BEFORE THE ARKANSAS PUBLIC SERVICE COMMISSION

IN THE MATTER OF THE APPLICATION OF	)	
OKLAHOMA GAS AND ELECTRIC COMPANY	)	
FOR APPROVAL OF A GENERAL CHANGE IN	)	DOCKET NO. 16-052-U
RATES AND TARIFFS	)	

Direct Testimony

of

David Smith

on behalf of

Oklahoma Gas and Electric Company

QUALIFICATIONS, EXPERIENCE AND PURPOSE

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

A. My name is David Smith. 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 Senior Costing Analyst.

Q. **What is your educational background and professional experience?**

A. I graduated with a bachelor's degree in economics from the University of Central Oklahoma. I am pursuing further education at the graduate level in areas of both Finance and Economics at Oklahoma City University and the University of Oklahoma. In addition, I worked approximately five and a half years as a public utility regulatory analyst for the OCC. While at the Oklahoma Corporation Commission ("OCC"), I testified to numerous rate filings and cost trackers. I joined OG&E in 2010 as a Senior Costing Analyst.

Q. **Have you previously filed testimony before the Arkansas Public Service Commission ("APSC" or "Commission")?**

A. Yes. I have filed testimony in Docket No. 07-075-TF.

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. I sponsor schedules G-1, Cost of Service Summary, G-2, Rate Base Detail, G-3, Revenue and Expense Detail, G-4, Development of Allocation Group and summarize the calculated output of the Company's cost of service study used in its development. I also sponsor schedules G-1-1A through G-3-1A, which reflect the cost of service shown on both a functional and classification basis. The Company's cost of service studies are based upon a test year ending June 30, 2016. In addition, I discuss the Blackwell Wind Energy Purchase Agreement ("WEPA") and the associated benefit to Arkansas customers.

I. COST OF SERVICE STUDIES

A. General Explanation of a Cost of Service Study

Q. **What is the primary purpose 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. 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 National Association of Regulatory Utility Commissioners ("NARUC") 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, statements of revenue, number of customers, energy sales, accounting reports, engineering records, customer billing records and load survey data. Investor-owned electric utilities operating in Arkansas 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 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

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

FERC. For purposes of a rate case, the costs recorded in each FERC account are typically adjusted to reflect applicable APSC policies and for known and measurable changes to the test year level of expenditures.

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

A. Fixed 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; and variable 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.

Q. **How are joint and common costs allocated?**

A. 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 whether it is beneficial. 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 is 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. Such as: 1) a customer's request for service at a new location causes the Company to incur costs such as 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

[2] NARUC Manual, page 15

monthly billing; or 2) a customer's energy use or usage, usually expressed in kilowatt-hours ("kWh"), causes OG&E to incur costs related to capacity and energy in order to meet customer's demand.

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

A. The COSS consists of O&M, depreciation expense, taxes (including income taxes) and return on rate base. "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. **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 process: functionalization, classification, and finally, allocation. Below I explain each of these steps.

<u>C. Functionalization Process</u>

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 power generating 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

[3] Accounting for Public Utilities, §7.08

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 produced, e.g., kWh consumption); and (3) customer costs (costs that are directly related to the number of customers served). 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. Typical cost classifications used in cost studies are shown in Chart 1.

Chart 1

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

E. Allocation Processes

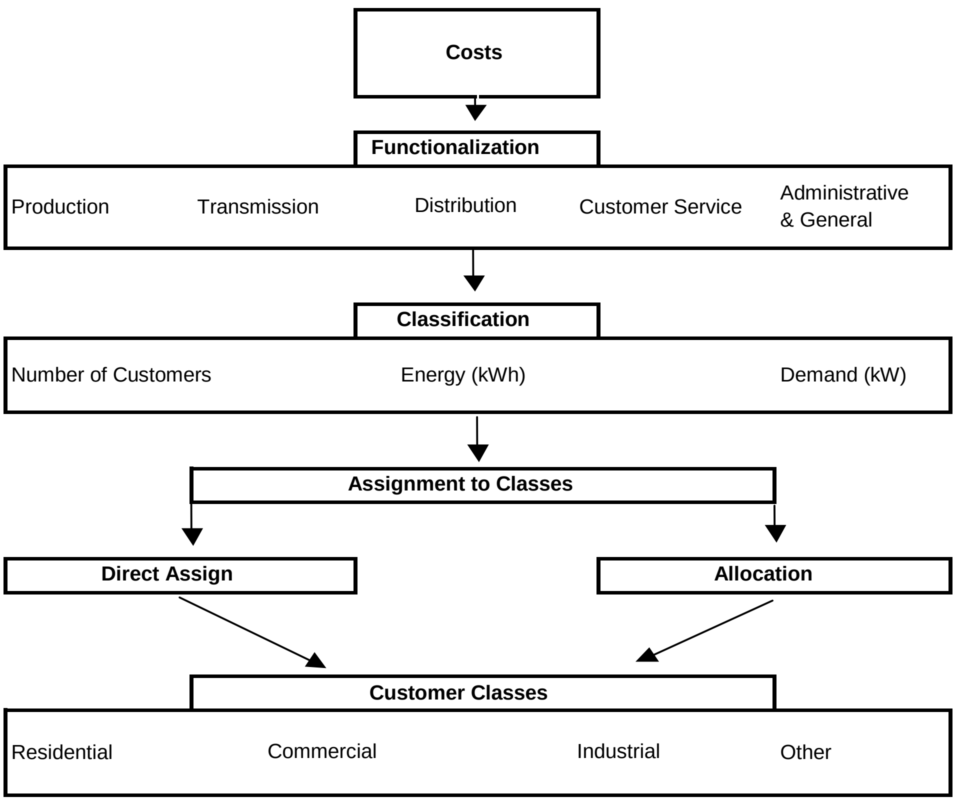
Q. **Please describe the allocation processes.**

A. After costs are functionalized and classified, they are allocated or directly assigned among jurisdictions (Oklahoma retail, Arkansas retail and FERC). Within the Arkansas retail jurisdiction, the functionally classified costs are then further 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, Lighting, and Other.

The objective of this process is to assign costs in a reasonable and understandable way. For instance, the costs associated with the poles and luminaries used for street lighting in Arkansas are directly assigned to the Arkansas 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 Arkansas 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 2 is a flowchart that provides an overview of the steps used to allocate costs to jurisdictional customer classes.

Chart 2

Cost Allocation Flowchart



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 which establishes the cost responsibility for each jurisdiction and customer class of service.

II. 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 Rules of Practice ("RPPs") and the general rate proceeding Minimum Filing Requirements ("MFRs")?**

A. Yes. The Company submitted its COSS as required by the RPPs and MFRs.

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

A. Functional Changes to the COSS

Q. **Is OG&E proposing functional allocation changes to the jurisdictional cost of service study?**

A. Yes, OG&E is proposing a functional allocation change for both Generation Step-up Transformers ("GSUs") and generation radial ties.

Q. **Has OG&E allocated GSUs and generation radial ties differently in this case versus the previous rate case?**

A. Yes. OG&E proposes in this case to allocate these costs as generation assets using a production energy allocator as opposed to a transmission demand allocator. Previously, these costs were booked and functionalized as transmission costs based on FERC accounting guidelines and were allocated as such in OG&E's previous rate case using a transmission demand allocator. However, both of these assets provide the transition phase of transferring electricity produced from generation sources to the transmission system. The FERC transmission formula rate does not consider GSUs or generation radial ties as transmission assets for cost recovery purposes at the FERC.

B. Classification Additions of the COSS

Q. **How does OG&E propose to classify those environmental costs associated with Low NO_X and Activated Carbon Injection?**

A. OG&E proposes to recover the environmental costs as demand-related and using the production demand allocator, which is the same as all other production plant.

Q. **How does OG&E propose to classify the Mustang Community Solar project?**

A. Due to the localized nature of the Mustang Community Solar project and its interconnection to the distribution system, the solar project's costs are allocated 100 percent to the Oklahoma jurisdiction. Below I will discuss additional modifications to address other Oklahoma only jurisdictional items.

C. Explanation of Demand Allocation Changes to the COSS

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 that support how costs should be allocated for the three main functions: production demand; transmission demand; and distribution demand.

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. Therefore, the demands imposed on OG&E's generating units utilize coincident peak demands at the time of the system peak for the production demand allocator, while the distribution demand allocator utilizes non-coincident peak demands that do not occur at the same time as the system peak.

Q. **What is OG&E current jurisdictional production demand allocation methodology as approved in its previous rate case?**

A. Currently, the Company uses the one-coincident peak and average ("1CP & Average") methodology as its approved demand allocation methodology. This allocation methodology incorporates two measurements; the coincident peak demand ("1CP") which is the load of all customer classes at the time of the Company's highest measured one-hour demand for the system in the test year and, a weighted energy measuring the total mega-watt hours used during the test year to determine the average demand ("Average"). The 1CP & Average demand method recognizes not only the class loads at the time of the system maximum peak, but also the amount of energy usage that all classes utilize during all hours of the test year.

Q. **Has the Company analyzed an alternative to its current production demand methodology?**

A. Yes. OG&E is submitting a 4CP Average and Excess ("A&E") cost allocation methodology, which the Company believes is the appropriate demand allocator.

Q. **What is the rationale behind the 4CP A&E methodology?**

A. The 4CP A&E method considers that OG&E builds peak facilities to meet the highest demands of the year. For the Company's system these peaks are typically June, July, August and September. The rationale behind the weighting of these four peaks on an average and excess demand basis is a more specific way to determine when the peaks are being caused and by which customer classes. Avoiding generalization of peak responsibility helps to better match costs to cost causers.

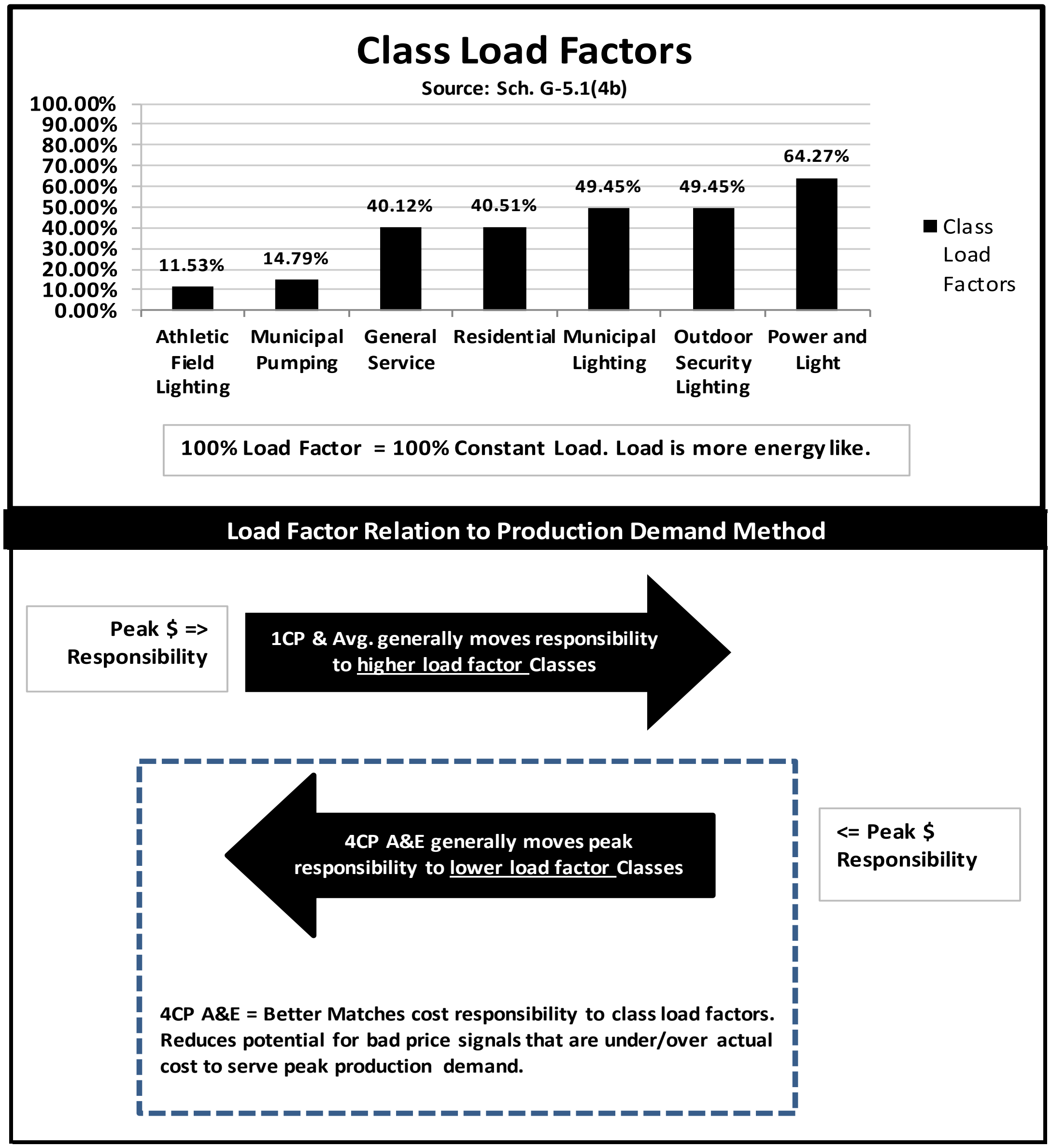
Q. **Are Class load factors an important consideration when choosing a production demand allocator?**

A. Yes. The goal of production demand allocator is to match cost to the cost causer. A high load factor means power usage is relatively constant. To serve the low load factor peaks, capacity is sitting idle for long periods, thereby imposing higher costs on the system. Electrical rates are designed so that customers with high load factors are charged less overall per kWh (Average Demand), while those with high peak demands are allocated more peak costs (Excess Demand) which are higher due to higher production costs of running peak generating units. The 4CP A&E better aligns cost assignment because it gives recognition to how each class is responsible for the services they consume and reduces the potential for generalization of cost assignment which may over or under allocate causation responsibility to the cost causer. It should be noted that the Company has made great strides to encourage the efficient use of electric service through various pricing initiatives such as SmartHours, Energy Efficiency Cost Recovery, Variable Peak Price, Time Of Use and others. These efforts are not generalized, but specific to peak usage (excess demand). The 4CP A&E better aligns with these initiatives because it refines the use of peak responsibility to those who cause it.

Q. **How do Class load factors relate to the two production demand allocation methods mentioned?**

A. Load factors are lower for those classes with significant variation between their demands and their energy usage. However, those classes with high load factors have less variation between demand and energy usage. Load factors convey a better insight into who is causing the loads being imposed on the system and who contributes more to peak production plant. In Chart 3 below, class load factors are displayed in the bar chart. Also in Chart 3, the arrows display a comparison of the 1CP A to the 4CP A&E and the effects of the allocator on OG&E’s classes.

Chart 3



Q. **Please describe how OG&E calculates the production demand allocator that is used in this case.**

A. The 4CP A&E demand method utilizes two types of demand components in the allocation of production demand-related costs, the "average" component and "excess" component. These are derived using average and peak demands. Average demand is determined using the annual kilowatt hours ("kWhs") consumed during the test year divided by 8784 hours[4]. The peak demand reflects the average of the peak demand loads

[4] The test year falls within a leap year, adding 24 hours to the typical 8760 hours in a year.

of the four summer months of all customer classes at the time of the Company's highest measured one-hour demands for the system in each of the four summer months. The "excess demand" is determined by subtracting the average demands from the peak demands. The system load factor is calculated by dividing the annual average demand by the annual system peak demand. The average component is weighted by calculating the average demand times the system load factor. The excess component is weighted by calculating the excess demand multiplied by one minus the system load factor. The allocation factors are derived by adding the average component to the excess component for each customer class.

Q. **Why does OG&E believe the 4CP A&E production demand allocation is appropriate?**

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

1. The use of an average of 4CPs for the jurisdictional demand input creates a more normalizing or smoothing effect from year to year;
2. The 4CP A&E reflects cost-causation by recognizing that OG&E is a summer-peaking utility, and is consistent with system planning principles;
3. The 4CP A&E method recognizes that customers benefit from both demand and energy produced from generation assets;
4. The 4CP A&E incorporates the class non-coincident peak which recognizes class load factors;
5. The 4CP A&E provides the incentive for customers to lower demand usage for those classes with low load factors which aligns with the Company's pricing plans that encourage efficient use of load;
6. When compared to the 1CP & Average method most classes see a reduction in production demand cost responsibility as well as that of the Arkansas jurisdiction; and,
7. 4CP A&E has been approved in multiple states including Arkansas and Oklahoma.

Q. In terms of revenue requirement, what are the benefits of moving to the 4CP A&E method from the 1CP & A method?

A. As shown below in Chart 4, change from a 1CP & A to a 4CP A&E benefits the Arkansas jurisdiction by a revenue requirement decrease of approximately $3.4 million.

Chart 4

	PRODUCTION DEMAND ALLOCATION METHOD Change from 1CP & Avg → 4CP A&E Method							
	Total Ark. Retail Jurisdiction	Total Residential	Total General Service	Total Municipal Pumping	Total Power & Light	Power & Light - Standard	Power & Light - TOU	Total Lighting
Δ Revenue Requirement ($)	($3,539,401)	$362,435	$2,745	($2,517)	($3,905,000)	($1,993,577)	($1,911,423)	$419
Δ Revenue Requirement (%)	-1.92%	0.55%	0.01%	-2.12%	-4.13%	-3.80%	-4.54%	0.01%
	Most Classes Receive a Reduction Under 4CP A&E							

Q. How does the 4CP A&E impact economic development in the Arkansas jurisdiction?

A. While an allocation method itself may not necessarily be a sole factor in dictating whether or not a new business development or business expansion project happens, it can send signals that costs are allocated fairly and are aligned based on each class' use of the system.

D. <u>Modifications to Demand Allocators</u>

1. <u>Generation Allocation</u>

Q. What adjustments did OG&E make to the jurisdictional load data to assure that Arkansas customers are not paying for Oklahoma jurisdictional costs?

A. The load data adjustments for the production demand allocator have not changed since OG&E's last general rate case. Specifically, the Company modified the demand and energy input components of the allocator by assigning the Oklahoma jurisdiction the entirety of the 440 MW peak demand related to cogeneration contracts, as well as the energy provided by cogeneration and the Sooner wind farm.

Q. **What was the change in the production demand allocator and why did OG&E make these modifications?**

A. The costs of OG&E's cogeneration contracts and the Sooner wind farm are assigned to Oklahoma retail customers in accordance with prior Oklahoma Corporation Commission Orders. Since the Oklahoma retail jurisdiction is responsible for all of the cogeneration costs, an adjustment is made to the jurisdictional allocator so these costs are not allocated to Arkansas. As a result of the change, the production demand allocator decreased for the Arkansas retail jurisdiction.

Q. **Is there any wholesale customer loads included in your jurisdictional production demand allocation in this case?**

A. No. Since OG&E's last general rate case, all wholesale contracts have expired, leaving only OG&E's two retail jurisdictions.

2. <u>Transmission and Distribution Allocation</u>

Q. **How has the Company classified and allocated transmission costs in this case?**

A. The Company classifies transmission on a demand allocator. Historically, and in this case, allocation of transmission costs to its retail and wholesale jurisdictions are done using an average of twelve monthly coincident peak demands ("12-CP").

Q. **How does OG&E classify distribution plant costs in its COSS?**

A. OG&E classifies distribution plant costs as either demand related or customer related depending on the FERC account. FERC accounts 360-363 are considered as demand related. Accounts 364-368 are considered demand which is the same method used in OG&E's previous case. Distribution plant accounts 369-373 are considered customer related. Additionally, distribution O&M accounts are classified in the same manner as the underlying plant accounts.

Q. **How has the Company allocated demand related distribution plant costs in its COSS?**

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 localized area loads that experience varying peaks rather than a system load that has coincident peaks. 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 plant costs?**

A. The customer-related distribution plant costs and certain associated expenses are allocated to the customers who require such facilities by using a weighted customer methodology. These customer-related distribution plant accounts apply to 369-372. As mentioned above, accounts 360-368 are allocated as demand related.

Q. **Is there a change in the allocation methodology of distribution-related customer costs in this case that is different than OG&E's previous case?**

A. Yes, meter costs are allocated differently in this case. In OG&E's previous case, Docket No. 10-109-U, meter costs were allocated using a weighted customer methodology. Due to the installation of SmartGrid meters in OG&E's service territory and the ability to capture current meter costs by customer class, the meter costs in this case are now directly assigned to each applicable class. This is similar to the direct assignment of costs for the lighting classes to more accurately reflect cost-causation.

Q. **Please describe the allocation of the other O&M expenses 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.

VI. BLACKWELL WIND ENERGY PURCHASE AGREEMENT

Q. **Please describe the Blackwell Wind Energy Purchase Agreement ("WEPA").**

A. Blackwell operates a renewable wind generation facility near Blackwell, Oklahoma with a capacity of 60 MW of which approximately 6 MW is allocated to the Arkansas jurisdictional portion of OG&E's customer base. The WEPA between OG&E and Blackwell was executed on November 8, 2011. The cost for energy purchased under this Agreement and any revenues received from the sale of Renewable Energy Credits ("RECs") are proposed to be recovered through the Energy Cost Recovery rider ("ECR"). Blackwell became operational in December 2012 and is currently providing benefits to both Oklahoma and Arkansas retail customers.

Q. **Please describe the benefits of the Blackwell WEPA.**

A. This WEPA benefits customers by displacing fossil fuel generation and allowing OG&E to avoid the higher costs of fossil fuel at its generating plants.

Q. **Have Arkansas customers been receiving the benefit from the Blackwell WEPA?**

A. Yes.

Q. **Have Arkansas customers been charged for that benefit to date?**

A. No. Currently, Arkansas customers are receiving the benefit from but have not yet been charged for the resulting energy from the Blackwell WEPA.

Q. **Has this contract been approved by the OCC?**

A. Yes. The OCC determined that OG&E's execution of the WEPA was in the public interest on March 12, 2012 in Cause No. PUD 201100186, Order No. 595098.

Q. **Will the WEPA provide savings to customers?**

A. Yes. OG&E performed an analysis comparing the net cost of the WEPA to the SPP market energy costs. The analysis indicates that for the remaining term of the WEPA the net benefit is $2,670,390. The Arkansas jurisdictional portion of these benefits is approximately $275,000. A copy of the updated net present value ("NPV") calculation is attached to this testimony as Direct Exhibit DWS-1.

Q. **Please explain the NPV calculation used in Direct Exhibit DWS-1.**

A. Direct Exhibit DWS-1 details the Agreement's stream of net benefits for total company and the Arkansas allocated portion of these benefits. The Arkansas allocated portion is based on monthly load that varies over time, an estimated allocation factor was used for the Arkansas portion. The allocation estimate was derived using an average of the last 12 months of actual Arkansas Energy Cost Recovery Factor's. The NPV is based on the Arkansas portion of the stream of net benefits over the remaining 16 year period of the WEPA using the company's last approved Weighted Cost of Capital of 6.01 percent to discount this stream of payments. The Arkansas result of these benefits is approximately $275,000.

Q. **Will a modification be required to OG&E's Energy Cost Recover ("ECR") rider if the WEPA is approved for recovery?**

A. No. The existing ECR language is sufficient to accommodate the WEPA for the Arkansas retail jurisdictional allocation of Blackwell. This treatment is consistent with the previous Commission treatment for OG&E's Taloga and Keenan WEPAs[5].

Q. **Is the WEPA prudent and in the public interest?**

A. Yes. The Blackwell WEPA will provide approximately $275,000 of benefits to Arkansas customers. In addition, Arkansas customers will benefit from the addition of a clean, renewable energy resource as contemplated in Ark. Code Ann. § 23-18-701 *et seq*. The Company is following the legislative intent in adding renewable resources to its portfolio with the added benefit that the resources may provide protection against possible future fossil fuel emission control legislation.

VII. CONCLUSION

Q. **Is the cost of service study in this filing transparent and verifiable?**

A. Yes, I believe that the jurisdictional and class cost of service study are transparent and verifiable. They provide complete detail as to each allocation made on an account-by-account basis. In addition, cross-references to supporting schedules are provided on all summary pages. Every calculation made in the model can be readily verified by Commission Staff and other parties to the case.

[5] Docket No. 10-073-U

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. Schedule G-3 in the Application Package shows the increase in revenues by class at the equalized rate of return of 6.01 percent.

Q. **What is your recommendation to the Arkansas Commission regarding the Blackwell WEPA?**

A. OG&E recommends that the Commission find the Blackwell WEPA (1) to be in the public interest, (2) prudent and (3) to be an energy only agreement (4) and payments recoverable through the ECR.

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

A. Yes, it does.

						Total Company			Arkansas		
Yr.	**Wind MWH**	**Cost Blackwell PPA**	**Base Revenue**	**High Gas Revenue**	**Low Gas Revenue**	**Base Profit/ Loss**	**High Gas Profit/ Loss**	**Low Gas Profit/ Loss**	**Base Profit/ Loss**	**High Gas Profit/ Loss**	**Low Gas Profit/ Loss**
2017	120,718	3,703,623	$ 2,892,993	$ 3,456,680	$ 2,172,117	$ (810,629)	$ (246,943)	$ (1,531,505)	$ (83,446)	$ (25,420)	$ (157,653)
2018	118,612	3,639,017	$ 3,097,375	$ 3,643,143	$ 2,409,730	$ (541,642)	$ 4,126	$ (1,229,287)	$ (55,757)	$ 425	$ (126,543)
2019	116,859	3,585,230	$ 3,342,265	$ 4,153,335	$ 2,570,966	$ (242,965)	$ 568,104	$ (1,014,265)	$ (25,011)	$ 58,481	$ (104,408)
2020	115,401	3,540,493	$ 3,579,361	$ 4,657,534	$ 2,646,134	$ 38,868	$ 1,117,041	$ (894,359)	$ 4,001	$ 114,988	$ (92,065)
2021	113,662	3,487,141	$ 3,519,052	$ 4,313,865	$ 2,644,151	$ 31,910	$ 826,723	$ (842,991)	$ 3,285	$ 85,103	$ (86,777)
2022	111,510	3,421,132	$ 3,559,279	$ 4,346,156	$ 2,663,567	$ 138,147	$ 925,024	$ (757,565)	$ 14,221	$ 95,222	$ (77,984)
2023	109,698	3,365,529	$ 3,759,037	$ 4,707,918	$ 2,796,280	$ 393,508	$ 1,342,389	$ (569,249)	$ 40,508	$ 138,186	$ (58,598)
2024	108,165	3,318,500	$ 3,875,638	$ 4,867,411	$ 2,870,087	$ 557,139	$ 1,548,912	$ (448,413)	$ 57,352	$ 159,445	$ (46,160)
2025	106,354	3,262,942	$ 4,086,641	$ 5,357,131	$ 2,948,516	$ 823,700	$ 2,094,189	$ (314,425)	$ 84,792	$ 215,576	$ (32,367)
2026	104,152	3,195,382	$ 3,868,448	$ 4,816,479	$ 2,877,827	$ 673,066	$ 1,621,097	$ (317,556)	$ 69,285	$ 166,876	$ (32,689)
2027	102,274	3,137,780	$ 3,844,022	$ 4,751,252	$ 2,832,786	$ 706,242	$ 1,613,471	$ (304,994)	$ 72,701	$ 166,091	$ (31,396)
2028	100,674	3,088,671	$ 3,874,080	$ 4,791,964	$ 2,821,011	$ 785,409	$ 1,703,294	$ (267,660)	$ 80,850	$ 175,337	$ (27,553)
2029	98,809	3,031,448	$ 3,916,045	$ 4,925,451	$ 2,832,608	$ 884,597	$ 1,894,003	$ (198,840)	$ 91,060	$ 194,969	$ (20,469)
2030	96,576	2,962,961	$ 3,935,205	$ 4,961,022	$ 2,828,609	$ 972,244	$ 1,998,061	$ (134,352)	$ 100,083	$ 205,680	$ (13,830)
2031	94,657	2,904,089	$ 3,947,241	$ 4,963,306	$ 2,807,348	$ 1,043,152	$ 2,059,217	$ (96,741)	$ 107,382	$ 211,976	$ (9,959)
2032	93,006	2,853,438	$ 4,012,866	$ 5,061,427	$ 2,810,102	$ 1,159,428	$ 2,207,989	$ (43,336)	$ 119,351	$ 227,290	$ (4,461)
Total	**1,711,127**	**52,497,376**	**59,109,549**	**73,774,074**	**43,531,839**	**6,612,173**	**21,276,698**	**(8,965,538)**	**680,657**	**2,190,223**	**(922,912)**

NPV Base Profit/Loss		
WACC	**6.01%**	**$2,670,390**
Ark Juris Alloc %	**10.29%**	**$274,890**
Source: WACC,Ark. Juris Energy Allocation Factor filed COSS 16-052-U		

Customer Impact

Savings/(Cost)		$ (83,446.19)	$ (55,756.66)	$ (25,010.82)	$ 4,001.07	$ 3,284.85	$ 14,220.85	$ 40,507.67	$ 57,351.85	$ 84,791.65	$ 69,285.41	$ 72,700.54	$ 80,850.00	$ 91,060.46	$ 100,082.79	$ 107,382.10	$ 119,351.50	
Year	**16-052-U**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	
	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	
SL1	400,636,754	403,641,530	409,696,153	415,841,595	422,079,219	428,410,407	434,836,563	441,359,112	447,979,498	454,699,191	461,519,679	468,442,474	475,469,111	482,601,148	489,840,165	497,187,767	504,645,584	
SL2	103,704,837	104,482,623	106,049,863	107,640,611	109,255,220	110,894,048	112,557,459	114,245,821	115,959,508	117,698,901	119,464,384	121,256,350	123,075,195	124,921,323	126,795,143	128,697,070	130,627,526	
SL3	524,619,790	528,554,438	536,482,755	544,529,996	552,697,946	560,988,415	569,403,242	577,944,290	586,613,455	595,412,656	604,343,846	613,409,004	622,610,139	631,949,291	641,428,531	651,049,959	660,815,708	
SL4	1,243,680	1,253,008	1,271,803	1,290,880	1,310,243	1,329,897	1,349,845	1,370,093	1,390,644	1,411,504	1,432,676	1,454,166	1,475,979	1,498,119	1,520,590	1,543,399	1,566,550	
SL5	1,538,969,559	1,550,511,831	1,573,769,508	1,597,376,051	1,621,336,692	1,645,656,742	1,670,341,593	1,695,396,717	1,720,827,668	1,746,640,083	1,772,839,684	1,799,432,279	1,826,423,763	1,853,820,120	1,881,627,422	1,909,851,833	1,938,499,610	**Energy Allocation Factor**
Incremental Factor																		
SL1		$ 0.0000311	$ 0.0000205	$ 0.0000090	$ (0.0000014)	$ (0.0000012)	$ (0.0000049)	$ (0.0000138)	$ (0.0000192)	$ (0.0000280)	$ (0.0000226)	$ (0.0000233)	$ (0.0000256)	$ (0.0000284)	$ (0.0000307)	$ (0.0000325)	$ (0.0000356)	0.0154770
SL2		$ 0.0000313	$ 0.0000206	$ 0.0000091	$ (0.0000014)	$ (0.0000012)	$ (0.0000050)	$ (0.0000139)	$ (0.0000194)	$ (0.0000282)	$ (0.0000227)	$ (0.0000235)	$ (0.0000257)	$ (0.0000286)	$ (0.0000309)	$ (0.0000327)	$ (0.0000358)	0.0040340
SL3		$ 0.0000317	$ 0.0000208	$ 0.0000092	$ (0.0000015)	$ (0.0000012)	$ (0.0000050)	$ (0.0000141)	$ (0.0000196)	$ (0.0000286)	$ (0.0000230)	$ (0.0000238)	$ (0.0000260)	$ (0.0000289)	$ (0.0000313)	$ (0.0000331)	$ (0.0000362)	0.0206440
SL4		$ 0.0000323	$ 0.0000213	$ 0.0000094	$ (0.0000015)	$ (0.0000012)	$ (0.0000051)	$ (0.0000144)	$ (0.0000200)	$ (0.0000292)	$ (0.0000235)	$ (0.0000243)	$ (0.0000266)	$ (0.0000295)	$ (0.0000320)	$ (0.0000338)	$ (0.0000370)	0.0000500
SL5		$ 0.0000328	$ 0.0000216	$ 0.0000095	$ (0.0000015)	$ (0.0000012)	$ (0.0000052)	$ (0.0000146)	$ (0.0000203)	$ (0.0000296)	$ (0.0000238)	$ (0.0000246)	$ (0.0000270)	$ (0.0000299)	$ (0.0000324)	$ (0.0000343)	$ (0.0000375)	0.0627350
Est. Customer Bill Impact																		**Avg. of 16yrs**
R-1		$ 0.03	$ 0.02	$ 0.01	$ (0.00)	$ (0.00)	$ (0.01)	$ (0.01)	$ (0.02)	$ (0.03)	$ (0.02)	$ (0.02)	$ (0.03)	$ (0.03)	$ (0.03)	$ (0.03)	$ (0.04)	$ (0.01)
GS		$ 0.07	$ 0.04	$ 0.02	$ (0.00)	$ (0.00)	$ (0.01)	$ (0.03)	$ (0.04)	$ (0.06)	$ (0.05)	$ (0.05)	$ (0.05)	$ (0.06)	$ (0.06)	$ (0.07)	$ (0.08)	$ (0.03)
PL		$ 1.64	$ 1.08	$ 0.48	$ (0.08)	$ (0.06)	$ (0.26)	$ (0.73)	$ (1.02)	$ (1.48)	$ (1.19)	$ (1.23)	$ (1.35)	$ (1.50)	$ (1.62)	$ (1.71)	$ (1.88)	$ (0.68)