**BEFORE THE CORPORATION COMMISSION OF OKLAHOMA**

| | | |
|---|---|---|
| IN THE MATTER OF THE APPLICATION OF | ) | |
| **OKLAHOMA GAS AND ELECTRIC COMPANY** | ) | |
| FOR AN ORDER OF THE COMMISSION | ) | CAUSE NO. PUD 201100087 |
| AUTHORIZING APPLICANT TO MODIFY ITS | ) | |
| RATES, CHARGES, AND TARIFFS FOR RETAIL | ) | |
| ELECTRIC SERVICE IN OKLAHOMA | ) | |

# Direct Testimony

of

Greg Veitch

on behalf of

Oklahoma Gas and Electric Company

July 28, 2011

TESTIMONY INDEX

## I. INTRODUCTION

Q. **Please state your name and business address.**

A. My name is Greg Veitch. My business address is 321 N. Harvey, Oklahoma City, Oklahoma 73102.

Q. **By whom are you employed and in what capacity?**

A. I am employed by Oklahoma Gas and Electric Company ("OG&E" or "Company") as Manager, Cost of Service.

## II. PURPOSE AND OUTLINE OF TESTIMONY

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

A. My testimony presents and supports OG&E's jurisdictional and class cost of service studies ("COSS"); and the development of the jurisdictional and class allocations and related schedules as required by OAC 165:70-5-4. The Company's cost of service studies are based upon a test year ending December 31, 2010.

Q. **Briefly outline the content of your cost of service study testimony.**

A. I will discuss the following topics:

1. Cost of Service Studies in General
2. OG&E's Jurisdictional Cost of Service Study
3. Class Cost of Service Study

## III. COST OF SERVICE STUDIES

### A. General Explanation of a Cost of Service Study

Q. **What is the purpose or nature of a cost of service study?**

A. A COSS is used to determine the portion of the overall revenue requirement to be recovered from each of the Company's jurisdictional and/or customer classes. The COSS is also used as a tool to determine rates of return for the various customer classes. In a COSS, particular costs are either allocated or directly assigned to jurisdictions and/or customer classes. Because costs are generally determined from historical accounting records, this type of analysis is referred to as an accounting or *embedded* COSS. Costs are allocated on a *cost causation* basis; and when the COSS is prepared and all costs are allocated, the result is a fully allocated embedded COSS that establishes cost responsibility and makes it possible to determine the cost of providing service to each jurisdiction and customer class. The fully allocated embedded COSS becomes the focal point for rate design discussions. NARUC's cost allocation manual notes that "While opinions vary on the appropriate methodologies to be used to perform cost studies, few analysts seriously question the standard that service should be provided at cost."[1]

### B. Data and Accounting Sources Utilized

Q. **What sources are used in a cost of service study?**

A. Cost of service studies rely on the utility company's historic, or "embedded", monthly 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, Part 101. The Oklahoma Corporation Commission ("Commission") adopted the USOA requirements, as well (OAC 165:35-27-4(a)). The USOA sets the guidelines for recording assets, liabilities, income, and expenses into various accounts. The costs recorded in each FERC

[1] National Association of Regulatory Utility Commissioners (NARUC) Electric Utility Cost Allocation Manual, January 1992, page 12.

account are examined to verify compliance with these guidelines and are typically adjusted to reflect applicable Commission policies and for known and measurable changes to the test year level of expenditures. Embedded costs are also used as the basis for FERC Form 1 annual reports prescribed by FERC.

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

A. The following broad categories of costs are included in the cost of service studies: 1) Fixed Costs – costs that do not vary with output, remain constant in the short run and include capital costs, return, depreciation, income taxes, property taxes, and some operation and maintenance ("O&M") expense; and 2) Variable Costs—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, i.e. costs that are shared by all customers because they are incurred to produce jointly beneficial products.

Q. **Please expand on the discussion of joint and common costs.**

A. Joint costs occur when the provision of one service is an automatic by-product of the production of another service. In the electric industry, the most common occurrence of joint costs are the costs of production where the capacity installed to serve peak demands is also available to serve demands at other times of the day or year. Common costs are incurred when an entity produces several services using the same facilities or inputs. Overhead expenses such as the Treasurer's salary or the accounting and legal expenses are examples of costs that are common to all of the separate services offered by the utility.

In an embedded cost study, the joint and common costs identified in the test year 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 such as

labor, wages or plant ratios, or by a detailed analysis of each account to determine beneficiality. As noted in the NARUC manual, "The classification and treatment of joint and common costs requires considerable judgment in an embedded cost study"[2]

Q. **What do you mean by *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. Examples of cost causation may include: 1) a customer's request for service at a new location that necessarily results in an immediate investment in line transformation, a service drop and metering facilities and establishes a commitment on the part of the Company to provide, among other things, answers to questions and a monthly billing; or 2) a customer's energy use or usage, usually expressed in kilowatt-hours (kWh). .

Q. **How are a utility's costs reflected in a cost of service study?**

A. In aggregate, the costs are normally expressed in terms of a revenue requirement. The COSS consists of O&M, depreciation, taxes (including income taxes) and capital costs (rate of return requirement). "The total of these four components produces the test period cost of service which equals the total revenue requirements upon which rates are designed"[3]. On a customer class basis, revenue requirement is the revenue required from each customer class to provide service to that customer class.

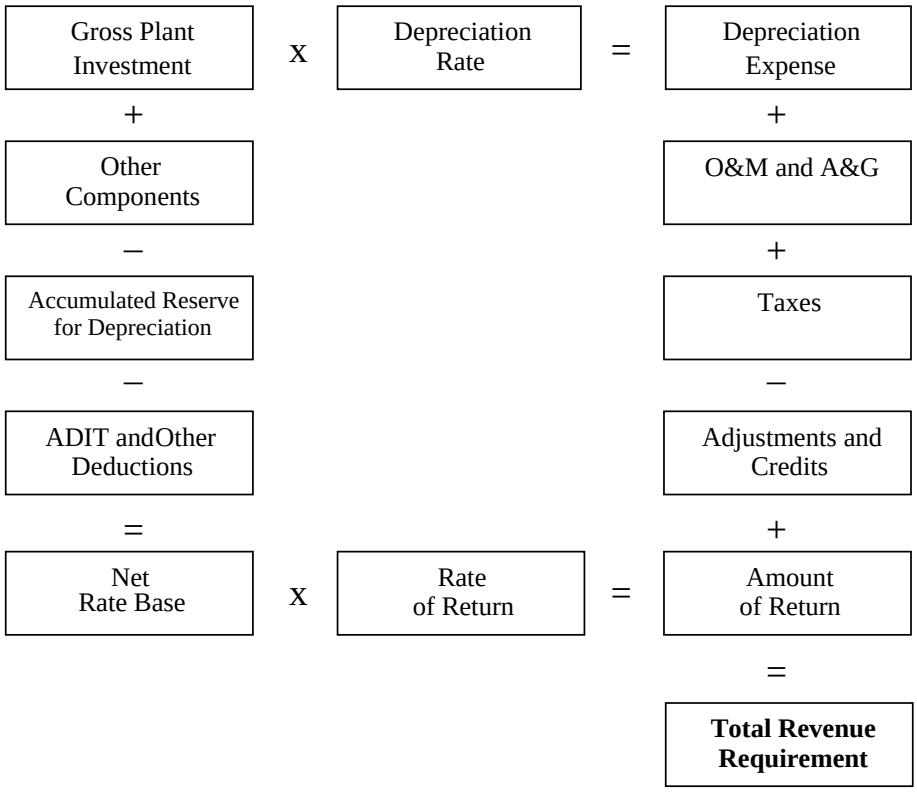
Q. **Please describe how a cost of service study is structured.**

A. Chart 1 summarizes the typical components of a cost of service study.

[2] NARUC Manual, page 15

[3] Accounting for Public Utilities, §7.08

**Chart 1**
Components of a Cost of Service Study

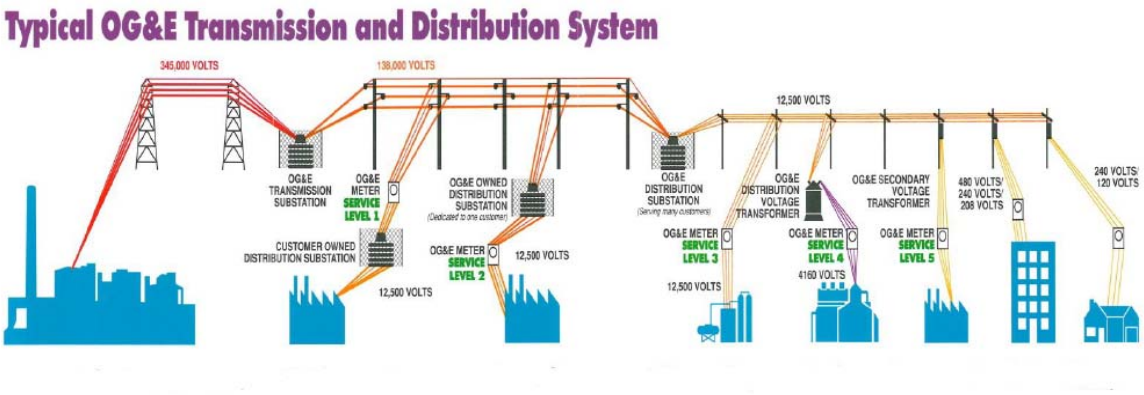



Q. **Please describe the physical characteristics of the electric industry that causes costs to be incurred.**

A. "In the electric utility industry, power is produced by the utility company at central generating stations, transmitted over high voltage power lines to the load centers within its franchise area or to other points of delivery, and finally distributed at lower voltages to the ultimate customers. Those three components, generation, transmission and distribution, comprise the basic elements of the physical structure of the electric utility industry".[4] Chart 2 illustrates how power flows from the power plant to ultimate consumers on the OG&E system.

[4] NARUC Manual, page 4

**Chart 2**




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

A. Costs are allocated to customers by using a three-step process to assign costs to the customer classes: functionalization, classification, and finally, allocation.

C. Functionalization Process

Q. **Would you 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 and Purchased Power;
2. Transmission;
3. Distribution;
4. Customer Service; and
5. Administrative and General (A&G).

The production function captures the costs associated with production facilities and power purchase agreements. The transmission function captures the costs associated with the high voltage lines and stations that deliver power to the distribution system and connects with other utilities, generators, and some large customers. The distribution function includes facilities and costs associated with distribution stations, 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 meter reading, billing, collection, customer information and related services such as advice and assistance. 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.

D. Classification Process

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

A. Functionalized costs are further separated into three classifications: (1) demand-related costs (costs associated with the maximum rate of energy use by the customer, also referred to as kW demand), (2) energy costs (costs that vary with the amount of energy used by customers, e.g., kWh consumption), and (3) customer costs (costs that are directly related to the number of customers served). Typical cost classifications used in cost studies are shown in Chart 3.

**Chart 3**

| 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-related costs. Fuel costs and certain production O&M expenses are energy-related because they vary with the quantity of energy produced. Transmission costs are typically considered as demand-related because they are mainly fixed and do not vary with energy usage. Distribution system costs are driven by the need to deliver the peak demand of customers served from each facility and by the number of customers served. Distribution costs for stations, primary lines and transformers tend to vary with the size of the load served, while service drop and meter

costs vary based on the number of customers receiving the service. 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.

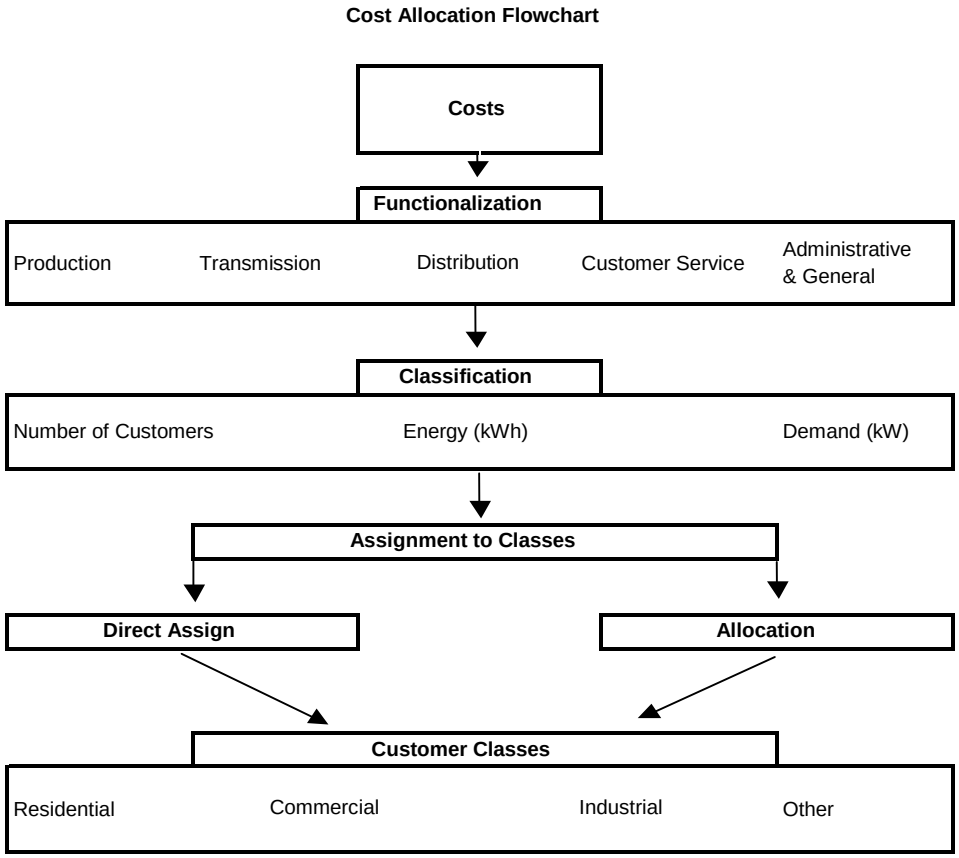
## E. Allocation Process

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

A. The functionally classified costs are allocated or assigned among jurisdictions (Oklahoma retail, Arkansas retail and FERC wholesale). Within the Oklahoma retail jurisdiction, the functionally classified costs are then allocated or assigned among classes of customers, based on the factors that most influence cost incurrence for each cost item. 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 allocation process involves dividing the classified costs among the jurisdictions and Oklahoma retail customer classes. The objective of this process is to assign costs in a reasonable and understandable way. As alluded to earlier, some costs are directly assigned and others are allocated among the classes. Directly assigned costs are costs that can be readily identified to a jurisdiction, a single class or even a single customer. For instance, 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 in that jurisdiction. Most costs, however, are attributable to more than one type of customer. These joint costs must be allocated to jurisdictions 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. Chart 4 is a flowchart that provides an overview of how the allocation of costs to jurisdictional customer classes is generally determined.

## Chart 4




The process described above is applied to each cost category and FERC account in the cost of service study by utilizing externally and internally developed allocators.

Q. **Please explain how external and internal allocators are used in OG&E's cost of service study.**

A. *External* allocation factors are based on data sources outside the cost of service model such as OG&E's accounting records and system load data. Generation costs are allocated based on external capacity and energy allocation factors using demand (kW) and energy (kWh) load data, depending on the nature of the account. Transmission costs are allocated using an external transmission allocation factor based on demand load data. Additionally, distribution system costs are allocated using demand and customer external allocators from multiple sources such as non-coincident demands and customer or meter

counts. The external allocator for certain distribution FERC accounts (Nos. 364-368) utilizes the zero-intercept method as discussed later in the testimony.

*Internal* allocation factors are generated within the cost of service model and based on some combination of external allocation factors, direct assigned costs, and other internal allocation factors. For example, the allocation factors for property insurance costs are based on plant investment amounts assigned to each function; therefore it is necessary to compute the amount of plant by function before property insurance costs can be assigned.

Q. **Please provide examples of how an external allocator would be derived for a COSS.**

A. Chart 5 below provides two examples of allocating costs between two separate jurisdictions and then among three customer classes in the second jurisdiction. Allocator "A" is an example of a demand allocation calculation using megawatt (MW) demands for each jurisdiction or classes. To arrive at the "Juris. 1" demand allocation of 50.63 percent, its 200 MW load was compared to the total company MW load of 395. The "Juris. 2" percentage was the remainder. The allocation for each of that jurisdiction's classes was derived by using the pro rata share of their MW loads to total company MW load. Allocator "B" is a customer allocation whereas each jurisdiction or class share of total number of customers is used to derive the percentages for allocation purposes.

**Chart 5**
**Externally Developed Allocators**

| **Allocator "A" (Demand)** | | | **Allocator "B" (Customer)** | | |
|---|---|---|---|---|---|
| Juris./Class | MW | % | Juris./Class | Customers | % |
| Juris. 1 | 200 | **50.63%** | Juris. 1 | 100 | **36.10%** |
| Class 1 | 100 | 25.32% | Class 1 | 75 | 27.08% |
| Class 2 | 75 | 18.99% | Class 2 | 50 | 18.05% |
| Class 3 | 20 | 5.06% | Class 3 | 52 | 18.77% |
| Juris. 2 | 195 | **49.37%** | Juris. 2 | 177 | **63.90%** |
| Total Co. | 395 | **100.00%** | Total Co. | 277 | **100.00%** |

Q. **Please provide an example of how an internal allocator would be derived.**

A. In Chart 6, allocator "C" percentages are calculated based on the summation of the dollars allocated to each jurisdiction or class for hypothetical FERC Accounts "abc" and "xyz". In this example, the Class 1 allocation percentage of 25.91 percent was calculated

by dividing its total costs for those accounts in the cost of service ($3,886) by the total company cost of $15,000. Chart 6 also illustrates how internal and external allocators may work together. The Class 1 dollar amount of $3,886 is the sum calculated by multiplying the demand allocator "A" percentage reflected in Chart 5 (25.32%) by the $10,000 total company amount for account "abc" and then multiplying the customer allocation "B" percentage in Chart 5 (27.08%) by the $5,000 total company cost for account "xyz". For these purposes, the different external allocators would be used because the source of costs accumulated in the respective accounts are best characterized as common to demand requirements for account "abc" and customer requirements for account "xyz".

**Chart 6**
**Internally Developed Allocator**

| (a) FERC ACCT | (b) ALLOC. | (c) TOTAL CO. | (d) Juris. 1 | (e) Juris. 2 (Sum Col.f~h) | (f) Class 1 | (g) Class 2 | (h) Class 3 |
|---|---|---|---|---|---|---|---|
| ACCT "abc" | "A" | $10,000 | $5,063 | $4,937 | $2,532 | $1,899 | $506 |
| ACCT "xyz" | "B" | $5,000 | $1,804 | $3,196 | $1,354 | $903 | $939 |
| TOTAL | | $15,000 | $6,867 | $8,133 | $3,886 | $2,802 | $1,445 |
| **ALLOCATOR "C"** | | **100.00%** | **45.78%** | **54.22%** | **25.91%** | **18.68%** | **9.63%** |

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

A. When the process is completed and all of 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 class of service.

## IV. OG&E'S JURISDICTIONAL COST OF SERVICE STUDY

### A. Contents of OG&E's Jurisdictional Cost of Service Study

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

A. Yes. The Company submitted its COSS as required in OAC 165:70-5-1 *et. seq*.

Q. **What criteria have been established to ensure that the allocation of costs to the customers is reasonable?**

A. The following criteria, although not an exhaustive list, provides an objective basis upon which to judge the appropriateness of an 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. **Do the allocation methods employed by OG&E meet these objectives?**

A. Yes, they do. The allocation methodologies used in the Company's jurisdictional and class cost of service studies were chosen while considering each of the criteria listed above. The results of the jurisdictional cost of service study can be relied upon to determine the revenue requirement for the Oklahoma retail jurisdiction and the class cost of service study can be relied upon to determine the cost to serve the retail rate classes.

Q. **Was the jurisdictional cost of service study developed in a manner consistent with the jurisdictional study previously filed by OG&E with the Commission?**

A. With the exception of some relatively minor changes which I will discuss, the methodologies employed by OG&E in the development of the jurisdictional cost of service study filed in the Company's previous rate review, Cause No. PUD 200800398, were used in the jurisdictional study filed in Section K of the Company's application package.

Q. **Briefly describe the contents of Section K.**

A. Section K sets forth the Company's Cost of Service and jurisdictional calculations; and the schedules in Section K provide the support for those calculations.

Schedule K-1, column one, shows the pro forma adjusted Total Company cost of service under existing rates. Columns two and three show the Oklahoma and Not-At-Issue (Arkansas Retail and FERC Wholesale) jurisdictional cost of service. The revenues, operating expenses, and rate base for the Oklahoma jurisdiction are indicated on lines 1, 11, and 31 respectively. Line 32 shows an earned rate of return of 7.41 percent for the Oklahoma jurisdiction under rates currently in effect.

Each of the supporting schedules details by account and the associated allocation basis for the amounts shown on Schedule K-1. Chart 7 lists such supporting schedules.

**Chart 7**

| 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 |

Q. **Would you please generally describe the contents of the jurisdictional cost of service study included in Workpaper K of the Company's supplemental package?**

A. Workpaper K-1 presents the summary results of the cost of service study for both the retail and the wholesale jurisdictions served by OG&E on a current rate of return basis. Workpapers K-2 and K-3 depict the allocation of revenue deductions and total rate base by jurisdiction. Workpapers K-4 and K-5 are not included in the Company's application

in printed format.[5] Workpaper K-6 provides a list of externally developed allocators used in the jurisdictional cost of service study set forth in Workpapers K-1 through K-5. Workpaper K-7 presents the demand and energy loss factors. Workpaper K-8 support for the demand allocation methodology is provided within my testimony. Workpaper K-9 details any changes in allocation factors from OG&E's last base rate case Cause No. PUD 200800398. Workpaper K-10 details the payroll distribution by account for each jurisdiction.

B. Classification Changes to Production Costs

Q. **Please describe the classification change in this case for production O&M expenses compared to OG&E's last filed case.**

A. Previously, OG&E used both a production demand allocator and an energy allocator to allocate production O&M expenses. As approved in Cause No. PUD 200800398 (Order No. 569281), OG&E is classifying all production O&M expenses in this case based on a production demand allocator. Using the production allocator CAP1SY for allocation of production O&M expenses is based on the theory that O&M accounts should generally follow the associated plant accounts, which is consistent with the treatment of OG&E's transmission and distribution expenses in the cost of service.

Q. **How have OG&E's owned wind farm costs been allocated in the past?**

A. Originally, in Cause No. PUD 200500059, Order No. 524078, the Commission approved an allocator based on the 2005 energy consumption or billed kWh sales and was 100 percent allocated to Oklahoma and Arkansas retail customers. The same wind generation allocation for the Oklahoma jurisdiction was used in OG&E's filed application in Cause No. PUD 200800398.

[5] Workpapers K-4, K-5, L-4, and L-5 detail classified expenses and rate base by account used in the Cost of Service. Printing requirements for these Workpapers are unnecessarily burdensome and voluminous to print from its electronic source. Therefore, OG&E, in agreement with the Director of the Public Utility Division, and in accordance with OAC 165:70-5-20 Part 5, sought waiver of the filing requirements for these said Workpapers to effectuate a more efficient case handling process. As such, OG&E will make available these Workpapers at its Corporate Headquarters located on 321 N. Harvey, Oklahoma City, Oklahoma 73102, as well as electronic copies of the same upon request.

Q. **How are OG&E's wind generation facilities investment and associated expenses classified and allocated differently in this case?**

A. As approved in Cause No. PUD 200800398, OG&E agreed to allocate all wind farm costs in this case using its production allocator CAP1SY. Therefore, in this proceeding, the Company is including the wholesale jurisdiction in the allocation of wind generation using the production allocator CAP1SY. This is a departure from previously filed cost of service studies which allocated OG&E's Centennial wind farm only to OG&E's retail customers and based on energy.

C. Classification Changes to Transmission Wind Farm Costs

Q. **Has OG&E allocated the transmission costs for wind farms differently than the allocation used in the previous case?**

A. Yes. OG&E is allocating all transmission facilities, including the wind farm related transmission, to the jurisdictions utilizing the CAP3SY allocator that is derived from the average of twelve monthly coincident peak demands ("12-CP").

D. Classification Changes to Distribution Costs

Q. **Did OG&E consider any changes from the last rate review related to classifications for the distribution function?**

A. Yes. OG&E hired a consulting firm, B & B Consulting International, L.L.C. ("BBCI"), to conduct "minimum system" and "zero intercept" studies.

Q. **What is the purpose of doing such an analysis of the minimum system or zero intercept methods?**

A. The purpose of such an analysis is to determine the best approach for allocating the portion of certain distribution costs that should be classified as customer-related. The distribution FERC Account Nos. 364 through 368 that were considered in the analysis are described in Chart 8.

**Chart 8**

| Account | Description |
|---|---|
| 364 | Poles, Towers and Fixtures |
| 365 | Overhead Conductors and Devices |
| 366 | Underground Conduit |
| 367 | Underground Conductors and Devices |
| 368 | Line Transformers |

The minimum system method assumes that a minimum size distribution system can be built to serve the minimum loading requirements of the customer. The zero intercept method seeks to identify that portion of plant related to a hypothetical no-load use situation.

Q. **What method is OG&E proposing?**

A. On the recommendation of BBCI, OG&E continues to support the "zero-intercept" method for classification of the customer-related component for distribution FERC Account Nos. 364 through 368. In support of this decision, the Company has provided the testimony of Mr. Larry Thompson for a more detailed description of the analysis and recommendation by BBCI.

E. Allocation Process

Q. **What are the primary demand allocators used in the COSS you are sponsoring?**

A. There are three primary demand allocators used in OG&E's COSS: production demand allocation factor (CAP1SY); transmission demand allocation factor (CAP3SY); and distribution demand-related allocation factor (CAP6OS). It should be noted that demand load data used in the development of these allocators in this case were weather normalized.

Q. **Why is it appropriate to use different demand allocation factors for production, transmission and distribution?**

A. Each of the three functional categories of production, transmission, and distribution have different cost drivers that require different allocation methods to most accurately match costs to the cost causers.

Q. **Does OG&E use the same production allocation methodology for both the jurisdictional split and class allocation?**

A. Yes. OG&E uses the CAP1SY allocator which is derived from the Average and Excess ("A&E") method using the system coincident peak demand ("1-CP").

Q. **Please describe how OG&E calculates the CAP1SY.**

A. The 1-CP A&E method utilizes two types of demand components in the allocation of production demand-related costs. The first component, the 1-CP, is the load of all customer classes at the time of the Company's highest measured weather normalized one-hour demand for the system. The 1-CP component is used to allocate the kW demands to each jurisdiction and Oklahoma retail customer class. The second component within the 1-CP A&E is an energy weighting component. The 1-CP A&E uses the total megawatt hours used during the test year to determine the average demand ("Average"). The 1-CP A&E demand method recognizes not only the class loads at the time of the maximum system peak, but also the amount of energy usage by each class during the test year to determine the excess component of the calculation. This allows OG&E to make a distinction between the cost of facilities to serve the average requirements and the cost of facilities to serve the excess. This distinction recognizes the diversity of various load requirements by the different customer classes. The determination of the factor for allocation to a jurisdiction or customer class on the basis of average demands utilizes the system annual load factor. The load factor is calculated by dividing the annual energy kWh consumption by the system peak demand. The excess factor is based on the difference between the jurisdiction's or customer class' coincident peak demands incurred at the time of system peak and the jurisdiction's or customer class' average demands.

Q. **Why does OG&E believe a CAP1SY production allocator is appropriate?**

A. This method is appropriate for the allocation of OG&E's production capacity costs for the following reasons:

1. The method recognizes the annual net system peak load (1-CP) used for resource planning in the Company and by the Southwest Power Pool, Inc. ("SPP") in its reserve capacity margin requirements;
2. The utilization of Company facilities by the classes of service throughout the year is considered in the method; and
3. The benefits of load diversity are shared among the jurisdictions and customer classes of service.

Q. **Please explain how the system coincident peak is determined.**

A. OG&E meters the energy produced from each generator within its control area and all system tie-lines between other control areas. This meter information is stored hourly for the test year. Summing all of the meter information, OG&E develops its hourly system load. The maximum value, and the associated date and time during the test year, determines the system coincident peak.

Q. **How does OG&E determine each class's contribution to the system coincident peak?**

A. OG&E uses hourly load research information to determine each class's load requirements at the date and time of the system peak, as defined in the previous question.

Q. **What adjustment did OG&E make to its production allocator CAP1SY calculation that is different than its last rate case?**

A. The production allocator CAP1SY methodology is the same in this proceeding. However, the Company modified the demand and energy input components of the allocator by crediting the Oklahoma jurisdiction for the direct assignment of 440 MW peak demand related to cogeneration contracts, as well as the energy provided by cogeneration and the

Sooner wind farm. I will discuss the changes to the energy allocator ENR1SY later in my testimony.

Q. **Why did OG&E make these modifications to the CAP1SY?**

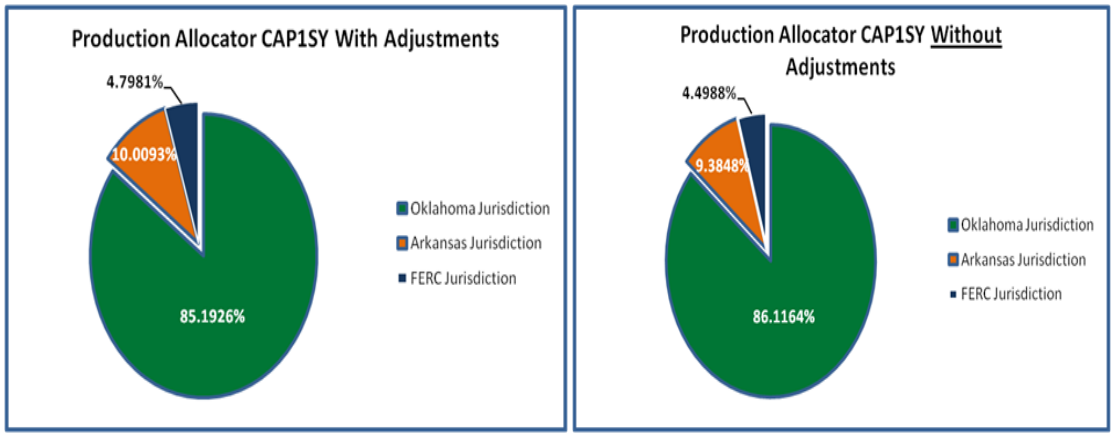
A. Costs not directly assigned in a COSS are considered joint costs. An example of a joint cost is generation resources. Appropriate allocators must be developed to assign these joint costs. Historically, the costs of OG&E's cogeneration contracts have only been charged to Oklahoma retail customers. The cogeneration contracts provide a 440 MW contribution to the Company's overall generation resources and should be considered in developing the allocation for OG&E's generation fleet.

Q. **What was the change in the CAP1SY from modifying the Oklahoma retail jurisdiction for the 440 MW demand supplied by cogeneration contracts and the associated cogeneration and Sooner wind farm energy kWhs?**

A. As a result of the change, the CAP1SY allocator decreased for the Oklahoma retail jurisdiction. This allocation methodology is supported by the cost causation principle discussed previously in my testimony and regulatory normalization practice. Chart 10 illustrates the change in allocation.

**Chart 10**

Production Allocator CAP1SY Comparison

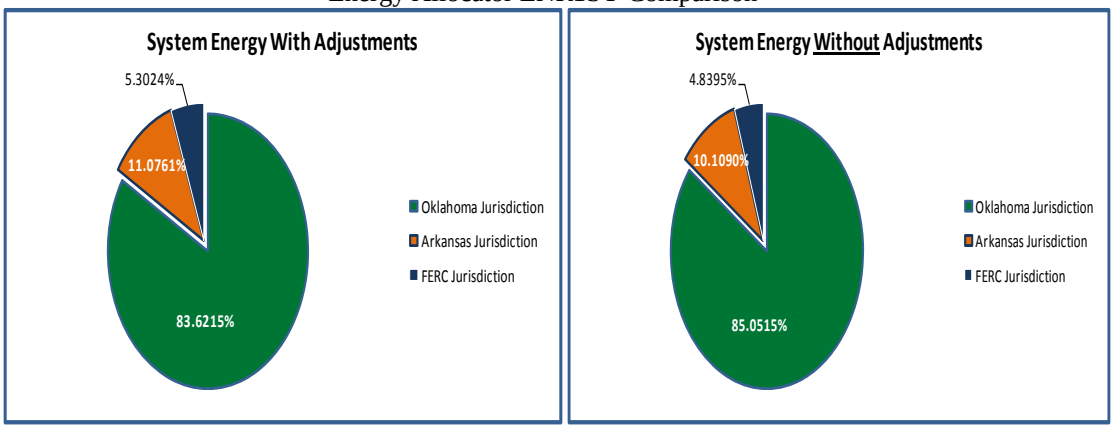


Q. **What modification did OG&E make to its energy allocator ENR1SY calculation that is different than its last rate case?**

A. The energy allocator ENR1SY methodology is the same in this proceeding. However, the Company modified the energy allocator to reflect the removal of the kilowatt hours associated with both cogeneration contracts and the Sooner wind farm. This modification was based on the same theory discussed above for the modification to the CAP1SY production allocator. Also, this modification follows the cost causation and regulatory normalization practices. Chart 11 illustrates the resulting decrease for the Oklahoma retail jurisdiction.

**Chart 11**

Energy Allocator ENR1SY Comparison




Q. **How has the Company historically allocated transmission costs?**

A. The Company has used an average of twelve monthly coincident peak demands (12-CP) allocation method for allocating these costs. Under this method, transmission demand costs are allocated in proportion to the average of the coincident monthly peak demands of the customer classes (adjusted for losses) at the time of the monthly net system peak demands. These demands were also weather normalized in this case.

Q. **Did you develop a new transmission allocator for SPP costs in this case?**

A. Yes. A new external allocator was developed and assigned the name "SPPCAP" in the COSS.

Q. **Please explain why this SPPCAP allocator was required.**

A. It was necessary to develop a new transmission allocator to allocate only those SPP investment costs and expenses that should be assigned 100% to retail customers. As a transmission owner and customer of SPP, OG&E is billed for such costs based on OG&E's load ratio share which does not include FERC wholesale customers which are billed directly by SPP. Additionally, the recently approved Southwest Power Pool Cost Tracker will utilize this allocator in its determination of billing factors.

Q. **How was the SPPCAP allocator developed?**

A. The CAP3SY transmission demand allocator was used as a starting point. The CAP3SY was rebased to 100% retail to exclude any allocation to the FERC wholesale jurisdiction.

Q. **What allocation methodology did you use for demand-related distribution costs?**

A. Demand-related distribution costs were allocated based on class non-coincident peak demands (NCPs), as opposed to CPs. The reason for using NCPs is that local distribution demand costs are incurred to serve area load, rather than a system load. Using NCPs instead of CPs in this methodology also recognizes that little or no diversity exists at this level except within each class.

Q. **What allocation methodologies did you use for customer-related distribution costs?**

A. Customer-related distribution costs are limited to the costs that vary directly with the number of customers (i.e., are incurred because of the existence of a customer). These costs include meters, service drops, transformers, and associated expenses. The customer-related distribution plant costs and associated expenses are allocated to the customers who require such facilities by using the weighted customer methodology. For example, meter reading expenses were allocated to jurisdictions based on the number of meters in each jurisdiction. This is the same method that was used in OG&E's previous rate cases.

Q. **Please describe the allocation of the remaining costs that are identifiable as customer-related.**

A. Customer accounting expenses, customer information expenses, and customer services expenses were allocated to each jurisdiction using a combination of adjusted test year end number of customers and various other customer-based allocators. This is the same method that was used in OG&E's previous rate cases.

## V. CLASS COST OF SERVICE STUDY

Q. P**lease describe the class cost of service study you are sponsoring.**

A. The class cost of service study is a fully allocated, embedded cost-based study, consistent with OG&E's previous filings before the Commission. An embedded class cost of service study assigns the retail jurisdictionally-allocated total Company costs to the individual retail customer classes to evaluate the cost the Company incurs in providing electric service to each individual retail customer class. Section L provides the revenue, revenue deductions, income taxes, return, rate base components and return on rate base for each Oklahoma customer class.

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

A. Schedule L-1 is the Rate Design Cost of Service for the test year. It shows the Oklahoma jurisdictional pro forma adjusted cost of service by customer class under rates placed in effect as of August 3, 2009. Revenue, revenue deductions and rate base are organized in the same manner as on Schedule K-1. Line 32 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. **Please describe the development of the allocation factors used in the class cost of service study shown in the Schedule L workpapers.**

A. A list of externally developed allocators used in the class cost of service study can be found in Workpaper L-6, along with a description of each allocation factor. A number of different allocation factors are employed in the study, consistent with the underlying cost causation for each item of rate base and expense separated into the three basic cost components: demand, energy, and customer.

Q. **Was the class cost of service study developed in a manner consistent with the study previously filed by OG&E with the Commission?**

A. Yes. The methodologies employed by OG&E in the development of the class cost of service study filed in Cause No. PUD 200800398 was used in the current class cost of service study.

Q. **Does the class cost of service study use the same allocation methods to allocate similar costs as is used in the jurisdictional cost of service study?**

A. Yes, for the most part the same methodologies for allocating costs are used in both the jurisdictional and class study; however, there is one major allocation methodology that differs in the class cost of service from those used in the jurisdictional study.

Q. **What allocation methodology differs between the jurisdictional cost of service and the class cost of service studies?**

A. The transmission demand-related costs are allocated somewhat differently in the jurisdictional and class cost of service studies.

Q. **Please discuss the difference in how the demand-related transmission costs were allocated in the Company's jurisdictional cost of service study versus the allocation methodology used in the class cost of service study.**

A. As I explained previously, the jurisdictional allocation of demand-related transmission costs is based upon a 12-CP methodology; however, the 4-CP method is used in the class cost of service study. This method is reasonable for customer class allocations because an examination of the OG&E system load characteristics over the past 27 years shows that the peak loads on the OG&E system are very seasonal. Additionally, as agreed to in Cause No. PUD 201000146, Order No. 583894, page 5 – paragraph 9:

> "The Commission finds that in OG&E's 2011 general rate case, the Company will file and recommend its customer class cost of service based on a 4-CP Transmission Plant allocator methodology."

OG&E witness James B. Long discusses the justification of using a 4-CP class allocator for transmission.

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 primarily used to: (1) provide embedded cost information that can be used as one tool in developing the pricing structures for each customer class; (2) provide information with which present and proposed relative rates of return by customer class can be compared and reviewed; and, (3) comply with Commission filing requirements. See the attached Exhibit GAV-1 (Schedule L-3 in the Application Package) that shows the increase in revenues by class at the equalized rate of return of 8.75 percent.

## VI. 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 wholesale jurisdictions. This embedded cost of service study is based upon sound cost allocation principles, reflects all of the 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 the Oklahoma retail individual customer classes that make up the Oklahoma retail jurisdiction. In addition, the class cost of service study provides information necessary to develop cost based rates for OG&E's retail customers.

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

A. Yes, it does.

SECTION L - RATE DESIGN COST OF SERVICE
SCHEDULE L-3

OKLAHOMA GAS AND ELECTRIC COMPANY
CHANGE IN SALES REVENUE
EQUAL RATE OF RETURN
TEST YEAR ENDING DECEMBER 31, 2010
CAUSE NO. PUD 201100087

| LINE NO. | DESCRIPTION | 1 TOTAL OKLA RETAIL JURISDICTION | 2 TOTAL RESIDENTIAL SERVICE | 3 TOTAL GENERAL SERVICE | 4 TOTAL OIL & GAS PRODUCTION | 5 TOTAL SCHOOLS NON_DEMAND | 6 TOTAL SCHOOLS DEMAND | 7 TOTAL POWER & LIGHT | 8 TOTAL LRG. POWER & LIGHT-TOU | 9 TOTAL MUNICIPAL PUMPING | 10 TOTAL LIGHTING SERVICE |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | SCHEDULE L-3 COS AT CLAIMED ROR | | | | | | | | | | |
| | EXPENSES | | | | | | | | | | |
| 1 | OPERATING EXPENSES | $1,389,977,894 | $620,098,184 | $124,139,466 | $9,998,032 | $13,854,651 | $7,623,567 | $336,114,652 | $249,077,291 | $6,295,430 | $22,776,619 |
| 2 | UNCOLLECTIBLE ACCOUNTS | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| 3 | TOTAL EXPENSES | $1,389,977,894 | $620,098,184 | $124,139,466 | $9,998,032 | $13,854,651 | $7,623,567 | $336,114,652 | $249,077,291 | $6,295,430 | $22,776,619 |
| | INCOME TAXES | | | | | | | | | | |
| 4 | EXISTING RATES | $64,675,517 | $29,898,296 | $9,458,290 | $1,028,994 | $1,162,265 | $652,744 | $20,479,764 | $830,969 | $475,541 | $688,654 |
| 5 | INCREASE | $28,393,350 | $19,400,672 | $1,345,528 | ($396,671) | $21,118 | ($147,284) | ($1,746,192) | $6,863,799 | ($103,343) | $3,155,722 |
| 6 | TOTAL INCOME TAXES | $93,068,867 | $49,298,968 | $10,803,818 | $632,323 | $1,183,383 | $505,460 | $18,733,572 | $7,694,768 | $372,198 | $3,844,376 |
| | RETURN | | | | | | | | | | |
| 7 | EXISTING RATES | $248,424,620 | $120,166,645 | $30,211,525 | $2,508,674 | $3,463,092 | $1,791,835 | $65,003,004 | $19,086,173 | $1,320,193 | $4,873,477 |
| 8 | INCREASE (DECREASE) | $44,862,607 | $30,653,824 | $2,125,988 | ($626,756) | $33,368 | ($232,715) | ($2,759,052) | $10,845,073 | ($163,286) | $4,986,164 |
| 9 | TOTAL RETURN | $293,287,227 | $150,820,469 | $32,337,513 | $1,881,919 | $3,496,460 | $1,559,120 | $62,243,952 | $29,931,245 | $1,156,908 | $9,859,641 |
| 10 | TOTAL REVENUE REQUIREMENT (L3 , L6 and L9) | $1,776,333,988 | $820,217,622 | $167,280,797 | $12,512,274 | $18,534,494 | $9,688,148 | $417,092,177 | $286,703,305 | $7,824,536 | $36,480,636 |
| 11 | RATE BASE | $3,351,854,028 | $1,723,662,503 | $369,571,578 | $21,507,640 | $39,959,540 | $17,818,520 | $711,359,453 | $342,071,376 | $13,221,802 | $112,681,615 |
| 12 | REQUESTED RATE OF RETURN | 8.75% | 8.75% | 8.75% | 8.75% | 8.75% | 8.75% | 8.75% | 8.75% | 8.75% | 8.75% |
| 13 | TOTAL REVENUE REQUIREMENT | $1,776,333,988 | $820,217,622 | $167,280,797 | $12,512,274 | $18,534,494 | $9,688,148 | $417,092,177 | $286,703,305 | $7,824,536 | $36,480,636 |
| 14 | OPERATING REVENUE | $1,703,078,031 | $770,163,126 | $163,809,281 | $13,535,701 | $18,480,008 | $10,068,147 | $421,597,421 | $268,994,433 | $8,091,164 | $28,338,750 |
| 15 | DEFICIENCY or (EXCESS) | $73,255,957 | $50,054,496 | $3,471,516 | -$1,023,427 | $54,486 | -$379,999 | -$4,505,244 | $17,708,872 | -$266,628 | $8,141,886 |
| 16 | SALES REVENUE (EXCLUDES MISC REVENUE) | $1,690,706,329 | $759,005,211 | $163,074,684 | $13,502,138 | $18,473,406 | $10,067,573 | $421,230,973 | $268,962,196 | $8,087,631 | $28,302,517 |
| 17 | PERCENT INCREASE IN SALES OF ELECTRICITY REVENUE | 4.30% | 6.50% | 2.12% | -7.56% | 0.29% | -3.77% | -1.07% | 6.58% | -3.30% | 28.73% |

**Exhibit GAV-1**