explain why this is also consistent with standard rate-making practice.

Q. WILL THE COMMISSION HAVE AN OPPORTUNITY TO DETERMINE WHETHER NEW GENERATION IS ECONOMIC THAN CONTINUING TO OPERATE EAST BEND IN A FUTURE PROCEEDING?

A. Yes. I agree with Mr. Kollen in this regard. When the Company knows the exact retirement date and the technology that is least-cost, most reasonable, to replace East Bend 2, the Company will file a CPCN before it can commence construction on any such new technology. Moreover, under the newly enacted Senate Bill 4, I understand the Company must also seek Commission approval prior to actually retiring a fossil-fueled generating unit. Nonetheless, Mr. Kollen would have future customers bear the majority of the burden of paying for the capital costs of owning, operating, maintaining, and eventually decommissioning East Bend 2, after the unit is retired, costs of which those future customers get no benefit. Whether that occurs in 2035 or sooner, the customers that are being served by that unit should pay for that unit. Addressing this issue now is in the best interests of all customers, present and future.

The net book value (NBV) of East Bend 2 over its remaining life is not static and will change. While today, the remaining current NBV of East Bend 2 is almost $500 million, as the Company continues to invest capital in the unit to keep it running, making necessary repairs and replacements, the NBV will increase, perhaps in excess of depreciation if not properly aligned with its probable remaining life. The goal of rate-making should be to align the depreciable life of the asset with its most likely service life. The Commission can and should use this tool of depreciation expense to align cost recovery of the plant with those who benefit from the plant's use.

Q. DOES MR. KOLLEN AGREE WITH THE COMPANY'S PROPOSAL TO REVISE THE ESTIMATED DEPRECIABLE LIFE OF WOODSDALE?

A. Yes.

Q. PLEASE EXPLAIN THE RISKS TO CUSTOMERS OF THE COMMISSION ACCEPTING MR. KOLLEN'S RECOMMENDATION TO REJECT ADJUSTING EAST BEND'S DEPRECIABLE LIFE TO 2035 AND KEEPING IT AT 2041 BUT ACCEPTING EXTENDING WOODSDALE'S EXTENSION OF ITS DEPRECIABLE LIFE TO 2040.

A. First, one must consider the practical implication of Mr. Kollen's recommendation and if it were to come to fruition. Under this scenario, whereby East Bend 2's life continues to be assumed as 2041, but the Commission accepts the extension of Woodsdale's depreciable life to 2040, Duke Energy Kentucky's entire fleet of generation, excluding its small solar installations, will be replaced within a twelve-month period. This is a significant cost burden for customers. This is not a prudent or reasonable outcome.

The risk of accepting Mr. Kollen's recommendation is that should an event happened that would make East Bend 2 less economic to operate compared to a replacement set of resources by 2035, as the Company predicts, the customers would be subject to greater amounts of undepreciated book value in rate base associated with East Bend 2 plus the cost of the new resources in rate base. This cost for customers will be exacerbated when Woodsdale retires in 2040 and customers are paying for the cost of the replacement generation to replace Woodsdale. This would lead to a higher rate increase than would be necessary if the depreciable life of East Bend 2 was set closer to the most likely retirement date of 2035.

Q. WHAT IS YOUR RECOMMENDATION AS IT RELATES TO MR. KOLLEN'S TESTIMONY REGARDING EAST BEND'S DEPRECIABLE LIFE?

A. The factors that will affect the economic life of East Bend 2 are biased toward restating the unit's economic retirement date sooner rather than keeping the current date or even extending it. While the future is uncertain, being unprepared for an earlier retirement date is not in the best interest of customers.

Based on Mr. Kollen's recommendation, if the unit retires before 2041, there will be an unrecovered portion of the book value in rate base in addition to the cost of the replacement capacity. That is clearly not in the best interest of customers. Given the uncertain future, it is far more prudent to move up the depreciable life of East Bend 2 to 2035 to be better prepared for the replacement capacity to go into rates. It boils down to what is the best decision today to best prepare for an uncertain future.

C. RESPONSE TO THE KROGER COMPANY

Q. PLEASE GENERALLY DESCRIBE THE TESTIMONY OF MR. BIEBER ON BEHALF OF KROGER AS IT RELATES TO THE COMPANY'S FOSSIL GENERATION IN THIS PROCEEDING.

A. Mr. Bieber's testimony touches on the Company's generating portfolio in two respects. First, in his discussion of the Company's Cost of Service Allocation methodologies, he points out the capacity factors of East Bend as they relate to his justification why the Commission should not adopt a Production Stacking Methodology for cost allocation. Company witness Mr. Ziolkowski addresses the cost-of-service allocation methodology issues in his rebuttal testimony. My testimony is merely to comment on Mr. Bieber's citation to capacity factors.

Mr. Bieber then recommends that the Commission not adopt the Company's proposal for a Generation True-Up Mechanism to recover any undepreciated remaining net book value of its fossil fleet at its retirement at this time. He believes the Commission should address the costs related to the Company's generating units in the context of a general rate case, "such as this one," with a "reasonable level of Test Year depreciation and other related costs being embedded in base rates."[2]

Q. IS MR. BIEBER'S CALCULATION OF EAST BEND'S CAPACITY FACTOR OF 47.0 PERCENT IN 2021 ACCURATE?

A. Yes.

[2] Bieber Direct pg. 14.

Q. WHAT WAS EAST BEND'S CAPACITY FACTOR FOR THE CALENDAR YEARS 2018, 2019, 2020, 2021 and 2022?

A.

YEAR	EAST BEND 2 CAPACITY FACTOR
2018	53%
2019	60%
2020	43%
2021	49%
2022	53%

Q. WHAT IS A DRIVER FOR EAST BEND, A BASE LOAD GENERATING UNIT, HAVING CAPACITY FACTORS AT OR BELOW 50 PERCENT?

A. Capacity factors are driven by how a generator's dispatch costs compare to the market power price. Factors that increase the dispatch cost or depress the power price result in lower capacity factors. As such, the primary drivers for scenarios in the Company's IRP where East Bend 2 has lower capacity factors are those with a carbon tax and low gas prices.

Q. ARE EAST BEND'S CAPACITY FACTORS PROJECTED TO IMPROVE IN THE FUTURE?

A. Yes, in some scenarios the capacity factor of East Bend 2 does improve. As has been discussed, several factors will determine the future capacity factor of East Bend 2. And while it is true that the unit's capacity factor does go down in some scenarios, it is also true that in other scenarios the unit's capacity factors do improve. It is this uncertainty that supports the likelihood and prudence of preparing for a retirement of the East Bend 2 unit in 2035

Q. WHAT DOES THAT MEAN FOR CUSTOMERS AS IT RELATES TO LOWER CAPACITY FACTORS FOR EAST BEND AND INCREASES IN ECONOMY ENERGY PURCHASES?

A. As was mentioned, lower power prices push down capacity factors and as the Company operates the system to keep costs to customers low, the Company will run East Bend 2 or buy power from the market depending on which is cheaper. This is true for any dispatchable generator and highlights the value of dispatchable generation because it gives the company a choice between generating or buying. Replacing East Bend 2 with capacity with intermittent resources takes away that choice during those times when the intermittent resource is not generating.

Q. IS DUKE ENERGY KENTUCKY SEEKING COMMISSION AUTHORIZATION TO RETIRE EAST BEND IN THIS PROCEEDING?

A. No. The Company is not requesting such authority here. The Company is merely advocating that the Commission act now, while it is in customers' best interests to do so, and properly align depreciation expense for the Company's fossil-fueled generating fleet with the current, most likely lives, namely 2035 for East Bend and 2040 for Woodsdale.

While I am not an attorney, I do understand there is a recently enacted statute that requires a utility to obtain Commission approval before retiring a fossil-fueled generating asset. The Commission will have the opportunity to consider the actual cessation and shut down of those units in a future proceeding. The Company's proposal in this proceeding is two-fold: 1) to align its depreciation rates of its generating portfolio with the estimated remaining useful lives that are based upon the most recent Integrated Resource Planning modeling; and 2) to create the Rider GTM as a placeholder for any remaining undepreciated plant that exists for those assets upon their retirement. While I understand that new law likely makes the Company's request for Rider GTM premature, adjusting depreciation, however, is something this Commission regularly does in base rates proceedings and has done so for decades. It is sound rate-making practice to do so. In fact, that is the purpose of depreciation – to recover the costs of the plant, including its retirement and decommissioning, over the life of the asset or as close to as possible. In this case, the Company's analysis and supporting testimony shows that East Bend's likely retirement date is now 2035 or earlier, versus the previous analysis that showed a 2041 retirement date. Moreover, the Company is requesting to adjust its Woodsdale depreciation to extend it longer. This partially mitigates the impact of increasing the depreciation expense for East Bend.

Q. DO YOU BELIEVE THE COMPANY'S REQUEST IN THIS PROCEEDING AS IT RELATES TO ADJUSTING BASE RATES SO TO ALIGN DEPRECIATION EXPENSE WITH THE USEFUL LIFE OF AN ASSET IS CONSISTENT WITH MR. BIEBER'S RECOMMENDATION IN HIS DIRECT TESTIMONY?

A. Yes.

Q. EVEN THOUGH MODELING SHOWS EAST BEND IS BECOMING LESS ECONOMIC AND ITS CAPACITY FACTOR CONTINUING TO DECLINE TO NEAR ZERO IN THE NEXT DECADE, WOULD DUKE ENERGY KENTUCKY HAVE TO CONTINUE TO MAKE CAPITAL INVESTMENTS IN THE UNIT FOR IT TO REMAIN DISPATCHABLE IN PJM AND INCLUDABLE IN THE COMPANY'S FRR PLAN?

A. Yes, continued operation of a coal plant would require investment in the unit to ensure clean and efficient operation. Those costs have been included in the analysis and has affected the economic retirements of the various optimized portfolios.

Q. DO YOU KNOW WHAT IMPACT THAT WILL HAVE ON THE COMPANY'S REMAINING NET BOOK VALUE OF ITS PLANT?

A. Based on my understanding of rate making, those capital investments in East Bend 2 would add to the net book value of the unit and could outpace depreciation if not properly aligned with the unit's most likely remaining life.

Q. COULD DUKE ENERGY KENTUCKY SIMPLY MOTHBALL EAST BEND AND STOP MAKING NECESSARY CAPITAL INVESTMENTS TO KEEP IT DISPATCHABLE, BUT NOT RETIRE IT?

A. As the Company explained in discovery in this proceeding, mothballing a unit presents risks to the Company and customers as it relates to PJM's capacity performance and will not alleviate the Company from having to continue to invest into an asset to make sure it remains dispatchable when called upon. Mothballing would require ongoing oversight, maintenance, and permitting costs, without being assured the unit would remain reliable. There are risks associated with not running any generation unit for a period of time and then "hoping" it will start up without incident when called upon. Because of PJM's capacity performance construct, Duke Energy Kentucky would still have to continue to make investments beyond the "mothballing" date, so the station is capable of performing if called upon. Such a strategy would increase the risks of non-performance assessments if the unit were unable to perform despite these continued investments. This will only serve to negatively impact the unit's dispatch economics in PJM and likely increase the undepreciated plant prior to the unit's eventual retirement."[3]

Q. PLEASE RESPOND TO MR. BIEBER'S RECOMMENDATION REGARDING REJECTING THE RIDER GTM PROPOSAL AND INSTEAD ADJUSTING DEPRECIATION RATES IN BASE RATE PROCEEDINGS.

A. I leave the merits of the Rider GTM proposal to other Company witnesses, but as it relates to adjusting depreciation rates to align with and reflect the appropriate remaining life of an asset, I completely agree with Mr. Bieber's position on page 14 of his testimony where he says, in relevant part, "…costs related to the Company's East Bend and Woodsdale units should be considered in the context of a general rate case, such as this one, with a reasonable level of Test Year depreciation and other related costs being embedded in base rates."[4] This is precisely what the Company is proposing here. Customers of tomorrow should not be saddled with increased costs and higher rates because today's rates were not accurately reflecting the Company's costs.

[3] Please See Response to AG-02-013, part e
[4] Direct Testimony of Justin Bieber, pg. 14, L 10-13.

III. <u>CONCLUSION</u>

Q. DOES THIS CONCLUDE YOUR REBUTTAL TESTIMONY?

A. Yes.

VERIFICATION

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

The undersigned, Scott Park, Managing Director IRP & Analytics, 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.

Scott Park Affiant

Subscribed and sworn to before me by Scott Park on this 3rd day of April, 2023.

Muriel R. Spear

NOTARY PUBLIC

My Commission Expires: Oct. 20, 2023

MURIEL R. SPEAR
NOTARY PUBLIC
Mecklenburg County
North Carolina
My Commission Expires 10/20/23

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 New Tariffs; 3) Approval of Accounting Practices to Establish Regulatory Assets and Liabilities; and 4) All Other Required Approvals and Relief.	)))))))	Case No. 2022-00372

REBUTTAL TESTIMONY OF

THOMAS J. HEATH, JR.

ON BEHALF OF

DUKE ENERGY KENTUCKY, INC.

April 14, 2023

TABLE OF CONTENTS

PAGE

I. INTRODUCTION AND PURPOSE

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Thomas J. Heath Jr. My current business address is 525 South Tryon Street, Charlotte, North Carolina 28202.

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

A. I am employed by Duke Energy Business Services LLC (DEBS) as Structured Finance Director. 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. PLEASE BRIEFLY SUMMARIZE YOUR EDUCATIONAL BACKGROUND AND PROFESSIONAL EXPERIENCE.

A. I have a Bachelor of Science degree with a major in Accounting from Southeastern Louisiana University and a Master of Arts degree in Theology from Saint Leo University. I am a Certified Public Accountant licensed in the Commonwealth of Kentucky. My professional work experience began in 1995 with the public accounting firm of Price Waterhouse (now PricewaterhouseCoopers), where my work focused on audits of Generally Accepted Accounting Principles (GAAP) and Securities and Exchange Commission (SEC)-compliant financial statements, including those in the electric utility industry, and the performance of due diligence procedures over mergers and acquisitions. In April 2004, I joined Cinergy Corp. (a predecessor company to today's Duke Energy) as a Lead Analyst in the Accounting Research Group where I was responsible for assessing the appropriate accounting and disclosure treatment for significant non-routine matters as well as certain regulatory accounting interpretations.

Over the next 10 years, I held various finance-related positions of increasing responsibility. In August 2014, I accepted a position as Corporate Finance Director in Duke Energy's Treasury Department and in June 2016 I became Structured Finance Director. During my time in treasury, I have been responsible for executing public debt offerings for Duke Energy and its utility subsidiaries, managing Duke Energy's $1.5 billion portfolio of accounts receivable securitization financing programs, managing Duke Energy's Master Credit Facility, executing various project debt financings for Duke Energy's nonregulated renewable portfolio, and leading the due diligence process for Duke Energy's Transaction and Risk Committee. I also led the approximately $1.3 billion 2016 Nuclear Asset-Recovery Bond issuance for Duke Energy Florida, LLC (Duke Energy Florida) and the approximately $770 million and $237 million 2021 North Carolina Storm Recovery Bond issuances for Duke Energy Carolinas, LLC (Duke Energy Carolinas) and Duke Energy Progress, LLC (Duke Energy Progress). I am currently working on the initial phase of an approximately $175 million South Carolina Storm Recovery Bond issuance for Duke Energy Progress.

Q. PLEASE SUMMARIZE YOUR RESPONSIBILITIES AS STRUCTURED FINANCE DIRECTOR.

A. I am responsible for the execution of project and structured financings of Duke Energy, its subsidiary utilities, and its nonregulated renewable operations. This includes the issuance, renewal, and refinancing of project and structured debt obligations.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THE KENTUCKY PUBLIC SERVICE COMMISSION?

A. No, I have not previously testified before the Kentucky Public Service Commission.

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

A. The purpose of my rebuttal testimony is to respond to the recommendations of Mr. Lane Kollen on behalf of the Kentucky Attorney General as it relates to the Company's cash-working capital requirements, and specifically, the structure of the Company's accounts receivable securitization financing program with Cinergy Receivables Company LLC (CRC). I sponsor Attachments TJH-1 through TJH-4, which demonstrate the only significant cash flows in the primary CRC bank account relate to monthly interest payments under the accounts receivable securitization financing program. I also address the recommendation of Ms. Sarah Shenstone-Harris on behalf of the Sierra Club as it relates to securitization as a financing tool for recovering undepreciated plant.

II. <u>DISCUSSION</u>

A. ACCOUNTS RECEIVABLE SECURITIZATION FINANCING

Q. PLEASE SUMMARIZE MR. KOLLEN'S RECOMMENDATION AS IT RELATES TO THE COMPANY'S CASH WORKING CAPITAL REQUIREMENTS.

A. As more fully discussed by Company witness, Mr. Paul Normand, Mr. Kollen recommends that the Commission reflect a factor of 1.46 in collection lag days in the collection component of the revenue lag days in the calculation of cash working capital included in rate base using the lead/lag approach. The result of Mr. Kollen's recommendations are a reduction of $17.945 million in the Company's rate base and a $1.677 million reduction in the base revenue requirement and requested base rate increase.

Q. DOES MR. KOLLEN ACCURATELY DESCRIBE THE COMPANY'S ACCOUNTS RECEIVABLE FINANCING PROGRAM ON PAGE 11 OF HIS DIRECT TESTIMONY?

A. No, he does not.

Q. PLEASE DESCRIBE AND EXPLAIN HOW THE COMPANY'S ACCOUNTS RECEIVABLE SECURITIZATION FINANCING PROGRAM WORKS.

A. The terms that have been used in this proceeding, sale of receivables and purchase of receivables, are a bit of a misnomer. The substance of the program is more accurately a securitization financing of the accounts receivable of Duke Energy Indiana, Duke Energy Ohio, and Duke Energy Kentucky in order to efficiently diversify the long-term debt raised by each these entities at reasonable interest rates. The CRC accounts receivable securitization financing program includes Duke Energy Indiana, Duke Energy Ohio, and Duke Energy Kentucky for scale of borrowing and efficiency of administration. In a traditional securitization, like the one utilized by CRC, an asset or group of assets (in this case accounts receivable) are isolated from other assets of the originator of those assets (Duke Energy Indiana, Duke Energy Ohio, and Duke Energy Kentucky), and financed in a manner that relies on the strength of the relevant assets rather than the creditworthiness of the originator. A securitization is a transaction in which a sponsor or originator raises capital by causing a special purpose entity to issue debt securities backed by and paid from the proceeds of the segregated assets. Duke Energy has four such programs, providing $1.5 billion of borrowing capacity, which provide reasonable cost financing for its regulated utilities.

Duke Energy Kentucky traditionally raises debt capital from fixed-rate long-term private placement issuances. Lenders for these types of financings are typically insurance companies, pension funds, and money managers. The accounts receivable securitization financing provides Duke Energy Kentucky the opportunity to raise floating-rate debt funded by financial institutions. This financing method provides diversification of both the interest rates and lending institutions.

The legal documentation does provide for the transfer of Duke Energy Kentucky's accounts receivable to CRC, a bankruptcy remote, special purpose entity owned by Cinergy Corp., a wholly-owned subsidiary of Duke Energy Corp. CRC uses the receivables it obtains from Duke Energy Indiana, Duke Energy Ohio, and Duke Energy Kentucky as collateral for borrowings under a credit facility with two financial institutions. The CRC credit facility currently has a maximum borrowing amount of

$350 million. Borrowing availability from the credit facility is limited to the amount of qualified receivables held by CRC, which generally exclude receivables past due more than a predetermined number of days and reserves for expected past-due balances. Amounts borrowed under the credit facility are reflected on Duke Energy's Consolidated Balance Sheets as Long-Term Debt but are not reflected on the Consolidated Balance Sheets of Duke Energy Indiana, Duke Energy Ohio, and Duke Energy Kentucky for GAAP due to technical consolidation accounting guidance. However, Duke Energy Kentucky does include its pro rata share (approximately $35.0 million) of the outstanding debt of CRC in its embedded cost of debt for ratemaking purposes (refer to Attachment CRB-Rebuttal-1 Updated Capital Structure sponsored by Company Witness Christopher R. Bauer). Mr. Kollen did not recognize this fact, nor did he recommend an adjustment to remove this debt from Duke Energy Kentucky's embedded cost of debt. His proposed recommendation for a change to the collections lag without any related change to the embedded cost of debt results in asymmetrical treatment of the accounts receivable securitization financing program.

Q. PLEASE FURTHER EXPLAIN THE CASH FLOWS UNDER THE CRC ACCOUNTS RECEIVABLE SECURITIZATION FINANCING PROGRAM?

A. The only cash inflows that Duke Energy Indiana, Duke Energy Ohio, and Duke Energy Kentucky receives from CRC are related to debt issuances. When the original accounts receivable financing was established in March 2002, Duke Energy Indiana, Duke Energy Ohio, and Duke Energy Kentucky received one-time cash receipts for their pro rata portion of the initial debt issuance, much like they do for other debt issuances. Since that time, Duke Energy Indiana, Duke Energy Ohio, and Duke

Energy Kentucky have received additional cash receipts only when either (1) the credit facility was increased or (2) when funds were reborrowed after recovery of a borrowing base deficiency. When the amount of qualified receivables exceeds the credit facility limit, no additional funds are received by Duke Energy Indiana, Duke Energy Ohio, and Duke Energy Kentucky. For any month in which the amount of qualified receivables is less than the credit facility limit (known as a borrowing base deficiency), Duke Energy Indiana, Duke Energy Ohio, and Duke Energy Kentucky fund their pro rata share of a repayment of the outstanding CRC loan. In subsequent months when the amount of qualified receivables meets or exceeds the credit facility limit, Duke Energy Indiana, Duke Energy Ohio, and Duke Energy Kentucky receive proceeds for their pro rata share of a reborrowing up to the credit facility limit.

On a monthly basis, Duke Energy Indiana, Duke Energy Ohio, and Duke Energy Kentucky pay interest expense on their pro rata share of CRC's outstanding debt to CRC for ultimate payment of interest expense to the lending financial institutions. On a periodic basis, Duke Energy Indiana, Duke Energy Ohio, and Duke Energy Kentucky funds their share of certain expenses of CRC related to the financing arrangement (i.e., bank administration fees, annual review fees, etc.)

On a daily basis, Duke Energy Indiana, Duke Energy Ohio, and Duke Energy Kentucky receive cash from their customers when bills are paid by those customers. Under the program, Duke Energy Indiana, Duke Energy Ohio, and Duke Energy Kentucky continue to process customer billings and receive cash from customers for payment of their bills. Cash collections from customers are received into collection accounts in the name of CRC that are reflected on the balance sheet of Duke Energy

Indiana, Duke Energy Ohio, and Duke Energy Kentucky. Cash received into these collection accounts are swept daily into Duke Energy Indiana, Duke Energy Ohio, and Duke Energy Kentucky's general concentration accounts. The lending banks have a security interest in the collection accounts through control agreements. In the event of a default on or termination of the credit facility, the lending banks have the right to take control of the collection accounts until cash is received from customers to repay outstanding borrowings. At all other times the collection accounts are under the control of Duke Energy Indiana, Duke Energy Ohio, and Duke Energy Kentucky. To be clear, CRC does not transfer any funds to Duke Energy Indiana, Duke Energy Ohio, and Duke Energy Kentucky immediately upon customer billings.

Q. PLEASE EXPLAIN THE STATEMENTS INCLUDED AS ATTACHMENTS TJH-1 THROUGH TJH-4.

A. TJH-1 includes a summary of the significant cash inflows to and outflows from the primary bank account for CRC for the months of January, February, and March 2023. This CRC bank account does not maintain a balance, it is only funded when there is a need to make cash disbursements. The schedule shows that the primary outflows are the payment of monthly interest to the lending banks and the primary inflows are from Duke Energy Indiana, Duke Energy Ohio, and Duke Energy Kentucky to fund the monthly interest payments to the lending banks. TJH-2 through TJH-4 include the actual CRC bank statements for these months with notations for the primary inflows and outflows as well as the monthly interest statements from the lending banks.

Q. WHAT IS THE DIFFERENCE BETWEEN THE COMPANY'S ACCOUNTS RECEIVABLE SECURITIZATION FINANCING PROGRAM AND A FACTORING OF RECEIVABLES PROGRAM?

A. An accounts receivable securitization financing program, like that used by CRC, is a borrowing that uses unpaid invoices as collateral. An accounts receivable factoring program (one that the Company does not employ) is generally more expensive than receivable financing and is used as a method of accelerating cash collections. The increased expense is typically related to the factoring company taking responsibility for collecting invoices and taking on the risk of collections from the seller of the receivables. In a receivables financing arrangement, the originator retains these risks and responsibilities. Factoring programs are often times utilized by small businesses or larger companies that are struggling financially.

Q. MR. KOLLEN ALLEGES ON PAGE 12 OF HIS TESTIMONY THAT THE COMPANY SELLS ITS RECEIVABLES TO CINERGY RECEIVABLES DAILY IN EXCHANGE FOR CASH. IS MR. KOLLEN'S CLAIM ACCURATE?

A. No, it is not accurate. Please refer to my response to the question related to cash flows above. Mr. Kollen appears to believe that the Company's program is a factoring program. It is not. It is an accounts receivable securitization financing program essentially designed for the Company to take advantage of reasonable cost debt from a diversified lender base which is why Duke Energy Kentucky's pro rata share of CRC's outstanding borrowings are reflected in the J schedules of the Company's rate request. This reasonable cost debt is a benefit to Duke Energy Kentucky's customers.

Q. MR. KOLLEN STATES THAT THE COMPANY ACCELERATES THE CONVERSION OF THE RECEIVABLES TO CASH AND WAITS AN AVERAGE OF ONLY 1.46 DAYS FROM THE DATE OF CUSTOMER BILLING TO THE DATE WHEN IT RECEIVES CASH FOR SERVICE. IS HIS STATEMENT CORRECT? PLEASE EXPLAIN.

A. No, it is not correct. As I have explained in my testimony Duke Energy Kentucky does not receive any cash from CRC immediately upon customer billing. Duke Energy Kentucky does not receive cash until it is paid by its customers.

Q. WHAT IS YOUR RECOMMENDATION REGARDING MR. KOLLEN'S POSITION REGARDING THE COMPANY'S PURCHASE OF RECEIVABLES PROGRAM?

A. I recommend that the Commission reject Mr. Kollen's position. His understanding of the Company's program is inaccurate and thus his conclusion and recommendation is unsupportable by facts. The Commission should find that Duke Energy Kentucky's collection lag proposed by Mr. Normand in this proceeding is reasonable and prudent and should be adopted.

B. SECURITIZATION OF RETIRED GENERATION

Q. PLEASE BRIEFLY SUMMARIZE MS. SHENSTONE-HARRIS'S RECOMMENDATION REGARDING THE USE OF SECURITIZATION.

A. Ms. Shenstone-Harris recommends that the Commission order the Company, as part of its IRP, to evaluate the economics of retiring East Bend early and using securitization to finance the remaining balance of undepreciated plant and retirement costs.

Q. DOES THE COMPANY AGREE WITH MS. SHENSTON-HARRIS'S RECOMMENDATION REGARDING SECURITIZATION?

A. Not entirely. First, as Ms. Shenstone-Harris admits, Kentucky does not currently have enabling legislation to make securitization a viable tool for all utilities. Therefore, much of her recommendation is purely academic and theoretical in nature. Nonetheless, the Company disagrees with her recommendation, particularly as it relates to her attempt to justify an even earlier retirement of East Bend than what the Company shows is most likely.

Q. WHAT IS THE COMPANY'S VIEW REGARDING SECURITIZATION?

A. The Company's view is that securitization is a tool that could be utilized to lower the customer impact of certain types of costs (extraordinary storm restoration, early retired generation costs, etc.,) but the use of securitization is an after-the-fact decision based upon a variety of factors and is and should be, ultimately a decision at the option of the utility. Decisions related to early retirement of generation assets should be made without consideration of securitization as a potential means of financing the asset. The evaluation of retirement should only be made with respect to economics of the underlying asset and existing regulatory recovery mechanism for the retired asset (i.e., base rates, etc.) The decision whether to use securitization should be left up to the utility and they should not be compelled or required by a legislative body, commission or intervenor to use this financial tool. Securitization transactions take time to execute. Capital markets are subject to great uncertainty and just because a securitization is available in theory at the time of evaluating a retirement does not mean an actual transaction will be executable at the time the unit is retired or at the time bonds would need to be issued which could be years after the retirement evaluation is conducted.

Q. WHY IS ENABLING LEGISLATION NECESSARY FOR SECURITIZATION TO BE A FINANCING ALTERNATIVE?

A. Utility rate securitizations are a specialized type of transaction employed by rate regulated utilities to recover discrete, specified costs. Utility rate securitizations require an enabling state statute, to authorize a state public utility commission to issue a financing order (a "Financing Order") to create an intangible property right (the "Intangible Property") to bill and collect a non-bypassable charge (the "Dedicated Charge") from a utility's customers. In addition to the right to the Dedicated Charge, the Intangible Property includes the right to obtain periodic adjustments to the Dedicated Charge to ensure collections are sufficient to timely pay principal, interest, and other amounts relating to the bonds issued pursuant to the Financing Order. The Intangible Property is then sold by the utility to a wholly-owned special-purpose entity (an "SPE Issuer") that uses the proceeds from the sale of bonds to fund its purchase of the Intangible Property from the utility. The Intangible Property is the primary asset securing the bonds.

Regardless of the types of costs being recovered via utility rate securitization structures, the basic blueprint of each structure is substantially consistent. The Intangible Property (i.e., the right to bill and collect the Dedicated Charge, which is subject to a periodic adjustment, from a utility's customers) is sold to a bankruptcy remote SPE Issuer, which in turn issues bonds secured by the property. The money received through the collection of the Dedicated Charge is used to pay principal, interest, and other ongoing costs associated with the bonds.

Q. ARE THERE RISKS FOR CUSTOMERS FOR SECURITIZATION?

A. Yes. In securitization, particularly for a retired generation asset, the bond maturity is likely 20 to 25 years, or longer from the date the bonds are issued. The result is that while the financing rate may be lower than through typical base rate or rider recovery, customers are paying over a far much longer period of time. Contrary to Ms. Shenstone-Harris's claims to the contrary, an early retirement, justified with securitization whereby the Company recovers remaining net book value of a retired asset, when coupled with the cost of replacement generation, will absolutely result in an increase in customer rates. This is true regardless, of course, whether or not the remaining net book value is recovered through securitization or through base rates and depreciation. The point is securitization is not a silver bullet as she would have this Commission believe.

Q. DO YOU AGREE WITH MS. SHENSTONE-HARRIS'S DESCRIPTION OF SECURITIZATION ON PAGE 49 OF HER TESTIMONY AND CLAIMS THAT WITH SECURITIZATION, "THERE IS ZERO RISK THAT FUTURE RATEPAYERS WILL NOT PAY THE BOND IN THE FUTURE?

A. No. First, Ms. Shenstone-Harris's claim that major credit rating agencies exclude securitization debt in their assessment of debt-to-equity ratio for utility credit scoring is inaccurate. Many rating agencies leave securitization in the utility's credit metrics. And although with securitization, payments are made by customers, typically through an assessment on the utility's bill, and such payments do go to the bondholders, it's not accurate to say this is without risk. There is no legal guarantee with securitization bonds and there is a risk of nonpayment. AAA ratings do not mean there is zero risk of repayment. It only means that the risk is lower than in debt rated below AAA.

Moreover, her description of how securitization is implemented on page 50, is inaccurate. Bonds are not issued on behalf of ratepayers. The security for the bonds is the charges to be assessed on customers, but these are not directly the obligations of the customers.

Q. DO YOU AGREE WITH MS. SHENSTONE-HARRIS'S CLAIM THAT SECURITIZATION OF STRANDED ASSETS, "PARTICULARLY COAL-RELATED ASSETS- IS QUICKLY BECOMMMING THE INDUSTRY NORM.?

A. No. Her statement is conflating separate facts. Securitization has not been widely used for, or as justification of retirement of generation assets. Her testimonial reference to the early 1990's is to mostly sales or transfers for deregulated generation assets to affiliates, not for the retirement of those assets. The vast majority of utility securitization have been done for storm restoration costs and stranded costs of generation related to transition to deregulation.

Q. PLEASE COMMENT ON MS. SHENSTONE-HARRIS'S RELAINCE UPON DUKE ENERGY FLORIDA'S FINANCING OF ITS CRYSTAL RIVER NUCLEAR PLANT AS AN EXAMPLE.

A. While it is true that Duke Energy Florida did use securitization related to its retirement of Crystal River, and the interest rates she quotes are accurate, it must also be acknowledged that there was enabling legislation in Florida to accomplish this, and the interest rates that were achieved at that time are not in the realm of possibility today.

Q. WHAT IS YOUR RECOMMENDATION REGARDING MS. SHENSTONE-HARRIS'S ADVOCACY FOR SECURITIZATION.

A. Again, while securitization is a useful tool in the correct circumstances, the Commission should disregard her testimony. Securitization requires enabling legislation in order to accomplish it correctly. It should not be used as a factor to justify or support retirement of generating assets. Rather, it should be a tool to evaluate potential financing after the retirement decision has been made. There is risk with securitization and once it is executed, the Commission loses any say or oversight regarding the cost recovery. The more restrictions placed upon a utility as part of a securitization transaction, the less likely a counterparty will be willing to enter into a transaction, particularly at a financing cost that is advantageous enough to warrant the securitization strategy.

III. CONCLUSION

Q. WERE ATTACHMENTS TJH-1 THROUGH TJH-4 PREPARED BY YOU OR UNDER YOUR SUPERVISION AND CONTROL?

A. Yes.

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

A. Yes.

VERIFICATION

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

The undersigned, Thomas J. Heath, Jr., Structured Finance Director, 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.

Thomas J. Heath, Jr. Affiant

Subscribed and sworn to before me by Thomas J. Heath, Jr. on this 10 day of April, 2023.

VIRGINIA M. ADAMS
My Comm. Expires
NOTARY PUBLIC
October 2, 2026
MECKLENBURG COUNTY, NC

Virginia M. Adams
NOTARY PUBLIC

My Commission Expires: 10/2/26

	Jan-23		Feb-23		Mar-23	
Funding of interest payments - based on percentage of outstanding receivables at each month end						
Duke Energy Indiana pro rata share of interest payments	869,572.29	55.55%	898,540.51	54.08%	827,561.05	53.70%
Duke Energy Ohio pro rata share of interest payments	530,172.69	33.87%	603,887.22	36.35%	574,380.14	37.27%
Duke Energy Kentucky pro rata share of interest payments	165,761.54	10.59%	159,018.57	9.57%	139,060.68	9.02%
Total transfers to CRC to fund interest payments	**1,565,506.52**	**100.00%**	**1,661,446.30**	**100.00%**	**1,541,001.87**	**100.00%**
Interest payments to lending banks						
Interest payment to BNP Paribas / Starbird Funding Corporation	598,158.15		628,158.83		587,529.56	
Interest payment to Scotia Bank / Liberty Street Funding	967,348.38		1,033,287.47		953,472.31	
Total interest payments to lending banks	**1,565,506.53**		**1,661,446.30**		**1,541,001.87**	

Corporate Business Account Statement

PNC BANK

Account Number: [redacted]7469

For the period 12/31/2022 to 01/31/2023

CINERGY CORP
CINERGY RECEIVABLES COMPANY LLC
139 E 4TH ST
CINCINNATI OH 45202-4003

Number of enclosures: 0
Tax ID Number: 31-1385023
For Client Services:
Call 1-800-669-1518

Visit us at PNC.com/treasury

Write to: Treas Mgmt Client Care
One Financial Parkway
Locator Z1-Yb42-03-1
Kalamazoo MI 49009

Account Summary Information

Balance Summary

Beginning balance	Deposits and other credits	Checks and other debits	Ending balance
.02	1,621,169.25	1,621,169.26	.01

Deposits and Other Credits

Description	Items	Amount
Deposits	0	.00
National Lockbox	0	.00
ACH Credits	0	.00
Funds Transfers In	5	1,568,669.25
Trade Services	0	.00
Investments	0	.00
Zero Balance Transfers	0	.00
Adjustments	0	.00
Other Credits	3	52,500.00
Total	8	1,621,169.25

Checks and Other Debits

Description	Items	Amount
Checks	0	.00
Returned Items	0	.00
ACH Debits	0	.00
Funds Transfers Out	6	1,621,169.26
Trade Services	0	.00
Investments	0	.00
Zero Balance Transfers	0	.00
Adjustments	0	.00
Other Debits	0	.00
Total	6	1,621,169.26

Ledger Balance

Date	Ledger balance	Date	Ledger balance	Date	Ledger balance
12/31	.02	01/25	.01	01/31	.01
01/09	.02				

Duke Energy Indiana pro rata share of interest payment

Duke Energy Ohio pro rata share of interest payment

Duke Energy Kentucky pro rata share of interest

Deposits and Other Credits

Funds Transfer In

5 transactions for a total of $1,568,669.25

Date posted	Amount	Transaction description	Reference number
01/09	1,496.45	Book Trn Credit 2319D0100Qzd7Gvk	W2319D0100QZD7GVK
01/25	869,572.29	Book Trn Credit 231Pd0220E1J3Kqj	W231PD0220E1J3KQJ
01/25	1,666.28	Book Trn Credit 231Pd0220Dvj3Kq8	W231PD0220DVJ3KQ8
01/25	530,172.69	Book Trn Credit 231Pd0220Dvj3Kqb	W231PD0220DVJ3KQB
01/25	165,761.54	Book Trn Credit 231Pd0220Dpj3Kq2	W231PD0220DPJ3KQ2

Other Credits

3 transactions for a total of $52,500.00

Date posted	Amount	Transaction description	Reference number
01/31	29,163.75	Rtp Received Cinergy Corp 01/31 00007	NA1VB3728HWA0FFT
01/31	17,781.75	Rtp Received Duke Energy Ohio Inc 01/31 00004	NA1VB3728NE951H4

Other Credits continued on next page

Corporate Business Account Statement

CINERGY CORP
CINERGY RECEIVABLES COMPANY LLC

For the period 12/31/2022 to 01/31/2023
Account number: [redacted]7469

Deposits and Other Credits *- continued*

Other Credits *- continued* — **3 transactions for a total of $52,500.00**

Date posted		Transaction description	Reference number
01/31	5,554.50	Rtp Received Duke Energy Kentucky I 01/31 00003	NA1VB3728BJA3YFK

Checks and Other Debits

Funds Transfers Out — **6 transactions for a total of $1,621,169.26**

Date posted	Amount	Transaction description	Reference number
01/09	1,496.45	Book Trn Debit 2319D0100Q5D7Gvg	W2319D0100Q5D7GVG
01/25	598,158.15	Wire Transfer Out 231Pd0223Ejj1Orf	W231PD0223EJJ1ORF
01/25	1,666.28	Book Trn Debit 231Pd0220Dkj3Kpx	W231PD0220DKJ3KPX
01/25	967,348.38	Wire Transfer Out 231Pf074101K1O8H	W231PF074101K1O8H
01/31	20,193.75	Wire Transfer Out 231Vg3826Prk6Ota	W231VG3826PRK6OTA
01/31	32,306.25	Wire Transfer Out 231Vg3826Prk6Ot9	W231VG3826PRK6OT9

Interest payment to BNP Paribas / Starbird Funding Corporation - see

Interest payment to Scotia Bank / Liberty Street Funding - see attached statement

Liberty Street Funding LLC
Settlement Period Calculation Report

Seller:	CINERGY RECEIVABLES COMPANY LLC

To		
Name	Bank / Seller	E-mail
Beverly Bockrath	Duke Energy	beverly.bockrath@duke-energy.com
Brad Evans		brad.evans@duke-energy.com
Cindy Rummel		cynthia.rummel@duke-energy.com
Stacey Snyder		stacey.snyder@duke-energy.com
Tom Heath		Tom.Heath@duke-energy.com

From		
Name	Bank	E-mail
Kelson Yang	Scotiabank	kelson.yang@scotiabank.com
Pia Manalac	Scotiabank	pia.manalac@scotiabank.com

Date:	January 3, 2023

BILLING PARAMETER

Collection Start Date	1-Dec-22
Collection End Date	1-Jan-23
Days	31

AMOUNT DUE

Interest / Yield Due	836,226.88
Program Fee Due	129,823.27
Unused Fee Due	1,298.23
DUE	**USD 967,348.38**
Payment Date	**25-Jan-23**

COMMITMENT

Effective Date	Max Program Amt	Program Name
28-Feb-22	219,682,500.00	LSF ABCP

PRICING

Cost of Funds 4.50889%

	Effective Date	Utilization From	Utilization To	Fee Percentage
Cinergy Receivables - Program Fee	28-Feb-22			0.70000%
Cinergy Receivables - Standby Fee	28-Feb-22			0.35000%

Please remit funds on Settlement Date to:

[redacted]

Liberty Street Funding LLC
Settlement Period Calculation Report

MONTHLY ACTIVITY

			Program: LSF ABCP							
From	To	# of days	(+) Increase / (-) Decrease in Capital	Outstanding Amount	Program Amount	Unused Commitment	Interest 4.50889%	Program Fee 0.70000%	Commitment Fee	Unused Fee 0.35000%
1-Dec-22	2-Dec-22	1	0.00	215,375,000.00	215,375,000.00	4,307,500.00	26,975.06	4,187.85		41.88
2-Dec-22	3-Dec-22	1	0.00	215,375,000.00	215,375,000.00	4,307,500.00	26,975.06	4,187.85		41.88
3-Dec-22	4-Dec-22	1	0.00	215,375,000.00	215,375,000.00	4,307,500.00	26,975.06	4,187.85		41.88
4-Dec-22	5-Dec-22	1	0.00	215,375,000.00	215,375,000.00	4,307,500.00	26,975.06	4,187.85		41.88
5-Dec-22	6-Dec-22	1	0.00	215,375,000.00	215,375,000.00	4,307,500.00	26,975.06	4,187.85		41.88
6-Dec-22	7-Dec-22	1	0.00	215,375,000.00	215,375,000.00	4,307,500.00	26,975.06	4,187.85		41.88
7-Dec-22	8-Dec-22	1	0.00	215,375,000.00	215,375,000.00	4,307,500.00	26,975.06	4,187.85		41.88
8-Dec-22	9-Dec-22	1	0.00	215,375,000.00	215,375,000.00	4,307,500.00	26,975.06	4,187.85		41.88
9-Dec-22	10-Dec-22	1	0.00	215,375,000.00	215,375,000.00	4,307,500.00	26,975.06	4,187.85		41.88
10-Dec-22	11-Dec-22	1	0.00	215,375,000.00	215,375,000.00	4,307,500.00	26,975.06	4,187.85		41.88
11-Dec-22	12-Dec-22	1	0.00	215,375,000.00	215,375,000.00	4,307,500.00	26,975.06	4,187.85		41.88
12-Dec-22	13-Dec-22	1	0.00	215,375,000.00	215,375,000.00	4,307,500.00	26,975.06	4,187.85		41.88
13-Dec-22	14-Dec-22	1	0.00	215,375,000.00	215,375,000.00	4,307,500.00	26,975.06	4,187.85		41.88
14-Dec-22	15-Dec-22	1	0.00	215,375,000.00	215,375,000.00	4,307,500.00	26,975.06	4,187.85		41.88
15-Dec-22	16-Dec-22	1	0.00	215,375,000.00	215,375,000.00	4,307,500.00	26,975.06	4,187.85		41.88
16-Dec-22	17-Dec-22	1	0.00	215,375,000.00	215,375,000.00	4,307,500.00	26,975.06	4,187.85		41.88
17-Dec-22	18-Dec-22	1	0.00	215,375,000.00	215,375,000.00	4,307,500.00	26,975.06	4,187.85		41.88
18-Dec-22	19-Dec-22	1	0.00	215,375,000.00	215,375,000.00	4,307,500.00	26,975.06	4,187.85		41.88
19-Dec-22	20-Dec-22	1	0.00	215,375,000.00	215,375,000.00	4,307,500.00	26,975.06	4,187.85		41.88
20-Dec-22	21-Dec-22	1	0.00	215,375,000.00	215,375,000.00	4,307,500.00	26,975.06	4,187.85		41.88
21-Dec-22	22-Dec-22	1	0.00	215,375,000.00	215,375,000.00	4,307,500.00	26,975.06	4,187.85		41.88
22-Dec-22	23-Dec-22	1	0.00	215,375,000.00	215,375,000.00	4,307,500.00	26,975.06	4,187.85		41.88
23-Dec-22	24-Dec-22	1	0.00	215,375,000.00	215,375,000.00	4,307,500.00	26,975.06	4,187.85		41.88
24-Dec-22	25-Dec-22	1	0.00	215,375,000.00	215,375,000.00	4,307,500.00	26,975.06	4,187.85		41.88
25-Dec-22	26-Dec-22	1	0.00	215,375,000.00	215,375,000.00	4,307,500.00	26,975.06	4,187.85		41.88
26-Dec-22	27-Dec-22	1	0.00	215,375,000.00	215,375,000.00	4,307,500.00	26,975.06	4,187.85		41.88
27-Dec-22	28-Dec-22	1	0.00	215,375,000.00	215,375,000.00	4,307,500.00	26,975.06	4,187.85		41.88
28-Dec-22	29-Dec-22	1	0.00	215,375,000.00	215,375,000.00	4,307,500.00	26,975.06	4,187.85		41.88
29-Dec-22	30-Dec-22	1	0.00	215,375,000.00	215,375,000.00	4,307,500.00	26,975.06	4,187.85		41.88
30-Dec-22	31-Dec-22	1	0.00	215,375,000.00	215,375,000.00	4,307,500.00	26,975.06	4,187.85		41.88
31-Dec-22	1-Jan-23	1	0.00	215,375,000.00	215,375,000.00	4,307,500.00	26,975.06	4,187.85		41.88
		31					836,226.88	129,823.27		1,298.23

Starbird Funding Corporation
Monthly Invoice for CP Interest & Program Fee Calculation

Borrowing Seller: Cinergy Receivables Company LLC

Interest Period: 12/1/2022 thru 12/31/2022 -----> 31 Days

Settlement Date: January 25, 2023

Total Payment Due: $598,158.15

On January 25, 2023, please wire $598,158.15 to Starbird Funding using the following wire instructions. The following page will provide you details of the CP interest and program fee calculation on a daily basis. If you have any questions, please contact me at the information below.

Wire Instructions -----> [redacted]

Attention To -- Cinergy Receivables Company LLC

Primary Contact:

Contact Info:

Secondary Contact:

Contact Info:

Info on Preparer -- Regarding Starbird Funding

Contact Name:	*Roderick Geoghegan*
Contact Phone:	*(631) 930-7200*
Contact E-Mail:	*starbird@gssnyc.com*

Starbird Funding Corporation

Cinergy Receivables Company LLC -- Monthly CP Interest and Program Fee Detail

Period from 12/1/2022 to and including 12/31/2022

Settlement Date: 1/25/2023

Date	Liquidity Limit	Program Limit	Used Investment	Unused Portion	Yield Rate	Used Rate	Unused Rate	Interest Cost	Used Fee	Unused Fee	SubTotal
12/1/2022	137,317,500	134,625,000	134,625,000	0	4.182690%	0.7000%	0.3500%	15,641.52	2,617.71	26.18	18,285.40
12/2/2022	137,317,500	134,625,000	134,625,000	0	4.196818%	0.7000%	0.3500%	15,694.35	2,617.71	26.18	18,338.24
12/3/2022	137,317,500	134,625,000	134,625,000	0	4.196818%	0.7000%	0.3500%	15,694.35	2,617.71	26.18	18,338.24
12/4/2022	137,317,500	134,625,000	134,625,000	0	4.196818%	0.7000%	0.3500%	15,694.35	2,617.71	26.18	18,338.24
12/5/2022	137,317,500	134,625,000	134,625,000	0	4.225375%	0.7000%	0.3500%	15,801.14	2,617.71	26.18	18,445.03
12/6/2022	137,317,500	134,625,000	134,625,000	0	4.241398%	0.7000%	0.3500%	15,861.06	2,617.71	26.18	18,504.95
12/7/2022	137,317,500	134,625,000	134,625,000	0	4.237723%	0.7000%	0.3500%	15,847.32	2,617.71	26.18	18,491.20
12/8/2022	137,317,500	134,625,000	134,625,000	0	4.254106%	0.7000%	0.3500%	15,908.58	2,617.71	26.18	18,552.47
12/9/2022	137,317,500	134,625,000	134,625,000	0	4.260710%	0.7000%	0.3500%	15,933.28	2,617.71	26.18	18,577.17
12/10/2022	137,317,500	134,625,000	134,625,000	0	4.260710%	0.7000%	0.3500%	15,933.28	2,617.71	26.18	18,577.17
12/11/2022	137,317,500	134,625,000	134,625,000	0	4.260710%	0.7000%	0.3500%	15,933.28	2,617.71	26.18	18,577.17
12/12/2022	137,317,500	134,625,000	134,625,000	0	4.252955%	0.7000%	0.3500%	15,904.28	2,617.71	26.18	18,548.16
12/13/2022	137,317,500	134,625,000	134,625,000	0	4.252382%	0.7000%	0.3500%	15,902.14	2,617.71	26.18	18,546.02
12/14/2022	137,317,500	134,625,000	134,625,000	0	4.277158%	0.7000%	0.3500%	15,994.79	2,617.71	26.18	18,638.67
12/15/2022	137,317,500	134,625,000	134,625,000	0	4.320314%	0.7000%	0.3500%	16,156.18	2,617.71	26.18	18,800.06
12/16/2022	137,317,500	134,625,000	134,625,000	0	4.611873%	0.7000%	0.3500%	17,246.48	2,617.71	26.18	19,890.37
12/17/2022	137,317,500	134,625,000	134,625,000	0	4.611873%	0.7000%	0.3500%	17,246.48	2,617.71	26.18	19,890.37
12/18/2022	137,317,500	134,625,000	134,625,000	0	4.611873%	0.7000%	0.3500%	17,246.48	2,617.71	26.18	19,890.37
12/19/2022	137,317,500	134,625,000	134,625,000	0	4.623971%	0.7000%	0.3500%	17,291.73	2,617.71	26.18	19,935.61
12/20/2022	137,317,500	134,625,000	134,625,000	0	4.623077%	0.7000%	0.3500%	17,288.38	2,617.71	26.18	19,932.27
12/21/2022	137,317,500	134,625,000	134,625,000	0	4.666477%	0.7000%	0.3500%	17,450.68	2,617.71	26.18	20,094.56
12/22/2022	137,317,500	134,625,000	134,625,000	0	4.662092%	0.7000%	0.3500%	17,434.28	2,617.71	26.18	20,078.17
12/23/2022	137,317,500	134,625,000	134,625,000	0	4.662117%	0.7000%	0.3500%	17,434.37	2,617.71	26.18	20,078.26
12/24/2022	137,317,500	134,625,000	134,625,000	0	4.662117%	0.7000%	0.3500%	17,434.37	2,617.71	26.18	20,078.26

Starbird Funding Corporation

Cinergy Receivables Company LLC -- Monthly CP Interest and Program Fee Detail

Period from 12/1/2022 to and including 12/31/2022

Settlement Date: 1/25/2023

Date	Liquidity Limit	Program Limit	Used Investment	Unused Portion	Yield Rate	Used Rate	Unused Rate	Interest Cost	Used Fee	Unused Fee	SubTotal
12/25/2022	137,317,500	134,625,000	134,625,000	0	4.662117%	0.7000%	0.3500%	17,434.37	2,617.71	26.18	20,078.26
12/26/2022	137,317,500	134,625,000	134,625,000	0	4.662117%	0.7000%	0.3500%	17,434.37	2,617.71	26.18	20,078.26
12/27/2022	137,317,500	134,625,000	134,625,000	0	4.660790%	0.7000%	0.3500%	17,429.41	2,617.71	26.18	20,073.30
12/28/2022	137,317,500	134,625,000	134,625,000	0	4.675236%	0.7000%	0.3500%	17,483.44	2,617.71	26.18	20,127.32
12/29/2022	137,317,500	134,625,000	134,625,000	0	4.675255%	0.7000%	0.3500%	17,483.50	2,617.71	26.18	20,127.39
12/30/2022	137,317,500	134,625,000	134,625,000	0	4.674243%	0.7000%	0.3500%	17,479.72	2,617.71	26.18	20,123.61
12/31/2022	137,317,500	134,625,000	134,625,000	0	4.674243%	0.7000%	0.3500%	17,479.72	2,617.71	26.18	20,123.61
31 days							***SubTotal:***	**516,197.70**	**81,148.96**	**811.49**	**598,158.15**

W/A CP rate = 4.452779% **Avg Investment = 134,625,000.01**

Corporate Business Account Statement

PNC BANK

Page 1 of 1
Account Number: [redacted]7469

For the period 02/01/2023 to 02/28/2023

CINERGY CORP
CINERGY RECEIVABLES COMPANY LLC
139 E 4TH ST
CINCINNATI OH 45202-4003

Number of enclosures: 0
Tax ID Number: 31-1385023
For Client Services:
Call 1-800-669-1518

Visit us at PNC.com/treasury

Write to: Treas Mgmt Client Care
One Financial Parkway
Locator Z1-Yb42-03-1
Kalamazoo MI 49009

Account Summary Information

Balance Summary

Beginning balance	Deposits and other credits	Checks and other debits	Ending balance
.01	1,663,190.72	1,663,190.72	.01

Interest payment to BNP Paribas / Starbird Funding Corporation - see

Interest payment to Scotia Bank / Liberty Street Funding - see attached statement

Deposits and Other Credits

Description	Items	Amount
	0	.00
	0	.00
	0	.00
	4	1,663,190.72
Trade Services	0	.00
Investments	0	.00
Zero Balance Transfers	0	.00
Adjustments	0	.00
Other Credits	0	.00
Total	4	1,663,190.72

Checks and Other Debits

Description	Items	Amount
	0	.00
	0	.00
	0	.00
Funds Transfers Out	3	1,663,190.72
Trade Services	0	.00
Investments	0	.00
Zero Balance Transfers	0	.00
Adjustments	0	.00
Other Debits	0	.00
Total	3	1,663,190.72

Ledger Balance

Date	Ledger balance	Date	Ledger balance	Date	Ledger balance
02/01	.01	02/27	.01	02/28	.01

Deposits and O

Duke Energy Kentucky pro rata share of interest

Duke Energy Indiana pro rata share of interest payment

Duke Energy Ohio pro rata share of interest payment

Funds Transfer In

tal of $1,663,190.72

Date posted	Amount	Transaction description	Reference number
02/27	1,744.42	Book Trn Credit 232Rd01084N13Aod	W232RD01084N13AOD
02/28	159,018.57	Book Trn Credit 232SD0104Pu22Pnh	W232SD0104PU22PNH
02/28	898,540.51	Book Trn Credit 232SD0104Q622Pns	W232SD0104Q622PNS
02/28	603,887.22	Book Trn Credit 232SD0104Q022Pnm	W232SD0104Q022PNM

Checks and Other Debits

Funds Transfers Out

3 transactions for a total of $1,663,190.72

Date posted	Amount	Transaction description	Reference number
02/27	1,744.42	Book Trn Debit 232Rd01083W13Ao0	W232RD01083W13AO0
02/28	628,158.83	Wire Transfer Out 232SD0212B532Al7	W232SD0212B532AL7
02/28	1,033,287.47	Wire Transfer Out 232Sf2951Ol13Sma	W232SF2951OL13SMA

Interest payment to BNP Paribas / Starbird Funding Corporation - see

Interest payment to Scotia Bank / Liberty Street Funding - see attached statement

Liberty Street Funding LLC
Settlement Period Calculation Report

Seller:	**CINERGY RECEIVABLES COMPANY LLC**

To		
Name	Bank / Seller	E-mail
Beverly Bockrath	Duke Energy	beverly.bockrath@duke-energy.com
Brad Evans		brad.evans@duke-energy.com
Cindy Rummel		cynthia.rummel@duke-energy.com
Stacey Snyder		stacey.snyder@duke-energy.com
Tom Heath		Tom.Heath@duke-energy.com

From		
Name	Bank	E-mail
Kelson Yang	Scotiabank	kelson.yang@scotiabank.com
Pia Manalac	Scotiabank	pia.manalac@scotiabank.com

Date:	**February 1, 2023**

BILLING PARAMETER

Collection Start Date	1-Jan-23
Collection End Date	1-Feb-23
Days	31

AMOUNT DUE

Interest / Yield Due	902,165.97
Program Fee Due	129,823.27
Unused Fee Due	1,298.23
DUE	**USD 1,033,287.47**
Payment Date	**27-Feb-23**

COMMITMENT

Effective Date	Max Program Amt	Program Name
28-Feb-22	219,682,500.00	LSF ABCP

PRICING

Cost of Funds 4.86443%

	Effective Date	Utilization From	Utilization To	Fee Percentage
Cinergy Receivables - Program Fee	28-Feb-22			0.70000%
Cinergy Receivables - Standby Fee	28-Feb-22			0.35000%

Please remit funds on Settlement Date to:

[redacted]

Liberty Street Funding LLC
Settlement Period Calculation Report

MONTHLY ACTIVITY

			Program: LSF ABCP							
From	To	# of days	(+) Increase / (-) Decrease in Capital	Outstanding Amount	Program Amount	Unused Commitment	Interest 4.86443%	Program Fee 0.70000%	Commitment Fee	Unused Fee 0.35000%
1-Jan-23	2-Jan-23	1	0.00	215,375,000.00	215,375,000.00	4,307,500.00	29,102.13	4,187.85		41.88
2-Jan-23	3-Jan-23	1	0.00	215,375,000.00	215,375,000.00	4,307,500.00	29,102.13	4,187.85		41.88
3-Jan-23	4-Jan-23	1	0.00	215,375,000.00	215,375,000.00	4,307,500.00	29,102.13	4,187.85		41.88
4-Jan-23	5-Jan-23	1	0.00	215,375,000.00	215,375,000.00	4,307,500.00	29,102.13	4,187.85		41.88
5-Jan-23	6-Jan-23	1	0.00	215,375,000.00	215,375,000.00	4,307,500.00	29,102.13	4,187.85		41.88
6-Jan-23	7-Jan-23	1	0.00	215,375,000.00	215,375,000.00	4,307,500.00	29,102.13	4,187.85		41.88
7-Jan-23	8-Jan-23	1	0.00	215,375,000.00	215,375,000.00	4,307,500.00	29,102.13	4,187.85		41.88
8-Jan-23	9-Jan-23	1	0.00	215,375,000.00	215,375,000.00	4,307,500.00	29,102.13	4,187.85		41.88
9-Jan-23	10-Jan-23	1	0.00	215,375,000.00	215,375,000.00	4,307,500.00	29,102.13	4,187.85		41.88
10-Jan-23	11-Jan-23	1	0.00	215,375,000.00	215,375,000.00	4,307,500.00	29,102.13	4,187.85		41.88
11-Jan-23	12-Jan-23	1	0.00	215,375,000.00	215,375,000.00	4,307,500.00	29,102.13	4,187.85		41.88
12-Jan-23	13-Jan-23	1	0.00	215,375,000.00	215,375,000.00	4,307,500.00	29,102.13	4,187.85		41.88
13-Jan-23	14-Jan-23	1	0.00	215,375,000.00	215,375,000.00	4,307,500.00	29,102.13	4,187.85		41.88
14-Jan-23	15-Jan-23	1	0.00	215,375,000.00	215,375,000.00	4,307,500.00	29,102.13	4,187.85		41.88
15-Jan-23	16-Jan-23	1	0.00	215,375,000.00	215,375,000.00	4,307,500.00	29,102.13	4,187.85		41.88
16-Jan-23	17-Jan-23	1	0.00	215,375,000.00	215,375,000.00	4,307,500.00	29,102.13	4,187.85		41.88
17-Jan-23	18-Jan-23	1	0.00	215,375,000.00	215,375,000.00	4,307,500.00	29,102.13	4,187.85		41.88
18-Jan-23	19-Jan-23	1	0.00	215,375,000.00	215,375,000.00	4,307,500.00	29,102.13	4,187.85		41.88
19-Jan-23	20-Jan-23	1	0.00	215,375,000.00	215,375,000.00	4,307,500.00	29,102.13	4,187.85		41.88
20-Jan-23	21-Jan-23	1	0.00	215,375,000.00	215,375,000.00	4,307,500.00	29,102.13	4,187.85		41.88
21-Jan-23	22-Jan-23	1	0.00	215,375,000.00	215,375,000.00	4,307,500.00	29,102.13	4,187.85		41.88
22-Jan-23	23-Jan-23	1	0.00	215,375,000.00	215,375,000.00	4,307,500.00	29,102.13	4,187.85		41.88
23-Jan-23	24-Jan-23	1	0.00	215,375,000.00	215,375,000.00	4,307,500.00	29,102.13	4,187.85		41.88
24-Jan-23	25-Jan-23	1	0.00	215,375,000.00	215,375,000.00	4,307,500.00	29,102.13	4,187.85		41.88
25-Jan-23	26-Jan-23	1	0.00	215,375,000.00	215,375,000.00	4,307,500.00	29,102.13	4,187.85		41.88
26-Jan-23	27-Jan-23	1	0.00	215,375,000.00	215,375,000.00	4,307,500.00	29,102.13	4,187.85		41.88
27-Jan-23	28-Jan-23	1	0.00	215,375,000.00	215,375,000.00	4,307,500.00	29,102.13	4,187.85		41.88
28-Jan-23	29-Jan-23	1	0.00	215,375,000.00	215,375,000.00	4,307,500.00	29,102.13	4,187.85		41.88
29-Jan-23	30-Jan-23	1	0.00	215,375,000.00	215,375,000.00	4,307,500.00	29,102.13	4,187.85		41.88
30-Jan-23	31-Jan-23	1	0.00	215,375,000.00	215,375,000.00	4,307,500.00	29,102.13	4,187.85		41.88
31-Jan-23	1-Feb-23	1	0.00	215,375,000.00	215,375,000.00	4,307,500.00	29,102.13	4,187.85		41.88
		31					**902,165.97**	**129,823.27**		**1,298.23**

Starbird Funding Corporation
Monthly Invoice for CP Interest & Program Fee Calculation

Borrowing Seller: Cinergy Receivables Company LLC

Interest Period: 1/1/2023 thru 1/31/2023 -----> 31 Days

Settlement Date: February 27, 2023

Total Payment Due: $628,158.83

On February 27, 2023, please wire $628,158.83 to Starbird Funding using the following wire instructions. The following page will provide you details of the CP interest and program fee calculation on a daily basis. If you have any questions, please contact me at the information below.

Wire Instructions -----> [redacted]

[redacted] [redacted]

Attention To -- Cinergy Receivables Company LLC

Primary Contact:

Contact Info:

Secondary Contact:

Contact Info:

Info on Preparer -- Regarding Starbird Funding

Contact Name: Roderick Geoghegan

Contact Phone: (631) 930-7200

Contact E-Mail: starbird@gssnyc.com

Starbird Funding Corporation

Cinergy Receivables Company LLC -- Monthly CP Interest and Program Fee Detail

Period from 1/1/2023 to and including 1/31/2023

Settlement Date: 2/27/2023

Date	Liquidity Limit	Program Limit	Used Investment	Unused Portion	Yield Rate	Used Rate	Unused Rate	Interest Cost	Used Fee	Unused Fee	SubTotal
1/1/2023	137,317,500	134,625,000	134,625,000	0	4.674243%	0.7000%	0.3500%	17,479.72	2,617.71	26.18	20,123.61
1/2/2023	137,317,500	134,625,000	134,625,000	0	4.674243%	0.7000%	0.3500%	17,479.72	2,617.71	26.18	20,123.61
1/3/2023	137,317,500	134,625,000	134,625,000	0	4.675407%	0.7000%	0.3500%	17,484.07	2,617.71	26.18	20,127.96
1/4/2023	137,317,500	134,625,000	134,625,000	0	4.681651%	0.7000%	0.3500%	17,507.42	2,617.71	26.18	20,151.31
1/5/2023	137,317,500	134,625,000	134,625,000	0	4.707589%	0.7000%	0.3500%	17,604.42	2,617.71	26.18	20,248.31
1/6/2023	137,317,500	134,625,000	134,625,000	0	4.724567%	0.7000%	0.3500%	17,667.91	2,617.71	26.18	20,311.80
1/7/2023	137,317,500	134,625,000	134,625,000	0	4.724567%	0.7000%	0.3500%	17,667.91	2,617.71	26.18	20,311.80
1/8/2023	137,317,500	134,625,000	134,625,000	0	4.724567%	0.7000%	0.3500%	17,667.91	2,617.71	26.18	20,311.80
1/9/2023	137,317,500	134,625,000	134,625,000	0	4.723364%	0.7000%	0.3500%	17,663.41	2,617.71	26.18	20,307.30
1/10/2023	137,317,500	134,625,000	134,625,000	0	4.723140%	0.7000%	0.3500%	17,662.58	2,617.71	26.18	20,306.46
1/11/2023	137,317,500	134,625,000	134,625,000	0	4.724045%	0.7000%	0.3500%	17,665.96	2,617.71	26.18	20,309.85
1/12/2023	137,317,500	134,625,000	134,625,000	0	4.717243%	0.7000%	0.3500%	17,640.53	2,617.71	26.18	20,284.41
1/13/2023	137,317,500	134,625,000	134,625,000	0	4.719501%	0.7000%	0.3500%	17,648.97	2,617.71	26.18	20,292.85
1/14/2023	137,317,500	134,625,000	134,625,000	0	4.719501%	0.7000%	0.3500%	17,648.97	2,617.71	26.18	20,292.85
1/15/2023	137,317,500	134,625,000	134,625,000	0	4.719501%	0.7000%	0.3500%	17,648.97	2,617.71	26.18	20,292.85
1/16/2023	137,317,500	134,625,000	134,625,000	0	4.719501%	0.7000%	0.3500%	17,648.97	2,617.71	26.18	20,292.85
1/17/2023	137,317,500	134,625,000	134,625,000	0	4.721167%	0.7000%	0.3500%	17,655.20	2,617.71	26.18	20,299.08
1/18/2023	137,317,500	134,625,000	134,625,000	0	4.725227%	0.7000%	0.3500%	17,670.38	2,617.71	26.18	20,314.26
1/19/2023	137,317,500	134,625,000	134,625,000	0	4.714350%	0.7000%	0.3500%	17,629.70	2,617.71	26.18	20,273.59
1/20/2023	137,317,500	134,625,000	134,625,000	0	4.717075%	0.7000%	0.3500%	17,639.90	2,617.71	26.18	20,283.78
1/21/2023	137,317,500	134,625,000	134,625,000	0	4.717075%	0.7000%	0.3500%	17,639.90	2,617.71	26.18	20,283.78
1/22/2023	137,317,500	134,625,000	134,625,000	0	4.717075%	0.7000%	0.3500%	17,639.90	2,617.71	26.18	20,283.78
1/23/2023	137,317,500	134,625,000	134,625,000	0	4.712142%	0.7000%	0.3500%	17,621.45	2,617.71	26.18	20,265.33
1/24/2023	137,317,500	134,625,000	134,625,000	0	4.711479%	0.7000%	0.3500%	17,618.97	2,617.71	26.18	20,262.85

Starbird Funding Corporation

Cinergy Receivables Company LLC -- Monthly CP Interest and Program Fee Detail

Period from 1/1/2023 to and including 1/31/2023

Settlement Date: 2/27/2023

Date	Liquidity Limit	Program Limit	Used Investment	Unused Portion	Yield Rate	Used Rate	Unused Rate	Interest Cost	Used Fee	Unused Fee	SubTotal
1/25/2023	137,317,500	134,625,000	134,625,000	0	4.710726%	0.7000%	0.3500%	17,616.15	2,617.71	26.18	20,260.04
1/26/2023	137,317,500	134,625,000	134,625,000	0	4.714346%	0.7000%	0.3500%	17,629.69	2,617.71	26.18	20,273.57
1/27/2023	137,317,500	134,625,000	134,625,000	0	4.708967%	0.7000%	0.3500%	17,609.57	2,617.71	26.18	20,253.46
1/28/2023	137,317,500	134,625,000	134,625,000	0	4.708967%	0.7000%	0.3500%	17,609.57	2,617.71	26.18	20,253.46
1/29/2023	137,317,500	134,625,000	134,625,000	0	4.708967%	0.7000%	0.3500%	17,609.57	2,617.71	26.18	20,253.46
1/30/2023	137,317,500	134,625,000	134,625,000	0	4.708465%	0.7000%	0.3500%	17,607.70	2,617.71	26.18	20,251.58
1/31/2023	137,317,500	134,625,000	134,625,000	0	4.709961%	0.7000%	0.3500%	17,613.29	2,617.71	26.18	20,257.18
31 days							***SubTotal:***	**546,198.38**	**81,148.96**	**811.49**	**628,158.83**

W/A CP rate = 4.711568% **Avg Investment = 134,625,000.01**

Corporate Business Account Statement

PNC BANK

Account Number: [redacted]7469

For the period 03/01/2023 to 03/31/2023

CINERGY CORP
CINERGY RECEIVABLES COMPANY LLC
139 E 4TH ST
CINCINNATI OH 45202-4003

Number of enclosures: 0
Tax ID Number: 31-1385023
For Client Services:
Call 1-800-669-1518

Visit us at PNC.com/treasury

Write to: Treas Mgmt Client Care
One Financial Parkway
Locator Z1-Yb42-03-1
Kalamazoo MI 49009

Account Summary Information

Balance Summary

Beginning balance	Deposits and other credits	Checks and other debits	Ending balance
.01	1,542,764.50	1,542,764.50	.01

IMPORTANT ACCOUNT INFORMATION

The information below amends certain information in our Funds Availability for Business Accounts (Agreements). All other information in our Agreements continues to apply to your account. Please read this information and retain it with your records.

Effective April 15, 2023, all cash deposits made at non-PNC Bank ATMs equipped with currency validation technology will be available the same business day as the day of their deposit if received prior to our cut-off time of 10:00pm ET.

As a reminder, deposits received after our cut-off time of 10:00 p.m. ET, or on a day that is not a business day, may be available for immediate withdrawal; however, we will consider the deposit as being received on the next business day to pay checks and other items that are presented to us that evening for posting.

Deposits and Other Credits

Description	Items	Amount
Deposits	0	.00
National Lockbox	0	.00
ACH Credits	0	.00
Funds Transfers In	4	1,542,764.50
Trade Services	0	.00
Investments	0	.00
Zero Balance Transfers	0	.00
Adjustments	0	.00
Other Credits	0	.00
Total	4	1,542,764.50

Checks and Other Debits

Description	Items	Amount
Checks	0	.00
Returned Items	0	.00
ACH Debits	0	.00
Funds Transfers Out	3	1,542,764.50
Trade Services	0	.00
Investments	0	.00
Zero Balance Transfers	0	.00
Adjustments	0	.00
Other Debits	0	.00
Total	3	1,542,764.50

Ledger Balance

Date	Ledger balance	Date	Ledger balance	Date	Ledger balance
03/01	.01	03/27	587,529.57	03/28	.01

Corporate Business Account Statement

CINERGY CORP
CINERGY RECEIVABLES COMPANY LLC

For the period 03/01/2023 to 03/31/2023
Account number: [redacted]7469

Duke Energy Ohio pro rata share of interest payment

Duke Energy Indiana pro rata share of interest payment

Duke Energy Kentucky pro rata share of interest

Deposits and Other Credits

Funds Transfer In — **4 transactions for a total of $1,542,764.50**

Date posted	Amount	Transaction description	Reference number
03/27	574,380.14	Book Trn Credit 233Rc0108Ek70Cbr	W233RC0108EK70CBR
03/27	827,561.05	Book Trn Credit 233Rc0108Ew70CC1	W233RC0108EW70CC1
03/27	139,060.68	Book Trn Credit 233Rc0108Eb70Cbe	W233RC0108EB70CBE
03/27	1,762.63	Book Trn Credit 233Rc0108Ek70Cbl	W233RC0108EK70CBL

Checks and Other Debits

Funds Transfers Out — **3 transactions for a total of $1,542,764.50**

Date posted	Amount	Transaction description	Reference number
03/27	1,762.63	Book Trn Debit 233Rc0108E170Cba	W233RC0108E170CBA
03/27	953,472.31	Wire Transfer Out 233Re5017G262Poz	W233RE5017G262POZ
03/28	587,529.56	Wire Transfer Out 233Sc01198Z72V7T	W233SC01198Z72V7T

Interest payment to BNP Paribas / Starbird Funding Corporation - see

Interest payment to Scotia Bank / Liberty Street Funding - see attached statement

Liberty Street Funding LLC
Settlement Period Calculation Report

Seller:	**CINERGY RECEIVABLES COMPANY LLC**

To		
Name	Bank / Seller	E-mail
Beverly Bockrath	Duke Energy	beverly.bockrath@duke-energy.com
Brad Evans		brad.evans@duke-energy.com
Cindy Rummel		cynthia.rummel@duke-energy.com
Stacey Snyder		stacey.snyder@duke-energy.com
Tom Heath		Tom.Heath@duke-energy.com

From		
Name	Bank	E-mail
Kelson Yang	Scotiabank	kelson.yang@scotiabank.com
Pia Manalac	Scotiabank	pia.manalac@scotiabank.com

Date:	**March 1, 2023**

BILLING PARAMETER

Collection Start Date	1-Feb-23
Collection End Date	1-Mar-23
Days	28

AMOUNT DUE

Interest / Yield Due	835,039.99
Program Fee Due	117,259.72
Unused Fee Due	1,172.60
DUE	**USD 953,472.31**
Payment Date	**27-Mar-23**

COMMITMENT

Effective Date	Max Program Amt	Program Name
28-Feb-22	219,682,500.00	LSF ABCP

PRICING

Cost of Funds 4.98490%

	Effective Date	Utilization From	Utilization To	Fee Percentage
Cinergy Receivables - Program Fee	28-Feb-22			0.70000%
Cinergy Receivables - Standby Fee	28-Feb-22			0.35000%

Please remit funds on Settlement Date to:

[redacted]

Liberty Street Funding LLC
Settlement Period Calculation Report

MONTHLY ACTIVITY

			Program: LSF ABCP							
From	To	# of days	(+) Increase / (-) Decrease in Capital	Outstanding Amount	Program Amount	Unused Commitment	Interest 4.98490%	Program Fee 0.70000%	Commitment Fee	Unused Fee 0.35000%
1-Feb-23	2-Feb-23	1	0.00	215,375,000.00	215,375,000.00	4,307,500.00	29,822.86	4,187.85		41.88
2-Feb-23	3-Feb-23	1	0.00	215,375,000.00	215,375,000.00	4,307,500.00	29,822.86	4,187.85		41.88
3-Feb-23	4-Feb-23	1	0.00	215,375,000.00	215,375,000.00	4,307,500.00	29,822.86	4,187.85		41.88
4-Feb-23	5-Feb-23	1	0.00	215,375,000.00	215,375,000.00	4,307,500.00	29,822.86	4,187.85		41.88
5-Feb-23	6-Feb-23	1	0.00	215,375,000.00	215,375,000.00	4,307,500.00	29,822.86	4,187.85		41.88
6-Feb-23	7-Feb-23	1	0.00	215,375,000.00	215,375,000.00	4,307,500.00	29,822.86	4,187.85		41.88
7-Feb-23	8-Feb-23	1	0.00	215,375,000.00	215,375,000.00	4,307,500.00	29,822.86	4,187.85		41.88
8-Feb-23	9-Feb-23	1	0.00	215,375,000.00	215,375,000.00	4,307,500.00	29,822.86	4,187.85		41.88
9-Feb-23	10-Feb-23	1	0.00	215,375,000.00	215,375,000.00	4,307,500.00	29,822.86	4,187.85		41.88
10-Feb-23	11-Feb-23	1	0.00	215,375,000.00	215,375,000.00	4,307,500.00	29,822.86	4,187.85		41.88
11-Feb-23	12-Feb-23	1	0.00	215,375,000.00	215,375,000.00	4,307,500.00	29,822.86	4,187.85		41.88
12-Feb-23	13-Feb-23	1	0.00	215,375,000.00	215,375,000.00	4,307,500.00	29,822.86	4,187.85		41.88
13-Feb-23	14-Feb-23	1	0.00	215,375,000.00	215,375,000.00	4,307,500.00	29,822.86	4,187.85		41.88
14-Feb-23	15-Feb-23	1	0.00	215,375,000.00	215,375,000.00	4,307,500.00	29,822.86	4,187.85		41.88
15-Feb-23	16-Feb-23	1	0.00	215,375,000.00	215,375,000.00	4,307,500.00	29,822.86	4,187.85		41.88
16-Feb-23	17-Feb-23	1	0.00	215,375,000.00	215,375,000.00	4,307,500.00	29,822.86	4,187.85		41.88
17-Feb-23	18-Feb-23	1	0.00	215,375,000.00	215,375,000.00	4,307,500.00	29,822.86	4,187.85		41.88
18-Feb-23	19-Feb-23	1	0.00	215,375,000.00	215,375,000.00	4,307,500.00	29,822.86	4,187.85		41.88
19-Feb-23	20-Feb-23	1	0.00	215,375,000.00	215,375,000.00	4,307,500.00	29,822.86	4,187.85		41.88
20-Feb-23	21-Feb-23	1	0.00	215,375,000.00	215,375,000.00	4,307,500.00	29,822.86	4,187.85		41.88
21-Feb-23	22-Feb-23	1	0.00	215,375,000.00	215,375,000.00	4,307,500.00	29,822.86	4,187.85		41.88
22-Feb-23	23-Feb-23	1	0.00	215,375,000.00	215,375,000.00	4,307,500.00	29,822.86	4,187.85		41.88
23-Feb-23	24-Feb-23	1	0.00	215,375,000.00	215,375,000.00	4,307,500.00	29,822.86	4,187.85		41.88
24-Feb-23	25-Feb-23	1	0.00	215,375,000.00	215,375,000.00	4,307,500.00	29,822.86	4,187.85		41.88
25-Feb-23	26-Feb-23	1	0.00	215,375,000.00	215,375,000.00	4,307,500.00	29,822.86	4,187.85		41.88
26-Feb-23	27-Feb-23	1	0.00	215,375,000.00	215,375,000.00	4,307,500.00	29,822.86	4,187.85		41.88
27-Feb-23	28-Feb-23	1	0.00	215,375,000.00	215,375,000.00	4,307,500.00	29,822.86	4,187.85		41.88
28-Feb-23	1-Mar-23	1	0.00	215,375,000.00	215,375,000.00	4,307,500.00	29,822.86	4,187.85		41.88
		28					**835,039.98**	**117,259.72**		**1,172.60**

Scotiabank™

Starbird Funding Corporation
Monthly Invoice for CP Interest & Program Fee Calculation

Borrowing Seller:	Cinergy Receivables Company LLC
Interest Period:	2/1/2023 thru 2/28/2023 -----> 28 Days
Settlement Date:	March 28, 2023
Total Payment Due:	$587,529.56

On March 28, 2023, please wire $587,529.56 to Starbird Funding using the following wire instructions. The following page will provide you details of the CP interest and program fee calculation on a daily basis. If you have any questions, please contact me at the information below.

Wire Instructions -----> [redacted]

Attention To -- Cinergy Receivables Company LLC

Primary Contact:

Contact Info:

Secondary Contact:

Contact Info:

Info on Preparer -- Regarding Starbird Funding

Contact Name: *Roderick Geoghegan*

Contact Phone: *(631) 930-7200*

Contact E-Mail: *starbird@gssnyc.com*

Starbird Funding Corporation

Cinergy Receivables Company LLC -- Monthly CP Interest and Program Fee Detail

Period from 2/1/2023 to and including 2/28/2023

Settlement Date: 3/28/2023

Date	Liquidity Limit	Program Limit	Used Investment	Unused Portion	Yield Rate	Used Rate	Unused Rate	Interest Cost	Used Fee	Unused Fee	SubTotal
2/1/2023	137,317,500	134,625,000	134,625,000	0	4.715664%	0.7000%	0.3500%	17,634.62	2,617.71	26.18	20,278.50
2/2/2023	137,317,500	134,625,000	134,625,000	0	4.742066%	0.7000%	0.3500%	17,733.35	2,617.71	26.18	20,377.24
2/3/2023	137,317,500	134,625,000	134,625,000	0	4.890389%	0.7000%	0.3500%	18,288.02	2,617.71	26.18	20,931.90
2/4/2023	137,317,500	134,625,000	134,625,000	0	4.890389%	0.7000%	0.3500%	18,288.02	2,617.71	26.18	20,931.90
2/5/2023	137,317,500	134,625,000	134,625,000	0	4.890389%	0.7000%	0.3500%	18,288.02	2,617.71	26.18	20,931.90
2/6/2023	137,317,500	134,625,000	134,625,000	0	4.892314%	0.7000%	0.3500%	18,295.21	2,617.71	26.18	20,939.10
2/7/2023	137,317,500	134,625,000	134,625,000	0	4.889529%	0.7000%	0.3500%	18,284.80	2,617.71	26.18	20,928.69
2/8/2023	137,317,500	134,625,000	134,625,000	0	4.890381%	0.7000%	0.3500%	18,287.99	2,617.71	26.18	20,931.87
2/9/2023	137,317,500	134,625,000	134,625,000	0	4.895778%	0.7000%	0.3500%	18,308.17	2,617.71	26.18	20,952.05
2/10/2023	137,317,500	134,625,000	134,625,000	0	4.899789%	0.7000%	0.3500%	18,323.17	2,617.71	26.18	20,967.05
2/11/2023	137,317,500	134,625,000	134,625,000	0	4.899789%	0.7000%	0.3500%	18,323.17	2,617.71	26.18	20,967.05
2/12/2023	137,317,500	134,625,000	134,625,000	0	4.899789%	0.7000%	0.3500%	18,323.17	2,617.71	26.18	20,967.05
2/13/2023	137,317,500	134,625,000	134,625,000	0	4.900678%	0.7000%	0.3500%	18,326.49	2,617.71	26.18	20,970.38
2/14/2023	137,317,500	134,625,000	134,625,000	0	4.895066%	0.7000%	0.3500%	18,305.51	2,617.71	26.18	20,949.39
2/15/2023	137,317,500	134,625,000	134,625,000	0	4.897437%	0.7000%	0.3500%	18,314.37	2,617.71	26.18	20,958.26
2/16/2023	137,317,500	134,625,000	134,625,000	0	4.893397%	0.7000%	0.3500%	18,299.27	2,617.71	26.18	20,943.15
2/17/2023	137,317,500	134,625,000	134,625,000	0	4.897162%	0.7000%	0.3500%	18,313.35	2,617.71	26.18	20,957.23
2/18/2023	137,317,500	134,625,000	134,625,000	0	4.897162%	0.7000%	0.3500%	18,313.35	2,617.71	26.18	20,957.23
2/19/2023	137,317,500	134,625,000	134,625,000	0	4.897162%	0.7000%	0.3500%	18,313.35	2,617.71	26.18	20,957.23
2/20/2023	137,317,500	134,625,000	134,625,000	0	4.897162%	0.7000%	0.3500%	18,313.35	2,617.71	26.18	20,957.23
2/21/2023	137,317,500	134,625,000	134,625,000	0	4.929111%	0.7000%	0.3500%	18,432.82	2,617.71	26.18	21,076.71
2/22/2023	137,317,500	134,625,000	134,625,000	0	4.951425%	0.7000%	0.3500%	18,516.27	2,617.71	26.18	21,160.15
2/23/2023	137,317,500	134,625,000	134,625,000	0	4.974229%	0.7000%	0.3500%	18,601.54	2,617.71	26.18	21,245.43
2/24/2023	137,317,500	134,625,000	134,625,000	0	4.975919%	0.7000%	0.3500%	18,607.86	2,617.71	26.18	21,251.75

Starbird Funding Corporation

Cinergy Receivables Company LLC -- Monthly CP Interest and Program Fee Detail

Period from 2/1/2023 to and including 2/28/2023

Settlement Date: 3/28/2023

Date	Liquidity Limit	Program Limit	Used Investment	Unused Portion	Yield Rate	Used Rate	Unused Rate	Interest Cost	Used Fee	Unused Fee	SubTotal
2/25/2023	137,317,500	134,625,000	134,625,000	0	4.975919%	0.7000%	0.3500%	18,607.86	2,617.71	26.18	21,251.75
2/26/2023	137,317,500	134,625,000	134,625,000	0	4.975919%	0.7000%	0.3500%	18,607.86	2,617.71	26.18	21,251.75
2/27/2023	137,317,500	134,625,000	134,625,000	0	4.975526%	0.7000%	0.3500%	18,606.39	2,617.71	26.18	21,250.28
2/28/2023	137,317,500	134,625,000	134,625,000	0	4.985429%	0.7000%	0.3500%	18,643.43	2,617.71	26.18	21,287.31
28 days							***SubTotal:***	**513,500.77**	**73,295.83**	**732.96**	**587,529.56**

W/A CP rate = 4.904106% **Avg Investment = 134,625,000.01**

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 New Tariffs; 3) Approval of Accounting Practices to Establish Regulatory Assets and Liabilities; and 4) All Other Required Approvals and Relief.	)))))))	Case No. 2022-00372

REBUTTAL TESTIMONY OF

WILLIAM LUKE

ON BEHALF OF

DUKE ENERGY KENTUCKY, INC.

April 14, 2023

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I. INTRODUCTION AND PURPOSE

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is William Luke and my business address is 1000 East Main Street, Plainfield, IN 46168.

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

A. I am Vice President Midwest Generation for Duke Energy Business Services, LLC (DEBS). DEBS is a service company subsidiary of Duke Energy Corporation (Duke Energy), which provides services to Duke Energy and its subsidiaries, including Duke Energy Kentucky, Inc. (Duke Energy Kentucky or the Company).

Q. ARE YOU THE SAME WILLIAM LUKE THAT SUBMITTED DIRECT TESTIMONY IN THIS PROCEEDING?

A. Yes.

Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY?

A. My rebuttal testimony addresses the remaining operational life of East Bend Unit 2, and claims and recommendations made by Mr. Lane Kollen on behalf of the Kentucky Attorney General and Ms. Sarah Shenstone Harris on behalf of the Sierra Club as it relates to the operation of the Company's fossil-fired generation fleet, including the anticipated retirements of those units and the Company's recovery of outage expenses.

II. DISCUSSION

A. REMAINING OPERATIONAL LIFE OF EAST BEND

Q. PLEASE EXPLAIN THE REMAINING OPERATIONAL LIFE OF EAST BEND UNIT 2 AS IT RELATES TO THE INTERVENOR TESTIMONY POSITIONS OF SARAH SHENSTONE-HARRIS AND LANE KOLLEN.

A. Two intervenors, the Sierra Club, through its witness, Ms. Sarah Shenstone-Harris, and the Kentucky Attorney General's Office, through its witness, Mr. Lane Kollen, have vastly differing opinions concerning the remaining operational life of East Bend Unit 2. Ms. Shenstone-Harris claims that East Bend's costs outweigh its benefits in future years and that the Company's projected retirement date of 2035 is too far in the future. Conversely, Mr. Kollen claims that the Company has not definitively set 2035 as the retirement date for East Bend, and 2041 should remain the projected retirement date of the unit until a CPCN is filed with the Commission for replacement generation. I will discuss the operating realities of maintaining a vintage generation asset and why continued reliability is paramount to support customers.

Q. PLEASE BRIEFLY PROVIDE AN OVERVIEW OF EAST BEND'S HISTORY AND OPERATION.

A. East Bend 2 was placed into service in 1981, and since being acquired by Duke Energy Kentucky in 2006, has been providing 600 MegaWatt (MWs) of generation for Duke Energy Kentucky's customers. The 42-year-old station has reliably served the Commonwealth through the years as a direct result of the Company making necessary and effective capital and O&M investments to maintain the unit. These investments over the years have primarily been completed during planned outage periods. The significant investments made in the past, such as turbine blade replacement and boiler component replacement, will be the same types of maintenance that will need to continue from 2023 through the planned retirement of East Bend in 2035.

As explained by Company witness Mr. Scott Park, based upon current modeling, and the recent legislative changes in Kentucky, the Company believes that retiring East Bend 2 before 2030 would be challenging from an execution standpoint. And as we sit today, it would not be in the best interest of customers from a long-term cost perspective due to the remaining undepreciated book value of the East Bend 2 asset.

Likewise, 2041 is no longer a reasonable retirement date assumption for East Bend. The Company is obligated to weigh the cost of continued reliability maintenance versus the cost to customers. East Bend would be a 60-year-old asset in 2041, requiring increasing major maintenance and operating costs to remain operational and dispatchable as a result of aging equipment and infrastructure.

As Mr. Park supports, the Company's recommended end of life for East Bend 2 in 2035 is based upon more rigorous and comprehensive analysis, and consideration of multiple factors to produce a most-likely outcome. Mr. Park's rebuttal testimony addresses this analysis in more detail.

Q. WHAT ABOUT WOODSDALE'S ANTICIPATED LIFE THAT IS NOW PROJECTED TO EXTEND TO 2040? PLEASE EXPLAIN WHY THAT IS REASONABLE IN LIGHT OF EAST BEND NOW BEING PROJECTED TO LIKELY RETIRE BY 2035.

A. Supporting a Woodsdale retirement date in 2040, especially when one factors the projected East Bend 2 2035 retirement date, is reasonable. Woodsdale is a six-unit, peaking combustion turbine (CT) site, whose first unit was placed into service in 1992. And although a CT like Woodsdale requires major maintenance, it doesn't have the same aging infrastructure costs associated with a large coal asset like East Bend 2. This is due to the fact that the units operate as peaking, are designed for intermittent operation with fast start and quick ramp-up capability. The number of hours of operation are far less than with a base-load generator like East Bend. Therefore, extending Woodsdale to 2040 is operationally feasible. In contrast, the likelihood of East Bend 2 lasting beyond 2035 and to 2041 is becoming increasingly unlikely given the age of the unit, its economics, increasing costs to operate and challenges in the coal market. Planning for the intermittent retirement dates of the two stations reduces the risks to customers of retiring both stations in a close period of time, as would be the case if Mr. Kollen's position carries the day, whereby Woodsdale would retire in 2040, and East Bend in 2041.

Based on my 30 years of power generation experience and my current experience overseeing the safe and reliable operation of 7,400 MWs of fossil-fired generation on behalf of Duke Energy's family of utilities, and in consideration of recent and projected planned major maintenance at East Bend 2, the age of the asset, and a concern for balancing the availability of customer benefits from the asset with its costs of maintenance and opportunity for the Company to recover its prudently incurred costs, not to mention Mr. Park's analysis, I believe that 2035 is a reasonable retirement date for East Bend from an operational standpoint.

B. PLANNED OUTAGE EXPENSE

Q. PLEASE SUMMARIZE MR. KOLLEN'S RECOMMENDATIONS REGARDING THE COMPANY'S PLANNED OUTAGE EXPENSE DEFERRALS.

A. Mr. Kollen recommends that the Commission deny, without prejudice, the Company's request to amortize and recover the planned maintenance outage expense regulatory asset in this proceeding. Mr. Kollen alleges that the Company did not provide justification for the costs in excess of the amounts included in base revenues for these expenses and should not be permitted to do so now.

Q. DO YOU AGREE WITH MR. KOLLEN'S CLAIMS THAT THE COMPANY DID NOT JUSTIFY ITS PLANNED OUTAGE COSTS INCLUDED IN THE PLANNED OUTAGE REGULATORY ASSET ?

A. No. In my direct testimony, I described the significant outages that occurred at East Bend since the Company's last base rate case. Specifically, on pages 5 through 6, I described how in the spring of 2021, the Company performed an 8-week outage at East Bend to perform significant maintenance to the station's turbine, generator, boiler, and Flue Gas Desulfurization System (FGD) (collectively, the East Bend 2021 Outage). The major scope of work associated with the East Bend 2021 Outage included a complete rewind of the Generator Stator, significant maintenance of boiler fuel, steam, and water components, main low-pressure turbine blade evaluation, and FGD absorber module inlet nozzle refurbishment.

Additionally, I also described how, in the fall of 2022, the Company conducted a 5-week outage at East Bend to perform significant maintenance to the station's boiler, FGD and coal handling equipment (East Bend 2022 Fall Outage). The major scope of work associated with the East Bend 2022 Fall Outage includes a complete replacement of secondary air heater baskets, a pulverizer overhaul, a primary air fan bearing upgrade, FGD module cleaning and maintenance of the coal barge unloader. This scope of work is part of the investment strategy to sustain reliability and long-term operation.

I also explained how the Company has made other capital investments as necessary, in addition to the aforementioned outages to ensure the reliability of the plant. Since the time of the Company's last rate case, investments have been made for a precipitator rebuild, construction of a lime injection system, a generator stator rewind, SCR catalyst replacements and a superheater outlet header replacement. All of the capital additions to East Bend including those listed above, are necessary to comply with environmental permit obligations and ensure the reliability of the station, and are typical of a coal-fired unit of the age and design of East Bend.

In addition, in discovery request AG-01-100 (c) (f), I supported a listing of all outages performed including their descriptions.

Q. DID THE COMPANY PROVIDE ANY COST DATA TO SUPPORT THESE INVESTMENTS?

A. Yes. The Company provided monthly outage expense data by unit for 2018 through 2021 in discovery request AG DR 01-100b Attachment 2.

Q. PLEASE EXPLAIN HOW THE OUTAGES WERE NECESSARY TO PERFORM THE WORK ON THE PROJECTS YOU DESCRIBED IN YOUR DIRECT TESTIMONY.

A. To ensure reliability of the units our customers depend upon to provide energy, these units must be taken out of service occasionally (*i.e.*, go into an outage) to perform inspections and repairs on the equipment. Scheduled maintenance intervals are based on industry standards, inspections, operating experience and Original Equipment Manufacturer guidance.

Q. PLEASE EXPLAIN THE STEPS THE COMPANY TOOK TO REDUCE THE OUTAGE TIME FOR THESE INVESTMENTS.

A. Outages are planned and optimized in accordance with Duke Energy's outage guidelines, procedures, and experience. Critical path activities and near-critical path activities are tracked to ensure the most efficient completion of all work. Also, planned outages are scheduled in calendar months when electricity demand is typically lower than other months, in the spring and the fall.

Q. WERE THESE OUTAGES AND THE CORRESPONDING CAPITAL AND O&M EXPENSES NECESSARY TO CONTINUE THE SAFE AND RELIABLE OPERATION OF THE COMPANY'S GENERATING UNITS?

A. Yes.

Q. WHAT WOULD HAPPEN IF THE COMPANY FAILED TO MAKE THESE NECESSARY INVESTMENTS AND PERFORM THE NEEDED MAINTENANCE?

A. If the Company failed to make these necessary investments and perform the necessary and recommended maintenance, the unit performance metrics would be impacted with an increase in forced outage rates and lower generation reliability factors, making the unit unavailable for the generation of electricity for our customers. PJM Interconnection LLC (PJM)planning is also affected, and the Company could be assessed performance penalties due to forced outages during a declared capacity performance event. Also, forced outages tend to cost more than planned outages because forced outages occur when the unit is running, causing substitute power requirements. Moreover, absent proper planning, performing routine and recommended maintenance and making necessary capital investments and replacement, the risk of forced outages increases, and the likelihood of more significant damage occurs. Forced outages likely increase overall repair costs as compared to performing the maintenance on a planned, more efficient manner.

In addition, the execution of these outages also prepares the unit for reliable performance during extraordinary events such as the cold weather event over Winter Storm Elliott in December 2022. By keeping this unit in reliable condition, as Company witness John Swez explains, Duke Energy Kentucky was able to run when power was critically needed. Mr. Swez discusses in his rebuttal testimony the typical financial benefits of scheduling a maintenance outage versus a forced outage which could occur if these investments were not made.

Q. DID THE ATTORNEY GENERAL HAVE AN OPPORTUNITY TO ASK QUESTIONS ABOUT ANY OF THOSE INVESTMENTS IN THIS PROCEEDING?

A. Yes. They did, and as I previously mentioned, the Company provided responses.

Q. WHAT IS YOUR RECOMMENDATION REGARDING MR. KOLLEN'S CLAIMS?

A. I believe the Commission should find that Mr. Kollen's position is unsupported and that the Company has adequately demonstrated the reasonableness of its planned outage expenses that were deferred and permit the recovery as the Company has requested. The purpose of the planned outage O&M regulatory deferral is to manage costs that deviate from the annual planned outage allowance that is "baked into" base rates. In Mr. Kollen's testimony, he agrees that "The Company's actual planned outage maintenance expense varies from year due to the scope and frequency of the actual outage activities." Contrary to Mr. Kollen's assumption, this deferral balance will not necessarily zero out over a five-year period, and hypothetically not over periods longer than five years. The deferral balance is largely dependent upon the type of planned outage work necessary to keep the unit reliable for our customers. These outage costs are continuing to rise due to supply chain constraints, and particularly for an asset the age of East Bend, where replacement components and qualified skilled labor who can work on this type of an asset are becoming ever scarcer.

III. CONCLUSION

Q. DOES THIS CONCLUDE YOUR REBUTTAL TESTIMONY?

A. Yes.

VERIFICATION

STATE OF INDIANA)
) **SS:**
COUNTY OF HENDRICKS)

The undersigned, William C. Luke, VP Midwest Generation, being duly sworn, deposes and says that he has personal knowledge of the matters set forth in the rebuttal foregoing testimony, and that it is true and correct to the best of his knowledge, information and belief.

William C. Luke, Affiant

Subscribed and sworn to before me by William C. Luke on this 30 day of March, 2023.

Treva K. Roussey
NOTARY PUBLIC

My Commission Expires: 10/2025

TREVA KAI ROUSSEY SEAL