COMMONWEALTH OF KENTUCKY
BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

ELECTRONIC APPLICATION OF DUKE ENERGY	)	
KENTUCKY, INC. FOR: 1) AN ADJUSTMENT OF	)	
THE ELECTRIC RATES; 2) APPROVAL OF AN	)	
ENVIRONMENTAL COMPLIANCE PLAN AND	)	
SURCHARGE MECHANISM; 3) APPROVAL OF	)	**CASE NO. 2017-00321**
NEW TARIFFS; 4) APPROVAL OF ACCOUNTING	)	
PRACTICES TO ESTABLISH REGULATORY	)	
ASSETS AND LIABILITIES; AND 5) ALL OTHER	)	
REQUIRED APPROVALS AND RELIEF	)	

DIRECT TESTIMONY OF BRIAN C. COLLINS
ON BEHALF OF
NORTHERN KENTUCKY UNIVERSITY

Filed: December 29, 2017

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Q. Please state your name and business address.

A. Brian C. Collins. My business address is 16690 Swingley Ridge Road, Suite 140, Chesterfield, MO 63017.

Q. What is your occupation?

A. I am a consultant in the field of public utility regulation and a Principal of Brubaker & Associates, Inc. ("BAI"), energy, economic and regulatory consultants.

Q. Please describe your educational background and experience.

A. This information is included in Appendix A to this testimony.

Q. On whose behalf are you appearing in this proceeding?

A. I am testifying on behalf of Northern Kentucky University ("NKU"). NKU purchases a substantial amount of electricity from Duke Energy Kentucky, Inc. ("DEK" or "Company").

Q. What is the subject matter of your testimony?

A. I will comment on the Company's proposed class cost of service studies ("CCOSS") as well as its proposed class revenue allocation. I will also respond to the Company's request for the approval of both its proposed Distribution Capital Investment Rider ("Rider DCI") and its proposed Federal Energy Regulatory Commission ("FERC") Transmission Cost Reconciliation Rider ("Rider FTR").

My silence on any issue addressed by the Company in its testimony should not be taken as tacit approval or agreement with that issue.

Q. What are your findings and recommendations?

A. My findings and recommendations are as follows:

1. I do not object to the Company's recommended CCOSS that allocates production related costs using the Average of the Twelve Coincident Peaks ("12 CP") and allocates certain distribution costs partially on a customer basis to the Company's rate classes in this proceeding.

2. I do not object to the Company's proposed class revenue allocation in this proceeding because it recognizes the principle of gradualism.

3. I recommend that the Company's proposed Rider DCI and Rider FTR be rejected because the Company has not demonstrated a compelling need for these riders.

<u>Company's Proposed CCOSS</u>

Q. Did the Company prepare a CCOSS in order to allocate its proposed revenue requirement to its rate classes?

A. Yes. According to the testimony presented by Company witness James E. Ziolkowski, the Company prepared three CCOSS for its test year consisting of the 12 months ending March 31, 2019. The three studies prepared by the Company differ by the methodology used to develop the allocation factor for the demand component of production related costs. The three methods used by the Company for allocating production related costs to classes include: (1) the 12 CP method; (2) the Average and Excess ("A&E") method; and (3) the Summer/Non-Summer ("S/NS") method.

For this proceeding, the Company recommends the use of the 12 CP cost of service methodology for allocating costs to its rate classes. This is the methodology used by the Company in its last rate case and is an accepted methodology in the electric utility industry.

Q. Have you reviewed the Company's proposed CCOSS in the context of developing your findings and recommendations?

A. Yes, I have.

Q. How does the Company's 12 CP cost allocation methodology allocate demand related costs to customer classes?

A. Each respective customer class's cost responsibility for production related costs is equal to the ratio of its respective demand in relation to the total demand placed on the Company's system. The 12 CP cost allocation methodology used by the Company allocates production and transmission demand-related costs to classes based upon the 12 monthly coincident peaks.

Q. Could an argument be made for the use of a 4 CP cost allocation methodology to allocate demand related costs to customer classes?

A. Yes. Based on my review of the Company's 12 monthly system peaks, an argument could be made to allocate costs on the four highest peaks of the Company which occur in the summer months. However, this would not capture any demands of the electric heating class because this class has approximately zero demand in the summer. The Company's use of a 12 CP methodology captures the non-summer demands of the electric heating class when allocating demand related costs to the Company's rate classes.

Q. Did the Company allocate a portion of certain distribution related costs on a customer basis to classes in its recommended CCOSS?

A. Yes. The costs of distribution poles, conductors, and transformers were allocated between customer and demand using the minimum size method. It is appropriate to allocate these costs partially on a demand basis because this equipment is sized to meet the maximum demand on the Company's system. It is also appropriate to allocate these costs partially on a customer basis because the utility also incurs the costs of this equipment to connect customers to its distribution system that are geographically dispersed through its service area. Allocating these costs on both a demand and customer basis appropriately reflects class cost of service and the principles of cost causation.

Q. How did the Company determine the customer component of distribution poles, conductors, and transformer costs?

A. The Company used the minimum size method to allocate these costs between customer and demand related cost components. The minimum size method assumes that a minimum size distribution system can be built to serve the minimum load requirements of the Company's customers.

Q. Is the Company's proposal for the allocation of poles, conductors and transformer costs to its rate classes partially on a customer basis reasonable?

A. Yes. Classifying and allocating these costs on both a demand and customer basis is consistent with cost causation and is a generally accepted costing methodology in the utility industry. The primary purpose of the distribution system is to deliver power from the transmission grid to the Company's customers in various geographical locations with service at different voltage levels. Certain distribution investments must be made just to connect a customer to the system. Also, many equipment manufacturers have only minimum sized equipment available. Safety concerns and construction practices often require minimum sized equipment which is not determined by demand. These investments are properly considered to be customer-related.

Q. Why do you believe that the minimum size system is an acceptable industry practice?

A. The concept of a minimum size distribution system has been accepted for decades as a valid consideration by numerous state public utility commissions. It has also been presented in the National Association of Regulatory Utility Commissioners Electric Utility Cost Allocation Manual ("NARUC Manual") published by NARUC.

The central idea behind the minimum size system concept is that there is a minimum cost incurred by any utility when it extends its primary and secondary distribution systems and connects an additional customer to them. By definition, the minimum size system comprises every distribution component necessary to provide service, i.e., meters, services, secondary and primary wires, poles, substations, etc. The cost of the minimum size system, however, is only that portion of the total distribution cost the utility must incur to provide service to customers. It does not include costs specifically incurred to meet the peak demand of the customers.

Q. Please elaborate further on the minimum size system concept and the distinction between customer-related and demand-related costs in the context of a CCOSS.

A. A certain portion of the cost of the distribution system–poles, conductors and transformers–is required just to attach customers to the system in different geographical locations, regardless of their demand or energy requirements. This minimum or "skeleton" distribution system may also be considered as customer-related cost since it depends primarily on the number of customers, rather than on demand or energy usage.

Q. Do you object to the use of the Company's recommended CCOSS based on the 12 CP method and on the classification of certain distribution costs as customer related for allocating costs to rate classes in this proceeding?

A. No, I do not.

Company's Proposed Class Revenue Allocation

Q. What is the overall rate of return calculated by the Company in its CCOSS?

A. The overall rate of return calculated by the Company in its CCOSS at present rates was 2.83%.

Q. What were the class rates of return results for the Company's recommended CCOSS based on the 12 CP cost of service methodology?

A. The results of the Company's 12 CP CCOSS indicate that five rate classes, specifically Rates DS, GS-FL, SP, DT-Secondary, and TT are providing rates of return above the system average rate of return of 2.83% at present rates. The CCOSS indicates that six rate classes, specifically Rates RS, EH, DT-Primary, DP, Lighting, and Water Pumping are providing rates of return below the system average rate of return.

A CCOSS compares the cost that each customer class imposes on the system to the revenues each class contributes. This relationship is generally presented by comparing the rate of return that a class is providing with the utility's overall jurisdictional rate of return. A rate class that produces a rate of return above the system average rate of return is providing revenue in excess of its allocated class cost of service. It is not only paying revenues sufficient to cover the cost attributable to it, but in addition, it is paying part of the cost attributable to other classes who produce below system average rates of return.

A rate class that produces a rate of return below the system average rate of return provides revenue that does not recover its allocated class cost of service. The revenue provided by the class is insufficient to cover all relevant costs to serve that class.

Q. Does the Company base its proposed class revenue allocation on its recommended CCOSS?

A. The Company uses the results of its recommended CCOSS as a guide in allocating its revenue requirement to its rate classes but does not propose to bring all classes to full cost of service. Because the Company's CCOSS indicated that there were considerable differences among the rate classes with respect to the rate of return provided to the Company at present rates, some classes would experience much greater increases on a percentage basis as compared to other classes in order to bring all classes to cost of service.

As a result, the Company determined that it was appropriate to mitigate rate shock for certain customer rate classes by not bringing all classes to their calculated class cost of service under proposed rates. To accomplish this, the Company is proposing a two-step process to allocate its proposed revenue increase to rate classes. The first step eliminates 10 percent of the subsidy/excess revenue between customer classes based on present revenues. The second step allocates the rate increase to customer classes based on rate base.

Q. Do you object to the Company's proposed class revenue allocation in this proceeding?

A. No, I do not. The Company's proposal recognizes that some classes would experience large cost of service based increases without some form of rate mitigation. The Company's proposed class revenue allocation results in some movement toward cost of service and appropriately recognizes the principle of gradualism.

Traditional Criteria for Establishment of Riders

Q. Has the Company proposed any riders in this proceeding?

A. Yes. The Company has proposed several riders in this proceeding. I will provide a recommendation regarding the Company's proposed Rider DCI and proposed Rider FTR.

Q. What is a rider?

A. In general terms, as relates to utility service rates, a rider is an adjunct to a utility's basic tariffs, with distinct pricing or other terms of service, that works in conjunction with an underlying base rate tariff.

Q. What are general criteria necessary for the establishment of a rider?

A. Traditionally, the criteria needed for establishment of a rider are that the cost elements subject to the regulatory mechanism meet the following: (1) must be outside the utility's control; (2) must be volatile and unpredictable; and (3) must be large enough to significantly affect the utility's ability to earn its authorized return.

Cost elements that do not satisfy all three criteria above are best recovered through the normal ratemaking process; otherwise, riders that recover single cost elements are burdensome to utility customers.

Q. Why are such riders burdensome to utility customers?

A. A rider permits changes in rates more frequently because the utility does not have to wait until the next rate case to address changes in the single cost element subject to rider recovery. As a result, customers could see frequent rate changes.

More importantly, rather than a complete review of the utility's cost of service in the context of a base rate case, the focus of the rider mechanism is on a single cost element. When a utility proposes to recover the increased expense associated with a particular cost element through a rider, there could be decreases in other cost elements that when examined in the context of base rate case would offset the cost increase to be recovered in the rider. As a result, ratepayers might pay additional costs via the rider that are otherwise unwarranted.

Q. What is regulatory lag?

A. Regulatory lag is the time period between the utility's incurrence of a cost and its actual recovery of that cost in base rates as approved by the regulatory commission. Because of regulatory lag, any increase in efficiency and reductions in cost are retained by a utility until rates are reset in the next rate case.

Q. What is the impact of riders on regulatory lag?

A. Riders significantly weaken or eliminate the positive incentives created by regulatory lag and effectively shift risk from the utility to customers.

Regulatory lag provides a powerful incentive for a utility to continuously seek ways to improve its processes and use its resources more efficiently in an attempt to reduce cost and increase profits. Between rate cases, a utility has a strong incentive to control its cost to be more profitable to its shareholders and to diminish the need for future rate cases.

Without regulatory lag, the utility has little incentive to control its costs since it can quickly receive relief through changes in rates provided by a rider.

When a utility implements a rider, it has little incentive to seek cost reductions through improvements in its processes because it has no ability to retain benefits of increased profits resulting from such actions. If a utility is guaranteed immediate recovery of cost through a rider, the utility has a far weaker incentive to be as diligent or efficient in its procurement and operations.

In addition, a rider also eliminates the incentive to minimize expenses and maximize revenues between rate proceedings because the utility knows it will not need to file a new rate case immediately in order to recover increases in costs.

Q. Should riders be avoided when possible?

A. Yes. Riders allow a utility to pursue single issue ratemaking rather than examining all of the relevant actions which influence the cost of service in a base rate case.

Single issue ratemaking potentially skews the relationship among revenues, expense and rate base, possibly leading to excessive utility charges for service.

Q. Please explain further the concept of single issue ratemaking.

A. The concept of looking at all of a utility's investment cost and revenue in conjunction during a common period known as the test year is the long-standing rate-setting process of regulatory commissions. In between rate cases, some utility cost or revenue elements may increase, but this may be offset by decreases in other cost elements. Even if a utility's cost structure exhibits a net increase over time, this circumstance alone does not mean a rate adjustment is warranted, as increased revenues from additional sales may be adequate to cover the increased costs. Because all of these factors combine to determine proper rates, looking at selected cost elements in isolation between comprehensive rate cases can tilt the balance of costs, savings, and revenues that determine appropriate rate levels. Doing so is what is known as single issue ratemaking. Riders that modify charges to customers for a single element or category of costs without regard to potential offsets should generally be avoided.

Q. What is the impact of riders on cost recovery risk for the utility?

A. Riders reduce the risk to a utility of not earning an appropriate return on equity because significant portions of the cost of service are subject to almost guaranteed full cost recovery of the particular cost elements that are the subject of the riders. Riders can result in customers paying for more utility service than traditional ratemaking with either an historical test year or budgeted future test year. Riders can shift the risk of cost recovery to utility customers.

Q. Please explain how riders can shift risk from the utility to its customers.

A. Utilities, like other business, face numerous factors that can affect overall profitability, positively or negatively, in any given period. For example, in any given year, the state of the economy in its service territory or the severity of weather can have significant effect on a utility's revenues and profitability. General economic factors can also affect levels of customer usage, and as a result, the utility's revenues and profitability.

The normal rate case process provides a utility with opportunities to take account of such factors, including normalizing adjustments, test year selection, and the right to seek needed rate relief. The overall business risk of the utility is also reflected in the utility's cost of capital. The constraints of predetermined rates and the formal justification and proof required to change rates provide incentives for the utility to operate efficiently. Riders shift the risk of cost variations from the utility to ratepayers and alter otherwise effective regulatory incentives. Deviating from the established ratemaking process by allowing a utility to establish riders for recovery of single cost elements should be considered only upon a showing of compelling need.

Company's Proposed Rider DCI

Q. Please describe the Company's proposed Rider DCI.

A. According to the testimony of Company witness Bruce L. Sailers, the Company is proposing to implement Rider DCI which is a discrete cost adjustment mechanism that would recover the ongoing incremental capital investments for specific Commission-approved distribution reliability and integrity enhancement programs.

Q. Does DKE's proposed Rider DCI meet the traditional criteria for a rider to be established?

A. No. This proposed rider recovers the incremental revenue requirement associated with certain programs to proactively improve the reliability of its electric distribution system.

These costs are more appropriately recovered in the Company's base rates. The Company has not demonstrated that this cost item is outside the utility's control nor is it volatile and unpredictable. The risk of recovery of these costs is mitigated by the Company's use of a forecasted test year.

To the extent the projects contemplated to be completed under Rider DCI are beneficial to consumers and determined to be good, prudent projects to undertake, the Company should do so as part of the normal capital budgeting process and include the cost of such projects in future rate cases.

Q. Did the Company provide a projection of the costs proposed to be recovered in Rider DCI?

A. Yes. According to the direct testimony of Company witness Anthony J. Platz at page 29, the Company has projected \$5 million of annual expenditures for each year of the period 2019-2021. It has projected annual expenditures of \$8 million each year for the period 2022- 2025, and $10 million of annual expenditures each year for the period 2026-2027. [1]

Q. Could implementing Rider DCI result in excessive charges to the Company's retail customers?

A. Yes, it could. The Company's CCOSS in this case includes annual distribution depreciation expense of approximately $14.4 million per year to be included in base rates.[2] This level of annual depreciation expense will exceed the annual level of distribution investment planned under Rider DCI. As a result, it appears the annual investment projected under Rider DCI will not grow rate base and as a result, Rider DCI could result in excessive charges to customers.

Q. Why does a comparison of the Company's annual expenditures under Rider DCI to its distribution depreciation expense recovery in base rates suggest that Rider DCI would result in excessive charges to customers?

A. A comparison of capital expenditures to depreciation expense recovery is an indication of whether or not the Company's total rate base will grow during the forecast period for Rider DCI. To the extent rate base does not grow, or only grows moderately, then base rate revenues may provide the Company an opportunity to recover its cost of service and earn its authorized rate of return during the rate effective period.

Rider mechanisms are typically used for expenses that cannot be controlled by utility management and reasonably threaten management's ability

[1]See Application, Vol. 16, at page 191 of 436.
[2]See Application, Vol. 10, FR-16(7)(v)-1, page 10 of 18, Line 11.

to time rate filings that will coincide with changes to its cost of service. The capital expenditures under Rider DCI are clearly identified by the Company, and, it can file an application with the PSC to change base rates if the Company believes current base rates are not adequate to fully recover its cost of service.

However, a base rate change may not be needed if other costs of service decrease, or sales growth provides additional revenue adequate to cover the increased rate base cost. For example, lower operation and maintenance ("O&M") expense as a result of the new investment could partially offset the need for a base rate change.

Q. Does improving reliability on a utility's system by investing in new infrastructure produce O&M savings?

A. Yes. Newer infrastructure requires less maintenance as compared to aging infrastructure. To my knowledge, the Company has not proposed to flow any reduced O&M expense experienced as a result of the Rider DCI investment to customers through its proposed rider.

Q. What is your recommendation with respect to Rider DCI?

A. I recommend that the Commission reject the Company's proposal for Rider DCI.

Company's Proposed Rider FTR

Q. Please describe the Company's proposed Rider FTR.

A. According to the testimony of Company witness Bruce L. Sailers, the Company is proposing to implement Rider FTR, which is a discrete cost adjustment mechanism that would allow recovery of certain ongoing costs incremental to those costs included in base rates for specific transmission related items.

Q. Does DKE's proposed Rider FTR meet all of the traditional criteria for a rider to be established?

A. No. Though the Company claims that these costs are out of its control and volatile, the Company has not demonstrated that the incremental transmission costs not included in base rates and proposed for recovery in Rider FTR would significantly affect the utility's ability to earn its authorized rate of return. The fact that the Company has established rates on a future test year minimizes the risk that its base rates will not recover all of its transmission costs by allowing it an opportunity to provide a reasonable forecast of these costs.

Q. What is your recommendation with respect to Rider FTR?

A. I recommend that the Commission reject the Company's proposal for Rider FTR.

Q. If the Commission approves Rider FTR, do you have any recommendation with respect to how the costs are allocated and recovered from classes?

A. Yes. Included in the rider is the recovery of Network Integrated Transmission Costs ("NITS"), which are incurred on a $ per kW basis by the utility. If Rider FTR is granted, NITS related costs, as well as other costs incurred on a demand basis, should be allocated on the basis of demand and collected from classes based on $ per kW charge as opposed to the collection of these costs on a $ per kWh or energy basis as proposed by the utility.

Q. Does this conclude your testimony?

A. Yes.

<u>Qualifications of Brian C. Collins</u>

Q. Please state your name and business address.

A. Brian C. Collins. My business address is 16690 Swingley Ridge Road, Suite 140, Chesterfield, MO 63017.

Q. What is your occupation and by whom are you employed?

A. I am a consultant in the field of public utility regulation and a Principal with the firm of Brubaker & Associates, Inc. ("BAI"), energy, economic and regulatory consultants.

Q. Please state your educational background and experience.

A. I graduated from Southern Illinois University Carbondale with a Bachelor of Science degree in Electrical Engineering. I also graduated from the University of Illinois at Springfield with a Master of Business Administration degree. Prior to joining BAI, I was employed by the Illinois Commerce Commission and City Water Light & Power ("CWLP") in Springfield, Illinois.

My responsibilities at the Illinois Commerce Commission included the review of the prudence of utilities' fuel costs in fuel adjustment reconciliation cases before the Commission as well as the review of utilities' requests for certificates of public convenience and necessity for new electric transmission lines. My responsibilities at CWLP included generation and transmission system planning. While at CWLP, I completed several thermal and voltage studies in support of CWLP's operating and planning decisions. I also performed duties for CWLP's Operations Department, including calculating CWLP's monthly cost of production. In addition, I determined CWLP's allocation of wholesale purchased power costs to retail and wholesale customers for use in the monthly fuel adjustment.

In June 2001, I joined BAI as a Consultant. Since that time, I have participated in the analysis of various utility rate and other matters in several states and before the Federal Energy Regulatory Commission ("FERC"). I have filed or presented testimony before the Arkansas Public Service Commission, the Delaware Public Service Commission, the Florida Public Service Commission, the Idaho Public Utilities Commission, the Illinois Commerce Commission, the Indiana Utility Regulatory Commission, the Minnesota Public Utilities Commission, the Missouri Public Service Commission, the North Dakota Public Service Commission, the Public Utilities Commission of Ohio, the Oregon Public Utility Commission, the Rhode Island Public Utilities Commission, the Virginia State Corporation Commission, the Public Service Commission of Wisconsin, the Washington Utilities and Transportation Commission, and the Wyoming Public Service Commission. I have also assisted in the analysis of transmission line routes proposed in certificate of convenience and necessity proceedings before the Public Utility Commission of Texas.

In 2009, I completed the University of Wisconsin – Madison High Voltage Direct Current ("HVDC") Transmission Course for Planners that was sponsored by the Midwest Independent Transmission System Operator, Inc. ("MISO").

BAI was formed in April 1995. BAI and its predecessor firm has participated in more than 700 regulatory proceeding in forty states and Canada.

BAI provides consulting services in the economic, technical, accounting, and financial aspects of public utility rates and in the acquisition of utility and energy services through RFPs and negotiations, in both regulated and unregulated markets. Our clients include large industrial and institutional customers, some utilities and, on occasion, state regulatory agencies. We also prepare special studies and reports, forecasts, surveys and siting studies, and present seminars on utility-related issues.

In general, we are engaged in energy and regulatory consulting, economic analysis and contract negotiation. In addition to our main office in St. Louis, the firm also has branch offices in Phoenix, Arizona and Corpus Christi, Texas.