Errata Sheet

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

FILING: Direct Testimony of James E. Ziolkowski, Filed December 1, 2022

DATE CORRECTED: May 10, 2023

CORRECTION	**LINE**	**PAGE**
Replace "DECREASE" with "INCREASE"	5	29
Replace "not change" with "increase" and replace "decrease" with "increase"	8	29
Replace "added to" with "subtracted from" and replace "S" in Rate DS with "T" so it reads Rate DT	9	29

James E. Ziolkowski
Signature

5/15/23
Date

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REVISED DIRECT TESTIMONY OF

JAMES E. ZIOLKOWSKI

ON BEHALF OF

DUKE ENERGY KENTUCKY, INC.

December 1, 2022

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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. PLEASE BRIEFLY SUMMARIZE YOUR EDUCATION AND PROFESSIONAL EXPERIENCE.

A. I received a Bachelor of Science degree in Mechanical Engineering from the U.S. Naval Academy in 1979 and a Master of Business Administration degree from Miami University in 1988. I am also a licensed Professional Engineer in the state of Ohio. I received certification as a Chartered Industrial Gas Consultant in 1994 from the Institute of Gas Technology and the American Gas Association. I have attended the EUCI Cost of Service seminar.

After graduating from the Naval Academy, I attended the Naval Nuclear Power School and other follow-on schools. I served as a nuclear-trained officer on various ships in the U.S. Navy through 1986. From 1988 through 1990, I worked for Mobil Oil Corporation as a Marine Marketing Representative in the New York City area.

I joined The Cincinnati Gas & Electric Company n/k/a Duke Energy Ohio, Inc., (Duke Energy Ohio) in 1990 as a Product Applications Engineer, in which capacity I designed and managed some of Duke Energy Ohio's demand side management programs, including Energy Audits and Interruptible Rates. From 1996 until 1998, I was an Account Engineer and worked with large customers to resolve various service-related issues, particularly in the areas of billing, metering, and demand management. In 1998, I joined the Rate Department, where I focused on rate design and tariff administration. I was appointed to my current position in January 2014.

Q. PLEASE SUMMARIZE YOUR RESPONSIBILITIES AS DIRECTOR RATES & REGULATORY PLANNING.

A. As Director Rates & Regulatory Planning, I am responsible for cost of service studies, tariff administration, billing, and revenue reporting issues in Kentucky and Ohio. I also prepare filings to modify charges and terms in the retail tariffs of both Duke Energy Kentucky and Duke Energy Ohio, and I develop rates for new services. During major rate cases, I help with the design of the new base rates. Additionally, I frequently work with Duke Energy Kentucky's and Duke Energy Ohio's customer contact and billing personnel to answer rate-related questions, and to apply the retail tariffs to specific situations. Occasionally, I meet with customers and Company representatives to explain rates or provide rate training. I also prepare reports that are required by regulatory authorities.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THE KENTUCKY PUBLIC SERVICE COMMISSION?

A. Yes.

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

A. I sponsor Schedules B-7, B-7.1, B-7.2, D-3, D-4, and D-5 in response to Filing Requirement FR 16(8)(b) and FR 16(8)(d), respectively. I also support the cost of service studies identified in response to Filing Requirement FR 16(7)(v).

II. SCHEDULES AND FILING REQUIREMENTS SPONSORED BY WITNESS

Q. PLEASE DESCRIBE SCHEDULES B-7 AND D-3.

A. These schedules report the allocation factors used to determine the jurisdictional percentages of electric plant, expenses, *etc*., necessary to allocate the amount of the proposed new electric rates between jurisdictional and non-jurisdictional customers. These schedules indicate that 100 percent of the costs are jurisdictional, because Duke Energy Kentucky does not provide service to any non-jurisdictional electric customers.

Q. PLEASE DESCRIBE SCHEDULES B-7.1 AND D-4.

A. These schedules are the support for Schedules B-7 and D-3 described above. They provide the basis for the actual jurisdictional allocation factors.

Q. PLEASE DESCRIBE SCHEDULES B-7.2 AND D-5.

A. These schedules explain changes made to the jurisdictional allocation from the Company's prior electric base rate proceeding in Case No. 2019-00271.

Q. PLEASE DESCRIBE FR 16(7)(v).

A. FR 16(7)(v) contains 25 schedules: Schedules FR 16(7)(v)-1 through FR 16(7)(v)-25 which represent the fully allocated, embedded cost of service study by rate class. I discuss these filing requirements in greater detail in my testimony below.

III. COST OF SERVICE STUDIES

Q. WHAT IS THE PURPOSE OF A COST-OF-SERVICE STUDY?

A. A cost-of-service study is an analytical tool used in traditional utility rate design to allocate costs to different classes of customers. When the process of preparing a cost-of-service study is completed, the resulting class cost-of-service study can (1) assist in determining the revenue requirement for the services offered by a utility; (2) analyze, at a very detailed level, the costs imposed on the utility's system by different classes of customers; (3) show the total costs the company incurs in serving each retail rate class, as well as the rate of return on capitalization earned from each class during the test year; and (4) establish cost responsibility that makes it possible to determine just and reasonable rates based on costs.

Q. WHAT INFORMATION DID THE COMPANY USE TO DEVELOP THE COST ALLOCATION FACTORS FOR THE COST OF SERVICE STUDIES USED IN THIS PROCEEDING?

A. The test year for this proceeding is the twelve months ending June 30, 2024, which is comprised of forecasted test period data. The development of the test year allocation factors is primarily based on historical data for the twelve months ended March 2022. Otherwise, forecasted test year information was used as appropriate. I will discuss the actual development of the various allocation factors used in this proceeding later in my testimony.

Q. HAS THE COMPANY PREPARED MULTIPLE COSTS OF SERVICE STUDIES?

A. Yes. The Company prepared three Class Cost of Service Studies that contain essentially the same data, except that different methodologies were used to develop the allocation factor for the demand component of Production-related costs. The demand allocation methods are as follows: (1) the Average of the Twelve (12) Coincident Peaks (12 CP) method; (2) the Average and Excess (A&E) method; and (3) the Production Stacking method.

Q. PLEASE DESCRIBE THE DEMAND METHODOLOGIES USED IN THESE COST OF SERVICE STUDIES.

A. The 12 CP method is designed to allocate capacity related costs to the customer classes using the system during maximum system load. The allocation of capacity costs to each customer class is based on the class load contribution to the maximum peak, at the time of peak, regardless of what their respective loads were at other times of the day.

The A&E method, also referred to as the "used and unused capacity method," recognizes both the class average use of the system capacity and the class contribution to the capacity required to meet the maximum system load. The capacity costs are allocated in a two-part formula. Attachment JEZ-3 shows the calculation of the production allocator K201 using the A&E method.

The "class-used" capacity component is the proportion of the class's respective average hourly kilowatt-hour (kWh) sales to the total average hourly sales. The "class-unused" capacity is the class excess hourly peak demand contribution ratio, which is the difference between the class average hourly demands and the hourly class peak demands. The used and unused capacity factors for each class are combined to allocate capacity costs to the respective rate classes.

The Production Stacking method is a time-differentiated method that allocates baseload plant costs on energy (kWh) and peaker plants costs on peak demands. As shown in Attachment JEZ-4, net plant associated with the East Bend plant is allocated to each rate class based on annual kWh. Net plant associated with the Woodsdale facility is allocated to each rate class based on 12 CP. The K201 production allocator combines both allocations.

Q. DID YOU COMPARE THE CLASS DEMAND RATIOS FOR EACH OF THE DEMAND METHODOLOGIES?

A. Yes. Attachment JEZ-1 shows the demand ratios for the different methods. Attachment JEZ-2 shows the rate impacts using the different methods.

Q. BASED UPON YOUR COMPARISON OF THE 12 CP, A&E AND PRODUCTION STACKING METHODOLOGIES, WHICH DO YOU RECOMMEND THE COMMISSION APPROVE IN THIS PROCEEDING?

A. I recommend using the Average 12 CP methodology for three reasons. First, the 12 CP method is generally accepted in the utility industry and was approved by the Commission in the Company's last electric base rate case. The 12 CP demand methodology has been used in other jurisdictions including Duke Energy Indiana's rate proceedings. Second, this methodology recognizes that Duke Energy Kentucky's current generating facilities are in place precisely to meet the monthly maximum peak loads of customers. Third, there was no compelling reason to adopt a new methodology. Rate subsidies will generally occur among customer classes, regardless of the cost of service methodology used. Changing to either the A&E or Production Stacking methodology will not change this fact. The Company believes that the use of the 12 CP methodology is the appropriate means to align capacity costs with the customer classes that are imposing the costs.

Q. PLEASE DESCRIBE THE ELECTRIC COST OF SERVICE STUDY.

A. The electric cost of service study contained in Schedules FR-16(7)(v)-1 through FR-16(7)(v)-25 is an embedded, fully allocated cost of service study by rate class for the test period ended June 30, 2024. In preparing the cost of service study, I used information provided by other Company employees. The cost of service study functionalizes, classifies, and allocates cost items such as plant investment, operating expenses, and taxes to the various customer classes and calculates the revenue responsibility of each class. Finally, the cost of service study calculates the revenue responsibility of each rate class required to generate the recommended rate of return.

Q. PLEASE DESCRIBE HOW THE COST OF SERVICE STUDY IS ORGANIZED IN SCHEDULES FR-16(7)(v)-1 THROUGH SCHEDULE FR-16(7)(v)-25.

A. The schedules provided in the cost of service study are organized as shown in the table below. The detailed calculation and derivation of the allocation factors utilized in the cost of service study are included in the workpapers filed in these proceedings.

Table 1		
Schedule	Page No.	Description
Schedule 1	1	Summary of Results
Schedule 2	2	Gross Plant in Service
Schedule 3	3	Depreciation Reserve
Schedule 4	4	Net Electric Plant in Service
Schedule 5	5	Subtractive Rate Base Adjustments
Schedule 5.1	6	Additive Rate Base Adjustments
Schedule 5.2	7	Working Capital
Schedule 6	8	O&M Expenses
Schedule 6.1	9	O&M Expenses
Schedule 7	10	Depreciation Expense
Schedule 8	11	Taxes Other Than Income Taxes
Schedule 9	12	Federal Income Tax Based on Return
Schedule 9.1	13	State Income Tax Based on Return
Schedule 10	14	Cost of Service Computation
Schedule 11	15	ROR, Tax Rates & Special Factors
Schedule 12	16	Allocation Factors
Schedule 12.1	17	Allocation Factors
Schedule 12.2	18	Allocation Factors

Q. WHAT JURISDICTIONAL RATE CLASSES WERE USED IN THE CLASS COST OF SERVICE STUDY?

A. The cost of service is organized showing the following rate classes:

- Residential: (Rate RS);
- Secondary Distribution Small: (Rates DS, GS-FL, EH and SP);
- Secondary Distribution Large: (Rates DT);
- Primary Distribution: (Rate DT and DP);
- Transmission: (Rates TT);
- Lighting: (Rates NSU, NSP, OL, SC, SE, SL, TL and UOLS combined); and
- Other: (Flood Control Water Pumping Stations).

Q. WHAT ARE THE ELEMENTS OF A COST OF SERVICE STUDY?

A. Much like the components of the overall revenue requirement, the elements of a cost of service study consist of the following elements, which are allocated to each function, classification and rate class:

Operating & Maintenance Expense

+ Depreciation

+ Other Taxes

+ Federal Income Tax

+ State Income Tax

+ Return (Jurisdictional Rate Base x Rate of Return (ROR))

- Revenue Credits

= Class Revenue Requirement or Cost of Service

Q. PLEASE DESCRIBE SCHEDULE FR-16(7)(v)-1.

A. Schedule FR-16(7)(v)-1 is a functional cost of service study that separates the cost items into the production, transmission, and distribution functions.

Q. PLEASE DESCRIBE SCHEDULE FR-16(7)(v)-2.

A. Schedule FR-16(7)(v)-2 is a classified cost of service study that separates the cost items contained in the production function on Schedule FR-16(7)(v)-1 between the demand, energy, and customer classifications.

Q. PLEASE DESCRIBE SCHEDULE FR-16(7)(v)-3.

A. Schedule FR-16(7)(v)-3 is an allocated cost of service study that allocates the cost items contained in the production demand classification from Schedule FR-16(7)(v)-2 to the various rate groups.

Q. PLEASE DESCRIBE SCHEDULE FR-16(7)(v)-4.

A. Schedule FR-16(7)(v)-4 is an allocated cost of service study that allocates the cost items contained in the production energy classification from Schedule FR-16(7)(v)-2 to the various rate groups.

Q. PLEASE DESCRIBE SCHEDULE FR-16(7)(v)-5.

A. Schedule FR-16(7)(v)-5 is an allocated cost of service study that allocates the cost items contained in the production customer classification from Schedule FR-16(7)(v)-2 to the various rate groups. As is evident on the schedule, there are no production costs classified as customer related.

Q. PLEASE DESCRIBE SCHEDULE FR-16(7)(v)-6.

A. Schedule FR-16(7)(v)-6 is a classified cost of service study that separates the cost items contained in the transmission function on Schedule FR-16(7)(v)-1 between the demand, energy, and customer classifications.

Q. PLEASE DESCRIBE SCHEDULE FR-16(7)(v)-7.

A. Schedule FR-16(7)(v)-7 is an allocated cost of service study that allocates the cost items contained in the transmission demand classification from Schedule FR-16(7)(v)-6 to the various rate groups.

Q. PLEASE DESCRIBE SCHEDULE FR-16(7)(v)-8.

A. Schedule FR-16(7)(v)-8 is an allocated cost of service study that allocates the cost items contained in the transmission energy classification from Schedule FR-16(7)(v)-6 to the various rate groups. As is evident on the schedule, there are no transmission costs classified as energy related.

Q. PLEASE DESCRIBE SCHEDULE FR-16(7)(v)-9.

A. Schedule FR-16(7)(v)-9 is an allocated cost of service study that allocates the cost items contained in the transmission customer classification from Schedule FR-

16(7)(v)-6 to the various rate groups.

Q. PLEASE DESCRIBE SCHEDULE FR-16(7)(v)-10.

A. Schedule FR-16(7)(v)-10 is a classified cost of service study that separates the cost items contained in the distribution function on Schedule FR-16(7)(v)-1 between the demand, energy, and customer classifications.

Q. PLEASE DESCRIBE SCHEDULE FR-16(7)(v)-11.

A. Schedule FR-16(7)(v)-11 is an allocated cost of service study that allocates the cost items contained in the distribution demand classification from Schedule FR-16(7)(v)-10 to the various rate groups.

Q. PLEASE DESCRIBE SCHEDULE FR-16(7)(v)-12.

A. Schedule FR-16(7)(v)-12 is an allocated cost of service study that allocates the cost items contained in the distribution energy classification from Schedule FR-16(7)(v)-10 to the various rate groups. As is evident on the schedule, there are no distribution costs classified as energy related.

Q. PLEASE DESCRIBE SCHEDULE FR-16(7)(v)-13.

A. Schedule FR-16(7)(v)-13 is an allocated cost of service study that allocates the cost items contained in the distribution customer classification from Schedule FR-16(7)(v)-10 to the various rate groups.

Q. PLEASE DESCRIBE SCHEDULE FR-16(7)(v)-14.

A. Schedule FR-16(7)(v)-14 is a total class cost of service study that sums the allocated costs from Schedules FR-16(7)(v)-3, FR-16(7)(v)-4, FR-16(7)(v)-5, FR-16(7)(v)-7, FR-16(7)(v)-8, FR-16(7)(v)-9, FR-16(7)(v)-11, FR-16(7)(v)-12 and FR-16(7)(v)-13, by the various rate groups.

Q. PLEASE DESCRIBE SCHEDULE FR-16(7)(v)-15.

A. Schedule FR-16(7)(v)-15 is a classified cost of service study for the residential class that shows the allocated costs from Schedules FR-16(7)(v)-3, FR-16(7)(v)-7 and FR-16(7)(v)-11, summarized by the demand, energy, and customer classifications.

Q. PLEASE DESCRIBE SCHEDULE FR-16(7)(v)-16.

A. Schedule FR-16(7)(v)-16 is a classified cost of service study for the Distribution Secondary class that shows the allocated costs from Schedules FR-16(7)(v)-3, FR-16(7)(v)-7 and FR-16(7)(v)-11, summarized by the demand, energy, and customer classifications.

Q. PLEASE DESCRIBE SCHEDULE FR-16(7)(v)-17.

A. Schedule FR-16(7)(v)-17 is a classified cost of service study for the GSFL Secondary class that shows the allocated costs from Schedules FR-16(7)(v)-3, FR-16(7)(v)-7 and FR-16(7)(v)-11, summarized by the demand, energy, and customer classifications.

Q. PLEASE DESCRIBE SCHEDULE FR-16(7)(v)-18.

A. Schedule FR-16(7)(v)-18 is a classified cost of service study for the EH Secondary class that shows the allocated costs from Schedules FR-16(7)(v)-3, FR-16(7)(v)-7 and FR-16(7)(v)-11, summarized by the demand, energy, and customer classifications.

Q. PLEASE DESCRIBE SCHEDULE FR-16(7)(v)-19.

A. Schedule FR-16(7)(v)-19 is a classified cost of service study for the SP Secondary class that shows the allocated costs from Schedules FR-16(7)(v)-3, FR-16(7)(v)-7 and FR-16(7)(v)-11, summarized by the demand, energy, and customer classifications.

Q. PLEASE DESCRIBE SCHEDULE FR-16(7)(v)-20.

A. Schedule FR-16(7)(v)-20 is a classified cost of service study for the DT Secondary class that shows the allocated costs from Schedules FR-16(7)(v)-3, FR-16(7)(v)-7 and FR-16(7)(v)-11, summarized by the demand, energy, and customer classifications.

Q. PLEASE DESCRIBE SCHEDULE FR-16(7)(v)-21.

A. Schedule FR-16(7)(v)-21 is a classified cost of service study for the DT Primary class that shows the allocated costs from Schedules FR-16(7)(v)-3, FR-16(7)(v)-7 and FR-16(7)(v)-11, summarized by the demand, energy, and customer classifications.

Q. PLEASE DESCRIBE SCHEDULE FR-16(7)(v)-22.

A. Schedule FR-16(7)(v)-22 is a classified cost of service study for the Distribution Primary class that shows the allocated costs from Schedules FR-16(7)(v)-3, FR-16(7)(v)-7 and FR-16(7)(v)-11, summarized by the demand, energy, and customer classifications.

Q. PLEASE DESCRIBE SCHEDULE FR-16(7)(v)-23.

A. Schedule FR-16(7)(v)-23 is a classified cost of service study for the Time-of-Day Rate for Service at Transmission Voltage (Rate TT) class that shows the allocated costs from Schedules FR-16(7)(v)-3, FR-16(7)(v)-7 and FR-16(7)(v)-11, summarized by the demand, energy, and customer classifications.

Q. PLEASE DESCRIBE SCHEDULE FR-16(7)(v)-24.

A. Schedule FR-16(7)(v)-24 is a classified cost of service study for the Lighting class that shows the allocated costs from Schedules FR-16(7)(v)-3, FR-16(7)(v)-7 and FR-16(7)(v)-11, summarized by the demand, energy, and customer classifications.

Q. PLEASE DESCRIBE SCHEDULE FR-16(7)(v)-25.

A. Schedule FR-16(7)(v)-25 is a classified cost of service study for the Other – Water Pumping class that shows the allocated costs from Schedules FR-16(7)(v)-3, FR-16(7)(v)-7 and FR-16(7)(v)-11, summarized by the demand, energy, and customer classifications.

Q. HOW DID YOU DEVELOP THE COST OF SERVICE STUDY THAT YOU USED TO ALLOCATE COSTS TO THE DIFFERENT RATE CLASSES?

A. First, I developed various allocation factors based on customer, energy usage, and demand statistics for the test period. Next, I functionalized costs into the specific utility functions, *i.e.,* production, transmission and distribution. I then classified the costs as demand, energy, or customer related, or a combination in some instances. Lastly, I allocated the demand, energy, and customer related costs to rate classes based on the cost causation guidelines published in the NARUC "Electric Utility Cost Allocation Manual," my utility company experience, and my knowledge of cost of service studies.

A. Functionalizing Costs

Q. PLEASE EXPLAIN HOW YOU FUNCTIONALIZE COSTS.

A. The production function includes the costs associated with power generation and power purchases and their delivery to the bulk transmission system. The transmission function consists of costs associated with the high voltage system utilized for the bulk transmission of power to and from interconnected utilities to the load centers of the utility's system. The distribution function includes the radial distribution system that connects the transmission system and the ultimate customer.

The Company's accounting records use the Uniform System of Accounts of the Federal Energy Regulatory Commission (FERC). These accounts functionalize the Company's investment into the primary categories of production (generation), transmission, distribution, and general plant. Similarly, the Company's operating costs are categorized into production, transmission, distribution, customer services, and administrative and general (A&G) functions.

B. Classifying Costs

Q. PLEASE EXPLAIN THE CLASSIFICATION OF COSTS.

A. Next, functionalized costs are grouped according to their cost-causation characteristics. This process is known as classification of costs. Typically, these cost-causing characteristics are defined as demand-related, energy-related, or customer-related.

Q. PLEASE DEFINE DEMAND-RELATED COSTS.

A. Demand-related costs are fixed costs incurred regardless of the level of energy sales and have a direct relationship to the kilowatts (kW) of demand that customers place on the various segments of the system. Costs that are classified as demand-related include major portions of the Company's investment and related expenses in its production and transmission facilities and a significant portion of the investment and related expenses of its distribution system. Until the Company has the full ability to bill all customers based on demand (both from a technical and a regulatory perspective), the Company will continue to use fixed and kWh charges to recover demand related costs for some base rates.

Q. PLEASE DEFINE ENERGY-RELATED COSTS.

A. Energy-related costs are costs incurred that vary in direct relationship to the amount of energy or kilowatt hours (kWh) generated and delivered. These costs are often referred to as variable costs. Fuel is an example of an energy-related cost.

Q. PLEASE DEFINE CUSTOMER-RELATED COSTS.

A. Customer-related costs are costs incurred primarily as a result of the number of customers being served. These fixed costs include items of investment and related expenses in functional categories such as metering, and costs associated with customer accounting and sales. Customer costs do not vary significantly with the customers' volume of usage but are influenced more by factors such as number of customers.

C. Allocation of Costs

Q. PLEASE EXPLAIN HOW COSTS ARE ALLOCATED TO VARIOUS CUSTOMER CLASSES.

A. The allocation of costs is the process of multiplying the functionalized and classified costs by allocation factors, resulting in costs being assigned to customer classes. Some costs are directly assignable to a single class of customers. Most costs, however, are attributable to more than one type of customer. Costs are allocated to the various customer groups in relationship to how those customers influence the

Company to incur the costs. This relationship is referred to as “cost causation.” Specific allocation factors are developed that relate to the demand, energy, and customer classifications identified above, to accomplish a proper matching of the costs to the customer groups, based on cost causation.

Q. PLEASE DESCRIBE THE ALLOCATION METHODOLOGY YOU USED IN THIS PROCEEDING TO ALLOCATE DEMAND-RELATED COSTS.

A. Each customer class’ cost responsibility (*i.e.*, the percentage of the demand related costs assigned to each customer class) is equal to the ratio of their demand in relation to the total demand placed on the system. The cost of service study supporting the Company’s proposed rate design in this proceeding allocates production and transmission demand-related costs based upon the 12 monthly coincident peaks (12 CP).

Q. HOW WERE THE DEMAND VALUES DEVELOPED FROM COMPANY CUSTOMER LOAD RESEARCH DATA?

A. kWh sales and load research data for the twelve months ended March 31, 2022, were used to calculate the monthly peak contributions. The calculations of the monthly demands appear on pages 11 through 32 of work paper FR-16(7)(v). The following is an example of how the class group demand was calculated for rate RS for the month of January 2022.

Step 1 – Determine the average demand by dividing the total kWh by the number of hours in the month.

150,942,818 kWh ÷ 744 hours = 202,880 kW

Step 2 – Determine the coincident peak demand by dividing the average demand from Step 1 by the coincident peak load factor supplied by load research.

202,880 kW ÷ 68.83 percent = 294,776 kW

Step 3 – To determine the demand at generation, line losses are added by multiplying the coincident peak demand from step 2 by the loss factor.

294,776 x 1.03751 = 305,833 kW (with losses)

This process was followed for all customer classes for the twelve months of the test year to determine each class' monthly peak coincident with Duke Energy Kentucky's monthly system peak. I used a similar procedure to develop each class's diversified class peak and highest (single) non-coincident peak demands.

Q. PLEASE DESCRIBE HOW THE 12 CP DEMAND ALLOCATOR WAS USED TO ALLOCATE COSTS.

A. The 12 CP demand allocator was used to allocate Production and Transmission capacity related investments and expenses to the customer classes.

Q. PLEASE DESCRIBE THE METHODS USED TO ALLOCATE DISTRIBUTION RELATED COSTS TO THE VARIOUS RATE CLASSES.

A. Several different allocation factors were used to allocate distribution plant to the customer classes. First, distribution plant was grouped by the type of plant such as substations, poles, conductors, *etc.* Then it was determined whether each type is customer- or demand-related factor. Finally, each customer- or demand-related cost was allocated to rate class.

Substations are considered 100 percent demand-related and were allocated using the average class group coincident peak demand ratios for the twelve months ending March 31, 2022. This factor takes into consideration the load diversity by rate group at the distribution substation level.

Poles and conductors are allocated partially on demand and partially based on customer counts using the minimum size method.

Transformers were allocated between customer and demand using the minimum size method. Transformers, as well as other distribution plant facilities, are considered to have a customer component because the number of facilities needed on the system, are dependent on the number of customers. The remaining costs are demand related. I allocated the demand portion of transformers among the customer classes using the maximum non-coincident peak load ratios. The maximum non-coincident peak demand allocator is appropriate because transformers are sized to meet the maximum demand and are close to the customer so there is little or no load diversity. I then allocated the customer portion of transformers among the customer classes based on the total number of customers.

Services are considered 100 percent customer-related and were allocated based on a weighted-average number of customers (K217). The weighting is based on an engineering analysis that prices various service drop costs based on demands. For example, it is twice as costly for a service drop at 100 kVA versus a service drop at 25 kVA. Customers with an average demand of 100 kVA are weighted at twice the cost of customers with an average demand of 25 kVA.

Other distribution and customer service-related costs can be more directly associated with a customer statistic such as the cost of meters (K407), customer charge-offs (K411) and other customer-related studies. As an example, the investment in meters can be directly associated with the costs of metering the various customer groups (K407).

Streetlights were directly assigned to the street lighting rate class.

Q. PLEASE DESCRIBE THE MINIMUM SIZE METHOD USED TO ALLOCATE TRANSFORMER COSTS BETWEEN CUSTOMER- AND DEMAND-RELATED COSTS.

A. The minimum size study is shown on Work Paper FR-16(7)(v), page 53. The minimum size method assumes that a minimum size distribution system can be built to serve the minimum load requirements of the customer. For transformers, the study involved determining the minimum size transformer currently installed by Duke Energy Kentucky. In this case, it is a 15 kVa transformer. Duke Energy Kentucky's 2022 cost of a 15 kVa transformer was $2,231.

I used asset accounting records to determine the number of overhead and pad-mounted transformers installed each year from 1910 to 2021. I then used the Handy-Whitman Index for Utility Plant Materials (specifically line transformers) to calculate the cost per transformer for each of the years 1910 to 2021, beginning with a 2022 Handy-Whitman index of 1192 and 2022 cost of $2,231. For each year, I multiplied the number of transformers by the cost per transformer to get the minimum size cost per year. I summarized each of the years 1910 to 2021 to arrive at the minimum size transformer cost of approximately $18.8 million. This was classified as a customer-related cost. The difference between this customer-related cost and the balance in FERC Line Transformer account 368 is the demand component, resulting in allocation factors of 22.69 percent to customer and 77.31 percent to demand. I allocated all transformer-related cost (plant, accumulated depreciation) to customer and demand using these factors.

Q. DID YOU PERFORM MINIMUM SIZE STUDIES FOR OTHER TYPES OF DISTRIBUTION EQUIPMENT?

A. Yes, in a manner like the transformer study, I prepared minimum size studies for primary poles, secondary poles, overhead primary conductor, secondary overhead conductor, underground primary conductor, and underground secondary conductor. The results of these analyses appear on the "Minimum Size Summary" tab. This tab also includes the results of the minimum size studies that were performed in Case No. 2019-00271.

Q. DID YOU PERFORM ANY ZERO-INTERCEPT ANALYSES TO DETERMINE THE CUSTOMER AND DEMAND COMPONENTS OF TRANSFORMERS, POLES, AND CONDUCTORS?

A. Yes. In its Order dated April 27, 2020, in Case No. 2019-00271, the Commission stated that the Company should perform a zero-intercept study in its next base rate case. Page 1 of Attachment JEZ-5 shows the results of the zero-intercept analyses and how they compare with the results of the minimum size studies.

Q. PLEASE DESCRIBE THE ZERO-INTERCEPT ANALYSIS OF TRANSFORMERS.

A. The zero-intercept analysis of transformers appears on page 4 of Attachment JEZ-5. Transformer cost and quantity data were obtained from the Company's plant accounting records, and the average cost for each transformer accounting group was calculated. Only transformers with ratings of about 500 kVA or lower were included. The accounting data groups transformers into size ranges, e.g., 46-150 kVA. For each accounting group, I assumed that the typical transformer in the group had a size that was approximately in the middle of the range. For example, I assumed that all transformers in the 46-150 kVA accounting group were 100 kVA transformers. These assumptions were necessary because more granular data is not available. If a straight line is drawn through the various data points (size versus average cost), the calculated zero-intercept cost (i.e., the cost of a zero-kW transformer) is $1,604. This is lower than the minimum size study cost of $2,231. The zero-intercept method results in a customer percentage of 69.55% versus the customer percentage of 22.69% in the minimum size study. This very large difference in customer percentages occurs because the zero-intercept method does not account for the age of the transformers that exist on the Company's distribution system. The minimum size study uses a Handy Whitman factor to recognize that many transformers were installed decades ago and recorded on the Company's books at much lower costs than current costs.

Q. PLEASE DESCRIBE THE ZERO-INTERCEPT ANALYSIS OF POLES.

A. The zero-intercept analysis of poles appears on page 2 of Attachment JEZ-5. Pole cost and quantity data were obtained from the Company's plant accounting records, and the average cost for each pole-size accounting group was calculated. Only poles with heights of 70 feet or smaller were included. If a straight line is drawn through the various data points (size versus average cost), the calculated zero-intercept cost (i.e., the cost of a zero-foot pole) is $186. This is lower than the minimum size study cost of $1,288 for primary poles and $820 for secondary poles. The analysis includes both primary and secondary poles because the accounting data does not specify the type of pole in each category. The zero-intercept method results in a customer percentage of 8.66% for primary poles versus the customer percentage of 27.20% in the minimum size study. The zero-intercept method results in a customer percentage of 10.62% for secondary poles versus the customer percentage of 21.61% in the minimum size study.

Q. PLEASE DESCRIBE THE ZERO-INTERCEPT ANALYSIS OF CONDUCTORS.

A. The zero-intercept analysis of conductors is based on three types of commonly used conductor on the Company's distribution system. Only three data points were used because of the difficulty of obtaining consistent engineering data that matches cost versus ampacity. The line compares the ampacity rating of the conductor versus the cost per circuit mile. The analysis uses overhead conductor costs and assumes that the minimum size for overhead would also apply to underground conductor. In other words, underground circuits would not exist in a hypothetical minimum size system. The zero-intercept cost of conductors with zero ampacity (i.e., a conductor that cannot carry any current) was calculated to be $10,494 per circuit mile. The use of this zero-intercept cost results in customer percentages of overhead conductor that are substantially higher than the percentage derived from the minimum size study. I believe that this large difference in customer percentage occurs because the zero-intercept method does not account for the age of the overhead conductor that exist on the Company's distribution system. For underground conductor, the zero-intercept method results in lower customer percentages versus the minimum size method.

Q. WHY DID YOU USE THE MINIMUM SIZE ANALYSES IN THE COST OF SERVICE STUDY INSTEAD OF THE ZERO-INTERCEPT ANALYSES?

A. I believe that the minimum size analyses, using the Handy Whitman indexes, more accurately calculate the costs of minimum size systems. The minimum size analyses use actual costs of actual minimum size equipment. I believe that the zero-intercept method has the following flaws:

- The zero-intercept method does not recognize that much of the equipment on the distribution system was installed many years ago, and the costs of the older equipment were recorded at much lower dollar values than current. This flaw is especially noticeable when looking at transformers.
- The zero-intercept method assumes that there is a linear relationship between equipment size and cost.
- The zero-intercept method assumes that this linear relationship between size and cost continues outside of the range of data that was used to develop the line.
- The zero-intercept method attempts to accurately compute the costs of fictitious equipment that do not and cannot exist (e.g., zero height poles).
- The Company's plant accounting records are not sufficiently detailed to perform the zero-intercept analyses without making numerous assumptions about the size of equipment within various accounting

groups.

On the other hand, the minimum size method uses actual costs of actual equipment, and it adjusts those costs for decades of inflation. I believe that the minimum size methodology more accurately depicts the split between the customer and demand components of transformers, poles, and conductors.

Q. PLEASE DESCRIBE THE METHODOLOGY USED TO ALLOCATE COMMON AND GENERAL PLANT.

A. I functionalized common and general plant based on functional salaries and wages as presented on pages 354-355 of Duke Energy Kentucky's 2021 FERC Form 1 annual report. I then used distribution kW and various weighted O&M expense ratios to allocate each function to customer classes.

Q. PLEASE EXPLAIN HOW YOU ALLOCATED A&G EXPENSES USING THIS METHODOLOGY.

A. I functionalized A&G expenses based on the same functional salaries and wages used for general and common plant. After I functionalized the expenses, I allocated the expenses to rate classes based on the allocation of direct O&M for that function. For example, A&G expenses functionalized as distribution were allocated to rate classes based on each rate class' allocation of direct distribution O&M.

Q. WHAT ARE THE RATE BASE ADJUSTMENTS THAT YOU IDENTIFY IN THE COST OF SERVICE?

A. While net plant is the largest single component of rate base, there are other items which must be added to or subtracted from rate base. These items include deferred income taxes, miscellaneous deferrals, and working capital which includes materials and supplies and prepayments.

Q. HOW DID YOU ALLOCATE THE ADJUSTMENTS THAT WERE SUBTRACTED FROM RATE BASE?

A. I allocated the subtractive adjustments based on the net plant ratios and other allocators for each rate class.

Q. HOW DID YOU ALLOCATE ADJUSTMENTS THAT WERE ADDED TO RATE BASE?

A. I used various factors to allocate the amounts reflected in the Accumulated Deferred Income Tax Account 190.

Q. HOW DID YOU ALLOCATE WORKING CAPITAL?

A. Working capital consists of the following items: fuel inventories, emission allowances, materials and supplies, prepayments, cash, and other miscellaneous items. Fuel Inventories and emission allowances were allocated to rate groups based on K301, class kWh ratios; materials and supplies were allocated using PD29, class net plant ratios; general insurance and excise tax were allocated to rate groups using net plant ratios NP29, collateral asset was allocated to rate groups based on K301 class kWh ratios.

Cash working capital is based on the lead/lag study.

Q. HOW DID YOU ALLOCATE DEPRECIATION EXPENSES?

A. I allocated depreciation expenses to rate class based on the functional class net-depreciable plant ratios.

Q. HOW DID YOU ALLOCATE REAL ESTATE AND PROPERTY TAXES?

A. I allocated real estate and property taxes to rate class based on the functional class net plant ratios.

Q. HOW DID YOU ALLOCATE PAYROLL AND HIGHWAY TAXES, THE PSC ASSESSMENT AND OTHER MISCELLANEOUS TAXES?

A. I allocated the PSC Maintenance Taxes to class based on each rate class revenue ratio. I allocated Payroll, Highway and Other Miscellaneous Taxes to rate class based the class-weighted A&G expense ratio (A315).

Q. HOW DID YOU ALLOCATE FEDERAL AND STATE INCOME TAX ADJUSTMENTS AND DEDUCTIONS?

A. I reviewed each income tax adjustment and deduction to determine the functional cause of the adjustment and deduction, then selected the appropriate allocation factor. For example, an "Other Deductions" item, tax depreciation in excess of book depreciation, was allocated to the rate classes based on the class depreciation expense ratio (DE49).

Q. HOW DID YOU ALLOCATE OTHER OPERATING REVENUES?

A. I evaluated each other operating revenue item to determine the source of the revenue, then selected the appropriate allocation factor. The class ratio of present revenues was the primary allocation factor used to allocate the revenue credits to the respective rate groups.

Q. DID YOU USE ANY OTHER ALLOCATION FACTORS IN THE COST OF SERVICE STUDY?

A. Yes, there are many plant and expense ratios that were developed internally in the cost of service study. The cost of service study lists each item's allocation factor under the column identified as "ALLO."

IV. RESULTS OF COST OF SERVICE STUDY

Q. WHAT DO THE RESULTS OF THE COST OF SERVICE STUDY SHOW?

A. Schedule FR-16(7)(v)-14, page 1 of 15, is a summary of the cost of service study that shows the costs allocated to each rate class.

Q. HOW WERE THE RESULTS OF YOUR COST OF SERVICE STUDY USED IN THESE PROCEEDINGS?

A. The results of the fully allocated cost of service study by rate class were supplied to Duke Energy Kentucky witness Bruce Sailers, who used this data to develop the proposed rate design for these proceedings.

V. DISTRIBUTION OF PROPOSED REVENUE INCREASE

Q. DID THE COST OF SERVICE STUDY SHOW THAT THE INCREASE REQUIRED FOR EACH CUSTOMER CLASS WAS PROPORTIONAL?

A. No. The cost of service study revealed that there are significant differences among the rate classes when comparing the actual return earned by each rate class to the 7.526 percent overall return on rate base being requested in this case. Put another way, developing rates that generate the amount of revenue that equals the allocated revenue requirement for each rate class will mean much greater increases for some rate classes, in terms of percentage increases, than other classes.

To mitigate the rate shock that may come from eliminating the subsidy/excess (or rate disparities) among the rate classes, the Company is proposing to use a two-step process to distribute the proposed revenue increase. The first step eliminates 5 percent of the subsidy/excess revenues between customer classes based on present revenues. The second step allocates the rate increase to customer classes based on electric original cost depreciated (OCD) rate base.

Q. THE WATER PUMPING RATE CLASS APPEARS TO BE RECEIVING A RATE INCREASE~~DECREASE~~. PLEASE EXPLAIN HOW THIS IS BEING HANDLED IN THE PROPOSED RATES.

A. The customers in this class are served under special contracts. The rates for these customers will increase~~not change~~. The proposed rate increase~~decrease~~ for this class was subtracted from~~added to~~ the proposed revenues for Rate DT~~S~~.

Q. PLEASE EXPLAIN IN GREATER DETAIL THE FIRST STEP THAT ELIMINATES 5 PERCENT OF THE SUBSIDY/EXCESS REVENUES.

A. Again, it is a general tenet of ratemaking that each class should, to the extent practicable, pay the costs of providing service to that class. The elimination of a portion of the subsidy/excess takes into consideration that the Company is not earning the same rate of return on all customer classes. It is unlikely that equal rates of return across all rate classes are achievable; nonetheless, to the extent possible, large variances among the customer classes should be eliminated. A comparison of revenues under present rates and at the retail average rate of return is made and then 5 percent of that amount is added to, or subtracted from, the rate increase to determine the proposed revenues in this proceeding.

Admittedly, this proposal lets a subsidy/excess persist but it will reduce the gap so that each class is paying rates that more closely reflect their costs of service.

Q. HOW DID THIS RATE DISPARITY ARISE?

A. Rate disparities exist mostly because over the years rates have not been set based on the cost to serve customers as determined by a cost of service study. Other factors include: (1) customer mix often changes between rate cases, *i.e.,* residential, for example, may make up more or less of the total today than it did the last time rates were set; (2) different asset classes depreciate at different rates and because different asset classes are allocated differently, long periods between rate cases can shift the relative costs to serve each rate class. Also, regulators may purposely allow subsidy/excesses to persist in the interest of rate gradualism.

Q. WHY DID YOU PROPOSE A FIVE PERCENT REDUCTION OF THE SUBSIDY/EXCESS REVENUES IN THESE PROCEEDINGS?

A. The present rate of returns by class shown on Work Paper FR-16(7)(v), page 1, indicate that there is a significant difference in those returns. To ensure that each rate class pays the actual cost to serve that class and move each class to the average rate of return, 100 percent of the subsidy/excess would need to be eliminated. However, given the wide disparity among rate classes, complete elimination of the subsidy excess would cause a dramatic swing in rate impacts between and among various rate classes. By proposing to eliminate only five percent of the subsidy/excess, the Company is choosing to invoke the rate making principle of gradualism so to mitigate the volatility of 100 percent subsidy/excess elimination.

VI. CONCLUSION

Q. WERE ATTACHMENTS JEZ-1 THROUGH JEZ-4, SCHEDULES B-7, B-7.1, B-7.2, D-3, D-4 AND D-5, AS WELL AS, FR 16(7)(v), AND WORKPAPER FR 16(7)(v), AND ATTACHMENT JEZ-5, ZERO INTERCEPT PREPARED BY YOU OR UNDER YOUR SUPERVISION?

A. Yes.

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

A. Yes.