Exhibit No.:	019
Issue(s):	Class Cost of Service Study
Witness:	Ryan P. Ryterski
Type of Exhibit:	Direct Testimony
Sponsoring Party:	Union Electric Company
File No.:	GR-2019-0077
Date Testimony Prepared:	December 3, 2018

MISSOURI PUBLIC SERVICE COMMISSION

FILE NO. GR-2019-0077

DIRECT TESTIMONY

OF

RYAN P. RYTERSKI

ON

BEHALF OF

UNION ELECTRIC COMPANY

D/B/A AMEREN MISSOURI

St. Louis, Missouri
December, 2018

TABLE OF CONTENTS

DIRECT TESTIMONY

OF

RYAN P. RYTERSKI

FILE NO. GR-2019-0077

I. INTRODUCTION

Q. Please state your name and business address.

A. My name is Ryan P. Ryterski and my business address is One Ameren Plaza, 1901 Chouteau Avenue, St. Louis, Missouri 63103.

Q. What is your position with Ameren Missouri?

A. I am employed by Union Electric Company d/b/a Ameren Missouri ("Ameren Missouri" or "Company") as a Regulatory Rate Specialist.

Q. Please describe your educational background and employment experience.

A. I received a Bachelor's Degree of Business Administration with majors in Economics & Finance and Management from McKendree University in 2013. While pursuing my undergraduate degrees, I interned at Ameren Services in the Strategic Sourcing Department. Following completion of my undergraduate degrees, I was hired by Ameren Services as a Procurement Specialist in the Strategic Sourcing Department. I subsequently earned a Master of Business Administration from McKendree University in 2015.

In February of 2017, I was promoted to Supplier Relationship Management Analyst in Strategic Sourcing where I was responsible for tracking both qualitative and quantitative performance measures from Ameren's Transmission and Distribution Construction

Services Groups in both Illinois and Missouri. In November of 2017, I accepted a position with Ameren Missouri as a Regulatory Rate Specialist.

II. PURPOSE OF TESTIMONY

Q. What is the purpose of your direct testimony in this proceeding?

A. My direct testimony in this proceeding explains the development of a fully allocated embedded customer class cost of service study for the Company's Missouri jurisdictional natural gas operations for the proposed test year period of twelve months ending June 30, 2018. I also explain the sub-aggregation, or unbundling, of the various functional cost components included in the Company's class cost of service study. I will also address the weather normalization process for both the billing units used in the class cost of service study and rate development, as well as the weather component of the proposed Weather and Conservation Adjustment Rider ("WCAR") described by Ameren Missouri witness Michael Harding.

III. CLASS COST OF SERVICE STUDY

Q. Please explain the information contained in Schedule RPR-D1.

A. Schedule RPR-D1 contains the results of the Company's customer class cost of service study ("CCOSS") for its Missouri jurisdictional natural gas operations for the proposed test year ended June 30, 2018. This study is based upon the Company's present rate levels and weather normalized billing units during the test year. The Missouri natural gas jurisdictional annual revenue requirement calculated by Ameren Missouri witness Laura Moore formed the starting point for this study.

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

A. A cost of service study allocates the utility's aggregate cost of providing utility services (the annual revenue requirement) to those who cause the costs to be incurred. For purposes of this proceeding, the "utility services" are those associated with the distribution of natural gas in Ameren Missouri's service territory. Due to the impracticality of tracking detailed cost information by rate classification, utilities routinely prepare and maintain detailed cost of service studies. These studies involve modeling various allocation factors and cost allocation methods to assign portions of the Company's total embedded cost of operating to each of the Company's rate classes. The study ultimately results in a target "cost to serve" or "revenue requirement" for each rate class. These target revenue requirements are used as a guide for rate design and pricing changes proposed by the Company within each rate classification. Another Ameren Missouri witness, Mr. Harding, will discuss the proposed rate design and any pricing changes for the Company's rate classes.

Q. What information is provided by the class cost of service study?

A. The Company's aggregate annual revenue requirement generally consists of rate base (with net plant investment and accumulated deferred income tax being the largest rate base components), depreciation expense, operating expenses, income and other taxes, and the return (at the weighted average cost of capital) on rate base. The revenue requirements for each of the Company's rate classifications are derived using various allocation methods, which I will discuss in detail later in my testimony. These allocated costs can vary significantly between customer classes depending upon the facilities required to serve each class of customers and the nature of their use of the gas system. By

assigning or allocating the costs of the natural gas system to the rate classes based on the cost of serving each of those rate classes, the appropriate costs can be covered by revenues from the cost causer. The final result of a gas cost of service study is essentially a matrix displaying a revenue requirement for each major cost category for each rate classification.

Q. What rate classes were included in the Company's CCOSS?

A. The Company's CCOSS includes all existing rate classes: the Residential, General Service, Interruptible Service, Standard Transportation Service, and Large Volume Transportation Service classes.

Q. Were the rate base investment and expenses associated with the Company's special contract customers considered in the CCOSS you performed?

A. Yes. However, in considering such costs in my study, I employed a cost of service approach consistent with that utilized by the Company in File No. GR-2010-0363. This approach consists of allocating the total of all Company investment and expense to the other customer classes as if there were no special contract customers. The allocation of such costs to the non-special contract customers is offset by also allocating, or crediting, existing special contract revenues to the other customer classes. This allocation of special contract costs and revenues was done based on each class' respective total net original cost rate base. This process presumes that the Company's current special contract revenues, which constitute about 0.4% of the Company's total revenues, currently provide a fair and reasonable recovery of the Company's total costs of providing such service. Said another way, it is presumed that allocated special contract revenues are equivalent to allocated special contract costs.

Q. Were the Company's other revenues treated in a similar way?

A. Yes. The Company takes a similar approach with its other revenues, which include revenues associated with such things as forfeited discounts, miscellaneous service revenue, and building rental agreements. Depending on the category of revenue, these amounts were allocated based on either the number of total bills, or the Labor Ratio. The Labor Ratio method of allocation calculates the percent of total production, transmission, distribution, customer, and sales labor expense that are attributable to the provision of service to each customer class, and allocates amounts based on that percentage.

Q. Did your CCOSS include purchased gas costs?

A. No. Purchased gas costs, including the cost of the gas commodity, demand, pipeline transportation, and a portion of storage costs, are fully recovered through the Company's Purchased Gas Adjustment ("PGA"). Purchased gas costs, therefore, do not affect the operating income or rate of return earned by the Company.

Q. What steps were used to prepare the CCOSS?

A. Three steps were used to prepare the CCOSS: (1) functionalization; (2) classification; and (3) allocation.

A) FUNCTIONALIZATION AND CLASSIFICATION

Q. Please describe the first step you took in the preparation of your CCOSS — functionalization — in more detail.

A. Functionalization is the separation of rate base and expenses into major functional areas, such as production, transmission, distribution, and customer service, based on the FERC Uniform System of Accounts.

Q. Please describe the second step you took in the preparation of your CCOSS — classification — in more detail.

A. Functionalized costs are further separated into classifications based on cost-causation principles.

Q. What classifications did you examine?

A. The three primary cost classifications for a natural gas utility are: customer-related, demand-related, and variable or commodity-related costs.

Q. Please describe these classifications of cost in greater detail.

A. Customer-Related Costs are those costs that are unrelated to customer usage and result from the very existence of a customer, i.e., the costs of making service available, including the costs of meter reading and billing, as well as the fixed costs associated with the customer's meter, service pipe, and some portion of the Company's investment in distribution mains. These costs do not vary from month-to-month and are unaffected by year-to-year fluctuations in the consumption level of existing customers.

Demand-Related Costs are those costs that the Company incurs in order to meet the maximum daily gas demands imposed by customers. These costs include a significant portion of all fixed costs associated with the Company's investment in plant and expenses to meet customers' expected maximum loads on the Company's gas distribution system.

Commodity-Related Costs are those costs that are a function of the actual volume of gas delivered or sold. As explained above, purchased gas costs are excluded from the CCOSS. Therefore, only gas supply expenses that are not included in the Company’s PGA and the costs of stored gas are considered commodity-related costs.

B) ALLOCATION

Q. What is done in the third step — allocation?

A. During allocation, appropriate allocation factors are applied to the functionalized and classified costs so that the rate base components and associated operating and maintenance expenses are allocated to the various rate classes.

Q. Please describe the development of the factors used to allocate such costs to each customer class.

A. The allocation factors for each customer class were determined by calculating the proportionate share of total customer or property units of each class and the total commodity or demand related units of each class.

Customer-Related allocation factors are generally proportionate to the annual number of customer bills issued to each rate class or to the weighted average of the customer-related costs of certain items, based on Company studies.

Demand-Related allocation factors are proportionate to either the coincident peak ("CP") or the non-coincident peak ("NCP") day delivered demand of the various rate classes (including the Interruptible class' peak demand) through the use of the Average and Excess Demand Method. CP and NCP (average and excess) day demands are explained further, below.

Commodity-Related allocation factors are proportionate to the volumes sold or transported to each rate class.

Q. Please describe how those costs and expenses were allocated to the various customer classes.

A. The original cost and depreciation reserves of the major functional components of the Company's natural gas rate base for the test year were allocated to the customer classes as described below. The resulting dollar amounts allocated to each class are provided in Schedule RPR-D1.

(1) Production Plant. Production plant was allocated to each customer class on the basis of the class CP demand allocation factor. CP demand is the customer class' peak load on the day of the Company's overall system peak. The CP day demands for the rate classes were determined by summarizing the daily meter reads of all customers by class and date. The coincident demand assigned to the Interruptible class was zero, because there is no longer an assurance gas level associated with any of the contracts of those customers. In other words, Ameren Missouri has the ability to curtail gas from its interruptible customers to customers of another class during times of peak demand to meet the requirements of the system as a whole without increasing the system peak demand and causing an increase in the cost to serve all customers. Customers who only take transportation service on the Company's distribution system were not allocated production plant costs since they purchase their gas supply from a third party.

(2) Transmission Plant. Transmission plant investment is demand-related and was allocated to each customer class based upon the Average and Excess Demand Method. This method allocates a portion of this investment according to the average use of all customers and a portion according to the additional use related to the NCP demand of each customer class. NCP demand is the customer class' actual peak day load regardless of the

day of its occurrence. The class NCP day demands were determined using daily meter reads for all customers in a given class throughout the test year.

(3) Distribution Plant. The Company's distribution plant was allocated to each customer class based upon an analysis of the functions performed by the facilities in Distribution Plant Accounts 374-387. This analysis determined the breakdown of each account into its customer-related and demand-related functions.

The customer-related portions of the distribution system include Services (Account 380), Meters (Account 381), and House and Industrial Regulators (Accounts 383 and 385). Distribution Account 380, Services, was allocated to each of the customer classes using allocation factors that weigh the results of multiplying the current cost of the typical services arrangement, determined for each customer class, by the number of customers in each class. Distribution Account 381, Meters, was allocated to each of the customer classes using allocation factors that weigh the results of multiplying the current cost of the typical metering arrangement, determined for each customer class, by the number of meters used in serving that class. Distribution Account 383, House Regulators, was allocated to each of the customer classes using allocation factors that weigh the results of multiplying the current cost of a typical regulator, determined for each customer class, by the number of regulators used in serving that class. Distribution Account 385, Industrial Regulators, was allocated to the Large Volume Transportation and Interruptible classes based on the number of customers in each class.

All distribution plant not located on the customer's property was classified as demand-related and allocated on a demand basis. Land and Land Rights (Account 374), Structures and Improvements (Account 375), Mains (Account 376), and Measuring and

Regulating Equipment – General and City (Accounts 378 and 379) were all allocated based on the Average and Excess Demand Method.

(4) General and Intangible Plant. The balances in these accounts were allocated to each customer class on the basis of the proportion of labor expense allocated to each class. This "Labor Ratio" method of allocation was described more in-depth above in the question and answer regarding other revenues.

(5) Incentive Compensation Capitalized. This is the portion of the incentive compensation that has been capitalized and booked to plant-in-service. It was also allocated based on the proportion of labor expense allocated to each class.

(6) Accumulated Reserves for Depreciation. As they are functionalized by type of plant, these reserves were allocated on the same basis as the corresponding plant accounts described above.

(7) Materials and Supplies. This component consists of local materials related to production, transmission, and distribution facilities and was allocated on the basis of allocated gross plant.

(8) Gas Stored Underground. This component consists of natural gas storage inventories and was allocated based on winter (November-March) sales volumes to each respective customer class because winter is typically the period when such underground storage is utilized. Transportation customers were not allocated stored gas since they purchase their gas supply from third parties.

(9) Cash Working Capital. This item is related primarily to operating expenses, and therefore was allocated to each customer class in proportion to the total operating expenses allocated to each class.

(10) Customer Advances and Deposits. This component of rate base was assigned to each class on the basis of the total customer deposits by rate class for the test year.

(11) Total Accumulated Deferred Income Taxes. This component is related primarily to investment in property, and therefore was allocated to each customer class on the basis of allocated gross plant.

Q. How did you allocate the Missouri jurisdictional test year natural gas operating and maintenance expenses, as developed by Laura Moore, to the various customer classes?

A. In general, with very few exceptions, the Missouri natural gas operating and maintenance expenses were allocated to the various customer classes on the same basis as the related investment in plant. This type of allocation employs the familiar and widely used "expenses follow plant" principle of cost allocation. For example, the allocator for distribution main plant was utilized to allocate distribution main expenses. The only exceptions to this allocation procedure are as follows:

(1) Production Expenses. This item consists of two categories: demand and commodity. The demand, or fixed, portion of production expenses was allocated on the same basis as production plant, while the commodity, or variable, portion was allocated based on volumes delivered to each customer class.

(2) Customer Accounts Expenses. Account 903, Customer Records and Collection Expenses, was allocated to each class based on the number of annual bills in each customer class. Account 904, Uncollectible Accounts, uses an external allocation factor that assigns costs on the basis of the amount of uncollectible accounts recorded in

the test year for each customer class. Accounts 902 and 905, Meter Reading and Miscellaneous Customer Accounts Expense, were allocated to each class based on the number of customers in each customer class. Account 901, Supervision, was allocated to each class on the basis of the percentage of all other Customer Accounts Expenses (Accounts 902-905) allocated to each class.

(3) Customer Service and Sales Expense. These expenses were allocated to each customer class using the same methodology referenced above for the Supervision expenses in Account 901.

(4) Administrative & General (A&G) Expense. A&G expenses were allocated to the various customer classes on the basis of the class composite distribution of previously allocated labor expenses. As indicated earlier, this allocation method calculates the percentage of total production, transmission, distribution, customer, and sales labor expense for each customer class and assigns A&G expenses to customer classes according to that breakdown.

Q. How did you allocate the test year depreciation expenses?

A. Since depreciation expenses are functionalized and are directly related to the Company's original cost investment in plant, this expense was allocated to each customer class on the basis of the previously allocated original cost production, transmission, distribution, and general plant.

Q. How did you allocate the test year real estate and property taxes?

A. Real estate and property tax expenses are directly related to the Company's original cost investment in plant. Thus, this expense was allocated to customer classes on the basis of gross plant.

Q. How did you allocate the test year income taxes?

A. Income tax expense is directly related to the Company's net operating income as a proportion of its net rate base investment; i.e., rate of return on its net original cost rate base. As a result, income taxes were allocated to each class on the basis of the net original cost rate base of each customer class.

C) CCOSS Results

Q. What were the results of your CCOSS?

A. Schedule RPR-D1 is a summary of the CCOSS results based on the currently effective rates. The summary in Table 1 below shows the results of this study including the Total Gas Operating Revenues, the Net Utility Operating Income, the Rate Base, and the Realized Rate of Return for each customer class. These results show what the Realized Rate of Return would be from each rate class based on revenues from currently effective rates after incorporating all new expenses for the proposed test year ending June 30, 2018. Any class that has a Rate of Return less than 7.581% is essentially not covering the cost to serve that class, and any class that has a Rate of Return greater than 7.581% is covering more than its fair share of the total costs. These new baseline amounts are used to determine the change in base rates that will be necessary for the Company to recover the new Revenue Requirement with an equal rate of return realized for all of the customer classes as calculated in Schedule RPR-D2.

Table 1

Item	Total Missouri	Residential	General Service	Interruptible	Standard Transportation	Large Volume Transportation
Total Gas Operating Revenues	$ 75,826,106	$ 46,002,637	$ 15,794,405	$ 385,625	$ 8,133,235	$ 5,510,204
Net Utility Operating Income	$ 15,393,540	$ 7,781,991	$ 2,538,294	$ (18,929)	$ 3,603,576	$ 1,488,608
Rate Base	$ 259,304,294	$ 149,251,272	$ 62,018,095	$ 2,335,553	$ 23,722,036	$ 21,977,338
Rate of Return Realized	5.94	5.21	4.09	(0.81)	15.19	6.77

Q. How was Schedule RPR-D2 developed?

A. To develop Schedule RPR-D2, I modified the base revenues of each class in Schedule RPR-D1 to reflect the class revenues necessary for the Company to realize equalized rates of return consistent with the Company's weighted average cost of capital from each customer class. This was considered by Mr. Harding in the development of rates for each class to assess how much base rates need to be adjusted to ensure that the new revenue requirement is being appropriately recovered from each rate class.

Q. Please describe the method used to equalize rates of return for each customer class, as reflected in your Schedule RPR-D2.

A. The total net original cost rate base of each customer class was multiplied by the proposed Missouri jurisdictional test year return of 7.581%, as indicated in Laura Moore's testimony, to obtain the required total net operating income of each class. This net operating income was then added to the operating expenses of each class to obtain the total operating revenue of each class required for equal class rates of return. The resulting cost of service of each customer class is set forth on line 5 of Schedule RPR-D2.

Q. What does Schedule RPR-D2 reveal?

A. As previously mentioned, this schedule shows the net utility operating income that would have to be recovered from each customer class in order to have Realized Rates of Return that are equal for all the classes. This schedule shows the revenues that each class would be responsible for if they were all paying their fair cost of service amount. A summary of these results are provided in Table 2 below.

Table 2

Item	Total Missouri	Residential	General Service	Interruptible	Standard Transportation	Large Volume Transportation
Total Gas Operating Revenues	$ 80,090,424	$ 49,471,825	$ 17,959,094	$ 585,522	$ 6,357,217	$ 5,716,765
Net Utility Operating Income	$ 19,657,858	$ 11,314,739	$ 4,701,592	$ 177,058	$ 1,798,367	$ 1,666,102
Rate Base	$ 259,304,294	$ 149,251,272	$ 62,018,095	$ 2,335,553	$ 23,722,036	$ 21,977,338
Rate of Return Realized	7.581	7.581	7.581	7.581	7.581	7.581

Q. How closely were the suggested revenue requirements for each class under Schedule RPR-D2 followed when establishing new rates proposed in this case?

A. These revenue requirements were an important factor when determining whether to shift the classes' revenue responsibility to be more in line with their cost of service. However, the classes may not be completely moved to the revenues suggested by the study because of other important rate design considerations, as described by Mr. Harding, such as the possibility of a significant increase for a particular class causing rate shock.

D) UNBUNDLING FUNCTIONAL COST COMPONENTS

Q. Does Schedule RPR-D3 provide calculations similar to the calculations shown in both RPR-D1 and RPR-D2?

A. No. The first two schedules were focused on allocating costs to the customer classes as a whole. Schedule RPR-D3 focuses on disaggregating, or further unbundling, the Company's class revenue requirements in the CCOSS. This goes a step further than the first two schedules to assign costs at a functional level to make sure that the rates being paid by the individual customers in the classes are developed in a manner that is consistent with the costs being caused by those customers. This requires that the costs be divided into Functionalized Cost Categories.

Q. What were the functionalized cost categories used in unbundling?

A. The costs from the Company's class revenue requirements were divided into the following functionalized cost categories:

(1) Customer-Related Costs;

(2) Distribution / Demand-Related Costs;

(3) Transmission / Demand Related Costs;

(4) Production / Energy-Related Costs; and

(5) Production / Demand-Related Costs.

Q. Why is a breakdown of such costs necessary?

A. This breakdown is required for Mr. Harding's use in the development of proposed rates in this case. The unbundling informs how much of the revenues from each customer class should be derived from the fixed customer charge and how much should be recovered through the volumetric energy charge, if cost causation was strictly followed.

Q. Please describe the general method for unbundling the Company's revenue requirement.

A. This unbundling process entailed an even more detailed analysis of the various components of the equalized customer class rates of return study presented in Schedule RPR-D2. As the Company's various components of cost presented in Schedule RPR-D2 were allocated to customer classes on either a customer, commodity, or demand-related basis, the unbundling process consisted of extracting these various components of cost and summarizing them into the functional cost categories indicated earlier.

Q. What is beneficial about identifying the base revenues for each of these categories?

A. The base revenues for each functionalized category (customer, production-demand, production-energy, transmission-demand, and distribution-demand) allow us to determine a target customer charge and delivery charge for each customer class. The customer charges are developed by dividing the total base revenue amount attributable to Customers (as identified through unbundling) by the total number of annual bills. The remaining base revenue amounts are added together and divided by the volume of sales in Ccf from the proposed test year to calculate an appropriate delivery charge for each customer class (demand and commodity-related costs for this example are both reflected in the delivery per Ccf charge because no demand charges are currently included in the Company's rate structure). These figures will be used by Mr. Harding as reference points in his development of rates being proposed in this case.

IV. WEATHER NORMALIZATION PROCESS

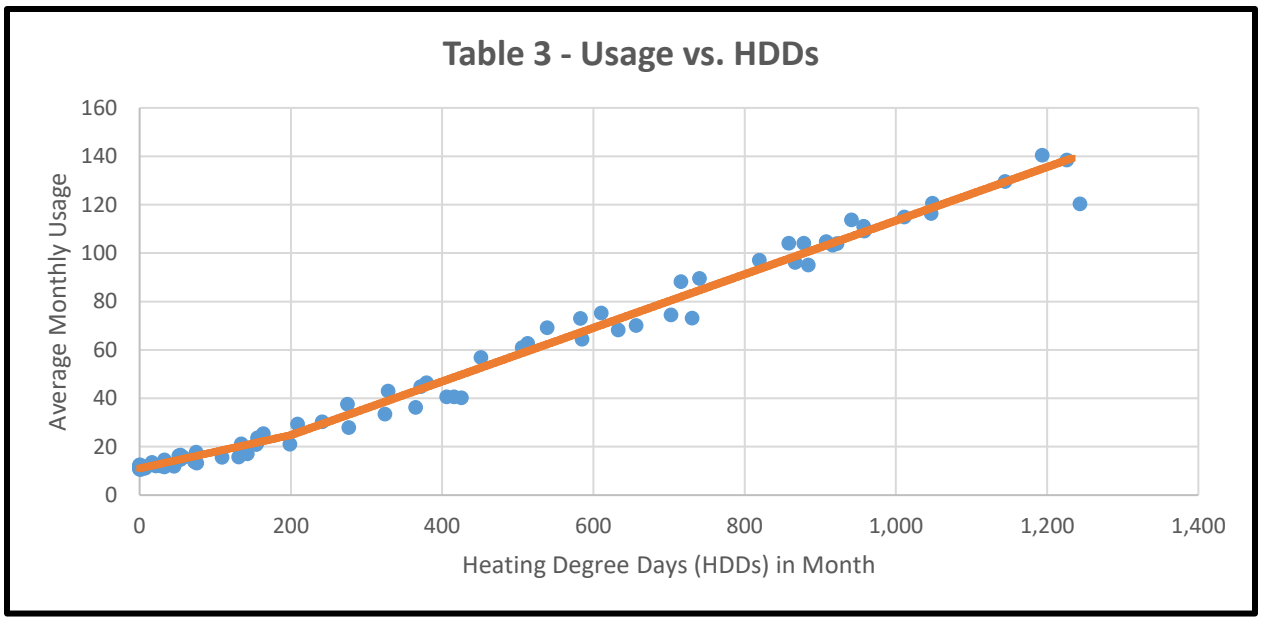
A) WEATHER NORMALIZATION FOR BILLING UNITS

Q. What was your next area of responsibility in this case?

A. My next area of responsibility in this case concerned the weather normalization of the test year billing units.

Q. What was your process for weather normalizing the billing units?

A. I began by creating a weighted average Heating Degree Day (HDD) measure for every month that weighted the weather from both Columbia and Cape Girardeau according to the percentage of total usage attributable to customers in each of those geographic areas. After the weighted average HDDs were established, I began analyzing the relationship between usage and HDDs for each customer class dating back to the beginning of 2011. I ran a regression analysis for every class with each group's monthly usage per customer being the dependent variable. The independent variable in each analysis was the weighted average number of HDDs each month. A regression technique called a spline was used to differentiate the relationship of usage and HDDs during very cold months (those with monthly HDDs greater than 200), and milder months with fewer HDDs. The results of these regressions were used to determine if there was a strong correlation between the class's usage and the weather. For example, the results of the regression line compared to average customer usage for the Residential class is shown in the graph below labeled as Table 3.



Q. What is a Heating Degree Day?

A. A HDD is a measurement that is used to determine the demand for energy needed to heat a customer's building. It is calculated by subtracting the day's average temperature from 65˚ Fahrenheit. Any day with an average temperature equal to or over 65˚ would have zero HDD.

Q. Did every class exhibit a statistically-sufficient relationship between the number of HDDs and the class usage for a weather adjustment to be warranted?

A. Yes. Although the relationship proved to be stronger in some classes, there was a strong enough correlation in all of the customer classes to warrant a weather adjustment.

Q. Please summarize the results of your regression analyses for the classes that were weather normalized.

A. The list of metrics with brief descriptions of the relationship between HDDs and class usage are shown in Table 4 below.

Table 4

Rate Code	R^2	1st Coefficient	1st Coefficient P-Value	2nd Coefficient	2nd Coefficient P-Value
Residential	0.98905	0.0688	8.88E-16	0.0420	2.76E-06
General Service	0.98896	0.1781	4.96E-09	0.2744	8.38E-13
Standard Transport	0.92296	3.4979	2.53E-51	N/A	N/A
Large Volume Transport	0.55873	56.3257	1.73E-17	N/A	N/A
Interruptible	0.36113	13.1048	2.40E-10	N/A	N/A

(1) 1st Coefficient. This coefficient is the amount of Ccf usage per customer that is attributable to each HDD in the month. It applies to all of the customer classes.

(2) 2nd Coefficient. This is an additional coefficient that is added to the first coefficient for months with more than 200 HDDs. This variable in the regression subtracted 200 HDDs from any month with more than 200 HDDs total to capture the incremental HDDs over 200. This would be applicable to the colder months, and represents the marginally higher gas usage that is typical for that weather. This coefficient was added to the Residential and General Service classes to implement a spline in the regression. The sum of the 1st and 2nd coefficients is the incremental usage per degree day in those colder months with more than 200 HDDs.

(3) R-Square. A statistical measure that represents the percent of variability in the dependent variable that is explained by the independent variables included in the regression.

(4) P-Value. The P-Value is an indicator that is used to determine the relevance of including a variable in the regression analysis. A low p-value (<0.05) indicates that the variable is statistically significant with 95% confidence, and therefore is appropriate to include in the analysis.

Q. After you performed the regressions on all the customer classes, what was the next step in weather normalizing the test year billing units?

A. The next step was to apply the results from the regressions that showed the amount of usage per customer each HDD would produce, and compare the actual monthly HDDs from the test year to the 30-year normal HDDs. After the difference between actual and normal HDDs was established, the coefficient from the regressions was applied to normalize the usage levels on a per customer basis, and that number was then multiplied by the number of customers that class had in the month under consideration.

Q. Where does the weather adjustment factor that was ultimately used to weather normalize the actual billing units come from?

A. Once the normal usage volume was established by multiplying the per HDD usage variable by the difference between actual HDDs and normal HDDs, a weather adjustment factor was calculated by taking the normal total usage level for each month and dividing it by the actual recorded usage. These factors were then multiplied by the billing units to determine the Weather Normalized Sales for the test year.

Q. How were the peak day demands weather normalized?

A. In order to weather normalize the CP day, January 16th, and the various NCP days of the weather impacted classes for purposes of developing the allocation factors for demand-related costs in the CCOSS discussed above, the actual weighted average HDDs

from those days were measured against the weighted average 30-year peak day HDDs. Once the peak day HDD difference from the 30-year average was determined, that number was multiplied by the HDD usage variable and applied to the number of customers for the class in the month under consideration. That calculation produced a weather adjustment that was applied to the actual class demands determined from the daily meter reads.

Q. Were the NCP days for all rate classes weather normalized?

A. No, the Large Volume Transportation class was not weather normalized. The NCP for that class was set in a non-winter month meaning that weather did not play a prominent role in the increased usage that established the peak. If we were to follow the process of peak day weather normalization that was used for the other classes, we would be comparing a summer day with little to no HDDs to the 30-year average peak day for that location. This would result in an extreme adjustment to the usage level that would no longer be a relevant measure. Therefore, the NCP for the Large Volume Transportation class was left as actual as opposed to being weather normalized.

B) WEATHER NORMALIZATION FOR THE WEATHER AND CONSERVATION ADJUSTMENT RIDER

Q. Was this weather normalization analysis used in any other portion of this case?

A. Yes. Mr. Harding's testimony discusses the Weather and Conservation Adjustment Rider ("WCAR") that Ameren Missouri is proposing in this case. The regressions that were run for the Residential and General Service classes will be used in the WCAR to calculate, on an ongoing basis, the adjustment that should be made to account for variations in customer usage that can be directly attributed to variations in the weather.

Q. Is there a strong enough correlation between the weather and usage levels in the Residential and General Service classes to justify implementation of the WCAR?

A. Yes. The relationship between HDDs and customer usage in these classes is incredibly strong. Across the two regressions that were run for these classes there was an average R-square value of 0.989. This is a statistical indication that 98.9% of the variability in usage within these classes can be explained by variability in HDDs, which suggests an extremely close relationship between the weather and the usage level of all of the customers in these classes.

Q. Does this conclude your direct testimony?

A. Yes, it does.

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MISSOURI

In the Matter of Union Electric Company d/b/a Ameren Missouri's Tariffs to Increase Its Revenues for Natural Gas Service.	)))	File No. GR-2019-0077

AFFIDAVIT OF RYAN P. RYTERSKI

STATE OF MISSOURI)
) ss
CITY OF ST. LOUIS)

Ryan P. Ryterski, being first duly sworn on his oath, states:

1. My name is Ryan P. Ryterski. I work in the City of St. Louis, Missouri, and I am employed by Union Electric Company d/b/a Ameren Missouri as a Regulatory Rate Specialist.

2. Attached hereto and made a part hereof for all purposes is my Direct Testimony on behalf of Union Electric Company d/b/a Ameren Missouri consisting of 23 pages and Schedule(s) RPR-D1 , RPR-D2, and RPR-D3 , all of which have been prepared in written form for introduction into evidence in the above-referenced docket.

3. I hereby swear and affirm that my answers contained in the attached testimony to the questions therein propounded are true and correct.

Ryan P. Ryterski

Subscribed and sworn to before me this 27th day of November, 2018.

Notary Public

My commission expires: March 7, 2021

CATHLEEN A DEHNE
Notary Public – Notary Seal
St. Louis City – State of Missouri
Commission Number 17119727
My Commission Expires Mar 7, 2021

Ameren Missouri

MISSOURI GAS OPERATIONS

CLASS COST OF SERVICE ALLOCATION STUDY

12 MONTHS ENDED JUNE 2018

TITLE: COST OF SERVICE SUMMARY (Current Rates)

LINE #	ITEM	TOTAL MISSOURI	RESIDENTIAL	GENERAL	INTERRUPTIBLE	TRANSPORTATION SERVICE STANDARD	TRANSPORTATION SERVICE LARGE VOLUME
1							
2	COST OF SERVICE SUMMARY						
3							
4	GAS OPERATING REVENUE						
5	Sale of Gas	$ 73,688,351	$ 44,340,157	$ 15,466,259	$ 379,194	$ 8,055,496	$ 5,447,244
6	Special Contract Revenues	$ 310,968	$ 178,988	$ 74,375	$ 2,801	$ 28,448	$ 26,356
7	Other Operating Revenues	$ 1,826,787	$ 1,483,492	$ 253,772	$ 3,630	$ 49,290	$ 36,604
8							
9	TOTAL GAS OPERATING REVENUES	$ 75,826,106	$ 46,002,637	$ 15,794,405	$ 385,625	$ 8,133,235	$ 5,510,204
10							
11	EXPENSES:						
12	Total Gas O&M Expenses	$ 32,685,268	$ 21,798,369	$ 6,696,613	$ 181,066	$ 2,155,236	$ 1,853,984
13	Depreciation Expense	$ 14,702,205	$ 8,640,280	$ 3,469,612	$ 121,176	$ 1,293,627	$ 1,177,510
14	Taxes Other than Income Taxes	$ 9,064,819	$ 5,427,457	$ 2,139,312	$ 70,372	$ 745,857	$ 681,821
15							
16	INCOME TAXES	$ 3,980,274	$ 2,354,540	$ 950,575	$ 31,941	$ 334,937	$ 308,281
17							
18	NET UTILITY OPERATING INCOME	$ 15,393,540	$ 7,781,991	$ 2,538,294	$ (18,929)	$ 3,603,576	$ 1,488,608
19							
20	RATE BASE	$ 259,304,294	$ 149,251,272	$ 62,018,095	$ 2,335,553	$ 23,722,036	$ 21,977,338
21							
22	RATE OF RETURN - REALIZED	5.94	5.21	4.09	(0.81)	15.19	6.77

Ameren Missouri

MISSOURI GAS OPERATIONS

CLASS COST OF SERVICE ALLOCATION STUDY

12 MONTHS ENDED JUNE 2018

TITLE: COST OF SERVICE SUMMARY (Equal Returns)

		TOTAL				TRANSPORTATION SERVICE	
LINE #	ITEM	MISSOURI	RESIDENTIAL	GENERAL	INTERRUPTIBLE	STANDARD	LARGE VOLUME
1							
2	COST OF SERVICE SUMMARY						
3							
4	GAS OPERATING REVENUE						
5	Sale of Gas (Margin)	$ 77,952,669	$ 47,809,345	$ 17,630,948	$ 579,091	$ 6,279,479	$ 5,653,806
6	Special Contract Revenues	$ 310,968	$ 178,988	$ 74,375	$ 2,801	$ 28,448	$ 26,356
7	Other Operating Revenues	$ 1,826,787	$ 1,483,492	$ 253,772	$ 3,630	$ 49,290	$ 36,604
8							
9	TOTAL GAS OPERATING REVENUES	$ 80,090,424	$ 49,471,825	$ 17,959,094	$ 585,522	$ 6,357,217	$ 5,716,765
10							
11	EXPENSES:						
12	Total Gas O&M Expenses	$ 32,685,268	$ 21,798,369	$ 6,696,613	$ 181,066	$ 2,155,236	$ 1,853,984
13	Depreciation Expense	$ 14,702,205	$ 8,640,280	$ 3,469,612	$ 121,176	$ 1,293,627	$ 1,177,510
14	Taxes Other than Income Tax	$ 9,064,819	$ 5,427,457	$ 2,139,312	$ 70,372	$ 745,857	$ 681,821
15							
16	INCOME TAXES	$ 3,980,274	$ 2,290,980	$ 951,967	$ 35,850	$ 364,129	$ 337,348
17							
18	NET UTILITY OPERATING INCOME	$ 19,657,858	$ 11,314,739	$ 4,701,592	$ 177,058	$ 1,798,367	$ 1,666,102
19							
20	RATE BASE	$ 259,304,294	$ 149,251,272	$ 62,018,095	$ 2,335,553	$ 23,722,036	$ 21,977,338
21							
22	RATE OF RETURN - REALIZED	7.581	7.581	7.581	7.581	7.581	7.581

Ameren Missouri

MISSOURI GAS OPERATIONS

CLASS COST OF SERVICE ALLOCATION STUDY

12 MONTHS ENDED JUNE 2018

				Transportation Service	
	Total	**Residential**	**General**	**Interruptible**	**Standard**	**Large Volume**
Revenue Requirement						
Customer	$ 35,716,417	$ 27,338,457	$ 6,807,083	$ 56,906	$ 1,055,604	$ 458,368
Production -- Demand	$ 1,893,865	$ 1,245,885	$ 647,979	$ -	$ -	$ -
Production -- Energy	$ 623,936	$ 411,806	$ 193,515	$ 7,923	$ 5,714	$ 4,978
Transmission -- Demand	$ 968,587	$ 479,763	$ 239,870	$ 11,311	$ 120,388	$ 117,255
Distribution -- Demand	$ 40,887,619	$ 19,995,913	$ 10,070,647	$ 509,383	$ 5,175,511	$ 5,136,165
	$ 80,090,424	$ 49,471,825	$ 17,959,094	$ 585,522	$ 6,357,217	$ 5,716,765
Other Revenue						
Customer	$ 1,826,787	$ 1,483,492	$ 253,772	$ 3,630	$ 49,290	$ 36,604
Production -- Demand	$ -	$ -	$ -	$ -	$ -	$ -
Production -- Energy	$ -	$ -	$ -	$ -	$ -	$ -
Transmission -- Demand	$ -	$ -	$ -	$ -	$ -	$ -
Distribution -- Demand	$ -	$ -	$ -	$ -	$ -	$ -
	$ 1,826,787	$ 1,483,492	$ 253,772	$ 3,630	$ 49,290	$ 36,604
Special Contracts	$ 310,968	$ 178,988	$ 74,375	$ 2,801	$ 28,448	$ 26,356
Customer	$ 95,093	$ 71,137	$ 20,783	$ 73	$ 2,570	$ 530
Production -- Demand	$ 1,946	$ 1,250	$ 697	$ -	$ -	$ -
Production -- Energy	$ 7,839	$ 5,267	$ 2,472	$ 100	$ (0)	$ (0)
Transmission -- Demand	$ 2,161	$ 1,071	$ 535	$ 25	$ 269	$ 262
Distribution -- Demand	$ 203,928	$ 100,263	$ 49,887	$ 2,602	$ 25,610	$ 25,565
	$ 310,968	$ 178,988	$ 74,375	$ 2,801	$ 28,448	$ 26,356
Base Revenue						
Customer	$ 33,794,538	$ 25,783,829	$ 6,532,528	$ 53,203	$ 1,003,744	$ 421,235
Production -- Demand	$ 1,891,918	$ 1,244,635	$ 647,283	$ -	$ -	$ -
Production -- Energy	$ 616,097	$ 406,539	$ 191,043	$ 7,822	$ 5,715	$ 4,978
Transmission -- Demand	$ 966,426	$ 478,692	$ 239,335	$ 11,285	$ 120,120	$ 116,994
Distribution -- Demand	$ 40,683,690	$ 19,895,649	$ 10,020,760	$ 506,781	$ 5,149,901	$ 5,110,599
	$ 77,952,669	$ 47,809,345	$ 17,630,948	$ 579,091	$ 6,279,479	$ 5,653,806
Customer		$ 18.29	$ 42.39	$ 648.81	$ 125.80	$ 1,726.37
Delivery		$ 0.2987	$ 0.3063	$ 0.2728	$ 0.1420	$ 0.1616