Exhibit No.: _____
Issue(s): Class Cost of Service Study and Rate Design
Witness: Timothy S. Lyons
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Sponsoring Party: The Empire District Electric Company d/b/a Liberty
Case No.: ER-2024-0261
Date Testimony Prepared: February 2025

Before the Public Service Commission
of the State of Missouri

Direct Testimony

of

Timothy S. Lyons

on behalf of

The Empire District Electric Company d/b/a Liberty

February 26, 2025

Liberty™

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FOR THE DIRECT TESTIMONY OF TIMOTHY S. LYONS
THE EMPIRE DISTRICT ELECTRIC COMPANY D/B/A LIBERTY
BEFORE THE MISSOURI PUBLIC SERVICE COMMISSION
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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 3 Speen Street, Suite 150, Framingham, Massachusetts 01701.

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

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

Q. On whose behalf are you testifying in this proceeding?

A. I am testifying on behalf of The Empire District Electric Company d/b/a Liberty ("Liberty" or "Company").

Q. Please describe your professional and educational 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 in 2016.

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.

Q. Have you previously testified before the Missouri Public Service Commission ("Commission")?

A. Yes. My testimony experience is included in **Direct Schedule TSL-1**.

Q. What is the purpose of your direct testimony?

A. The purpose of my testimony is to sponsor the Company's proposed retail base rates, the Company's compliance with various stipulations/agreements, and the Company's lead/lag days associated with test year revenues and expenses. Furthermore, my direct testimony includes a description of: (a) the Company's current rate classes and base rates; (b) the Company's revenue normalization, annualization, and load growth process; (c) the Class Cost of Service Study ("COSS"); and (d) the proposed class revenue requirements, rate design, and customer bill impacts for each rate class.

Q. Have you prepared schedules to support this testimony?

A. Yes. **Direct Schedules TSL-2** through **TSL-5** summarize the results of the COSS, the proposed base rates, and customer bill impacts.

- **Direct Schedule TSL-2**: Class Cost of Service Study Summary
- **Direct Schedule TSL-3**: Class Cost of Service Study Schedules
- **Direct Schedule TSL-4**: Class Revenue Requirements
- **Direct Schedule TSL-5**: Rate Design and Bill Impacts

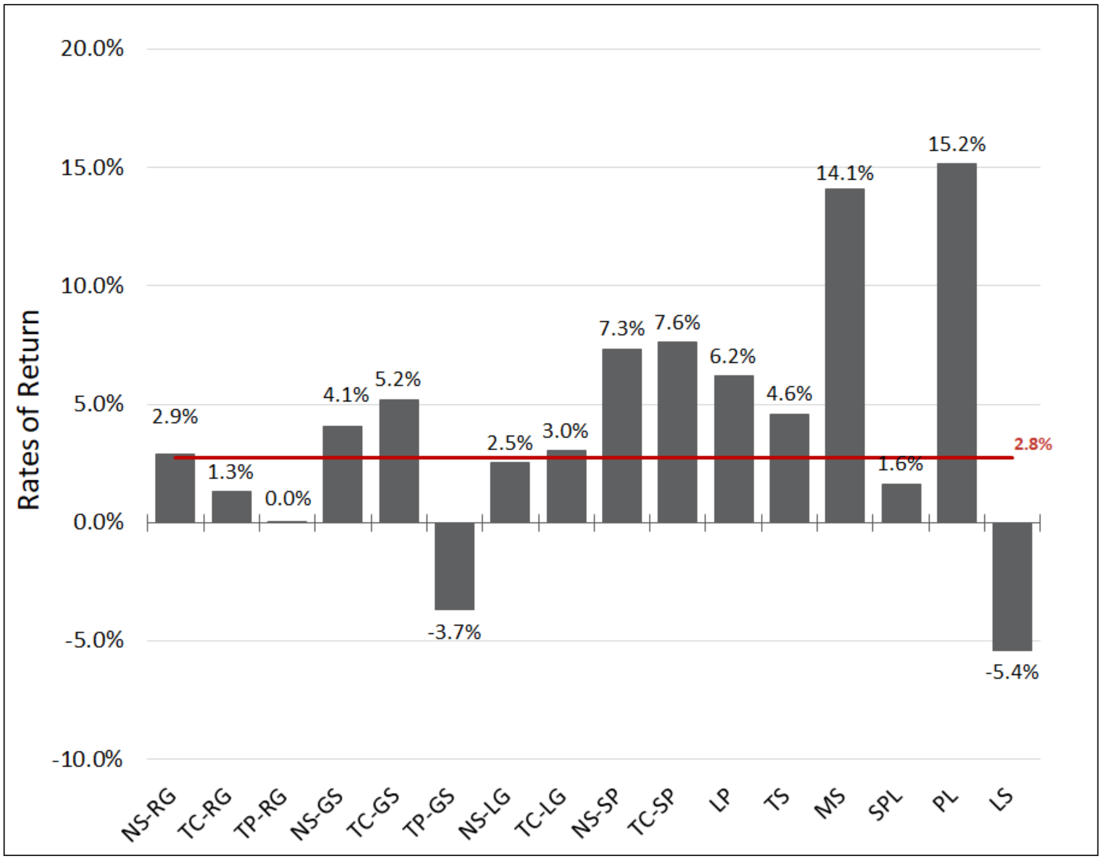
These Schedules were prepared by me or under my direction.

II. OVERVIEW

Q. Please summarize your direct testimony.

A. The results of the Company's COSS show differences in class rates of return ("ROR") at current base rates as compared to the system or overall ROR, as shown in Figure 1 (below).

Figure 1: COSS Results



The Figure shows several rate classes, such as the Non-Standard Residential (Schedule "NS-RG"), Time Choice Residential (Schedule "TC-RG"), Time Choice Plus Residential (Schedule "TP-RG"), Time Choice Plus General Service (Schedule "TP-GS"), and Non-Standard Large General Service (Schedule "NS-LG") rate classes, yield RORs that are less than the system or overall ROR. The Figure also shows other rate classes, such as the Non-Standard General Service (Schedule "NS-GS"), Time Choice General Service (Schedule "TC-GS"), Time Choice Large General Service (Schedule "TC-LG"), Small Primary General Service (Schedules "NS-SP" and "TC-SP"), Large Power (Schedule "LP"), and Transmission (Schedule "TS") rate classes, yield RORs that are more than the system or overall ROR. Except as described in this testimony, the COSS was prepared consistent with the methodologies used in the Company's rebuttal testimony in Case No. ER-2021-0312, the Company's prior rate case.

The results of the COSS support a movement toward a more equitable rate structure where class RORs move closer to the system ROR. However, the proposed movement to the system ROR was subject to certain limitations to address customer bill impact considerations.

The proposed base rates reflect three important 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.

The Company prepared total bill impact analysis to evaluate the impact of the proposed base rate changes. The total bill impact analysis evaluated a range of customer rate components that compares:

(i) the proposed base rates plus the current Demand-side Investment Mechanisms Rider ("DSIM"), Securitized Utility Tariff Charge ("SUTC")[1], and current Fuel Adjustment Clause ("FAC") rate to

(ii) the current base rates plus the current Energy Efficiency Cost Recovery ("EECR") charge, current DSIM charge, SUTC charge[2], and current FAC rate.

[1] As effective on November 6, 2025. Will need to revise when developing customer notice.
[2] As effective on November 6, 2025. Will need to revise when developing customer notice.

The approximately $152M proposed base rate deficiency will impact monthly bills for a Residential customer using 1,000 kWh per month by $47.41 per month, or 31.05 percent.[3]

However, if the $152M proposed base rate deficiency is adjusted for the portion of test year FAC and EECR revenues collected from customers, the proposed impact on the monthly bill for a Residential customer using 1,000 kWh per month by $32.71 per month, or 19.54 percent.[4]

Furthermore, if the $152M proposed base rate deficiency is adjusted for the amount of the Company's proposed base fuel costs, the proposed increase will impact monthly bills for a Residential customer using 1,000 kWh per month by $38.81 per month, or 24.06 percent.[5]

Q. Please briefly describe the Company's service area.

A. The Company is a regulated utility providing electric service in parts of Missouri, Kansas, Oklahoma, and Arkansas. In the Missouri jurisdiction, the Company provides electric service to residential, commercial and industrial ("C&I"), and street lighting customers. The Company serves an average of 166,405 electric customers in Missouri, including 140,994 (84.73 percent) residential customers, 25,063 (15.06 percent) C&I customers, and 348 (0.21 percent) lighting customers.

Customers are presently served under one of 16 rate classes based on type of service, load characteristics, and customer choice. The rate classes consist of three

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[3] Based on a monthly bill for a Residential customer using 1,000 kWh per month, including DSIM charge of $0.00080 per kWh and SUTC charge of $0.01047 per kWh. SUTC charge is as of Nov. 2024.

[4] Based on a monthly bill for a Residential customer using 1,000 kWh per month, including EECR of $0.00028 per kWh, DSIM charge of $0.00080 per kWh, FAC charge of $0.01442 per kWh based on test year FAC revenues, and Nov. 2024 SUTC charge of $0.01047 per kWh.

[5] Based on a monthly bill for a Residential customer using 1,000 kWh per month, including DSIM charge of $0.00080 per kWh, Nov. 2024 SUTC charge of $0.01047 per kWh, and fuel rebasing charge of $0.00860 per kWh.

residential rate schedules (Non-Standard, Time Choice, and Time Choice Plus) class, ten C&I classes (Non-Standard, Time Choice, and Time Choice Plus General Service; Non-Standard and Time Choice Large General Service; Non-Standard and Time Choice Primary Service; Large Power; Transmission; and Miscellaneous Service), and three Lighting classes, as shown in Figure 2 (below).

Figure 2: Customers and kWh Sales by Current Rate Classes

EDE MO Rate Classes	Number of Customers	% of Customers	Normalized Usage (kWh)	% Usage	kWh Use per Customer
NS-RG	567	0.34%	9,067,286	0.21%	15,992
TC-RG	140,353	84.34%	1,740,855,838	41.21%	12,403
TP-RG	74	0.04%	919,662	0.02%	12,428
NS-GS	966	0.58%	14,305,214	0.34%	14,809
TC-GS	21,269	12.78%	405,154,003	9.59%	19,049
TP-GS	3	0.00%	6,234	0.00%	2,078
NS-LG	319	0.19%	197,590,621	4.68%	619,406
TC-LG	2,403	1.44%	852,362,886	20.18%	354,708
NS-SP	38	0.02%	95,932,609	2.27%	2,524,542
TC-SP	18	0.01%	10,966,305	0.26%	609,239
LP	44	0.03%	800,548,330	18.95%	18,125,623
TS	1	0.00%	67,932,326	1.61%	67,932,326
MS	2	0.00%	135,540	0.00%	65,059
SPL	7	0.00%	16,879,087	0.40%	2,411,298
PL	219	0.13%	11,436,802	0.27%	52,124
LS	122	0.07%	684,952	0.02%	5,637
Total	**166,405**	**100.00%**	**4,224,777,695**	**100.00%**	
Residential	140,994	84.73%	1,750,842,786	41.44%	12,418
General Service	25,063	15.06%	2,444,934,068	57.87%	97,551
Lighting	348	0.21%	29,000,841	0.69%	83,356

Q. Please describe the Company's current rate structure.

A. The Company's current base rate structure consists of base rates which reflect a normalized level of fuel and purchased power costs, and an EECR charge.[6] The base rates include monthly customer charges, energy (kWh) charges, and demand (kW) charges. For certain rate classes, the energy charges vary by season and consist of declining rate steps or blocks; i.e., the rates decrease as monthly consumption increases. For example, the energy charges for the RG class vary by winter (October through

[6] The Company's tariffs are available at: https://central.libertyutilities.com/all/residential/rates/mo-electric-rates.html.

May) and summer (June through September) seasons. The first 600 kWh of monthly energy consumption during the winter season (i.e., first rate step or block) is charged a higher rate than consumption greater than 600 kWh (i.e., second rate step or block). For certain rate classes, the energy charges vary by time-of-use.

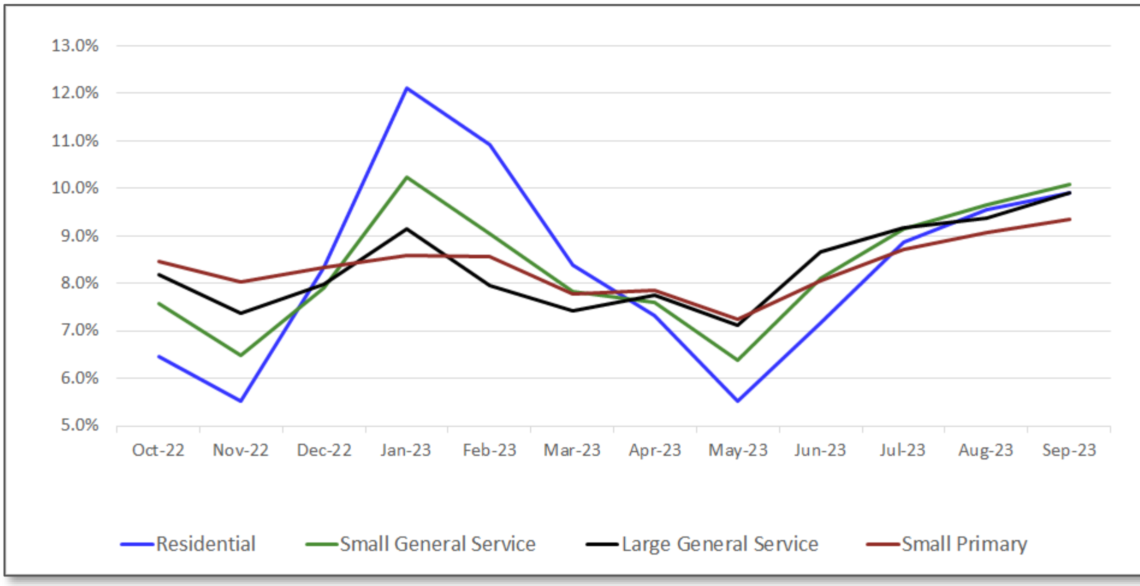
Q. Please describe the Company's rate classes.

A. Figure 2 (above) provides a breakdown of test year customers and kWh sales by rate class. The test year represents the period October 1, 2022 through September 30, 2023. The usage in Figure 2 has been normalized for weather.

The Figure shows the residential rate class in aggregate represents a majority of the Company's customers. The Figure also shows variations in annual use per customer among the rate classes. Residential customers, for example, use on average 12,418 kWh per year, while Large Power customers use on average 18,125,623 kWh per year.

Figure 3 (below) shows monthly kWh usage by rate class. The Figure shows usage varies seasonally for certain rate classes.

Figure 3: Monthly kWh Usage as % of Annual Usage



The Figure shows the residential class, for example, demonstrates a seasonal load pattern, with monthly sales increasing during the winter and summer months, reflecting heating and cooling use, respectively. The C&I rate classes show relatively consistent load patterns throughout the year, with slight increases during the winter and summer months. The load pattern differences, as discussed below, have implications on the allocation of costs in the COSS.

III. REVENUE ADJUSTMENTS

Q. What is the purpose of the revenue adjustments?

A. The purpose of the revenue adjustments is to adjust test year revenues to reflect a normalized level of revenue in a given year utilizing current approved retail rates.

Q. What are the proposed revenue adjustments?

A. The Company proposes three revenue adjustments: (1) weather normalization adjustment, (2) customer annualization adjustment, and (3) load growth/loss adjustment.

Q. What was the approach to derive the weather normalization adjustment?

A. The approach to derive the weather normalization adjustment consisted of (1) utilizing the weather normalization sales kWh adjustment prepared by Company witness Fox, (2) apportioning the weather normalization sales kWh adjustment to each billing determinant to reflect the impact of colder and warmer than normal weather, (3) adjusting the kW demands to reflect the impact of colder and warmer than normal weather, and (4) applying the current base rates to the weather normalization sales kWh adjustments and kW demand adjustments

Q. What was the approach to derive the customer annualization adjustment?

A. The approach to derive the customer annualization adjustment consisted of (1) identifying new customers added during the test year and annualizing their revenues based on class average revenues per customer per month, and (2) identifying existing customers who switched rate classes during the test year and assigning their revenues to the new rate class based on each customer's revenue per month.

Q. What was the approach to derive the load growth/loss adjustment?

A. The approach to derive the load growth/ loss adjustment consisted of (1) identifying significant changes in kWh usage among three Large Power customers during the test year, (2) annualizing the usage to reflect a full year at the new kWh usage, and (3) calculating the difference in revenues between the actual kWh usage and annualized kWh usage.

Q. What were the net results of the revenue adjustment process?

A. The net results of the revenue adjustment process yielded an increase in class revenues of $848,291, as shown in Figure 4 (below).

Figure 4: Summary of Revenue Adjustments

12 ME Sep'23		Adjustments			Normalized
Total Revenue	Actual Revenues	Weather Norm.	Cust. Annualization	Load Growth	Revenues
NS RG-Residential	26,588,837	101,910	(25,360,937)		1,329,809
TC RG-Residential	215,087,792	1,706,452	25,838,849		242,633,092
TP RG-Residential	91,960	678	32,478		125,116
NS GS-General	9,135,734	31,804	(7,052,284)		2,115,255
TC GS-General	50,420,084	73,438	7,524,727		58,018,249
TP GS-General	763	(27)	899		1,635
LG-Large General	42,313,075	(4,913)	(21,605,462)		20,702,699
TC LG-Large General	71,746,451	(210,403)	21,538,223		93,074,270
SP-Small Primary	9,857,806	(9,247)	(303,827)		9,544,732
TC SP-Small Primary	954,652	(649)	248,375		1,202,378
LP-Large Power	69,891,347	-	-	(1,701,792)	68,189,555
TS-Transmission	4,294,509	-	-		4,294,509
MS-Miscellaneous	14,995	-	-		14,995
SPL-Municipal St Lighting	2,306,516	-	-		2,306,516
PL-Private Lighting	4,184,760	-	-		4,184,760
LS-Special Lighting	127,321	-	-		127,321
Total	**507,016,602**	**1,689,042**	**861,041**	**(1,701,792)**	**507,864,892**

IV. ALLOCATED COST OF SERVICE STUDY

Q. Please describe the purpose of a COSS.

A. The purpose of a COSS is to allocate 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.[7]

Q. Please describe the approach used to develop the COSS for this case.

A. The approach to develop the COSS in this rate case filing was based on three steps. First, costs were functionalized or assigned into functional categories. Next, functionalized costs were classified into one of three cost drivers, based on whether the costs are related to: (1) serving peak demands, (2) serving energy demands, or (3) meeting customer service requirements. Finally, classified costs were allocated to each rate class based on methods that best reflect how the costs were incurred.

[7] See Principles of Public Utility Rates by James C. Bonbright.

The three steps were performed using two types of assignments: direct assignment and indirect assignment. Direct assignments utilized the Company's financial and plant records to assign plant investments and expenses to specific functions, classifications, and rate classes. Indirect assignments utilized composite allocators based on direct and indirect assignments developed during the functionalization, classification, and allocation process.

The functionalization, classification, and allocation of costs is included in **Direct Schedule 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.

Q. How were costs functionalized in the COSS?

A. The functionalization of costs in the COSS was based on accounting data arranged 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 into transmission accounts and allocated based on demand allocators. Distribution facilities and associated costs were functionalized into primary and secondary distribution since certain customers take service from only 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:

Customer-related – 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 billing.

Demand-related – 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.

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

Q. What is allocation?

A. Allocation is the process of assigning rate base and expense items to each rate class based on allocators that best reflect how the costs were incurred. In other words, cost allocation should follow how costs were incurred.

Q. What types of allocators were used to develop the COSS?

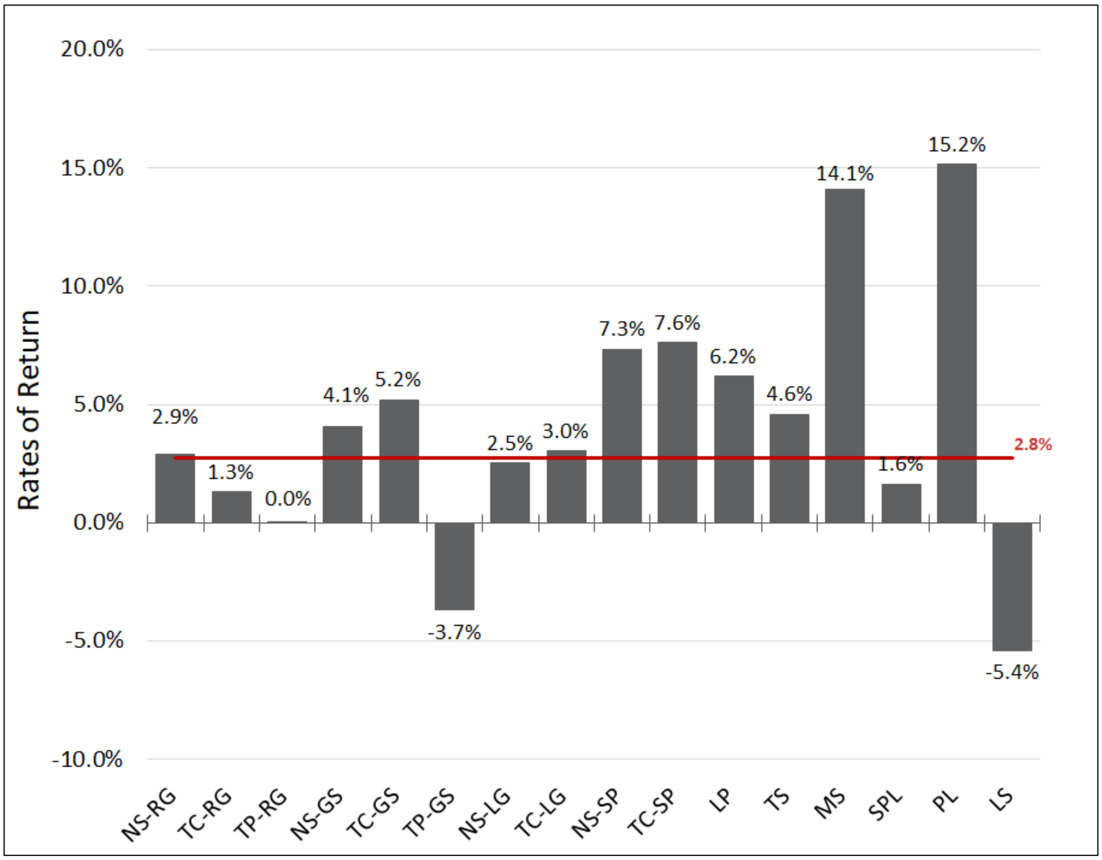
A. Three types of allocators were used to develop the COSS:

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

Q. Please describe the overall results of the Company's cost of service study.

A. The results of the COSS are shown in Figure 1 (replicated below for ease of reference). The Figure compares the calculated ROR for each rate class (based on current rates) to the system or overall ROR (based on current rates).

Figure 5: COSS Results (Replicated)



The Figure shows certain rate classes yield RORs that are less than the system or overall ROR, while others yield RORs that are more than the system or overall ROR.

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., the unit cost of service) varies across the Company's rate classes, as shown in Figure 6 (below).

Figure 6: Unit Cost of Service by Rate Class[8]

	Class Revenue Requirements	
Rate Class	$ per Customer	$ per kWh
NS-RG	$ 3,026	$ 0.19
TC-RG	$ 2,482	$ 0.20
TP-RG	$ 2,767	$ 0.22
NS-GS	$ 2,610	$ 0.18
TC-GS	$ 3,043	$ 0.16
TP-GS	$ 1,146	$ 0.55
NS-LG	$ 86,962	$ 0.14
TC-LG	$ 50,019	$ 0.14
NS-SP	$ 250,509	$ 0.10
TC-SP	$ 65,514	$ 0.11
LP	$ 1,627,733	$ 0.09
MS	$ 5,533	$ 0.09
SPL	$ 616,730	$ 0.26
PL	$ 13,790	$ 0.26
LS	$ 4,276	$ 0.76

The Figure shows, for example, the unit cost of service for Schedule TC-RG is $2,482 per customer, while the unit cost of service for Schedule LP is $1,627,733 per customer. By comparison, the unit cost of service for Schedule TC-RG is $0.20 per kWh, while the unit cost of service for Schedule LP is $0.09 per kWh.

Q. How do variations in the unit cost of service relate to the class rates of return?

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 yields a ROR for each rate class that is equal to the system ROR.

Q. What conclusions can be reached when a rate class ROR is higher or lower than the system ROR?

A. If a rate class yields a ROR that is lower than the system ROR (assuming the system ROR achieves full cost of service recovery), then the revenues recovered from the rate

[8] For confidentiality purpose, TS rate class average cost of service is not shown in this testimony.

class are less than its cost of service. Conversely, if a rate class yields 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 study results were used as a guide to establish revenue targets for each rate class, subject to bill continuity concerns, 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 study was based on test year data for the period October 1, 2022 through September 30, 2023. 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, annualization of customers switching among rate class, and customer, sales, and revenue growth/ loss.

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 deferred income taxes ("ADIT"), customer deposits, customer advances for construction, and other regulatory liabilities. The COSS also includes operations and maintenance ("O&M") expenses, including transmission, distribution, customer service, customer account, sales, administrative and general expenses, income taxes, and taxes other than income taxes, such as payroll and property taxes.

Q. Please describe the functionalization process used in developing the COSS.

A. As discussed earlier, functionalization is an important first step in development of the COSS study. 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 expenses.
- Transmission – plant investment and expenses associated with the Company's high voltage transmission facilities. These include transmission plant, accumulated depreciation, depreciation expense, and related O&M expenses.
- 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 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 – expenses associated with providing customer service. These costs are largely related to customer service, customer accounts, and sales expenses.

The remaining rate base and cost of service accounts were assigned to one of 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, distribution, and customer service expenses.

The functionalization of costs is included in **<u>Direct Schedule TSL-3.</u>**

Q. Please describe the classification process used in developing the COSS study.

A. The COSS study was classified into one of the following three categories:

- Customer – costs associated with providing customer access to the electric system as well as providing on-going customer service, such as billing services.
- Demand – costs associated with meeting customer peak demand requirements.
- Energy – costs associated with meeting customer energy requirements.

In some cases, costs were classified into only one of three categories. The cost of billing services, for example, was classified as customer. In other cases, costs were classified into more than one category. For example, the cost associated with primary distribution plant was classified based on its underlying characteristics. Some costs were classified as customer, while others were classified as demand.

Q. Please explain the classification of distribution facilities.

A. Distribution plant represents 33.70 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 cost driver is peak demands, i.e., distribution facilities are designed to meet customer peak demands throughout the year. The 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.[9]

The classification of distribution plant in this study is consistent with the approach described in the NARUC manual as well as the approach described in the Company's prior rate case filing in Case No. ER-2021-0312. As discussed earlier, distribution plant and related costs were separated into two functions: primary and secondary distribution. The primary distribution facilities and line transformers were classified as customer- or demand-related, while Secondary distribution facilities were generally classified as customer-related.

Q. Please explain the approach used 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 (Accounts 360-363), the plant was classified as demand and allocated to each rate class based on class Non-Coincident Peak ("NCP") demands. Substations generally reflect the peak demands of customers served from the substation and thus can peak at times different

[9] NARUC Electric Utility Cost Allocation Manual, p. 90.

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. The customer-related costs are allocated to each rate class based on the number of customers. The demand-related costs are allocated to each rate class based on customer peak demands.

Q. Please describe the methods to classify Accounts 364-368 costs between customer and demand.

A. There are two methods recognized in the NARUC manual for classifying Accounts 364-368 costs between customer and demand: the 'minimum-size' and 'zero-intercept' methods.

The minimum-size method represents the 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 minimum demand requirements of customers. The "minimum system" costs are classified as customer-related, while distribution plant in excess of the minimum system reflect the cost of serving customer peak demands and is classified as demand-related. The approach is described in the NARUC manual as follows:

> 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.[10]

[10] NARUC Electric Utility Cost Allocation Manual, p. 90.

The zero-intercept method represents the cost of connecting customers to the system with a hypothetical "zero size" facility. The method includes a regression analysis conducted to examine the relationship between the facility sizes and their average costs. The intercept of the regression equation represents the average cost of a hypothetical zero size facility. The "zero size" facility costs are classified as customer-related, while distribution plant in excess reflects the cost of serving customer peak demands and is classified as demand-related. The approach is described in the NARUC manual as follows:

> The minimum-intercept method seeks to identify that portion of plant related to a hypothetical no-load or zero-intercept situation….The technique is related to installed cost to current carrying capacity or demand rating, creating a curve for various sizes of the equipment involved, using regression techniques, and extend the curve to a no-load intercept. The cost related to the zero-intercept is the customer component.[11]

Q. Please describe the Company's approach to classify Accounts 364-368 costs between customer and demand in this proceeding.

A. The Company classified distribution plant for Accounts 365, 367 and 368 based on using the minimum-size method and for Accounts 364 and 366 based on using the zero-intercept methods. The minimum-size and zero-intercept methods utilized the Company's installed costs for each plant account adjusted for current dollars utilizing the Handy-Whitman Index of Public Utility Construction Costs ("Handy-Whitman").

Q. Please summarize the results of the zero-intercept and minimum-size studies.

A. The results of the studies are provided in **<u>Direct Schedule TSL-3</u>**.

- Poles, Towers, and Fixtures (Account 364): The Company's minimum-size and zero-intercept studies for Account 364 resulted in, respectively, 44.7 percent

[11] Id. at p. 92.

and 39.3 percent of costs classified as customer-related. Since both methods are recognized by NARUC, the Company used the lower of the two results for use in the COSS study, i.e., 39.3 percent of costs are classified as customer-related with the remaining portion classified as demand-related.

- Overhead conductors and devices (Account 365): The Company's minimum-size study for Account 365 resulted in 35.5 percent of costs classified as customer-related with the remaining portion as demand-related.
- Underground Conduits (Accounts 366): The Company's minimum-size and zero-intercept studies for Account 366 resulted in, respectively, 54.3 percent and 46.1 percent of costs classified as customer-related. Since both methods are recognized by NARUC, the Company used the lower of the two results for use in the COSS study, i.e., 46.1 percent of costs are classified as customer-related with the remaining portion classified as demand-related.
- Underground Conductors and Devices (Accounts 367): The Company's minimum-size study for Account 367 resulted in 39.6 percent of costs classified as customer-related with the remaining portion as demand-related.
- Line Transformers (Account 368): The Company's minimum size study resulted in 45.6 percent of costs classified as customer-related with the remaining portion classified as demand-related.

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 and service cost investments were classified as customer-related since they enable customers access to the electric system. Rate base items which are not directly associated with one of the classification categories, such as intangible plant, were classified using a composite classifier based on the classification of total plant.

Q. Please discuss the classification of operations and maintenance expenses.

A. O&M expenses were classified in a manner similar to their respective plant items. 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 study.

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.

The allocation of costs is included in **Direct Schedule TSL-3**.

Q. What methodology was used to allocate production plant costs?

A. The methodology to allocate production plant costs was the Average and Excess ("A&E") 8NCP method. The method is consistent with the Company's approach to designing and building production facilities.

Q. Please describe the development of the A&E allocator.

A. The A&E allocator 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 average demand, which represents the energy portion of 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 100.0 percent load factor.

The second component of the A&E allocator is excess demand, which represents the peak demand portion of production plant. It represents each rate class's share of the peak demand – i.e., the demand in excess of the average demand. This component is calculated as each rate class's share of the excess demand – or the difference between the class peak demand and the class average demand. The rate class peak demand is based on NCP demands, consistent with the methodology described in the NARUC Manual.[12] The approach to calculate the A&E allocator in the Company's class cost of service study followed the methodology described in the NARUC Manual, which utilizes NCP demands rather than Coincident Peak ("CP") demands.[13] The

[12] NARUC Electric Utility Cost Allocation Manual, pp. 49-52.
[13] Id. at p. 50.

NARUC Manual points out that it is a "mistake" to use CP demands instead of NCP demands since it produces an allocator that is equivalent to a CP allocator.[14] Thus, using the CP demands approach is contrary to the purpose of the A&E allocator since the A&E allocator is designed to allocate costs based on peak and average demands. 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 were based on an average of four months of winter (December through March) and four months of summer (June through September). The method is consistent with the Company's planning requirements, which are based on the Southwest Power Pool's ("SPP") resource adequacy requirements in the summer and winter periods. The summer requirements are based on peak loads and reserve margins in June through September, while the winter requirements are based on peak loads and reserve margins in December through March.

The A&E allocators were developed utilizing average demand (kWh), and CP and NCP demand data gathered by the Company for each customer class through its AMI meter reading data. The CP demand represents class demand at the time of the system peak, while NCP represents aggregate customer peak demand.

Derivation of the A&E allocator is included in **Direct Schedule TSL-3**.

Q. Please describe the results of the A&E method.

A. Figure 7 (below) shows the results of the A&E method.

[14] NARUC Electric Utility Cost Allocation Manual states at page 50: "If your objective is -- as it should be using this method -- to reflect the impact of average demand on production plant costs, then it is a mistake to allocate the excess demand with a coincident peak allocation factor because it produces allocation factors that are identical to those derived using a CP method. Rather, use the NCP to allocate the excess demands."

Figure 7: Results of A&E Method

Average and Excess (8 NCP)						
Rate Class	Peak Demand 8 NCP (MW)	Average Demand (MW)	Excess Demand (MW)	Average Demand (%)	Excess Demand (%)	A&E Allocator (%)
NS Residential	2,703	1,121	1,582	0.22%	0.32%	0.27%
TC Residential	507,978	215,302	292,676	41.42%	58.41%	50.61%
TP Residential	283	114	170	0.02%	0.03%	0.03%
NS General Service	3,681	1,769	1,912	0.34%	0.38%	0.36%
TC General Service	96,702	50,108	46,594	9.64%	9.30%	9.46%
TP General Service	3	1	2	0.00%	0.00%	0.00%
NS Large General	48,924	24,437	24,487	4.70%	4.89%	4.80%
TC Large General	198,142	105,417	92,725	20.28%	18.50%	19.32%
NS Small Primary	18,065	11,576	6,489	2.23%	1.29%	1.72%
TC Small Primary	2,521	1,323	1,198	0.25%	0.24%	0.25%
Large Power	124,676	96,887	27,789	18.64%	5.55%	11.56%
Transmission	8,451	8,111	340	1.56%	0.07%	0.75%
MS-Miscellaneous	17	17	0	0.00%	0.00%	0.00%
SPL-Municipal St Lighting	4,658	2,088	2,570	0.40%	0.51%	0.46%
PL-Private Lighting	3,227	1,414	1,813	0.27%	0.36%	0.32%
LS-Special Lighting	847	85	762	0.02%	0.15%	0.09%
Total	1,020,879	519,770	501,109	100.00%	100.00%	100.00%

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. The Figure shows that the TC-RG rate class allocator is 50.61 percent based on the A&E method, representing a composite of their average demand of 41.42 percent and their peak (in excess of average) demand of 58.41 percent.

The A&E method in this study is generally consistent with the methodology described in the NARUC Manual and the methodology used in the Company's most recent rate case proceeding.

Q. What was the method to allocate transmission plant?

A. Transmission plant represents 16.50 percent of the Company's utility plant. Transmission costs are incurred consistent with the design of the Company's 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 SPP. Thus, transmission plant is allocated based on 12-month average coincident peak ("12CP"). The 12CP allocator is recognized by NARUC as a reasonable transmission cost allocator,[15] and it is consistent with the methodologies utilized in the Company's prior rate case filing.

Q. What was the method to allocate distribution plant costs?

A. Distribution costs are incurred consistent with the design of the Company's distribution facilities to provide customer access to the electric system (customer-related) and to meet customer peak demands throughout the year (demand-related).

The Company allocated the demand portion of distribution costs based on the 1NCP method. The method reflects that the distribution plant is designed to meet customer peak demands.

Q. Please describe the process used to develop special studies allocators.

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

- <u>Meter investments</u> 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.
- <u>Service investments</u> 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.
- <u>Line transformers</u> were allocated based on number of customers for each customer class. The number of customers were weighted to reflect the average

[15] NARUC Electric Utility Cost Allocation Manual, p. 79.

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 RG customers per Company estimates).

The approach to prepare the special studies is consistent with the methodologies utilized in the Company's prior rate case filing.

Derivation of the meter and services allocators is included in **Direct Schedule TSL-3**.

Q. Please describe the process 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,[16] and it is consistent with the methodologies utilized in the Company's prior rate case filing.

Q. Please describe the allocation of O&M expenses to the customer classes.

A. O&M expenses were allocated generally consistent with their respective plant accounts. For example, fixed production O&M expenses were allocated using the A&E Method. Similarly, the allocation of distribution O&M expenses followed the allocation of their respective plant account.

[16] NARUC Electric Utility Cost Allocation Manual, p. 105.

V. OVERVIEW OF RATE DESIGN

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.[17]

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, demand, and energy charges based on test year bills, kW billing demands, 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 class 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 presently some rate classes yield a ROR that is less than the overall ROR. The proposed rate design reduces that difference by proposing rate increases for certain rate classes 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 then again while setting rate elements.

Q. Please summarize the steps taken to develop the proposed rates.

[17] See Bonbright, James, Danielsen, Albert, and Kamerschen, David. "Principles of Public Utility Rates." Public Utilities Reports, Inc. pp. 377-407 (2nd Ed. 1988).

A. The first step to develop the proposed rates was to establish the overall revenue requirement to be recovered by 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 Schedule TSL-4**. Rates within each rate class were then designed to recover the revenue targets based on test year customer, kW demand, and kWh 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 Charlotte T. Emery, which indicates a total revenue requirement of $668.4 million. The total revenue requirement was then reduced by revenues other than base rates to calculate base rate revenue requirements.

Q. Please describe the process to set class revenue targets for each rate class.

A. Since each rate class currently yields 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 for each rate class. 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 kWh sales charges, and for certain rate classes kW demand charges, as shown in **Direct Schedule TSL-5**.

VI. RATE DESIGN AND BILL IMPACT ANALYSES

Q. What was the process to derive class revenue targets for each rate class.

A. To mitigate bill impact concerns, the proposed class revenue targets for each rate class were based on a 10.0 percent movement toward Equalized Rates of Return ("EROR"), as shown in **Direct Schedule TSL-4**.

Specifically, **Direct Schedule TSL-4** shows revenue requirements for each rate class based on their cost of service with full movement to EROR. The percentage increase in revenues for the Residential TC-RG class with full movement to EROR is 43.2 percent, or 1.46 times the overall percentage increase in revenues. The Figure also shows revenue requirements for each rate class based on a uniform increase in revenues with no movement toward EROR. The revenue increase for the Residential class is 29.60 percent, consistent with the overall revenue increase.

However, the Company believes a 10.0 percent movement to EROR strikes an appropriate balance between moving to cost-based rates (full movement to EROR) and addressing rate continuity considerations (uniform increase in revenues).

Q. Please describe the proposed revenue requirement targets for each rate class.

A. The proposed revenue requirement targets for each class are presented in Figure 8 (below).

Figure 8: Target Revenues

Rate Class		Proposed Revenues		Current Revenues		Increase $	Increase %
NS-RG Residential	$	1,741,947	$	1,344,630	$	397,317	29.5%
TC-RG Residential		320,291,800		244,494,482		75,797,317	31.0%
TP-Residential		167,932		126,278		41,653	33.0%
NS-GS General Service		2,741,804		2,132,347		609,456	28.6%
TC-GS General Service		74,747,152		58,476,210		16,270,942	27.8%
TC-GS General Service		2,268		1,648		620	37.6%
NS-LG Large General		27,152,465		20,878,486		6,273,978	30.0%
TC-LG Large General		121,556,975		93,815,800		27,741,176	29.6%
NS-SP Small Primary		12,669,799		10,003,508		2,666,291	26.7%
TC-SP Small Primary		1,799,107		1,422,036		377,071	26.5%
LP-Large Power		89,047,549		70,001,656		19,045,893	27.2%
TS-Transmission		6,466,645		5,064,450		1,402,195	27.7%
SPL-Municipal Lighting		18,809		15,121		3,687	24.4%
MS-Miscellaneous		4,531,768		3,418,650		1,113,119	32.6%
PL-Private Lighting		5,238,363		4,226,641		1,011,722	23.9%
LS-Special Lighting		201,505		128,106		73,398	57.3%
Total Company	**$**	**668,375,888**	**$**	**515,550,051**	**$**	**152,825,837**	**29.6%**

Q. Please describe the proposed rate design for the residential rate class.

A. The proposed residential rates were based on a revenue requirement of $322.2 million, which represents an increase of $76.2 million, or 31.0 percent. The proposed rates were based on 1.7 million residential bills and 1.7 million MWH in residential sales.

The proposed customer charge of $16.00 per month is well below the underlying cost of service, as shown in **Direct Schedule TSL-5**. The Schedule shows basic customer-related costs of $30.81 per customer per month and fully loaded customer-related costs of $48.59. The Company proposes an increase to the customer charge as a step towards full recovery of the Company's fixed costs in the fixed charge component. The increase in customer charge has two benefits: (1) it helps mitigate a basic misalignment between the structure of utility rates and the structure of utility costs; and (2) it helps minimize intra-class subsidies.

The revenue requirement not recovered through the customer charge is recovered from winter volumetric charges of $0.19774 per kWh for the first 600 kWh of usage and $0.13981 per kWh for all additional usage and summer volumetric charges of $0.19774 per kWh for the first 600 kWh of usage and $0.16837 per kWh for all additional usage. The proposed volumetric charges for the first 600 kWh of usage reflect customer costs not recovered in the proposed customer charge. The proposed TC-RG rate design maintains the current Off-Peak kWh credit of $0.02000 for usage during the Off-Peak period between 10:00 PM and 6:00 AM. The proposed rate design and bill impact analyses are included in **Direct Schedule TSL-5**.

Overall, the proposed revenue deficiency will increase the monthly bill of a Residential customer using 1,000 kWh per month by $47.41 per month, or 31.05 percent.[18]

Q. Please describe the proposed rate design for the C&I rate classes.

A. The proposed revenue deficiency for C&I and Lighting rate classes are developed based on the revenue targets presented in Figure 8 (above). The proposed revenue targets, billing determinants, rate design and bill impact analyses are included in **Direct Schedule TSL-5**.

Q. Is the Company proposing any new lamp charges in the lighting schedules?

A. Yes. The Company is proposing to add an additional 4,000 to 5,000 lumens LED lamp size as part of Private Lighting Service ("Schedule PL").

Q. Does the proposed rate design for C&I customers reflect seasonal demand charges?

[18] Based on a monthly bill for a Residential customer using 1,000 kWh per month, including DSIM charge of $0.00080 per kWh and SUTC charge of $0.01047.

A. Yes. As shown in **Direct Schedule TSL-5**, the proposed rate design for the LG and LP rate cases reflects seasonal demand charges.

Q. Have you examined the impact of your proposed changes in base rates on customers for each rate class?

A. Yes. As shown in **Direct Schedule TSL-5**, the Company prepared a total bill impact analysis to evaluate the impact of the proposed base rate changes.

Q. What is the annual bill impacts for residential and commercial customers?

A. Figures 9 through 11 (below) present the Minimum Filing Requirement as stated by 20 CSR 4240-3.030(3)(B)(3), (4) & (5) for the residential and commercial customer classes in three variations:

1) Figure 9 represents bill impacts based on the $152M of proposed deficiency in base rates,
2) Figure 10 represents bill impacts based on the $152M adjusted for the portion of test year FAC and EECR revenues collected from customers, and
3) Figure 11 represents bill impacts based on the $152M adjusted for the amount of the Company's proposed base fuel costs.

Figure 9: Bill Impact Analysis – $152M Base Rate Deficiency

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4 CSR 240-3.030(3)(B)(3)(4)(5)

Customer Classes	Average Customer Count	Average Customer Impact [1] Bill Change $	Bill Change %	Aggregate Class Impact Annual Change $	Annual Change %
Residential (NS-RG, TC-RG, TP-RG)	140,994	542	29.0%	76,423,866	29.0%
General Service (NS-GS, TC-GS, TP-GS)	22,238	761	26.1%	16,917,197	26.1%
Large General (NS-LG, TC-LG)	2,722	12,529	27.1%	34,104,040	27.1%
Small Primary (NS-SP, TC-SP)	56	54,475	25.5%	3,050,619	25.5%
LP-Large Power	44	432,192	24.7%	19,088,486	24.7%
TS-Transmission	1	1,036,483	20.5%	1,036,483	20.5%
MS-Miscellaneous	2	1,773	22.5%	3,693	22.5%
SPL-Municipal St Lighting	7	159,260	44.9%	1,114,820	44.9%
PL-Private Lighting	219	4,616	23.5%	1,012,903	23.5%
LS-Special Lighting	122	607	54.8%	73,729	54.8%
Total	166,405			$ 152,825,837	27.5%

(1) The current annual bill reflects the current base rates, DSIM of $0.00080, and SUTC of $0.01047.
The proposed annual bill reflects the proposed base rates, DSIM of $0.00080, and SUTC of $0.01047.

Figure 10: Bill Impact Analysis – $152M Base Rate Deficiency Adjusted for Test Year FAC & EECR Revenue

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4 CSR 240-3.030(3)(B)(3)(4)(5)

Customer Classes	Average Customer Count	Average Customer Impact [1] Bill Change $	Bill Change %	Aggregate Class Impact Annual Change $	Annual Change %
Residential (NS-RG, TC-RG, TP-RG)	140,994	359	17.5%	50,687,148	17.5%
General Service (NS-GS, TC-GS, TP-GS)	22,238	485	15.2%	10,794,101	15.2%
Large General (NS-LG, TC-LG)	2,722	6,935	13.4%	18,876,828	13.4%
Small Primary (NS-SP, TC-SP)	56	26,874	11.1%	1,504,923	11.1%
LP-Large Power	44	190,675	9.6%	8,421,467	9.6%
TS-Transmission	1	71,354	1.2%	71,354	1.2%
MS-Miscellaneous	2	843	9.6%	1,756	9.6%
SPL-Municipal St Lighting	7	123,712	31.7%	865,985	31.7%
PL-Private Lighting	219	3,869	19.0%	848,839	19.0%
LS-Special Lighting	122	529	44.6%	64,224	44.6%
Total	166,405			$ 92,136,624	15.0%

(1) The current annual bill reflects the current base rates; Test Year FAC, Test Year EECR, DSIM of $0.00080, and SUTC of $0.01047.
The proposed annual bill reflects the proposed base rates, DSIM of $0.00080, and SUTC of $0.01047.

Figure 11: Bill Impact Analysis – $152M Base Rate Deficiency Adjusted for Company's Proposed Base Fuel Costs

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4 CSR 240-3.030(3)(B)(3)(4)(5)

Customer Classes	Average Customer Count	Average Customer Impact [1] Bill Change $	Bill Change %	Aggregate Class Impact Annual Change $	Annual Change %
Residential (NS-RG, TC-RG, TP-RG)	140,994	435	22.0%	61,369,031	22.0%
General Service (NS-GS, TC-GS, TP-GS)	22,238	599	19.4%	13,310,372	19.4%
Large General (NS-LG, TC-LG)	2,722	9,212	18.6%	25,075,887	18.6%
Small Primary (NS-SP, TC-SP)	56	38,061	16.6%	2,131,435	16.6%
LP-Large Power	44	276,337	14.5%	12,204,874	14.5%
TS-Transmission	1	452,359	8.0%	452,359	8.0%
MS-Miscellaneous	2	1,213	14.4%	2,527	14.4%
SPL-Municipal St Lighting	7	138,526	36.9%	969,683	36.9%
PL-Private Lighting	219	4,168	20.8%	914,562	20.8%
LS-Special Lighting	122	558	48.3%	67,839	48.3%
Total	166,405			$ 116,498,570	19.7%

(1) The current annual bill reflects the current base rates; and FAC Rebase of $0.00860, DSIM of $0.00080, and SUTC of $0.01047.
The proposed annual bill reflects the proposed base rates, DSIM of $0.00080, and SUTC of $0.01047.

Q. Has the Company updated electric grid charges for the Community Solar Pilot Program ("Schedule CSPP")?

A. Yes. The electric grid charges for solar energy in Schedule CSPP have been updated to reflect the Company's proposed class cost of service and rate design. The updated electric grid charges are generally based on the methodology approved by the Commission in Case No. ET-2020-0259.[19] The updated electric grid charges are presented in **Direct Schedule TSL-5**.

Q. Has the Company updated the tariffs related to electrification pilot programs?

A. Yes. The Company has updated tariffs for Residential Smart Charge Pilot Program ("Schedule RG-SCPP"), Ready Charge Pilot Program ("Schedule RCPP"), Commercial Electrification Pilot Program ("Schedule CEPP"), and Electric School Bus Pilot Program ("Schedule ESBPP"). These tariff schedules are updated to reflect the

[19] File No. ET-2020-0259, Order Approving Stipulation and Agreement (May 13, 2023).

Company's proposed class cost of service and rate design. The charges are updated consistent with the methodology approved by the Commission in Case No. ET-2020-0390.[20] The updated charges are presented in **Direct Schedule TSL-5**.

VII. COMMITMENTS FROM OTHER CASES

Q. Will the Company provide billing determinants consistent with the Stipulation in Case No. EE-2024-0232?[21]

A. Yes. The Company will provide in its update filing billing determinants consistent with the Stipulation in Case No. EE-2024-0232.

Q. Has the Company identified customer-specific transmission and distribution investments that are recovered through the Excess Facilities Rider ("Schedule XC") and 'Transformer Ownership' charges, consistent with Item 21.c in the Stipulation in Case No. ER-2021-0312?

A. Yes. The Company identified and directly assigned to the respective FERC Accounts and rate classes in the COSS customer-specific transmission and distribution investments recovered through Schedule XC and Transformer Ownership charges.

Q. Has the Company developed time-variant demand charges consistent with Item 21.a in the Stipulation in Case No. ER-2021-0312?

A. Yes. The Company developed time-variant demand charges with supporting billing determinants for classes with demand charges, as shown in **Direct Schedule TSL-5**.

[20] File No. ET-2020-0390, Order Approving Stipulation and Agreement (January 29, 2022).

[21] "In its next general rate case, Liberty will provide each tariffed rate class billing determinants (customer usage, number of bill and number of customers) by month, cycle with cycle dates that were utilized for billing purposes, and season to Staff in the following format: raw billing determinants, any and all adjustments separately (for proration, season, or any other reason) that were made to raw billing determinants, and the ending billing determinants. The ending monthly billing determinants should be the billing determinants Liberty utilizes to conduct its revenue requirement analysis in its general rate case."

VIII. CASH WORKING CAPITAL REQUIREMENT

Q. Please define the term "Cash Working Capital."

A. The term "cash working capital" refers to the net funds required by the Company to finance goods and services used to provide service to customers from the time those goods and services are paid for by the Company to the time that payment is received from customers. Goods and services considered in the Company's lead-lag study include O&M expenses, including labor and non-labor expenses; federal, state, and local taxes; and employment taxes.

Q. Please describe the Company's lead-lag study.

A. The Company's lead-lag study consists of two components: a revenue lag and expense leads. The revenue lag represents the number of days from the time customers receive service to the time customers pay for their service, *i.e.,* when the funds are available to the Company. The longer the revenue lag, the more cash the Company needs to finance its day-to-day operations.

The expense lead represents the number of days from the time the Company receives goods and services used to provide service to the time payments are made for those goods and services, *i.e.,* when the funds are no longer available to the Company. The longer the expense lead, the less cash the Company needs to fund its day-to-day operations. Together, the revenue lag and expense leads are used to measure the lead-lag days.

The results of the lead-lag study were used to determine the Company's CWC requirement by applying the lead-lag days to the Company's adjusted test year expenses. The CWC requirement is included in the Company's rate base.

Q. What lead-lag study did the Company rely upon for its calculation of the CWC requirement?

A. The Company relied in large part on its lead-lag study approved by the Commission in its most recent, fully litigated rate proceeding in Case No. ER-2019-0374. Specifically, the Company utilized the expense lead days that were approved by the Commission in that proceeding.

The Company utilized the revenue lag days that were calculated in its most recent rate case filing in Case No. ER-2021-0312 to reflect more recent collections experience.

Q. What is the Company's proposed CWC requirement?

A. The Company proposes a CWC requirement of (negative) $9.6 million, as shown in the revenue requirements workpaper RB ADJ 5.

IX. CONCLUSION

Q. Please briefly summarize your direct testimony.

A. This testimony describes the approach used to design the proposed electric rates for the Missouri jurisdiction of the Company. The proposed base 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.

The Company's proposed rate design is based on the results of the Company's COSS, which shows that the current rate design produces a disparity in class rates of return. The results of the COSS support a movement toward a more equitable rate structure where class RORs move closer to the system ROR.

The Company prepared a bill impact analysis to evaluate the impact of the proposed revenue change. Overall, the proposed change of $152M base rate deficiency will impact monthly bills for a Residential customer using 1,000 kWh per month by $47.41 per month, or 31.05 percent.[22]

Q. Does this conclude your direct testimony at this time?

A. Yes, it does.

[22] Based on a monthly bill for a Residential customer using 1,000 kWh per month, including DSIM charge of $0.00080 per kWh and SUTC charge of $0.01047 per kWh.

VERIFICATION

I, Timothy S. Lyons, under penalty of perjury, on this 26th day of February, 2025, declare that the foregoing is true and correct to the best of my knowledge and belief.

/s/ Timothy S. Lyons