Exhibit No.:
Issue: Class Cost of Service, Rate Design, CWC Study
Witness: Timothy S. Lyons
Type of Exhibit: Direct
Sponsoring Party: The Empire District Electric Company
Docket No.: 19-EPDE-223-RTS
Date Testimony Prepared: December 2018

Before the Kansas Corporation Commission

Direct Testimony

of

Timothy S. Lyons

December 2018

Liberty Utilities
EMPIRE DISTRICT

**DIRECT TESTIMONY
OF
TIMOTHY S. LYONS
ON BEHALF OF
THE EMPIRE DISTRICT ELECTRIC COMPANY
BEFORE THE
KANSAS CORPORATION COMMISSION
DOCKET NO. 19-EPDE-___-RTS**

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LIST OF EXHIBITS

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I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Timothy S. Lyons. My business address is 1900 West Park Drive, Suite 250, Westborough, Massachusetts 01581.

Q. PLEASE DESCRIBE YOUR CURRENT POSITION.

A. I am a Partner at ScottMadden, Inc. ("ScottMadden").

Q. PLEASE DESCRIBE YOUR PROFESSIONAL EXPERIENCE.

A. I have more than 30 years of experience in the energy industry. I started my career in 1985 at Boston Gas Company, eventually becoming Director of Rates and Revenue Analysis. In 1993, I moved to Providence Gas Company, eventually becoming Vice President of Marketing and Regulatory Affairs. Starting in 2001, I held a number of management consulting positions in the energy industry first at KEMA and then at Quantec, LLC. In 2005, I became Vice President of Sales and Marketing at Vermont Gas Systems, Inc. before joining Sussex Economic Advisors, LLC ("Sussex") in 2013. Sussex was acquired by ScottMadden on June 1, 2016.

Q. PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND.

A. I hold a Bachelor's degree from St. Anselm College, a Master's degree in Economics from The Pennsylvania State University, and a Master's degree in Business

Administration from Babson College. A summary of my testimony experience is included in Direct Exhibit TSL-1.

II. PURPOSE OF TESTIMONY

Q. **WHAT IS THE PURPOSE OF YOUR TESTIMONY?**

A. This testimony describes the approach used to design the proposed electric rates for the Kansas jurisdiction of The Empire District Electric Company ("Empire" or the "Company"). The testimony includes: (a) a description of the current rate classes; (b) development of the allocated Cost of Service Study ("COSS"); (c) development of the proposed revenue targets, rate design, and bill impact analyses for each rate class; (d) proposal to implement a Revenue Stabilization Rider; and (e) proposal to implement a Capital Tracker Rider. In addition my testimony includes testimony is to sponsor the lead-lag study, which is used to determine Empire's Kansas jurisdiction Cash Working Capital ("CWC") requirement.

Q. HAVE YOU PREPARED EXHIBITS TO SUPPORT THIS TESTIMONY?

A. Yes. Direct Exhibit TSL-2 through TSL-10 summarize the results of the COSS and rate design, Direct Exhibit TSL-11 includes the proposed Revenue Stabilization Rider, and Direct Exhibit TSL-12 includes the proposed Capital Tracker Rider. Direct Exhibit TSL-13 and TSL 14 summarize the results of the lead-lag study, and contain the supporting schedules. The Exhibits were prepared by me or under my direction.

III. SUMMARY OF FINDINGS AND RECOMMENDATIONS CLASS COST OF SERVICE/RATE DESIGN

Q. PLEASE SUMMARIZE YOUR TESTIMONY.

A. The results of the Company's COSS show that the current rate design produces a disparity in class rates of return ("ROR"). The Residential, Municipal Street Lighting, and Special Lighting rate classes produce RORs that are less than the system or overall ROR, indicating their rates recover less than their cost of service. The remaining C&I and Lighting rate classes produce RORs that are more than the system ROR, indicating their rates recover more than their cost of service. Except as described in testimony, the COSS was prepared consistent with the methodologies described in the Company's prior rate case filing.[1]

The results of the COSS support a movement toward a more equitable rate structure where class RORs move closer to the system ROR. To meet that objective, the proposed rate increases for the Residential, Municipal Street Lighting, and Special Lighting rate classes are higher than the overall rate increase. However, the proposed rate increases were subject to certain limitations that address customer bill impact considerations. The proposed rates for the remaining C&I and Lighting rate classes also moved the class RORs closer to the system ROR.

The proposed rate design largely reflects a uniform increase in each rate element to minimize intraclass bill impacts.

The Company prepared a bill impact analysis to evaluate the impact of the proposed rate changes on customers. The bill impact analysis evaluated a wide range of customer usage across rate classes. The bill impact analysis was prepared in two ways:

1. Proposed Base Rates vs. Current Base Rates, comparing (i) the proposed base rates, and (ii) the current base rates; and

[1] Docket No. 10-EPDE-314-RTS, *In the Matter of The Empire District Electric Company for Approval of the Commission to Make Certain Changes in Its Charges for Electric Service*

2. Proposed Total Bill vs. Current Total Bill, comparing (i) the proposed base rates plus the Energy Cost Adjustment ("ECA") charge and the proposed Transmission Delivery Charge Rider ("TDC") charge, and (ii) the current base rates plus ECA charge and the current Ad Valorem Tax Surcharge Rider ("AVT") and the Asbury Environmental and Riverton Rider ("AERR") charges.

The latter provides a better representation of the bill impact that customers will actually experience since the proposed rate design transfers recovery of test year AVT and AERR costs from the AVT and AERR Riders to base rates and transfers recovery of test year transmission costs from base rates to the proposed TDC Rider. Overall, the proposed rate design would increase monthly bills for a typical Residential General customer by $20.00 per month, or 17.8 percent.

The proposed rates reflect three important utility rate design principles: (a) rates should recover the overall cost of providing service; (b) rates should be fair, minimizing inter- and intra-class inequities to the extent possible; and (c) rate changes should be tempered by rate continuity concerns.

IV. <u>OVERVIEW</u>

Q. PLEASE DESCRIBE THE EMPIRE DISTRICT ELECTRIC'S SERVICE AREA.

A. The Empire District Electric Company, a subsidiary of Algonquin Power & Utilities Corp., is a regulated utility providing electric service in parts of Missouri, Kansas, Oklahoma, and Arkansas. In the Kansas jurisdiction, the Company provides electric service to residential, commercial and industrial ("C&I"), and street lighting customers. The Company serves approximately 9,669 customers, including 8,173 (84.5 percent) residential customers, 1,445 (15.0 percent) C&I customers, and 51 (0.5 percent) lighting customers. In addition, the Company provides service to special contract customers. These customers, however, were not evaluated in the COSS since their rates will not change in this proceeding.

Customers are presently served under one of eleven rate classes based on type of service and load characteristics. The rate classes consist of three residential classes, five C&I classes, and three lighting classes. The rate classes and their current rates are described in Figure 1.

Figure 1: Current Rate Structure

Rate Class	Availability	Current Base Rates	
Residential General Service ("RG")	Available for residential service to single-family dwellings or to multi-family dwellings within a single building.	Customer charge (Monthly) Energy charges (per kWh) First 600 kWh Additional kWh	$14.00 $0.06858 $0.06112
Residential General – Water Heating Service ("RGW")	Available for residential general service customers with electric water heaters to supply the customer's total requirements for hot water.	Customer charge (Monthly) Energy charges (per kWh) First 600 kWh Additional kWh	$14.00 $0.06309 $0.06112
Residential Total Electric Service ("RH")	Available for residential service to total electric single-family dwellings or to multi-family dwellings within a single building.	Customer charge (Monthly) Energy charges (per kWh) All kWh	$14.00 $0.05723
Commercial Service ("CB")	Available for any C&I customers having electric load below 40kW.	Customer charge (Monthly) Energy charges (per kWh) First 600 kWh Additional kWh	$19.00 $0.09284 $0.08263
Small Heating Service ("SH")	Available for any C&I customers having electric load below 40kW, and who have permanently installed and regular usage of electric space heating equipment.	Customer charge (Monthly) Energy charges (per kWh) First 1000 kWh Additional kWh	$19.00 $0.07891 $0.06963
General Power Service ("GP")	Available for any commercial or industrial customers.	Demand Charges (per kW) First 40kW Next 460 kW All additional kW Energy Charge (per kWh) All kWh	 $13.02 $10.39 $8.15 $0.03400
Total Electric Building Service ("TEB")	Available for any commercial or industrial customers.	Energy charges (per kWh) First 150 kWh or less Next 9850 kWh Additional to 1,000 kWh	 $30.46 $0.08460 $0.05935
Transmission Service ("PT")	Available for any commercial or industrial customers.	Demand Charges (per kW) First 1,000kW All additional kW Energy Charge (per kWh) All kWh	 $11,858.75 $5.61 $0.02083
Municipal Street Lighting Service ("SPL")	Available to municipalities served by the Company for outdoor lighting for streets, alleys, parks, and public places.	Varying charges by lamp size and type	
Private Lighting Service ("PL")	Available for outdoor lighting service to any retail customer.	Varying charges by lamp size and type	
Special Lighting Service ("LS")	Available for electric service to sport field lighting, carnival, holiday decorative lighting or similar temporary or seasonal use.	Minimum Monthly Charge Energy charges (per kWh) First 1,000 kWh All kWh	$39.60 $0.1308 $0.0960

Q. PLEASE DESCRIBE THE COMPANY'S CURRENT RATE STRUCTURE.

A. The Company's current rate structure consists of base rates, Energy Cost Adjustment ("ECA") factors, and several riders, including the Ad Valorem Tax Surcharge Rider and the Asbury Environmental and Riverton Rider.[2] The base rates include a monthly customer charge, energy charges, and demand charges. For certain rate classes, the minimum bill consists of a minimum use charge or a minimum demand charge rather than a customer charge. For example, the minimum bill for the TEB rate class is $30.46 for usage up to 150 kWh per month. Similarly, the minimum bill for the GP and PT rate classes is based on customer billing demand and associated demand charges.

Q. PLEASE DESCRIBE THE LOAD PROFILE OF THE COMPANY'S RATE CLASSES.

A. Figure 2 provides a breakdown of test year customers and kWh sales by rate class. The test year represents the period July 1, 2017 through June 30, 2018. The usage in Figure 2 has been normalized for weather.

[2] The Company's tariffs are available at: https://www.empiredistrict.com/CustomerService/Rates/Electric/KS

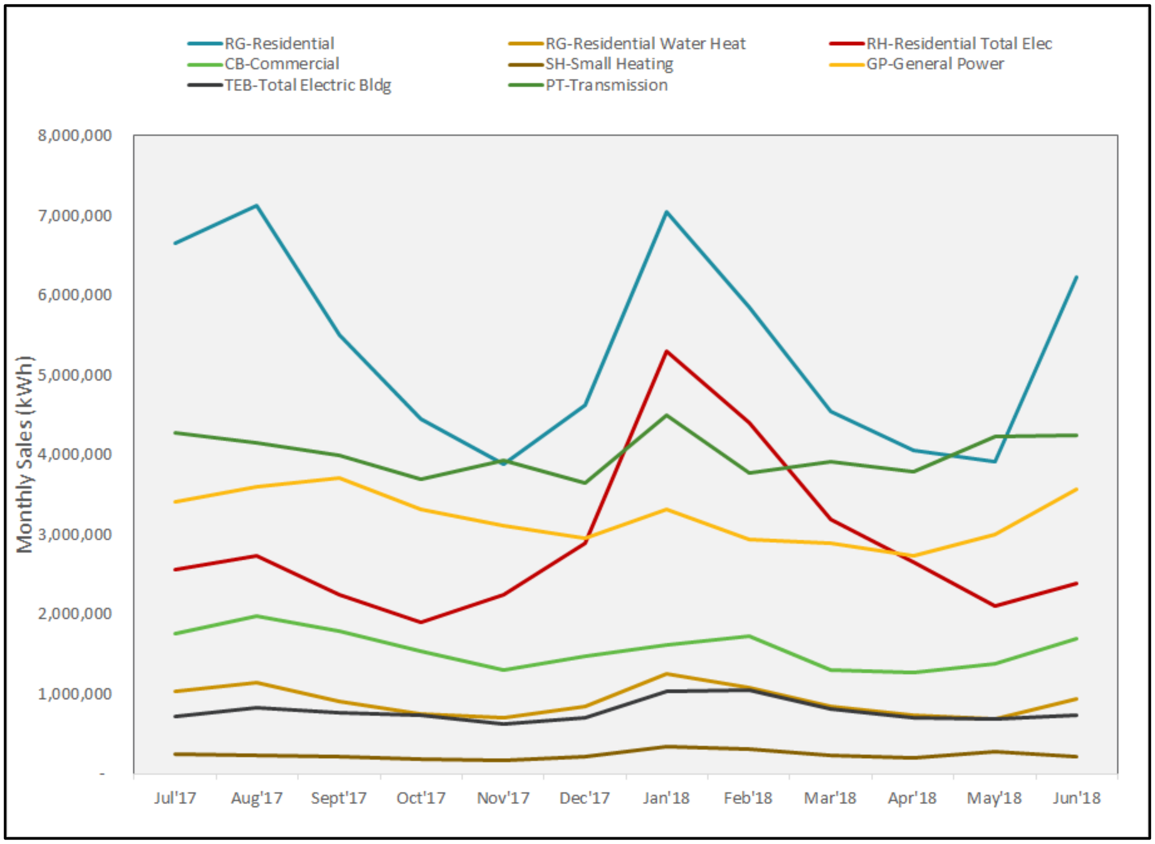
Figure 2: Test Year Customers and Sales

Rate Class	Number of Customers	% of Customers	Sales kWh	% of Sales	kWh Usage per Customer
RG-Residential	5,544	57.3%	62,362,298	27.4%	11,248
RG-Residential Water Heat	762	7.9%	10,735,927	4.7%	14,097
RH-Residential Total Elec	1,867	19.3%	34,436,656	15.1%	18,447
CB-Commercial	1,185	12.3%	18,430,731	8.1%	15,559
SH-Small Heating	110	1.1%	2,779,399	1.2%	25,325
GP-General Power	106	1.1%	38,200,653	16.8%	360,951
TEB-Total Electric Bldg	40	0.4%	9,327,899	4.1%	235,652
PT-Transmission	5	0.1%	48,142,857	21.2%	9,628,571
SPL-Municipal St Lighting	-	0.0%	1,554,951	0.7%	
PL-Private Lighting	33	0.3%	1,462,318	0.6%	44,651
LS-Special Lighting	19	0.2%	154,007	0.1%	8,325
Total	9,669	100.0%	227,587,696	100.0%	23,539
Total Residential	8,173	84.5%	107,534,881	47.2%	13,158

The Figure shows that the Residential class represents a majority (84.5 percent) of the Company's customers. The Figure also shows variations in annual use per customer among the rate classes. Residential General customers, for example, use on average 13,158 kWh per year, while General Power customers use on average 360,951 kWh per year.

Figure 3 shows kWh sales by Company's rate classes throughout the year. The Figure shows sales vary seasonally for certain rate classes in the winter and summer months.

Figure 3: Monthly kWh Sales by Customer Class



The Residential General rate class, for example, shows a seasonal load pattern, with monthly sales increasing during the winter and summer months, reflecting heating and cooling consumption, respectively. The Residential Total Electric rate class also shows a seasonal load pattern, with monthly sales increasing during the winter months, reflecting heating consumption. The Residential Water Heating rate class shows a relatively consistent load pattern throughout the year, reflecting water heating consumption. The C&I rate classes also show relatively consistent load patterns throughout the year, with slight increases during the summer months in some cases. The load pattern differences, as discussed below, have implications on the allocation of costs in the COSS.

V. ALLOCATED COST OF SERVICE STUDY

Q. PLEASE DESCRIBE THE PURPOSE OF AN ALLOCATED COST OF SERVICE STUDY.

A. The COSS allocates a utility's overall cost of service to each rate class in a manner that reflects its underlying cost of service. The COSS sponsored in this testimony was developed by identifying the relationship between the service requirements for each rate class and their respective cost drivers. This approach is well established in industry literature[3] and is consistent with the methodologies described in the Company's prior rate case.[4]

Q. PLEASE DESCRIBE THE APPROACH USED TO DEVELOP THE COSS.

A. The cost of service study was based on three steps. First, costs were functionalized or assigned into one of five functional categories: production, transmission, primary distribution, secondary distribution, and customer service. Next, functionalized costs were classified into one of three cost drivers: whether costs are related to serving peak demands, serving energy demands, or meeting customer service requirements. Finally, classified costs were allocated to each rate class based on a method that best represents how costs are incurred.

Each of the three steps was performed using two types of assignments: direct assignment and indirect assignment. Direct assignments utilized the Company's test year financial data, knowledge of its system, and special studies to assign plant investments and expenses to certain functions, classifications and rate classes. Indirect assignments utilized composite allocators based on direct and indirect assignments developed during

[3] See Principles of Public Utility Rates by James C. Bonbright
[4] Docket No. 10-EPDE-314-RTS, *In the Matter of The Empire District Electric Company for Approval of the Commission to Make Certain Changes in Its Charges for Electric Service*

the functionalization, classification and allocation process. A description of the functional factors, classifiers and allocators is included in Direct Exhibit TSL-3.

Q. WHAT IS FUNCTIONALIZATION?

A. Functionalization is the process of assigning rate base and expense items into four operational components, including production, transmission, distribution, and customer service. The functionalization of costs in this study is generally based on accounting data organized by the Federal Energy Regulatory Commission's ("FERC") Uniform System of Accounts ("USOA"). Generation plant and associated costs were functionalized into production accounts and allocated based on demand and energy allocators. Transmission plant and associated costs were functionalized and assigned to the proposed TDC Rider. The Company proposes in this proceeding to recover transmission plant and associated costs through the proposed TDC Rider. Distribution facilities and associated costs were functionalized into primary and secondary distribution since some customers take service from the primary distribution system while other customers take service from the secondary distribution system.

Q. WHAT IS CLASSIFICATION?

A. Classification is the process of assigning rate base and expense items into categories that reflect cost-causation. There are three principle causes or drivers of costs related to the electric system: (a) Customer-related, these are costs that vary with the number of customers, such as costs associated with connecting customers to the electric system and providing basic customer services, such as metering and billing; (b) Demand-related, these are costs that vary with maximum customer demands at the time of the system peak, at the time of the rate class peak, or at the time of the customer peak; and (c)

Energy-related, these are costs that vary with the production, transmission and delivery of energy, such as fuel and purchased power expenses.

Q. WHAT IS ALLOCATION?

A. Allocation consists of assigning rate base and expense items to individual rate classes based on allocators that reflect their underlying cost of service.

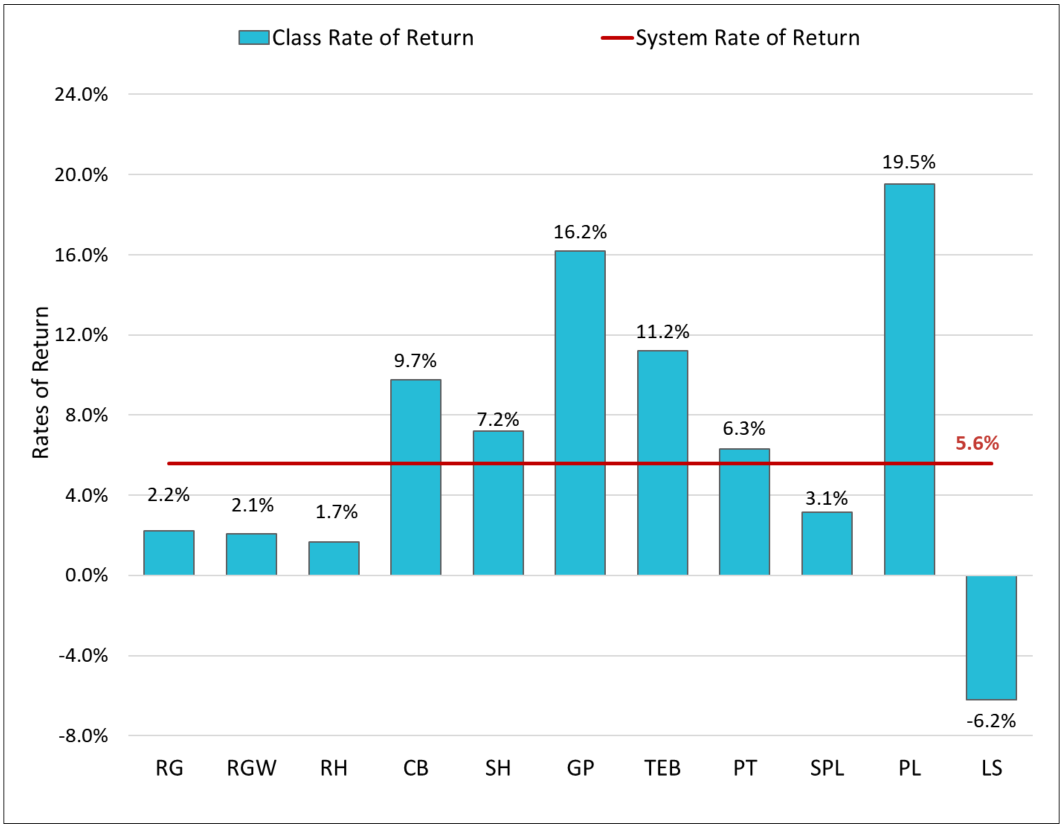
Q. HOW WAS THE COSS DEVELOPED?

A. The COSS was based on a spreadsheet model developed by ScottMadden for this filing. Each rate base and expense item in the COSS was assigned to each rate class in Figure 1 based on the three-step process described above.

Q. PLEASE DESCRIBE THE OVERALL RESULTS OF THE COMPANY'S COST OF SERVICE STUDY.

A. The results of the COSS are shown in Figure 4. The Figure compares the calculated ROR for each rate class based on current rates to the system or overall ROR.

Figure 4: Class ROR vs. Overall ROR at Current Delivery Rates

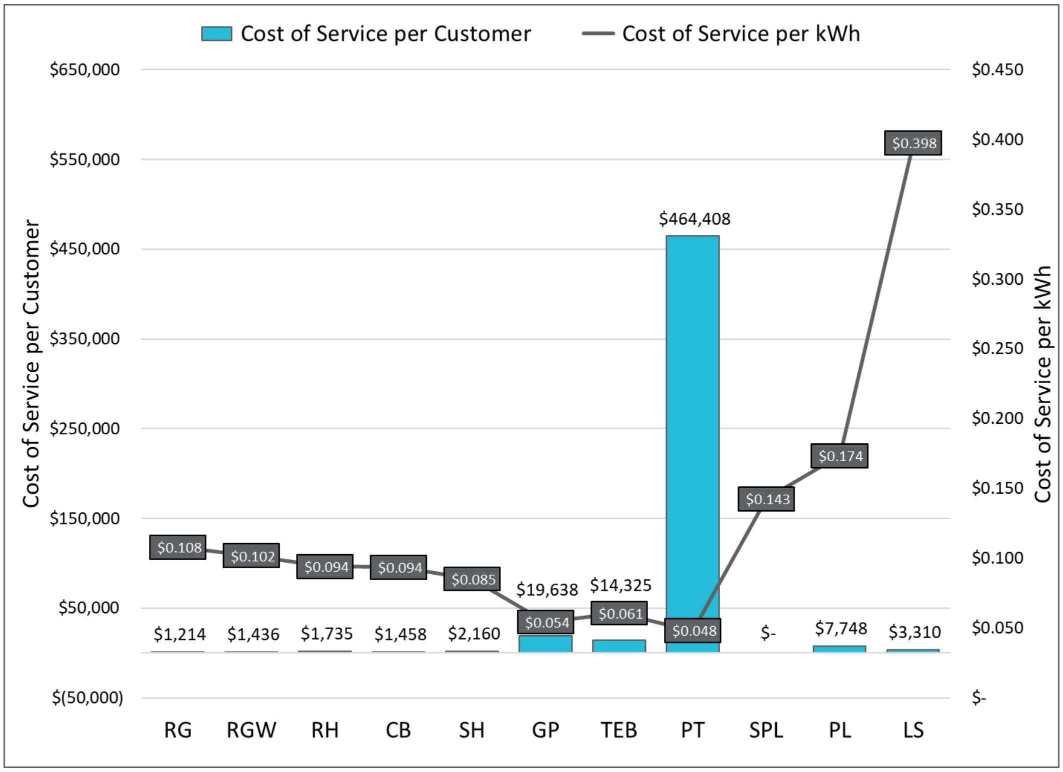


The Figure shows that the Company's Residential, Municipal Street Lighting, and Special Lighting rate classes produce a ROR below the system ROR. The remaining Commercial and Industrial ("C&I") and Lighting rate classes produce a ROR above the system ROR. Further details are included in Direct Exhibit TSL-2.

Q. DOES THE COST OF SERVICE VARY ACROSS THE COMPANY'S RATE CLASSES?

A. Yes, the cost of service per customer and per kWh (i.e., unit cost of service) varies across the Company's rate classes, as shown in Figure 5.

Figure 5: Unit Cost of Service by Rate Class



The Figure shows, for example, that the unit cost of service for the Residential General rate class is $1,214 per customer, while the unit cost of service for the Transmission rate class is $464,408 per customer. In comparison, the unit cost of service for the Residential General class is $0.108 per kWh, while the unit cost of service for the Transmission rate class is $0.048 per kWh.

Q. HOW DOES THE VARIATION IN THE UNIT COST OF SERVICE RELATE TO THE CLASS RATE OF RETURNS?

A. Variations in the unit cost of service support the need for separate classes since a rate that is equal to the unit cost of service produces a ROR for each rate class that is equal to the system ROR.

Q. WHAT DOES IT MEAN WHEN A RATE CLASS ROR IS HIGHER OR LOWER THAN THE SYSTEM ROR?

A. If a rate class produces a ROR that is lower than the system ROR, then the revenues recovered from the rate class are less than its cost of service. Conversely, if a rate class produces a ROR that is higher than the system ROR, then the revenues recovered from the rate class are more than its cost of service. As discussed below, the COSS results were used to establish revenue targets for each rate class that move the Company's proposed rates in aggregate closer to the system ROR to achieve more fair and equitable rates across customer classes.

Q. PLEASE DESCRIBE THE DATA USED TO PREPARE THE COSS.

A. The COSS is based on test year data for the period July 1, 2017 through June 30, 2018. The COSS includes the number of customers, sales and revenues by rate class. Sales and revenues have been adjusted to reflect the impact of normal weather. The COSS also includes rate base items, including intangible plant, production, transmission, distribution and general plant-in-service as well as (a) additions to plant-in-service, including materials and supplies, prepayments, cash working capital, and other regulatory assets, and (b) reductions to plant-in-service, including accumulated, customer deposits, customer advances, and other regulatory liabilities. The COSS also includes operations and maintenance ("O&M") expenses, including transmission, distribution, customer service, customer account, sales, and administrative and general expenses as well as taxes other than income, such as payroll and property taxes, and income taxes.

Q. PLEASE DESCRIBE THE FUNCTIONALIZATION PROCESS USED IN DEVELOPING THE COST OF SERVICE STUDY.

A. As discussed earlier, functionalization is an important first step in development of the COSS. The functionalization process in this study generally followed the USOA.

However, distribution plant was further functionalized into primary and secondary distribution facilities to ensure that the cost of service at these functional levels was separately identified and applied.

The overall cost of service was functionalized into one of the following categories:

- Production – plant investment and expenses associated with the Company's generation facilities. These include production plant, accumulated depreciation, depreciation expense, and production fixed and variable expenses.
- Transmission – plant investment and expenses associated with the Company's high voltage transmission facilities were functionalized and assigned to the proposed TDC Rider. The Company proposes in this proceeding to recover transmission plant and associated costs through the proposed TDC Rider.
- Primary Distribution – plant investment and expenses associated with the Company's primary voltage distribution facilities. These include primary distribution plant, accumulated depreciation, depreciation expense, and related O&M expenses. Some costs that support both the primary and secondary distribution systems were identified and functionalized into primary and secondary functions. Such costs include poles and towers, overhead conductors and devices, underground conduit, and underground conductors and devices.
- Secondary Distribution – plant investment and expenses associated with the Company's secondary voltage distribution facilities. These include secondary distribution plant, accumulated depreciation, depreciation expense, and related O&M expenses. The secondary portion of poles and towers, overhead conductors

and devices, underground conduit, and underground conductors and devices are also included in this function.

- Customer Service – plant investment and expenses associated with the Company's customer service facilities. These costs are largely related to meters and services, accumulated depreciation, depreciation expense, and related O&M expenses.

The remaining rate base and cost of service accounts were assigned to one of the five functional categories based on composite functionalization of the plant accounts. For example, general plant and labor-related administrative and general ("A&G") expenses were assigned to all five functional categories based on the composite functionalization of labor-related production, transmission, and distribution expenses. Further descriptions of the functionalization factors are included in Direct Exhibit TSL-3.

Q. PLEASE DESCRIBE THE CLASSIFICATION PROCESS USED IN DEVELOPING THE COST OF SERVICE STUDY.

A. The cost of service is classified into one of the following three categories:

- Customer-related – costs associated with providing customer access to the electric system as well as providing on-going customer services, such as meter reading and billing services.
- Demand-related – costs associated with meeting customer peak demand requirements.
- Energy-related – costs associated with the kWh sales by the customers.

In some cases, costs were classified into only one of the three categories. The cost of meter reading, for example, was classified as customer related. In other cases, costs were classified into more than one category. For example, the costs associated with primary distribution plant were segmented based on their underlying characteristics. Some costs were classified as customer-related, while others were classified as demand-related. The minimum-size method was used to develop the segmentation.

Q. PLEASE EXPLAIN THE CLASSIFICATION OF DISTRIBUTION FACILITIES.

A. Distribution plant represents 38.0 percent of the Company's investment in utility plant. The classification of distribution plant reflects two primary cost drivers. The first cost driver is the number of customers, i.e., distribution facilities are designed to provide customer access to the electric system. The second driver is peak demands, i.e., distribution facilities are designed to meet peak demands throughout the year. This approach to classification of distribution facilities is well-established and recognized by the National Association of Regulatory Commissioners ("NARUC"). Specifically, NARUC states,

> "Distribution plant accounts 364 through 370 involve demand and customer costs. The customer component of distribution facilities is that portion of costs which varies with the number of customers. Thus, the number of poles, conductors, transformers, services and meters are directly related to the number of customers on the utility's system…each primary plant account can be separately classified into demand and customer components"[5]

The classification of distribution plant in this study is consistent with the approach described in the NARUC manual as well as the methodologies described in the

[5] NARUC Electric Utility Cost Allocation Manual, Pg. 90

Company's prior rate case filing.[6] As discussed earlier, distribution plant and related costs are separated into two functions: primary and secondary distribution. The Primary distribution facilities and line transformers are classified as either customer- or demand-related using the minimum-size method. Secondary distribution is generally classified as customer-related.

Q. PLEASE EXPLAIN THE APPROACH TO CLASSIFY PRIMARY DISTRIBUTION PLANT.

A. Distribution plant accounts were classified based on their specific functions. For distribution plant related to facilities associated with distribution substations (360-363), the plant was classified based on demand and allocated to each rate class based on class Non-Coincidental Peak ("NCP") demands. Substations generally reflect the peak demands of customers served from the substation and thus can peak at times different than the system peak. The class NCP reflects peak demands of customers served from the substations.

For distribution plant related to facilities associated with overhead and underground lines (Accounts 364-368), the costs were classified as both customer and demand. While there are several methods to classify costs between customer and demand, the Minimum-size Method was used in this study since it represents the actual cost of connecting customers to the system to serve minimum demands. The Minimum-size Method assumes that a minimum size distribution system can be built to serve the minimum demand requirements of customers. The "minimum system" costs are allocated to each rate class based on the number of customers. Distribution plant in

[6] Docket No. 10-EPDE-314-RTS, *In the Matter of The Empire District Electric Company for Approval of the Commission to Make Certain Changes in Its Charges for Electric Service*

excess of the minimum system reflect the cost of serving peak demands. The "peak demand" costs are allocated to each rate class based on customer peak demands. The approach is consistent with the methodology described in the NARUC manual,

> "Classifying distribution plant with the minimum-size method assumes that a minimum size distribution system can be built to serve the minimum loading requirements of the customer. The minimum-size method involves determining the minimum size pole, conductor, cable, transformer, and service that is currently installed by the utility."[7]

The approach used in this study was based on the current cost of the minimum-sized installation of each plant account relative to the historical cost of each plant account indexed to current costs utilizing the Handy-Whitman Index of Public Utility Construction Costs ("Handy-Whitman"). The analysis was performed on a consolidated basis across the Company's four jurisdictions. The minimum-size studies are provided in Direct Exhibit TSL-5.

Q. PLEASE DISCUSS THE RESULTS OF THE MINIMUM-SIZE ANALYSIS.

A. The results of the minimum system analysis are provided in Direct Exhibit TSL-7.

- Poles, Towers, and Fixtures (Account 364): The analysis shows that 53.1 percent of costs are related to minimum sized installations with the remaining portion related to serving customer maximum demands.
- Overhead conductors and devices (Account 365): The analysis shows that 12.8 percent of costs are related to minimum sized installations with the remaining portion related to serving customer maximum demands.

[7] NARUC Electric Utility Cost Allocation Manual, Pg. 90

- Underground Conduits, Conductors, and Devices (Accounts 366-367): The analysis shows that 44.6 percent of costs are related to minimum sized installations with the remaining portion related to serving customer maximum demands.
- Line Transformers (Account 368): The analysis shows that 43.5 percent of costs are related to minimum sized installations with the remaining portion related to serving customer maximum demands.

Q. PLEASE DISCUSS THE CLASSIFICATION OF OTHER RATE BASE ITEMS.

A. Other rate base items were similarly classified based on their underlying cost drivers. For example, meter cost, meter installation, service cost, and house regulator investments were classified as customer-related since they enable customers access to the electric system. Rate base items not directly associated with one of the classification categories, such as intangible plant, were classified through a composite classifier based on the classification of total plant. Further details on the classification factors developed for this study are included in Direct Exhibit TSL-5.

Q. PLEASE DISCUSS THE CLASSIFICATION OF OPERATIONS AND MAINTENANCE EXPENSES.

A. Operations and maintenance expenses were classified in a manner similar to their respective plant items. For example, distribution O&M expenses followed the classification of their respective plant accounts. For example, Maintenance of line transformers (Account 595) was classified based on the classification of Line Transformers (Account 368).

O&M expense items not directly associated with one of the classification categories, such as non-labor related A&G expenses, were classified through a composite classifier based on related costs.

Q. PLEASE DESCRIBE THE ALLOCATION PROCESS USED IN DEVELOPING THE COSS.

A. Costs were allocated to each rate class based on how costs are incurred to serve that class. In other words, for each component of cost, the Company developed an allocator that best reflected how costs are incurred.

Q. PLEASE DESCRIBE THE ALLOCATORS USED IN DEVELOPING THE COSS.

A. The COSS was based on three types of allocators:

1. Class determinants – class characteristics, such as number of customers, peak demands, kWh sales, and revenues by rate class;
2. Special studies – detailed analysis of specific plant or expense items, such as meters and uncollectible expenses; and
3. Indirect – composite allocators based on how other costs were allocated.

Direct Exhibit TSL-3 contains a description of each allocator used in the COSS, including what costs are allocated, how each allocator was derived, and the rationale for utilizing the allocator. For example, the 'number of customers' allocator is used to allocate meter reading expenses based on the number of customers in each rate class. The rationale is that meter reading expenses are driven primarily by the number of customer meters that are read monthly. Further details on the allocation factors developed for this study are included in Direct Exhibit TSL-6.

Q. PLEASE DESCRIBE THE PROCESS USED TO ALLOCATE PRODUCTION PLANT.

A. Production plant is the largest component of Company's rate base, representing 45.0 percent of total utility plant. Production plant costs are incurred consistent with the Company's design of its production facilities to meet both energy and capacity requirements. Thus, a portion of production plant is related to producing energy and a portion of production plant is related to meeting peak demand requirements. The approach used in this study to allocate production plant was the Average and Excess (A&E) method since it is consistent with how costs are incurred, allocating a portion of production plant based on energy consumption and the remaining portion based on peak demands. Specifically, the energy portion of plant costs are allocated to each rate class based on kWh sales throughout the year, while peak demands are based on kW demands throughout the year. As with the most recent COSS, the Company used the sum of monthly NCPs (12NCP) to represent peak demand since production capacity need is largely driven by peak demands throughout the year rather than in any one particular season or month.

Q. PLEASE DESCRIBE THE PROCESS USED TO DEVELOP THE A&E ALLOCATOR.

A. Rather than assign production plant based on energy consumption or peak demand, the A&E incorporates both energy consumption and peak demand since it follows the purpose of production plants to provide both energy and meet peak demands.

The A&E allocator consists of two components. The first component of the A&E allocator is the average demand, which represents the energy portion of the production plant. It represents each rate class's share of the average demand. This component is calculated as each class's share of total kWh sales. The average demand component is weighted by the system load factor representing that portion of the utility's generating capacity that would be needed if all customers used energy at a constant 100.0 percent load factor.

The second component of the A&E allocator is the excess demand, which represents the peak demand portion of the production plant. It represents each rate class's share of the excess demand. This component is calculated as each class's share of the excess demand – or the difference between the class peak demand and the class average demand. The class peak demand is based on NCP demands since using CP demands mathematically would be equivalent to using a CP demand allocator (and thus contrary to the design of the production plant). The excess demand component is weighted by the remaining portion of production plant – i.e., by 1 minus the system load factor – and then added to the average demand component to derive the A&E allocator. The NCP demands in this study are based on an average of the twelve-monthly NCP demands (12NCP).

The A&E allocator was developed utilizing average demand (kWh), and coincident peak (CP) and non-coincident peak (NCP) demand data gathered by the Company for each customer class through load research. The CP demand represents class demand at the time of the system peak, while NCP represents aggregate customer peak demand. Further details on the A&E allocator developed for this study are included in Direct Exhibit TSL-7.

Q. WHY DID THE A&E ALLOCATOR IN THIS STUDY USE 12NCP?

A. The A&E allocator in this study used 12NCP since it is consistent with the design of production plant. The Company's production plant is designed to meet peak demands throughout the year since monthly peak demands are within a relatively narrow range and the monthly reserve margins are similar across the year when considering maintenance schedules, as shown in Figure 6.

Figure 6: Production Plant Generating Capacity and Reserve Margin

	Peak Load	Generating Capacity	Unit Derating	Wtd. Scheduled Maintenance	Assumed Wtd. Forced Outage	Net Generating Capacity	Reserve Margin	Peak Plus Outages
Jan	1,143	1,653	7	-	134	1,511	75.6%	1,285
Feb	1,066	1,586	74	-	134	1,377	77.4%	1,275
Mar	887	1,660	-	174	131	1,355	65.5%	1,192
Apr	751	1,530	130	326	128	947	79.3%	1,334
May	862	1,560	100	189	128	1,143	75.4%	1,279
Jun	1,050	1,486	174	7	122	1,183	88.7%	1,353
Jul	1,091	1,497	163	-	122	1,212	90.0%	1,376
Aug	1,098	1,459	201	-	122	1,136	96.6%	1,421
Sep	1,020	1,568	92	-	122	1,354	75.3%	1,234
Oct	786	1,589	71	331	128	1,059	74.2%	1,316
Nov	864	1,570	90	216	131	1,133	76.3%	1,301
Dec	1,098	1,616	44	-	134	1,437	76.4%	1,277
Total	11,716	18,774	1,148	1,242	1,536	14,848	78.9%	1,304

The Figure shows that the reserve margin is similar across each month of the year; thus, changes in demand in any month can have implications on production capacity decisions.

In addition, the Company's planners have indicated to me that they consider peak loads throughout the year when making production capacity decisions.

Q. PLEASE DESCRIBE THE RESULTS OF THE A&E METHOD.

A. Figure 7 shows the results of the A&E method.

Figure 7: Results of A&E Method

Average and Excess	Average and Excess (12 NCP)					
Rate Class	Peak Demand 12 NCP (MW)	Average Demand (MW)	Excess Demand (MW)	Average Demand (%)	Excess Demand (%)	Total Allocator (%)
RG-Residential	16,272	7,833	8,439	27.82%	37.94%	31.71%
RG-Residential Water Heat	2,782	1,341	1,441	4.76%	6.48%	5.42%
RH-Residential Total Elec	8,748	4,248	4,499	15.09%	20.23%	17.06%
CB-Commercial	4,272	2,312	1,960	8.21%	8.81%	8.44%
SH-Small Heating	669	347	322	1.23%	1.45%	1.31%
GP-General Power	7,123	4,728	2,395	16.79%	10.77%	14.48%
TEB-Total Electric Bldg	1,903	1,158	745	4.11%	3.35%	3.82%
PT-Transmission	7,598	5,801	1,797	20.60%	8.08%	15.79%
SPL-Municipal St Lighting	428	191	237	0.68%	1.07%	0.83%
PL-Private Lighting	413	179	234	0.64%	1.05%	0.80%
LS-Special Lighting	192	19	174	0.07%	0.78%	0.34%
Total	50,402	28,158	22,244	100.00%	100.00%	100.00%
Residential						54.19%

The Figure shows the results of the A&E Method, including the average demand and excess demand components for each rate class, weighted by the system load factor of 61.6 percent. The Figure shows that the Residential General rate class allocator is 31.71 percent based on the A&E method, representing a composite of their average demand of 27.82 percent and their peak demand of 37.94 percent.

Q. PLEASE DESCRIBE THE PROCESS USED TO ALLOCATE TRANSMISSION PLANT.

A. Transmission plant represents 12.5 percent of the Company's utility plant and is assigned to the proposed TDC Rider. Transmission costs are incurred consistent with the Company's design of its transmission facilities to meet system capacity requirements. Transmission plant is designed to meet peak demands throughout the year since monthly peak demands are within a relatively narrow range and transmission capacity must be ready throughout the year to move generation output on and off the system when dispatched for the Southwest Power Pool ("SPP"). Thus, transmission plant is allocated based on 12CP, which becomes the basis for the calculation of TDC Rider for each customer class. The 12CP allocator is recognized by NARUC as a reasonable transmission cost allocator,[8] and is consistent with the methodologies described in the Company's prior rate case filing.[9]

Q. PLEASE DESCRIBE THE PROCESS USED TO ALLOCATE DISTRIBUTION PLANT.

A. Distribution plant is the second largest component of rate base representing 43 percent of total utility plant. Distribution costs are incurred consistent with the Company's design of its distribution facilities to provide customer access to the electric system (customer-related), and to meet customer peak demands through the year (demand-related). The customer portion of distribution plant is allocated to each rate class based on the number of customers. The demand portion of distribution plant costs are allocated based on the rate class's NCP demands. The demand portion is based on an average of 6-month NCP demands (6-NCP) to reflect that the distribution plant is designed to meet customer winter (December through February) and summer (June through August) demands. The approach is a departure from the Company's prior cost of service study. Previously, the demand portion of distribution plant was allocated based on 1-month NCP demands (August). The Company believes that the proposed 6-NCP better reflects the design of the distribution system to meet winter as well as summer customer demands.[10]

Q. PLEASE DESCRIBE THE PROCESS USED TO DEVELOP SPECIAL STUDIES ALLOCATORS.

[8] NARUC Electric Utility Cost Allocation Manual, Pg. 79
[9] Docket No. 10-EPDE-314-RTS, *In the Matter of The Empire District Electric Company for Approval of the Commission to Make Certain Changes in Its Charges for Electric Service*
[10] Docket No. 10-EPDE-314-RTS, *In the Matter of The Empire District Electric Company for Approval of the Commission to Make Certain Changes in Its Charges for Electric Service*

A. The Company prepared three special studies to allocate meter investments, service investments, and line transformers investments.

- Meters investments were allocated based on the current cost of meters in each rate class. The allocator reflects the Company's estimated cost of meter and meter installation for each rate class.
- Services investments were allocated based on the current cost of services in each rate class. The allocator reflects the Company's estimated cost of service line and installation for each customer class.
- Line transformers were allocated based on number of customers for each customer class. The number of customers were weighted to reflect the average number of customers by rate class served by a single transformer. The allocator recognizes that transformers are built to address varying customer demands and may serve multiple customers within a rate class depending on the demand (e.g., a single transformer serves approximately 2.7 residential general customers per Company estimates).

The approach to prepare the special studies is consistent with the methodologies described in the Company's prior rate case filing. The derivation of the meters and services allocators is included in Direct Exhibit TSL-8.

Q. PLEASE DESCRIBE THE PROCESS USED TO DEVELOP THE COMPOSITE ALLOCATORS.

A. There are several composite allocators developed internally based on the allocation of various plant investments and expenses. These are used to allocate cost items that cannot be readily categorized. For example, general plant is allocated based on the composite allocation of all labor-related production, transmission, distribution, customer accounts, and customer service O&M expenses. This approach is well established in industry literature[11] and is consistent with the methodologies described in the Company's prior rate case filing.

Q. PLEASE DESCRIBE THE ALLOCATION OF O&M EXPENSES TO THE CUSTOMER CLASSES.

A. The O&M expenses were allocated generally consistent with their respective plant accounts. For example, all production O&M expenses were allocated using the A&E Method. Similarly, the allocation of each distribution O&M expense followed the allocation of their respective plant account. For example, Maintenance of Line Transformers expense was allocated based on the line transformers special study discussed earlier. Further details on the allocation factors developed for this study are included in Direct Exhibit TSL-3.

VI. <u>OVERVIEW OF RATE DESIGN</u>

Q. PLEASE DESCRIBE THE PRINCIPLES USED TO GUIDE THE PROPOSED RATE DESIGN.

A. The proposed rate design was guided by several principles commonly used throughout the industry, including: (a) rates should recover the overall cost of providing service; (b) rates should be fair, minimizing inter- and intra-class inequities to the extent possible; and (c) rate changes should be tempered by rate continuity concerns.[12]

[11] NARUC Electric Utility Cost Allocation Manual, Pg. 105
[12] See Bonbright, James, Danielsen, Albert, and Kamerschen, David. "Principles of Public Utility Rates." Public Utilities Reports, Inc. pp. 377-407 (2nd Ed. 1988).

Because these principles can conflict, the proposed rate design reflects a level of judgment to balance these principles.

Q. HOW WERE THESE PRINCIPLES APPLIED IN THIS PROCEEDING?

A. First, rates were designed to recover the overall cost of service. This was done by developing customer and energy charges based on test year bills and kWh sales, while incorporating the results of the COSS. In addition, rates were designed to be fair and equitable. This was done by setting revenue targets for each rate class that reflected in aggregate a movement toward the system ROR. As discussed earlier, the results of the COSS show that some rate classes produce a ROR that is less than the overall ROR. The proposed rate design reduces that difference by proposing rate increases that are higher than the system average. Another rate design objective is to moderate rate changes to address rate continuity concerns. This objective was considered while setting revenue targets and again while setting rate elements.

Q. PLEASE SUMMARIZE THE STEPS TAKEN TO DEVELOP THE PROPOSED RATES.

A. The first step to develop the proposed rates was to establish the overall revenue requirement to be recovered from base rates. The next step was to set revenue targets for each rate class based on the results of the COSS, as shown on Direct Exhibit TSL-9. Rates within each rate class were then designed to recover the revenue targets based on test year customer and usage data.

Q. WHAT IS THE TOTAL REVENUE REQUIREMENT THAT YOU USED AS A STARTING POINT?

A. To determine the total revenue requirement, I relied on the overall cost of service presented in the testimony and accounting schedules of Company witness Schwartz, which indicates a total revenue requirement of $18.5 million. The total revenue requirement was then reduced by revenues related to other revenues to calculate base rate revenue requirements.

Q. PLEASE DESCRIBE THE PROCESS TO SET THE REVENUE TARGETS FOR EACH RATE CLASS.

A. Since each rate class currently produces a ROR that is different than the overall system ROR, the starting point for setting the revenue targets was to compare current class revenues and class revenues at equalized rates of return.

Q. IN GENERAL, HOW DID YOU DETERMINE THE APPROPRIATE RATE DESIGN WITHIN EACH RATE CLASS?

A. The proposed rates were designed by first ensuring the rates recover the proposed revenue target. The proposed rates were then designed by reviewing the customer charge to evaluate what level of fixed cost is reasonable to be recovered through the proposed customer charges consistent with rate design objectives described above. Once the proposed customer charges were established, the remaining revenue target for each class was recovered via the kWh sales charges, as shown in Direct Exhibit TSL-10.

VII. RATE DESIGN AND BILL IMPACT ANALYSES

Q. PLEASE DESCRIBE THE PROCESS USED TO SET THE REVENUE REQUIREMENT TARGETS FOR EACH RATE CLASS.

A. The starting point for setting the revenue targets was evaluation of the results of the COSS. Specifically, the process included identifying the rate changes necessary to achieve equalized rates of return for all rate classes. For those rate classes that produce a ROR less than the system ROR (i.e., the three residential classes, municipal street lighting, and special lighting class), the rate increases necessary to achieve equalized rates of return were relatively large; thus, the movement to equalized rates of return for all rate classes was moderated by bill continuity concerns. Below is a brief description of the process for setting the revenue targets.

- The Residential General, Residential Water Heating, and Residential Total Electric classes would require, respectively, rate increases of 31.6 percent, 33.7 percent and 37.7 per to achieve the system rate of return. The Municipal Street Lighting and Special Lighting classes would require revenue increases of 26.8 percent and 218.3 percent to achieve the system rate of return. Absent the rate moderation step discussed below, the rate increases would represent approximately 3.0 times the overall revenue increase of 10.0 percent.
- Based on these results, the revenue targets were set based on a four-step process that balances the rate design principles discussed earlier, including the bill continuity and gradualism concerns.
    - In the first step, revenues were maintained at current levels for rate classes with COSS results indicating a revenue decrease. These rate classes include Commercial, General Power, Total Electric Building, and private lighting rate classes. This step ensures that no rate class receives a decrease in the context of an overall rate increase.
    - In the second step, revenues were capped at 1.6 times the overall rate increase for those classes with a ROR less than the system ROR. These rate classes

included the residential, municipal street lighting, and special lighting classes. This step ensures that no rate class receives an increase more than 1.6 times the overall rate increase.

- In the third step, revenues were increased to class revenues at equalized rate of return for Small Heating, and Transmission rate classes.
- In the fourth and final step, the remaining revenue shortfall was assigned to Commercial, Small Heating, Total Electric Building, and Transmission rate classes proportional to each rate classes' current revenues.

Q. DOES THE COMPANY'S PROPOSAL INCLUDE ANY NEW RATE CLASSES OR RATE DESIGNS?

A. No, the Company's proposal does not include any new rate classes or rate designs.

Q. PLEASE DESCRIBE THE PROPOSED RATE DESIGN FOR THE RESIDENTIAL RATE CLASSES.

A. The proposed rate design for residential rate classes is described below.

<u>Residential General</u>

The proposed rates were based on a revenue requirement of $5.8 million, which represents a 16.5 percent increase over the current revenues of $5.0 million. The proposed rates were also based on 66,530 annual bills and 62,362 MWh annual usage.

The Company proposes to increase the monthly customer charge from $14.00 per month to $17.00 per month, representing a 21.4 percent increase in the monthly customer charge. The proposed customer charge is consistent with the COSS results, as shown in Figure 8. The Figure shows that the basic customer-related cost is $18.04 per customer per month for the Residential General rate class, and the fully-load customer-related cost is $32.26. The Figure also shows that the proposed customer charge is comparable to other electric utilities in Kansas. The proposed customer charge improves the alignment between fixed costs and fixed customer revenues. The revenue requirement not recovered through the customer charge was recovered from volumetric charges of $0.07920 per kWh for first 600 kWh of usage, and $0.07058 per kWh for all additional kWh usage. The proposed rate design and bill impact analyses are included in Direct Exhibit TSL-10.

Overall, the proposed rate design would increase Residential General monthly bills for a typical Residential General using 1,000 kWh per month by $20.00 per month, or 17.9 percent.

Residential Water Heating

The proposed rates were based on a revenue requirement of $0.9 million, which represents a 16.5 percent increase over the current revenues of $0.8 million. The proposed rates were also based on 9,139 annual bills and 10,736 MWh annual usage.

The Company proposes to increase the monthly customer charge from $14.00 per month to $17.00 per month, consistent with the increase in the Residential General customer charge. The revenue requirement not recovered through the customer charge was recovered from volumetric charges of $0.07341 per kWh for first 600 kWh of usage, and $0.07058 per kWh for all additional kWh usage. The proposed rate design and bill impact analyses are included in Direct Exhibit TSL-10.

Overall, the proposed rate design would increase Residential Water Heating monthly bills for a typical Residential Water Heating customer using 1,000 kWh per month by $19.71 per month, or 18.1 percent.

Residential Total Electric

The proposed rates were based on a revenue requirement of $2.7 million, which represents a 16.5 percent increase over the current revenues of $2.3 million. The proposed rates were also based on 22,401 annual bills and 34,437 MWh annual usage.

The Company proposes to increase the monthly customer charge from $14.00 per month to $17.00 per month, consistent with the increase in the Residential General customer charge. The revenue requirement not recovered through the customer charge was recovered from volumetric charges of $0.06626 per kWh for all kWh usage. The proposed rate design and bill impact analyses are included in Direct Exhibit TSL-10.

Overall, the proposed rate design would increase Residential Total Electric monthly bills for a typical Residential Total Electric customer using 1,000 kWh per month by $18.52 per month, or 17.9 percent.

Figure 8: Kansas Utilities' Customer Charges

Empire District Electric (KANSAS) Customer Charge Analysis		Residential
Proposed Customer Charge	$	17.00
Customer Costs		
Basic Customer Costs	$	18.04
Fully Loaded Customer Costs	$	32.26
Kansas Electric Utility Customer Charges		
Butler Rural Electric Cooperative Association, Inc.		31.00
Ark Valley Electric Cooperative		30.00
Doniphan Electric Cooperative Association, Inc.		25.00
Lane-Scott Electric Cooperative, Inc.		25.00
Sedgwick County Electric Cooperative Association, Inc.		25.00
DS&O Electric Cooperative, Inc.		25.00
Prairie Land Electric Cooperative, Inc.		20.00
Pioneer Electric Cooperative, Inc.		18.40
Wheatland Electric Cooperative, Inc. (Urban Only)		16.00
The Victory Electric Cooperative Association, Inc. (Urban Only)		15.00
Westar Energy		14.50
Kansas City Power & Light Company		14.00
Average	$	21.58

Q. PLEASE DESCRIBE THE PROPOSED RATE DESIGN FOR THE C&I RATE CLASSES.

A. The proposed rate design for C&I rate classes is described below.

Commercial

The proposed rates were based on a revenue requirement of $1.9 million, which represents a 3.9 percent change over the current revenues of $1.8 million. The proposed rates were also based on 14,215 annual bills and 18,431 MWh annual usage.

The Company proposes to increase the monthly customer charge from $19.00 per month to $20.00 per month, representing a 5.3 percent increase in the monthly customer charge. The revenue requirement not recovered through the customer charge was recovered from volumetric charges of $0.09589 per kWh for first 700 kWh of usage, and $0.08534 per kWh for all additional kWh usage. The proposed rate design and bill impact analyses are included in Direct Exhibit TSL-10.

Overall, the proposed rate design would increase Commercial Service monthly bills for a typical Commercial Service customer using 1,300 kWh per month by $9.55 per month, or 5.4 percent.

Small Heating

The proposed rates were based on a revenue requirement of $239,147, which represents a 5.4 percent increase over the current revenues of $226,836. The proposed rates were also based on 1,317 annual bills and 2,779 MWh annual usage.

The Company proposes to increase the monthly customer charge from $19.00 per month to $20.00 per month, representing a 5.3 percent increase in the monthly customer charge. The revenue requirement not recovered through the customer charge was recovered from volumetric charges of $0.08320 per kWh for first 1,000 kWh of usage, and $0.07341 per kWh for all additional kWh usage. The proposed rate design and bill impact analyses are included in Direct Exhibit TSL-10.

Overall, the proposed rate design would increase Commercial Small Heating Service monthly bills for a typical Commercial Small Heating Service customer using 2,000 kWh per month by $20.21 per month, or 8.7 percent.

<u>General Power</u>

The proposed rates were based on a revenue requirement of $2.9 million, which represents no change over the current revenues. The Company proposes no change in their revenue requirement since a movement to equalized rate of return for this rate class would results in a rate decrease while most other rate classes would receive a rate increase. The proposed rates were also based on 1,270 annual bills and 38,201 MWh annual usage. The Company proposes to maintain the volumetric and demand charges for general power customers. The proposed rate design and bill impact analyses are included in Direct Exhibit TSL-10.

<u>Total Electric Building</u>

The proposed rates were based on a revenue requirement of $676,969, which represents a 3.9 percent increase over the current revenues of $651,774. The proposed rates were also based on 475 annual bills and 9,328 MWh annual usage.

The Company proposes to increase the monthly customer charge from $30.46 per month to $32.00 per month, representing a 5.1 percent increase in the monthly customer charge. The revenue requirement not recovered through the customer charge was recovered from volumetric charges of $0.08723 per kWh for usage between 150 kWh and

10,000 kWh, and $0.06120 per kWh for all additional kWh usage. The proposed rate design and bill impact analyses are included in Direct Exhibit TSL-10.

Transmission Service

The proposed rates were based on a revenue requirement of $2.2 million, which represents a 11.0 percent increase over the current revenues of $2.0 million. The proposed rates were also based on 60 annual bills and 48,143 MWh annual usage.

The Company proposes to increase the monthly customer charge from $11,858.75 per month to $13,158.00 per month, representing a 11.0 percent increase in the monthly customer charge. The revenue requirement not recovered through the customer charge was recovered from volumetric charges of $0.02311 per kWh usage, and a demand charge of $6.22 per kW for billed demand above 1,000 kW. The proposed rate design and bill impact analyses are included in Direct Exhibit TSL-10.

Q. PLEASE DESCRIBE THE PROPOSED RATE DESIGN FOR THE LIGHTING RATE CLASSES.

A. The proposed rate design for Lighting rate classes is described below.

Municipal Street Lighting

The proposed rates were based on revenue requirements of $150,398 which represents a -23.0 percent decrease over the current revenues of $122,320. The rates for each lamp size and type were increased on an equal percentage basis based on the overall revenue increase.

Private Lighting

The proposed rates were based on revenue requirements of $398,294 which represents a 0.0 percent change over the current revenues of $398,294. The rates for each lamp size and type were maintained at current rates.

Special Lighting

The proposed rates were based on revenue requirements of $21,621 which represents a 16.7 percent increase over the current revenues of $18,533. The volumetric rates per kWh were increased on an equal percentage basis based on the overall revenue increase.

Q. HAVE YOU EXAMINED THE IMPACT OF YOUR PROPOSED CHANGES IN RATES ON CUSTOMERS WITHIN EACH RATE CLASS BY REGION?

A. Yes. As shown in Direct Exhibit TSL-10, the Company evaluated the bill impacts of the proposed changes on customers based on a range of annual usage within each rate class. The proposed annual bill is based on the proposed base rates that include the rider accounts that the Company has proposed to include in base rates. The bill impact analysis was prepared in two ways:

1. Proposed Base Rate Bill vs. Current Base Bill, comparing (i) the proposed base rates, and (ii) the current base rates; and
2. Proposed Total Bill vs. Current Total Bill, comparing (i) the proposed base rates plus the ECA charge and the proposed TDC Rider charge, and (ii) the current base rates plus ECA charge and the current AVT and the AERR charges. The total bill comparison better reflects the impact of the rate changes on customer bills since the Company proposes to recover transmission costs in the proposed TDC Rider rather than base rates. Thus, transmission costs are reflected in the TDC Rider under the proposed total bill, but reflected in base rates under the

current total bill. In addition, the Company proposes to recover test year AVT and AERR costs in the proposed base rates rather than the AVT and AERR Riders. Thus, test year AVT and AERR costs are reflected in the proposed base rates under the proposed total bill, but reflected in AVT and AERR Rider charges under the current total bill.

Figure 9 shows monthly bill impact analysis for residential and commercial customer classes at average usage.

Figure 9: Bill Impact Analysis

Customer Class	Avg. Monthly Usage (kWh)	Monthly Bill Proposed ($)	Monthly Bill Current ($)	Monthly Bill Impact ($)	Monthly Bill Impact (%)
Residential General Service	1,000	$ 132.0	$ 112.0	$ 20.0	17.8%
Residential - Water Heating Service	1,000	128.4	108.7	19.7	18.1%
Residential Total Electric Service	1,000	122.1	103.6	18.5	17.9%
Commercial Service	1,300	185.2	175.7	9.5	5.4%
Small Heating Service	2,000	252.5	232.3	20.2	8.7%

Proposed Monthly Bill: includes ECA Charge and TDC Rider
Current Monthly Bill: includes ECA Charge, AERR and AVTS Riders

VIII. <u>REVENUE STABILIZATION RIDER</u>

Q. PLEASE SUMMARIZE THE COMPANY'S PROPOSAL FOR A REVENUE STABILIZATION RIDER.

A. The Company proposes to implement a Revenue Stabilization Rider. The Revenue Stabilization Rider is a form of revenue decoupling that addresses the basic misalignment between the structure of utility costs and the structure of utility rates.

Specifically, electric utility costs are largely fixed and change very little in the short run as usage levels change. However, electric utility rates have a significant variable or usage-based component that changes revenues substantially as usage levels change. The proposed Revenue Stabilization Rider corrects for this misalignment by adjusting the Company's revenues to match the revenue requirements from the Company's most recent base rate proceeding.

Q. PLEASE EXPLAIN THE MISALIGNMENT BETWEEN ELECTRIC UTILITY COSTS AND RATES.

A. Electric utilities incur three types of costs in providing electric service to customers:

- <u>Fixed costs</u> – including meter, billing and a portion of distribution costs that generally varies by the number of customers;
- <u>Demand-related costs</u> – including transmission and distribution costs that generally varies by demand, and;
- <u>Energy-related costs</u> – including variable O&M expenses that generally varies by energy consumed.

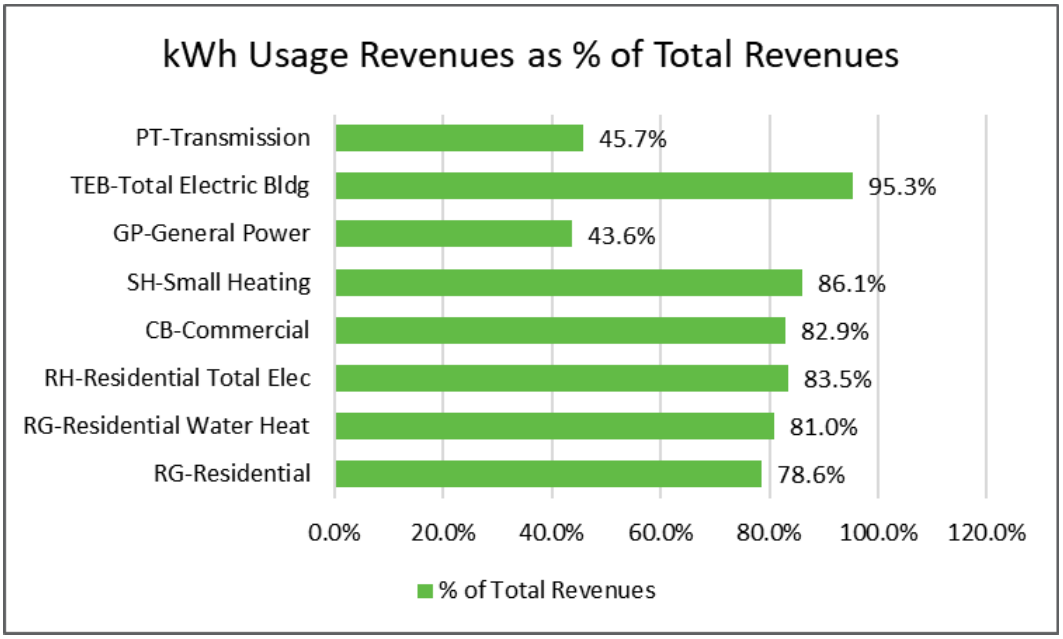
Utility rates are designed to recover all of these costs. However, especially for residential and small commercial customers, a significant portion of the costs are recovered on the basis of usage (or per kWh) charges reflecting usage at the time rates are established (*i.e.*, rates are based upon the level of usage embodied in a historic test year). Thus, to the extent that actual usage is significantly lower than the level assumed in rates, then the utility rates no longer recover the full cost of service. Conversely, to the extent that actual usage is significantly higher than the amount assumed in rates, then the utility rates recover revenues in excess of the cost of service.

There are many causes for variations in usage, including the impact of weather, energy conservation, installation of energy efficiency measures, and the installation of DER, which include rooftop solar panels.

Q. DO THE COMPANY'S RATES EXHIBIT THIS MISALIGNMENT BETWEEN UTILITY COSTS AND RATES?

A. Yes, the Company's rates exhibit this misalignment between utility costs and rates. The portion of the Company's charges that are based on usage (or kWh) varies depending on rate class, as shown in Figure 10.

Figure 10: Volumetric Revenues as Percentage of Total Revenues



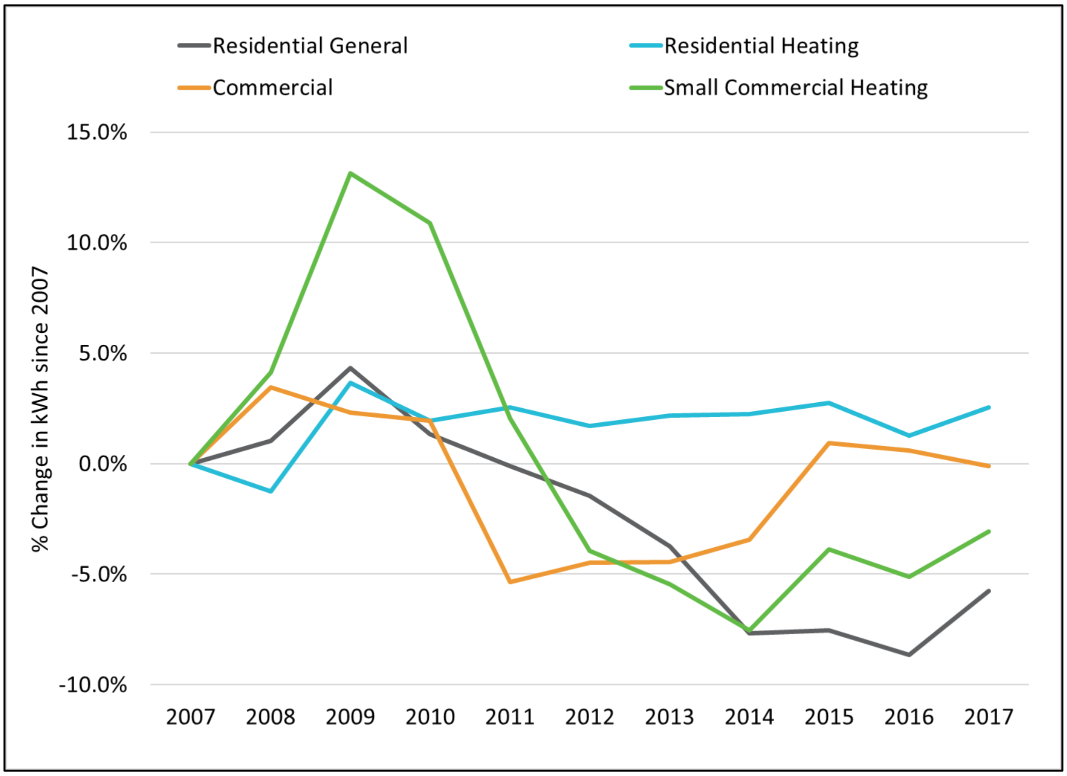
The Figure shows that a significant portion of the Company's revenues are recovered through volumetric rates. For example, the Figure shows that over 78.6 percent of the Residential General revenue requirement is recovered through volumetric charges, and 95.3 percent of Total Electric Building revenue requirement is recovered through volumetric charges.

Q. WHY IS THIS MISALIGNMENT A PROBLEM?

A. The misalignment between utility costs and rates is a problem for three reasons. First, increases or decreases in usage will cause the utility to over- or under-collect its fixed costs. This creates financial disincentives for utilities to encourage customers to be as energy efficient as possible or to facilitate DER. Second, since the Company's total energy consumption has declined over the past decade (see Figure 11), actual sales are likely to be below historic test year sales, reducing the likelihood that the Commission-approved cost of service can be recovered. Figure 11 shows the kWh usage of the Company's Residential and Commercial rate classes for the period 2007 through 2017. The Figure shows the annual percentage change in sales (kWh) per customer as compared to 2007. As a result of the decline in sales (kWh) shown in Figure 10, the approved level of rates are unlikely to allow recovery of the approved level of revenue requirement, which represents a violation of a basic ratemaking principle of establishing rates that are fair, just and reasonable.[13]

[13] James Bonbright, Albert Danielsen & Davis Kamerschen, *Principles of Public Utility Rates* (Pub. Utils. Reports 2nd ed. 1988) (1961).

Figure 11: Decline in Normalized Annual kWh Sales

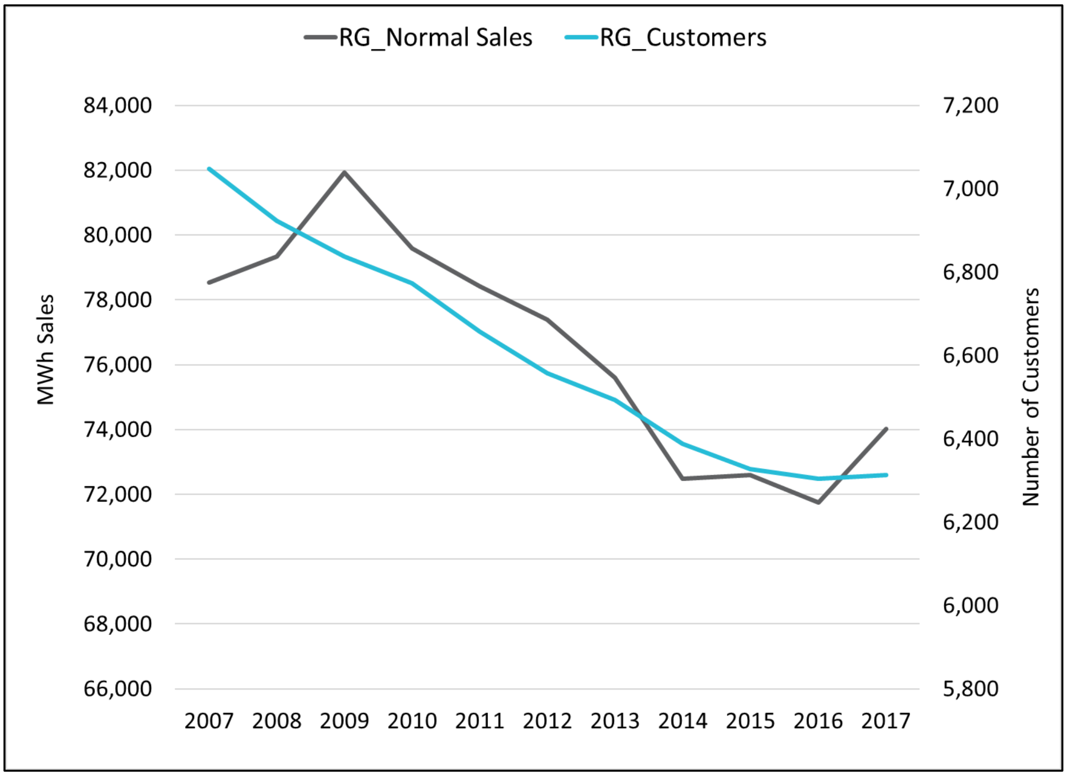


Third, the mismatch between utility costs and rates creates bill volatility for customers as well as revenue and earnings volatility for utilities. For example, colder-than-normal winter temperatures may lead to higher customer bills and higher utility revenues without a corresponding increase in utility costs. Conversely, warmer-than-normal winter temperatures may lead to lower customer bills and lower utility revenues without a corresponding decrease in utility delivery costs.

Q. WHAT ARE THE PRIMARY FACTORS CONTRIBUTING TO THE DECLINE IN SALES?

A. The primary factors contributing to the decline in sales include energy efficiency and a decline in the number of customers, as shown in Figure 12.

Figure 12: Residential General Decline in Customers and kWh Sales



The Figure shows the relationship between the decline in Residential General number of customers and MWh sales. Specifically, the Figure shows that Residential General MWh sales have decreased by 5.8 percent since 2007 while the number of customers has decreased by 10.4 percent.

Q. HOW IS THE PROPOSED REVENUE STABILIZATION RIDER A SOLUTION TO THE MISMATCH BETWEEN UTILITY COSTS AND RATES?

A. Revenue decoupling is a solution to the mismatch between utility costs and rates because it separates or 'decouples' the relationship between the amount of electricity delivered by a utility and the revenues it receives from such delivery. Thus, reductions in the Company's kWh sales would not necessarily result in lower revenues and an under collection of fixed costs.

Q. HAVE MANY REGULATORY COMMISSIONS ADOPTED REVENUE DECOUPLING?

A. Yes, according to the ACEEE 2018 Scorecard,[14] sixteen states have implemented revenue decoupling mechanisms for electric utilities with another fifteen states having a form of partial decoupling, known as a "Lost Revenue Adjustment Mechanism (LRAM")."[15] In addition, 23 states have a revenue decoupling mechanism for gas utilities and seven states have an LRAM for gas utilities.[16]

Q. PLEASE PROVIDE A BRIEF DESCRIPTION OF THE REVENUE STABILIZATION RIDER.

A. The Revenue Stabilization Rider is a form of revenue decoupling that corrects for the mismatch between utility costs and rates by adjusting the Company's revenues to match the revenue requirements from the Company's most recent base rate proceeding. Specifically, the Rider tracks monthly under- or over-collections in the Company's authorized revenue requirement by customer class and adjusts the customer's distribution rate for variations in revenue. The Rider credit or surcharge is assessed monthly on a rate per kWh for the rate class.

Q. WHAT ARE THE BENEFITS OF THE REVENUE STABILIZATION RIDER?

A. There are two primary benefits associated with the Revenue Stabilization Rider. First, the Rider promotes bill stability for customers. Customers in aggregate pay no more or less in base rates than the amount authorized by the Commission despite changes in consumption. The Rider formula is transparent and symmetrical, comparing actual

[14] Berg et. al., *The 2018 State Energy Efficiency Scorecard* (2018) at pg. 46-47
[15] LRAM is a ratemaking mechanism designed to allow utilities to recover the revenue deficiency associated with a decline in sales due to energy efficiency programs.
[16] Berg et. al., *The 2018 State Energy Efficiency Scorecard* (2018) at pg. 46-47

revenues that are reported in its annual filing to authorized revenues approved by the Commission in the most recent rate proceeding.

The second benefit is that the Rider promotes revenue stability for the Company. Similar to the customer benefits, the Company recognizes revenues that are no more or less than the amount authorized by the Commission despite changes in the number of customers or changes in use per customer. As a result, the Rider helps address potential revenue erosion issues related to declining use attributable to weather, energy efficiency and Solar PV initiatives as well as declining number of customers.

Q. WHAT FACTORS CONTRIBUTE TO FLUCTUATIONS IN SALES VOLUMES?

A. There are several factors that contribute to the fluctuations in customer usage. For the Company, a significant factor that contributes to fluctuations in customer usage is weather, and more specifically, fluctuations in temperature. Other factors include customer conservation, implementation of energy efficiency measures, installation of Solar PV technologies, and the number of customers.

Q. DO OTHER UTILITIES EXPERIENCE SIMILAR OVER- AND UNDER-RECOVERY OF COSTS?

A. Yes. This type of over- and under-collection of costs is not unique to the Company. As stated above multiple states have implemented mechanisms to address this issue.

Q. WHY IS REVENUE STABILITY IMPORTANT?

A. The Rider provides revenue stability that enables the Company to recover its cost of service, the majority of which is fixed. As such, the Rider supports the Company's financial health that provides financial support to provide safe, reliable and efficient service to its customers.

Q. PLEASE DESCRIBE HOW THE COMPANY'S PROPOSED REVENUE STABILIZATION RIDER WILL OPERATE.

A. The proposed Rider will reconcile monthly the difference between actual revenues billed and the revenue requirements approved by the Commission by rate class in the most recent rate proceeding. Under the Rider, the Company files monthly a Revenue Stabilization adjustment factor that reflects the differences between actual and authorized revenues by rate class. To the extent that actual revenues exceed authorized revenues, then the factor will be a credit to customers. To the extent that authorized revenues exceed actual revenues, then the factor will be a surcharge to customers

The Company proposes that the factor be assessed on a per kWh basis in the second succeeding month. That is, a Revenue Stabilization adjustment in January would be assessed to customers in March based on the adjusted amount divided by March forecast kWh sales. The factor would be subject to an ongoing reconciliation.

Q. WHAT REPORTING REQUIREMENTS ARE INCLUDED IN THE REVENUE STABILIZATION RIDER?

A. The proposed Rider requires the Company to file with the Commission the Bill Stabilization factors by rate class at least ten days prior to application on customer bills. The Company shall provide Commission Staff with workpapers sufficient to review and audit the factors.

Q. WILL THE PROPOSED RIDER ADJUST THE COMPANY'S REVENUE REQUIREMENT?

A. No. The proposed Rider does not adjust the Company's revenue requirements. The Company's revenue requirements will continue to be set by the Commission in ratemaking proceedings. The proposed Rider helps ensure that the Company is able to achieve the revenues established and approved during its ratemaking proceedings.

Q. PLEASE SUMMARIZE THE BENEFITS OF THE PROPOSED REVENUE STABILIZATION RIDER.

A. The proposed Revenue Stabilization Rider stabilizes customer bills and revenues over time resulting in benefits to both the Company and its customers since it corrects for the mismatch between utility costs and rates. The primary benefits of the Rider are:

- Stabilizes customer bills and improves the Company's ability to recover its costs;
- Provides the Company with a more stable stream of revenues and prevents over-collection and under-collection of costs as actual sales vary from test year sales due to weather conditions, energy efficiency, and/or number of customers; and
- Helps ensure fixed-cost recovery.

IX. CAPITAL TRACKER RIDER

Q. PLEASE SUMMARIZE THE COMPANY'S PROPOSAL FOR A CAPITAL TRACKER.

A. The Company proposes to implement a Capital Tracker Rider. The Capital Tracker Rider is a form of the current AERR and proposed TDC riders that enable the Company to recover the costs associated with certain investments between rate cases.

The benefits of the Capital Tracker Rider include:

- Stabilizes customer bills by implementing gradual changes in rates;
- Provides funding for maintaining a safe and reliable system; and
- Reduces the number of rate cases, which can be time consuming and expensive.

Capital Trackers have been approved in numerous jurisdictions, including Kansas.

Q. PLEASE DESCRIBE THE INVESTMENTS THAT WOULD BE INCLUDED IN THE CAPITAL TRACKER RIDER.

A. The Company proposes to limit the types of investments included in the Capital Tracker. Specifically, the Company proposes to limit investments related to: (1) Grid Resiliency; (2) generation capacity; and (3) Other investments.

Q. WHAT ARE THE PRIMARY FACTORS DRIVING THE NEED FOR THESE INVESTMENTS?

A. The utility industry is capital intensive and requires significant investments to ensure safe and reliable electric service for the customers. The primary factors driving the need for Company's investments proposed to be included in the Capital Tracker Rider are: (1) improve system safety and reliability; (2) add new generation resources to replace generation facilities scheduled to be retired; and (3) improve customer service and operational efficiency. Recovery of these investments in a timely manner is important for the Company's financial health and attract capital, as addressed in the testimony of Company Witness Robert Hevert.

Q. HOW DOES THE PROPOSED CAPITAL TRACKER RIDER STABLIZE CUSTOMER BILLS?

A. The proposed Capital Tracker Rider stabilizes customer bills by phasing in over time the costs associated with the investments. The approach is similar to the AERR Rider, which phases in over time the costs associated with investments in the Riverton and Asbury generation facilities. The Company believes that the AERR Rider has worked well and has resulted in benefits to customers and the Company and thus proposes to expand those benefits to other types of investments.

Under the current approach, the incremental costs associated with investments are reflected in rates following a rate case proceeding. However, rate case proceedings can be infrequent since rate cases are generally time consuming and expensive. As a result, the costs can accumulate over time and when incorporated in the base rates, may lead to abrupt rate increases following periods of substantial investment.

Under the proposed Capital Tracker Rider approach, the costs associated with new investments are reflected in rates in the year after they are placed in service, resulting in more gradual rate changes following periods of substantial investments.

Q. HAVE MANY REGULATORY COMMISSIONS ADOPTED CAPITAL TRACKERS?

A. Yes. Capital Trackers have been approved by State Commissions throughout the US. As per a 2015 report,[17] some form of capital cost trackers is approved for 180 utility operating companies in 46 states. These include 77 electric operating companies in 34 states. These trackers help recover various types of costs for the utilities including investment for improving reliability, adding new generation, enhancing renewables portfolio, and installing advanced metering infrastructure.

Capital cost trackers have also been approved by the Commission in Kansas. Specifically, the Commission has approved the AERR for Empire, and the TDC Rider for Kansas City Power & Light ("KCP&L") and Westar Energy. The Commission has also approved a Gas System Reliability Surcharge Rider ("GSRS") for Kansas gas utilities to recover costs of eligible infrastructure investments. The Company believes that its

[17] Alternative Regulation for Emerging Utility Challenges: 2015 Update; prepared for Edison Electric Institute by Pacific Economics Group Research LLC, at pg. 9-19.

proposed Capital Tracker Rider will provide benefits similar to trackers previously approved by the Commission.

Q. PLEASE DESCRIBE HOW THE PROPOSED CAPITAL TRACKER RIDER WILL OPERATE.

A. The Capital Tracker Rider is consistent with the current AERR except the Capital Tracker provides for recovery of incremental O&M expenses. The Company proposes to calculate the costs associated with the incremental investment as follows:

Revenue requirements for Capital Tracker = (RB x r) + D + OM

Where:

RB = Rate base associated with the investments recovered through the Capital Tracker.

r = Pretax rate of return approved by the Commission in the Company's most recent rate proceeding, unless otherwise agreed to by the parties and the Commission.

D = Depreciation Expense, calculated using depreciation rates approved by the Commission in the Company's most recent rate proceeding, and the Commission approved Gross Plant component of A- Rate Base described above.

OM = Incremental O&M expenses associated with the investments recovered through the Capital Tracker.

The Company proposes to allocate costs associated with the incremental investment in a manner consistent with the cost allocation methodology approved in the Company's most recent rate proceeding.

The Company proposed to design the Capital Tracker Rider charges for each rate class in a manner consistent with the methodology approved in the Company's most recent rate proceeding. The Capital Tracker Rider charges for each rate class shall be determined by dividing the Capital Tracker Rider revenue requirements by the applicable billing units. The General Power and Transmission rate class shall be billed on a per kW basis, all other class shall be billed on a per kWh basis.

Q. WILL THE REVENUES COLLECTED FROM THE CAPITAL TRACKER RIDER CHARGES BE SUBJECT TO REFUND?

A. Yes, the revenues collected pursuant to the Capital Tracker Rider, as approved by the Commission, shall be collected on an interim basis, subject to refund. For purposes of determining whether a refund is necessary, each component of the Capital Tracker Rider revenue requirement will be determined by the Commission during the Company's next general rate case. The Capital Tracker Rider revenue requirement will then be compared against the Capital Tracker Rider revenue requirement approved by the Commission. If the Capital Tracker Rider revenue requirement calculated by the Commission in the Company's next general rate case is less than the Capital Tracker Rider revenue requirement approved by the Commission, then the Company shall refund the difference through a bill credit. The refund rates (bill credits) shall be distributed to customers in the same fashion as the original Capital Tracker Rider rates contained in this tariff.

Q. WHAT ARE THE REPORTING REQUIREMENTS?

A. The Company will file reports with the Commission annually, and include a true-up calculation. The revenue collected pursuant to the application of the Capital Tracker Rider shall be compared to the estimated revenue approved for collection by the

Commission on an annualized basis. The amount of any over (under) recovery shall be included in any refund calculation that may result from the re-calculation of the revenue requirement to take place during Empire's next rate case.

Q. PLEASE PROVIDE A SUMMARY OF THE BENEFITS OF THE CAPITAL TRACKER RIDER.

A. The proposed Capital Tracker Rider stabilizes customer bills and the Company's recovery of incremental investments over time resulting in benefits to both the Company and its customers since it provides for recovery of important infrastructure investments without a full rate case, which can be time consuming and expensive. The primary benefits of the Capital Tracker Rider are:

- Stabilizes customer bills by implementing gradual changes in rates;
- Helps ensure that the Company obtains funding to invest in maintaining a safe and reliable system; and
- Reduces the number of rate cases, which can be time consuming and expensive.

X. KANSAS JURISDICTION CASH WORKING CAPITAL ("CWC") REQUIREMENT

Q. PLEASE DEFINE THE TERM "CASH WORKING CAPITAL" AS A RATE BASE COMPONENT.

A. The term "cash working capital" refers to the net funds required by the Company to pay for goods and services between the time they are paid for by the Company and the time customer payments are received by the Company. The cost of goods and services includes: purchased fuel and power expenses; operations and maintenance ("O&M")

expenses; federal, state, and local taxes; employment taxes; and interest payments on long-term debt.

Q. HOW DID YOU DETERMINE THE CWC REQUIREMENT?

A. The CWC requirement was based on the results of a lead-lag study, which compares the net difference between the revenue lag and expense lag. The revenue lag represents the number of days between the time customers receive their service and the time customer payments are received by the Company. The longer the revenue lag, the more cash the Company needs to fund its day-to-day operations. The expense lag represents the number of days between the time the Company receives goods and services used to provide service, and the time the Company pays for those goods and services, *i.e.*, when the funds are no longer available to the Company. The longer the expense lag, the less cash the Company needs to fund its day-to-day operations.

Q. DO THE RESULTS OF THE LEAD-LAG STUDY REPRESENT AN ACCURATE ASSESSMENT OF THE COMPANY'S CWC REQUIREMENT?

A. Yes. The lead-lag study represents an accurate assessment of the actual CWC needs during the test year for the Company's Kansas jurisdiction. Furthermore, the methods used to conduct the lead-lag study in this filing are generally consistent with those filed with the Commission in the Company's most recent rate case.[18]

XI. LEAD-LAG STUDY APPROACH

Q. PLEASE SUMMARIZE THE RESULTS AND APPROACH OF THE LEAD-LAG STUDY.

[18] Docket No. 10-EPDE-314-RTS, *In the Matter of The Empire District Electric Company for Approval of the Commission to Make Certain Changes in Its Charges for Electric Service*

A. The lead-lag study is summarized in Direct Exhibit TSL-13 and shows net CWC requirements of $149,519 for the Company's Kansas jurisdiction for the period July 1, 2017 through June 30, 2018. The lead-lag study relied on data provided by the Company for its four jurisdictions (i.e., Arkansas, Kansas, Missouri and Oklahoma) including: customer data to determine the revenue lag; a sample of invoices to determine the expense lag, and various other financial data and supporting documents.

Q. PLEASE DESCRIBE DEVELOPMENT OF THE LEAD-LAG STUDY.

A. The lead-lag study consists of two elements: revenue lags and expense lags. Revenue lags measure from the time service is provided to customers until the time customer payments are received by the Company. Expense lags measure from the time service is provided to the Company until payment is made by the Company. The lags are measured in days, converted to dollar-days, and summarized for each cost element in the lead-lag study. The difference between the revenue lag and expense lag determines if there is a net revenue lag (revenue lag days are more than the expense lag days) or a net expense lead (revenue lag days are less than the expense lag days) for each cost element in the lead-lag study.

A. Revenue Lag

Q. PLEASE DESCRIBE THE COMPONENTS OF THE REVENUE LAG.

A. Calculation of the revenue lag is summarized in Direct Exhibit TSL-14. The revenue lag consists of three components: (1) the service lag; (2) the billing lag; and (3) the collection lag.

Q. WHAT IS THE SERVICE LAG?

A. The service lag represents the number of days from the midpoint of the service period, *i.e.*, when service is provided to customers, to the end of the service period. Since service is provided during a calendar month, the service lag is one-half of a calendar month, or on average 15.21 days.

Q. WHAT IS THE BILLING LAG?

A. The billing lag represents the number of days from the end of the service period to the time bills are recorded and mailed to customers. The billing lag begins the day meters are read, and ends the day bills are recorded and mailed to customers. The lag includes review and validation of billing usage and amounts. The billing lag was based on the Company's test year customer billing data.

Q. WHAT IS THE COLLECTION LAG?

A. The collection lag represents the number of days from the time bills are recorded and mailed to customers to when payment is received. The collection lag was based on the Company's test year customer billing data.

Q. HOW WERE LAG DAYS DETERMINED FOR REVENUES?

A. The revenue lag was based on the sum of the revenue lag components discussed above. The calculations are shown on Direct Exhibit TSL-14.

B. Expense Lag

1. Purchased Fuel and Power Expenses

Q. HOW WERE LAG DAYS DETERMINED FOR PURCHASED FUEL AND POWER EXPENSES?

A. Lag days for purchased fuel and power expenses were based on the service lag (i.e., the midpoint of the service period) and payment lag (i.e., the number of days between the end of the service period and payment date). The analysis utilized test year purchased fuel (coal, natural gas, fuel oil and tires) and purchased power transactions.

2. O&M Expenses

Q. HOW WERE LAG DAYS DETERMINED FOR O&M EXPENSES?

A. Lag days for O&M expenses were determined by first separating the expenses into four groups: (1) Operations and Maintenance ("O&M") expenses, separated between labor and non-labor expenses; (2) Taxes Other than Income Taxes; (3) Income Taxes, and (4) Interest Payments on long-term debt. The lag days for each group were measured separately.

Q. HOW WERE LAG DAYS DETERMINED FOR LABOR EXPENSES?

A. Lag days for labor or payroll expenses were based on the Company's salary and wage payment schedule, which pays employees on a bi-weekly basis. The lag days for regular payroll expenses were based on the number of days between the midpoint of the pay period and the payment date.

Q. HOW WERE LAG DAYS DETERMINED FOR PENSION BENEFITS?

A. Lag days for pension benefits were based on the Company's payment schedule. Payments were made bi-weekly. The lag days for pension expenses were based on the number of days between the midpoint of the service period to the payment date.

Q. HOW WERE LAG DAYS DETERMINED FOR POST-RETIREMENT BENEFIT PAYMENTS?

A. Lag days for post-retirement benefits were based on the Company's payment schedule. Payments were made weekly and bi-monthly. The lag days for post-retirement benefit expenses were based on the number of days between the midpoint of the service period and the payment date.

Q. HOW WERE LAG DAYS DETERMINED FOR MEDICAL, VISION, AND DENTAL EXPENSES?

A. Lag days for medical, vision, and dental expenses were based on the Company's payment schedule. Payments are made weekly and monthly. The lag days for medical, vision, and dental expenses were based on the number of days between the midpoint of the service period and the payment date.

Q. HOW WERE LAG DAYS DETERMINED FOR LIFE AND ACCIDENTAL DEATH AND DISMEMBERMENT (AD&D) INSURANCE EXPENSES?

A. Lag days for life and AD&D insurance expenses were based on the Company's payment schedule. Payments are made monthly. The lag days for life and AD&D insurance expenses were based on the number of days between the midpoint of the service period and the payment date.

Q. HOW WERE LAG DAYS DETERMINED FOR INTERCOMPANY TRANSFERS?

A. Lag days for intercompany transfers were based on the Company's payment schedule. Transfers are made in the month following the service period, which is generally from the middle of a calendar month to the middle of the following calendar month. The lag days for intercompany transfers were based on the number of days between the midpoint of the service period and the payment date.

Q. HOW WERE LAG DAYS DETERMINED FOR PUBLIC SERVICE COMMISSION ("PSC") ASSESSMENT EXPENSES?

A. Lag days for PSC Assessment were based on the Company's payment schedule. Payments are made monthly, quarterly, or annually based on each state's requirements. The lag days for PSC Assessment expenses were based on the number of days between the midpoint of the service period and the payment date.

Q. HOW WERE LAG DAYS DETERMINED FOR OTHER NON-LABOR O&M EXPENSES?

A. Lag days for Other Non-Labor O&M expenses were based on a stratified sample of invoices paid during the test year. The expense lag for each stratum was then calculated and weighed in proportion to the number of transactions in each stratum. The sum of the weighted expense lag represents the overall Other Non-Labor O&M expense lag.

Q. DOES THE SAMPLING METHODODOLGY DIFFER FROM THE APPROACH USED IN THE COMPANY'S PRIOR RATE CASE?

A. Yes, the sampling methodology differs from the approach used in the prior case. By developing a stratified sample, the analysis is more representative of Other Non-Labor O&M Expenses for the test year. The study determined the lag days between the date services were provided to the Company and the date payment was made for those services. If no information was available regarding the date services were provided, then the date of the invoice was used. If no payment information was available, the invoice was removed from the sample.

3. Income Tax Expense

Q. HOW WERE LAG DAYS DETERMINED FOR FEDERAL INCOME TAXES?

A. Lag days for state and federal income taxes were based on the number of days between the midpoint of the applicable tax period and the payment dates. The payment dates were based on quarterly payments on April 15, June 15, September 15, and December 15.

4. Taxes Other than Income Taxes

Q. WHAT TAXES ARE INCLUDED IN THE TAXES OTHER THAN INCOME TAXES?

A. Taxes Other than Income Taxes includes: (1) payroll-related taxes (FICA, Federal Unemployment, State Unemployment, Income Tax withholding); and (2) Property taxes.

Q. HOW WERE LAG DAYS DETERMINED FOR THOSE TAXES?

A. Lag days for taxes other than income taxes were based on the number of days between the midpoint of the service period and payment date.

5. Interest Expense

Q. HOW WERE LAG DAYS DETERMINED FOR INTEREST EXPENSE?

A. Lag days for interest expense were based on actual interest payments in the test year. The lag days are calculated from the midpoint of the period for which the interest was paid to the payment date.

XII. <u>CONCLUSION</u>

Q. WHAT WERE THE RESULTS OF THE LEAD-LAG STUDY?

A. The CWC requirement for the Company is $149,519 for the Kansas jurisdiction, as shown in Schedule TSL-13.

Q. DO THE RESULTS OF THE LEAD-LAG STUDY REPRESENT AN ACCURATE ASSESSMENT OF THE COMPANY'S CWC REQUIREMENT?

A. Yes. The lead-lag study represents an accurate assessment of the Company's actual CWC needs during the test year. Furthermore, the methods used to conduct this lead-lag study are generally consistent with those previously filed with the Commission.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes, it does.

Summary

Tim Lyons is a partner with ScottMadden and has more than 30 years of experience in the energy industry. Tim has held senior positions at several gas utilities and energy consulting firms. His experience includes rate and regulatory support, sales and marketing, customer service and strategy development. Prior to joining ScottMadden, Tim was Vice President of Sales and Marketing for Vermont Gas, where he was responsible for all customer-related functions, including sales and marketing, call center and field service operations. He has also served as Vice President of Marketing and Regulatory Affairs for Providence Gas Company, Director of Rates at Boston Gas Company, and Project Director at Quantec, LLC, an energy consulting firm.

Tim has sponsored testimony before several public utilities commissions, including Connecticut, Maine, Massachusetts, Rhode Island, Vermont, Maryland, Iowa and Oklahoma. Tim holds a B.A. from St. Anselm College, an M.A. in Economics from The Pennsylvania State University, and an M.B.A. from Babson College.

Areas of Specialization

- Regulation and Rates
- Retail Energy
- Utilities
- Natural Gas
- Corporate and Shared Services

Capabilities

- Regulatory Strategy and Rate Case Support
- Strategic and Business Planning
- Capital Project Planning
- Process Improvements

Recent Articles and Speeches

- "Country Strong: Vermont Gas shares its comprehensive effort to expand natural gas service into rural communities." ***American Gas Association***, June 2011 (with Don Gilbert).
- "Talking Safety With Vermont Gas." ***American Gas Association***, February 2009 (with Dave Attig).
- "Consumers Say 'Act Now' To Stabilize Prices." ***Power & Gas Marketing***, September/ October 2001 (with Jim DeMetro and Gerry Yurkevicz).
- "Rate Reclassification: Who Buys What and When." ***Public Utilities Fortnightly***, October 15, 1991 (with John Martin).

Recent Assignments

- Sponsored cost of service/rate design testimony for a Mid-Atlantic gas utility. Testimony included a proposal for new residential and commercial rate classes and introduction of a block break rate design.
- Sponsored cost of service/rate design testimony for a Midwest gas utility. Testimony included a proposal for new commercial rate classes and a revenue decoupling mechanism.
- Sponsored cost of service/ rate design and lead-lag testimony for a Midwest gas utility. The testimony included proposals for Revenue Decoupling/ Weather Normalization Mechanism and Tracker Accounts for certain O&M expenses and capital costs.
- Sponsored rate design testimony for a Northeast gas utility. The testimony included: a proposal for zonal rates to promote expansion of natural gas service in the state; market analysis; and financial modeling.
- Led a study for the Massachusetts Department of Energy Resources to evaluate the benefits, costs and policies options associated with natural gas expansion by Massachusetts gas utilities. The study included: (a) research on state regulatory policies; (b) financial modeling and analysis of the economic and environmental impacts of pursuing various policy options; and (c) a survey of Massachusetts homeowners on their opinion of home heating fuels.
- Prepared a transmission and distribution (T&D) avoided cost study and report for a Midwest electric utility. The study was used to support the utility's energy efficiency programs.
- Prepared a review and evaluation of cost of service/ rate design studies for an electric utility. The assignment included review of proposed rate designs that address cost shifting concerns with serving residential distribution generation customers through introduction of higher customer charges, a demand charge and time-of-use energy charges.
- Assisted in the development of an electric portfolio of cost of service, rate design, and rate planning tools. The tools were used to evaluate the impact of future rate filings and resource portfolio decisions on individual rate classes.

- Prepared a market analysis for a utility to evaluate natural gas expansion into new areas, including: (a) survey of homes and businesses; (b) estimate of construction and operating costs; (c) analysis of alternative supply options (including pipeline, LNG and CNG); and (d) financial modeling.
- Directed a process review of natural gas expansion projects for a gas utility. The assignment included a review, evaluation and recommendations related to: (a) policies and procedures; (b) process steps and personnel; (c) financial models and analysis; (d) project decisions and schedules; and (e) post-construction review and evaluation.
- Assisted a New York electric utility in preparation of an Earnings Adjustment Mechanisms (EAM) incentive filing that supports the state's Reforming the Energy Vision (REV). Prepared research and analysis on electric utility incentive mechanisms. Assisted in review and evaluation of other electric utilities EAM incentive proposals, including cost recovery mechanisms. Assisted in development of the utility's EAM incentive proposals. Assisted in preparation of testimony and supporting analysis and workpapers for the EAM incentive proposals filed as part of a rate case.
- Sponsored lead-lag testimonies for several Mid-Atlantic and Texas gas utilities.

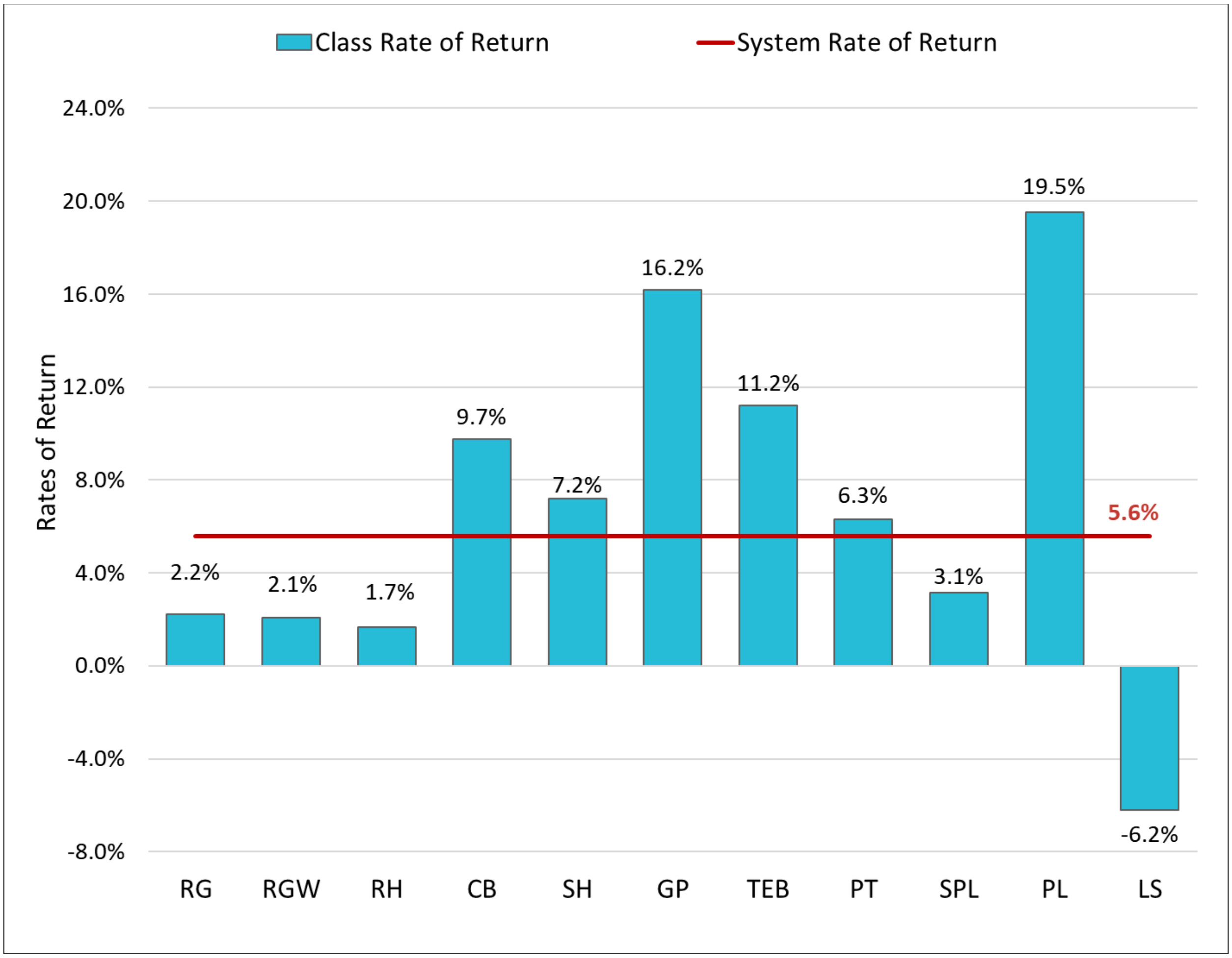
Sponsor	**Date**	**Docket No.**	**Subject**
Regulatory Commission of Alaska			
ENSTAR Natural Gas Company	06/16	Docket No. U-16-066	Adopted testimony and sponsored Lead/Lag study for a general rate case proceeding.
Connecticut Public Utilities Regulatory Authority			
Yankee Gas Company	07/14	Docket No. 13-06-02	Sponsored report and testimony supporting the review and evaluation of gas expansion policies, procedures and analysis.
Illinois Commerce Commission			
Liberty Utilities (Midstates Natural Gas)	07/16	Docket No. 16-0401	Sponsored testimony supporting the cost of service, rate design and bill impact studies for a general rate case proceeding. The testimony includes proposal for new commercial classes and a decoupling mechanism.
Iowa Utilities Board			
Liberty Utilities (Midstates Natural Gas)	07/16	Docket No. RPU-2016-0003	Sponsored testimony supporting the cost of service, rate design and bill impact studies for a general rate case proceeding. The testimony includes proposal for new commercial classes.
Maine Public Utilities Commission			
Northern Utilities, Inc. d/b/a Unitil Gas Limited	06/15	Case No. 2015-00146	Sponsored testimony supporting the proposed gas expansion program, including a zone area surcharge.
Maryland Public Service Commission			
Sandpiper Energy, a Chesapeake Utilities company	12/15	Case No. 9410	Sponsored testimony supporting the cost of service, rate design and bill impact studies for a general rate case proceeding. The testimony includes proposal for new residential and commercial classes.
Massachusetts Department of Public Utilities			
Boston Gas	03/88	Docket No. DPU 88-67-II	Sponsored testimony supporting the rate reclassification of commercial and industrial customers for a rate design proceeding.
Boston Gas	03/90	DPU 90-55	Sponsored testimony supporting the weather and other cost of service adjustments, rate design and customer bill impact studies for a general rate case proceeding.
Boston Gas	10/93	DPU 92-230	Sponsored testimony describing the Company's position regarding rate treatment of vehicular natural gas investments and expenses.
Liberty Utilities (New England Gas Company)	07/16	DPU 16-109	Sponsored the Long-Range Forecast and Supply Plan filing for the five-year forecast period 2016/2017 through 2020/2021.
Missouri Public Service Commission			
Liberty Utilities (Midstates Natural Gas)	09/17	Docket No. GR-2018-0013	Sponsored testimony supporting the cost of service, rate design, bill impact and Lead/Lag studies for a general rate case proceeding.
Laclede Gas Company	04/17	Docket No. GR-2017-0215	Sponsored testimony supporting the cost of service, rate design, bill impact and Lead/Lag studies for a general rate case proceeding. The testimony included support for a decoupling mechanism.
Missouri Gas Energy	04/17	Docket No. GR-2017-0216	Sponsored testimony supporting the cost of service, rate design, bill impact and Lead/Lag studies for a general rate case proceeding. The testimony included support for a decoupling mechanism.

Sponsor	***Date***	***Docket No.***	***Subject***
New Hampshire Public Utilities Commission			
Liberty Utilities d/b/a Granite State Electric Company	04/16	Docket No. DE 16-383	Adopted testimony and sponsored Lead/Lag study for a general rate case proceeding.
Liberty Utilities (EnergyNorth Natural Gas) Corp. d/b/a Liberty Utilities	11/17	Docket No. DG 17-198	Sponsored testimony supporting a levelized cost analysis for approval of firm supply and transportation agreements.
New Jersey Board of Public Utilities			
Pivotal Utility Holdings, Inc. d/b/a Elizabethtown Gas Company	8/16	GR16090826	Sponsored testimony supporting the Lead/Lag study for a general rate case proceeding.
Corporation Commission of Oklahoma			
The Empire District Electric Company	04/17	Cause No. PUD 201600468	Adopted direct testimony and sponsored rebuttal testimony supporting the revenue requirements for a general rate case proceeding. The testimony included proposals for alternative ratemaking mechanisms.
Rhode Island Public Utilities Commission			
Providence Gas Company	01/96	Docket No. 2076	Sponsored testimony supporting the rate reclassification of customers into new rate classes, rate design (including introduction of demand charges), and customer bill impact studies for a rate design proceeding.
Providence Gas Company	11/92	Docket No. 2025	Sponsored testimony supporting the Integrated Resource Plan filing, including a performance-based incentive mechanism.
Providence Gas Company	02/96	Docket No. 2374	Sponsored testimony supporting the rate design, customer bill impact studies and retail access tariffs for largest commercial and industrial customers for a rate design proceeding.
Providence Gas Company	04/97	Docket No. 2552	Sponsored testimony supporting the rate design, customer bill impact studies and retail access tariffs for commercial and industrial customers, including redesign of cost of gas adjustment clause, for a rate design proceeding.
Providence Gas Company	08/01 09/00 08/96	Docket No. 1673	Sponsored testimony supporting the changes in cost of gas adjustment factor related to projected under-recovery of gas costs; Filed testimony and witness for pilot hedging program to mitigate price risks to customers; Filed testimony and witness for changes in cost of gas adjustment factor related to extension of rate plan.
Providence Gas Company	06/97	Docket No. 2581	Sponsored testimony supporting a rate plan that fixed all billing rates for three-year period; included funding for critical infrastructure investments in accelerated replacement of mains and services, digitized records system, and economic development projects.
Providence Gas Company	08/00	Docket No. 2581	Sponsored testimony supporting the extension of a rate plan that began in 1997 and included certain modifications, including a weather normalization clause.
Providence Gas Company	03/00	Docket No. 3100	Sponsored testimony supporting the de-tariff and deregulation of appliance repair service, enabling the Company to have needed pricing flexibility.
Railroad Commission of Texas			
CenterPoint Energy – Texas Gulf Division	11/16	GUD No. 10567	Sponsored testimony supporting the Lead/Lag study for a general rate case proceeding.
Atmos Pipeline – Texas	01/17	GUD No. 10580	Sponsored testimony supporting the Lead/Lag study for a general rate case proceeding.

Sponsor	***Date***	***Docket No.***	***Subject***
Texas Gas Service Company – Rio Grande Valley Service Area	6/17	GUD No. 10656	Sponsored testimony supporting the Lead/Lag study for a general rate case proceeding.
CenterPoint Energy – South Texas Division	11/17	GUD No. 10669	Sponsored testimony supporting the Lead/Lag study for a general rate case proceeding.
Texas Gas Service Company – North Texas Service Area	6/18	GUD No. 10739	Sponsored testimony supporting the Lead/Lag study for a general rate case proceeding.
Vermont Public Service Board			
Vermont Gas Systems	02/11	Docket No. 7712	Sponsored testimony supporting the market evaluation and analysis for a system expansion and reliability regulatory fund.
Vermont Gas Systems	12/12	Docket No. 7970	Sponsored testimony describing market to be served by $90 million natural gas expansion project to Addison County, VT. Also described the benefits of the project as well as the Company's programs and service offerings. Sponsored testimony describing the economic benefits and terms of a special contract with International Paper.

The Empire District Electric Company

Cost of Service Summary



Cost of Service Summary (1/2)

Empire District Electric (KANSAS) COSS Summary	Total Company	Res Gen RG	Res Gen-Water RGW	Res Gen RH	Comm CB	Sm Heating SH
Current Delivery Service Rates						
Rate base	63,773,350	22,443,399	3,723,239	11,196,663	5,716,063	820,828
Net operating income	3,558,797	497,330	76,796	187,321	557,000	59,214
Rate of return	5.58%	2.22%	2.06%	1.67%	9.74%	7.21%
Relative rate of return	100%	40%	37%	30%	175%	129%
Revenues	$ 16,843,574	$ 5,117,464	$ 818,197	$ 2,352,005	$ 1,896,795	$ 233,484
Test Period Usage (MWh)	227,588	62,362	10,736	34,437	18,431	2,779
Revenue per MWh	$ 74.01	$ 82.06	$ 76.21	$ 68.30	$ 102.91	$ 84.01
Revenues at Equalized Rates of Return						
Rate of return	7.5%	7.5%	7.5%	7.5%	7.5%	7.5%
Return requirement	4,809,558	1,692,601	280,793	844,412	431,085	61,904
Revenue required	18,533,473	6,732,258	1,093,794	3,239,552	1,726,641	237,024
Revenue deficiency	1,689,899	1,614,794	275,597	887,546	(170,154)	3,540
Percent increase required	10.0%	31.6%	33.7%	37.7%	-9.0%	1.5%
Test Period Usage (MWh)	227,588	62,362	10,736	34,437	18,431	2,779
Revenue Required per MWh	$ 81	$ 108	$ 102	$ 94	$ 94	$ 85
Revenue Deficiency per MWh	$ 20,752	$ 14,958	$ 2,705	$ 9,435	$ (1,816)	$ 42

Cost of Service Summary (2/2)

Empire District Electric (KANSAS) COSS Summary	Gen Pow GP	Total Elect Bldg TEB	Transmission PT	Street Lts SPL	Private Lts PL	Spec Lts LS
Current Delivery Service Rates						
Rate base	7,607,535	2,083,699	8,198,746	783,832	973,216	226,130
Net operating income	1,230,227	233,804	516,504	24,616	190,004	(14,020)
Rate of return	16.17%	11.22%	6.30%	3.14%	19.52%	-6.20%
Relative rate of return	290%	201%	113%	56%	350%	-111%
Revenues	$ 2,965,274	$ 670,696	$ 2,184,519	$ 174,912	$ 410,988	$ 19,239
Test Period Usage (MWh)	38,201	9,328	48,143	1,555	1,462	154
Revenue per MWh	$ 77.62	$ 71.90	$ 45.38	$ 112.49	$ 281.05	$ 124.92
Revenues at Equalized Rates of Return						
Rate of return	7.5%	7.5%	7.5%	7.5%	7.5%	7.5%
Return requirement	573,733	157,145	618,320	59,114	73,396	17,054
Revenue required	2,078,380	567,045	2,322,041	221,748	253,761	61,229
Revenue deficiency	(886,895)	(103,651)	137,522	46,836	(157,228)	41,991
Percent increase required	-29.9%	-15.5%	6.3%	26.8%	-38.3%	218.3%
Test Period Usage (MWh)	38,201	9,328	48,143	1,555	1,462	154
Revenue Required per MWh	$ 54	$ 61	$ 48	$ 143	$ 174	$ 398
Revenue Deficiency per MWh	$ (16,301)	$ (1,705)	$ 2,851	$ 328	$ (906)	$ 106

Summary of Functional Factors

Functional Factor	Functionalization of:	Factor Derivation	Rationale
EXTERNAL FACTORS			
Production Only (PRODUCTION)	**Rate Base:** All Production Plant, and Accumulated Depreciation **Cost of Service:** All Production O&M and Depreciation Expenses	100.0 percent assigned to production Function	Costs and plant accounts only related to procurement and supply of electricity
Transmission Only (TRANSMISSION)	**Rate Base:** All Transmission Plant, and Accumulated Depreciation **Cost of Service:** All Transmission O&M and Depreciation Expenses	100.0 percent assigned to high voltage Transmission Function	Costs and plant accounts only related to transmission facilities

Functional Factor	Functionalization of:	Factor Derivation	Rationale
Primary Distribution Only (PRIMARY)	**Rate Base:** Account 360: Land and Land Rights Account 361: Structures and Improvements Account 362: Station Equipment Primary Plant Accumulated Depreciation **Cost of Service:** Account 582: Station Expenses Account 591: Maintenance of Structures Account 592: Maintenance of Station Equipment Primary Plant Depreciation Expense	100.0 percent assigned to Primary Distribution Function	Costs and plant accounts only related to primary distribution plant

Functional Factor	Functionalization of:	Factor Derivation	Rationale
Secondary Distribution Only (SECONDARY)	**Rate Base:** Account 368: Line Transformers Account 369: Services Account 371: Installations on Customers' Premises Account 372: Street Lighting and Signal Systems Secondary Plant Accumulated Depreciation Customer Deposits Customer Advances Interest on Customer Deposits **Cost of Service:** Account 585: Street lighting and signal system expenses Account 587: Customer installations expenses Account 595: Maintenance of line transformers Account 596: Maintenance of street lighting and signal systems Secondary Plant Depreciation Expenses	100.0 percent assigned to Secondary Distribution Function	Costs and plant accounts only related to secondary distribution plant
Customer Service Only (CUSTSERVICE)	**Rate Base:** Account 370: Meters Onsite Plant Accumulated Depreciation **Cost of Service:** Account 586: Meter expenses Account 597: Maintenance of meters Onsite Plant Depreciation Expense	100.0 percent assigned to Customer Service Function	Costs and plant accounts only related to providing customer service e.g., meters

Functional Factor	Functionalization of:	Factor Derivation	Rationale
Poles and Fixtures (POLES)	**Rate Base:** Account 364: Poles, Towers & Fixtures	Company's estimated cost of poles related to primary vs. secondary distribution plant	Cost generally related to Primary and Secondary Plant.
Overhead Conductors & Devices (OHCOND&DEV)	**Rate Base:** Account 365: Overhead Conductors & Devices **Cost of Service:** Account 583: Overhead line expenses Account 593: Maintenance of Overhead Lines	Company's estimated cost of overhead lines related to primary vs. secondary distribution plant	Cost generally related to Primary and Secondary Plant.
Underground Conduits and Devices (UGCOND&DEV)	**Rate Base:** Account 366: Underground Conduit Account 367: Underground Conduit & Device **Cost of Service:** Account 584: Underground line expenses Account 594: Maintenance of underground lines	Company's estimated cost of underground lines related to primary vs. secondary distribution plant	Cost generally related to Primary and Secondary Plant.
Plant Labor Functional Factor (LABOR)	**Rate Base:** All General Plant Accounts **Cost of Service:** Labor Related A&G Expenses (Accounts 920 through Account 926) Payroll Taxes Federal Unemployment Tax	Composite factor based on the functionalization of Labor-related O&M expenses	Costs generally related to labor costs
INTERNAL FACTORS			

Functional Factor	Functionalization of:	Factor Derivation	Rationale
Total Distribution Plant Factor (DISTPT)	**Cost of Service:** Account 588: Miscellaneous distribution expenses Account 589: Rents Account 598: Maintenance of miscellaneous distribution plant	Composite factor based on functionalization of total distribution plant	Costs generally related to all distribution plant accounts
Total General Plant Factor (GENPT)	**Rate Base:** All General Plant Accumulated Depreciation **Cost of Service:** All General Plant Depreciation Expenses	Composite factor based on functionalization of total general plant	Costs related to all general plant accounts
Total Operating Expenses (OPEXP)	Cash Working Capital	Composite factor based on functionalization of total O&M expenses	Costs generally related to all operation and maintenance expenses
Total Plant excluding Intangible (TPIS)	**Rate Base:** All Intangible Plant and Accumulated Depreciation Other Rate Base Items (CWIP, Materials and Supplies, Prepayments, ADIT, Regulatory Assets, Regulatory Liabilities) **Cost of Service:** Intangible Plant Depreciation Expenses Amortization Plant-related A&G expenses (Accounts 924, 925, and 935) Property Taxes Franchise Tax City Tax	Composite factor based on functionalization of all plant accounts excluding intangible plant	Costs generally related to all plant accounts

Functional Factor	Functionalization of:	Factor Derivation	Rationale
Distribution Labor Factor (D-LABOR)	**Cost of Service:** Account 580: Operation Supervision & Engineering Account 590: Maintenance Supervision and Engineering	Composite factor based on functionalization of Labor-related distribution expenses	Costs generally related to labor-related distribution expenses
A&G Labor (PTLABOR)	**Rate Base:** All General Plant Accounts **Cost of Service:** Other A&G Expenses (Accounts 928 through Account 933)	Composite factor based on functionalization of Labor and Plant related A&G Expenses	Costs generally related to labor-related and plant-related A&G expenses

Summary of Classifiers

Classifier	Classification of:	Classifier Derivation	Rationale
EXTERNAL FACTORS			
Customer Factor (CUS)	**Rate Base:** Distribution Plant (Secondary Distribution and Customer Service related only) Customer Deposits Customer Advances **Cost of Service:** Distribution O&M Expenses - Accounts 585-587 (Primary) - Accounts 583-587, 593, 594, 596 (Secondary) - All Accounts (Customer Service) All Customer Account Expenses All Customer Service Expenses All Sales Expenses	Customer-related costs.	Costs related to providing customer-related services.
Demand Factor (DEM)	**Rate Base:** All Production and Transmission Plant Account 362: Station Equipment **Cost of Service:** All Production Expense – except fuel and purchased power expenses All Transmission Expenses Account 582: Station Expenses Account 592: Maintenance of Station Equipment	Demand-related costs.	Costs related to providing demand-related services.

Classifier	Classification of:	Classifier Derivation	Rationale
Commodity Factor (COM)	**Cost of Service:** Accounts 501, 547: Fuel Expenses Account 555: On-System Purchase Power Account 556: System Control and Load Dispatching	Commodity-related costs.	Costs related to providing supply-related services.
Poles and Fixtures (Poles)	**Rate Base:** Account 364: Poles, Towers & Fixtures – Primary Distribution only	Poles and Fixtures Classifier based on Minimum-System Study.	Investment in poles and fixtures related to providing customer-related and demand-related services. Methodology to develop classifier consistent with Company's approach in prior study.
Overhead Lines (P-LINES)	**Rate Base:** Account 365: Overhead Conductors & Devices – Primary Distribution only **Cost of Service:** Account 583: Overhead line expenses – Primary Distribution only Account 593: Maintenance of Overhead Lines – Primary Distribution only	Overhead Lines Classifier based on Minimum-System Study.	Investment in overhead lines related to providing customer-related and demand-related services. Methodology to develop classifier consistent with Company's approach in prior study.
Underground Conduit (U-LINES)	**Rate Base:** Account 366: Underground Conduit – Primary Distribution only	Underground Lines Classifier based on Minimum-System Study.	Investment in underground conduits related to providing customer-related and demand-related services. Methodology to develop classifier consistent with Company's approach in prior study.

Classifier	Classification of:	Classifier Derivation	Rationale
Underground Conductors and Devices (UD-LINES)	**Rate Base:** Account 367: Underground Conductors & Device – Primary Distribution only **Cost of Service:** Account 584: Underground line expenses – Primary Distribution only Account 594: Maintenance of underground lines – Primary Distribution only	Underground Conductors and Devices Classifier based on Minimum-System Study.	Investment in underground conductors and devices related to providing customer-related and demand-related services. Methodology to develop classifier consistent with Company's approach in prior study.
Line Transformers (L-Transformers)	**Rate Base:** Account 368: Line Transformers **Cost of Service:** Account 595: Maintenance of line transformers – Secondary Distribution only	Transformers Classifier based on Minimum-System Study.	Investment in transformers related to providing customer-related and demand-related services. Methodology to develop classifier consistent with Company's approach in prior study.
INTERNAL FACTORS [CALCULATED FOR EACH FUNCTION]			
Total Plant Factor (TOTPLT)	**Rate Base:** All Intangible Plant All Additions to Utility Plant All Other Rate Base Items – except Cash Working Capital, Customer Deposits, Customer Advances, & Interest on Customer Deposits **Cost of Service:** Plant-related A&G expenses (Accounts 924, 925, & 935) Amortization Property Taxes Franchise Tax City Tax Interest Expenses	Composite classifier based on total gross plant excluding intangible plant.	Items generally consistent with total plant accounts.

Classifier	Classification of:	Classifier Derivation	Rationale
Intangible Plant Factor (INTPLT)	**Rate Base:** Intangible Plant Accumulated Depreciation **Cost of Service:** Intangible Plant Depreciation Expense	Composite classifier based on total intangible plant.	Items generally consistent with intangible accounts.
Transmission Plant Factor (TRANSPLT)	**Rate Base:** Transmission Plant Accumulated Depreciation **Cost of Service:** Transmission Plant Depreciation Expense	Composite classifier based on total transmission plant.	Items generally consistent with transmission plant accounts.
Production Plant Factor (PRODPLT)	**Rate Base:** Production Plant Accumulated Depreciation **Cost of Service:** Production Plant Depreciation Expense	Composite classifier based on total production plant.	Items generally consistent with production plant accounts.
Distribution Plant Factor (DISTPLT)	**Rate Base:** Primary, Secondary, & Customer Service-related Distribution Plant Accumulated Depreciation **Cost of Service:** Primary, Secondary, & Customer Service-related Distribution Plant Depreciation Expense	Composite classifier based on total distribution plant.	Items generally consistent with distribution plant accounts.
General Plant Factor (GENPLT)	**Rate Base:** General Plant Accumulated Depreciation **Cost of Service:** General Plant Depreciation Expense	Composite classifier based on total general plant.	Items generally consistent with general plant accounts.
Plant Accounts 362-375 Factor (ACCT362-375)	**Rate Base:** Account 360: Land and Land Rights Account 361: Structures and Improvements	Composite classifier based on major distribution plant accounts.	Items generally consistent with major distribution plant accounts.

Classifier	Classification of:	Classifier Derivation	Rationale
O&M Classifier (O&M)	**Rate Base:** Cash Working Capital	Composite classifier based on total O&M expenses.	Items generally consistent with total O&M expenses.
Labor Classifier (LABOR)	**Rate Base:** All General Plant **Cost of Service:** Administration & General Expense (Accounts 920 through 926) Payroll Taxes Federal Unemployment Tax	Composite classifier based on total labor-related O&M expenses.	Items generally consistent with labor-related expenses.
A&G Labor Classifier (A&GLAB)	**Cost of Service:** Administrative & General Expense (Accounts 929 & 930 through 933)	Composite classifier based on labor-related A&G expenses.	Items generally consistent with labor-related A&G expenses.
O&M Accounts 582-587 (OPEX582-587)	**Cost of Service:** Account 580: Operation Supervision & Engineering – except Customer Service Account 588: Miscellaneous distribution expenses – except Customer Service Account 589: Rents – except Customer Service	Composite classifier based on major distribution operations expenses.	Items generally consistent with major distribution operations expenses.
O&M Accounts 591-597 (OPEX592-597)	**Cost of Service:** Account 590: Maintenance Supervision and Engineering – except Customer Service Account 591: Maintenance of Structures – except Customer Service Account 598: Maintenance of miscellaneous distribution plant – except Customer Service	Composite classifier based on major distribution maintenance expenses.	Items generally consistent with major distribution maintenance expenses.
O&M Expenses Less A&G (NonAG)	**Cost of Service:** Account 928: Regulatory commission expenses	Composite classifier based on non-A&G O&M expenses.	Items generally consistent with non-A&G O&M expenses.

Summary of Allocators

Allocator	Allocation of:	Allocator Derivation	Rationale

Allocator	Allocation of:	Allocator Derivation	Rationale
EXTERNAL FACTORS			
Number of Customers (CUSTOMERS)	**Rate Base:** Distribution Plant (Customer-related portion of Primary Distribution only) **Cost of Service:** Major Distribution O&M Expenses (Customer-related portion of Primary Distribution only) Account 902: Meter reading Customer Service Expenses (Accounts 909 & 910)	Allocator is based on the percentage of bills within each rate class.	Costs are generally related to the number of customers. This is consistent with the approach taken in the most recent cost of service study.
Number of Customers (Secondary Voltage) (CUSTOMERS-SEC)	**Rate Base:** Distribution Plant Accounts 364 through 367 (Secondary Distribution-related only) Account 375: Charging Stations (Customer-related only) **Cost of Service:** Distribution Expenses Accounts 583 & 584, 593 & 594 (Customer-related portion of Secondary Distribution only)	Allocator is based on the percentage of bills within each rate class served through secondary distribution system.	Costs are generally related to the number of customers. This is consistent with the approach taken in the most recent cost of service study.

Allocator	Allocation of:	Allocator Derivation	Rationale
Annual Sales (KWH)	**Cost of Service:** Accounts 501, 547: Fuel Expenses Account 555: On-System Purchase Power (Energy & Demand) Account 556: System Control and Load Dispatching Expenses	Allocator is based on annual kWh usage of each rate class.	Costs generally related to kWh sales.
Average & Excess - 12 Month Non-Coincident Peak @ Generation (A&E 12NCP)	**Rate Base:** All Production Plant **Cost of Service:** All Production-related O&M Expenses – except fuel and purchased power expenses	Allocator is based on the Average and Excess 12-month Coincident Peak Allocator.	Production investments and costs are generally driven by customer demands which are represented by two components: 1) average customer demands, and customer demands in excess of average demand. This is generally consistent with the approach taken in the Company's most recent cost of service study.
12 Month Coincident Peak @ Transmission (12 CP Trans)	**Rate Base:** All Transmission Plant **Cost of Service:** All Transmission Expenses	Allocator is based on each customer class' 12-month Coincident Peaks.	Transmission investments and costs are generally related to addressing customers' peak demands through the year. This is consistent with the approach taken in the Company's most recent cost of service study.
Non-Coincident Primary (6 NCP Primary)	**Rate Base:** Distribution Plant (Accounts 362 through 368 – Demand-related portion of 'Primary Distribution') **Cost of Service:** Distribution Expenses (Accounts 582 through 584, 592 through 594 – Demand & Primary Distribution-related only)	Allocator is based on each customer class' non-coincident peak demands during three months of winter (December, January, February) and three months of summer (June, July, August) at primary voltage level.	Distribution investments and costs are generally related to addressing customers' peak demands in the year. This is generally consistent with the approach taken in the most recent cost of service study, where customer classes' single non-coincident peaks were the basis of distribution cost allocation.

Allocator	Allocation of:	Allocator Derivation	Rationale
Non-Coincident Secondary (6 NCP Secondary)	**Rate Base:** Distribution Plant (Accounts 368 & 375 – Demand & Secondary Distribution-related only) **Cost of Service:** Distribution Expenses (Accounts 593 through 595 – Demand & Secondary Distribution-related only)	Allocator is based on each customer class' non-coincident peak demands during three months of winter (December, January, February) and three months of summer (June, July, August) at secondary voltage level.	Distribution investments and costs are generally related to addressing customers' peak demands in the year. This is generally consistent with the approach taken in the most recent cost of service study, where customer classes' single non-coincident peaks were the basis of distribution cost allocation.
Transformers Allocation (Line-Transformers)	**Rate Base:** Account 368: Line Transformers – Customer & Secondary Distribution-related only **Cost of Service:** Account 595: Maintenance of line transformers – Customer-related only	Allocator based on number of customers, weighted by a factor representing the number of customers in each customer class served by a single transformer. Weighted factor based on Company's mapping data.	Transformers are installed in proportion to the number of customers that need to be served in the area. This is consistent with the approach taken in the Company's prior cost of service study.
Account 369 Services Allocator (SERVICES)	**Rate Base:** Account 369: Services **Cost of Service:** Account 587: Customer installations expenses	Allocator is based on Company-provided average service costs (including labor, material, and overheads) for each customer class.	Service costs can be reasonably allocated based on average service line installation costs for different types of customers. This is consistent with the approach taken in the Company's prior cost of service study.
Customer Deposits (CustDeposits)	**Rate Base:** Customer Deposits	Allocator is based on percentage of actual customer deposits by each rate class during the test year period.	Costs are directly assigned based on Company data.

Allocator	Allocation of:	Allocator Derivation	Rationale
Account 370 Meters Allocator (METERCOST)	**Rate Base:** Account 370: Meters **Cost of Service:** Account 586: Meter expenses Account 597: Maintenance of meters	Allocator is based on Company-provided average meter costs (including labor, material, and overheads) for each customer class.	Meter costs can be reasonably allocated based on average meter installation costs for different types of customers. This is consistent with the approach taken in the Company's prior cost of service study.
Account 903 Collections (ACCT-903)	**Cost of Service:** Customer Account Expense – except Accounts 902 & 904	Allocator is based on a combination of allocators applied on individual GL accounts. Allocators include number of customers, revenues, and uncollectible expenses.	Individual GL accounts can be reasonably allocated based on a combination of allocators. This is consistent with the approach taken in the Company's prior cost of service study.
Account 904 (Uncollectibles)	**Cost of Service:** Account 904: Uncollectible accounts	Allocator is based on the Company's bad debt data for each customer class.	Costs are directly assigned using Company provided actual data. This is generally consistent with the approach taken in the Company's prior cost of service study.
Account 908 Customer Assistance (ACCT-908)	**Cost of Service:** Account 907: Customer Service Supervision Account 908: Customer Assistance	Allocator is based on individual GL account allocations to residential, commercial, and industrial customers.	Individual GL accounts can be reasonably allocated to different customer categories. This is consistent with the approach taken in the Company's prior cost of service study.
Account 912 Allocator (ACCT-912)	**Cost of Service:** Account 912: Demonstration and Selling Expenses	Allocator is based on individual GL account allocations to residential, commercial, and industrial customers.	Individual GL accounts can be reasonably allocated to different customer categories. This is generally consistent with the approach taken in the Company's prior cost of service study.
Installations on Customer Premises (ACCT-371)	**Rate Base:** Account 371: Installation on Customers' Premises	Allocation mostly to Private Lighting customer class.	Costs are generally related private lighting.

Allocator	Allocation of:	Allocator Derivation	Rationale
Street Lighting Plant Allocation (ACCT-373)	**Rate Base:** Account 373: Street Lighting & Signal Systems	Allocation 100.0 percent to municipal street lighting customer class	Costs are generally related municipal street lighting.
Street Lighting Expenses Allocation (ACCT-595-596)	**Cost of Service:** Account 585: Street lighting and signal system expenses Account 596: Maintenance of street lighting and signal systems	Allocator is based on Company's estimates of street lighting expense allocation to municipal street and private lighting customer classes.	Costs are generally related to serving municipal street and private lighting classes.
INTERNAL FACTORS [CALCULATED FOR EACH FUNCTION]			
Total Plant (TOTPLT)	**Rate Base:** All Intangible Plant All Additions to Utility Plant All Other Rate Base Items – except Cash Working Capital, Customer Deposits, and Interest on Customer Deposits **Cost of Service:** Plant-related A&G expenses (Accounts 924, 925, & 935) Amortization Property Taxes Franchise Tax City Tax Interest Synchronization	Allocator is based on total plant allocation.	Costs are generally related to total plant.
Intangible Plant (INTPLT)	**Rate Base:** Intangible Plant Accumulated Depreciation **Cost of Service:** Intangible Plant Depreciation Expense	Allocator is based on intangible plant allocation.	Costs are generally related to intangible plant.

Allocator	Allocation of:	Allocator Derivation	Rationale
Transmission Plant (TRANSPLT)	**Rate Base:** Transmission Plant Accumulated Depreciation **Cost of Service:** Transmission Plant Depreciation Expense	Allocator is based on transmission plant allocation.	Costs are generally related to transmission plant.
Production Plant (PRODPLT)	**Rate Base:** Production Plant Accumulated Depreciation **Cost of Service:** Production Plant Depreciation Expense	Allocator is based on production plant allocation.	Costs are generally related to production plant.
Distribution Plant (DISTPLT)	**Rate Base:** Distribution Plant Accumulated Depreciation **Cost of Service:** Distribution Plant Depreciation Expense	Allocator is based on distribution plant allocation.	Costs are generally related to distribution plant.
General Plant (GENPLT)	**Rate Base:** General Plant Accumulated Depreciation **Cost of Service:** General Plant Depreciation Expense	Allocator is based on general plant allocation.	Costs are generally related to general plant.
Distribution Plant Accounts 362-375 (ACCT362-375)	**Rate Base:** Account 360: Land and Land Rights Account 361: Structures and Improvements	Allocator is based on composite allocation of major distribution plant accounts (Account 362 through Account 375)	Costs generally follow major distribution plant accounts.

Allocator	Allocation of:	Allocator Derivation	Rationale
Labor Allocator (LABOR)	**Rate Base:** All General Plant **Cost of Service:** A&G Expenses (Accounts 920 through 923 & 926) Payroll Taxes, Federal Unemployment Tax	Allocator is based on composite allocation of labor-related production, transmission, distribution, customer service, customer accounts, and sales expenses.	Costs generally follow labor-related O&M expenses.
A&G Labor (A&GLAB)	**Cost of Service:** A&G Expenses (Accounts 929 through 933)	Allocator is based on composite allocation of labor-related A&G expenses.	Costs generally follow labor-related O&M expenses.
Total O&M (O&M)	**Rate Base:** Cash Working Capital	Allocator is based on composite allocation of total O&M expenses.	Costs generally follow total O&M expenses.
O&M Accounts 582-587 (OPEX582-587)	**Cost of Service:** Account 580: Operation Supervision & Engineering Account 588: Miscellaneous distribution expenses Account 589: Rents	Allocator is based on composite allocation of major distribution operations expenses (Account 582 through Account 587)	Costs generally follow major distribution operations expenses.
O&M Accounts 591-597 (OPEX592-597)	**Cost of Service:** Account 590: Maintenance Supervision and Engineering Account 591: Maintenance of Structures Account 598: Maintenance of miscellaneous distribution plant	Allocator is based on composite allocation of major distribution maintenance expenses (Account 592 through Account 597)	Costs generally follow major distribution maintenance expenses.
O&M Expenses Less A&G (NonAG_O&M)	**Cost of Service:** Account 928: Regulatory commission expenses	Allocator based on total O&M expenses other than A&G expenses.	Costs generally related to all O&M expenses other than A&G expenses.

The Empire District Electric Company

Summary of Functionalization Factors

Empire District Electric (KANSAS) Functional Factors	Code	Total	Production	Transmission	Primary Distribution	Secondary Distribution	Customer Service
INTERNAL FUNCTIONAL FACTORS							
Production Only	PRODUCTION	100.0%	100.0%	0.0%	0.0%	0.0%	0.0%
Transmission Only	TRANSMISSION	100.0%	0.0%	100.0%	0.0%	0.0%	0.0%
Primary Distribution Only	PRIMARY	100.0%	0.0%	0.0%	100.0%	0.0%	0.0%
Secondary Distribution Only	SECONDARY	100.0%	0.0%	0.0%	0.0%	100.0%	0.0%
Customer Service Only	CUSTSERVICE	100.0%	0.0%	0.0%	0.0%	0.0%	100.0%
Total Distribution Plant Factor	DISTPT	100.0%	0.0%	0.0%	68.5%	28.9%	2.6%
Total General Plant Factor	GENPT	100.0%	49.6%	0.0%	16.0%	3.7%	30.6%
Total Operating Expenses	OPEXP	100.0%	54.4%	0.0%	20.7%	3.7%	21.3%
Total Plant excl. Intangible	TPIS	100.0%	54.1%	0.0%	30.8%	12.9%	2.1%
EXTERNAL FUNCTIONAL FACTORS							
Poles and Fixtures	POLES	100.0%	0.0%	0.0%	90.8%	9.2%	0.0%
Overhead Conductors & Devices	OHCOND&DEV	100.0%	0.0%	0.0%	92.9%	7.1%	0.0%
Underground Conduits and Devices	UGCOND&DEV	100.0%	0.0%	0.0%	92.2%	7.8%	0.0%
LABOR FUNCTIONAL FACTORS							
Plant Labor Functional Factor	LABOR	100.0%	49.6%	0.0%	16.0%	3.7%	30.6%
Distribution Labor Factor	D-LABOR	100.0%	0.0%	0.0%	54.0%	12.6%	33.4%
A&G Labor	PTLABOR	100.0%	49.9%	0.0%	16.9%	4.2%	29.0%
INTERNAL FUNCTIONAL FACTORS DERIVATION							
Total Plant (All Plant excl. Intangible)		121,147,033	65,561,627	-	37,333,269	15,649,394	2,602,743
Total Plant excl. Intangible	TPIS	100.0%	54.1%	0.0%	30.8%	12.9%	2.1%
Total Distribution Plant		53,609,073	-	-	36,704,550	15,502,984	1,401,538
Total Distribution Plant Factor	DISTPT	100.0%	0.0%	0.0%	68.5%	28.9%	2.6%
Total General Plant		3,922,214	1,945,880	-	628,719	146,410	1,201,205
Total General Plant Factor	GENPT	100.0%	49.6%	0.0%	16.0%	3.7%	30.6%
Plant Labor Functional Factor		1,441,502	715,155	-	231,068	53,809	441,470
Labor Functional Factor	LABOR	100.0%	49.6%	0.0%	16.0%	3.7%	30.6%
Distribution Labor Factor		372,900	-	-	201,302	46,877	124,721
Distribution Labor Factor	D-LABOR	100.0%	0.0%	0.0%	54.0%	12.6%	33.4%
A&G Labor		2,321,206	1,157,454	-	391,321	98,597	673,834
A&G Labor	PTLABOR	100.0%	49.9%	0.0%	16.9%	4.2%	29.0%
Total Operating Expenses		7,571,133	4,121,166	-	1,564,261	276,418	1,609,287
Total Operating Expenses	OPEXP	100.0%	54.4%	0.0%	20.7%	3.7%	21.3%

Functionalization of Poles and Fixtures

OH Poles Account 364	%
Primary	90.8%
Secondary	9.2%
Total	100.0%

Functionalization of Overhead Conductors and Devices

OH Conductors & Devices Account 365	Miles		Cost per Mile		Cost	%
Primary	5,591	$	64,151	$	358,665,753	92.9%
Secondary	566	$	48,398	$	27,369,818	7.1%
Total	6,156			$	386,035,571	100.0%

Functionalization of Underground Conductors and Devices

UG Conduits & Devices Account 366-367	Miles	Cost per Mile	Cost	%
Primary	705	$ 74,026	$ 52,158,695	92.2%
Secondary	151	$ 29,380	$ 4,431,930	7.8%
Total	855		$ 56,590,625	100.0%

The Empire District Electric Company

Summary of Classification Factors

Empire District Electric (KANSAS)					
Summary of Classifiers					
Classifier Description	Classifier Code	Total	- Demand	- Customer	- Commodity
External Classifiers					
Common					
Customer Factor	CUS	100.0%	0.0%	100.0%	0.0%
Demand Factor	DEM	100.0%	100.0%	0.0%	0.0%
Commodity Factor	COM	100.0%	0.0%	0.0%	100.0%
Poles and Fixtures	Poles	100.0%	46.9%	53.1%	0.0%
Overhead Lines	P-LINES	100.0%	87.2%	12.8%	0.0%
Underground Conduit	U-LINES	100.0%	0.0%	100.0%	0.0%
Underground Conductors and Devices	UD-LINES	100.0%	55.4%	44.6%	0.0%
Line Transformers	L-Transformers	100.0%	57.0%	43.0%	0.0%

Classification of Poles and Fixtures

Poles FERC Account 364	Current Cost	Indexed Costs Qty	Total Cost
Pole & Fixtures	$ 751.14	211,686	$ 159,005,822
Anchors	$ 265.41	75,773	$ 20,110,912
Guys	$ 226.76	92,361	$ 20,943,780
Total		211,686	$ 200,060,514
Per Pole Cost for Minimum Size System			$ 945
Per Pole Cost for Minimum Size System (Primary only)			$ 858
Per Pole Cost for Total System			$ 1,615
Minimum System Study: Customer Portion			**53.1%**

Classification of Overhead Conductors and Devices

OH Conductors		Indexed Costs	
FERC Account 365	Current Costs	Qty	Total Cost
Circuit Miles	$ 11,301	6,185	$ 69,898,861
Per Mile Cost for Minimum Size System			$ 11,301
Per Mile Cost for Minimum Size System (Primary)			$ 10,263
Per Mile for Total System			$ 80,392
Minimum System Study: Customer Portion			**12.8%**

Classification of Underground Conductors and Devices

UG Conductors		Indexed Costs	
FERC Account 366	Current Costs	Qty	Total Cost
Per Mile Cost for Minimum Size System		$	154,695
Per Mile for Total System		$	123,598
Minimum System Study: Customer Portion			100.0%

Classification of Underground Conductors and Devices

UG Conductors FERC Account 367		Indexed Costs Current Costs	Qty		Total Cost
Per Circuit Mile	$	70,642	798	$	56,372,112
Per Mile Cost for Minimum Size System				$	70,642
Per Mile for Total System				$	158,385
Minimum System Study: Customer Portion					44.6%

Classification of Transformers

Transformers FERC Account 368	Current Costs	Indexed Costs Qty	Total Cost
Minimum Size Transformer	$ 1,484	101,345	$ 150,370,257
Per Unit Cost for Minimum Size System			$ 1,483.75
Per Unit Cost for Total System			$ 3,451.20
Minimum System Study: Customer Portion			43.0%

The Empire District Electric Company

Summary of Allocation Factors

Empire District Electric (KANSAS) Summary of Allocators	Description	Total Company	Res Gen RG	Res Gen-Water RGW	Res Gen RH	Comm CB	Sm Heating SH	Gen Pow GP	Total Elect Bldg TEB	Transmission PT	Street Lts SPL	Private Lts PL	Spec Lts LS
External Allocators													
External Allocators													
CUSTOMERS	Number of Customers	100.00%	57.34%	7.88%	19.31%	12.25%	1.14%	1.09%	0.41%	0.05%	0.00%	0.34%	0.19%
CUSTOMERS-SEC	Number of Customers (Secondary)	100.00%	57.37%	7.88%	19.32%	12.26%	1.14%	1.08%	0.41%	0.02%	0.00%	0.34%	0.19%
KWH	Annual Sales	100.00%	27.40%	4.72%	15.13%	8.10%	1.22%	16.79%	4.10%	21.15%	0.68%	0.64%	0.07%
REV	Revenues	100.00%	30.38%	4.86%	13.96%	11.26%	1.39%	17.60%	3.98%	12.97%	1.04%	2.44%	0.11%
A&E 12NCP	A&E (12NCP)	100.00%	31.71%	5.42%	17.06%	8.44%	1.31%	14.48%	3.82%	15.79%	0.83%	0.80%	0.34%
12 CP Trans	12CP	100.00%	33.53%	5.74%	18.14%	8.07%	1.38%	13.74%	3.98%	15.14%	0.16%	0.12%	0.00%
6 NCP Primary	NCP (Primary)	100.00%	34.08%	5.72%	18.27%	8.20%	1.32%	12.59%	3.73%	14.09%	0.77%	0.75%	0.49%
6 NCP Secondary	NCP (Seconary)	100.00%	38.45%	6.45%	20.61%	9.25%	1.49%	13.76%	4.21%	3.51%	0.87%	0.85%	0.55%
Line-Transformers	Transformers	100.00%	40.39%	13.70%	27.58%	14.48%	1.19%	1.90%	0.70%	0.06%	0.00%	0.00%	0.00%
SERVICES	Services (369)	100.00%	56.53%	7.62%	19.04%	13.28%	1.25%	1.53%	0.54%	0.00%	0.00%	0.00%	0.21%
CustDeposits	Customer Deposits	100.00%	62.35%	6.80%	9.98%	9.98%	0.16%	10.61%	0.00%	0.00%	0.00%	0.12%	0.00%
METERCOST	Meters (370)	100.00%	52.95%	7.14%	17.83%	13.75%	1.30%	1.25%	0.47%	5.18%	0.00%	0.00%	0.14%
ACCT-903	Collections (903)	100.00%	56.33%	7.91%	19.91%	11.09%	1.05%	2.02%	0.60%	0.61%	0.02%	0.34%	0.11%
Uncollectibles	Uncollectibles (904)	100.00%	55.90%	8.94%	25.70%	2.81%	0.35%	4.39%	1.00%	0.27%	0.00%	0.65%	0.00%
ACCT-908	Customer Assistance (908)	100.00%	18.08%	2.48%	6.09%	30.72%	2.85%	2.74%	1.03%	34.67%	0.00%	0.85%	0.48%
ACCT-912	Sales (912)	100.00%	26.69%	4.24%	12.11%	9.68%	1.18%	14.71%	3.34%	16.98%	0.63%	7.35%	3.10%
ACCT-371	Installations on Cust. Premises (371)	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	98.49%	1.51%
ACCT-373	Street Lighting Plant (373)	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	100.00%	0.00%	0.00%
ACCT-585-596	Street Lighting Expenses (585, 596)	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	68.00%	32.00%	0.00%

The Empire District Electric Company

Average and Excess Allocator

Average and Excess	Average and Excess (12 NCP)					
Rate Class	Peak Demand 12 NCP (MW)	Average Demand (MW)	Excess Demand (MW)	Average Demand (%)	Excess Demand (%)	Total Allocator (%)
RG-Residential	16,272	7,833	8,439	27.82%	37.94%	31.71%
RG-Residential Water Heat	2,782	1,341	1,441	4.76%	6.48%	5.42%
RH-Residential Total Elec	8,748	4,248	4,499	15.09%	20.23%	17.06%
CB-Commercial	4,272	2,312	1,960	8.21%	8.81%	8.44%
SH-Small Heating	669	347	322	1.23%	1.45%	1.31%
GP-General Power	7,123	4,728	2,395	16.79%	10.77%	14.48%
TEB-Total Electric Bldg	1,903	1,158	745	4.11%	3.35%	3.82%
PT-Transmission	7,598	5,801	1,797	20.60%	8.08%	15.79%
SPL-Municipal St Lighting	428	191	237	0.68%	1.07%	0.83%
PL-Private Lighting	413	179	234	0.64%	1.05%	0.80%
LS-Special Lighting	192	19	174	0.07%	0.78%	0.34%
Total	50,402	28,158	22,244	100.00%	100.00%	100.00%
Residential						54.19%

Kansas System Load Factors	12CP
Coincident Peak Demand	45,718
Average Hourly Demand	28,158
System Load Factor	**61.6%**

The Empire District Electric Company

Meters Cost Allocator

Meter Study Rate Class	Number Of Meters		Current Cost per Meter		Current Total Cost	Allocator %
RG-Residential	5,547	$	217	$	1,202,689	52.95%
RG-Residential Water Heat	748		217		162,180	7.14%
RH-Residential Total Elec	1,868		217		405,016	17.83%
CB-Commercial	1,166		268		312,206	13.75%
SH-Small Heating	110		268		29,453	1.30%
GP-General Power	106		268		28,382	1.25%
TEB-Total Electric Bldg	40		268		10,710	0.47%
PT-Transmission	6		19,591		117,544	5.18%
SPL-Municipal St Lighting	0		-		-	0.00%
PL-Private Lighting	0		-		-	0.00%
LS-Special Lighting	21		148		3,100	0.14%
Total	9,612			$	2,271,281	100.0%
Residential						77.9%

Services Cost Allocator

Services Study Rate Class	Number Of Services		Current Cost per Service		Current Total Cost	Allocator %
RG-Residential	5,547	$	1,107	$	6,141,991	56.5%
RG-Residential Water Heat	748		1,107		828,233	7.6%
RH-Residential Total Elec	1,868		1,107		2,068,368	19.0%
CB-Commercial	1,166		1,237		1,442,456	13.3%
SH-Small Heating	110		1,237		136,081	1.3%
GP-General Power	106		1,573		166,713	1.5%
TEB-Total Electric Bldg	40		1,456		58,256	0.5%
PT-Transmission	6		-		-	0.0%
SPL-Municipal St Lighting	0		-		-	0.0%
PL-Private Lighting	0		-		-	0.0%
LS-Special Lighting	21		1,072		22,505	0.2%
Total	9,612			$	10,864,603	100.0%
Residential						83.2%

The Empire District Electric Company

Revenue Targets

Empire District Electric (KANSAS) Target Revenues	Total Company	Res Gen RG	Res Gen-Water RGW	Res Gen RH	Comm CB	Sm Heating SH	Gen Pow GP	Total Elect Bldg TEB	Transmission PT	Street Lts SPL	Private Lts PL	Spec Lts LS
Target Revenues												
Class Revenues at EROR	18,533,473	6,732,258	1,093,794	3,239,552	1,726,641	237,024	2,078,380	567,045	2,322,041	221,748	253,761	61,229
Current Class Revenues	16,843,574	5,117,464	818,197	2,352,005	1,896,795	233,484	2,965,274	670,696	2,184,519	174,912	410,988	19,239
Difference ($)	1,689,899	1,614,794	275,597	887,546	(170,154)	3,540	(886,895)	(103,651)	137,522	46,836	(157,228)	41,991
Difference (%)	10.0%	31.6%	33.7%	37.7%	-9.0%	1.5%	-29.9%	-15.5%	6.3%	26.8%	-38.3%	218.3%
Target Revenues	18,533,473	5,938,952	949,539	2,729,564	1,968,048	245,795	2,965,274	695,891	2,404,103	202,991	410,988	22,327
Current Revenues	16,843,574	5,117,464	818,197	2,352,005	1,896,795	233,484	2,965,274	670,696	2,184,519	174,912	410,988	19,239
$ Difference	1,689,899	821,488	131,342	377,559	71,253	12,311	-	25,195	219,584	28,078	-	3,088
% Difference	10.0%	16.1%	16.1%	16.1%	3.8%	5.3%	0.0%	3.8%	10.1%	16.1%	0.0%	16.1%
Customers	9,669	5,544	762	1,867	1,185	110	106	40	5	-	33	19
Usage (MWh)	227,588	62,362	10,736	34,437	18,431	2,779	38,201	9,328	48,143	1,555	1,462	154
Target Increase ($/ Customer/ Mo.)		$ 12.35	$ 14.37	$ 16.85	$ 5.01	$ 9.35	$ -	$ 53.04	$ 3,659.73	$ -	$ -	$ 13.91
Target Increase ($ per MWh)		$ 13.17	$ 12.23	$ 10.96	$ 3.87	$ 4.43	$ -	$ 2.70	$ 4.56	$ 18.06	$ -	$ 20.05

Target Revenues	Total Company	Res Gen RG	Res Gen-Water RGW	Res Gen RH	Comm CB	Sm Heating SH	Gen Pow GP	Total Elect Bldg TEB	Transmission PT	Street Lts SPL	Private Lts PL	Spec Lts LS
Steps	1.60											
Step 1: Maintain Revenues for CB, GP, TEB, PL	5,943,753				1,896,795		2,965,274	670,696			410,988	
Step 2: Move Residential, SPL to 150% of EROR	9,843,373	5,938,952	949,539	2,729,564						202,991		22,327
Step 3: Move SH and PT to EROR	2,559,065					237,024			2,322,041			
Step 4: Allocate Remaining based on Revenues	187,281				71,253	8,771		25,195	82,062			
Proposed Revenue Targets	18,533,473	5,938,952	949,539	2,729,564	1,968,048	245,795	2,965,274	695,891	2,404,103	202,991	410,988	22,327

The Empire District Electric Company

Revenue Targets

Target Revenues From Base Rates	Total Company	Res Gen RG	Res Gen-Water RGW	Res Gen RH	Comm CB	Sm Heating SH	Gen Pow GP	Total Elect Bldg TEB	Transmission PT	Street Lts SPL	Private Lts PL	Spec Lts LS
Target Revenues												
Total Target Revenues	18,533,473	5,938,952	949,539	2,729,564	1,968,048	245,795	2,965,274	695,891	2,404,103	202,991	410,988	22,327
less:												
Excess Facility Revenues	178,485	-	-	-	585	-	7,960	-	121,489	48,451	-	-
Net Metering	(1,159)	(84)	(13)	(39)	(325)	(42)	(532)	(124)	-	-	-	-
TDC Adjustment	(53,808)	(18,040)	(3,088)	(9,759)	(4,344)	(744)	(7,395)	(2,142)	(8,146)	(84)	(64)	(2)
(450) Forfeited Discounts	122,568	37,634	6,018	17,303	13,942	1,718	21,754	4,935	15,182	926	3,016	140
(451) Reconnect Charges and Other Misc Reven	10,280	3,156	505	1,451	1,169	144	1,824	414	1,273	78	253	12
(454) Rent From Elec Property	40,377	14,210	2,357	7,089	3,619	520	4,817	1,319	5,191	496	616	143
(456, 457) Other Electric Revenue	360,569	110,710	17,703	50,903	41,014	5,053	63,996	14,519	44,661	2,725	8,872	413
Target Revenues from Base Rates	17,876,161	5,791,366	926,057	2,662,617	1,912,389	239,147	2,872,849	676,969	2,224,454	150,398	398,294	21,621
Current Revenues												
Total Current Revenues	16,843,574	5,117,464	818,197	2,352,005	1,896,795	233,484	2,965,274	670,696	2,184,519	174,912	410,988	19,239
less:												
Excess Facility Revenues	178,485	-	-	-	585	-	7,960	-	121,489	48,451	-	-
Net Metering	(1,159)	(84)	(13)	(39)	(325)	(42)	(532)	(124)	-	-	-	-
TDC Adjustment	(53,808)	(18,040)	(3,088)	(9,759)	(4,344)	(744)	(7,395)	(2,142)	(8,146)	(84)	(64)	(2)
(450) Forfeited Discounts	122,568	37,634	6,018	17,303	13,942	1,718	21,754	4,935	15,182	926	3,016	140
(451) Reconnect Charges and Other Misc Reven	10,280	3,156	505	1,451	1,169	144	1,824	414	1,273	78	253	12
(454) Rent From Elec Property	40,377	14,210	2,357	7,089	3,619	520	4,817	1,319	5,191	496	616	143
(456, 457) Other Electric Revenue	360,569	110,710	17,703	50,903	41,014	5,053	63,996	14,519	44,661	2,725	8,872	413
Current Revenues from Base Rates	16,186,263	4,969,879	794,715	2,285,058	1,841,135	226,836	2,872,849	651,774	2,004,870	122,320	398,294	18,533

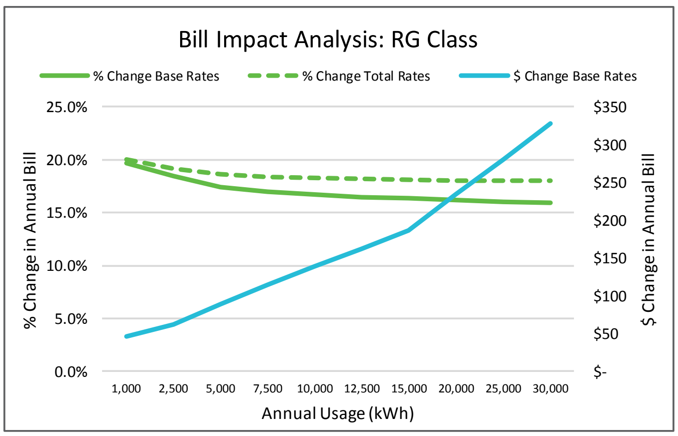
Rate Design: Residential General Class

Empire District Electric (KANSAS) Residential General Rate Design			
Base Rate Revenues			
Target Revenues	5,791,366		
Current Revenues	4,969,879		
$ Difference	821,488		
% Difference	16.5%		
	kWh Usage		
Annual Usage - First Block	30,026,795	600	
Annual Usage - Second Block	32,335,503		
Number of Bills	66,530		
Average Annual Use (kWh)	11,248		
Residential General Rate Design	**Rate**	**Units**	**Revenues**
Proposed Rates			
Customer Charge	$ 17.00	66,530	$ 1,131,010
1st Block kWh	$ 0.07920	30,026,795	2,378,041
2nd Block kWh	$ 0.07058	32,335,503	2,282,316
Revenue at Proposed Rates			$ 5,791,366
Current Rates			
Customer Charge	$ 14.00	66,530	$ 931,420
1st Block kWh	$ 0.06858	30,026,795	2,059,238
2nd Block kWh	$ 0.06112	32,335,503	1,976,346
Revenue at Current Rates			$ 4,967,004

Bill Impact: Residential General Class

Bill Impact Analysis - RG Rate			Annual Bill (w/o ECA, AERR, AVTS and TDC Riders)				Annual Bill (w/ ECA, AERR, AVTS and TDC Riders)			
Annual Use	Cumulative Bills	Cumulative Use	Proposed Base Rates	Current Base Rates	$ Change Base Rates	% Change Base Rates	Proposed Total Rates	Current Total Rates	$ Change Total Rates	% Change Total Rates
1,000	6.8%	0.2%	$ 283	$ 237	$ 47	19.7%	$ 320	$ 267	$ 53	20.0%
2,500	10.0%	0.6%	402	339	63	18.4%	495	415	80	19.2%
5,000	17.4%	3.1%	600	511	89	17.4%	786	662	123	18.6%
7,500	29.8%	9.6%	790	676	115	17.0%	1,068	903	166	18.4%
10,000	45.8%	21.3%	972	833	139	16.7%	1,343	1,136	207	18.2%
12,500	59.3%	34.0%	1,148	986	163	16.5%	1,612	1,364	248	18.2%
15,000	70.3%	46.5%	1,325	1,138	186	16.4%	1,881	1,593	289	18.1%
20,000	85.6%	68.4%	1,678	1,444	234	16.2%	2,420	2,050	370	18.1%
25,000	93.4%	82.8%	2,031	1,750	281	16.1%	2,958	2,507	452	18.0%
30,000	97.3%	91.6%	2,383	2,055	328	16.0%	3,496	2,963	533	18.0%

Proposed Total Rates: includes ECA Charge and TDC Rider
Current Total Rates: includes ECA Charge, AERR and AVTS Riders



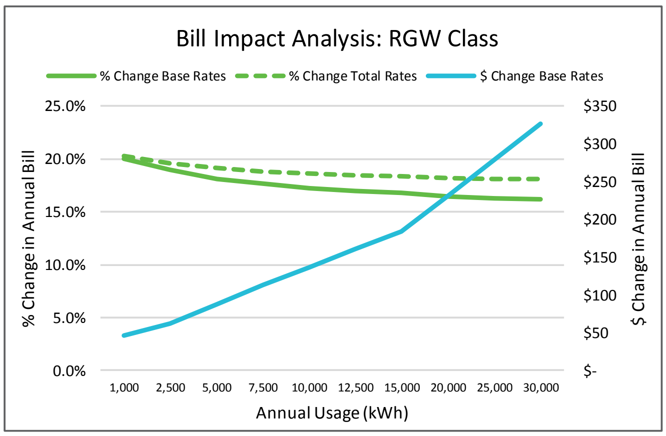
Rate Design: Residential Water Class

Empire District Electric (KANSAS)				
Residential Water Rate Design				
Revenues				
Target Revenues	926,057			
Current Revenues	794,715			
$ Difference	131,342			
% Difference	16.5%			
	kWh Usage			
Annual Usage - First Block	4,569,222	600		
Annual Usage - Second Block	6,166,706			
Number of Bills	9,139			
Average Annual Use (kWh)	14,097			
Residential Water Rate Design	Rate	Units		Revenues
Proposed Rates				
Customer Charge	$ 17.00	9,139	$	155,363
1st Block kWh	$ 0.07341	4,569,222		335,434
2nd Block kWh	$ 0.07058	6,166,706		435,261
Revenue at Proposed Rates			$	926,057
Current Rates				
Customer Charge	$ 14.00	9,139	$	127,946
1st Block kWh	$ 0.06309	4,569,222		288,272
2nd Block kWh	$ 0.06112	6,166,706		376,909
Revenue at Current Rates			$	793,127

Bill Impact: Residential Water Class

Bill Impact Analysis - RGW Rate										
			Annual Bill (w/o ECA, AERR, AVTS and TDC Riders)				Annual Bill (w/ ECA, AERR, AVTS and TDC Riders)			
Annual Use	Cumulative Bills	Cumulative Use	Proposed Base Rates	Current Base Rates	$ Change Base Rates	% Change Base Rates	Proposed Total Rates	Current Total Rates	$ Change Total Rates	% Change Total Rates
1,000	3.1%	0.1%	$ 277	$ 231	$ 46	20.0%	$ 314	$ 261	$ 53	20.3%
2,500	6.2%	0.4%	388	326	62	19.0%	480	401	79	19.6%
5,000	11.5%	1.8%	571	483	88	18.1%	756	635	121	19.1%
7,500	19.2%	5.1%	752	640	113	17.6%	1,030	867	163	18.8%
10,000	32.0%	12.9%	930	793	137	17.2%	1,300	1,096	204	18.6%
12,500	45.3%	23.0%	1,107	946	160	17.0%	1,569	1,325	245	18.5%
15,000	57.0%	33.8%	1,283	1,099	184	16.8%	1,838	1,553	285	18.4%
20,000	77.7%	58.0%	1,636	1,405	231	16.5%	2,376	2,010	366	18.2%
25,000	87.7%	73.3%	1,989	1,710	279	16.3%	2,914	2,467	447	18.1%
30,000	93.8%	84.4%	2,342	2,016	326	16.2%	3,452	2,924	528	18.1%

Proposed Total Rates: includes ECA Charge and TDC Rider
Current Total Rates: includes ECA Charge, AERR and AVTS Riders



Rate Design: Residential Total Electric Class

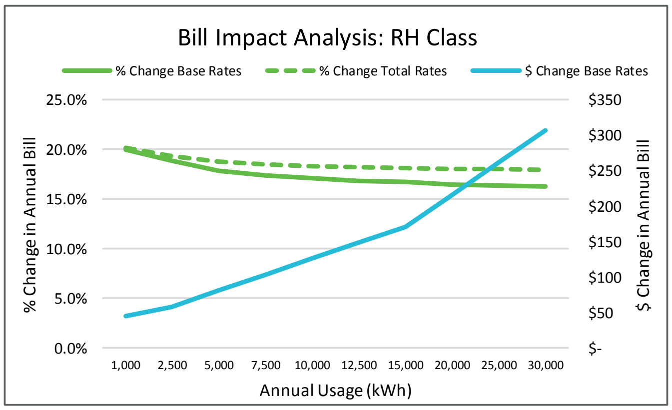
Empire District Electric (KANSAS) Residential Heating Rate Design				
Revenues				
Target Revenues		2,662,617		
Current Revenues		2,285,058		
$ Difference		377,559		
% Difference		16.5%		
		kWh Usage		
Annual Usage - First Block		34,436,656		
Annual Usage - Second Block		-		
Number of Bills		22,401		
Average Annual Use (kWh)		18,447		
Residential Heating Rate Design		**Rate**	**Units**	**Revenues**
Proposed Rates				
Customer Charge	$	17.00	22,401	$ 380,817
1st Block kWh	$	0.06626	34,436,656	2,281,800
Revenue at Proposed Rates				$ 2,662,617
Current Rates				
Customer Charge	$	14.00	22,401	$ 313,614
1st Block kWh	$	0.05723	34,436,656	1,970,810
Revenue at Current Rates				$ 2,284,424

Bill Impact: Residential Total Electric Class

Bill Impact Analysis - RH Rate										
			Annual Bill (w/o ECA, AERR, AVTS and TDC Riders)				Annual Bill (w/ ECA, AERR, AVTS and TDC Riders)			
Annual Use	Cumulative Bills	Cumulative Use	Proposed Base Rates	Current Base Rates	$ Change Base Rates	% Change Base Rates	Proposed Total Rates	Current Total Rates	$ Change Total Rates	% Change Total Rates
1,000	3.1%	0.0%	$ 270	$ 225	$ 45	20.0%	$ 307	$ 256	$ 52	20.2%
2,500	4.7%	0.2%	$ 370	$ 311	59	18.8%	462	387	75	19.3%
5,000	7.9%	0.9%	$ 535	$ 454	81	17.9%	719	606	114	18.8%
7,500	13.3%	2.6%	$ 701	$ 597	104	17.4%	977	824	152	18.5%
10,000	19.0%	5.2%	$ 867	$ 740	126	17.1%	1,234	1,043	191	18.3%
12,500	24.8%	8.7%	$ 1,032	$ 883	149	16.9%	1,492	1,262	230	18.2%
15,000	33.3%	14.8%	$ 1,198	$ 1,026	171	16.7%	1,749	1,480	269	18.2%
20,000	54.6%	34.2%	$ 1,529	$ 1,313	217	16.5%	2,264	1,918	346	18.1%
25,000	75.2%	58.2%	$ 1,861	$ 1,599	262	16.4%	2,780	2,356	424	18.0%
30,000	87.4%	75.6%	$ 2,192	$ 1,885	307	16.3%	3,294	2,793	502	18.0%

Proposed Total Rates: includes ECA Charge and TDC Rider

Current Total Rates: includes ECA Charge, AERR and AVTS Riders



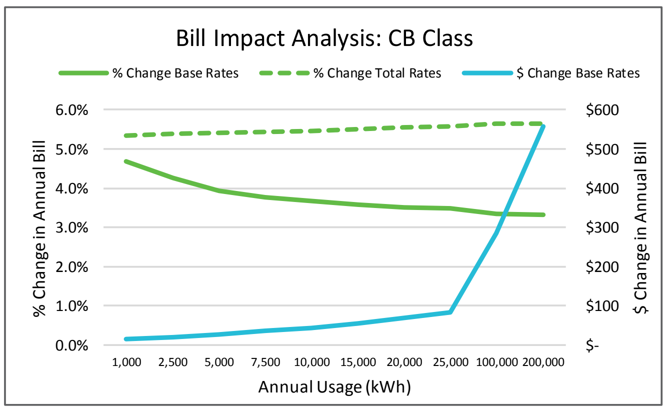
Rate Design: Commercial Class

Empire District Electric (KANSAS)			
Commercial Rate Design			
Revenues			
Target Revenues	1,912,389		
Current Revenues	1,841,135		
$ Difference	71,253		
% Difference	3.9%		
	kWh Usage		
Annual Usage - First Block	5,230,724	700	
Annual Usage - Second Block	13,200,007		
Number of Bills	14,215		
Average Annual Use (kWh)	15,559		
Commercial Rate Design	**Rate**	**Units**	**Revenues**
Proposed Rates			
Customer Charge	$ 20.00	14,215	$ 284,300
1st Block kWh	$ 0.09589	5,230,724	501,564
2nd Block kWh	$ 0.08534	13,200,007	1,126,525
Revenue at Proposed Rates			$ 1,912,389
Current Rates			
Customer Charge	$ 19.00	14,215	$ 270,085
1st Block kWh	$ 0.09284	5,230,724	485,620
2nd Block kWh	$ 0.08263	13,200,007	1,090,717
Revenue at Current Rates			$ 1,846,422

Bill Impact: Commercial Class

Bill Impact Analysis - CB Rate										
			Annual Bill (w/o ECA, AERR, AVTS and TDC Riders)				Annual Bill (w/ ECA, AERR, AVTS and TDC Riders)			
Annual Use	Cumulative Bills	Cumulative Use	Proposed Base Rates	Current Base Rates	$ Change Base Rates	% Change Base Rates	Proposed Total Rates	Current Total Rates	$ Change Total Rates	% Change Total Rates
1,000	20.0%	0.4%	$ 336	$ 321	$ 15	4.7%	$ 370	$ 351	$ 19	5.3%
2,500	31.9%	1.6%	480	460	20	4.3%	565	536	29	5.4%
5,000	45.1%	4.5%	719	692	27	3.9%	889	844	46	5.4%
7,500	53.8%	7.8%	958	923	35	3.8%	1,213	1,150	62	5.4%
10,000	62.6%	12.3%	1,182	1,140	42	3.7%	1,521	1,442	79	5.5%
15,000	69.0%	17.0%	1,609	1,553	56	3.6%	2,118	2,007	111	5.5%
20,000	74.6%	22.8%	2,035	1,966	69	3.5%	2,714	2,572	143	5.5%
25,000	79.6%	29.6%	2,462	2,380	83	3.5%	3,311	3,136	175	5.6%
100,000	97.6%	81.9%	8,863	8,577	286	3.3%	12,258	11,604	654	5.6%
200,000	99.9%	98.8%	17,397	16,840	557	3.3%	24,187	22,894	1,293	5.6%

Proposed Total Rates: includes ECA Charge and TDC Rider
Current Total Rates: includes ECA Charge, AERR and AVTS Riders



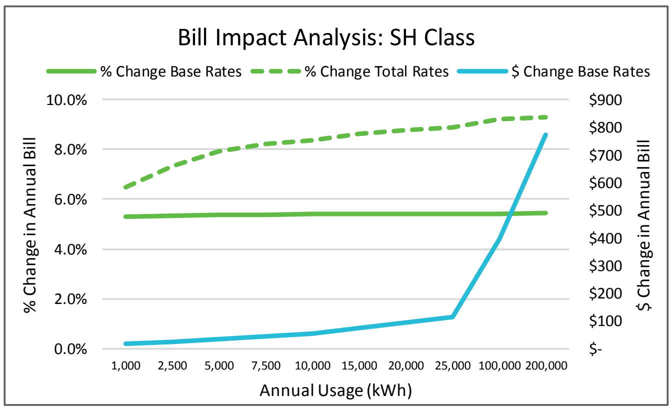
Rate Design: Small Heating Class

Empire District Electric (KANSAS)			
Small Heating Rate Design			
Revenues			
Target Revenues	239,147		
Current Revenues	226,836		
$ Difference	12,311		
% Difference	5.4%		
	kWh Usage		
Annual Usage - First Block	896,011	1000	
Annual Usage - Second Block	1,883,388		
Number of Bills	1,317		
Average Annual Use (kWh)	25,325		
Small Heating Rate Design	**Rate**	**Units**	**Revenues**
Proposed Rates			
Customer Charge	$ 20.00	1,317	$ 26,340
1st Block kWh	$ 0.08320	896,011	74,544
2nd Block kWh	$ 0.07341	1,883,388	138,263
Revenue at Proposed Rates			$ 239,147
Current Rates			
Customer Charge	$ 19.00	1,317	$ 25,023
1st Block kWh	$ 0.07891	896,011	70,704
2nd Block kWh	$ 0.06963	1,883,388	131,140
Revenue at Current Rates			$ 226,868

Bill Impact: Small Heating Class

Bill Impact Analysis - SH Rate										
			Annual Bill (w/o ECA, AERR, AVTS and TDC Riders)				Annual Bill (w/ ECA, AERR, AVTS and TDC Riders)			
Annual Use	Cumulative Bills	Cumulative Use	Proposed Base Rates	Current Base Rates	$ Change Base Rates	% Change Base Rates	Proposed Total Rates	Current Total Rates	$ Change Total Rates	% Change Total Rates
1,000	6.1%	0.0%	$ 323	$ 307	$ 16	5.3%	$ 359	$ 337	$ 22	6.5%
2,500	17.2%	0.8%	448	425	23	5.3%	538	501	37	7.3%
5,000	27.3%	2.4%	656	623	33	5.4%	835	774	61	7.9%
7,500	31.3%	3.3%	864	820	44	5.4%	1,133	1,047	86	8.2%
10,000	37.4%	5.3%	1,069	1,014	55	5.4%	1,427	1,317	110	8.4%
15,000	45.5%	9.3%	1,457	1,383	75	5.4%	1,995	1,837	158	8.6%
20,000	53.5%	14.9%	1,826	1,732	94	5.4%	2,542	2,337	205	8.8%
25,000	61.6%	21.9%	2,193	2,080	113	5.4%	3,089	2,837	252	8.9%
100,000	99.0%	95.5%	7,699	7,302	396	5.4%	11,283	10,329	953	9.2%
200,000	100.0%	100.0%	15,040	14,265	774	5.4%	22,208	20,319	1,888	9.3%

Proposed Total Rates: includes ECA Charge and TDC Rider
Current Total Rates: includes ECA Charge, AERR and AVTS Riders



Rate Design: General Power Class

Empire District Electric (KANSAS) General Power Rate Design			
Revenues			
Target Revenues	2,872,849		
Current Revenues	2,872,849		
$ Difference	-		
% Difference	0.0%		
	kWh Usage	kW Demand	
Annual Usage - First Block	38,200,653	45,372	
Annual Usage - Second Block	-	85,264	
Annual Usage - Third Block	-	4,360	
Number of Bills	1,270	1,270	
Average Annual Use	360,951	1,276	

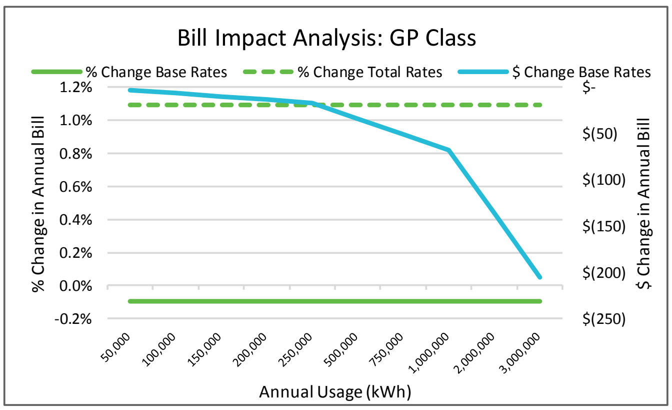
General Power Rate Design	Rate	Units	Revenues
Proposed Rates			
Customer Charge	$ -	1,270	$ -
1st Block kWh	$ 0.03397	38,200,653	1,297,613
Minimum Adjustment (Demand >= 40kW)			64,473
1st Block kW	$ 13.01	45,372	590,189
2nd Block kW	$ 10.38	85,264	885,070
3rd Block kW	$ 8.14	4,360	35,503
Revenue at Proposed Rates			$ 2,872,849
Current Rates			
Customer Charge	$ -	1,270	$ -
1st Block kWh	$ 0.03400	38,200,653	1,298,822
Minimum Adjustment (Demand >= 40kW)			64,473
1st Block kW	$ 13.02	45,372	590,739
2nd Block kW	$ 10.39	85,264	885,895
3rd Block kW	$ 8.15	4,360	35,537
Revenue at Current Rates			$ 2,875,466

Bill Impact: General Power Class

Bill Impact Analysis - GP Rate

			Annual Bill (w/o ECA, AERR, AVTS and TDC Riders)				Annual Bill (w/ ECA, AERR, AVTS and TDC Riders)			
Annual Use	Cumulative Bills	Cumulative Use	Proposed Base Rates	Current Base Rates	$ Change Base Rates	% Change Base Rates	Proposed Total Rates	Current Total Rates	$ Change Total Rates	% Change Total Rates
50,000	11.7%	0.8%	$ 3,676	$ 3,679	$ (3)	-0.1%	$ 5,249	$ 5,193	$ 57	1.1%
100,000	19.1%	2.1%	7,352	7,358	(7)	-0.1%	$ 10,499	$ 10,385	113	1.1%
150,000	34.0%	6.7%	11,027	11,038	(10)	-0.1%	$ 15,748	$ 15,578	170	1.1%
200,000	43.6%	10.9%	14,703	14,717	(14)	-0.1%	$ 20,998	$ 20,771	227	1.1%
250,000	56.4%	17.9%	18,379	18,396	(17)	-0.1%	$ 26,247	$ 25,964	283	1.1%
500,000	80.9%	38.3%	36,758	36,792	(34)	-0.1%	$ 52,494	$ 51,927	566	1.1%
750,000	87.2%	48.1%	55,137	55,189	(51)	-0.1%	$ 78,741	$ 77,891	850	1.1%
1,000,000	92.6%	58.4%	73,516	73,585	(68)	-0.1%	$ 104,988	$ 103,855	1,133	1.1%
2,000,000	95.7%	69.1%	147,033	147,170	(137)	-0.1%	$ 209,975	$ 207,710	2,266	1.1%
3,000,000	98.9%	90.9%	220,549	220,755	(205)	-0.1%	$ 314,963	$ 311,565	3,398	1.1%

Bill Impact calculated based on Average kW Demand Usage
Proposed Total Rates: includes ECA Charge and TDC Rider
Current Total Rates: includes ECA Charge, AERR and AVTS Riders



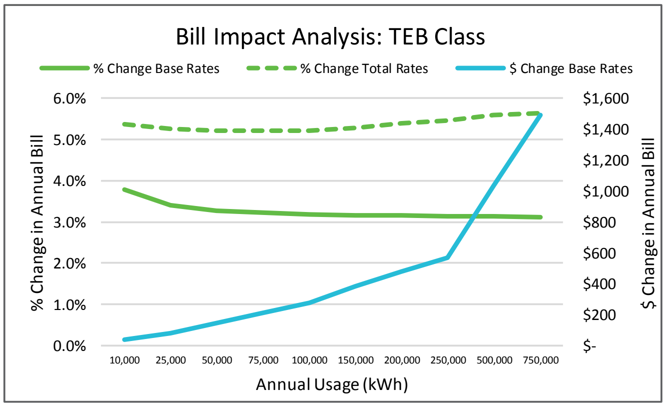
Rate Design: Total Electric Building

Empire District Electric (KANSAS)			
Total Electric Building Rate Design			
Revenues			
Target Revenues	676,969		
Current Revenues	651,774		
$ Difference	25,195		
% Difference	3.9%		
	kWh Usage		
Annual Usage - First Block	-	150	
Annual Usage - Second Block	3,493,071	10000	
Annual Usage - Third Block	5,834,828	10000+	
Number of Bills	475		
Average Annual Use (kWh)	235,652		
Total Electric Building Rate Design	**Rate**	**Units**	**Revenues**
Proposed Rates			
Customer Charge	$ 32.00	475	$ 15,200
1st Block kWh		-	-
2nd Block kWh	$ 0.08723	3,493,071	304,703
3rd Block kWh	$ 0.06120	5,834,828	357,066
Revenue at Proposed Rates			$ 676,969
Current Rates			
Customer Charge	$ 30.46	475	$ 14,469
1st Block kWh		-	-
2nd Block kWh	$ 0.08460	3,493,071	295,514
3rd Block kWh	$ 0.05935	5,834,828	346,297
Revenue at Current Rates			$ 656,279

Bill Impact: Total Electric Building

Bill Impact Analysis - TEB Rate										
			Annual Bill (w/o ECA, AERR, AVTS and TDC Riders)				Annual Bill (w/ ECA, AERR, AVTS and TDC Riders)			
Annual Use	Cumulative Bills	Cumulative Use	Proposed Base Rates	Current Base Rates	$ Change Base Rates	% Change Base Rates	Proposed Total Rates	Current Total Rates	$ Change Total Rates	% Change Total Rates
10,000	10.3%	0.1%	$ 1,099	$ 1,059	$ 40	3.8%	$ 1,435	$ 1,362	$ 73	5.4%
25,000	12.8%	0.3%	2,408	2,328	80	3.4%	3,247	3,085	163	5.3%
50,000	12.8%	0.3%	4,589	4,443	145	3.3%	6,268	5,957	311	5.2%
75,000	23.1%	2.8%	6,769	6,558	211	3.2%	9,289	8,828	460	5.2%
100,000	30.8%	5.5%	8,893	8,618	275	3.2%	12,252	11,645	607	5.2%
150,000	51.3%	16.6%	12,530	12,145	385	3.2%	17,569	16,686	883	5.3%
200,000	61.5%	23.2%	15,590	15,113	477	3.2%	22,308	21,167	1,141	5.4%
250,000	71.8%	32.2%	18,650	18,081	569	3.1%	27,048	25,648	1,399	5.5%
500,000	89.7%	57.1%	33,949	32,918	1,031	3.1%	50,744	48,053	2,691	5.6%
750,000	94.9%	68.7%	49,248	47,756	1,492	3.1%	74,440	70,458	3,982	5.7%

Proposed Total Rates: includes ECA Charge and TDC Rider
Current Total Rates: includes ECA Charge, AERR and AVTS Riders



Rate Design: Transmission Service

Empire District Electric (KANSAS)
Transmission Rate Design

Revenues			
Target Revenues	2,224,454		
Current Revenues	2,004,870		
$ Difference	219,584		
% Difference	11.0%		
	kWh Usage	kW Demand	
Annual Usage - First Block	48,142,857	-	
Annual Usage - Second Block	-	51,788	
Number of Bills	60	60	
Average Annual Use	9,628,571	10,358	

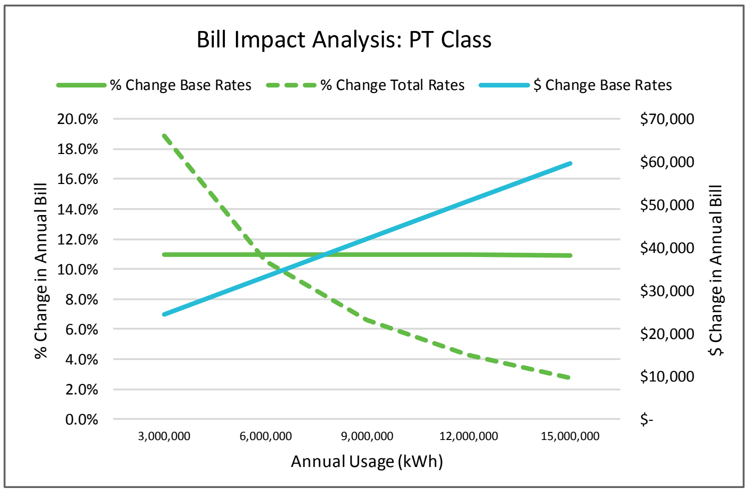
Transmission Rate Design	Rate	Units	Revenues
Proposed Rates			
Minimum Demand Charge (<1,000 kW)	$ 13,158.00	60	$ 789,480
1st Block kWh	$ 0.02311	48,142,857	1,112,630
1st Block kW			
2nd Block kW	$ 6.22	51,788	322,344
Revenue at Proposed Rates			$ 2,224,454
Current Rates			
Minimum Demand Charge (<1,000 kW)	$ 11,858.75	60	$ 711,525
1st Block kWh	$ 0.02083	48,142,857	1,002,816
1st Block kW			
2nd Block kW	$ 5.61	51,788	290,529
Revenue at Current Rates			$ 2,004,870

Bill Impact: Transmission Service

Bill Impact Analysis - PT Rate

			Annual Bill (w/o ECA, AERR, AVTS and TDC Riders)				Annual Bill (w/ ECA, AERR, AVTS and TDC Riders)			
Annual Use	Cumulative Bills	Cumulative Use	Proposed Base Rates	Current Base Rates	$ Change Base Rates	% Change Base Rates	Proposed Total Rates	Current Total Rates	$ Change Total Rates	% Change Total Rates
3,000,000	25.0%	9.5%	$ 247,316	$ 222,899	$ 24,417	11.0%	$ 372,851	$ 313,709	$ 59,141	18.9%
6,000,000	50.0%	25.7%	$ 336,735	$ 303,493	33,242	11.0%	$ 536,348	$ 485,113	51,235	10.6%
9,000,000	75.0%	50.3%	$ 426,155	$ 384,088	42,068	11.0%	$ 699,846	$ 656,518	43,329	6.6%
12,000,000	75.0%	50.3%	$ 515,575	$ 464,682	50,893	11.0%	$ 863,344	$ 827,922	35,422	4.3%
15,000,000	100.0%	100.0%	$ 604,995	$ 545,276	59,719	11.0%	$ 1,026,842	$ 999,326	27,516	2.8%

Bill Impact calculated based on Average kW Demand Usage
Proposed Total Rates: includes ECA Charge and TDC Rider
Current Total Rates: includes ECA Charge, AERR and AVTS Riders



Rate Design: Municipal Street Lighting

Empire District Electric (KANSAS)				
Street Lighting Rate Design				
Revenues				
Target Revenues	150,398			
Current Revenues	122,320			
$ Difference	28,078			
% Difference	23.0%			
	kWh Usage			
Annual Usage - First Block	1,554,951			
Annual Usage - Second Block	-			
Annual Usage - Third Block	-			
Number of Bills	-			
Average Annual Use (kWh)				
Street Lighting - SPL Rate Design	**Current Charge Per Lamp**	**Proposed Increase %**	**Proposed Charge Per Lamp**	**Average Monthly kWh**
Facilities Charges				
Mercury Vapor Lamp Sizes				
7,000 Lumen Mercury	$ 140.74	23.0%	$ 173.05	175
11,000 Lumen Mercury	164.58	23.0%	202.36	200
20,000 Lumen Mercury	234.29	23.0%	288.07	400
53,000 Lumen Mercury	381.58	23.0%	469.17	1,000
High Pressure Sodium Vapor Lamp Sizes				
6,000 Lumen HP Sodium	133.00	23.0%	163.53	70
16,000 Lumen HP Sodium	167.53	23.0%	205.99	150
27,500 Lumen HP Sodium	207.95	23.0%	255.68	250
50,000 Lumen HP Sodium	305.76	23.0%	375.95	400
130,000 Lumen HP Sodium	477.89	23.0%	587.59	1,000

Rate Design: Private Lighting

Empire District Electric (KANSAS) Private Lighting Rate Design				
Revenues				
Target Revenues	398,294			
Current Revenues	398,294			
$ Difference	-			
% Difference	0.0%			
	kWh Usage			
Annual Usage - First Block	1,462,318			
Annual Usage - Second Block	-			
Annual Usage - Third Block	-			
Number of Bills	393			
Average Annual Use (kWh)	44,651			

Private Lighting - PL Rate Design	Current Charge Per Lamp	Proposed Increase %	Proposed Charge Per Lamp	Average Monthly kWh
Installation Charge: Standard Street Lighting				
Mercury Vapor Lamp Sizes				
6,800 Lumen Std Mercury	$ 12.94	0.0%	$ 12.94	65
20,000 Lumen Std Mercury	19.76	0.0%	19.76	156
54,000 Lumen Std Mercury	35.79	0.0%	35.79	373
Sodium Vapor Lamp Sizes				
6,000 Lumen Std Sodium	12.15	0.0%	12.15	31
16,000 Lumen Std Sodium	17.42	0.0%	17.42	58
50,000 Lumen Std Sodium	26.77	0.0%	26.77	157
Metal Halide Lamp Sizes				
12,000 Lumen Std MetalH	36.31	0.0%	36.31	71
20,500 Lumen Std MetalH	26.25	0.0%	26.25	101
36,000 Lumen Std MetalH	28.33	0.0%	28.33	153
Installation Charge: Standard Flood Lighting				
Mercury Vapor Lamp Sizes				
20,000 Lumen Mercury FL	29.84	0.0%	29.84	156
54,000 Lumen Mercury FL	45.87	0.0%	45.87	373
Sodium Vapor Lamp Sizes				
27,500 Lumen Sodium FL	29.47	0.0%	29.47	106
50,000 Lumen Sodium FL	39.52	0.0%	39.52	157
140,000 Lumen Sodium FL	55.22	0.0%	55.22	359
Metal Halide Lamp Sizes				
12,000 Lumen MetalH FL	53.36	0.0%	53.36	71
36,000 Lumen MetalH FL	39.67	0.0%	39.67	153
110,000 Lumen MetalH FL	54.16	0.0%	54.16	364
Total Installation Charge Revenue				
Additional Charges				
Conductor	0.01964	0.0%	0.01964	
Pole	1.79	0.0%	1.79	
Anchor	1.79	0.0%	1.79	

Rate Design: Special Lighting

Empire District Electric (KANSAS)			
Special Lighting Rate Design			
Revenues			
Target Revenues	21,621		
Current Revenues	18,533		
$ Difference	3,088		
% Difference	16.7%		
	kWh Usage		
Annual Usage - First Block	78,091	1000	
Annual Usage - Second Block	75,916		
	-		
Number of Bills	222		
Average Annual Use (kWh)	8,325		
Special Lighting Rate Design	**Rate**	**Units**	**Revenues**
Proposed Rates			
Customer Charge	$ -	222	$ -
1st Block kWh	$0.16158	78,091	12,618
2nd Block kWh	$0.11859	75,916	9,003
Revenue at Proposed Rates			$ 21,621
Current Rates			
Customer Charge	$ -	222	$ -
1st Block kWh	$0.13080	78,091	10,214
2nd Block kWh	$0.09600	75,916	7,288
Revenue at Current Rates			$ 17,502

Detailed Bill Impact: Residential General Service

		Monthly Bills at Usage Levels				
Bill Impact: Residential General Service	**Rates**	**500**	**1,000**	**1,500**	**2,000**	**2,500**
Bill Impacts						
Proposed Bill		$ 75.1	$ 129.9	$ 183.7	$ 237.5	$ 291.4
Current Bill		$ 63.4	$ 109.9	$ 155.6	$ 201.3	$ 247.0
Bill Impact $		$ 11.7	$ 20.0	$ 28.1	$ 36.3	$ 44.4
Bill Impact %		18.5%	18.2%	18.1%	18.0%	18.0%
Proposed Base Rates						
Customer Charge	17.00	$ 17.0	$ 17.0	$ 17.0	$ 17.0	$ 17.0
1st Block kWh	$0.07920	$ 39.6	$ 47.5	$ 47.5	$ 47.5	$ 47.5
2nd Block kWh	$0.07058	$ -	$ 28.2	$ 63.5	$ 98.8	$ 134.1
Proposed Riders						
ECA - Energy Cost Adjustment	$0.02008	$ 10.0	$ 20.1	$ 30.1	$ 40.2	$ 50.2
AERR - Asbury Environmental and Riverton		$ -	$ -	$ -	$ -	$ -
AVTS - Ad Valorem Tax Surcharge Rider		$ -	$ -	$ -	$ -	$ -
TDC - Transmission Delivery Charge	$0.01702	$ 8.5	$ 17.0	$ 25.5	$ 34.0	$ 42.6
Current Base Rates						
Customer Charge	14.00	$ 14.0	$ 14.0	$ 14.0	$ 14.0	$ 14.0
1st Block kWh	$0.06858	$ 34.3	$ 41.1	$ 41.1	$ 41.1	$ 41.1
2nd Block kWh	$0.06112	$ -	$ 24.4	$ 55.0	$ 85.6	$ 116.1
Current Riders						
ECA - Energy Cost Adjustment	$0.02008	$ 10.0	$ 20.1	$ 30.1	$ 40.2	$ 50.2
AERR - Asbury Environmental and Riverton	$0.00798	$ 4.0	$ 8.0	$ 12.0	$ 16.0	$ 20.0
AVTS - Ad Valorem Tax Surcharge Rider	$0.00221	$ 1.1	$ 2.2	$ 3.3	$ 4.4	$ 5.5
TDC - Transmission Delivery Charge		$ -	$ -	$ -	$ -	$ -

* Green highlighted represents approximate average class usage

Detailed Bill Impact: Residential Water Service

		Monthly Bills at Usage Levels				
Bill Impact: Residential General Water	**Rates**	**500**	**1,000**	**1,500**	**2,000**	**2,500**
Bill Impacts						
Proposed Bill		$ 72.2	$ 126.3	$ 180.1	$ 233.9	$ 287.7
Current Bill		$ 60.7	$ 106.6	$ 152.3	$ 198.0	$ 243.7
Bill Impact $		$ 11.5	$ 19.7	$ 27.8	$ 35.9	$ 44.0
Bill Impact %		19.0%	18.5%	18.3%	18.1%	18.1%
Proposed Base Rates						
Customer Charge	17.00	$ 17.0	$ 17.0	$ 17.0	$ 17.0	$ 17.0
1st Block kWh	$0.07341	$ 36.7	$ 44.0	$ 44.0	$ 44.0	$ 44.0
2nd Block kWh	$0.07058	$ -	$ 28.2	$ 63.5	$ 98.8	$ 134.1
Proposed Riders						
ECA - Energy Cost Adjustment	$0.02008	$ 10.0	$ 20.1	$ 30.1	$ 40.2	$ 50.2
AERR - Asbury Environmental and Riverton		$ -	$ -	$ -	$ -	$ -
AVTS - Ad Valorem Tax Surcharge Rider		$ -	$ -	$ -	$ -	$ -
TDC - Transmission Delivery Charge	$0.01692	$ 8.5	$ 16.9	$ 25.4	$ 33.8	$ 42.3
Current Base Rates						
Customer Charge	14.00	$ 14.0	$ 14.0	$ 14.0	$ 14.0	$ 14.0
1st Block kWh	$0.06309	$ 31.5	$ 37.9	$ 37.9	$ 37.9	$ 37.9
2nd Block kWh	$0.06112	$ -	$ 24.4	$ 55.0	$ 85.6	$ 116.1
Current Riders						
ECA - Energy Cost Adjustment	$0.02008	$ 10.0	$ 20.1	$ 30.1	$ 40.2	$ 50.2
AERR - Asbury Environmental and Riverton	$0.00798	$ 4.0	$ 8.0	$ 12.0	$ 16.0	$ 20.0
AVTS - Ad Valorem Tax Surcharge Rider	$0.00221	$ 1.1	$ 2.2	$ 3.3	$ 4.4	$ 5.5
TDC - Transmission Delivery Charge		$ -	$ -	$ -	$ -	$ -

* Green highlighted represents approximate average class usage

Detailed Bill Impact: Residential Total Electric Service

		Monthly Bills at Usage Levels								
Bill Impact: Residential Total Electric	Rates		500		1,000		1,500		2,000		2,500
Bill Impacts											
Proposed Bill		$	68.5	$	120.0	$	171.5	$	223.0	$	274.6
Current Bill		$	57.8	$	101.5	$	145.3	$	189.0	$	232.8
Bill Impact $		$	10.8	$	18.5	$	26.3	$	34.0	$	41.8
Bill Impact %			18.6%		18.2%		18.1%		18.0%		18.0%
Proposed Base Rates											
Customer Charge	17.00	$	17.0	$	17.0	$	17.0	$	17.0	$	17.0
1st Block kWh	$0.06626	$	33.1	$	66.3	$	99.4	$	132.5	$	165.7
Proposed Riders											
ECA - Energy Cost Adjustment	$0.02008	$	10.0	$	20.1	$	30.1	$	40.2	$	50.2
AERR - Asbury Environmental and Riverton		$	-	$	-	$	-	$	-	$	-
AVTS - Ad Valorem Tax Surcharge Rider		$	-	$	-	$	-	$	-	$	-
TDC - Transmission Delivery Charge	$0.01668	$	8.3	$	16.7	$	25.0	$	33.4	$	41.7
Current Base Rates											
Customer Charge	14.00	$	14.0	$	14.0	$	14.0	$	14.0	$	14.0
1st Block kWh	$0.05723	$	28.6	$	57.2	$	85.8	$	114.5	$	143.1
Current Riders											
ECA - Energy Cost Adjustment	$0.02008	$	10.0	$	20.1	$	30.1	$	40.2	$	50.2
AERR - Asbury Environmental and Riverton	$0.00798	$	4.0	$	8.0	$	12.0	$	16.0	$	20.0
AVTS - Ad Valorem Tax Surcharge Rider	$0.00221	$	1.1	$	2.2	$	3.3	$	4.4	$	5.5
TDC - Transmission Delivery Charge		$	-	$	-	$	-	$	-	$	-

* Green highlighted represents approximate average class usage

Detailed Bill Impact: Commercial Service

		Monthly Bills at Usage Levels				
Bill Impact: Commercial	**Rates**	**650**	**1,300**	**2,500**	**5,000**	**10,000**
Bill Impacts						
Proposed Bill		$ 104.4	$ 182.5	$ 325.6	$ 623.8	$ 1,220.3
Current Bill		$ 99.0	$ 172.9	$ 308.4	$ 590.6	$ 1,155.1
Bill Impact $		$ 5.4	$ 9.5	$ 17.2	$ 33.2	$ 65.2
Bill Impact %		5.4%	5.5%	5.6%	5.6%	5.6%
Proposed Base Rates						
Customer Charge	20.00	$ 20.0	$ 20.0	$ 20.0	$ 20.0	$ 20.0
1st Block kWh	$0.09589	$ 62.3	$ 67.1	$ 67.1	$ 67.1	$ 67.1
2nd Block kWh	$0.08534	$ -	$ 51.2	$ 153.6	$ 367.0	$ 793.7
Proposed Riders						
ECA - Energy Cost Adjustment	$0.02008	$ 13.1	$ 26.1	$ 50.2	$ 100.4	$ 200.8
AERR - Asbury Environmental and Riverton		$ -	$ -	$ -	$ -	$ -
AVTS - Ad Valorem Tax Surcharge Rider		$ -	$ -	$ -	$ -	$ -
TDC - Transmission Delivery Charge	$0.01387	$ 9.0	$ 18.0	$ 34.7	$ 69.4	$ 138.7
Current Base Rates						
Customer Charge	19.00	$ 19.0	$ 19.0	$ 19.0	$ 19.0	$ 19.0
1st Block kWh	$0.09284	$ 60.3	$ 65.0	$ 65.0	$ 65.0	$ 65.0
2nd Block kWh	$0.08263	$ -	$ 49.6	$ 148.7	$ 355.3	$ 768.5
Current Riders						
ECA - Energy Cost Adjustment	$0.02008	$ 13.1	$ 26.1	$ 50.2	$ 100.4	$ 200.8
AERR - Asbury Environmental and Riverton	$0.00798	$ 5.2	$ 10.4	$ 20.0	$ 39.9	$ 79.8
AVTS - Ad Valorem Tax Surcharge Rider	$0.00221	$ 1.4	$ 2.9	$ 5.5	$ 11.1	$ 22.1
TDC - Transmission Delivery Charge		$ -	$ -	$ -	$ -	$ -

* Green highlighted represents approximate average class usage

Detailed Bill Impact: Small Heating Service

Bill Impact: Small Heating	Rates	500	1,000	2,000	5,000	10,000
		Monthly Bills at Usage Levels				
Bill Impacts						
Proposed Bill		$ 79.5	$ 139.0	$ 248.3	$ 576.0	$ 1,122.3
Current Bill		$ 73.6	$ 128.2	$ 228.1	$ 527.8	$ 1,027.3
Bill Impact $		$ 5.9	$ 10.9	$ 20.2	$ 48.3	$ 95.0
Bill Impact %		8.1%	8.5%	8.9%	9.1%	9.2%
Proposed Base Rates						
Customer Charge	20.00	$ 20.0	$ 20.0	$ 20.0	$ 20.0	$ 20.0
1st Block kWh	$0.08320	$ 41.6	$ 83.2	$ 83.2	$ 83.2	$ 83.2
2nd Block kWh	$0.07341	$ -	$ -	$ 73.4	$ 293.6	$ 660.7
Proposed Riders						
ECA - Energy Cost Adjustment	$0.02008	$ 10.0	$ 20.1	$ 40.2	$ 100.4	$ 200.8
AERR - Asbury Environmental and Riverton		$ -	$ -	$ -	$ -	$ -
AVTS - Ad Valorem Tax Surcharge Rider		$ -	$ -	$ -	$ -	$ -
TDC - Transmission Delivery Charge	$0.01576	$ 7.9	$ 15.8	$ 31.5	$ 78.8	$ 157.6
Current Base Rates						
Customer Charge	19.00	$ 19.0	$ 19.0	$ 19.0	$ 19.0	$ 19.0
1st Block kWh	$0.07891	$ 39.5	$ 78.9	$ 78.9	$ 78.9	$ 78.9
2nd Block kWh	$0.06963	$ -	$ -	$ 69.6	$ 278.5	$ 626.7
Current Riders						
ECA - Energy Cost Adjustment	$0.02008	$ 10.0	$ 20.1	$ 40.2	$ 100.4	$ 200.8
AERR - Asbury Environmental and Riverton	$0.00798	$ 4.0	$ 8.0	$ 16.0	$ 39.9	$ 79.8
AVTS - Ad Valorem Tax Surcharge Rider	$0.00221	$ 1.1	$ 2.2	$ 4.4	$ 11.1	$ 22.1
TDC - Transmission Delivery Charge		$ -	$ -	$ -	$ -	$ -

* Green highlighted represents approximate average class usage

REVENUE STABILIZATION RIDER

PURPOSE

The purpose of this Rider is to stabilize customer bills and the Company's recovery of revenue requirements approved by the Commission in the most recent rate proceeding,

APPLICABILITY

This Rider is applicable to all customers served under Schedules Residential General (RG), Residential Heating (RH), Small Commercial Building Service (SH), and Small Commercial Total Electric Service (TEB). A separate adjustment shall be calculated for each applicable Schedule, expressed in cents per kWh.

The Revenue Stabilization adjustment shall be computed monthly for application on customer bills in the second succeeding month. It shall consist of a factor designed to reflect differences between actual base rate revenues and authorized base rate revenues approved in the most recent rate proceeding, plus a factor designed to reconcile prior period Revenue Stabilization adjustments.

The Revenue Stabilization adjustment can be a credit or charge that is applied to monthly bills. The Revenue Stabilization adjustment shall be combined with the Base Rates of the associated rate class and applied to customer bills.

CALCULATION OF REVENUE STABILIZATION ADJUSTMENT

The Revenue Stabilization adjustment shall be computed monthly by dividing the difference between the actual monthly revenue and authorized base rate revenues approved in the most recent rate proceeding by the forecast kWh sales for the applicable rate class for the second succeeding month. Authorized base rate revenues is defined as the base rate revenues approved by the Commission in the most recent rate proceeding.

$$RSA = \left\lfloor \frac{A - B + C}{D} \right\rfloor$$

where:

RSA = The monthly Revenue Stabilization adjustment factor for the rate class in $ per kWh
A = Actual Base Rate Revenues for the class
B = Authorized Base Rate Revenues for the class

C = Cumulative true-up for over/under-collection
D = Forecast kWh sales for the second succeeding month for the rate class

DEFINITIONS

"*Actual Base Rate Revenues*" represents the dollar amount of revenues by rate class arising from the base rates approved by the Commission in the most recent rate proceeding.

"*Authorized Base Rate Revenues*" represents the dollar amount of revenues by rate class approved by the Commission in the most recent rate proceeding.

"*Forecast kWh Sales*" represents the recovery period for the Revenue Stabilization adjustment as the forecast kWh sales for the second succeeding month

FILING

The Company shall file monthly with the Commission the Revenue Stabilization factors by rate class at least ten days prior to application on customer bills. The Company shall provide Commission Staff workpapers sufficient to review and audit the factors.

CAPITAL TRACKER RIDER

APPLICATION:

To all bills rendered by the Company for utility service, permitting the recovery of such cost.

TERM:

This Capital Tracker will have a term beginning with the effective date of a Commission Order approving this Capital Tracker and ending with the rate effective date of the next general rate case, unless extended by the State Corporation Commission of Kansas ("Commission").

The Company will collect from customers as an adjustment to the aforementioned bills, an additional charge equal to the annual capital investment-related revenue requirements associated with investments qualified under this Capital Tracker ("Qualified Investments"). Qualified Investments include: (1) Grid Resiliency investments; (2) generation capacity; and (3) Other investments.

The calculation of such revenue requirements will be made in conformity with the formula stated in this Capital Tracker, and will not change absent Commission approval.

The Company shall provide periodic reports to the Commission of its collections including a calculation of the total collected under this Rider.

METHOD OF BILLING:

The additional charge shall be collected by applying the Capital Tracker charge to each applicable customer's bill. The Capital Tracker charges shall be based on the following method:

1. The Capital Tracker revenue requirement shall be allocated to each rate class consistent with the applicable cost allocator approved in the most recent rate proceeding. E.g., production-related investments costs shall be allocated based on the production plant allocator.
2. The Capital Tracker charges for each rate class shall be determined by dividing the Capital Tracker revenue requirements by the applicable billing units. The General

Power and Transmission rate class shall be billed on a per kW basis, all other class shall be billed on a per kWh basis.

BASIS FOR DETERMINING THE CAPITAL TRACKER CHARGES:

The monthly charge shall reflect the recovery of the Capital Tracker revenue requirement as approved by the Commission. The Capital Tracker charge shall be implemented on an interim basis subject to refund and shall remain fixed until otherwise ordered by the Commission.

ANNUAL TRUE-UP:

The revenue collected pursuant to the application of this Capital Tracker shall be compared to the estimated revenue approved for collection by the Commission on an annualized basis. The amount of any over (under) recovery shall be included in any refund calculation that may result from the re-calculation of the revenue requirement to take place during Empire's next rate case.

INTERIM SUBJECT TO REFUND:

The revenue collected pursuant to this Capital Tracker, as approved by the Commission, shall be collected on an interim basis, subject to refund. For purposes of determining whether a refund is necessary, each component of the Capital Tracker revenue requirement will be determined by the Commission during Empire's next general rate case. The Capital Tracker revenue requirement will then be compared against the Capital Tracker revenue requirement approved by the Commission. If the Capital Tracker revenue requirement calculated by the Commission in Empire's next general rate case is less than the Capital Tracker revenue requirement approved by the Commission, then Empire shall refund the difference through a bill credit. The refund rates (bill credits) shall be distributed to customers in the same fashion as the original Capital Tracker rates contained in this tariff.

The components of the Capital Tracker revenue requirement shall include the following:

Revenue requirements for Capital Tracker = (RB x r) + D + OM

Where:

RB = the rate base investment associated with the Capital Tracker. Rate base will consist of all prudently incurred gross plant investment associated with the Capital Tracker, less Accumulated Depreciation associated with the Capital

Tracker, less any applicable Accumulated Deferred Income Taxes directly associated with the Capital Tracker.

r = the pretax rate of return approved by the Commission in the Company's most recent rate proceeding, unless otherwise approved by the Commission.

D = the Depreciation Expense, calculated using depreciation rates approved by the Commission in the Company's most recent rate proceeding, and the Commission approved Gross Plant component of A- Rate Base described above.

OM = Incremental O&M expenses associated with the investments recovered through the Capital Tracker.

BILLING ADJUSTMENT FACTORS:

The following charges are applied to a customer's monthly energy of each rate schedule as indicated. The amount determined by the application of such unit adjustment shall become a part of the total bill for electric service furnished and will be itemized separately on customer's bill.

DEFINITIONS AND CONDITIONS:

The Company for the purposes of this rate schedule is defined as The Empire District Electric Company.

Empire District Electric Company
Lead-Lag Study Ending June 30, 2018
Cash Working Capital Requirement
Summary

Line	Description	Revenue Requirement Amount	Average Daily Amount	Revenue Lag	Ref.	Expense Lag	Ref.	Net Lead / (Lag) Days	Working Capital Requirement
1	Purchased Fuel and Power Expenses	$ 5,885,048	16,123	43.40	A	(31.13)	B	12.27	$ 197,834
	Operation and Maintenance Expenses								
2	O&M, Labor	$ 2,096,977	5,745	43.40	A	(12.00)	C	31.40	$ 180,397
3	Pension Benefits (401K)	851,845	2,334	43.40	A	(12.00)	C	31.40	73,282
4	Post Retirement Benefits	124,560	341	43.40	A	(5.66)	C	37.74	12,879
5	Medical, Vision, and Dental Expenses	343,299	941	43.40	A	(16.29)	C	27.11	25,498
6	Life Insurance / AD&D	11,001	30	43.40	A	(16.34)	C	27.06	816
7	Intercompany Transfers	437,702	1,199	43.40	A	(35.13)	C	8.27	9,917
8	PSC Assessment	112,594	308	43.40	A	17.23	C	60.63	18,703
9	O&M, Other Non-Labor	5,044,504	13,821	43.40	A	(29.21)	C	14.19	196,114
10	Total O&M Expenses	$ 9,022,481							$ 517,606
	Taxes Other Than Income Taxes								
11	Property Taxes	$ 971,003	2,660	43.40	A	(195.13)	E	(151.73)	$ (403,645)
12	Payroll Taxes	137,494	377	43.40	A	(11.17)	E	32.23	12,141
13	Total Taxes Other Than Income Taxes	$ 1,108,497							$ (391,504)
14	Federal Income Tax	$ 625,083	1,713	43.40	A	(37.00)	D-1	6.40	$ 10,960
15	State Income Tax	267,115	732	43.40	A	(37.00)	D-2	6.40	4,684
16	Interest Payments	1,449,491	3,971	43.40	A	(91.26)	F	(47.86)	(190,062)
17	Sales and Use Taxes	-	-	43.40	A	(29.20)	G	14.20	-
18	Total	$ 18,357,715	50,295						$ 149,519

Empire District Electric Company
Lead-Lag Study Ending June 30, 2018
Revenue and Collection Lag

Revenue Lag

Line	Description	Revenue Lag	Reference
1	Service Lag	(15.21)	
2	Billing Lag	(5.20)	WP (A)
3	Collection Lag	(22.99)	WP (A)
4	Composite Revenue Lag	(43.40)	

Empire District Electric Company
Lead-Lag Study Ending June 30, 2018
Purchased Fuel and Power

Line	Description	Amount	Lead / (Lag) Days	Reference	Weighted Dollar Amount
1	Purchased Fuel and Power				
2	Coal	$ 42,982,825	(11.78)	B-1	$ (506,228,571)
3	Natural Gas	65,787,361	(38.95)	B-2	(2,562,270,761)
4	Fuel Oil and Tires	3,002,351	(13.49)	B-3	(40,487,578)
5	Power	103,834,870	(34.71)	B-4	(3,603,673,324)
6	Total Purchased Fuel and Power Expenses	$ 215,607,407	(31.13)		$ (6,712,660,234)

Empire District Electric Company
Lead-Lag Study Ending June 30, 2018
O&M Expenses

Line	Description	Lead / (Lag) Days	Reference
1	Operation and Maintenance Expenses		
2	O&M, Labor	(12.00)	C-1
3	Pension Benefits (401K)	(12.00)	C-2
4	Post Retirement Benefits	(5.66)	C-3
5	Medical, Vision, and Dental Expenses	(16.29)	C-4
6	Life Insurance / AD&D	(16.34)	C-5
7	Intercompany Transfers	(35.13)	C-6
8	PSC Assessment	17.23	C-7
9	O&M, Other Non-Labor	(29.21)	C-8
10	Total O&M Expenses		

Empire District Electric Company
Lead-Lag Study Ending June 30, 2018
Federal Income Taxes

Line	Description	Service Period Start	Service Period End	Midpoint of Service Period	Payment Date	Percent of Taxes Due	Lead / (Lag) Days: Days from Midpoint to Payment Date	Lead / (Lag) Days: Lead / (Lag) Days
1	Third Quarter	1/1/2017	12/31/2017	(182.50)	9/15/2017	25.0%	(75.5)	(18.9)
2	Fourth Quarter	1/1/2017	12/31/2017	(182.50)	12/15/2017	25.0%	(166.5)	(41.6)
3	First Quarter	1/1/2018	12/31/2018	(182.50)	4/15/2018	25.0%	77.5	19.4
4	Second Quarter	1/1/2018	12/31/2018	(182.50)	6/15/2018	25.0%	16.5	4.1
5	Federal Income Tax Lead / (Lag) Days							(37.0)

Empire District Electric Company
Lead-Lag Study Ending June 30, 2018
State Income Taxes

							Lead / (Lag) Days	
Line	Description	Service Period Start	Service Period End	Midpoint of Service Period	Payment Date	Percent of Taxes Due	Days from Midpoint to Payment Date	Lead / (Lag) Days
1	Third Quarter	1/1/2017	12/31/2017	(182.50)	9/15/2017	25.0%	(75.5)	(18.9)
2	Fourth Quarter	1/1/2017	12/31/2017	(182.50)	12/15/2017	25.0%	(166.5)	(41.6)
3	First Quarter	1/1/2018	12/31/2018	(182.50)	4/15/2018	25.0%	77.5	19.4
4	Second Quarter	1/1/2018	12/31/2018	(182.50)	6/15/2018	25.0%	16.5	4.1
5	State Income Tax Lead / (Lag) Days							(37.0)

Empire District Electric Company
Lead-Lag Study Ending June 30, 2018
Taxes Other Than Income Taxes

Line	Description	Amount	Lead / (Lag) Days	Reference	Weighted Dollar Amount
1	Payroll Taxes				
2	FICA	$ 22,335,685	(11.0)	E-1	$ (245,692,540)
3	Federal Income Taxes Withheld	20,164,615	(11.0)	E-2	(221,810,761)
4	State Income Taxes Withheld	340,877	(11.0)	E-3	(3,749,649)
5	Federal Unemployment	83,680	(75.2)	E-4	(6,291,250)
6	State Unemployment	32,388	(75.2)	E-5	(2,434,444)
7	Total Payroll Taxes	$ 42,957,245	(11.2)		(479,978,644)
8	Property Taxes	$ 22,767,628	(195.1)	E-6	(4,442,535,712)
9	Total Taxes Other Than Income Taxes	$ 65,724,873	(74.9)		(4,922,514,356)

Empire District Electric Company
Lead-Lag Study Ending June 30, 2018
Interest Expense Payment

Line	Description	Service Period Start	Service Period End	Midpoint of Service Period	Payment Date	Cleared Check Dt	Amount	Check Lag	Payment Lag	Lead / (Lag) Days	Weighted Dollar Amount	Composite Lead / (Lag) Days
1	Bank Of New York	2/22/2017	8/21/2017	(90.5)	8/21/2017	8/21/2017	$ 1,077,000	0.0	(90.5)	(90.5)	$ (97,468,500)	
2	Bank Of New York	3/2/2017	9/1/2017	(92.0)	9/1/2017	9/1/2017	1,300,000	0.0	(92.0)	(92.0)	(119,600,000)	
3	Bank Of New York	4/3/2017	10/2/2017	(91.5)	10/2/2017	10/2/2017	1,575,200	0.0	(91.5)	(91.5)	(144,130,800)	
4	Bank Of New York	4/3/2017	10/2/2017	(91.5)	10/2/2017	10/2/2017	2,350,000	0.0	(91.5)	(91.5)	(215,025,000)	
5	Wells Fargo Bank, N.A.	5/16/2017	11/15/2017	(92.0)	11/15/2017	11/15/2017	2,077,000	0.0	(92.0)	(92.0)	(191,084,000)	
6	Bank Of New York	5/31/2017	11/30/2017	(92.0)	11/30/2017	11/30/2017	559,500	0.0	(92.0)	(92.0)	(51,474,000)	
7	Bank Of New York	5/31/2017	11/30/2017	(92.0)	11/30/2017	11/30/2017	2,592,000	0.0	(92.0)	(92.0)	(238,464,000)	
8	Bank Of New York	6/2/2017	12/1/2017	(91.5)	12/1/2017	12/1/2017	1,281,000	0.0	(91.5)	(91.5)	(117,211,500)	
9	Bank Of New York	6/2/2017	12/1/2017	(91.5)	12/1/2017	12/1/2017	2,325,000	0.0	(91.5)	(91.5)	(212,737,500)	
10	Bank Of New York	6/2/2017	12/1/2017	(91.5)	12/1/2017	12/1/2017	2,868,750	0.0	(91.5)	(91.5)	(262,490,625)	
11	Wells Fargo Bank, N.A.	7/3/2017	1/2/2018	(92.0)	1/2/2018	1/2/2018	1,160,000	0.0	(92.0)	(92.0)	(106,720,000)	
12	Bank Of New York	8/21/2017	2/20/2018	(92.0)	2/20/2018	2/20/2018	1,077,000	0.0	(92.0)	(92.0)	(99,084,000)	
13	Bank Of New York	9/2/2017	3/1/2018	(90.5)	3/1/2018	3/1/2018	1,300,000	0.0	(90.5)	(90.5)	(117,650,000)	
14	Bank Of New York	10/3/2017	4/2/2018	(91.0)	4/2/2018	4/2/2018	1,575,200	0.0	(91.0)	(91.0)	(143,343,200)	
15	Bank Of New York	10/3/2017	4/2/2018	(91.0)	4/2/2018	4/2/2018	2,350,000	0.0	(91.0)	(91.0)	(213,850,000)	
16	Wells Fargo Bank, N.A.	11/16/2017	5/15/2018	(90.5)	5/15/2018	5/15/2018	2,077,000	0.0	(90.5)	(90.5)	(187,968,500)	
17	Bank Of New York	12/1/2017	5/30/2018	(90.5)	5/30/2018	5/30/2018	559,500	0.0	(90.5)	(90.5)	(50,634,750)	
18	Bank Of New York	12/1/2017	5/30/2018	(90.5)	5/30/2018	5/30/2018	2,592,000	0.0	(90.5)	(90.5)	(234,576,000)	
19	Bank Of New York	12/2/2017	6/1/2018	(91.0)	6/1/2018	6/1/2018	1,281,000	0.0	(91.0)	(91.0)	(116,571,000)	
20	Bank Of New York	12/2/2017	6/1/2018	(91.0)	6/1/2018	6/1/2018	1,875,500	0.0	(91.0)	(91.0)	(170,670,500)	
21	Bank Of New York	12/2/2017	6/1/2018	(91.0)	6/1/2018	6/1/2018	2,325,000	0.0	(91.0)	(91.0)	(211,575,000)	
22	Bank Of New York	12/2/2017	6/1/2018	(91.0)	6/1/2018	6/1/2018	2,868,750	0.0	(91.0)	(91.0)	(261,056,250)	
23	Subtotal						$ 39,046,400				$ (3,563,385,125)	(91.3)

Empire District Electric Company
Lead-Lag Study Ending June 30, 2018
Sales and Use Taxes

Line	Invoice	Service Period Start	Service Period End	Midpoint of Service Period	Payment Date	Check Clear Date	Amount	Payment Lag	Check Clear Lag	Lead / (Lag) Days	Weighted Dollar Amount
1	PE073117 04201	7/1/2017	7/31/2017	(15.5)	7/12/2017	7/12/2017	$ 28,500	3.5	0.0	3.5	$ 99,750
2	PE-06302017-04020	6/1/2017	6/30/2017	(15.0)	7/20/2017	7/20/2017	31,045	(35.0)	0.0	(35.0)	(1,086,583)
3	PE073117 04202	7/1/2017	7/31/2017	(15.5)	7/24/2017	7/24/2017	28,500	(8.5)	0.0	(8.5)	(242,250)
4	PE083117 04201	8/1/2017	8/31/2017	(15.5)	8/14/2017	8/14/2017	27,800	1.5	0.0	1.5	41,700
5	PE-07312017-04020	7/1/2017	7/31/2017	(15.5)	8/21/2017	8/21/2017	22,616	(36.5)	0.0	(36.5)	(825,493)
6	PE083117 04202	8/1/2017	8/31/2017	(15.5)	8/24/2017	8/24/2017	27,800	(8.5)	0.0	(8.5)	(236,300)
7	PE 9/30/17 04201	9/1/2017	9/30/2017	(15.0)	9/12/2017	9/12/2017	25,600	3.0	0.0	3.0	76,800
8	PE 8-31 04020	8/1/2017	8/31/2017	(15.5)	9/20/2017	9/20/2017	29,381	(35.5)	0.0	(35.5)	(1,043,026)
9	PE093017 04202	9/1/2017	9/30/2017	(15.0)	9/25/2017	9/25/2017	25,600	(10.0)	0.0	(10.0)	(256,000)
10	PE 10/31 04201	10/1/2017	10/31/2017	(15.5)	10/12/2017	10/12/2017	21,600	3.5	0.0	3.5	75,600
11	PE-09302017-04020	9/1/2017	9/30/2017	(15.0)	10/19/2017	10/19/2017	25,760	(34.0)	0.0	(34.0)	(875,849)
12	PE103117 04202	10/1/2017	10/31/2017	(15.5)	10/24/2017	10/24/2017	21,600	(8.5)	0.0	(8.5)	(183,600)
13	PE113017 04201	11/1/2017	11/30/2017	(15.0)	11/13/2017	11/13/2017	15,600	2.0	0.0	2.0	31,200
14	PE 10/31 04020	10/1/2017	10/31/2017	(15.5)	11/20/2017	11/20/2017	24,677	(35.5)	0.0	(35.5)	(876,045)
15	PE113017 04202	11/1/2017	11/30/2017	(15.0)	11/22/2017	11/22/2017	15,600	(7.0)	0.0	(7.0)	(109,200)
16	PE123117 04201	12/1/2017	12/31/2017	(15.5)	12/12/2017	12/12/2017	17,700	3.5	0.0	3.5	61,950
17	PE-11302017-04020	11/1/2017	11/30/2017	(15.0)	12/20/2017	12/20/2017	21,360	(35.0)	0.0	(35.0)	(747,612)
18	P E12/31/17 04202	12/1/2017	12/31/2017	(15.5)	12/21/2017	12/21/2017	17,700	(5.5)	0.0	(5.5)	(97,350)
19	PE013118 04201	1/1/2018	1/31/2018	(15.5)	1/12/2018	1/12/2018	19,700	3.5	0.0	3.5	68,950
20	PE-12312017-04020	12/1/2017	12/31/2017	(15.5)	1/22/2018	1/22/2018	16,959	(37.5)	0.0	(37.5)	(635,945)
21	PE013118 04202	1/1/2018	1/31/2018	(15.5)	1/24/2018	1/24/2018	19,700	(8.5)	0.0	(8.5)	(167,450)
22	PE 2/28 04201	2/1/2018	2/28/2018	(14.0)	2/12/2018	2/12/2018	16,900	2.0	0.0	2.0	33,800
23	PE-01312018-04020	1/1/2018	1/31/2018	(15.5)	2/20/2018	2/20/2018	33,119	(35.5)	0.0	(35.5)	(1,175,737)
24	PE 2/28 04202	2/1/2018	2/28/2018	(14.0)	2/23/2018	2/23/2018	16,900	(9.0)	0.0	(9.0)	(152,100)
25	PE 3/31 04201 PREPAY	3/1/2018	3/31/2018	(15.5)	3/12/2018	3/12/2018	14,400	3.5	0.0	3.5	50,400
26	PE 2/28 04020 SALES TAX	2/1/2018	2/28/2018	(14.0)	3/20/2018	3/20/2018	33,870	(34.0)	0.0	(34.0)	(1,151,588)
27	3-18 Monthly Sales Tax 04202	3/1/2018	3/31/2018	(15.5)	3/23/2018	3/23/2018	14,400	(7.5)	0.0	(7.5)	(108,000)
28	PE 4/30 04201	4/1/2018	4/30/2018	(15.0)	4/12/2018	4/12/2018	15,300	3.0	0.0	3.0	45,900
29	PE 3/31/18 04020	3/1/2018	3/31/2018	(15.5)	4/20/2018	4/20/2018	28,878	(35.5)	0.0	(35.5)	(1,025,158)
30	PE 4/30/18 04202	4/1/2018	4/30/2018	(15.0)	4/24/2018	4/24/2018	15,300	(9.0)	0.0	(9.0)	(137,700)
31	PE 5/31 04201	5/1/2018	5/31/2018	(15.5)	5/11/2018	5/11/2018	14,400	4.5	0.0	4.5	64,800
32	PE 4/30 04020	4/1/2018	4/30/2018	(15.0)	5/21/2018	5/21/2018	26,196	(36.0)	0.0	(36.0)	(943,072)
33	PE 5/31 04202	5/1/2018	5/31/2018	(15.5)	5/24/2018	5/24/2018	14,400	(8.5)	0.0	(8.5)	(122,400)
34	PE 6/30 04201	6/1/2018	6/30/2018	(15.0)	6/12/2018	6/12/2018	17,100	3.0	0.0	3.0	51,300
35	PE 5/31 04020	5/1/2018	5/31/2018	(15.5)	6/20/2018	6/20/2018	27,270	(35.5)	0.0	(35.5)	(968,068)
36	PE 6/30 04202	6/1/2018	6/30/2018	(15.0)	6/22/2018	6/22/2018	17,100	(7.0)	0.0	(7.0)	(119,700)
37	PE-06302017-04200	6/1/2017	6/30/2017	(15.0)	7/25/2017	7/25/2017	33,471	(40.0)	0.0	(40.0)	(1,338,822)
38	PE-07312017-04201	7/1/2017	7/31/2017	(15.5)	7/25/2017	7/25/2017	39,300	(9.5)	0.0	(9.5)	(373,350)
39	PE 7-31 04200	7/1/2017	7/31/2017	(15.5)	8/25/2017	8/25/2017	38,386	(40.5)	0.0	(40.5)	(1,554,634)
40	PE 8-31 04201 PRE-PAY	8/1/2017	8/31/2017	(15.5)	8/25/2017	8/25/2017	39,600	(9.5)	0.0	(9.5)	(376,200)
41	PE-08312017-04200	8/1/2017	8/31/2017	(15.5)	9/25/2017	9/25/2017	44,665	(40.5)	0.0	(40.5)	(1,808,928)
42	PE-09302017-04201	9/1/2017	9/30/2017	(15.0)	9/25/2017	9/25/2017	36,600	(10.0)	0.0	(10.0)	(366,000)
43	PE 10/31 04201	10/1/2017	10/31/2017	(15.5)	10/25/2017	10/25/2017	31,700	(9.5)	0.0	(9.5)	(301,150)
44	PE 9-30 04200	9/1/2017	9/30/2017	(15.0)	10/25/2017	10/25/2017	41,090	(40.0)	0.0	(40.0)	(1,643,612)
45	PE-11302017-04201	11/1/2017	11/30/2017	(15.0)	11/22/2017	11/22/2017	20,000	(7.0)	0.0	(7.0)	(140,000)
46	PE-10312017-04200	10/1/2017	10/31/2017	(15.5)	11/22/2017	11/22/2017	37,897	(37.5)	0.0	(37.5)	(1,421,122)
47	PE 11/30 04200	11/1/2017	11/30/2017	(15.0)	12/21/2017	12/21/2017	46,846	(36.0)	0.0	(36.0)	(1,686,459)
48	PE 12/31 04201 PRE-PAY	12/1/2017	12/31/2017	(15.5)	12/21/2017	12/21/2017	24,700	(5.5)	0.0	(5.5)	(135,850)

Empire District Electric Company
Lead-Lag Study Ending June 30, 2018
Sales and Use Taxes

Line	Invoice	Service Period Start	Service Period End	Midpoint of Service Period	Payment Date	Check Clear Date	Amount	Payment Lag	Check Clear Lag	Lead / (Lag) Days	Weighted Dollar Amount
49	PE 1/13/18 04201	1/1/2018	1/31/2018	(15.5)	1/25/2018	1/25/2018	36,000	(9.5)	0.0	(9.5)	(342,000)
50	PE 12/31/17 04200	12/1/2017	12/31/2017	(15.5)	1/25/2018	1/25/2018	44,244	(40.5)	0.0	(40.5)	(1,791,862)
51	PE 2/28/18 04201	2/1/2018	2/28/2018	(14.0)	2/26/2018	2/26/2018	33,400	(12.0)	0.0	(12.0)	(400,800)
52	PE 1/31/18 04200	1/1/2018	1/31/2018	(15.5)	2/26/2018	2/26/2018	48,400	(41.5)	0.0	(41.5)	(2,008,603)
53	PE-03312018-04201	3/1/2018	3/31/2018	(15.5)	3/26/2018	3/26/2018	33,000	(10.5)	0.0	(10.5)	(346,500)
54	PE-02282018-04200	2/1/2018	2/28/2018	(14.0)	3/26/2018	3/26/2018	43,401	(40.0)	0.0	(40.0)	(1,736,030)
55	PE 3/31 04200	3/1/2018	3/31/2018	(15.5)	4/25/2018	4/25/2018	35,819	(40.5)	0.0	(40.5)	(1,450,678)
56	PE 4/30 04201	4/1/2018	4/30/2018	(15.0)	4/25/2018	4/25/2018	29,500	(10.0)	0.0	(10.0)	(295,000)
57	PE 5/31 04201	5/1/2018	5/31/2018	(15.5)	5/25/2018	5/25/2018	28,600	(9.5)	0.0	(9.5)	(271,700)
58	PE 4/30 04200	4/1/2018	4/30/2018	(15.0)	5/25/2018	5/25/2018	38,677	(40.0)	0.0	(40.0)	(1,547,096)
59	PE 5/31 04200	5/1/2018	5/31/2018	(15.5)	6/25/2018	6/25/2018	41,329	(40.5)	0.0	(40.5)	(1,673,806)
60	PE 6/30 04201	6/1/2018	6/30/2018	(15.0)	6/25/2018	6/25/2018	32,500	(10.0)	0.0	(10.0)	(325,000)
61	PP6/30/2017 04204	6/1/2017	6/30/2017	(15.0)	7/6/2017	7/6/2017	330,377	(21.0)	0.0	(21.0)	(6,937,907)
62	PP7/07/2017 04201	7/1/2017	7/31/2017	(15.5)	7/12/2017	7/12/2017	111,090	3.5	0.0	3.5	388,814
63	PP7/14/2017 04202	7/1/2017	7/31/2017	(15.5)	7/19/2017	7/19/2017	173,850	(3.5)	0.0	(3.5)	(608,476)
64	6/30 SALES TAX	6/1/2017	6/30/2017	(15.0)	7/19/2017	7/28/2017	418,730	(34.0)	(9.0)	(43.0)	(18,005,369)
65	PE 7/22/2017 04203	7/1/2017	7/31/2017	(15.5)	7/26/2017	7/26/2017	72,045	(10.5)	0.0	(10.5)	(756,470)
66	PP 7/31 04204	7/1/2017	7/31/2017	(15.5)	8/4/2017	8/4/2017	424,070	(19.5)	0.0	(19.5)	(8,269,362)
67	PP8/07/2017 04201	8/1/2017	8/31/2017	(15.5)	8/10/2017	8/10/2017	124,166	5.5	0.0	5.5	682,916
68	PP8/15/2017 04202	8/1/2017	8/31/2017	(15.5)	8/18/2017	8/18/2017	138,555	(2.5)	0.0	(2.5)	(346,388)
69	TGPE 7/31 SALES TAX	7/1/2017	7/31/2017	(15.5)	8/21/2017	9/20/2017	538,018	(36.5)	(30.0)	(66.5)	(35,778,173)
70	PE 8/22 04203	8/1/2017	8/31/2017	(15.5)	8/25/2017	8/25/2017	119,766	(9.5)	0.0	(9.5)	(1,137,779)
71	PP 8/31 04204	8/1/2017	8/31/2017	(15.5)	9/6/2017	9/6/2017	415,765	(21.5)	0.0	(21.5)	(8,938,950)
72	PP9/07/2017 04201	9/1/2017	9/30/2017	(15.0)	9/19/2017	9/19/2017	113,637	(4.0)	0.0	(4.0)	(454,550)
73	PP 9-15 04202	9/1/2017	9/30/2017	(15.0)	9/20/2017	9/20/2017	162,400	(5.0)	0.0	(5.0)	(812,000)
74	PE 8/31 SALES TAX	8/1/2017	8/31/2017	(15.5)	9/20/2017	9/26/2017	543,390	(35.5)	(6.0)	(41.5)	(22,550,691)
75	PE 9-22 04203	9/1/2017	9/30/2017	(15.0)	9/27/2017	9/27/2017	139,025	(12.0)	0.0	(12.0)	(1,668,303)
76	PP 9/30 04204	9/1/2017	9/30/2017	(15.0)	10/4/2017	10/4/2017	321,362	(19.0)	0.0	(19.0)	(6,105,887)
77	PP10/15/2017 04202	10/1/2017	10/31/2017	(15.5)	10/18/2017	10/18/2017	97,636	(2.5)	0.0	(2.5)	(244,090)
78	PP 10/22/17 04203	10/1/2017	10/31/2017	(15.5)	10/25/2017	10/25/2017	104,231	(9.5)	0.0	(9.5)	(990,197)
79	SALES TAX PE 9/30/17	9/1/2017	9/30/2017	(15.0)	10/31/2017	11/17/2017	484,052	(46.0)	(17.0)	(63.0)	(30,495,245)
80	PP 10-07 04201.CORRECTI	10/1/2017	10/31/2017	(15.5)	11/1/2017	11/1/2017	98,440	(16.5)	0.0	(16.5)	(1,624,258)
81	PP10/312017 04204	10/1/2017	10/31/2017	(15.5)	11/3/2017	11/3/2017	333,445	(18.5)	0.0	(18.5)	(6,168,734)
82	PP11/07/2017 04201	11/1/2017	11/30/2017	(15.0)	11/13/2017	11/13/2017	94,765	2.0	0.0	2.0	189,530
83	PE 11/15 04202	11/1/2017	11/30/2017	(15.0)	11/20/2017	11/20/2017	109,379	(5.0)	0.0	(5.0)	(546,893)
84	ST/CITY/CO Sales Tx m/e 1(	10/1/2017	10/31/2017	(15.5)	11/20/2017	11/29/2017	348,009	(35.5)	(9.0)	(44.5)	(15,486,395)
85	PP 11-22-2017 04203	11/1/2017	11/30/2017	(15.0)	11/28/2017	12/5/2017	121,279	(13.0)	(7.0)	(20.0)	(2,425,588)
86	PP 11-30-17 04204	11/1/2017	11/30/2017	(15.0)	12/5/2017	12/5/2017	227,829	(20.0)	0.0	(20.0)	(4,556,574)
87	PP12/07/2017 04201	12/1/2017	12/31/2017	(15.5)	12/12/2017	12/12/2017	95,224	3.5	0.0	3.5	333,282
88	ST/City/CO Sales Tax m/e 1'	11/1/2017	11/30/2017	(15.0)	12/20/2017	12/29/2017	373,914	(35.0)	(9.0)	(44.0)	(16,452,221)
89	PP 12-22-17 04203	12/1/2017	12/31/2017	(15.5)	12/28/2017	12/28/2017	77,579	(12.5)	0.0	(12.5)	(969,737)
90	PE 12/15/17 04202	12/1/2017	12/31/2017	(15.5)	12/28/2017	12/28/2017	169,260	(12.5)	0.0	(12.5)	(2,115,746)
91	PPE 12-31-2017 04204	12/1/2017	12/31/2017	(15.5)	1/5/2018	1/5/2018	226,926	(20.5)	0.0	(20.5)	(4,651,987)
92	PP 1-07-18 04201	1/1/2018	1/31/2018	(15.5)	1/10/2018	1/10/2018	73,688	5.5	0.0	5.5	405,282
93	PE 1/15/18 04202	1/1/2018	1/31/2018	(15.5)	1/18/2018	1/18/2018	113,525	(2.5)	0.0	(2.5)	(283,812)
94	PE 1/23/18 04203	1/1/2018	1/31/2018	(15.5)	1/25/2018	1/25/2018	107,711	(9.5)	0.0	(9.5)	(1,023,256)
95	SALES TAX PE 12/31/2017	12/1/2017	12/31/2017	(15.5)	1/31/2018	2/20/2018	410,066	(46.5)	(20.0)	(66.5)	(27,269,377)
96	PP01/31/2018 04204	1/1/2018	1/31/2018	(15.5)	2/5/2018	2/5/2018	366,309	(20.5)	0.0	(20.5)	(7,509,327)

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97	PE 2/07/2018 04201	2/1/2018	2/28/2018	(14.0)	2/12/2018	2/12/2018	136,099	2.0	0.0	2.0	272,198
98	ST/City/CO Sales Tx m/e 1/1	1/1/2018	1/31/2018	(15.5)	2/20/2018	3/1/2018	563,463	(35.5)	(9.0)	(44.5)	(25,074,104)
99	PE 2/15/18 04202	2/1/2018	2/28/2018	(14.0)	2/21/2018	2/21/2018	105,684	(7.0)	0.0	(7.0)	(739,791)
100	PP 02/22/2018 04203	2/1/2018	2/28/2018	(14.0)	2/27/2018	2/27/2018	139,094	(13.0)	0.0	(13.0)	(1,808,219)
101	PP 02/28/2018 04204	2/1/2018	2/28/2018	(14.0)	3/5/2018	3/5/2018	233,998	(19.0)	0.0	(19.0)	(4,445,969)
102	PP 3/07 04201	3/1/2018	3/31/2018	(15.5)	3/12/2018	3/12/2018	98,554	3.5	0.0	3.5	344,939
103	PP 3/15 04202	3/1/2018	3/31/2018	(15.5)	3/20/2018	3/20/2018	121,387	(4.5)	0.0	(4.5)	(546,240)
104	SALES TAX PE 2/28/18	2/1/2018	2/28/2018	(14.0)	3/20/2018	3/28/2018	501,738	(34.0)	(8.0)	(42.0)	(21,072,994)
105	PP 3/22/18 04203	3/1/2018	3/31/2018	(15.5)	3/27/2018	3/27/2018	124,220	(11.5)	0.0	(11.5)	(1,428,530)
106	PP 3/31 04204	3/1/2018	3/31/2018	(15.5)	4/4/2018	4/4/2018	227,234	(19.5)	0.0	(19.5)	(4,431,057)
107	PP04/07/2018 04201	4/1/2018	4/30/2018	(15.0)	4/11/2018	4/11/2018	94,133	4.0	0.0	4.0	376,533
108	PE 4/15 04202	4/1/2018	4/30/2018	(15.0)	4/18/2018	4/18/2018	87,100	(3.0)	0.0	(3.0)	(261,299)
109	PE 4/22 04203	4/1/2018	4/30/2018	(15.0)	4/25/2018	4/25/2018	89,805	(10.0)	0.0	(10.0)	(898,053)
110	P 3/31 SALES TAX	3/1/2018	3/31/2018	(15.5)	4/30/2018	5/15/2018	416,999	(45.5)	(15.0)	(60.5)	(25,228,461)
111	PP 4/30 04204	4/1/2018	4/30/2018	(15.0)	5/3/2018	5/3/2018	301,285	(18.0)	0.0	(18.0)	(5,423,139)
112	PP 5/07 04201	5/1/2018	5/31/2018	(15.5)	5/10/2018	5/10/2018	92,085	5.5	0.0	5.5	506,468
113	PP 5/15 04202	5/1/2018	5/31/2018	(15.5)	5/18/2018	5/18/2018	110,692	(2.5)	0.0	(2.5)	(276,730)
114	SALES TAX PE 4/30/18	4/1/2018	4/30/2018	(15.0)	5/21/2018	6/19/2018	410,550	(36.0)	(29.0)	(65.0)	(26,685,723)
115	PP 5/22 04203	5/1/2018	5/31/2018	(15.5)	5/25/2018	5/25/2018	110,608	(9.5)	0.0	(9.5)	(1,050,779)
116	PE 5/31 04204	5/1/2018	5/31/2018	(15.5)	6/5/2018	6/5/2018	265,056	(20.5)	0.0	(20.5)	(5,433,649)
117	PE 6/07 04201	6/1/2018	6/30/2018	(15.0)	6/12/2018	6/12/2018	100,615	3.0	0.0	3.0	301,844
118	PE 6/15 04202	6/1/2018	6/30/2018	(15.0)	6/20/2018	6/20/2018	135,681	(5.0)	0.0	(5.0)	(678,405)
119	PE 5/31 SALES TAX	5/1/2018	5/31/2018	(15.5)	6/20/2018	6/28/2018	378,316	(35.5)	(8.0)	(43.5)	(16,456,763)
120	PE 6/22 04203	6/1/2018	6/30/2018	(15.0)	6/27/2018	6/27/2018	146,225	(12.0)	0.0	(12.0)	(1,754,694)
121	PE 6/30 04204	6/1/2017	6/30/2017	(15.0)	7/5/2017	7/5/2017	7,020	(20.0)	0.0	(20.0)	(140,400)
122	PE 7/31 04201	7/1/2017	7/31/2017	(15.5)	7/11/2017	7/11/2017	7,020	4.5	0.0	4.5	31,590
123	7-17 Qtr Mon Sls & WH 0420	7/1/2017	7/31/2017	(15.5)	7/19/2017	7/19/2017	7,020	(3.5)	0.0	(3.5)	(24,570)
124	PE 7/31 04203	7/1/2017	7/31/2017	(15.5)	7/26/2017	7/26/2017	7,020	(10.5)	0.0	(10.5)	(73,710)
125	ST/City/CO Sales Tx m/e 6/1	6/1/2017	6/30/2017	(15.0)	7/31/2017	8/17/2017	19,157	(46.0)	(17.0)	(63.0)	(1,206,897)
126	7-17 Qtr Mon Sales & WH 04	7/1/2017	7/31/2017	(15.5)	8/2/2017	8/2/2017	7,020	(17.5)	0.0	(17.5)	(122,850)
127	PE 8/31/2017 04201	8/1/2017	8/31/2017	(15.5)	8/9/2017	8/9/2017	7,020	6.5	0.0	6.5	45,630
128	PE 8/31 04202	8/1/2017	8/31/2017	(15.5)	8/17/2017	8/17/2017	7,020	(1.5)	0.0	(1.5)	(10,530)
129	ST/City/CO Sales Tx m/e 7/1	7/1/2017	7/31/2017	(15.5)	8/21/2017	9/20/2017	7,264	(36.5)	(30.0)	(66.5)	(483,083)
130	8-17 Qtr Mon Sales & WH 04	8/1/2017	8/31/2017	(15.5)	8/24/2017	8/24/2017	7,020	(8.5)	0.0	(8.5)	(59,670)
131	PE 08/31 04204	8/1/2017	8/31/2017	(15.5)	9/1/2017	9/1/2017	7,020	(16.5)	0.0	(16.5)	(115,830)
132	PE 9-30 04201	9/1/2017	9/30/2017	(15.0)	9/8/2017	9/8/2017	7,020	7.0	0.0	7.0	49,140
133	9-17 Qtr Mon Sales & WH 04	9/1/2017	9/30/2017	(15.0)	9/19/2017	9/19/2017	7,020	(4.0)	0.0	(4.0)	(28,080)
134	PE 8-31-2017 SALES TAX	8/1/2017	8/31/2017	(15.5)	9/20/2017	10/19/2017	7,167	(35.5)	(29.0)	(64.5)	(462,288)
135	9/30 04203	9/1/2017	9/30/2017	(15.0)	9/27/2017	9/27/2017	7,020	(12.0)	0.0	(12.0)	(84,240)
136	PE 9-30 04204	9/1/2017	9/30/2017	(15.0)	10/4/2017	10/4/2017	7,020	(19.0)	0.0	(19.0)	(133,380)
137	PE 10/31 04201	10/1/2017	10/31/2017	(15.5)	10/12/2017	10/12/2017	7,020	3.5	0.0	3.5	24,570
138	10-2017 Qtr Mon Sales WH (	10/1/2017	10/31/2017	(15.5)	10/18/2017	10/18/2017	7,020	(2.5)	0.0	(2.5)	(17,550)
139	PE 10-31 04203	10/1/2017	10/31/2017	(15.5)	10/25/2017	10/25/2017	7,020	(9.5)	0.0	(9.5)	(66,690)
140	ST/City/CO Sales Tax m/e 9/	9/1/2017	9/30/2017	(15.0)	10/31/2017	11/29/2017	6,298	(46.0)	(29.0)	(75.0)	(472,364)
141	10-31-17 Qtr Mon Sls WH 04	10/1/2017	10/31/2017	(15.5)	11/3/2017	11/3/2017	7,020	(18.5)	0.0	(18.5)	(129,870)
142	11-17 Qtr Mon Sls & WH 042	11/1/2017	11/30/2017	(15.0)	11/9/2017	11/9/2017	7,020	6.0	0.0	6.0	42,120
143	11-30-17 04202	11/1/2017	11/30/2017	(15.0)	11/17/2017	11/17/2017	7,020	(2.0)	0.0	(2.0)	(14,040)
144	ST/CITY/CO Sales Tx m/e 1(	10/1/2017	10/31/2017	(15.5)	11/20/2017	12/1/2017	11,657	(35.5)	(11.0)	(46.5)	(542,069)

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145	11-17 Qtr Mon Sls & WH 042	11/1/2017	11/30/2017	(15.0)	11/22/2017	11/22/2017	7,020	(7.0)	0.0	(7.0)	(49,140)
146	11-30-17 04204	11/1/2017	11/30/2017	(15.0)	12/1/2017	12/1/2017	7,020	(16.0)	0.0	(16.0)	(112,320)
147	PE 12-31-17 04201	12/1/2017	12/31/2017	(15.5)	12/8/2017	12/8/2017	7,020	7.5	0.0	7.5	52,650
148	ST/City/CO Sales Tax m/e 1'	11/1/2017	11/30/2017	(15.0)	12/20/2017	12/29/2017	20,917	(35.0)	(9.0)	(44.0)	(920,333)
149	PE 12-31 04202	12/1/2017	12/31/2017	(15.5)	12/19/2017	12/19/2017	7,020	(3.5)	0.0	(3.5)	(24,570)
150	12-2017 Qtr Mon Sls WH 042	12/1/2017	12/31/2017	(15.5)	12/27/2017	12/27/2017	7,020	(11.5)	0.0	(11.5)	(80,730)
151	PE 12/31/17 04204	12/1/2017	12/31/2017	(15.5)	1/2/2018	1/2/2018	7,020	(17.5)	0.0	(17.5)	(122,850)
152	1-18 Qtr Mon Sls & WH 0420	1/1/2018	1/31/2018	(15.5)	1/12/2018	1/12/2018	7,020	3.5	0.0	3.5	24,570
153	PE 1/31/18 04202	1/1/2018	1/31/2018	(15.5)	1/19/2018	1/19/2018	7,020	(3.5)	0.0	(3.5)	(24,570)
154	1-18 Qtr Mon Sls & WH 0420	1/1/2018	1/31/2018	(15.5)	1/26/2018	1/26/2018	7,020	(10.5)	0.0	(10.5)	(73,710)
155	SALES TAX PE 12/31/2017	12/1/2017	12/31/2017	(15.5)	1/31/2018	2/20/2018	65,505	(46.5)	(20.0)	(66.5)	(4,356,094)
156	1-2018 Qtr Mon Sls WH 042(	1/1/2018	1/31/2018	(15.5)	2/2/2018	2/2/2018	7,020	(17.5)	0.0	(17.5)	(122,850)
157	PE 2/28 04201	2/1/2018	2/28/2018	(14.0)	2/9/2018	2/9/2018	7,020	5.0	0.0	5.0	35,100
158	2-2018 Qtr Mon Sls & WH 04	2/1/2018	2/28/2018	(14.0)	2/16/2018	2/16/2018	7,020	(2.0)	0.0	(2.0)	(14,040)
159	ST/City/CO Sales Tax m/e 1/	1/1/2018	1/31/2018	(15.5)	2/20/2018	3/1/2018	104,087	(35.5)	(9.0)	(44.5)	(4,631,862)
160	PE 2/28 04203	2/1/2018	2/28/2018	(14.0)	2/23/2018	2/23/2018	7,020	(9.0)	0.0	(9.0)	(63,180)
161	2-18 Qtr Mon Sls & WH 0420	2/1/2018	2/28/2018	(14.0)	3/2/2018	3/2/2018	7,020	(16.0)	0.0	(16.0)	(112,320)
162	PE 3/31 04201	3/1/2018	3/31/2018	(15.5)	3/9/2018	3/9/2018	7,020	6.5	0.0	6.5	45,630
163	3-31-18 04202	3/1/2018	3/31/2018	(15.5)	3/16/2018	3/16/2018	7,020	(0.5)	0.0	(0.5)	(3,510)
164	STATE SALES TAX PER 2/2	2/1/2018	2/28/2018	(14.0)	3/20/2018	3/28/2018	174,913	(34.0)	(8.0)	(42.0)	(7,346,362)
165	3-18 Qtr Mon Sales & WH 04	3/1/2018	3/31/2018	(15.5)	3/23/2018	3/23/2018	7,020	(7.5)	0.0	(7.5)	(52,650)
166	PE 3/31 04204	3/1/2018	3/31/2018	(15.5)	4/4/2018	4/4/2018	7,020	(19.5)	0.0	(19.5)	(136,890)
167	4-2018 Qtr Mon Sls & WH 04	4/1/2018	4/30/2018	(15.0)	4/11/2018	4/11/2018	7,020	4.0	0.0	4.0	28,080
168	PE 4/30 04202	4/1/2018	4/30/2018	(15.0)	4/19/2018	4/19/2018	7,020	(4.0)	0.0	(4.0)	(28,080)
169	PE 4/30 04203	4/1/2018	4/30/2018	(15.0)	4/26/2018	4/26/2018	7,020	(11.0)	0.0	(11.0)	(77,220)
170	PE 3/31 SALES TAX	3/1/2018	3/31/2018	(15.5)	4/30/2018	5/15/2018	128,746	(45.5)	(15.0)	(60.5)	(7,789,133)
171	4/30 04204	4/1/2018	4/30/2018	(15.0)	5/3/2018	5/3/2018	7,020	(18.0)	0.0	(18.0)	(126,360)
172	5/31 04201	5/1/2018	5/31/2018	(15.5)	5/10/2018	5/10/2018	7,020	5.5	0.0	5.5	38,610
173	PE 5/31/18 04202	5/1/2018	5/31/2018	(15.5)	5/17/2018	5/17/2018	7,020	(1.5)	0.0	(1.5)	(10,530)
174	SALES TAX PE 4/30/18	4/1/2018	4/30/2018	(15.0)	5/21/2018	6/19/2018	87,775	(36.0)	(29.0)	(65.0)	(5,705,404)
175	PE 5/31/18 04203	5/1/2018	5/31/2018	(15.5)	5/24/2018	5/24/2018	7,020	(8.5)	0.0	(8.5)	(59,670)
176	PE 5/31 04204	5/1/2018	5/31/2018	(15.5)	6/1/2018	6/1/2018	7,020	(16.5)	0.0	(16.5)	(115,830)
177	pe 6/30 04201	6/1/2018	6/30/2018	(15.0)	6/8/2018	6/8/2018	7,020	7.0	0.0	7.0	49,140
178	PE 6/30 04202	6/1/2018	6/30/2018	(15.0)	6/15/2018	6/15/2018	7,020	0.0	0.0	0.0	-
179	PE 5/31 SALES TAX	5/1/2018	5/31/2018	(15.5)	6/20/2018	6/28/2018	71,697	(35.5)	(8.0)	(43.5)	(3,118,803)
180	PE 6/30 04203	6/1/2018	6/30/2018	(15.0)	6/22/2018	6/22/2018	7,020	(7.0)	0.0	(7.0)	(49,140)
181	PE-06302017-04200	6/1/2017	6/30/2017	(15.0)	7/20/2017	7/20/2017	15,801	(35.0)	0.0	(35.0)	(553,028)
182	PE-07312017-04200-PRE	7/1/2017	7/31/2017	(15.5)	7/20/2017	7/20/2017	16,500	(4.5)	0.0	(4.5)	(74,250)
183	PE-07312017-04200	7/1/2017	7/31/2017	(15.5)	8/21/2017	8/21/2017	14,325	(36.5)	0.0	(36.5)	(522,873)
184	PE-08312017-04200-PRE	8/1/2017	8/31/2017	(15.5)	8/21/2017	8/21/2017	17,300	(5.5)	0.0	(5.5)	(95,150)
185	PE 08-31 04200	8/1/2017	8/31/2017	(15.5)	9/20/2017	9/20/2017	17,112	(35.5)	0.0	(35.5)	(607,486)
186	PE 9-30 04200 PREPAY	9/1/2017	9/30/2017	(15.0)	9/20/2017	9/20/2017	17,100	(5.0)	0.0	(5.0)	(85,500)
187	PE-10312017-04200-PRE	10/1/2017	10/31/2017	(15.5)	10/19/2017	10/19/2017	13,900	(3.5)	0.0	(3.5)	(48,650)
188	PE-09302017-04200	9/1/2017	9/30/2017	(15.0)	10/19/2017	10/19/2017	16,239	(34.0)	0.0	(34.0)	(552,139)
189	PE 10-30-17 04200	10/1/2017	10/31/2017	(15.5)	11/20/2017	11/20/2017	16,849	(35.5)	0.0	(35.5)	(598,153)
190	PE 11/30/17 04200 PRE	11/1/2017	11/30/2017	(15.0)	11/20/2017	11/20/2017	11,100	(5.0)	0.0	(5.0)	(55,500)
191	PE-12312017-04200-PRE	12/1/2017	12/31/2017	(15.5)	12/20/2017	12/20/2017	12,900	(4.5)	0.0	(4.5)	(58,050)
192	PE-11302017-04200	11/1/2017	11/30/2017	(15.0)	12/20/2017	12/20/2017	15,501	(35.0)	0.0	(35.0)	(542,525)

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193	PE-01312018-04200-PRE	1/1/2018	1/31/2018	(15.5)	1/22/2018	1/22/2018	15,400	(6.5)	0.0	(6.5)	(100,100)
194	PE-12312017-04200	12/1/2017	12/31/2017	(15.5)	1/22/2018	1/22/2018	14,294	(37.5)	0.0	(37.5)	(536,031)
195	PE-01312018-04200	1/1/2018	1/31/2018	(15.5)	2/20/2018	2/20/2018	17,635	(35.5)	0.0	(35.5)	(626,059)
196	PE-02282018-04200-PRE	2/1/2018	2/28/2018	(14.0)	2/20/2018	2/20/2018	13,200	(6.0)	0.0	(6.0)	(79,200)
197	PE 3/31 04200-PREPAY	3/1/2018	3/31/2018	(15.5)	3/20/2018	3/20/2018	12,400	(4.5)	0.0	(4.5)	(55,800)
198	PE 2/28 04200	2/1/2018	2/28/2018	(14.0)	3/20/2018	3/20/2018	21,948	(34.0)	0.0	(34.0)	(746,216)
199	PE 4/30 04200-PRE	4/1/2018	4/30/2018	(15.0)	4/20/2018	4/20/2018	9,900	(5.0)	0.0	(5.0)	(49,500)
200	PE 3/31 04200	3/1/2018	3/31/2018	(15.5)	4/20/2018	4/20/2018	16,437	(35.5)	0.0	(35.5)	(583,520)
201	PE 4/30 04200	4/1/2018	4/30/2018	(15.0)	5/21/2018	5/21/2018	20,307	(36.0)	0.0	(36.0)	(731,052)
202	PE 5/31 04200-PRE	5/1/2018	5/31/2018	(15.5)	5/21/2018	5/21/2018	10,200	(5.5)	0.0	(5.5)	(56,100)
203	PE 5/31 04200	5/1/2018	5/31/2018	(15.5)	6/20/2018	6/20/2018	15,112	(35.5)	0.0	(35.5)	(536,482)
204	PE 6/30 04200 PRE-PAY	6/1/2018	6/30/2018	(15.0)	6/20/2018	6/20/2018	13,700	(5.0)	0.0	(5.0)	(68,500)
205	PE 7-31 04500 USE TAX	7/1/2017	7/31/2017	(15.5)	8/25/2017	8/25/2017	501	(40.5)	0.0	(40.5)	(20,286)
206	PE-08312017-04500-KSUSE	8/1/2017	8/31/2017	(15.5)	9/25/2017	9/25/2017	747	(40.5)	0.0	(40.5)	(30,258)
207	PE 9-30 04500 USE TAX	9/1/2017	9/30/2017	(15.0)	10/25/2017	10/25/2017	327	(40.0)	0.0	(40.0)	(13,074)
208	PE 11/30 04500 USE TAX	11/1/2017	11/30/2017	(15.0)	12/21/2017	12/21/2017	607	(36.0)	0.0	(36.0)	(21,838)
209	PE 1-31-18 04500 USE TAX	1/1/2018	1/31/2018	(15.5)	2/26/2018	2/26/2018	5,733	(41.5)	0.0	(41.5)	(237,907)
210	PE-02282018-04500-KSUSE	2/1/2018	2/28/2018	(14.0)	3/26/2018	3/26/2018	971	(40.0)	0.0	(40.0)	(38,839)
211	PE 3/31 04500	3/1/2018	3/31/2018	(15.5)	4/25/2018	4/25/2018	771	(40.5)	0.0	(40.5)	(31,244)
212	PE 4/30 04500 USE TAX	4/1/2018	4/30/2018	(15.0)	5/25/2018	5/25/2018	366	(40.0)	0.0	(40.0)	(14,639)
213	PE 5/31 04500 USE TAX	5/1/2018	5/31/2018	(15.5)	6/25/2018	6/25/2018	114	(40.5)	0.0	(40.5)	(4,599)
214	2nd Qtr 2017 MO Cons Use T	4/1/2017	6/30/2017	(45.5)	7/31/2017	8/10/2017	63,230	(76.5)	(10.0)	(86.5)	(5,469,354)
215	3rd Qtr 2017 MO Cons Use T	7/1/2017	9/30/2017	(46.0)	10/31/2017	11/16/2017	74,557	(77.0)	(16.0)	(93.0)	(6,933,759)
216	4th Qtr 2017 MO Use Tax ED	10/1/2017	12/31/2017	(46.0)	1/31/2018	2/20/2018	39,603	(77.0)	(20.0)	(97.0)	(3,841,478)
217	4th Qtr 2017 MO Use Tax ED	10/1/2017	12/31/2017	(46.0)	1/31/2018	2/20/2018	50	(77.0)	(20.0)	(97.0)	(4,871)
218	1ST QTR 2018 CONSUMER	1/1/2018	3/31/2018	(45.0)	4/30/2018	5/21/2018	61,935	(75.0)	(21.0)	(96.0)	(5,945,759)
219	1ST QTR 2018 CONSUMER	1/1/2018	3/31/2018	(45.0)	4/30/2018	5/21/2018	262	(75.0)	(21.0)	(96.0)	(25,172)
220	2nd Qtr 2017 Gas Co MO Us	4/1/2017	6/30/2017	(45.5)	7/31/2017	8/9/2017	1,383	(76.5)	(9.0)	(85.5)	(118,273)
221	3rd Qtr 2017 EDG MO Cons	7/1/2017	9/30/2017	(46.0)	10/31/2017	12/29/2017	3,839	(77.0)	(59.0)	(136.0)	(522,171)
222	4th Qtr Missouri Use Tax ED	10/1/2017	12/31/2017	(46.0)	1/31/2018	3/12/2018	2,271	(77.0)	(40.0)	(117.0)	(265,677)
223	1ST QTR 2018 GAS USE TA	1/1/2018	3/31/2018	(45.0)	4/30/2018	5/31/2018	3,108	(75.0)	(31.0)	(106.0)	(329,414)
224	PE-06302017-OK-USE	6/1/2017	6/30/2017	(15.0)	7/20/2017	7/20/2017	1,703	(35.0)	0.0	(35.0)	(59,605)
225	PE-073120017-OK -USE	7/1/2017	7/31/2017	(15.5)	8/21/2017	8/21/2017	2,212	(36.5)	0.0	(36.5)	(80,739)
226	PE 8-31 USE TAX	8/1/2017	8/31/2017	(15.5)	9/20/2017	9/20/2017	2,201	(35.5)	0.0	(35.5)	(78,145)
227	PE-09302017-OK-USE	9/1/2017	9/30/2017	(15.0)	10/19/2017	10/19/2017	815	(34.0)	0.0	(34.0)	(27,712)
228	PE 10/31/2017 USE TAX	10/1/2017	10/31/2017	(15.5)	11/20/2017	11/20/2017	602	(35.5)	0.0	(35.5)	(21,376)
229	PE-11302017-OK-USE	11/1/2017	11/30/2017	(15.0)	12/20/2017	12/20/2017	883	(35.0)	0.0	(35.0)	(30,905)
230	PE-12312017-OK-USE	12/1/2017	12/31/2017	(15.5)	1/22/2018	1/22/2018	1,796	(37.5)	0.0	(37.5)	(67,349)
231	PE-01312018-OK-USE	1/1/2018	1/31/2018	(15.5)	2/20/2018	2/20/2018	293	(35.5)	0.0	(35.5)	(10,411)
232	PE 2/28 USE TAX	2/1/2018	2/28/2018	(14.0)	3/20/2018	3/20/2018	781	(34.0)	0.0	(34.0)	(26,559)
233	PE 3-31 USE TAX	3/1/2018	3/31/2018	(15.5)	4/20/2018	4/20/2018	761	(35.5)	0.0	(35.5)	(27,008)
234	PE 4/30 USE TAX	4/1/2018	4/30/2018	(15.0)	5/21/2018	5/21/2018	1,293	(36.0)	0.0	(36.0)	(46,553)
235	PE 5/31 04500 USE TAX	5/1/2018	5/31/2018	(15.5)	6/20/2018	6/20/2018	698	(35.5)	0.0	(35.5)	(24,773)
236	Total						$ 16,521,307			(29.2)	$ (482,376,851)

AFFIDAVIT OF TIMOTHY S. LYONS

STATE OF VERMONT)
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On the 6TH day of December, 2018, before me appeared Timothy S. Lyons, to me personally known, who, being by me first duly sworn, states that he a partner at ScottMadden, Inc and acknowledges that he has read the above and foregoing document and believes that the statements therein are true and correct to the best of his information, knowledge and belief.

Timothy S. Lyons.

Timothy S. Lyons

Subscribed and sworn to before me this 6TH day of December 2018.

Notary Public

KARL GEORGE NOTARY PUBLIC STATE OF VERMONT

My commission expires: 2/10/2019