Exhibit No.: _____
Issues: CCOS, Rate Design, CWC
Witness: Timothy S. Lyons
Type of Exhibit: Direct Testimony
Sponsoring Party: Liberty Utilities (Midstates Natural Gas) Corp. d/b/a Liberty
Case No.: GR-2024-0106
Date Testimony Prepared: February 2024

Before the Public Service Commission
of the State of Missouri

Direct Testimony

of

Timothy S. Lyons

on behalf of

Liberty Utilities (Midstates Natural Gas) Corp. d/b/a Liberty

February 9, 2024

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FOR THE DIRECT TESTIMONY OF TIMOTHY S. LYONS
LIBERTY UTILITIES (MIDSTATES NATURAL GAS) CORP. D/B/A LIBERTY
BEFORE THE MISSOURI PUBLIC SERVICE COMMISSION
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SUBJECT **PAGE**

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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. 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 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 in 2013. Sussex was acquired by ScottMadden in 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.

Q. On whose behalf are you testifying?

A. I am testifying on behalf of Liberty Utilities (Midstates Natural Gas) Corp. d/b/a Liberty ("Liberty" or the "Company").

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

A. Yes. A summary of my testimony experience is included in **Direct Schedule TSL-1**.

II. PURPOSE OF TESTIMONY

Q. What is the purpose of your direct testimony?

A. The purpose of my testimony is to sponsor the proposed distribution base rates for Liberty. Presently, the two sets of distribution base rates for the Company's two service districts in Missouri are determined by two sets of revenue requirement/cost of service calculations for each respective district. One set of distribution base rates is for customers in Northeast Missouri ("NEMO") and Western Missouri ("WEMO") service area ("NEMO/WEMO"), and a second set of distribution base rates is for customers in the Southeast Missouri ("SEMO") service area[1].

In this proceeding, the Company proposes to further consolidate the revenue requirement calculation to determine its distribution base rates. However, due to bill impact considerations discussed further in my testimony, the Company proposes to continue having separate distribution base rates for SEMO Residential ("RS") and Small General Service ("SGS") customers and one set of distribution base rates for all remaining customers.

To support the Company's proposed distribution base rate design and Class Cost of Service ("COSS") my testimony includes: (a) description of the Company's rate classes and current rates; (b) description of the allocated COSS; (c) description of

[1] Approved by the Commission in the Company's prior base rate proceeding in Case No. GR-2018-0013.

the proposed revenue targets, distribution base rate design, and bill impact analysis for each rate class; and (d) discussion of the Company's inverted or inclining rate structure.

Lastly, my testimony supports the results of the lead-lag study. The lead-lag study was used to determine the Company's cash working capital requirement, which is included in the Company's rate base, reflected in Company witness Charlotte T. Emery's RB ADJ-5.

Q. Have you prepared schedules to support your testimony?

A. Yes. My testimony is supported by the schedules below. The direct schedules were prepared by me or under my direction.

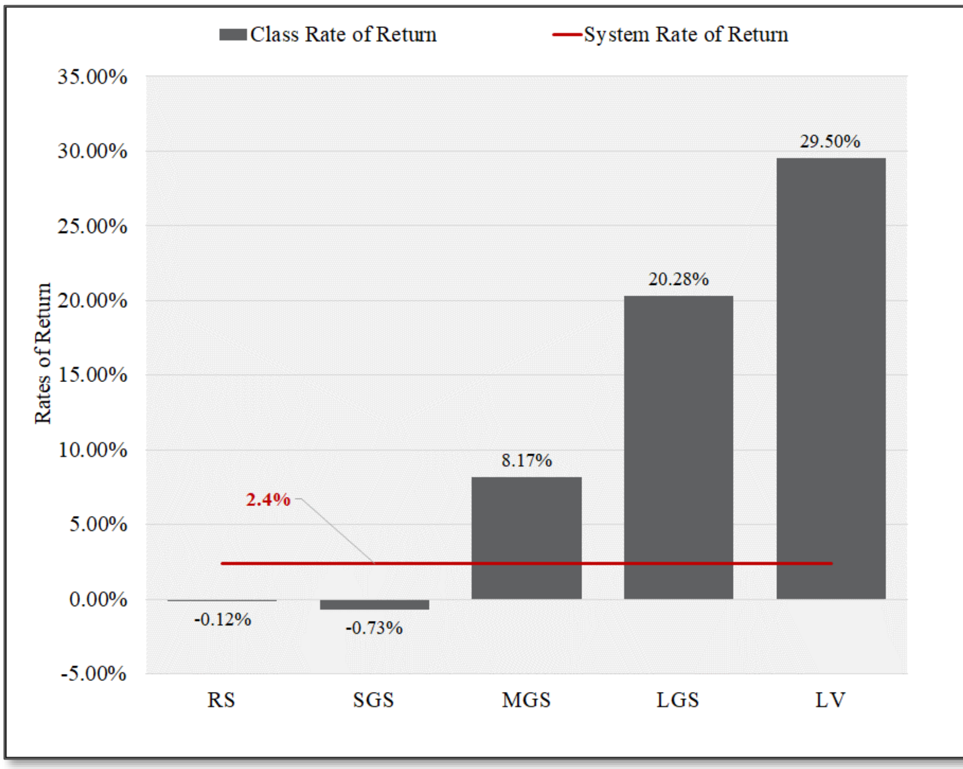
LIST OF SCHEDULES

DIRECT SCHEDULE TSL-1	Qualifications
DIRECT SCHEDULE TSL-2	COSS Summary Results
DIRECT SCHEDULE TSL-3	COSS Schedules
DIRECT SCHEDULE TSL-4	Mains Classification Factor
DIRECT SCHEDULE TSL-5	Demand Allocator
DIRECT SCHEDULE TSL-6	Meter and Services Allocator
DIRECT SCHEDULE TSL-7	Revenue Targets
DIRECT SCHEDULE TSL-8	Rate Design and Bill Impact Analysis
DIRECT SCHEDULE TSL-9	Analysis of Inclining Rate Structure
DIRECT SCHEDULE TSL-10	Summary of Lead-Lag Study
DIRECT SCHEDULE TSL-11	Lead-Lag Study Schedules

Q. Please summarize your COSS 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 Summary Results



The Figure shows the RS and SGS rate classes yield RORs below the system ROR while the remaining rate classes yield RORs above the system ROR. Except as noted below, the approach used to prepare the Company's COSS in this distribution base rate proceeding was generally consistent with the approach utilized in the Company's prior base rate proceeding in Case No. GR-2018-0013[2].

[2] *Case GR-2018-0013, In the Matter of Liberty Utilities (Midstates Natural Gas) Corp. d/b/a Liberty Utilities' Tariff Revisions Designed to Implement a General Rate Increase for Natural Gas Service in the Missouri Service Area of the Company.*

The proposed distribution base rates reflect three important rate design principles: (a) rates should recover the overall cost of providing service; (b) rates should be fair and equitable in that each rate class should recover the costs caused by that customer class, minimizing inter- and intra-class inequities to the extent possible; and (c) rate changes should be tempered by rate continuity concerns. Because these principles can conflict, the proposed rate design reflects a level of judgment to balance these principles.

The proposed distribution base rates result in movement towards a more fair and equitable rate structure where class RORs move closer to the system ROR. However, the movement towards the system ROR was moderated to address customer bill impact considerations.

As mentioned earlier, the Company proposes one set of distribution base rates for customers in its Missouri service area, except for those customers in the SEMO Residential and SGS rate classes, as shown in Figure 2 (below).

Figure 2: Proposed Distribution Base Rates

Liberty Utilities (Midstates Natural Gas): MO Summary of Rates	Residential RS	Small General Srv SGS	Medium General Srv MGS	Large General Srv LGS	Large Volume LV
Proposed Rates - NEMO/WEMO					
Customer Charge	$ 32.00	$ 42.00	$ 180.00	$ 900.00	$ 900.00
Delivery Charge ($ per CCF)	$ 0.48582	$ 0.26705	$ 0.38594	$ 0.26239	$ 0.24109
Proposed Rates - SEMO					
Delivery Charge ($ per CCF) - Summer Block 2	$ 26.75	$ 37.25	$ 180.00	$ 900.00	$ 900.00
Delivery Charge ($ per CCF)	$ 0.36017	$ 0.18701	$ 0.38594	$ 0.26239	$ 0.24109
Current PGA Rates					
PGA Rate (NEMO)	$ 0.54904	$ 0.54904	$ 0.54904	$ 0.54904	$ 0.44219
PGA Rate (WEMO)	$ 0.86923	$ 0.86923	$ 0.86923	$ 0.86923	$ 0.81032
PGA Rate (SEMO)	$ 0.48712	$ 0.48712	$ 0.48712	$ 0.48712	$ 0.36314

The Figure shows the Company's proposed distribution base rates, including the proposal to continue having separate distribution base rates for SEMO's RS and SGS customers and consolidated distribution base rates for SEMO's MGS, LGS and LV customers.

Class revenue targets not recovered in the customer charges are then recovered through per CCF delivery charges, as shown in **Direct Schedule TSL-8**.

The Company prepared customer bill impacts to evaluate the effect of the proposed base rate changes, as shown in **Direct Schedule TSL-8**. The customer bill impacts included other applicable charges to reflect the overall impact of the proposed changes, as shown in Figure 2 (above).[3]

Overall, the proposed base rates increase monthly bills for a residential customer using 54 CCF per month by: $15.00 or 20.60 percent in NEMO; $15.00 or 16.60 percent in WEMO; and $15.87 or 28.00 percent in SEMO. 54 CCF represents the combined average of monthly usage for residential customers in the NEMO, WEMO, and SEMO service areas.

III. OVERVIEW AND CURRENT RATE STRUCTURE

Q. Please describe the service area.

A. The Company, an indirect subsidiary of Algonquin Power & Utilities Corp., provides natural gas service to multiple communities in Missouri including Butler, Kirksville, Canton, Hannibal, Jackson, Sikeston, Malden, and Caruthersville.

The Company provides natural gas service to 52,711 customers in Missouri, of which 45,817 (86.9 percent) are residential and 6,918 (13.1 percent) are commercial and industrial ("C&I").

[3] Other applicable charges include: (1) Purchase Gas Adjustment ("PGA") charges of $0.54904 per CCF in NEMO, $0.86923 in WEMO, and $0.48712 in SEMO, and (2) Infrastructure System Replacement Surcharge ("ISRS") approved by the Commission in Case No. GT-2023-0229.

Q. Please describe the Company's rate classes and current rates.

A. Customers are presently served under one of five rate classes based on type of service and load characteristics, as shown in Figure 3 (below).

Figure 3: Rate Classes and Current Rates

Rate Class	Availability	Current Rates[4]	NEMO/ WEMO	SEMO
Residential ("RS")	Available to any residential customer	Customer charge Usage charge	$22.00 $0.33607(W) $0.32935(S1) $0.38193(S2)	$15.00 $0.24335
Small General Service ("SGS")	Available to C&I customers who use a type A or B meter	Customer charge Usage charge	$33.79 $0.14216	$25.10 $0.08312
Medium General Service ("MGS")	Available to C&I customers having annual usage less than 75,000 CCF	Customer charge Usage charge	$136.13 $0.27711	$140.00 $0.23906
Large General Service ("LGS")	Available to C&I customer having annual usage more than 75,000 CCF	Customer charge Usage charge	$750.00 $0.17276	$750.00 $0.20334
Large Volume ("LV")	Available to C&I customers having daily demand of at least 1,000 CCF during off-peak periods, and annual usage more than 200,000 CCF	Customer charge Usage charge	$650.00 $0.17002	$750.00 $0.20179

The Figure shows residential customers are assigned to the RS rate class. The Figure also shows C&I customers are assigned to one of four rate classes based on type of service and load characteristics. C&I customers are further designated by whether customers purchase gas supply from the Company through sales service or from a third-party supplier or marketer through transportation service.

[4] The customer charges in Figure 3 excludes ISRS charges.

The Company's current rate structure consists of both distribution base rates and gas commodity rates for sales service customers through the Purchase Gas Adjustment ("PGA"). The current distribution base rates were approved by the Commission in June 2018 in the Company's prior distribution base rate proceeding in Case GR-2018-0013.[5]

Distribution base rates for residential customers consist of a monthly customer charge and usage charges that are based on One Hundred Cubic Feet ("CCF") of gas. The current usage charges for NEMO/WEMO residential customers vary by season and usage through a block or step rate structure during the summer months. The current usage charge for SEMO residential customers is the same throughout the year.

Distribution base rates for C&I customers consist of a monthly customer charge and usage charge that is based on CCF of gas.

Q. Please provide a breakdown of the Company's customers and usage.

A. Figure 4 (below) provides a breakdown of the Company's customers and usage for the combined service areas for the period January 1, 2022 through December 31, 2022. The usage in Figure 4 has been normalized for weather.

Figure 4: 2022 Customers and Normalized Usage

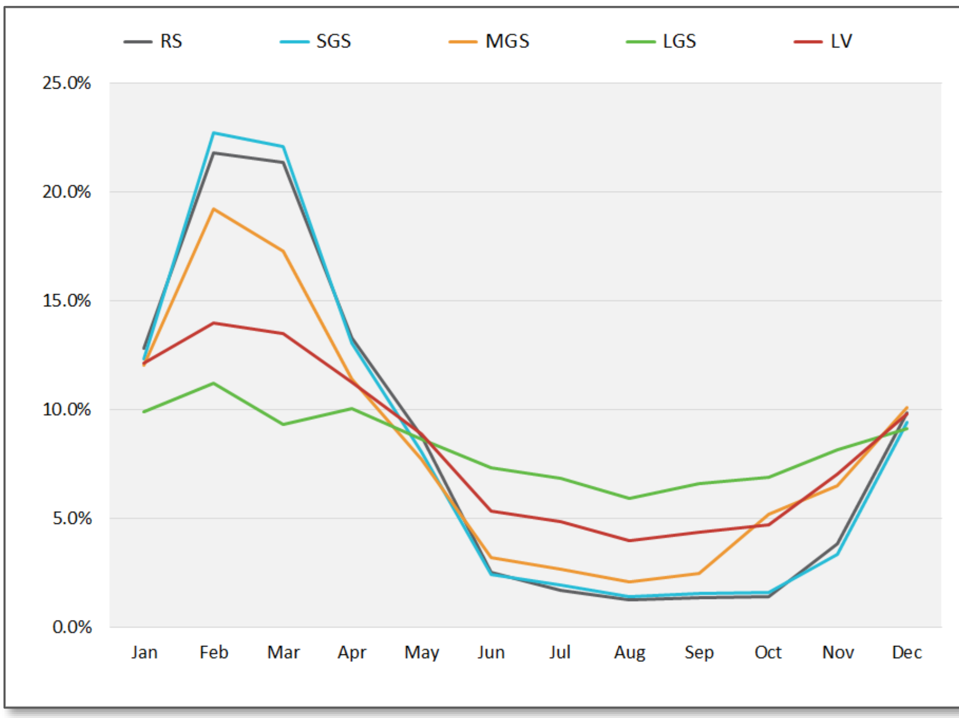
2022 Test Year Customers and Usage	Number of Customers	% of Customers	Annual Use	% of Use	Annual Use per Customer
Residential - RS	45,817	86.9%	29,824,225	40.4%	651
Small C&I - SGS	5,954	11.3%	9,082,268	12.3%	1,525
Medium C&I - MGS	893	1.7%	10,506,555	14.2%	11,761
Large C&I - LGS	43	0.1%	22,752,220	30.8%	531,180
Large Volume - LV	4	0.0%	1,692,770	2.3%	423,193
Total	52,711	100.0%	73,858,038	100.0%	1,401

[5] *Case GR-2018-0013, In the Matter of Liberty Utilities (Midstates Natural Gas) Corp. d/b/a Liberty Utilities' Tariff Revisions Designed to Implement a General Rate Increase for Natural Gas Service in the Missouri Service Area of the Company.*

The Figure shows the residential class represents 86.90 percent of the Company's customers. The Figure 4 also shows residential customers use on average 651 CCF per year, while LGS customers use on average 531,180 CCF per year.

Figure 5 (below) shows seasonal variation of the Company's rate classes, measured as monthly usage divided by annual usage.

Figure 5: Monthly Use as a Percentage of Annual Usage



The Figure shows class usage varies seasonally for certain rate classes. The residential and small and medium C&I rate classes, for example, show a seasonal load pattern, with monthly usage increasing during the winter months, reflecting heating usage. The Large General Service and Large Volume rate classes, by comparison, show relatively consistent monthly usage throughout the year, with only a slight increase in the winter months. Demand differences, as discussed below, have implications on the allocation of costs in the COSS.

IV. ALLOCATED COST OF SERVICE STUDY

Q. What is 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 approach is well established in industry literature.[6]

Q. What approach was used to develop the COSS in this rate case filing?

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.

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.

Q. What is functionalization?

A. Functionalization is the process of assigning rate base and expense items into operational components. The functionalization of costs was based on the Company's

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

accounting records, which are maintained in accordance with the Federal Energy Regulatory Commission's ("FERC") Uniform System of Accounts ("USOA").

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 primary causes or drivers of costs related to the gas system:

- Customer-related – costs that vary with the number of customers, such as costs associated with connecting customers to the gas system and providing basic customer services, such as metering and billing;
- Demand-related – costs that vary with customer usage at the time of the system peak demand; and
- Energy-related – costs that vary with energy usage, such as the cost of gas.

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 follows how costs are incurred.

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

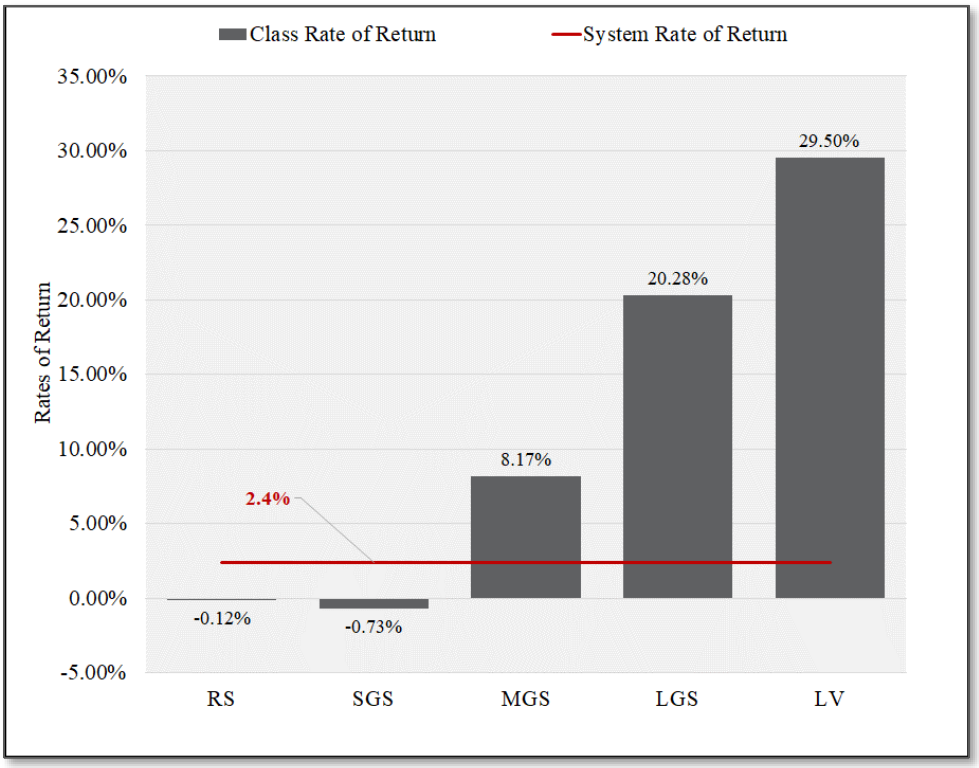
A. Three types of allocators were used to develop the COSS:

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. What were the results of the COSS?

A. The results of the COSS were derived from a spreadsheet model developed specifically for this distribution base rate case proceeding. Rate base and expense items in the COSS were assigned to each rate class based on the three-step process described above. The results of the COSS are shown in Figure 6 (below).

Figure 6: COSS Results (Replicated from Figure 1)



Q. What conclusions can be reached when class RORs are lower than or higher than the system or overall ROR?

A. When class RORs are lower than the system or overall ROR, then revenues recovered from the rate class are less than its cost of service. Conversely, when class RORs are higher than the system ROR, then revenues recovered from the rate class are more than its cost of service. As discussed below, the COSS results were used as a guide to develop revenue targets for each rate class that move the Company's proposed distribution base rates in aggregate to the system ROR to achieve fair and equitable rates.

Q. What data was used to prepare the COSS?

A. The COSS was based on the Company's consolidated revenue requirement. The COSS includes rate base items, including intangible plant, distribution plant, general plant, and working capital (e.g., materials and supplies). The COSS also includes operations and maintenance ("O&M") expenses, including distribution, customer accounting, sales, administrative and general expenses, depreciation expenses, taxes other than income taxes, such as payroll and property taxes, and income taxes.

Q. What was the approach to functionalize costs in the COSS?

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. Specifically, the overall cost of service was functionalized into one of the following categories:

- Intangible – investments associated with the Company's intangible plant. These include intangible plant, accumulated depreciation, and depreciation expense.
- Transmission – investments and expenses associated with the Company's transmission facilities. These include transmission plant, accumulated depreciation, depreciation expenses, and related O&M expenses.
- Distribution – investments and expenses associated with the Company's distribution facilities. These include distribution plant, accumulated depreciation, depreciation expenses, and related O&M expenses.

- General – investments and expenses associated with the Company's general plant facilities. These include general plant, accumulated depreciation, depreciation expenses, and related expenses.

Q. What was the approach to classify costs?

A. The COSS classified costs into one of the following two categories:

- Customer – costs associated with customer access to the gas distribution system as well as on-going customer services, such as meter reading and billing services.
- Demand – costs associated with peak demand requirements.

Q. What was the approach to classify distribution mains?

A. Classification of distribution mains – the largest portion of distribution plant – reflects two cost drivers. The first cost driver is number of customers. Distribution mains are designed to provide customers access to the natural gas system. The second driver is customer demands. Distribution mains are designed to meet average daily and design day demands.

The classification of distribution mains in this distribution base rate case reflects a refinement to the approach in the prior rate case. Specifically, the Company in this distribution base rate case classified distribution mains into customer and demand based on an average of two recognized approaches to classify distribution main: (1) the minimum mains or minimum system method, and (2) the zero-inch or zero-intercept method. Both methods are recognized by the National Association of Regulated Utility Commissions ("NARUC"). NARUC states,

> One argument for inclusion of distribution related items in the customer cost classification is the 'zero or minimize size main theory.' This theory

> assumes that there is a zero or minimum size main necessary to connect the customer to the system and thus affords the customer an opportunity to take service as he/she so desires.
>
> Under the minimum size main theory, all distribution mains are priced out at the historical unit cost of the smallest main installed in the system, and assigned as customer costs. The remaining book cost of distribution mains is assigned to demand. The zero-inch main method would allocate the cost of a theoretical main of zero-inch diameter to the customer function, and allocate the remaining costs associated with mains to demand.[7]

Previously, distribution mains were classified based only on the minimum system method.

Q. How was the estimated cost of a minimum size main determined?

A. The estimated cost of a minimum size main was based on two-inch plastic main, which is the smallest main commonly installed by the Company. Multiplying the estimated cost of two-inch plastic main by the actual number of feet in the system yielded the theoretical cost of a system comprised of two-inch mains. The customer portion of distribution mains was calculated as the ratio of the cost of a two-inch mains system to the cost of the total mains system. The cost of mains was based on historical costs, adjusted to reflect 2023 costs utilizing the Handy-Whitman index.

Q. What were the results of the minimum size main method?

[7] NARUC Gas Distribution Rate Design Manual, pgs. 22-23.

A. The results of the minimum size main method show the customer portion of the mains investment is 52.12 percent, as shown in Figure 7 (below).

Figure 7: Results of Minimum System Method

Type	Minimum System Pipe Size	% of Type Footage	Total Footage	HW Adj. Cost Per Foot	Cost of Minimum System
Plastic	2		8,923,526	$ 15.73	$ 140,398,777
Minimum Size Main Cost					$ 140,398,777
Total Cost					$ 269,366,018
Minimum System					52.12%

The Figure shows the estimated cost of a minimum size main is $140.4 million, which is based on the estimated cost of a two-inch plastic main and the actual number of feet in the system. The customer portion of distribution mains of 52.12 percent was calculated as the ratio of the cost of minimum size main of $140.4 million to the total cost of the mains of $269.4 million. The demand portion of the mains investment was 47.88 percent.

Q. What is the zero-inch or zero-intercept method?

A. The zero-inch or zero-intercept method represents the cost of connecting customers to the distribution system with a hypothetical "zero-size" main. The method is based on a regression analysis that examines the relationship between distribution main sizes and their average costs. The regression analysis produces an intercept that represents the average cost of a theoretical zero-inch distribution main, or a distribution main that serves no demand. Zero-inch main costs are classified as customer, while costs in excess of the zero-inch main costs are classified as demand.

Q. How was the estimated cost of a zero-inch main determined?

A. The estimated cost of a zero-inch main was based on a regression analysis of distribution main sizes and their average costs. The regression analysis produced an intercept that represents the average cost ($ per foot) of a theoretical zero-inch distribution main. Multiplying the average cost of a zero- inch main by the actual number of feet in the system yielded a theoretical cost of a system comprised of zero-inch mains. The customer portion of distribution mains was calculated as the ratio of the cost of a zero-inch main to the total cost of all mains.

Q. What were the results of the zero-inch method?

A. The results of the zero-inch method show the customer portion of the mains investment is 50.01 percent, as shown in Figure 8 (below).

Figure 8: Results of Zero-Inch Method

Type	Total Type Footage	Zero-Int. Cost per Foot	Cost of Minimum System
PLASTIC	3,156,367	$ 6.56	$ 20,705,391
STEEL	5,767,159	19.77	$ 114,006,875
Zero-Intercept System Costs			$ 134,712,267
Total Cost			$ 269,366,018
Zero-Intercept Costs			50.01%

The Figure shows the estimated cost of a zero-inch plastic and steel main was $6.56 per foot and $19.77 per foot, respectively. Multiplying the estimated cost of a zero-inch main by the actual number of feet in the system yielded a theoretical cost of a system comprised of zero-inch mains of $134.7 million. The customer portion of distribution mains of 50.01 percent was calculated as the ratio of the cost of zero-inch mains of $134.7 million to the total cost of the mains system of $269.4 million. The demand portion of the total cost of the mains system was 49.99 percent.

Q. What is the Company's recommendation regarding the classification of distribution main?

A. The Company recommends classifying distribution mains in this proceeding as 51.07 percent customer and 48.93 percent demand. The proposed approach reflects an average of the minimum size and zero-inch methods, as shown in Figure 9 (below).

Figure 9: Proposed Classification of Distribution Main

Mains Classification Study	Customer -Related Portion of Distribution Mains
Zero-Intercept Study	50.01%
Minimum System Study	52.12%
Average	**51.07%**

Q. What was the approach to classify meters and services?

A. Services (Account 380) were classified as customer. Meters, Meter Installation, House Regulators, and Industrial Measuring & Regulation (Accounts 380-385) were classified as customer.

Q. How were other plant items classified?

A. Other plant items were similarly classified based on their underlying cost drivers. Rate base items not directly associated with one of the classification categories were classified through a composite classifier based on related costs.

Q. Please discuss the classification of O&M expenses.

A. Distribution O&M expenses were classified in a manner similar to the respective plant items. For example, distribution O&M expenses followed the classification of their respective plant accounts. O&M expense items not directly associated with one of the classification categories were classified through an indirect 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 reflects how costs are incurred.

Q. How were plant costs classified as demand allocated?

A. Plant costs classified as demand were allocated based on the Average and Peak ("A&P") method. Plant costs classified as demand include transmission plant and the demand portion of distribution mains, as discussed earlier. The A&P method is a recognized approach for allocating plant costs classified as demand.[8]

The allocator is based on each rate class's responsibility to the average day and peak day (or design day) demands of the system.

The average day portion of the allocator is based on each rate class's responsibility to the average daily demands on the system. The "Peak" portion of the allocator is based on each rate class's responsibility to the peak day (or design day) demands of the system. The "Average" portion is weighted by the system's load factor. The "Peak" portion is weighted by the remaining amount (1 minus the system load factor).

Development of the demand allocator in this rate case reflects a refinement to the approach in the prior rate case. Specifically, the Company in this rate case assigned to the Large Volume class no peak day or design day demand responsibility to reflect the rate class is interruptible; *i.e.,* the Company does not plan for customers to be taking service on the design day. Previously, the Company assigned to the Large Volume class design day demand responsibility.

[8] NARUC Gas Distribution Rate Design Manual, p. 27 (June 1989).

Q. How was meter plant allocated?

A. Meter plant was allocated to each rate class based on the results of a study that reflects the cost of meters serving each rate class. The allocator reflects the Company's estimate of meter and meter installation costs for each type of meter serving each rate class.

Q. How was service plant allocated?

A. Service plant was allocated to each rate class based on the results of a study that reflects the material and installation cost of a service line for each rate class. The allocator reflects the Company's estimate of service line and service line installation costs for each type of service line for each rate class.

Q. What was 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 other plant allocations.

Q. How were expenses allocated to each rate class?

A. Expenses were generally allocated to each rate class consistent with their respective plant accounts allocation method. Certain expenses, such as administration and general and payroll taxes, were allocated using a labor allocation.

Q. Does the unit cost of service vary across the Company's rate classes?

A. Yes, the cost of service per customer and per CCF (i.e., unit cost of service) varies across the Company's rate classes, as shown in Figure 10 (below).

Figure 10: Unit Cost of Service by Rate Class

Rate Class	Revenue Requirements Per Customer		Per CCF
Residential - RS	734	$	1.13
Small C&I - SGS	1,002	$	0.66
Medium C&I - MGS	4,973	$	0.42
Large C&I - LGS	67,742	$	0.13
Large Volume - LV	35,910	$	0.08

The Figure shows, for example, the unit per customer cost of service for the residential class is $734 per customer, while the unit cost of service for the LGS class is $67,742 per customer. By comparison, the unit per CCF cost of service for the residential class is $1.13 per CCF while the unit cost of service for the LGS rate class is $0.13 per CCF.

Q. How are variations in the unit cost of service used to support the Company's rate design?

A. Variations in the unit cost of service support the need for distinct rate classes and rates.

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

Q. What were the principles used to guide the proposed rate design?

A. As previously discussed, 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 in that each rate class should recover the costs caused by that customer class, minimizing inter- and intra-class inequities to the extent possible; and (c) rate changes should be tempered by rate continuity concerns.

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 consolidated cost of service for its Missouri customers. This was done by developing customer charges and distribution base rates based on test year customers and usage. In addition, rates were designed to be fair and equitable. This was done by setting revenue targets for each rate class that reflect in aggregate a movement toward the system ROR based on the results of the COSS. Specifically, the results of the COSS show certain classes produce a ROR that is less than the system ROR. The proposed rate design moves the ROR closer to the system ROR. Another rate design objective is to moderate rate changes to address rate continuity concerns (i.e., bill impact). This objective was considered while setting revenue targets and then again while setting rate elements.

Q. What is the Company's rate design proposal?

A. As mentioned earlier, the Company proposes to further consolidate the revenue requirement calculation to determine its distribution base rates. However, due to bill impact considerations for this case, the Company proposes to continue having separate distribution base rates for SEMO Residential ("RS") and Small General Service ("SGS") customers and one set of distribution base rates for all remaining customers.

Specifically, the Company proposes as a transition measure to continue to maintain one set of distribution base rates for residential and SGS customers in the NEMO/WEMO service areas, and a second set of distribution base rates for residential and SGS customers in the SEMO service area. The purpose in maintaining separate distribution base rates for NEMO/WEMO and SEMO is to better manage customer bill impacts in the transition to consolidate or establish one set of distribution base rates for all service districts. The Company also proposes one set of distribution base rates for customers in the MGS, LGS, and LV rate classes.

Customer bill impact concerns were most apparent for residential and SGS customers in the SEMO service area. Residential bill increases in the SEMO service area, for example, would be approximately 38.00 percent under complete rate consolidation. By comparison, residential bill increases in the NEMO/WEMO service area would be approximately 10.00 percent under complete rate consolidation.

To better manage such bill impact disparities, the Company proposes as a transition measure to move the SEMO rates 75.00 percent toward consolidated rates, thus reducing residential bill increases in the SEMO service area to approximately 28.00 percent and increasing residential bill increases in the NEMO/WEMO service area to approximately 19.00 percent.

The Company believes the proposed transition of residential and SGS distribution base rates toward consolidated rates better addresses rate continuity concerns for its Missouri customers.

Q. What steps were taken to develop the proposed base rates?

A. The first step to develop the proposed distribution base rates was to establish the overall consolidated revenue requirement to be recovered through distribution base rates. The next step was to set revenue targets for each rate class based on the results of the COSS, moderated by rate continuity concerns. Rates within each rate class were then designed to recover the revenue targets based on test year bills and usage. The class revenue targets are included in **<u>Direct Schedule TSL-7.</u>**

Q. What is the total consolidated revenue requirement that you used as a starting point?

A. To determine the total consolidated revenue requirement, I relied on the overall cost of service presented in the Direct Testimony of Witness Charlotte T. Emery, which indicates an overall revenue requirement of $47.6 million.

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

A. The starting point for setting class revenue targets was first identifying the revenue changes needed to achieve an equal rate of return ("EROR") for each rate class. For certain rate classes that yield RORs less than the system ROR, the proposed distribution base rate increases were higher than the system average to move the classes closer to the system ROR; however, the movement to EROR for all rate classes was moderated by bill continuity concerns.

Specifically, to address bill continuity concerns the proposed revenue targets for each rate class were based on a 10.00 percent movement toward EROR, as shown in Figure 11 (below).

Figure 11: Proposed Class Revenue Targets

Liberty Utilities (Midstates Natural Gas): MO Target Revenues	Total Company	Residential RS	Small General Srv SGS	Medium General Srv MGS	Large General Srv LGS	Large Volume LV
Target Revenues						
Class Revenues at EROR	46,136,164	32,683,583	5,964,404	4,442,939	2,901,600	143,638
Current Class Revenues	32,987,719	19,963,653	3,395,739	4,401,413	4,879,778	347,136
Difference ($)	13,148,445	12,719,930	2,568,665	41,526	(1,978,179)	(203,498)
Difference (%)	39.9%	63.7%	75.6%	0.9%	-40.5%	-58.6%
Class Revenues at Uniform Increase	46,136,164	27,920,886	4,749,233	6,155,754	6,824,790	485,500
Current Class Revenues	32,987,719	19,963,653	3,395,739	4,401,413	4,879,778	347,136
Difference ($)	13,148,445	7,957,233	1,353,494	1,754,342	1,945,012	138,364
Difference (%)	39.9%	39.9%	39.9%	39.9%	39.9%	39.9%
Movement to EROR	10.0%					
Target Revenues	46,136,164	28,397,156	4,870,751	5,984,473	6,432,471	451,314
Current Revenues	32,987,719	19,963,653	3,395,739	4,401,413	4,879,778	347,136
$ Difference	13,148,445	8,433,503	1,475,011	1,583,060	1,552,693	104,178
% Difference	39.9%	42.2%	43.4%	36.0%	31.8%	30.0%
Customers	52,711	45,817	5,954	893	43	4
Usage (CCF)	73,858,038	29,824,225	9,082,268	10,506,555	22,752,220	1,692,770
Target Increase ($/ Customer/ Mo.)		$ 15.34	$ 20.65	$ 147.67	$ 3,020.80	$ 2,170.37
Target Increase ($ per CCF)		$ 0.28	$ 0.16	$ 0.15	$ 0.07	$ 0.06

The Figure shows revenue requirements for each rate class based on three approaches: (1) a full movement to EROR, (2) a uniform increase in revenues, and (3) a partial movement to EROR, which is the Company's proposal. A full movement to EROR would reduce inter-class inequities but raise bill continuity concerns for certain classes, such the residential class. A uniform increase would produce a more consistent increase across rate classes but not reduce inter-class inequities. The Company's proposed revenue targets reflect a partial movement to EROR of 10.00 percent.

The Company believes a 10.00 percent movement to EROR strikes an appropriate balance between moving to cost-based rates and addressing bill continuity considerations.

Q. What was the process to derive the proposed customer charge and distribution base rates for the residential class?

A. The Company proposed increases in the customer charge that were informed by underlying customer costs, moderated to address the impact on low-use customers. For example, the Company proposed residential customers charges of $32.00 per month in the NEMO/WEMO district and $26.75 per month in the SEMO district as compared to fully allocated residential customer cost of $50.99 per month. Class revenue targets not recovered in the customer charges are then recovered through per CCF delivery charges, as shown in **Direct Schedule TSL-8**.

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

A. Yes. The Company prepared customer bill impacts to evaluate the effect of the proposed distribution base rate changes, as shown in **Direct Schedule TSL-8**. The customer bill impacts included other applicable charges to reflect the overall impact of the proposed changes.[9]

Overall, the proposed distribution base rates increase monthly bills for a residential customer using 54 CCF per month by $15.00, or 20.60 percent in NEMO, $15.00, or 16.60 percent in WEMO, and $15.87, or 28.00 percent in SEMO. 54 CCF represents the combined average of monthly usage for residential customers in NEMO, WEMO, and SEMO service areas.

VI. INCLINING RATE ANALYSIS

Q. Has the Company prepared analysis of its inclining rates for residential customers in NEMO/WEMO?

A. Yes. The Company prepared analysis of its inclining rate structure for residential customers in NEMO/WEMO, consistent with the terms of the Company's Unanimous Stipulation and Agreement in Case No. GR-2018-0013, the Company's most recent base rate case proceeding.

Specifically, the Company's analysis examined the change in the beta coefficients (i.e., the relationship between customer usage and heating degree days) for NEMO/WEMO customers (who have an inclining rate structure) and SEMO customers (who do not have an inclining rate structure) during the period 2018 through 2022, the effective period of the inclining rate structure. The beta coefficients were derived through regression analysis, which examined changes in usage per customer per day and changes in heating degree days ("HDD") per day. The beta coefficients are shown in Figure 12 (below).

[9] Other applicable charges include: (1) PGA charges of $0.54904 per CCF in NEMO, $0.86923 in WEMO, and $0.48712 in SEMO, and (2) ISRS charges approved by the Commission in Case No. GT-2023-0229.

Figure 12: Results of Regression Analysis

Beta Coefficient	NEMO	WEMO	SEMO
2018	0.0930	0.0815	0.0855
2019	0.0707	0.0634	0.0507
2020	0.0818	0.0028	0.0521
2021	0.0703	0.0628	0.0505
2022	0.0745	0.0527	0.0430
% Change (2018-2022)	**-5.4%**	**-10.3%**	**-15.8%**

The Figure shows the beta coefficients have declined during the period 2018 through 2022. Specifically, the beta coefficients for NEMO have declined from 0.0930 CCF per customer per day per HDD in 2018 to 0.0745 in 2022, or a decline of 5.40 percent. WEMO and SEMO have experienced similar declines of 10.30 percent and 15.80 percent, respectively.

The results of the Company's analysis suggest that an inclining rate structure does not appear to have a significant impact on changes in use per customer per HDD; consequently, the Company proposes to eliminate the inclining rate structure in NEMO/WEMO. In addition, the Company does not propose to expand the inclining rate structure to the winter months based on the results of the inclining rates during the summer months and the potential for more volatility in customer bills due to inclining rates during the winter months.

VII. CASH WORKING CAPITAL

Q. Please define the term "cash working capital" as a rate base component.

A. The term "cash working capital," or "CWC" 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 lead-lag study include

O&M expenses, including labor and non-labor expenses, federal, state, and local taxes, and employment taxes.

Q. How was the Company's CWC requirement determined?

A. The Company's CWC requirement was based on the results of the lead-lag study. The lead-lag study compares differences between the Company's revenue lag and expense leads. The revenue lag represents the number of days from the time customers receive their service to the time customers pay for 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 lead-lag days were then applied to the Company's adjusted test year expenses to derive the CWC requirement, which was included in the Company's rate base.

VIII. LEAD-LAG STUDY APPROACH

Q. Please summarize the results of the lead-lag study.

A. The results of the lead-lag study are summarized in **Direct Schedule TSL-10**. The results of the lead-lag study were provided to Company witness Emery and applied to adjusted test year expenses to derive the Company's proposed CWC requirement.

Q. Please describe the approach used to develop the lead-lag study.

A. The lead-lag study consists of two elements: revenue lag and expense leads. The revenue lag measures from the time service is provided to customers until the time customer payments are received by the Company. Expense leads measure from the time the Company receives goods and services used to provide service, to the time the Company pays for those goods and services. The lag-leads 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 leads determines if there is a net revenue lag (revenue lag days are more than the expense lead days) or a net expense lead (revenue lag days are less than the expense lead days) for each cost element in the lead-lag study. The net lead-lag days are applied to projected test year expenses since it reflects the Company's ongoing expenses and thus is more representative of the Company's ongoing cash working capital requirements.

Q. Please describe the financial data used in the lead-lag study.

A. The lead-lag study was largely based on the Company's financial data from January 1, 2022 through December 31, 2022.[10] The financial data included customer billing; O&M expenses; and federal, state, local, and employment taxes.

A. Revenue Lag

Q. Please describe development of the revenue lag.

A. The revenue lag measures the number of days from the time service is provided to customers to the time payment is received from customers. 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 measures the average number of days in the service period; *i.e.*, the number of days from the start of the billing month to the end of the billing month.

[10] The lead-lag study utilized certain 2023 invoice payments related to employee benefits since 2022 invoice payments were not available.

Meters are read at the end of the billing month. The service lag in this lead-lag study was based on the midpoint of the service period, which reflects that natural gas service is provided evenly over the service period.

Q. What is the billing lag?

A. The billing lag measures the number of days from the time meters are read to the time bills are recorded and sent to customers. The billing lag includes time for review and validation of billed usage and dollars.

Q. What is the collection lag?

A. The collection lag measures the number of days from the time bills are recorded and sent to customers to the time customer payments are received (*i.e.*, funds are available to the Company). The collection lag in this lead-lag study was based on monthly accounts receivable balances and billed revenue data. This information was used to calculate the average time to receive customer payments.

Q. How were lag days determined for revenues?

A. The revenue lag was based on the sum of the revenue lag components discussed above. Derivation of the revenue lag is shown in **Direct Schedule TSL-3**.

B. Expense Leads

1. O&M Expenses

Q. Please describe development of lead days for O&M expenses.

A. Lead days for O&M expenses were measured separately for the following categories: (1) purchased gas costs; (2) regular payroll; (3) incentive compensation; (4) 401k Company match; (5) pension expense; (6) Other Post-Employment Benefits, or

"OPEB;" (7) employee benefits; (8) uncollectible expenses; and (9) other non-labor O&M expenses.

Q. How were lead days determined for purchased gas expenses?

A. Lead days for purchased gas expenses were based on the number of days from the midpoint of the service period to the payment date.

Q. How were lead days determined for regular payroll expenses?

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

Q. How were lead days determined for incentive compensation?

A. Lead days for the Company's incentive compensation plan were based on the number of days from the midpoint of the performance period (i.e., twelve-months ending December 31, 2021) to the payment date in April 2022.

Q. How were lead days determined for the company's 401k match?

A. Lead days for the Company's 401k match were based on the number of days from the midpoint of the pay period to the payment date.

Q. How were lead days determined for pension expenses?

A. Lead days for pension expenses were based on the Company's pension payment schedule. Pension payments were made quarterly in the month following the service period. Lead days for pension expenses were based on the number of days from mid-quarter to the payment date for that quarter.

Q. How were lead days determined for OPEB payments?

A. Lead days for OPEB payments were based on the Company's OPEB payment schedule. OPEB payments were made in December for that calendar year. Lead days for OPEB payments were based on the number of days from the midpoint of the calendar year to the payment date.

Q. How were lead days determined for employee benefits?

A. Lead days for employee benefits were based on the Company's payment schedule for medical and dental expenses. The lead days for medical and dental expenses were based on the number of days from midpoint of the service period to the payment date.

Q. How were lead days determined for other non-labor O&M expenses?

A. Lead days for Other O&M expenses were based on the sum of two components: (1) lead days from the service period to the invoice date; and (2) lead days from the invoice date to the payment date.

Lead days from the service period to the invoice date were based on a stratified sample of invoices paid by the Company over the period January 1, 2022 through December 31, 2022. Lead days were measured for each invoice in the sample as the number of days from the midpoint of the service period to the invoice date. Invoices were then converted to "dollar days" to reflect a weighting by expense amount and then summed by invoice amounts to determine the lead days. The study relies on a sample of invoices to measure the lead days because the service periods were not readily available electronically and required detailed inspection of individual invoices.

Lead days from the invoice date to the payment date were based on the full population of invoices paid by the Company over the period January 1, 2022 through December 31, 2022. Lead days were measured for each invoice as the number of days from the invoice date to the payment date. Invoices were then converted to "dollar days" to reflect a weighting by expense amount and then summed by invoice amounts to determine the lead days.

2. Current Federal Income Tax Expense

Q. How were lead days determined for federal income taxes?

A. Lead days for federal income taxes were based on due dates for tax payments: April 15, June 15, September 15, and December 15. Lead days for federal income taxes were based on the number of days from the midpoint of the taxing period (*i.e.*, the calendar year) to the due dates.

Q. How were lead days determined for state income taxes?

A. Lead days for state income taxes were based on due dates for tax payments: April 15, June 15, September 15, and December 15. Lead days for state income taxes were based on the number of days from the midpoint of the taxing period (*i.e.*, the calendar year) to the due dates.

3. Taxes Other than Income Taxes

Q. Please describe development of lead days for taxes other than income taxes.

A. Taxes Other than Income Taxes includes: (1) payroll-related taxes (FICA, Federal Unemployment, and State Unemployment); (2) Ad Valorem taxes; and (3) Missouri Public Service Commission Assessment.

Q. How were lead days determined for those taxes?

A. Lead days for payroll-related taxes were based on the number of days from the liability date to the payment date. Lead days for non-payroll-related taxes were based on the number of days from the midpoint of the taxing period to the payment date.

C. Other Adjustments – Working Funds and Other

Q. How were lead days determined for interest expense?

A. Lead days for interest expense were based on interest payments. The lead days were calculated from the midpoint of the period for which the interest was paid to the payment date.

Q. Please summarize the results of the lead-lag study.

A. The results of the lead-lag study are summarized in **Direct Schedule TSL-11**. The results of the lead-lag study were provided to Company witness Emery and applied to adjusted test year expenses to derive the Company's proposed CWC requirement.

Q. Does this complete your direct testimony?

A. Yes.

VERIFICATION

I, Timothy S. Lyons, under penalty of perjury, on this 9th day of February, 2024, declare that the foregoing is true and correct to the best of my knowledge and belief.

/s/ Timothy S. Lyons