Exhibit No.:	
Issue:	Class Cost of Study, Revenue Allocation, Rate Design
Witness:	Kavita Maini
Type of Exhibit:	Direct Testimony
Sponsoring Parties:	MECG
Case No.:	ER-2024-0261
Date Testimony Prepared:	July 21, 2025

BEFORE THE PUBLIC SERVICE
COMMISSION OF THE STATE OF MISSOURI

In the Matter of The Empire District Electric Company d/b/a Liberty for Authority to File Tariffs Increasing Rates for Electric Service Provided to Customers in Its Missouri Service Area	)))))	**File No. ER-2024-0261**

Direct Testimony and Schedules of

Kavita Maini

On behalf of

MIDWEST ENERGY CONSUMERS GROUP

July 21, 2025

Protecting Your Bottom Line

KM ENERGY CONSULTING, LLC

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<u>Direct Testimony of Kavita Maini</u>

INTRODUCTION

Q. Please state your name and occupation.

A. My name is Kavita Maini. I am the principal and sole owner of KM Energy Consulting, LLC.

Q. Please state your business address.

A. My office is located at 961 North Lost Woods Road, Oconomowoc, WI 53066.

Q. Please state your educational and professional background.

A. I am an economist with over 33 years of experience in the energy industry. I graduated from Marquette University, Milwaukee, Wisconsin with a Master's degree in Business Administration and a Master's degree in Applied Economics. From 1991 to 1997, I worked for Wisconsin Power & Light Company ("WP&L") as a Market Research Analyst and Senior Market Research Analyst. In this capacity, I conducted process and impact evaluations for WP&L's Demand Side Management ("DSM") programs. I also conducted forward price curve and asset valuation analysis. From 1997 to 1998, I worked as Senior Analyst at Regional Economic Research, Inc. in San Diego, California. From 1998 to 2002, I worked as a Senior Economist at Alliant Energy Integrated Services' Energy Consulting Division. In this role, I was responsible for providing energy consulting services to commercial and industrial customers in the area of electric and natural gas procurement, contract negotiations, forward price curve analysis, rate design and on-site generation feasibility analysis. I was also involved in strategic planning and due diligence on acquisitions.

Since 2002, I have been an independent consultant. In this role, I have provided consulting services in the areas of class cost of service studies, rate design, revenue allocation, resource planning and revenue requirement related issues, Midcontinent Independent System Operator ("MISO") related matters and various policy matters. I also represent industrial trade associations at MISO's various task forces and committees and am the End Use Sector representative at MISO's Advisory and Planning Advisory Committees.

Q. Have you participated in utility related proceedings?

A. Yes, I have testified before a number of state regulatory commissions, including in Wisconsin, Minnesota, Missouri, Iowa, Kansas, North Dakota and South Dakota. I have testified on a variety of issues related to revenue requirements, resource planning and generation resource acquisition, cost of service, revenue allocations and rate design. I have also provided technical comments in Federal Energy Regulatory Commission ("FERC") proceedings, several of which have involved MISO-related activities.

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

A. I am testifying as an expert witness on behalf of the Midwest Energy Consumers Group ("MECG"). The MECG is an incorporated entity representing the interests of large commercial and industrial customers including those taking service from Empire District Electric Company d/b/a Liberty ("Liberty" or "Company") on its Large General Service ("NS- LG", "TC-LG") Large Power Service ("LP") and Transmission Service ("TS") Schedules respectively.

Q. How are the companies represented by MECG impacted by this proceeding?

A. I am advised that many of companies whose interest MECG represents operate energy intensive facilities and compete in a regional and national environment. Therefore, energy costs are typically among the primary costs of doing business for these companies. Thus, energy affordability affects the competitiveness, output and potential employment levels for these companies.

In this rate case proceeding, Liberty proposes $152,825,837 increase in revenue requirement or a 29.64% increase over total operating revenues on a systemwide basis in the Missouri jurisdiction. The Company proposes: 30% increase for the Schedule NS-LG, 29.6% TC-LG, 27.2% for Schedule LP and 27.7% for Schedule TS respectively.[1] The large commercial and industrial customers members served by Liberty will therefore be significantly impacted by the outcome of this proceeding.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to discuss and provide recommendations regarding the Company's: (a) class cost of service study ("COSS"); (b) an appropriate allocation approach for any rate change; and (c) rate design for Schedules NS-LG, TC-LG, LP and TS respectively. The rest of my testimony is organized as follows:

Section I: Class Cost of Service Study

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[1] See Schedule TSL-4 for Company witness Mr. Timothy Lyons.

Section II: Revenue Requirement Allocation

Section III: Rate Design

Q. Does the fact that you may not address an issue or position advocated by the Company indicate your support?

A. No. The fact that an issue is not addressed herein or in related filings should not be construed as an endorsement of, agreement with, or consent to any filed position.

I. COST OF SERVICE

A. Importance of A Utility's Cost of Service Study

Q. What is the importance of a utility's cost of service study?

A. A utility's cost of service study is the fundamental basis for establishing just and reasonable rates in the ratemaking process. The cost of service study helps determine a utility's revenue requirement, guides revenue allocation to classes and informs rate design.

Revenue Requirement: A utility's cost of service is used in the determination of the revenue requirement of the utility and whether an increase, decrease or no change is necessary. Efforts are made to align total company revenues with the utility's cost of service.

Revenue Allocation to Classes: Given a certain revenue requirement, a utility's cost of service study guides the manner in which a given revenue requirement should be allocated to classes. The level of the revenue requirement for each class should be based primarily on aligning each class's revenues with its cost of service providing the same or equal rates of return.

Setting Rates: For a certain revenue allocation to each class, a utility's cost of service also informs the design of class rates by setting rates with the goal of providing appropriate pricing signals and proper allocation within the class that reflects costs to serve.

Q. For a given revenue requirement, what is the impact of closely aligning rates with the costs to serve each class?

A. Provided that the class cost of service study is properly developed to reflect cost causation, closely aligning rates with each class's cost of service fulfills the important goals of promoting equity among classes and encouraging economic efficiency.

Q. Please explain how equity is promoted among classes.

A. If rates are aligned with the cost of service, then equity is promoted because each class pays its fair share of costs. Given this, a class that has rates that are not recovering its cost of service should receive an above system average increase while a class paying rates above cost of service should receive a below average increase. In cases where the class revenues are significantly misaligned with cost responsibility, larger corrections or adjustments may be warranted in order to restore equity among classes.

Q. How is economic efficiency achieved?

A. If retail rates align with the cost of service, then they provide accurate pricing signals that drive consumer behavior, which in turn results in more efficient use of the system and minimizes system costs. For example, in instances where the class rates are set above cost, say for business customers, the resulting rates would incent customers in this class to reduce production or shift production elsewhere. Such a consequence results in higher costs for all customers since the utility's fixed costs would need to be recovered from a lesser number of billing determinants. On the other hand, for classes where rates are set at artificially low levels, then the rates are not sending the price signal that those customers should engage in energy efficiency measures.

Economic efficiency is not only affected by the misallocation of the revenue requirement among the rate classes but also impacted by the class rate design. In instances where the class revenue responsibility is at the cost of service, but rates are designed such that cost recovery is inconsistent with unit cost of service guidance, then the pricing signals are distorted and have the potential once again of sending inappropriate cost signals.

B. COSS Steps

Q. What are the different steps involved in the cost of service process?

A. A cost of service study generally follows three basic steps. First, the various costs are identified as production, transmission, and distribution (functionalization step). Next, these functionalized costs are classified as demand-related; energy-related; or customer-related (classification step). Finally, these classified costs are allocated among the various rate classes based upon factors which attempt to measure each customer class' contribution to that total classified cost (allocation step).

Functionalization: Various costs are separated according to function such as generation, transmission, distribution, customer service and administration. To a large extent, this is done in accordance with the Federal Energy Regulatory Commission's ("FERC") Uniform System of Accounts.

Classification: The functionalized costs are classified based on the components of utility service being provided and the underlying cost causative factors. As described by the NARUC Manual, the three principal cost classifications are: (1) demand-related costs (costs that vary with the kW demand imposed by the customer), (2) energy-related costs (costs that vary with energy or kWh that the utility provides), and (3) customer-related costs (costs that are directly related to the number of customers served). See NARUC Manual page 20.

Allocation: Once the costs are classified as demand-related, energy-related or customer-related, they are then allocated to classes using the relevant demand, energy or customer allocators. Each of these allocators measures each class's contribution to the total system cost.

Each of the three steps – functionalization, classification, and allocation, is very important because it sets the foundation for developing rates and sending accurate pricing signals. If costs are improperly functionalized, classified or allocated, they result in cross subsidies and economically inefficient pricing signals in rate design.

C. COSS: Fixed Production Plant Cost Allocation

Q. What are fixed production plant-related costs?

A. Fixed production plant-related costs are costs that are functionalized as production related and incurred in acquiring or procuring generation resources. Utilities are required to build or acquire sufficient generation capacity to ensure that they can reliably meet system peak demands. Primarily, these costs consist of the fixed investment in power plants, but do not include the variable cost (e.g., fuel) of generation. These costs include return on and of investment and fixed operations and maintenance costs. Once the generation investment is made, the costs are sunk costs, fixed in nature and do not vary with energy usage. According to the Company's cost of service study, fixed production plant represents approximately 40% of the Company's utility plant.

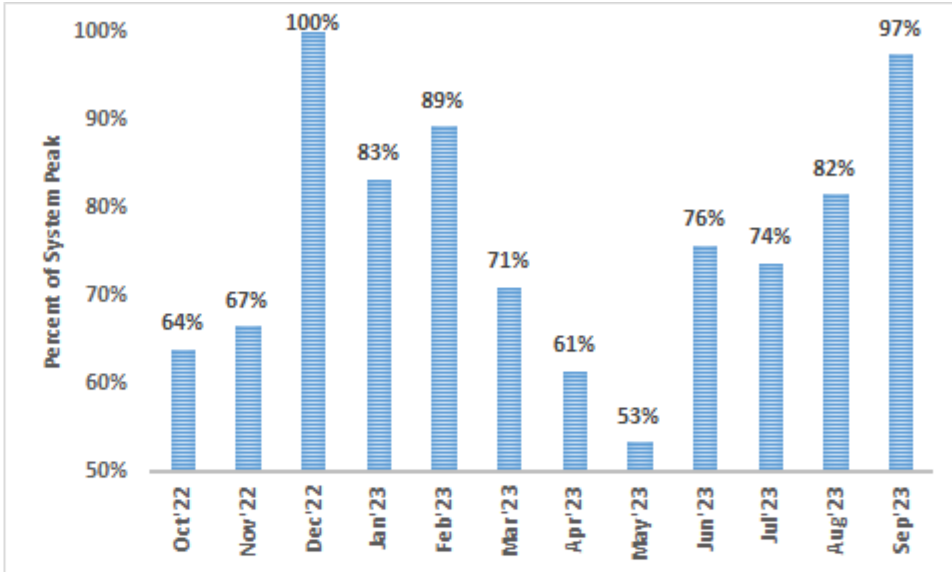
Q. What should be considered in determining the appropriate allocator for fixed production plant-related costs?

A. Since a utility needs to ensure that it has sufficient generation capacity to reliably meet its peak load requirements, the most important factor is the annual load pattern of the utility and the annual system peak. Further, since production plant must be sized to meet the maximum load or demand imposed on these facilities, the appropriate allocation method should reflect the load characteristics (system peaks) of the utility.

Q. Did you analyze Liberty's system load?

A. Yes, I did. Figure 1.1 shows the system monthly peak demands as a percentage of overall annual peak for the test year in the Missouri jurisdiction. This chart shows that Liberty's Missouri jurisdictional system peak is in the winter in December followed by the next highest peak (97% of the annual peak) in the summer in September. Other months are less than 90% of the annual peak. Relative to the peak load characteristics in the last rate case, the current profile is "spikier" meaning that the peaks do not lie within a narrow band and further, there is only one month that is within 10% of the system's peak demand.

Figure 1.1: Test Year Liberty's Missouri Jurisdiction Monthly Peaks as a Percent of Annual Peak



In the last case, there were five months with monthly peak demands within 10% of the annual peak. For ease of reference, Schedule KM-1 shows the chart from page 16 of my direct testimony in docket ER-2021-0312. Generally speaking, the chart shows that the peak demands in the last rate case were less spiky compared to the monthly peak demands in this rate case.

Q. In the last case, you recommended class contribution to the five months with peak demands within 10% of the annual peak. What is appropriate in this rate case?

A. Since generation capacity is sized to reliably meet the system peak demands, it would be appropriate to consider class contributions to monthly demands that are within 5% to 10% of the system peak as the cost causers.

Given the change in the load profile characteristics, class contributions to the months of December and September seem to be the most appropriate since the annual peak occurs in December and September is the only other month within 10% of the annual peak. However, for the sake of being conservative, it would not be unreasonable to include the two highest peak months each in the summer and winter since Liberty tends to be dual peaking. That said, we would deviate substantially from cost causation if additional months, compared to what I am recommending here, were included due to the peakier nature of the peak demands compared to the profile in the last case.

Thus, for the Test year, the class contributions to the months of December, February, August and September respectively, reasonably capture cost causation associated with the Company's decision to acquire generation capacity to reliably serve load. The utilization of four months with the highest system peak loads is also consistent with the average and excess method defined in Section 393.1620, which is discussed further below.

Q. What allocation methods are reasonable in allocating fixed production plant-related costs?

A. Either the Peak Demand method or the Average and Excess ("A&E") Demand method are reasonable methods for allocating fixed production costs.

In the Peak Demand method, the fixed production plant-related costs are allocated to rate classes on demand factors that measure the class contribution to system peak or peaks. As discussed above, in Liberty's current case, class contributions coincident with the peak demands in the months of December, February, August and September would be reasonable to use in calculating the production cost allocator.

While the Peak Demand method relies solely on class contribution coincident to the relevant monthly peak demands, the A&E methodology considers demand as well as class energy usage. As the name implies, the A&E Demand method consists of an average demand component and an excess demand component. The average demand component, which considers the class energy, is calculated by dividing the energy usage of each class by the number of hours in a year (8,760 for a non-leap year). The excess component, which considers the class peak demand, is calculated as the difference between the customer class's maximum non-coincident peak or peaks and the average demand. The average demand component for each class is then weighted by the system load factor and the excess component for each class is weighted by 1-load factor.[2] The composite allocator is simply the sum of the weighted average and excess components.

The A&E approach considers the load profile of customer classes by incorporating the maximum demands, load factor and average energy use. While the average demand measures the duration, the excess portion measures the variability of the load profile of a class. For example, as noted in the Commission decision in its Report and Order in Docket ER-2010-0036 (pages 84-85),

> Some customer classes, such as large industrials, may run factories at a constant rate, 24 hours a day, 7 days a week. Therefore, their usage of electricity does not vary significantly by hour or by season. Thus, while they use a lot of electricity, that usage does not cause demand on the system to hit peaks for which the utility must build or acquire additional capacity. Another customer class, for example, the residential class, will contribute to the average amount of electricity used on the system, but it will also contribute a great deal to the peaks on system usage, as residential usage will tend to vary a great deal from season to season, day to day, and hour to hour.

Q. Are you familiar with Section 393.1620 enacted in 2021?

A. It is my understanding, from talking to counsel, that Section 393.1620 limits the Commission to considering class cost of service studies that utilize a method reflected

[2] See NARUC Manual, page 49,81-82

in the NARUC manual for the allocation of fixed production plant costs associated with nuclear and fossil generating units. Specifically, Section 393.1620 provides:

> In determining the allocation of an electrical corporation's total revenue requirement in a general rate case, the commission shall only consider class cost of service study results that allocate the electrical corporation's production plant costs from nuclear and fossil generating units using the average and excess method or one of the methods of assignment or allocation contained within the National Association of Regulatory Utility Commissioners 1992 manual or subsequent manual.

Q. How is the average and excess method defined in Section 393.1620?

A. Section 393.1620.1 (1) defines the average and excess method as:

> A method for allocation of production plant costs using factors that consider the classes' average demands and excess demands, determined by subtracting the average demands from the noncoincident peak demands, for the four months with the highest system peak loads. The production plant costs are allocated using the class average and excess demands proportionally based on the system load factor, where the system load factor determines the percentage of production plant costs allocated using the average demands, and the remainder of production plant costs are allocated using the excess demands.

Q. Are the peak demand and A&E methods included in the NARUC Manual?

A. Yes, the Peak Demand and A&E methods are included in the NARUC manual. While the general approach is included in the NARUC manual, the manual appears to leave some discretion to the analyst regarding the specifics of application. For instance, the peak demand approach or the A&E approach could consider a single monthly peak or multiple month peaks. In terms of developing the allocator for Liberty, utilizing the class contribution to the Company's four highest system monthly demands in December, February, August and September, while using the Peak Demand method or the A&E method are valid and reasonable approaches.

Q. What allocation method does the Company use for allocating fixed production plant related costs?

A. The Company uses the A&E method for allocating fixed production costs as described on pages 23-25 of Mr. Timothy Lyons' direct testimony. I support the Company's decision to continue to use the A&E method in this case.

Q. Has the A&E methodology seen widespread adoption by Missouri utilities?

A. Yes, as the Commission is aware from the recent rate cases, the A&E methodology has been adopted by Ameren, Empire and Evergy respectively.

Q. What class peaks does Liberty use to calculate the excess demand portion?

A The Company's A&E approach relies on class contribution to eight non coincident peak demands ("8NCP") – four in the summer from June through September and four in the winter from December through March, to calculate the excess demand. As support for the use of 8NCP, Mr. Lyons indicates that this 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. Specifically, he indicates that 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.

Q. What is your understanding of the SPP resource adequacy requirements?

A. My understanding is that the SPP resource adequacy requirements consist of calculating the capacity obligations based on the utility's highest peak in the summer and highest peak in the winter respectively (that is two months) and not the average of the eight months (that is, four months in the summer and four months in the winter) . Specifically, SPP defines the highest peak by summer or winter as Peak Demand:

> The highest demand including a) transmission losses for energy, b) the projected impacts of Non-Controllable and Non-Dispatchable Behind-The-Meter Generation, and c) the projected impacts of Non-Controllable and Non-Dispatchable Demand Response Programs measured over a one clock hour period (emphasis added).[3]

Q. Do you support the Company's 8NCP to calculate the excess demand in this case?

A. No, not in this case. If the Company load profile had monthly peaks within a narrow band of the annual peak, then applying 8NCP would have been reasonable. However, as demonstrated previously, the utility's load profile has become peakier. Further, the load factor has decreased by approximately five percentage points since the last rate case, which is significant and another indicator of a peakier load profile.

Q. What do you recommend?

A. For reasons discussed earlier, I recommend the average of class contributions to the four non coincident peaks (or "4NCP") from December, February, August and September.

Q. Have you calculated the A&E allocator using non-coincident peak demands for the four highest system peak loads?

A. Yes. I did. I used class non-coincident peak demands for the four highest system peak load months of December, February, August and September or 4NCP to make this calculation.

Q. Please explain in detail the derivation of the A&E 4NCP allocator.

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[3] Source is SPP Tariff, Attachment AA, Section 2.

A. Figure 1.2 shows the derivation of the A&E 4NCP allocator.

Figure 1.2: Derivation of the A&E 4NCP Allocator

Column	1	2	3	4	5	6
Rate Class	Peak Demand 4NCP (MW)	Average Demand (MW)	Excess Demand (MW)	Average Demand (%)	Excess Demand (%)	A&E Allocator (%)
NS Residential	2,927	1,121	1,805	0.22%	0.31%	0.26%
TC Residential	551,786	215,302	336,484	41.42%	56.94%	49.84%
TP Residential	306	114	192	0.02%	0.03%	0.03%
NS General Service	3,900	1,769	2,131	0.34%	0.36%	0.35%
TC General Service	101,648	50,108	51,541	9.64%	8.72%	9.14%
TP General Service	3	1	2	0.00%	0.00%	0.00%
NS Large General	44,612	24,437	20,175	4.70%	3.41%	4.00%
TC Large General	236,246	105,417	130,829	20.28%	22.14%	21.29%
NS Small Primary	18,934	11,576	7,357	2.23%	1.25%	1.69%
TC Small Primary	2,525	1,323	1,201	0.25%	0.20%	0.23%
Large Power	130,962	96,887	34,075	18.64%	5.77%	11.66%
Transmission	8,604	8,111	493	1.56%	0.08%	0.76%
MS-Miscellaneous	17	17	0	0.00%	0.00%	0.00%
SPL-Municipal St Lighting	4,558	2,088	2,471	0.40%	0.42%	0.41%
PL-Private Lighting	3,056	1,414	1,642	0.27%	0.28%	0.28%
LS-Special Lighting	611	85	527	0.02%	0.09%	0.06%
Total	1,110,695	519,770	590,926	100.00%	100.00%	100.00%

Column 1 shows the average of the 4NCP by class. Column 2 shows the average demand (MW) which was calculated by dividing the class annual energy usage (KWh) by 8,760 (number of hours in the test year). The excess demand shown in Column 3 is calculated by subtracting the class average demand in Column 2 from the class average 4NCP in Column 1. Column 4 shows each class's average demand share as a percentage of the total average demand. So, for instance the TC residential average demand percentage share is 215302 KW divided by the total of 519770 or 41.42%. Column 5 then shows each class's excess demand share as a percentage of the total excess demand for all classes. So, continuing to use the TC residential class as an example, this component would be 336484 KW divided by 590,926 KW or 56.94%. Column 6 represents that sum of (a) weighting class average demand as a proportion to the system average demand (Column 5) by the system load factor (45.77%) and (b) weighting the class excess as a proportion to the total excess demand (Column 6) by 1 minus the system load factor (54.33%). This method is consistent with the NARUC manual.

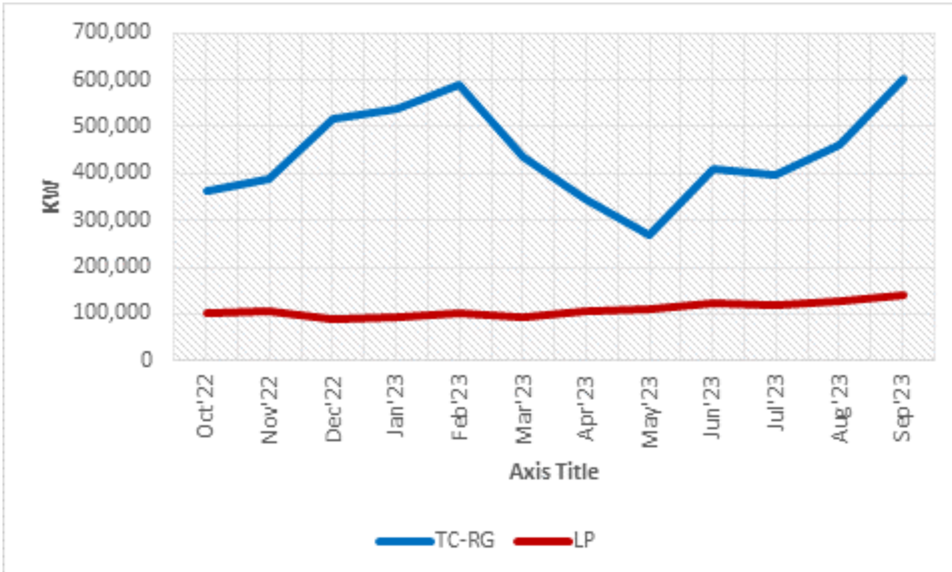
The total allocator calculated in Column 6 of Figure 1.2 is used to allocate fixed production plant-related costs to the classes. For example, based upon this methodology, the TC residential class should be allocated 49.83% of the total fixed production plant-related costs, while the NS Large General Service, Large Power and Transmission classes should be allocated 4%, 11.66% and 0.76% of these costs respectively.

Q. What insights can be gained from Figure 1.2?

A. As the Commission recognized in its 2010 Ameren decision, the class average and excess demand calculations provide important insights regarding the relative variability in each class's load profile. Classes with higher variability use the system less efficiently, are generally weather sensitive and cause demand on the system to hit peaks. From a relative standpoint, classes with excess demand percentage shares (Column 5 in Figure 2) that exceed their respective average demand percentage shares (Column 4 in Figure 2) have higher variability in their load profile such as the TC residential class. Conversely, classes with average demand percentage shares higher than their excess demand shares have lesser variability and utilize the system more efficiently such as the Large Power and Transmission classes.

Figure 1.3 below further reinforces the difference in variability in monthly peak demand for two classes, namely, TC residential and LP classes respectively. The graph show the higher variability or "peakiness" in TC residential peak demands compared to the LP class, which looks relatively flatter.

Figure 1.3: Residential and LP Class Monthly CP Demands



Q. Did you use the Company's COSS model to calculate the results using the A&E 4NCP allocator?

A. Yes, I did. I changed the Company's A&E allocator in the Company's COSS model from the A&E 8NCP to MECG's A&E 4NCP allocator. I did not make any other changes to the Company's COSS model.

Q. Please explain how the COSS results are shown.

A. Upon completion of the class cost of service study, the net income for each class (revenues less expenses) is divided by the rate base dedicated to serving that class to calculate the rate of return ("ROR") earned at present rates. To the extent that a class rate of return is greater than the system return, then the revenues recovered from the class are more than the costs to serve that class. Similarly, to the extent that a class rate of return is lower than the system return, then the revenues recovered from the class are less than the costs to serve this class. For instance, as reflected in Figure 4, Liberty's overall earned return under the class cost of service study is 2.75% at present rates. As can be observed from MECG's COSS results, the Company earned a below system average return from the TC Residential class, TP Residential class, TC Large General Service and Municipal Lighting and above system average return from all other classes except for Special Lighting and TP General Service. For these two classes, the Company earned a negative return meaning that revenues were not enough to cover its expenses.

Figure 1.4: MECG COSS ROR and Relative ROR Index at Present Rates

Class	MECG COSS - ROR	Relative ROR Index at Present Rates
NS Residential	3.03%	1.10
TC Residential	1.38%	0.50
TP Residential	0.12%	0.05
NS General Service	4.25%	1.55
TC General Service	5.41%	1.97
TP General Service	-3.36%	-1.22
NS Large General	3.55%	1.29
TC Large General	2.52%	0.92
NS Small Primary	7.50%	2.73
TC Small Primary	8.31%	3.02
Large Power	6.14%	2.23
Transmission	4.49%	1.63
MS-Miscellaneous	14.02%	5.10
SPL-Municipal St Lighting	1.88%	0.68
PL-Private Lighting	16.40%	5.96
LS-Special Lighting	-4.78%	-1.74
Total Company	2.75%	1.00

In Figure 1.4, the relative RORs[4] display wide deviations from 1 thereby reinforcing that at present rates, some classes are contributing significantly more than

[4] Relative ROR is calculated as Class ROR divided by retail system ROR at present rates.

their costs to serve with relative RORs more than 1 while others are contributing significantly less than their costs with relative RORs less than 1. Classes with a negative relative ROR such as Special Lighting and TP General Services class imply that such classes are not fully covering their expenses. Therefore, these results show that at present rates, there is a wide misalignment between the class cost and class revenue responsibility. This information provides important insights regarding cross subsidization and determining revenue allocation to move all rate classes closer to cost-based rates.

Q. How do your COSS results compare with the Company's results?

A. Schedule KM-2 shows this comparison. Generally speaking, the class RORs and relative ROR are directionally consistent for almost all classes except NS Large General Service and TC Large General Service classes respectively. While my COSS results show that the NS Large General Service class is earning above Missouri jurisdictional average at present rates and below average for TC Large General Service, the Company's COSS results are directionally opposite to my results for these two classes.

Q. Which fixed production cost allocation method should be used in this case?

A. I recommend that the Commission adopt MECG A&E 4NCP allocator (and the related MECG COSS results). Schedule KM-3 shows a summary of the COSS results at present rates.

II. REVENUE REQUIREMENT ALLOCATION

Q. What should be the primary guiding principle in establishing fair and reasonable rates?

A. A properly developed COSS is important to establish fair and reasonable rates. It is used to determine revenue requirement for the Company and should be used as the primary guiding principle in allocating revenue requirement to classes and informing rate design. Also as discussed earlier in my testimony, such an approach fulfills the important goals of promoting equity among classes and encouraging economic efficiency. If revenues are allocated to classes and align closely with the class cost responsibility, equity is maintained because each class pays its fair share of costs. Further, if retail rates align with cost of service, they reflect accurate pricing signals that drive consumer behavior, which in turn results in more efficient use of the system and minimizes system costs.

Q. Can other factors be also considered?

A. Yes. Other factors such as gradualism and rate continuity may also be considered. At the same time, however, these factors should not be the dominating elements such that there is little to no movement towards cost responsibility. We must also weigh in the fairness consideration and not ignore the important aspect that when one class is not paying their full share, one or more classes are being asked to pay more than their cost responsibility.

Q. Do you rely on MECG's COSS results to make recommendations regarding revenue apportionment to the customer classes?

A. Yes. I do. My revenue allocation recommendations are directionally consistent with MECG's COSS results meaning that:

- Customer classes with negative ROR at present rates get the highest increase and customer classes with the highest ROR (that is, in double digits) at present rates receive the lowest increase.
- Customers classes with below system average ROR at present rates receive an above system average increase; and
- Customer classes with above system average ROR at present rates receive a below system average increase.

Further, in terms of the specific allocations, I rely on the relative RORs at present rates to get classes closer to cost while recognizing that moderation is necessary given the double digit increase. My recommendations shown in Figure 1.5 below are in terms of a class multiplier to the average system increase as has been regularly used by Evergy in its two most recent rate cases.

Q. Please provide your specific revenue allocation recommendation applicable to classes.

A. Columns 1 and 2 in Figure 2.1 show the MECG COSS based increases by class as well as the multipliers. The multipliers are calculated by taking the class increase and dividing it by the system average. MECG's recommended multipliers by class are shown in Column 3. The class multiplier would be applied to the final authorized increase. For instance, if the final authorized increase is 10%, the NS residential would receive an increase of 10% X 0.88 multiplier=8.8% and so on. My recommendations have incorporated significant moderation for certain classes as can be observed by comparing the MECG COSS multipliers with the MECG recommended multipliers. For example, under the MECG COSS results, the TC residential class should receive a multiplier of 1.43 meaning that this class should receive an increase that is 1.43 times greater than the system average. However, I am recommending a multiplier of 1.15 which is substantially lower than the cost based multiplier in order to temper the rate impacts to this class. On the other hand, the LP class should receive a cost based multiplier of 0.19 and in order to help moderate the rate impact on other classes, I am recommending a much higher multiplier of 0.76. While I would have preferred a much closer alignment with COSS results, the Company's proposed increase necessitates moderation. If the Company's final increase is lower, steps should be taken to adjust the multipliers and move closer to the MECG cost based results.

Figure 2.1: MECG COSS Based Multiplier and MECG Recommended Class Multiplier

Column	1	2	3
Class	MECG COSS	MECG COSS Class Multiplier	MECG Recommended Class Multiplier
NS Residential	27.7%	0.94	**0.88**
TC Residential	42.5%	1.43	**1.15**
TP Residential	61.7%	2.08	**1.20**
NS General Service	17.7%	0.60	**0.80**
TC General Service	10.1%	0.34	**0.80**
TP General Service	98.7%	3.33	**1.25**
NS Large General	24.3%	0.82	**0.85**
TC Large General	34.1%	1.15	**1.01**
NS Small Primary	-1.0%	-0.03	**0.74**
TC Small Primary	-5.0%	-0.17	**0.74**
Large Power	5.6%	0.19	**0.76**
Transmission	10.4%	0.35	**0.77**
MS-Miscellaneous	-22.7%	-0.77	**0.70**
SPL-Municipal St Lighting	55.1%	1.86	**1.20**
PL-Private Lighting	-30.1%	-1.01	**0.70**
LS-Special Lighting	240.8%	8.13	**1.25**
Total Company	29.64%	1.00	**1.00**

Q. What is the Company's revenue allocation proposal?

A I calculated the multipliers for each of the classes from the Company's revenue allocation recommendation. Figure 2.2 shows a comparison of the Company's COSS based multiplier versus the revenue allocation multiplier.

Figure 2.2: Company COSS Based Multiplier and Company Class Multiplier

Column	1	2	3
Class	Company COSS	Company COSS Multiplier	Company Recommended Multiplier
NS Residential	28.7%	0.97	1.00
TC Residential	43.2%	1.46	1.05
TP Residential	63.1%	2.13	1.11
NS General Service	19.0%	0.64	0.96
TC General Service	11.5%	0.39	0.94
TP General Service	109.3%	3.69	1.27
NS Large General	33.7%	1.14	1.01
TC Large General	28.9%	0.98	1.00
NS Small Primary	-0.3%	-0.01	0.90
TC Small Primary	-1.6%	-0.05	0.89
Large Power	5.3%	0.18	0.92
Transmission	10.1%	0.34	0.93
MS-Miscellaneous	-22.9%	-0.77	0.82
SPL-Municipal St Lighting	58.8%	1.98	1.10
PL-Private Lighting	-27.4%	-0.93	0.81
LS-Special Lighting	306.2%	10.33	1.93
Total Company	29.64%	1.00	1.00

Generally speaking, the Company has employed more moderation and less movement towards COSS compared to my recommendations. For instance, the TC residential class should receive the Company's COSS based multiplier of 1.46 compared to the Company's recommendation of 1.05 whereas I am recommending 1.15 for a similar COSS based multiplier. Similarly, the Company's recommendation is resulting in more subsidization by the Large Power class by recommending a multiplier of 0.92 compared to my recommended ratio of 0.76 with both MECG and the Company showing a similar and much lower COSS based multiplier (0.19 for MECG versus 0.18 the Company).

Q. What do you recommend?

A. I recommend that for the proposed increase, the Commission adopt MECG's recommended revenue allocation multiplier shown in Figure 2.1 (Column 3) to calculate the final increase for each class. If the Company's final increase is lower, steps should be taken to move the multipliers closer to MECG's COSS results.

III. RATE DESIGN

Q. Which rate schedules do you discuss in this Section?

A. I discuss issues and related recommendations associated with Schedule NS Large General Service rate, Schedule LP Large Power Rate and Schedule TS Transmission Service rate respectively. At the outset, it is important to state that as discussed in the earlier section, I have provided alternative revenue allocation recommendations compared to the Company's proposal for each of these classes and therefore do not support the Company's revenue allocation. However, I have assumed the same revenue allocation as proposed by the Company in the rate design section in order to demonstrate an apples-to-apples comparison with the Company's recommended rate design.

A. Schedule NS Large General Service

Q. What are the major components of the NS Large General Service Rate?

A. Figure 3.1 shows the major components. As shown below, the rate consists of a customer charge, facility charge, seasonally differentiated demand charges and seasonally differentiated energy charges with hours use three tiered blocks.

Figure 3.1: Current NS Large General Service Rate

Customer Charge	$69.49
First 150 Hours - Winter	$0.07676
Next 200 Hours - Winter	$0.06253
All Additional - Winter	$0.06198
First 150 Hours - Summer	$0.08941
Next 200 Hours - Summer	$0.06939
All Additional - Summer	$0.06231
Facility Demand kW - Winter	$2.13
Billed Demand kW - Winter	$6.96
Facility Demand kW - Summer	$2.13
Billed Demand kW - Summer	$8.93

Q. What is the Company's proposal for allocating the revenue allocation increase to the NC Large General Service class?

A. Except for the customer charge, which is essentially proposed to be rounded to $70, the Company proposes an equal percentage increase of 30.7% to all components of the rate. Figure 3.2 shows the proposed increases to the rate components.

Figure 3.2: Company Proposed Increases to NS Large General Service Rate

Current Rates	Current Rates	Company Proposed	Percentage Increase
Customer Charge	$69.49	$70.00	1%
First 150 Hours - Winter	$0.07676	$0.10032	30.7%
Next 200 Hours - Winter	$0.06253	$0.08172	30.7%
All Additional - Winter	$0.06198	$0.08100	30.7%
First 150 Hours - Summer	$0.08941	$0.11685	30.7%
Next 200 Hours - Summer	$0.06939	$0.09069	30.7%
All Additional - Summer	$0.06231	$0.08143	30.7%
Facility Demand kW - Winter	$2.13	$2.78	30.7%
Billed Demand kW - Winter	$6.96	$9.10	30.7%
Facility Demand kW - Summer	$2.13	$2.78	30.7%
Billed Demand kW - Summer	$8.93	$11.67	30.7%

Q. Do you support the Company's proposed approach to allocate the revenue increase to this class?

A. No. The reason is because the current rate design under recovers fixed costs from demand charges. Specifically, at present, the billing demand charges recover 23% of the total base rate costs while the cost of service study indicates that 57% of the costs should be recovered from these demand charges. This suggests that there is over recovery of fixed costs from the energy charges.

Q. What do you recommend?

A. While I recognize that it is not practical to correct the flaw of recovering all the fixed costs from energy rates in one case, I recommend the following in this case:

1. No increase to the tail block rates. The increase aimed at the tail block rates should instead be recovered from the billed demand charges. As Figure 3.3(a) shows, the increase of \$1.566 million and \$1.202 million proposed to be recovered from the tail blocks should instead be recovered from the billed demand charges. The resulting incremental increase is \$0.69/KW in the winter and \$1.02/KW in the summer respectively, to the Company's proposed billing demand charges. As shown in Figure 3.3(b), these incremental increases should be added to the Company's proposed billing demand charges resulting in \$9.78/KW-month and \$12.70/KW-month applicable to the winter and summer respectively.

Figure 3.3(a): Removal of Company Proposed Increases to NS Large General Service Rate Energy Tail Block Rate

Rate Design Component	Company Proposal	MECG Proposal	Recovery from Winter Billing Demand Charge
All Additional - Winter Tail Block	$6,669,583	$5,103,307	$1,566,276
All Additional - Summer Tail Block	$5,120,554	$3,918,050	$1,202,504

Figure 3.3(b): Incremental Increase to Company Proposed Increases to NS Large General Service Rate Billing Demand Charge

	Company's Proposed $/KW-month Billing Demand Charge	MECG $/KW-Month Increase to Company Proposal	MECG $/KW-Month Total Billing Demand Charge
Winter Billing Demand Charge	$9.10	$0.69	$9.78
Summer Billing Demand Charge	$11.67	$1.03	$12.70

2. Any reduction in the revenue allocation to this class should be directed towards proportionally lowering the energy charges. The Company proposed customer charges and facility charges should remain at the levels currently being proposed by the Company and the billed demand charges should remain at the levels recommended in the last column on Figure 3.3(b) above.

Q. Do you have any comments regarding the TC-Large General Service rate?

A. The only difference between the current NS-Large General Service Rate and TC-Large General Service Rate is that TC-Large General Service rate includes an off peak credit of $0.005/kWh for usage between 10 PM and 6 AM. However, the Company is proposing to increase all three hours use energy block rates higher than the proposed increases to the NS-LG rate with no changes to the off peak credit.

From an overarching perspective, I believe it would be more constructive to develop a proper time differentiated rate instead of incorporating an off peak overlay on top of an existing hours use rate design as is the case with the current rate. Additional analysis is necessary to ascertain whether a three part time differentiated energy rate could be used to recover embedded costs. The pricing signals would be more efficient with a three part energy rate that is time differentiated as opposed to the overlapping rate design components in the current rate. Further, efforts should be made to begin phasing out fixed cost recovery from energy rates and recover it through demand charges in order to provide more accurate pricing signals. I therefore recommend that the Company work with interested parties on developing such a rate applicable to the TC-LG class.

B. Schedule LP – Large Power Class

Q. What is the Company's proposed increase to the various rate components in the LP rate?

A. Figure 3.4 shows the current rate; the Company proposed increase and the related proposed percentage increase to each rate component. As can be observed below, the Company proposes to increase the energy tail blocks by 40% for the winter and 57% for the summer while leaving the first energy block price the same. Further, there is no change in the facility charge and the billing demand charges are increased by 70%.

Figure 3.4: Company Proposed Increases to LP – Large Power Rate

	Current Rates	Company Proposal	Percent Increase
Customer Charge	$283.55	$325.00	15%
First 350 Hours - Winter	$0.05995	$0.05995	0%
All Additional - Winter	$0.03394	$0.04745	40%
First 350 Hours - Summer	$0.06790	$0.06790	0%
All Additional - Summer	$0.03528	$0.05540	57%
Facility Demand kW - Winter	$1.88	$1.88	0%
Billed Demand kW - Winter	$10.27	$17.43	70%
Facility Demand kW - Summer	$1.88	$1.88	0%
Billed Demand kW - Summer	$18.61	$31.58	70%

Q. Please comment on the Company's proposal.

A. The Company has provided no explanation with regards to the manner in which it spread the revenue allocation increase to each of the rate components. I am concerned about the 40% to 57% increase to the tail energy blocks when these rates are already much higher than the base cost of energy and there is already over recovery of fixed costs through volumetric rates. I also believe the demand charge differential between the winter and summer seasons should be narrower since the utility is dual peaking. Further, the facility charges should also be subject to an increase due to the cost of service guidance.

Q. Please provide your recommendation.

A. My recommendations are provided in Figure 3.5 below. Under my proposal, I narrow the demand charge differentials between the winter and summer seasons due to the dual peaking nature of the utility. Further, in order to better align with cost of service guidance:

- I increased the percentage share of billing demand based cost recovery compared to existing rates.
- I increased the facility charges and
- I recovered the remaining increase by modifying the first energy block. I left the tail block unchanged. The no change to the tail block and a lower increase to the energy charges relative to demand charges is to lessen the recovery of fixed costs from energy charges.

Figure 3.5: MECG Recommendations LP – Large Power Rate

	Current Rates	MECG Proposal	Percent Increase
Customer Charge	$283.55	$325.00	15%
First 350 Hours - Winter	$0.05995	$0.07092	18%
All Additional - Winter	$0.03394	$0.03394	0%
First 350 Hours - Summer	$0.06790	$0.08033	18%
All Additional - Summer	$0.03528	$0.03528	0%
Facility Demand kW - Winter	$1.88	$2.41	28%
Billed Demand kW - Winter	$10.27	$18.49	80%
Facility Demand kW - Summer	$1.88	$2.41	28%
Billed Demand kW - Summer	$18.61	$23.82	28%

C. Schedule TS – Transmission Service

Q. Please briefly describe Schedule TS or Transmission Service rate.

A. Schedule TS consists of time and seasonally differentiated demand charges, time and seasonally differentiated energy charges, a substation facilities charge and a customer service charge respectively. This rate has interruptible provisions which includes a maximum level of curtailment at 100 hours. Customers served on this rate are provided with a credit of $4.01 per KW-month or $48.12 per KW-year in exchange for providing interruptible service. At present there is one customer at this rate. Figure 3.6 shows the current charges associated with the rate.

Figure 3.6: Current Schedule TS – Transmission Service

Current Rates	
Customer Charge	$ 275.00
On-Peak Period kWh - Winter	$0.03890
Shoulder Period kWh - Winter	
Off-Peak Period kWh - Winter	$0.03181
On-Peak Period kWh - Summer	$0.05594
Shoulder Period kWh - Summer	$0.04467
Off-Peak Period kWh - Summer	$0.03387
Facility Demand kW - Winter	$0.53
Billed Demand kW - Winter	$18.39
Facility Demand kW - Summer	$0.53
Billed Demand kW - Summer	$27.06
Interruptible Credit ($/KW-month)	$4.01

Q. Has the company proposed any changes to the interruptible credits in this rate?

A Not at the present time. While other components of the bill are increasing, the Company has not proposed any changes to the interruptible credit. In particular, it is worth noting that while the billed demand charge (i.e., the component that recovers capacity costs) is a high charge and has been on an increasing trend, there has been no change in the interruptible credit since at least since 2013 when I first testified in a rate case proceeding associated with the Company.

Q. How do interruptible customers benefit the utility system?

A. Interruptible customers forgo firm service. Liberty utilizes the interruptible load to net against its load forecast prior to determining the planning reserve margin requirement. According to SPP rules, utilities' system load obligations are currently based on firm load plus a 15% planning reserve margin on an installed capacity basis. So, for illustrative purposes, if it is assumed that the Liberty system firm load was 1000 MW, it would need to have 1000 MW plus 150 MW capacity =1150 MW to comply with the SPP resource adequacy requirement. Now if it were further assumed that Liberty had 100 MW of interruptible load, the utility would be required to carry 1035 MW of capacity (900 MW + 135 MW), a reduction of 115 MW in reserve margin requirements compared to the situation without the 100 MW of interruptible load. Thus, interruptible customers benefit the system by avoiding the acquisition of generation resources for the amount of the interruptible load plus the planning reserve margin requirement. This is the reason that customers that provide interruptible service get interruptible credits. To be clear, this is not a discount but rather a credit to compensate interruptible customers for forgoing firm service and being available for curtailment.

Q. Why do customers forgo firm service and instead opt for interruptible service?

A. Customers opt for an inferior service and agree to curtailments in order to manage their power costs. It is a business decision that considers the trade-off between shutting down certain processes and forgoing revenue against the compensation received for providing the interruptible service. Therefore, if the compensation is not adequate, it undermines the success of the interruptible schedule.

Q. Has the only customer on Schedule TS responded to the Company's interruption instructions when called?

A. Yes. it is my understanding that this customer has consistently responded to the Company's instructions for interruptions for the last twenty years. This customer has made investments in sprint capacity and/or storage which has increased the facility's operational flexibility to provide curtailable service.

Q. Does the Company believe that interruptible load has increased in value due to the changing SPP resource adequacy related requirements?

A. Yes. I asked the Company's position on the value of interruptible load given potential and future changes to resource adequacy requirements at SPP. The Company indicated the following in response to MECG 3.1:

> Consistent with the Policy Objectives as stated in Commission Rule 20 CSR 4240-22.010 (2) (A), the Company views demand side resources on an equivalent basis with supply side resources. At this specific point in time, the resource adequacy ("RA") construct at SPP is going through a massive overhaul that is creating a challenge for load responsible entities to maintain compliance. The changes to planning reserve margins, performance-based accreditation and effective load carrying capability, fuel assurance policies and outage management activities, have created a dynamic and challenging target for load responsible entities. Interruptible load is a tool in the tool belt for addressing resource adequacy and, given the RA environment, interruptible load is extremely helpful in navigating this rapidly changing environment.

Based on this response, I believe that the Company could benefit from retaining and potentially expanding interruptible load.

Q. Have the changing methodologies associated with various elements of resource adequacy at SPP resulted in having the Company revisit its capacity situation to fulfill firm load requirements?

A. Yes. In response to MECG 2.2, the Company made efforts to provide an indicative perspective for the next five years. The big takeaway from the Company's response was that aside from some expiring purchase power contracts, there is a lot of uncertainty due to many changing rules at SPP including changes in accredited capacity calculations, and on an indicative basis, the Company projected small negative balances in capacity for some periods within the next five years.[5] This response further reinforces that interruptible load can provide an important and valuable service, especially at a time of uncertainty regarding changes in accredited capacity calculations and other SPP rule changes.

Q. Given the importance of interruptible load to the Company at the present time, is it reasonable to increase the interruptible credit in Schedule TS?

A. Yes. Given the Company's situation, it makes sense to increase the interruptible credit in Schedule TS in order to provide more equitable compensation commensurate with the increase in value and ensure that the interruptible load on this schedule can be retained and possibly expanded.

Q. How are interruptible credits conventionally calculated?

A. Provided that interruptible credit agreements are for three or more years, interruptible credits are conventionally guided by the avoided cost of a combustion turbine. Given that SPP provides the cost of a new combustion turbine in its tariff as the cost of new entry, I asked the Company if SPP's cost of new entry value of $85.61/KW-year or $7.13/KW-month represent a reasonable proxy for the value of interruptible load. The Company provided the following response:

> The Cost of New Entry (CONE), as defined in Attachment AA of the SPP Open Access Transmission Tariff ("OATT") , which reflects the cost of a new simple cycle combustion turbine, is considered a reasonable proxy for capacity. If interruptible load meets the characteristics needed for inclusion in the SPP resource adequacy construct, then the CONE is a reasonable proxy for the value of interruptible load.

Q. Does Schedule TS include interruptible provisions that meet the characteristics needed for inclusion in the SPP resource adequacy construct?

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[5] The Company cautioned that many of the accredited capacity calculations are dynamic and subject to change. Additionally, these calculations are made well in advance of the years in question, allowing time for adjustments.

A. Yes. Considering that the Company currently includes the interruptible load from Schedule TS as an offset to calculate the Net Peak Demand in calculating the resource adequacy planning reserve margin requirements, I believe that the interruptible load meets the SPP criteria.

Q. What is your recommended increase to the interruptible credit for Schedule TS?

A. While it can be argued that the interruptible credit should increase up to the CONE value at $7.13/KW-month, in this rate case, I recommend an increase in credit from the current $4.01/KW-month to $6/KW-month so that the interruptible load resource remains more cost effective than building capacity and therefore provides system benefits. At the same, the increase in credit from the existing amount will help provide equitable compensation for the value provided by the interruptible load.

Q. How should the cost of these credits be allocated?

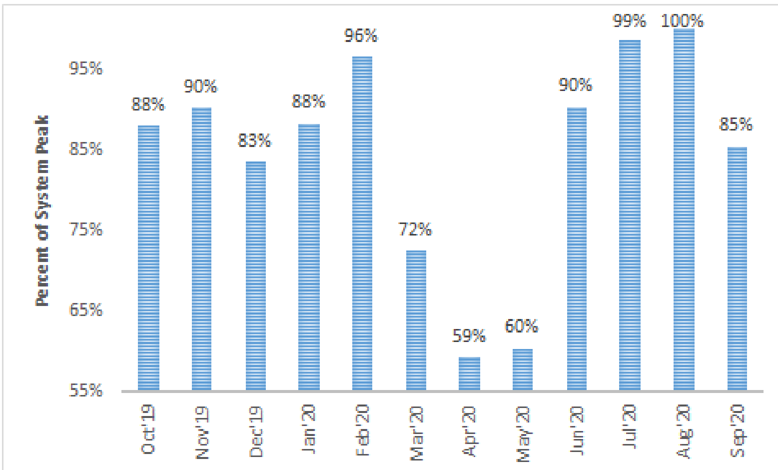
A. I support the Company's approach to allocating these credits to all firm service customers who benefit from the service provided by interruptible load.

Q. Does this conclude your direct testimony?

A Yes.

SCHEDULE KM-1: MONTHLY PEAK DEMANDS AS A PERCENT OF ANNUAL PEAK FROM LAST RATE CASE (ER-2021-0312)

Figure 2: Liberty-Empire Missouri's Monthly Peak Demands As a Percent of Annual Peak [1]



[1] Demand Data source: Mr. Timothy Lyons COSS model (demand data tab, Table 12 Month CP at Generation)

SCHEDULE KM-2: COMPANY AND MECG ROR AT PRESENT RATES

Class	MECG COSS - ROR	MECG Relative ROR Index at Present Rates	Company COSS -ROR	Company Relative ROR Index at Present Rates
NS Residential	3.03%	1.10	2.92%	1.06
TC Residential	1.38%	0.50	1.32%	0.48
TP Residential	0.12%	0.05	0.04%	0.01
NS General Service	4.25%	1.55	4.07%	1.48
TC General Service	5.41%	1.97	5.20%	1.89
TP General Service	-3.36%	-1.22	-3.69%	-1.34
NS Large General	3.55%	1.29	2.54%	0.92
TC Large General	2.52%	0.92	3.04%	1.11
NS Small Primary	7.50%	2.73	7.35%	2.67
TC Small Primary	8.31%	3.02	7.61%	2.77
Large Power	6.14%	2.23	6.21%	2.26
Transmission	4.49%	1.63	4.56%	1.66
MS-Miscellaneous	14.02%	5.10	14.11%	5.13
SPL-Municipal St Lighting	1.88%	0.68	1.64%	0.60
PL-Private Lighting	16.40%	5.96	15.16%	5.51
LS-Special Lighting	-4.78%	-1.74	-5.38%	-1.96
Total Company	2.75%	1.00	2.75%	1.00

SCHEDULE KM-3: MECG COSS RESULTS AT PRESENT RATES

Empire District Electric (MISSOURI)	Total Company	Res Gen NS-RG	Res Gen TC-RG	Res Gen TP-RG	General NS-GS	General TC-GS	General TP-GS	Large Gen NS-LG	Large Gen TC-LG	Small Prim NS-SP	mall Prim TC-SP	Large Power LP	ansmission TS	sc. Service MS	nicipal Lts SPL	Private Lts PL	Spec Lts LS
Rate Base	2,563,858,141	6,656,943	1,338,971,119	827,116	9,485,982	241,046,481	11,724	103,022,609	509,522,606	36,408,151	5,331,742	259,851,757	14,299,742	38,924	26,049,662	10,373,927	1,959,658
Operating Revenues	515,550,051	1,344,649	244,497,299	126,281	2,132,389	58,477,362	1,649	20,881,427	93,808,539	10,003,612	1,422,108	70,001,287	5,064,450	15,121	3,418,838	4,226,809	128,231
Operating Expenses																	
O&M Expenses	258,127,866	660,188	135,074,918	74,920	972,701	25,439,143	1,253	9,607,170	45,864,196	3,981,287	513,977	30,690,107	2,998,396	5,005	1,236,277	896,466	111,863
Depreciation & Amortization	146,024,638	368,899	74,347,658	43,598	550,100	14,046,384	736	5,829,877	27,907,127	2,225,250	293,981	16,834,753	1,130,416	2,709	1,396,678	928,037	118,434
Taxes Other than Income	35,835,895	94,213	19,175,113	11,734	138,734	3,437,492	218	1,384,540	6,838,130	476,656	71,181	3,401,651	195,532	523	332,536	243,496	34,144
Interest on Customer Deposits	1,465,043	5,023	1,243,314	656	10,003	167,016	42	4,457	33,578	-	-	-	-	-	-	-	954
Total Operating Expenses	441,453,442	1,128,322	229,841,003	130,908	1,671,538	43,090,036	2,250	16,826,045	80,643,030	6,683,192	879,140	50,926,511	4,324,344	8,238	2,965,490	2,068,000	265,395
Total Operating Income	74,096,609	216,327	14,656,296	(4,627)	460,851	15,387,326	(602)	4,055,382	13,165,509	3,320,420	542,968	19,074,776	740,105	6,884	453,348	2,158,809	(137,164)
Less:																	
Interest Expense	50,791,391	131,878	26,525,729	16,386	187,922	4,775,259	232	2,040,933	10,093,913	721,265	105,625	5,147,801	283,285	771	516,058	205,513	38,822
Net Income Before Taxes	23,305,218	84,449	(11,869,433)	(21,013)	272,929	10,612,067	(834)	2,014,450	3,071,596	2,599,155	437,343	13,926,975	456,820	6,113	(62,709)	1,953,296	(175,986)
Taxable Income	23,305,218	84,449	(11,869,433)	(21,013)	272,929	10,612,067	(834)	2,014,450	3,071,596	2,599,155	437,343	13,926,975	456,820	6,113	(62,709)	1,953,296	(175,986)
Total Income Tax	5,555,994	20,133	(2,829,688)	(5,010)	65,067	2,529,930	(199)	480,247	732,272	619,642	104,263	3,320,209	108,906	1,457	(14,950)	465,668	(41,955)
Excess ADIT Amortization & ITC	(2,005,827)	(5,208)	(1,047,540)	(647)	(7,421)	(188,582)	(9)	(80,599)	(398,624)	(28,484)	(4,171)	(203,294)	(11,187)	(30)	(20,380)	(8,116)	(1,533)
Net Income after Taxes	70,546,442	201,402	18,533,524	1,029	403,206	13,045,978	(394)	3,655,734	12,831,860	2,729,262	442,876	15,957,862	642,386	5,457	488,678	1,701,257	(93,675)
Rate of Return	2.75%	3.03%	1.38%	0.12%	4.25%	5.41%	-3.36%	3.55%	2.52%	7.50%	8.31%	6.14%	4.49%	14.02%	1.88%	16.40%	-4.78%