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BEFORE THE CORPORATION COMMISSION OF THE STATE OF OKLAHOMA

IN THE MATTER OF THE APPLICATION OF	)	
OKLAHOMA GAS AND ELECTRIC COMPANY	)	
FOR AN ORDER OF THE COMMISSION	)	
AUTHORIZING APPLICANT TO MODIFY ITS	)	CASE NO. PUD 2023-000087
RATES, CHARGES, AND TARIFFS FOR RETAIL	)	
ELECTRIC SERVICE IN OKLAHOMA	)	

Direct Testimony

of

Lauren E. Maxey

on behalf of

Oklahoma Gas and Electric Company

December 29, 2023

Lauren E. Maxey

Direct Testimony

Q. **Please state your name, position, by whom you are employed, and your business address.**

A. My name is Lauren Maxey. I am the Manager of the Cost of Service department for Oklahoma Gas and Electric Company ("OG&E"). My business address is 321 N. Harvey, Oklahoma City, Oklahoma, 73102.

Q. **Please summarize your professional qualifications and educational background.**

A. I have worked in OG&E's regulatory department since January 2020 as a Lead Cost Analyst in the Cost of Service and Rates Administration department. In July of 2023, I accepted my current role as Manager of Cost of Service. My Cost of Service responsibilities include responsibility for operating and maintaining the Cost of Service model, including ensuring that all costs are properly classified and each class of customers are charged based on their proportionate share of these costs, which is determined by the allocators that are developed in the Cost of Service model. Prior to joining OG&E's regulatory department, I worked as a Senior Accountant for three years in OG&E's Fuel and Revenue Accounting department. My responsibilities included calculation of the Oklahoma Fuel Adjustment Clause, accounting for OG&E transactions in the Southwest Power Pool for transmission service, accounting for fuel purchases and balancing transactions, and other revenue accounting tasks and reporting.

Prior to joining OG&E, I was employed by Enable Midstream Partners LP (formerly Enogex LLC) as a Senior Accountant in the Corporate Accounting department from 2014 to 2017. I was responsible for consolidations, preparation of financial statements, external reporting requirements, incentive compensation accounting and reporting, and general accounting monthly, quarterly, and annual tasks. I began my career in 2007 at Oklahoma Natural Gas Company as an Accountant in the General Accounting department where I was responsible for various tasks of increasing complexity, including accounts receivable and payable analysis, gas purchase accounting, preparation of internal and external reporting, financial statement preparation and analysis, and general accounting functions such as monthly journal entries and reconciliations. I earned a Bachelor of Science in Accounting from Southwestern Oklahoma State University in 2007 and a Master's in Business Administration from Oklahoma City University in 2022.

Q. **Have you previously testified before this Commission?**

A. Yes. I have submitted testimony in Case No. PUD 2021000164.

Q. **What is the purpose of your direct testimony?**

A. The purpose of my direct testimony is to support the Company's cost-of-service study ("COSS") and the resulting update to the Oklahoma retail jurisdictional and class allocations. The COSS is designed to reflect allocation and functionalization of rate base and other costs based on accepted cost causation principles which supports the proper rate design for retail customers.

<u>COST OF SERVICE STUDY RESULTS</u>

Q. **Please provide a brief summary of the results of the update to the Oklahoma retail jurisdictional and class revenue requirements?**

A. The COSS reveals that Oklahoma retail revenues are deficient by $332.5 million. The impact to the class revenue requirements are as follows: Residential revenues are deficient by $160.5 million; General Service revenues are deficient by $37.7 million; Power & Light revenues are deficient by $62.7 million, Large Power & Light revenues are deficient by $47.5 million; and all other classes are deficient by $24.2 million.

Q. **Please provide a brief summary of the results of the update to the Oklahoma retail jurisdictional allocators as computed in the COSS.**

A. The Production Demand allocator is 91.74% and the Transmission Demand and Transmission Demand Southwest Power Pool ("SPP") allocators are 80.38% and 91.71%, respectively.

Q. **How do these results compare with the final jurisdictional allocators from the Company's last general rate case, Cause No. PUD 2021000164?**

A. The allocators between jurisdictions have remained relatively flat. The current production allocator is 0.35% higher than the final production allocator from Cause No. PUD 2021000164 filing which was 91.39%. The current Transmission Demand and Transmission Demand SPP allocators are 0.78% and 0.52% higher than the final transmission allocators from the 2021 filing which were 79.60% and 91.19%. Figure 1 shows a side-by-side comparison of the results of the two cases.

Figure 1: Jurisdictional Demand Allocators

	PUD 2023000087	PUD 202100164	Difference
Production Demand	91.74%	91.39%	0.35%
Transmission Demand	80.38%	79.60%	0.78%
Transmission Demand SPP	91.71%	91.19%	0.52%

COST OF SERVICE STUDIES

General Explanation of a Cost of Service Study

Q. **What is a cost of service study?**

A. A COSS is used to determine the revenue requirement to be recovered from a utility company's jurisdictional and individual customer classes. In the COSS, historical *pro forma* test year embedded costs are either allocated or directly assigned to the jurisdiction and customer classes.

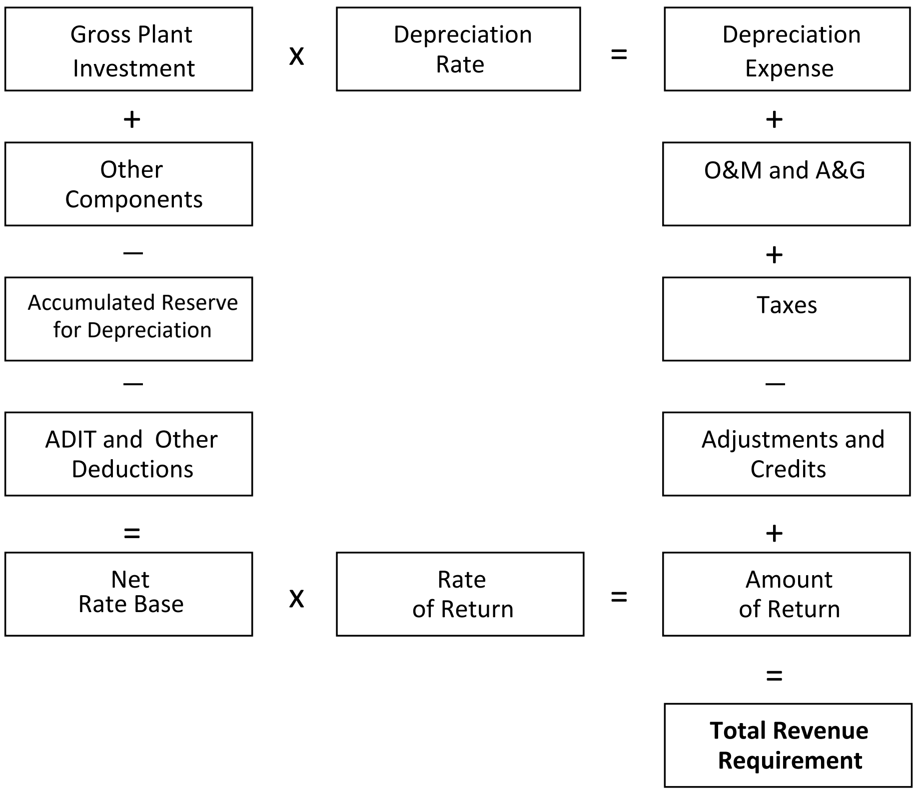
Q. **What sources are used for the historical costs in a cost of service study?**

A. Cost of service studies rely on the utility company's historic, or embedded, statements of revenue, number of customers, energy sales, accounting reports, engineering records, customer billing records, and load survey data. Investor-owned electric utilities in Oklahoma are required by the Federal Energy Regulatory Commission ("FERC") to keep their accounting records according to the "Uniform System of Accounts for Public Utilities and Licensees" ("USOA"), CFR Title 18, Subchapter C, Part 101. The OCC adopted the USOA requirements as well (see OAC 165:35-27-4(a)). The USOA sets the guidelines for recording assets, liabilities, income, and expenses into various accounts. Embedded costs are used as the basis for FERC Form 1 annual reports prescribed by FERC.

Q. **Please describe how a cost of service study is structured.**

A. The cost of service study is designed to determine a revenue requirement. The components of the revenue requirement within the COSS model are summarized in Figure 2.

Figure 2: Components of a Cost of Service Study



Q. **What type of costs and cost components are included in the cost of service studies you are sponsoring?**

A. Fixed costs and variable costs are two types of broad cost categories included in cost of service studies. Fixed costs are costs that do not vary with output, remain constant in the short run, and include capital costs, return, depreciation expense, income taxes, property taxes, and some operation and maintenance ("O&M") expense. Variable costs are costs that vary with output which include fuel costs, purchased power and some O&M expense.

Additionally, there are sub-components of the fixed and variable costs. These include directly assigned costs that are incurred to serve a particular customer or class of service (street lighting, dedicated substation circuits, etc.) and what are called joint or common costs. Joint or common costs are those costs that are shared by all customers because they are incurred to produce jointly beneficial products. These costs are allocated either on the basis of the overall ratios of those costs that have been directly assigned, or by a series of allocators that best reflect "cost causation" principles, or by a detailed analysis of each account to determine who receives the benefits.

Q. **Please define cost causation.**

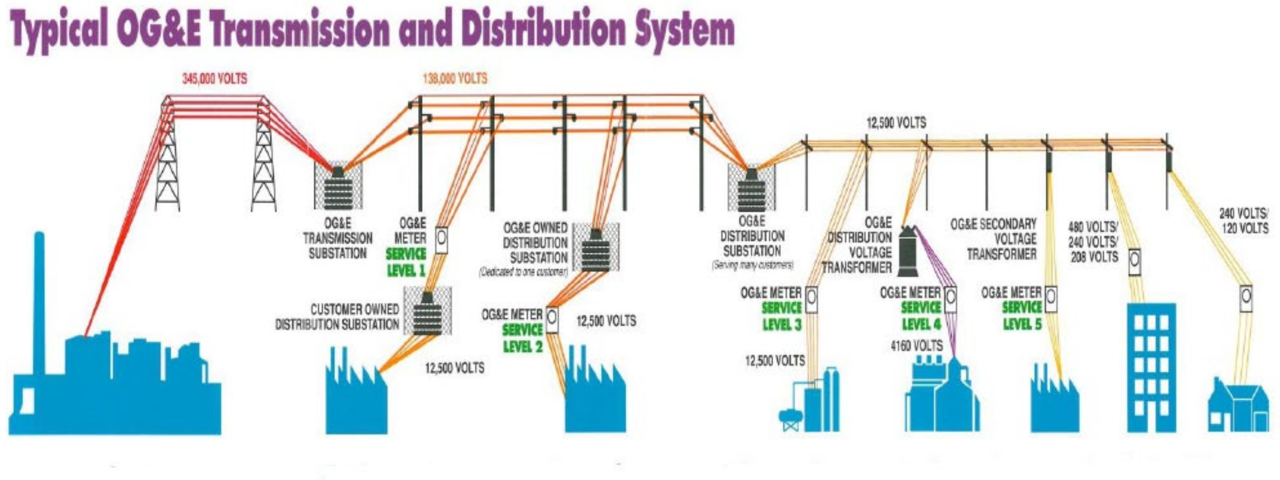
A. Cost causation is the determination as to what, or who, is causing costs to be incurred by the utility in providing service to its customers. An examples of cost causation is when a customer request service at a new location. This request could cause the Company to incur costs such as investment in line transformation, a service drop, metering facilities. It will establish a commitment on the part of the Company to provide, among other things, monthly billings and customer service.

Q. **Please generally describe the physical characteristics of the electric industry that cause costs to be incurred.**

A. Generation, transmission, and distribution are the three main components of a vertically integrated utility.[1] Figure 3 illustrates how power flows from the power plant to ultimate consumers on the OG&E system.

[1] NARUC Manual, page 4

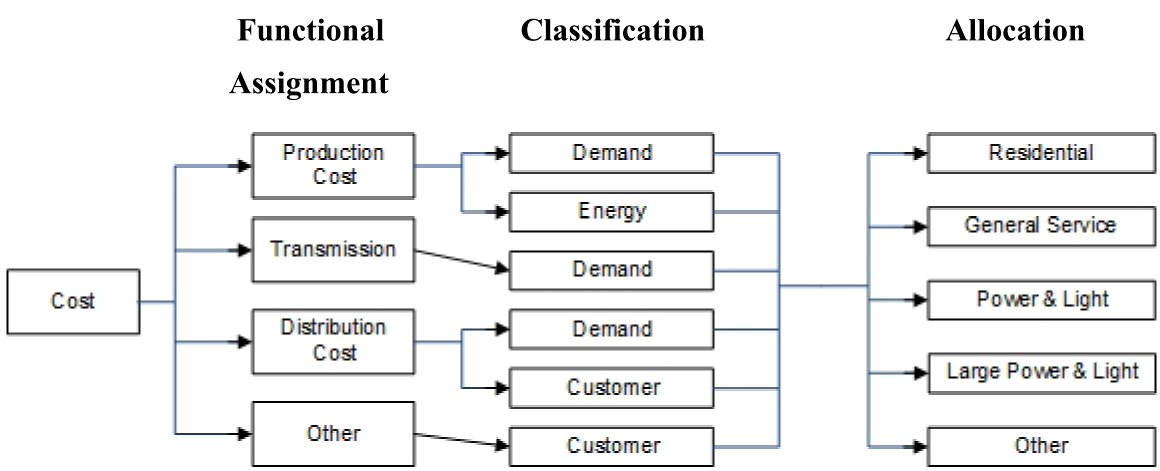
Figure 3: OG&E Transmission and Distribution System



Q. **How is this information separated to determine the cost of serving the various classes of utility customers?**

A. Costs are allocated to customer classes using a three-step method including functionalization, classification, and allocation. This methodology is shown in Figure 4.

Figure 4: Three-Step Method



Functionalization Process

Q. **Please describe the functionalization process?**

A. Once the relevant data is gathered, the costs are separated by function. Typically, functions in a fully integrated electric utility are:

1. Production
2. Transmission
3. Distribution
4. Customer Service
5. Administrative and General ("A&G")

The production function captures the costs associated with power generating facilities. The transmission function captures the costs associated with the high voltage lines and substations that deliver power from generators to the distribution system, other utilities, and some large customers. The distribution function includes facilities and costs associated with distribution substations, primary and secondary lines, transformers, service drops, and meters that connect most customers to the utility network. The customer service function encompasses the services and costs associated with providing billing, collection, customer information, and related services. The A&G function is a general service category that captures the costs associated with management of the business and general services such as staffing, accounting, legal, regulatory, communications, general purpose buildings, maintenance of such facilities, and other costs that may not be directly assignable to the other functions.

Classification Process

Q. **Please describe the classification process.**

A. Classification is a refinement of functionalized costs. Functionalized costs are further separated into three classifications:

1. Demand costs – costs associated with the maximum rate of energy used by the customer
2. Energy costs – cost that vary with the amount of energy used by customers
3. Customer costs – costs related to billing, metering, payment collections, and customer service

Typical cost classifications used in cost studies are shown in Figure 5.

Figure 5: Classifications

FUNCTION	CLASSIFICATION
Production	Demand, Energy
Transmission	Demand
Distribution	Demand, Customer
Customer Service	Customer

As seen above, production plant costs, such as depreciation expense and return on investment, are generally considered to be demand costs. Fuel costs and certain production O&M expenses are energy costs because they vary with the quantity of energy produced. Transmission costs are typically considered as demand because they are mainly fixed and do not vary with energy usage. Distribution system costs are driven by the need to deliver the diversified peak demand of customers served from each facility and by the number of customers served. Distribution costs for substations, primary lines and transformers tend to vary with the size of the load served. Customer service costs vary with the number of customers and the complexity of meeting their needs. The classification process provides a basis on which to allocate different categories of costs (demand, energy, or customer) to the Company's jurisdictions, and ultimately to the customer classes through the allocation process.

<u>Allocation Process</u>

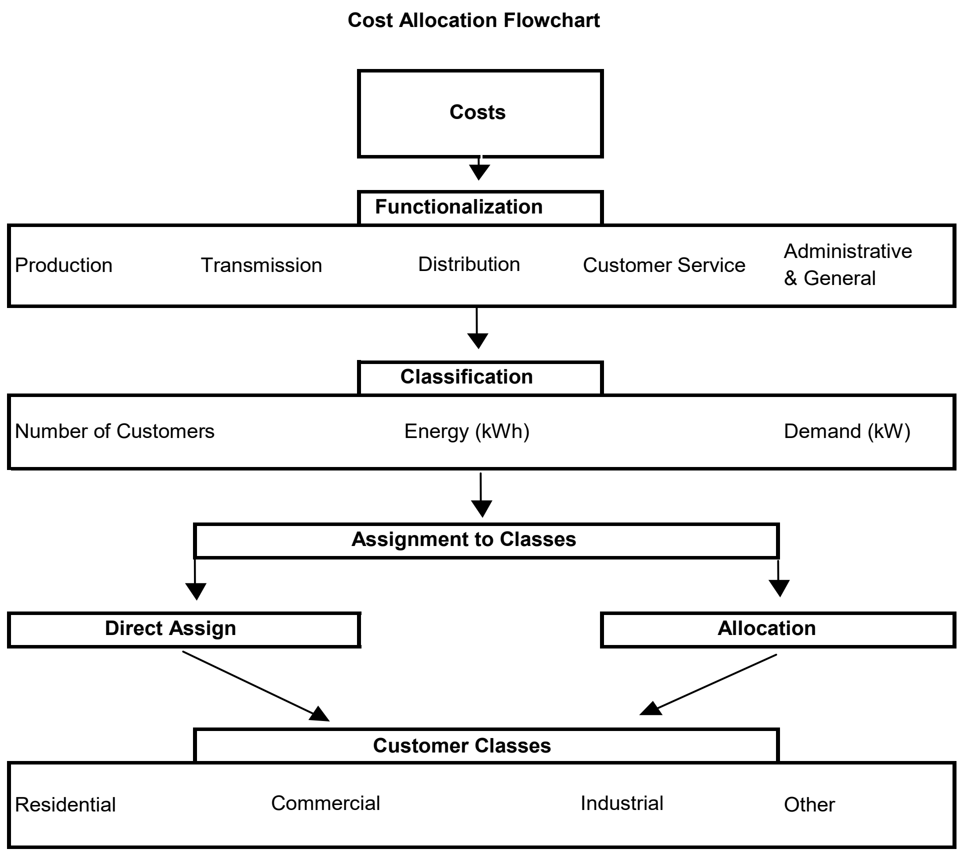
Q. **Please describe the allocation process.**

A. After costs are functionalized and classified, they are either allocated or directly assigned among jurisdictions. Within the Oklahoma retail jurisdiction, the functionally classified costs are then further allocated or assigned among classes of customers, based on cost causation. OG&E's customer classes have been determined and grouped according to the nature of service provided and the load characteristics. OG&E's major customer classes are generally grouped as Residential, General Service, Power and Light, Large Power and Light, and Other.

The objective of this process is to assign costs in a reasonable and understandable way. As discussed earlier, some costs are directly assigned and others are allocated among the classes; directly assigned costs are costs that can be readily identified as belonging to a jurisdiction, a single class or even a single customer. For example, customer meters are directly assigned to their respective customer class. Similarly, the costs associated with the poles and luminaries used for street lighting in Oklahoma are directly assigned to the Oklahoma jurisdiction and then to the street lighting class.

Most costs, however, are attributable to more than one type of customer. These joint costs must be allocated to the appropriate jurisdiction and then to the Oklahoma jurisdictional retail customer classes by an allocation methodology that recognizes each class's contribution to the cost driver that ultimately determines the overall level of cost for each sub-category of utility service. Figure 6 is a flowchart that provides an overview of the steps used to assign/allocate costs to jurisdictional customer classes. The process detailed below is applied to each cost category in the cost of service study.

Figure 6: Cost Allocation Flowchart



Q. **What is the result of the functionalization, classification, and assignment/allocation process?**

A. When the process is completed and all the costs are allocated to the jurisdictions and customer classes, the result is a fully allocated embedded cost of service study that establishes the cost responsibility for each jurisdiction and customer class of service within that jurisdiction.

OG&E'S JURISDICTIONAL COST OF SERVICE STUDY

Q. **Did OG&E submit a jurisdictional cost of service study as described in the Commission's minimum filing requirements?**

A. Yes. The Company submitted its COSS and is provided in Section K of the MFR package. The jurisdictional cost of service study allocates costs between OG&E's Oklahoma and Arkansas retail operations, and FERC jurisdictional costs. These Oklahoma jurisdictional retail costs are then used to conduct the Oklahoma jurisdiction's class costs of service study as described below.

Q. **What does the Company do to ensure that the fully allocated costs are reasonable?**

A. The Company uses the following criteria to judge the appropriateness of its allocation methodology:

1. The method should reflect the planning and operating characteristics of the utility's system.
2. The method should recognize individual customer class characteristics such as energy use, peak demand on the relevant portion of the system, service diversity characteristics, or the number of customers.
3. The method should produce reliable results that are relatively stable from year-to-year.
4. Customers who benefit from the use of the system should also bear appropriate cost responsibility for the system.

Q. Does Section K of the Minimum Filing Requirements ("MFR") package contain the Company's jurisdictional cost of service?

A. Yes. Section K of the MFR package sets forth the Company's jurisdictional Cost of Service. The schedules in Section K and supporting work papers in the supplemental package provide the support for those calculations.

Schedule K-1 shows the pro forma adjusted Total Company cost of service. Each of the supporting schedule's details, by account, the associated allocation basis for the amounts shown on Schedule K-1. Figure 7 lists such supporting schedules.

Figure 7: Supporting Schedules

Schedule Name	Description
Schedule K-2.1	Pro forma electric revenues based on current rates
Schedule K-2.2	Operation and maintenance expenses
Schedule K-2.3	Depreciation expense
Schedule K-2.4	Taxes other than income
Schedule K-2.5	Plant in service
Schedule K-2.6	Accumulated depreciation
Schedule K-2.7	Construction work in progress
Schedule K-2.8	Plant held for future use
Schedule K-2.9	Working capital
Schedule K-2.10	Other rate base adjustments

OG&E's CLASS COST OF SERVICE STUDY

Q. **Please describe Section L of the MFR package as it relates to the class cost of service study you are sponsoring.**

A. Section L identifies the revenue, revenue deductions, income taxes, rate base components and return on rate base for each Oklahoma customer class. With the exception of the two proposed changes to allocation methodologies discussed below, these costs are allocated in a manner consistent with OG&E's previous filings before the Commission.

Q. **Please generally describe the contents and organization of Section L.**

A. Schedule L-1 is the Rate Design Cost of Service for the *pro forma* test year. It shows the Oklahoma jurisdictional pro forma adjusted cost of service by customer class under rates placed in effect as of October 1, 2021. Revenue, revenue deductions and rate base are organized in the same manner as on Schedule K-1. Line 31 shows the percentage rates of return earned from each class under current rates.

Supporting Schedules, L-2.1 through L-2.10, show in detail the revenue, allocation of costs and rate base components to each Oklahoma customer class. These schedules provide the same information as the schedules in Section K, except that the information is provided by Oklahoma customer class.

Schedule L-3 presents the change in sales revenue for each class if a rate of return on rate base was to be applied equally to all classes of service. Line 13 is the total class revenue requirement needed to achieve the Company's proposed return on rate base. Line 14 is the pro forma class revenue based on existing rates for the test year. Line 15 is the difference between the class revenue requirement and the current tariff revenue. This deficiency or excess represents the class change needed in current tariffs for rate design. Line 16 shows the class revenues received from current tariffs.

Schedule L-4 indicates the percent increases necessary to recover the revenue deficiency through sales revenue for each class. Line 12 indicates the return on rate base by class of service adjusted for the deficiency at these levels of revenue.

Q. **How are the results of the class cost of service study used in this proceeding?**

A. The results of the class cost of service submitted in this proceeding are used for two reasons.

1. Provide embedded cost information that is used as a tool in developing the pricing structures for each customer class; and
2. Provide information with which present and proposed relative rates of return by customer class can be compared and reviewed.

CHANGES TO THE COST OF SERVICE STUDY

Q. **Are there any updates or changes to the COSS model filed in this case?**

A. Yes. The Company's COSS includes two improvements to allocations in this case to more accurately align with cost causation and to assign costs in a manner that provides a more accurate relative rate of return (RROR) for each customer class. First, OG&E allocates wind production costs to customers on a blended demand and energy allocator. Second, OG&E allocates transmission costs to retail customer classes by using a twelve coincident peak ("12CP") allocator.

Q. **What does it mean when you use a coincident peak allocator?**

A. A coincident peak ("CP") methodology is used to assign costs to a jurisdiction or customer class based on the jurisdiction's or class's contribution to the total at the peak of the system. A 4 CP allocator assigns costs based on the jurisdiction's or class's contribution to peak demand during OG&E's four highest peaks coincident with the system peak and a 12 CP allocator assigns costs based on the jurisdiction's or class's peak demand during OG&E's twelve highest peaks coincident with the monthly system peak.

<u>Proper Allocation of Wind Production Costs</u>

Q. **Please describe the proposed change to the allocation of wind production costs.**

A. The Company is proposing to change the allocation of wind production costs to a blended allocation of 84% energy and 16% demand. The Commission recently approved this blended allocator for a PSO wind facility in Order No. 738571 in Case No. PUD 2022-000093. Currently, the Company allocates all wind production costs based on its production demand allocator, which is a four coincident peak ("4CP") average and excess ("A&E") allocator ("4CP A&E").

Q. **Why is the Company proposing this change?**

A. The Company is proposing this change to reflect the proper allocation of these costs and better align the cost allocation with the cost causation related to these production assets. The use of a production demand allocator alone does not match how the particular costs and benefits of wind generation are delivered to customers. The goal is to match the demand and energy characteristics of wind generation so that costs are allocated properly.

Q. How do you determine the percentage of demand characteristic for allocating wind generation?

A. SPP uses an "effective load carrying capability" ("ELCC") methodology to "correctly assess the capacity value of renewable resources."[2] Under this approved ELCC methodology, OG&E's wind facilities have been assigned a capacity value of 14% of their nameplate value by the SPP. OG&E has 791 MW of wind generation in its generating resource portfolio, but the SPP accreditation rules only lets OG&E count 109 MW or 14% of the nameplate value for purposes of generating capacity. That is, while wind generating resources provide significant amounts of *energy* to the grid, the value assigned for reliable *capacity* is limited given the intermittent nature of those resources.

The proposed split between demand and energy allocators is meant to reflect the value of the wind resources to customers. OG&E and its customers receive a capacity value of 14% from the wind facilities, but most of the benefit comes from the fuel-free energy sold into the SPP Integrated Marketplace. Attributing 14% of the nameplate capacity as providing demand benefits is a reasonable value to assign as it matches the portion of the cost providing capacity value to OG&E's system.

Q. **Why is OG&E proposing the 16% production demand/84% production energy blended allocator in this case when OG&E is only accredited 14% of its wind facilities for capacity purposes?**

A. OG&E is proposing 16% demand to reflect the average summer value of wind determined by the SPP ELCC Wind and Solar Study,[3] as well as the blended allocator approved for PSO. Based on OG&E's specific accreditation, OG&E could propose a blended allocator of 14% production demand and 86% production energy but has slightly modified the allocator to reflect the blended allocator contained in the SPP study and the recently issued PSO order.

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[2] SPP ELCC Wind and Solar Study Report, SPP Resource Adequacy, November 2022 https://spp.org/documents/68931/2022%20spp%20elcc%20study%20wind%20and%20solar%20report%20correction%2020230303.pdf

[3] *Id.* at Table 9.

Q. **Can you expand on why the continued use of a production demand allocator is inappropriate for wind production assets?**

A. The main benefit of producing wind energy is the fuel savings related to any production. These energy benefits are then captured by customers through their kWh consumption through fuel cost savings. This means that high volume users retain a greater proportion of fuel offsets compared to the amount these same customers contribute to wind facility costs when using the production demand allocator. Moreover, the significant financial benefits derived from production tax credits associated with wind generation are provided to customers on an energy basis. This means the current methodology allocates costs on a demand basis while providing the unique benefits of wind generation on an energy basis. Therefore high-volume users reap unproportional benefits solely due to the unique nature of wind generation versions traditional generation resources.

Q. **Is the Company proposing using only a production energy allocator for wind costs?**

A. No. As discussed above, while wind production benefits could be assigned solely on a production energy allocator, OG&E is proposing a blended allocator that better mirrors the appropriate capacity and energy benefits of the wind resources. While the larger benefit of wind energy production is the lower cost of energy produced by these assets (via fuel cost offsets), the SPP does recognize a certain value of the capacity provided by wind resources and has assigned OG&E a 14% value for that capacity. OG&E believes that the blended allocation of 16% production *demand* and 84% production *energy* reflects the value of wind more accurately.

Q. **Is this allocation methodology for wind generation supported by parties other than the Company?**

A. Yes. This allocation methodology has been described and supported by a variety of parties such as the PUD Staff,[4] Attorney General, and AARP.

For example, the AG has opposed the continued use of a production demand allocation stating the "a demand allocation factor should reflect the capacity credit received

[4] Stroup Resp. Test., Feb. 24, 2023, Cause No. PUD 2022-121, pp. 10-13 (recommending a blended cost allocator of 50% demand/50% energy).

from the generation facility."[5] The AG further argued that the associated production tax credits are being supplied to customers on an energy basis which results in costs allocated on a demand basis while benefits are allocated on an energy basis. The AG stated, "[t]his situation significantly benefits high-load-factor customers as they are assigned less cost allocation and more benefit allocation, while it is detrimental to low-load-factor customers such as residential customers."[6] Therefore, the AG recommended a blended allocation for PSO similar to OG&E's proposal.[7]

AARP has also recognized that using only production allocation for wind generation ignores the unique nature of wind generation and is not consistent with cost causation and unfairly assigns costs harming residential customers.[8] AARP argued that "residential customers cross-subsidize other customers, including large commercial and industrial classes."[9] AARP also relied on the ELCC methodology used by SPP to support a blended allocation for PSO similar to OG&E's proposal.[10]

In addition, this 16% production demand and 84% production energy blended allocation methodology was recently approved in Public Service Company of Oklahoma's ("PSO") most recent rate case for PSO's Sundance wind facility.[11] In that PSO case, the adoption of a blended wind allocator was supported by PSO, the AG, the AARP and the PUD Staff.

<u>Proper Allocation of Transmission Costs</u>

Q. **Please describe the proposed change to the allocation of transmission costs.**

A. The Company is proposing to use a 12CP allocator for transmission costs within the Oklahoma jurisdiction. This will mirror the allocation method that is used to assign transmission costs across OG&E's jurisdictions, will be consistent with the allocator used by OG&E within the FERC and Arkansas jurisdictions, and will reflect the allocation of these costs to customers using cost causation principles.

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[5] Alexander Resp. Test., Nov. 1, 2019. Cause No. PUD 2019-48, p. 7.
[6] *Id.* at 8.
[7] *Id.* at 9.
[8] Nelson Resp. Test., March 20, 2023, Case No. PUD 2022-93, pp. 41-43.
[9] *Id.* at 42.
[10] *Id.* at 43.
[11] See Case No. PUD 2022-000093, Order No. 738571 (Order Modifying Final Order No. 738226), at p.16.

Q. **How does OG&E assign transmission costs across its jurisdictions?**

A. OG&E assigns transmission costs to customers using a 12CP allocation in the other jurisdictions in which it operates, both to determine what portion of costs to assign to each jurisdiction and what portion of costs to assign to each class within the jurisdiction. The only exception is the use of a 4CP allocator that was being used to allocate costs to each customer class in Oklahoma. The use of a 12CP is aligned with cost causation principles and is recognized in the other jurisdictions in which the Company operates, with this exception.

Q. What allocator does the FERC jurisdiction use for allocating transmission plant?

A. The FERC jurisdiction currently and historically uses a 12CP when setting rates for transmission service through the FERC approved formula rates. The SPP also uses a 12 CP allocator when assigning costs across the SPP on a load ratio share basis.

Q. How does OG&E allocate transmission costs in its Arkansas retail jurisdiction?

A. OG&E uses a 12CP allocator to assign costs within the Arkansas retail jurisdiction, both to determine the jurisdictional portion of costs Arkansas customers will pay and to assign costs to each customer class.

Q. Please explain why this change in allocation reflects cost causation principles?

A. A 12 CP allocator makes sense when you consider how SPP plans its transmission system. SPP plans for and operates the transmission grid in order to provide access to the most cost-effective power to all customers throughout the SPP footprint across all twelve months of a year; not just in the summer months. A cost allocation method that allocates transmission costs based on customer contributions to each of the 12 coincident peaks reflects the OG&E customers and their usage of the transmission system across the year. Transmission is not built to only meet peak demand in certain seasons, but to transmit electric energy from generating facilities to load during all months of the year. Moreover, as noted above, the SPP utilizes a 12-CP allocator when assigning costs across its SPP footprint and OG&E uses a 12-CP allocator when setting its FERC transmission rates and its Arkansas retail rates. By allocating transmission plant costs to customers using a 12CP allocator, the Company moves to align all cost allocations for transmission services.

Also, the use of the 4CP allocator is not only inconsistent with the SPP's use of a 12CP allocator, but it allows certain customers classes to receive the benefits of transmission while not paying their proportionate share of plant costs. This is demonstrated in Figure 8 below.

Figure 8: Class Impact of 4CP to 12CP Allocation Change

Customer Class	Transmission Costs - 12CP	Transmission Costs - 4CP	Dollar Difference	% Difference
Residential	**$160,494,539**	**$165,981,818**	**($5,487,280)**	**(3%)**
Gen. Service	**$37,717,056**	**$38,695,838**	**($978,783)**	**(3%)**
Public Sch.	**$12,083,634**	**$12,602,318**	**($518,684)**	**(4%)**
PL SL1	($2,653,627)	($3,055,210)	$401,582	(15%)
PL SL2	$4,225,765	$4,159,759	$66,006	2%
PL SL3	$2,071,299	$1,315,968	$755,331	36%
PL SL4	$1,595,927	$1,499,233	$96,693	6%
PL SL5	$57,413,802	$57,571,476	($157,674)	0%
PL Total	**$60,575,602**	**$61,491,227**	**$1,161,939**	**2%**
LPL SL1	$3,177,216	$2,651,622	$525,595	17%
LPL SL2	$36,329,096	$32,696,104	$3,632,992	10%
LPL SL3	$5,776,558	$5,188,786	$587,771	10%
LPL SL4	$812,540	$734,418	$78,123	10%
LPL SL5	$1,404,252	$1,297,269	$106,982	8%
LPL Total	**$41,100,527**	**$42,568,199**	**$4,931,464**	**10%**
Other	**$12,089,285**	**$11,197,941**	**$891,343**	**5%**

Figure 8 demonstrates the cross-subsidization that is occurring across the various customer classes should 4CP allocation continue. The proper allocation of transmission costs is critical because transmission costs make up 14% of total gross plant in service. By making these changes, the allocations will now reflect proper allocation treatment which matches cost causation of these costs, which in turn corrects and, in the future, prevents the creation of any cost inequities between the classes.

Q. **Is there anything preventing the Company from proposing changes to its allocations in each general case?**

A. No. OG&E can propose changes to its allocator in each rate case. When an allocator no longer allocates costs in a fair way, OG&E believes a change in allocation is appropriate.

1MW COSS

Q. **Did the Final Order in OG&E's last rate case, Cause No. PUD 2021000164, require OG&E to prepare a COSS with a separate class for customers served pursuant to 17 O.S. § 158.25(E) ("1 MW Exception") for new load being initially served by OG&E after January 1, 2014?**

A. Yes. This study was performed and a separate 1MW COSS has been provided as part of my workpapers and it includes additional columns for applicable 1MW loads.

CONCLUSION

Q. **Would you please summarize your testimony regarding the cost of service studies you are supporting?**

A. The jurisdictional cost of service study identifies the embedded cost of service for the Oklahoma retail, Arkansas retail and FERC jurisdictions. This embedded cost of service study is based upon sound cost allocation principles, reflects all test year adjustments, and establishes the cost responsibility for the provision of electric service to each jurisdiction.

The class cost of service study quantifies the embedded cost of service for each Oklahoma retail jurisdictional class based on cost causation. In addition, the class cost of service study provides information necessary to develop cost-based rates for OG&E's retail customers as discussed in the Direct Testimony of Company witness Bryan J. Scott.

Q. **What is your recommendation to the Commission?**

A. I recommend the Commission accept the Company's filed COSS.

Q. **Does this conclude your direct testimony?**

A. Yes.

AFFIDAVIT

STATE OF OKLAHOMA)
)
COUNTY OF OKLAHOMA)

On the 28th day of December 2023, before me appeared Lauren Maxey, to me personally known, who, being by me first duly sworn, states that she is the Manager of Cost of Service for Oklahoma Gas and Electric ("OG&E") and acknowledges that she has read the above and foregoing document and believes that the statements therein are true and correct to the best of her information, knowledge, and belief.

Print Lauren Maxey

Signature Lauren Maxey

Subscribed and sworn to before this 28th day of December, 2023.

Harrison L. Burton
Notary Public

My commission expires: 10-17-2026

Seal

HARRISON L. BURTON
NOTARY
14009452
EXP. 10/17/26
PUBLIC
STATE OF OKLAHOMA