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-2022-0130
Date Testimony Prepared:	June 22, 2022

BEFORE THE PUBLIC SERVICE
COMMISSION OF THE STATE OF MISSOURI

In the Matter of Evergy Missouri West, Inc. d/b/a Every Missouri West's Request for Authority to Implement A General Rate Case Increase for Electric Service	)))))	**File No. ER-2022-0130**

Direct Testimony and Schedules of

Kavita Maini

On behalf of

MIDWEST ENERGY CONSUMERS GROUP

June 22, 2022

Protecting Your Bottom Line

KM ENERGY CONSULTING, LLC

**BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MISSOURI**

In the Matter of Evergy Missouri West, Inc. d/b/a Every Missouri West's Request for Authority to Implement A General Rate Case Increase for Electric Service	))))	Case No. ER-2022-0130

STATE OF WISCONSIN COUNTY OF WAUKESHA	)))	SS

AFFIDAVIT OF KAVITA MAINI

Kavita Maini, being first duly sworn, on her oath states:

1. My name is Kavita Maini. I am a consultant with KM Energy Consulting, LLC. having its principal place of business at 961 North Lost Woods Road, Oconomowoc, WI 53066. I have been retained by the Midwest Energy Consumers Group ("MECG") in this proceeding on its behalf.

2. Attached hereto and made a part hereof for all purposes are my direct testimony and schedules which were prepared in written form for introduction into evidence in Missouri Public Service Commission Case No. ER-2022-0130.

3. I hereby swear and affirm that the testimony and schedules are true and correct and that they show the matters and things that they purport to show.

Kavita Maini
Kavita Maini

**BEFORE THE PUBLIC SERVICE
COMMISSION OF THE STATE OF MISSOURI**

In the Matter of Evergy Missouri West, Inc. d/b/a Every Missouri West's Request for Authority to Implement A General Rate Case Increase for Electric Service	**)))))**	**File No. ER-2022-0130**

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BEFORE THE PUBLIC SERVICE COMMISSION OF THE STATE OF MISSOURI

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Direct Testimony of Kavita Maini

I. 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 30 years of experience in the energy industry. I graduated from Marquette University, Milwaukee, Wisconsin with a Master's in Business and a Masters 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, 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. **Schedule KM-1** identifies the regulatory proceedings in which I have been involved.

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 Evergy West, Inc. ("West" or "Company") on its Large General Service ("LGS") and Large Power Service ("LPS") rate schedules.

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 the LPS and LGS rate schedules. The rest of my testimony is organized as follows:

Section II: Summary

Section III: Importance of competitive industrial rates

Section IV: Class Cost of Service Study

Section V: Revenue Requirement Allocation

Section VI: LPS and LGS Rate Design

II. SUMMARY

Q. PLEASE SUMMARIZE YOUR TESTIMONY AND RECOMMENDATIONS.

A. The following is a summary of my testimony and recommendations:

Section III: Importance of Competitive Industrial Rates

a) Many of the companies represented by MECG operate energy intensive facilities that are sensitive to energy cost increases, which affect their overall cost of doing business.

b) Competitive industrial rates are an important factor in influencing Missouri customers' ability to compete on a regional and national level, which, in turn, impacts the economic health of the state. Large companies not only provide jobs in the Evergy West service area, but the existence of a competitive industrial base helps to keep all rates lower than they otherwise would be. The Commission recognized this fact in its decision in a 2014 rate case for Empire District Electric (now Liberty-Empire).

c) While the average industrial rates are competitive compared to the national average, the Company's average industrial rates have declined in competitiveness since the rates have grown faster than the national average.

Section IV: Class Cost of Service Study ("COSS")

a) A COSS study is critical in establishing fair and reasonable rates because it: (i) guides how the revenue requirement should be allocated to classes and (ii) informs rate design. Thus, it is important that the COSS approach reflect cost causation;

b) Metro's load profile characteristics indicate that it is a summer peaking utility. The contribution to summer demands should be used to derive the allocators for fixed production plant-related costs since these peaks drive the need for capacity to reliably serve firm load requirements;

c) Either the Peak Demand or the Average & Excess (A&E) method are reasonable allocation methods for fixed production plant-related costs; the Company uses the A&E method and I support this method in this case;

d) The A&E approach considers the load profile of customer classes by incorporating the class' maximum demands, load factor and average energy use. Therefore, the A&E approach is a reasonable method to use in this case. In fact, the Commission has supported the use of this approach in the Ameren rate cases.

e) While the Company uses class coincident peak contribution to the four summer peaks in calculating the excess demand portion, I recommend the class average of the four summer non-coincident peaks as shown in the NARUC manual for the A&E approach.

f) The results of my COSS are substantially similar to the Company's COSS except for the lighting class. At present rates and equal rates of return, the results show that the residential class is paying rates that are substantially below cost responsibility. Other classes such as the LPS and LGS class are paying rates substantially above cost.

Section V: Revenue Requirement Allocation

a) The COSS should be used as the primary guiding principle in allocating revenue requirement to classes and informing rate design. Such an approach will foster equity amongst classes, send appropriate price signals and encourage economic efficiency. While other factors such as gradualism and rate continuity may also be considered, these factors should not be the dominating elements such that there is limited to no movement towards class cost responsibility.

b) Given an average jurisdictional proposed increase of 8.31%, I am generally supportive of the Company's method to move class revenue responsibility towards cost responsibility.

The Company has followed its COSS results from a directional standpoint and used a multiplier of 128% for classes that require above system average increases such as the residential class and multipliers of 50% for the small general service class and 75% for all classes such as LPS, LGS and thermal service respectively.

c) My recommendations are as follows

- Use the MECG's COSS study results as guidance regarding revenue allocation to classes;
- While a much larger revenue neutral adjustment is very justifiable given the COSS results, for an average jurisdictional increase of 8.31%, I am not opposed to applying a multiplier of approximately 128% to calculate the average increase for classes that show above jurisdictional average increases in MECG's COSS results such as the residential, lighting and CCN classes respectively.
- The Company's proposal should be modified such that all classes with indexed ROR at present rates above 150 showing a decrease with a system wide average increase of 8.31% should use the same multiplier. Given that this approach now includes the small general service class, the multiplier would be lower than 75%.
- The multipliers should change with revenue requirement reductions such that the lower the average increase, the higher the revenue neutral shifts become. I suggest an approach to modify the multipliers depending on the percent change to the Company's proposed jurisdictional rate increase. Incorporating higher revenue neutral shifts with lower rate increases will result in a more balanced trade-off between equity and moderation compared to the Company's proposal which contemplates no change in multipliers with lower revenue deficiency.

Section VI: LPS and LGS Rate Design

(1) Recovery of Proposed Revenue Allocation

a) **LPS Rates:** The Company's proposed allocation approach to allocate 125% of the revenue allocation class increase of 7.05% to the fixed cost rate components such as customer and demand charges and 75% to the variable components such as energy charges is reasonable.

The LPS rate design has the same winter seasonal energy charges regardless of voltage service differentials. Accounting for voltage differentials is fundamentally addressed in designing rates as demonstrated in the LGS rate design for winter seasonal energy charges. By ignoring these differentials, customers at higher voltage levels are not getting the benefit of incurring lesser losses and therefore, lower rates compared to the current situation. I recommend that the Company take the corrective measures to incorporate the voltage service differentials in this case.

b) **LGS Rates:** Similar to the proposal for LPS, the Company proposes to allocate 125% of the revenue allocation class increase of 7.77% to the fixed cost rate components (i.e., 9.7%) such as customer and demand charges and 75% to the variable components such as energy charges (i.e., 5.8%). A review of the proposed charges and related calculations confirms the increase to the fixed cost components at the appropriate levels.

Given that LGS demand charges are much lower than suggested by the unitized guidance from the COSS, I recommend that the fixed cost components be increased by 150% of the average rate increase to the LGS class and the multiplier applied to the energy charges be decreased correspondingly to recover the remaining revenue requirement increase.

(2) FEEDBACK REGARDING FUTURE CHANGES

a) **LPS:** The Company would like to implement changes in the future in order to simplify the rate design while making efforts to moderate rate impacts for customers on LPS rates. With regards to the Company's proposal, I suggest the following to show my support for the Company's proposal regarding some elements and address my concerns regarding others:

- Shift fixed costs from energy charges to demand charges but do not change the energy charge differentials.
- Introduce an on-peak provision whereby the maximum demand set in the specified on peak hours is the billing demand for the month.
- Evaluate a time differentiated on and off-peak energy rate to recognize the cost differentials and provide better pricing signals than a flat energy rate.
- Set up a working group of interested parties to evaluate these alternatives and assess rate impacts.
- Gather consensus on the steps and introduce to be introduced in the future.

b) **LGS:** In concept, the Company has a similar proposal for the LGS class with the end goal of higher fixed cost recovery from demand charges and a flat, seasonally differentiated energy rate. Therefore, my concerns and subsequent recommendations are the same as listed above for the LPS rate design.

III. IMPORTANCE OF COMPETITIVE INDUSTRIAL RATES

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. Furthermore, since it affects the competitiveness of these companies that are operating in a regional and national environment, it also affects the ability of the state to attract and retain companies and jobs. In this rate case proceeding, West proposes to increase base LPS rates and LGS rates by 7.05% and 7.77% respectively. The large commercial and industrial customers members served by West will therefore, be significantly impacted by the outcome of this proceeding.

Q. ARE COMPETITIVE INDUSTRIAL RATES IMPORTANT?

A. Yes, as mentioned, competitive industrial rates are an important factor in influencing Missouri businesses' ability to compete on a regional and national level, which in turn, impacts Missouri's economic health.

High energy costs directly impact the bottom line of industrial customers because, in many cases, these costs cannot be passed to downstream customers or markets due to highly competitive business conditions. For those businesses with facilities in many locations throughout North America, competitive rates are often central to the decision to reduce production, or expand production, at a particular facility. As such, rate disparity among sister plants or competitors has the potential to result in reducing production or shifting production elsewhere, especially if such disparity is sustained over time. Competitive rates are, therefore, important to Missouri's economy and the decisions in this case may determine whether industrial customers become more or less competitive.

Q. ARE COMPETITIVE INDUSTRIAL RATES BENEFICIAL TO THE OTHER CUSTOMER CLASSES?

A. Yes. Not only do large companies provide jobs in the West service area, but the existence of a competitive industrial base helps to keep all rates lower than they otherwise would be. The Commission expressly recognized this fact in its decision in a 2014 Empire rate case:

> Competitive industrial rates are important for the retention and expansion of industries within Empire's service area. If businesses leave Empire's service area, Empire's remaining customers bear the burden of covering the utility's fixed costs with a smaller amount of billing determinants. This may result in increased rates for all of Empire's remaining customers.[1]

In reaching this conclusion, the Commission relied on testimony that presented industrial rate comparison data from the Edison Electric Institute's (EEI) Typical Bills and Average Rate Report.

Q. HAS THE COMPANY ACKNOWLEDGED THE IMPORTANCE OF COMPETITIVE INDUSTRIAL RATES?

A Yes. In the prior case, the Company expressly acknowledged the economic benefit of competitive commercial and industrial rates.[2]

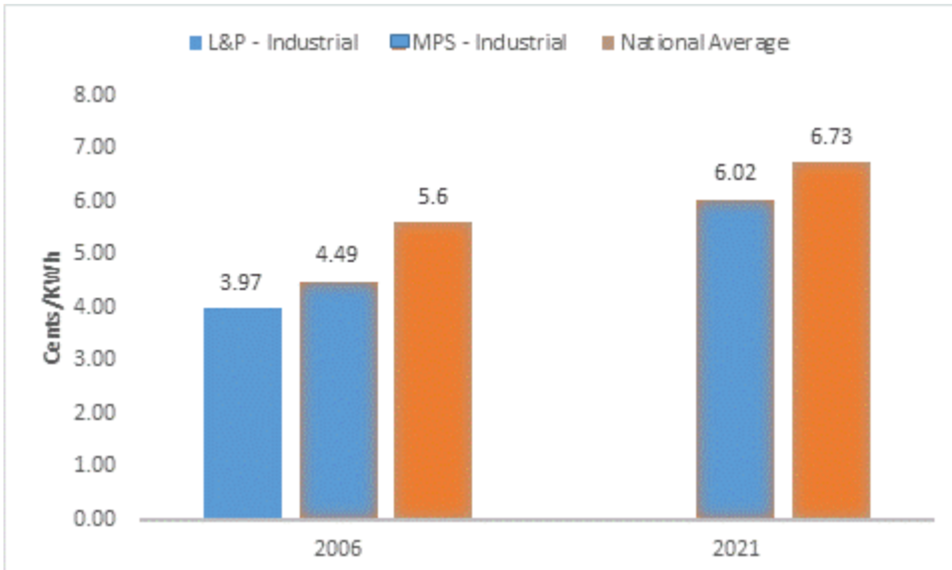
Q. HOW COMPETITIVE ARE WEST'S RATES?

A. Compared to Metro, West's average industrial rates are more competitive as they were 11% below the national average in 2021. Using the same yardstick year of 2006 as Mr. Greg Meyer used in his direct testimony for comparing the percent changes over time, while the national average increased by 20% between 2006 and 2021, the LPS and MPS average industrial rates increased by 52% and 34% respectively. Figure 1 shows the comparison. [3] Thus, while the average industrial rates are competitive compared to the

[1] Report and Order, Case No. ER-2014-0351, issued June 24, 2015, page 18.
[2] See Mr. Bradley Lutz's direct testimony, page 6 in docket ER-2018-0145, pages 25-26.
[3] Data from Winter 2006 and Summer 2021 Reports

national average, the Company's average industrial rates have declined in competitiveness since the rates have grown faster than the national average.

Figure 1: Average Industrial Rate Comparison: Evergy West v. U.S.



Note: 2021 blue bar is Evergy West

Q. WHAT STEPS CAN BE TAKEN TO ADDRESS FURTHER DETERIORATION OF THE COMPETITIVENESS OF WEST'S AVERAGE INDUSTRIAL RATES?

A. In order to prevent the competitiveness from deteriorating further, steps should be taken in aligning each class' revenue responsibility with the class cost responsibility. The Company's class cost of service study indicates that, even if West is given a 8.31% rate increase, the LPS class should receive a 4.4% rate decrease. Similarly, the LGS class should receive a 9.6% decrease. It is important to be mindful of these results as the Commission considers revenue allocation to classes.

Q. DO YOU BELIEVE THAT THE EEI REPORTS ARE VALUABLE FOR THE PURPOSE OF COMPARING THE COMPETITIVENESS OF RATES?

A. Yes. EEI Reports are used by state utility commissions, utilities, and customers for purposes of assessing the competitiveness of rates. As I previously mentioned, this Commission has expressly relied on my testimony in a previous Empire case that utilized the EEI data for purposes of assessing the competitiveness of Empire's industrial rates. Further, utilities also use this data to gauge the competitiveness of their industrial rates against other utilities. For instance, as shown in **Schedule KM-2** attached to this testimony, both Xcel Energy and Evergy have utilized the same EEI report that I utilized in this testimony. Finally, as reflected in the testimony filed by Steve Chriss (Walmart) and Rick Nelson (Praxair) in Case No. ER-2016-0023, the data reflected in the EEI Report is indicative of the real-life experience of these companies that operate in numerous states. For instance, as Mr. Chriss points out, Walmart's "experience mirrors the results of the EEI Report." Given its ubiquitous acceptance in the industry, I believe that they are valuable and accurate for purposes of assessing the competitiveness of Evergy's industrial rates.

IV. CLASS COST OF SERVICE STUDY

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 rate 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 way 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.

Q. FOR A GIVEN REVENUE REQUIREMENT, WHAT IS THE IMPACT OF CLOSELY ALIGNING RATES WITH EACH CLASS' COST OF SERVICE?

A. Provided that the class cost of service study is properly developed to reflect cost causation, closely aligning rates with each class' 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 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 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 the industrial class, 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. As mentioned, the Commission expressly recognized this fact in 2014 when it found that "if businesses leave Empire's service area, Empire's remaining customers bear the burden of covering the utility's fixed costs with a smaller amount 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, it is also affected by the class rate design. In instances where the class revenue responsibility is at cost of service but rates are designed such that there is recovery of fixed costs through volumetric charges, then the pricing signals are distorted and have the potential once again of sending inappropriate cost signals. For example, if fixed generation costs are recovered through variable charges then the demand charge is kept artificially low, thus sending the improper price signal that generation capacity is cheaper than is actually the case. Similarly, if the energy charge is artificially high then there is an implication that energy costs are more expensive than is actually the case. Such a signal could then result in customers choosing to use less energy but contributing more to peak conditions. This has the effect of increasing the need for capacity thereby increasing system costs, which once again, must be recovered from customers through higher rates.

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. In West's case, the production net plant fixed costs represent 36% of the total net plant fixed costs.

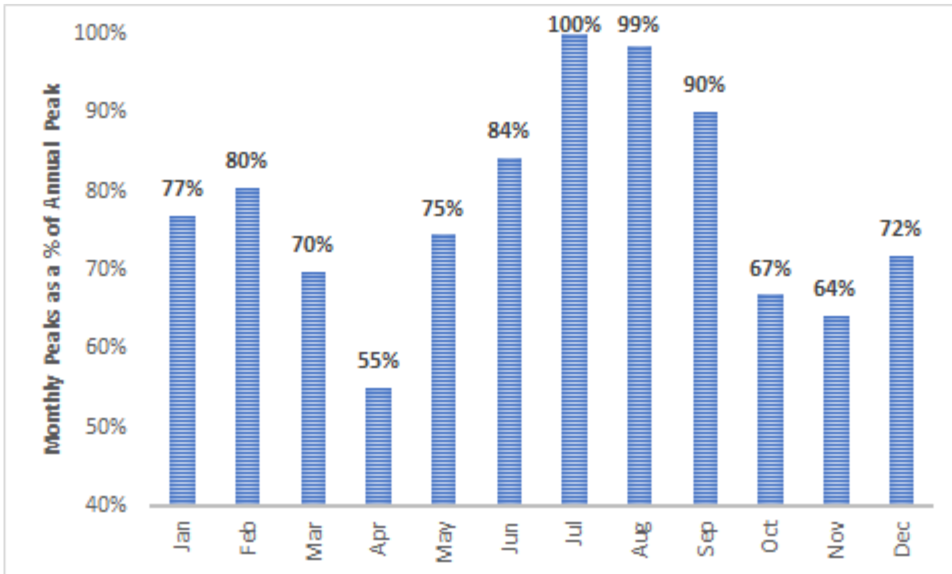
Q. WHAT SHOULD BE CONSIDERED IN DETERMINING THE APPROPRIATE ALLOCATOR FOR FIXED PRODUCTION PLANT-RELATED COSTS?

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. For example, if a utility is summer peaking as is the case with West, then each class' contribution to the summer peak demands is an appropriate cost causative allocator.

Q. DID YOU ANALYZE WEST'S MISSOURI'S SYSTEM LOAD?

A. Yes, I did. Figure 2 shows the system monthly peak demands as a percent of overall annual peak for the test year. This chart shows that West is a summer peaking utility. West's annual system peak is in July followed closely by August at 90% of the annual system peak. Since generation capacity is sized to reliably meet the highest peak demands, it would be appropriate to consider class contributions to monthly demands for all months that are within 5% to 10% of the system peak. During the test year there were three months (July, August and September) that were within 10% of the annual system peak. Therefore, it is theoretically appropriate to only consider class demands for these three months. However, in order to narrow the issue with the Company in this case, I can support utilizing class demand contributions to all summer months (i.e., June through September).

Figure 2: Test Year West Missouri's Monthly Peak Demands As a Percent of Annual Peak Demand



The non-summer monthly peak demands are much lower than the annual peak demand and do not cause the Company to build or acquire more capacity. Rather, the class contributions to the summer months reasonably capture cost causation associated with the Company's decision to acquire generation capacity to reliably serve load.

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 demonstrated above, in West's case, class contributions coincident with the monthly summer demands are appropriate because of the summer peaking nature of its load.

While the Peak Demand method relies solely on class contribution to the relevant monthly peak demands, the A&E methodology considers both 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' 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.[4] 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

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

> 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 RECENTLY ENACTED SECTION 393.1620?

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 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. ARE THE PEAK DEMAND AND A&E METHODS INCLUDED IN THE NARUC MANUAL?

A. The Peak Demand and A&E methods are included in the NARUC manual and are also compatible with least cost resource planning. 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 West, utilizing the class contribution to West's summer demands using the Peak Demand method or the A&E method are reasonable approaches.

Q. WHAT ALLOCATION METHOD DOES THE COMPANY USE FOR ALLOCATING FIXED PRODUCTION PLANT?

A. The Company uses the A&E method for allocating fixed production costs.[5] Ms. Marisol Miller indicates in her testimony that the Company conducted a comprehensive investigation to determine the most appropriate production allocation methodology in the prior rate case (docket ER-2018-0146) and concluded that the A&E approach was most appropriate. In that case, the Company evaluated a number of methodologies and chose the A&E method in large part to acknowledge and appropriately recognize that industrial facilities with relatively high load factors efficiently use the system and to develop industrial rates that are competitive with neighboring utilities.[6]

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.

Q. HAS THE A&E APPROACH BEEN ADOPTED BY THE MISSOURI COMMISSION?

A. Yes. For instance, in the 2010 Ameren rate case, the Commission found

> To evaluate how best to allocate costs among these customer classes, four parties prepared and presented class cost of service studies. The studies presented by AmerenUE and MIEC used versions of the Average and Excess Demand Allocation method (A&E). Since the class cost of service studies offered by Staff and Public Counsel are unreliable, the Commission must choose between the Average and Excess method studies submitted by AmerenUE and MIEC. After carefully considering all the studies, the

[5] The A&E allocator is also used to allocate transmission costs, which is appropriate for all of the same cost causative reasons as identified in my testimony for fixed production plant.

[6] See Mr. Thomas Sullivan's direct testimony in docket ER-2018-0145.

> Commission finds that AmerenUE's class cost of service study, modified to allocate revenues from off-system sales on the basis of class energy requirements, is the ***most reliable*** of the submitted studies.[7]

More recently, in the latest Ameren rate case, the Commission once again found that the A&E methodology was most reliable:

> Generation (production) plant comprises more than half of Ameren Missouri's total plant investment. For allocation of that investment, Ameren Missouri used the 4 NCP (non-coincident peak) version of the A (average) & E (excess) demand methodology. . . [T]he Commission finds that Ameren Missouri's class cost of service study offers a reasonable estimation of class cost of service.[8]

Q. WHAT CLASS PEAKS DOES WEST USE TO CALCULATE THE EXCESS DEMAND PORTION?

A West's A&E approach relies on class contribution coincident to the four summer peak demands or 4CP to calculate the excess demand. The method prescribed in the NARUC manual for the A&E method, however, appears to encourage the use of non-coincident peak demands (NCP) and is also a more common approach used by other Missouri utilities.

Q. HAVE YOU CALCULATED THE A&E ALLOCATOR USING NON-COINCIDENT PEAK DEMANDS?

A. Yes. Like the summer coincident peaks, the class non-coincident demands are highest in the summer and I used the average of the class non-coincident peak demands for the summer months of June through September (4NCP) to make this calculation.

[7] Case No. ER-2010-0036, Report and Order, issued May 28, 2010 at pages 82, 86-87 (emphasis added).
[8] Case No. ER-2021-0240, Report and Order, issued February 2, 2022, at pages 16 and 23.

Q. PLEASE EXPLAIN IN DETAIL THE DERIVATION OF THE A&E 4NCP ALLOCATOR.

A. Figure 3 shows the derivation of the A&E 4NCP allocator.

Figure 3: Derivation of the A&E 4NCP Allocator

Column	1	2	3	4	5	6	7
	Peak Demand	Energy Sales	Average Demanc	Excess Demand	Average Demanc	Excess Demand	Total Allocator
	4NCP (MW)	vith Losses (MWh	(MW)	(MW)	(%)	(%)	(%)
Residential	1,124.55	3,797,424	433.50	691.05	45.14%	68.16%	**57.20%**
Small General Service	287.76	1,268,777	144.84	142.92	15.08%	14.10%	**14.57%**
Large General Service	251.29	1,257,785	143.58	107.71	14.95%	10.62%	**12.68%**
Large Power Service	294.24	2,034,413	232.24	62.00	24.18%	6.12%	**14.71%**
Thermal Service	1.12	7,881	0.90	0.22	0.09%	0.02%	**0.06%**
Lighting	15.22	46,633	5.32	9.89	0.55%	0.98%	**0.78%**
CCN	0.07	170	0.02	0.06	0.00%	0.01%	**0.004%**
Total	1,974.24	8,413,082	960	1,014	100.00%	100.00%	**100.00%**

Column 1 shows the average of the four non-coincident peaks (“NCP”) for the four peaking months by class. Column 2 shows the annual energy (MWh) by class and Column 3 converts this annual energy (MWh) to average demand (MW) by dividing the annual energy usage by 8,760 (number of hours in the test year). The excess demand shown in Column 4 is calculated by subtracting the average demand in Column 3 from the average demand for the 4 summer months as reflected in Column 1. Column 5 shows each class’ average demand as a percentage of the West system average demand. So, for instance the residential average demand percentage is 433.50 MW divided by 960 MW or 45.14%. Column 6 then shows each class’ excess demand as a percentage of the total excess demand for all classes. So, using the residential class as an example, this component would be 691.05 MW divided by 1014 MW or 68.16%. Column 7 represents that sum of (a) weighting class average demand as a proportion to the system average demand (Column 5) by the system load factor (47.6%) and (b) weighting the class excess as a proportion to the total excess demand (Column 6) by 1 minus the system load factor (52.4%). This method is consistent with the NARUC manual.

The total allocator calculated in Column 7 of Figure 3 is used to allocate fixed production plant-related costs to the classes. For example, based upon this methodology, the residential class should be allocated 57.2% of the total fixed production plant-related costs, while the LPS and LGS classes should be allocated 14.71% and 12.68% of these costs respectively.

Q. WHAT INSIGHTS CAN BE GAINED FROM FIGURE 3 ABOVE?

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' 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 6 in Figure 3) that exceed their respective average demand percentage shares (Column 5 in Figure 3) have higher variability in their load profile such as the 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 General Service and Large Power Service classes.

Figure 4(a) and 4(b) demonstrate the difference in variability in both monthly coincident and non-coincident peak demand for two classes, namely, residential and LPS classes respectively. The graphs show the higher variability in residential peak demands compared to the LPS class, which looks relatively flatter.

Figure 4 (a): Residential and LPS Class Monthly NCP Demands

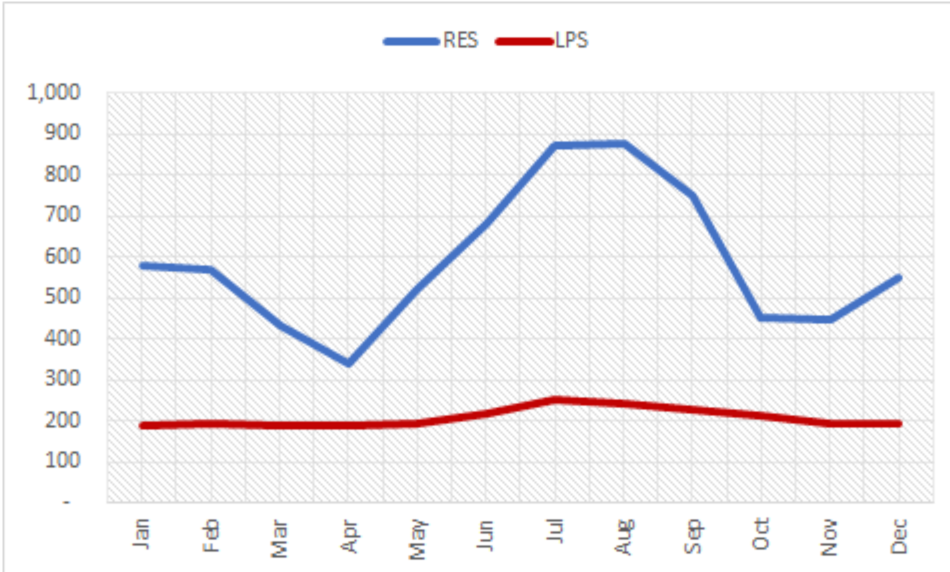
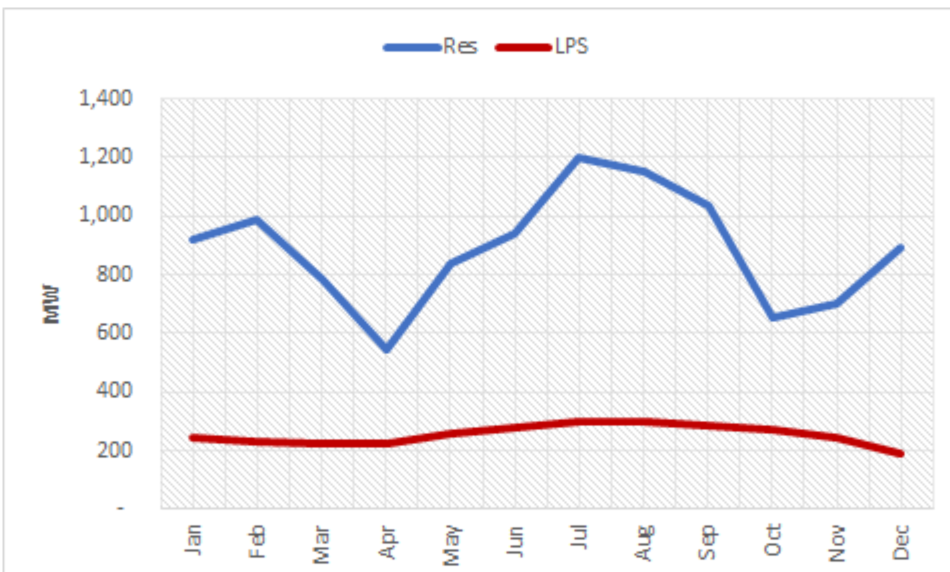


Figure 4 (b): Residential and LPS Class Monthly CP Demands



Q. DID YOU USE THE COMPANY'S COSS MODEL TO CALCULATE THE RESULTS USING THE A&E 4NCP ALLOCATOR?

A. Yes, I did. I only changed the Company's A&E allocator in the Company's COSS model from the A&E 4CP to A&E 4NCP and did not find it necessary to make any other changes.

Q. PLEASE EXPLAIN HOW THE RESULTS OF THE CLASS COST OF SERVICE STUDY 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 earned. 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 5, West's overall earned return under the class cost of service study is 5.29%. That said, however, West only earned a return of 2.79% from the residential class as can been observed under MECG COSS results. In contrast, West earned a return of 9.22% and 8,47% from the LGS and LPS classes respectively. Therefore, at present rates, residential class revenue recovery is significantly less than the costs to serve this class while the LGS and LPS class revenues are significantly more than the costs to serve these classes respectively. These results mean that the Company's industrial rates would benefit from and improve in competitiveness by addressing the significant deviations from class cost responsibility in this case.

Q. ARE THE COSS RESULTS USING WEST'S A&E 4CP METHOD AND YOUR A&E 4NCP METHOD GENERALLY CONSISTENT?

A. Yes. I compared the earned rate of return ("ROR") and the indexed rate of return derived from my study as well as the Company's COSS at present rates. Figure 5 shows this data. Except for the Lighting class, the RORs and the indexed rates of return are substantially similar. Given that both methods utilize class contribution to summer peak demands, it is not surprising to note the similarity in the results. Classes with indexed rate of return below 100 are currently paying rates that are below the cost to serve those classes such as the residential class. Conversely, Classes with indexed rate of return above 100 are currently paying rates that are above the cost to serve those classes such as small general service, LGS, thermal service and Large Power Class respectively. **Schedule KM-3** shows a summary of the COSS results utilizing the A&E 4NCP method at present rates.

Figure 5: MECG v. West's CCOSS Earned Rate of Return ("ROR") and Indexed ROR by Class at Present Rates

	METRO COSS RESULTS (A&E 4CP)		MECG COSS RESULTS (A&E 4NCP)	
	Earned ROR	Indexed ROR	Earned ROR	Indexed ROR
Residential	2.68%	51	2.79%	53
Small General Service	10.36%	196	10.35%	196
Large General Service	9.70%	183	9.22%	174
Large Power Service	8.41%	159	8.47%	160
Thermal Service	9.68%	183	9.72%	184
Lighting	6.52%	123	4.61%	87
CCN	-67.05%	-1267	-66.72%	-1261
	5.29%	**100**	**5.29%**	**100**

Q. WHICH FIXED PRODUCTION COST ALLOCATION METHOD SHOULD BE USED IN THIS CASE?

A. I recommend that the Commission adopt the A&E 4NCP allocator (and the related MECG COSS results), since this method is more consistent with the A&E methodology described in the NARUC manual.

V. REVENUE REQUIREMENT ALLOCATION

Q. WHAT SHOULD BE THE PRIMARY GUIDING PRINCIPLE IN ESTABLISHING FAIR AND REASONABLE RATES?

A. A properly developed COSS is critical to establishing 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.

Q. WHAT ARE THE TOTAL REVENUE NEUTRAL ADJUSTMENTS NEEDED BY CLASS TO COMPLETELY ELIMINATE THE CROSS SUBSIDIZATION AT PRESENT RATES IN THIS CASE?

A. Figure 6 shows the derivation of the MECG COSS revenue neutral adjustments needed to align revenue responsibility with cost responsibility at present rates. Lines 1 through 5 show the results for each class at present rates and the related ROR and indexed ROR. Line 6 shows the income required to achieve equal ROR and Line 7 shows the difference between the income required to achieve equal ROR (Line 6) and income that produces the current ROR (Line 3). Lines 8 and 9 show the revenue neutral changes (in both nominal dollars and %) needed to class revenues in order to completely eliminate cross subsidization. As can be observed, in order to bring it completely to cost of service and eliminate any subsidization, double digit revenue changes are required for all classes except for the lighting class. For example, the Residential class would need a revenue neutral increase of 13.1% to base rate revenues in order to achieve cost based responsibility. On the other hand, the LGS and LP classes would need a 15.1% and 10.8% decrease respectively.

Figure 6: MECG COSS: Revenue Neutral Adjustments Needed for Equal ROR at Present Rates

	MO West Retail	Residential	Small General Service	Large General Service	Large Power Service	Thermal Service	Lighting	CCN
Test Year Revenue	$719,045,350	$376,086,292	$116,686,565	$88,729,808	$116,143,926	$460,184	$13,006,951	$33,302
Rate Base	$2,484,954,452	$1,500,510,217	$342,145,860	$259,031,838	$299,571,954	$1,140,834	$67,876,471	$1,512,850
Net Operating Income at Present Rates	$131,492,223	$41,918,251	$35,412,756	$23,880,084	$25,361,203	$110,862	$3,126,256	-$1,009,416
Rate of Return at Present Rates	**5.29%**	**2.79%**	**10.35%**	**9.22%**	**8.47%**	**9.72%**	**4.61%**	**-66.72%**
Relative Rate of Return	100.00	52.79	195.60	174.22	159.99	183.64	87.04	(1,260.93)
Income at Equal ROR at Present Rates	$131,492,223	$79,400,016	$18,104,766	$13,706,759	$15,851,953	$60,368	$3,591,707	$80,053
Difference in Income @ Equal ROR	$0	$37,481,765	-$17,307,989	-$10,173,325	-$9,509,250	-$50,494	$465,451	$1,089,469
Revenue Neutral Change to attain Equal ROR ($)	$0	$49,217,087	-$22,727,020	-$13,358,534	-$12,486,540	-$66,303	$611,181	$1,430,575
Revenue Neutral Change to attain Equal ROR (%)		13.1%	-19.5%	-15.1%	-10.8%	-14.4%	4.7%	4295.7%

The significant deviation from class cost responsibility is of concern especially because as discussed earlier, the Company's average industrial rate competitiveness has declined over time. Closer alignment of the industrial classes' revenue responsibility with cost responsibility will be instrumental in preventing further decline in competitiveness.

Q. WHAT IS THE COMPANY'S REVENUE ALLOCATION PROPOSAL?

A. The Company proposes to apply certain multipliers to the average system increase in order to move classes closer to cost. For example, the Company applies 128% of the jurisdictional rate increase to the Residential class to recognize that this class' revenues are below costs to serve. The Company proposes the following increases for each class for a system average increase of 8.31%:

- Apply a 10.84% (approximately 128% of the jurisdictional rate increase) increase to the Residential class;
- Apply a 10.50% (approximately 128% of the jurisdictional rate increase) increase to the CCN class;
- Apply a 7.05% (approximately 75% of the jurisdictional rate increase) increase to the Large Power Service class;
- Apply a 7.77% (approximately 75% of the jurisdictional rate increase) increase to the Large General Service class;
- Apply a 4.30% (approximately 50% of the jurisdictional rate increase) increase to the Small General Service class;
- Apply a 6.39% (approximately 75% of the jurisdictional rate increase) increase to the Thermal class; and
- Apply a 5.03% (approximately 75% of the jurisdictional rate increase) increase to the Lighting class

Q. PLEASE COMMENT ON THE COMPANY'S PROPOSED APPROACH.

A. Given an average jurisdictional increase of 8.31%, I am generally supportive of the Company's method to move class revenue responsibility towards cost responsibility. The Company has followed its COSS results from a directional standpoint. As shown in Figure 7, the Company used a multiplier of 128% for classes that require above system average increases such as the residential class and CCN. Similarly, the Company used a multiplier of 75% for classes such as LGS and LPS that should get a decrease. For the small general service class, the multiplier is the lowest at 50%.

Figure 7: Company's COSS Results vs. Revenue Allocation Proposal

	MO West Retail	Residential	Small General Service	Large General Service	Large Power Service	Thermal Service	Lighting	CCN
Company COSS	8.3%	23.5%	-12.4%	-9.6%	-4.4%	-8.3%	3.7%	4398.8%
Company Revenue Allocation	8.3%	10.84%	4.30%	7.77%	7.05%	6.39%	5.03%	10.50%
Multiplier		128%	50%	75%	75%	75%	75%	128%

While the Company's approach is directionally reasonable, at a minimum, however, the proposal should be modified such that all classes that have indexed ROR at present rates above 150 (in Figure 5) and showing a decrease with a system wide average increase of 8.31% should use the same multiplier. Further, the multipliers should change with revenue requirement reductions such that the lower the average increase, the higher the revenue neutral shift becomes. Since the Company's multiplier for the residential class is lower in West's case with an 8.31% increase (i.e., 128%) compared to Metro's case of 5.65% (i.e. 136%), it is likely that the Company further moderated the impacts to the residential class in this case due to the higher jurisdictional rate increase. Therefore, conversely, it would be appropriate to increase the multipliers with revenue requirement reductions to have a more balanced trade-off between moderation and equity.

Q. WHAT IS YOUR RECOMMENDATION TO THE COMMISSION?

A. I recommend the following at a minimum:

- Use the MECG's COSS study results as guidance regarding revenue allocation to classes.

- While a large revenue neutral adjustment is very justifiable given the COSS results, I considered moderating the impacts to classes for an average jurisdictional increase of 8.31%:
    - Given this increase, I am not opposed to applying a multiplier of approximately 128% to calculate the average increase for classes that show above jurisdictional average increases such as the residential, lighting and CCN classes respectively;
    - However, unlike the Company's proposal that uses a different multiplier for small general service and other remaining classes, the multiplier should be the same for all classes that show decreases with the Company's proposed increase such as the small general service, thermal service, LGS and LPS respectively.
- Further, for every 1% decrease in the jurisdictional rate increase compared to the Company's original proposal, the multipliers should be adjusted to move classes closer to cost. While there could be other ways to achieve this objective, one suggested way is to take 50% or 100% of the percent change and add to the multiplier to apply to classes that continue to be subsidized such as the residential, lighting and CCN classes. After calculating the rate increase and resulting revenue requirements for these classes, the multiplier to be applied to the remaining classes can be calculated. For example, as shown in Figure 8, under this proposal, if the rate increase reduced by 1% to 7.31%, then the absolute % change from 8.31% is 12% [9] Either 50% or 100% of this change could be added to the initial 128% multiplier. Using 50% of the change or 6%, the modified multiplier is 134%. Similarly, using 100% of the change would result in a modified multiplier of 140%. Either of these modified multipliers can then be applied

[9] (7.31%/8.31% -1) x -1

to a jurisdictional increase of 7.31% used in this example, for the residential, lighting and CCN classes. For instance, using the 134% and 140% modified multiplier, the resulting increase would be 9.8% and 10.2% respectively for these classes. After completing the step of allocating the revenue requirement increases using either of these multipliers to the residential, lighting and CCN classes, the next step would consist of calculating the rate increase to be used for the remaining classes – this can be done by dividing the remaining revenue requirement by the sum of revenues of classes who would be subject to this calculated rate.

Figure 8: Modification of Multiplier with Jurisdictional Rate Decreases

Jurisdictional Rate Increase	Absolute % Change from Company Proposal	50% of Change	Change in Multiplier for Res, Ltg, CCN at 50% of Change	Change in Multiplier for Res, Ltg, CCN at 100% of Change
8.31%			128%	128%
7.31%	12%	6%	134%	140%
6.31%	24%	12%	140%	152%

VI RATE DESIGN

Q. WHAT ARE THE MAIN UNIT CHARGE COMPONENTS OF THE LPS RATE?

A. The main unit charges consist of facilities charge, customer charge, demand and energy charges. The demand and energy charges are seasonally differentiated. Further, the demand charge includes base billing demand charges for the summer and winter and seasonal demand charges for the summer only. The energy charges reflect Hours Use structure and consist of three blocks for seasonal and energy charges respectively. As more energy is consumed, the rates are lower, which is implicitly accounting for higher use of energy in the off-peak hours. Figure 9 shows the existing charges for the LPS at the secondary voltage service level. The rate schedule also includes service at the primary, sub transmission and transmission voltage service level.

Figure 9: LPS Rate at Secondary Voltage Service Level

Demand Charge	Summer	Winter
Base Billing Demand	$10.54	$5.49
Seasonal Billing Demand	$10.54	
Base Energy Charges		
First 180 Hours of Use per month	$0.05359	$0.05002
Next 180 Hours of Use per month	$0.04219	$0.03936
Over 360 Hours of Use per month	$0.03699	$0.03451
Seasonal Energy Charges		
First 180 Hours of Use per month	$0.05359	$0.03139
Next 180 Hours of Use per month	$0.04219	$0.03139
Over 360 Hours of Use per month	$0.03699	$0.03139
Customer Charge per Month	$659.84	
Facilities Charge ($/KW-Month)	$3.148	

Q. WHAT IS THE COMPANY'S RATE DESIGN PROPOSAL FOR THE LPS CLASS?

A As indicated in Ms. Miller's testimony, the Company proposes to allocate 125% of the revenue allocation class increase of 7.05% to the fixed cost rate components (i.e., 8.81%) such as customer and demand charges and 75% to the variable components such as energy charges (i.e., 5.28%). A review of the proposed charges and related calculations confirms the increase to the fixed cost components at 8.81% and slightly lower energy charge increases are 5.13% or approximately 73% of the average increase to recover the revenue allocation. The proposed changes are shown in Figure 9 below.

Figure 10: Company's Proposal: LPS Rate at Secondary Voltage Service Level

Demand Charge	Summer	% Change from Current	Winter	% Change from Current
Base Billing Demand	$11.47	8.8%	$5.97	8.8%
Seasonal Billing Demand	$11.47	8.8%		
Base Energy Charges				
First 180 Hours of Use per month	$0.05634	5.13%	$0.05259	5.14%
Next 180 Hours of Use per month	$0.04435	5.12%	$0.04138	5.13%
Over 360 Hours of Use per month	$0.03889	5.14%	$0.03628	5.13%
Seasonal Energy Charges				
First 180 Hours of Use per month	$0.05634	5.13%	$0.03300	5.13%
Next 180 Hours of Use per month	$0.04435	5.12%	$0.03300	5.13%
Over 360 Hours of Use per month	$0.03889	5.14%	$0.03300	5.13%
Customer Charge per Month	$717.99	8.81%		
Facilities Charge ($/KW-Month)	$3.43	8.80%		

Q. DO YOU SUPPORT THE COMPANY'S PROPOSAL?

A Yes, I support the company's proposal to allocate 125% to demand and 75% to energy. However, I have an issue with the current winter rate design for energy charges as discussed below.

Q. DO YOU HAVE ANY ISSUE THAT NEED TO BE ADDRESSED IN THE CURRENT LPS RATES?

A. Yes. My issue is related to voltage differentials. Specifically, the winter seasonal charges are the same for all voltage levels. For instance, under the current rate, the winter seasonal energy charge for all blocks at the secondary, primary, substation and transmission level is the same at $0.03139/kWh as shown in Figure 8. However, these charges should vary by voltage service level. That is, the higher the voltage service level, the lower should be the charges to account for losses. In response to MECG 5-10, the Company indicated that making the charges the same was a result of settlement in 2016 and the Company did not attempt to abandon or undo settled pricing since then. The current rate proposal also does not propose any changes.

Q. WHAT ARE YOUR OBSERVATIONS REGARDING THIS RESPONSE?

A. The LPS rate design should reflect proper energy voltage level differentials reflective of costs to serve. Accounting for voltage differentials is fundamentally addressed in designing rates as demonstrated in the Company's LGS rate design for winter seasonal energy charges. By ignoring these differentials, customers at higher voltage levels are not getting the benefit of incurring lesser losses and therefore, lower rates compared to the current situation. It is my understanding that the 2016 rate case was unique in that it was the first case in which the MPS and L&P rates were aligned to be the same. Now that Evergy West is in its second subsequent rate case, the company should take steps to adjust the design of its winter seasonal energy rates to account for cost principles.

Q. WHAT DO YOU RECOMMEND?

A. I recommend that the Company take the corrective measures to price out the voltage differentials for the seasonal winter energy charges in the LPS rate.

Q. WHAT ARE THE MAIN UNIT CHARGE COMPONENTS OF THE LGS RATE?

A. The main unit charges consist of facilities charge, customer charge, demand and energy charges. The LGS rate design is similar to the LPS rate design and consists of the same components as described earlier for the LPS rate. Figure 10 shows the current charges. The difference is in the charges. While LPS demand rates are high, the demand charges for LGS are $10.54/KW-month in the summer and $5.49 in the winter (base only), the demand charges are less than $1/KW-month for LGS at shown in Figure 11 below.

Figure 11 shows the existing charges for the LGS at the secondary voltage service level. The rate schedule also includes service at the primary voltage service level.

Figure 11: LGS Rate at Secondary Voltage Service Level

Demand Charge	Summer	Winter
Base Billing Demand	$0.875	$0.59
Seasonal Billing Demand	$0.875	
Base Energy Charges		
First 180 Hours of Use per month	$0.08736	$0.06655
Next 180 Hours of Use per month	$0.06610	$0.06100
Over 360 Hours of Use per month	$0.04625	$0.04177
Seasonal Energy Charges		
First 180 Hours of Use per month	$0.08736	$0.03654
Next 180 Hours of Use per month	$0.06610	$0.03654
Over 360 Hours of Use per month	$0.04625	$0.03654
Customer Charge per Month	$72.26	
Facilities Charge ($/KW-Month)	$2.211	

Q. WHAT IS THE COMPANY'S RATE DESIGN PROPOSAL FOR THE LGS CLASS?

A. Similar to the proposal for LPS, the Company proposes to allocate 125% of the revenue allocation class increase of 7.77% to the fixed cost rate components (i.e., 9.7%) such as customer and demand charges and 75% to the variable components such as energy charges (i.e., 5.8%). A review of the proposed charges and related calculations confirms the increase to the fixed cost components at the appropriate levels (see Figure 12).

Figure 12: Company's Proposal: LGS Rate at Secondary Voltage Service Level

Demand Charge	Summer	% Change from Current	Winter	% Change from Current
Base Billing Demand	$0.96	9.7%	$0.65	9.7%
Seasonal Billing Demand	$0.96	9.7%		
Base Energy Charges				
First 180 Hours of Use per month	$0.09243	5.80%	$0.07042	5.82%
Next 180 Hours of Use per month	$0.06994	5.81%	$0.06454	5.80%
Over 360 Hours of Use per month	$0.04894	5.82%	$0.04420	5.82%
Seasonal Energy Charges				
First 180 Hours of Use per month	$0.09243	5.80%	$0.03866	5.80%
Next 180 Hours of Use per month	$0.06994	5.81%	$0.03866	5.80%
Over 360 Hours of Use per month	$0.04894	5.82%	$0.03866	5.80%
Customer Charge per Month	$79.28	9.71%		
Facilities Charge ($/KW-Month)	$2.43	9.71%		

Q. DO YOU HAVE ANY CONCERNS REGARDING THE COMPANY'S PROPOSAL?

A. I am concerned that the LGS demand charges are very low and not consistent with cost of service guidance. [10] Consequently, energy charges include a substantive portion of fixed costs.

Q. WHAT DO YOU RECOMMEND?

A. Given these concerns it would appropriate to increase demand charges at much higher multipliers than 125% to achieve the unitized demand charges reflected by the COSS. However, in order to be sensitive to rate impacts, I recommend a multiplier of 150% for increasing the fixed cost components. The multiplier to apply to the energy charges

[10] Ms. Miller's Schedule MEM-2 shows the unit demand cost from the COSS at $10.438 per KW-month. Given the similarity in COSS results between MECG and the Company for the LGS and LPS classes, I rely on the Company's results for unit cost guidance in order to make a consistent comparison with the Company's proposal.

should correspondingly be decreased to recover the remaining revenue requirement increase.

Q. WHAT PROPOSED CHANGES IS THE COMPANY SEEKING FEEDBACK ON FOR IMPLEMENTATION IN FUTURE RATE CASES FOR THE LPS CLASS?

A. I understand from reviewing Ms. Marisol's testimony that the Company wants to implement the following changes in a future case:

- Remove the no charge provision for winter seasonal demand and increase fixed cost recovery through demand charges and corresponding lower such recovery from energy charges with larger reductions in the winter energy charge.
- Replace energy block rates with a flat and seasonally differentiated energy charge

The steps can be observed in Table 6 from the Confidential Concentric Advisors report which illustrates that rate changes.

The Company is seeking comments on this proposal.

Q. PLEASE PROVIDE YOUR FEEDBACK REGARDING THE COMPANY'S PROPOSED APPROACH FOR FUTURE RATE CASES.

A. I support the concept of shifting fixed costs from energy charges to demand charges as this will improve the pricing signal to customers. However, I am very concerned about the narrowing of the energy charge differentials with the ultimate goal of one flat seasonally differentiated energy charge. This is because a flat energy charge will fail to recognize the lower off-peak energy prices thereby resulting in an inefficient pricing signal that will not be reflective of cost.

Q. WHAT ARE YOUR SUGGESTIONS FOR CONSIDERATION?

A. I recommend the following be considered:

- Shift fixed costs from energy charges to demand charges but do not eliminate the energy charge differentials.
- Introduce an on-peak provision whereby the maximum demand set in the specified on peak hours is the billing demand for the month.
- Evaluate a time differentiated on and off-peak energy rate to recognize the cost differentials and provide better pricing signals than a flat energy rate.
- Set up a working group of interested parties to evaluate these alternatives and assess rate impacts.
- Gather consensus on the steps and introduce to be introduced in the future.

Q. IS THE COMPANY'S PROPOSAL FOR THE LGS RATE DESIGN SIMILAR IN CONCEPT AS THE LPS RATE DESIGN?

A. Yes. The Company conceptually has a similar proposal for the LGS class with the end goal of higher fixed cost recovery from demand charges and a flat, seasonally differentiated energy rate. Therefore, my concerns and subsequent recommendations are the same as listed above for the LPS rate design.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes.

Kavita Maini, KM Energy Consulting, LLC - Project Experience

	Docket Number	Type by State/FERC	Major Issues	Role
	Retail Jurisdiction			
		North Dakota		
1	PU-05-131	Otter Tail: Cost of Energy Adjustment Clause	Time of use rate related issues	Expert Witness - Large Industrial Group
2	PU-08-862	Otter Tail: Base Rate Case Application	Revenue Requirement, rate design	Expert Witness - Large Industrial Group
3	PU-08-742	Otter Tail: Renewable Resource Cost Recovery Rider	Revenue Requirement, cost allocation and rate design	Expert Witness - Large Industrial Group
4	PU-11-153;162	Otter Tail: Transmission Cost Recovery Rider	Revenue Requirement, cost allocation and rate design	Expert Witness - Large Industrial Group
5	PU-17-398	OTP Base Rate Case Application	Revenue Requirement, cost allocation and rate design	Expert Witness - Midwest Large Energy Consumers
		South Dakota		
6	EL11-019	Xcel Energy Base Rate Case Application	Renewable related revenue requirements	Expert Witness - PUC Staff
7	EL12-027, EL14-082	Otter Tail Petition to Establish an Environmental Quality Cost Recovery Tariff	Evaluation of Big Stone AQCS as a least cost resource	Expert Witness - PUC Staff
8	EL12-062	Black Hills Phase In - Cheyenne Prairie Generating Station	Evaluation of a Combined Cycle Addition - Need and least cost resource	Expert Witness - PUC Staff
9	EL14-058	Xcel Energy Base Rate Case Application	Least cost resource evaluation and related revenue requirements	Expert Witness - PUC Staff
10	EL15-024	MDU Base Rate Case Application	Least cost resource evaluation and related revenue requirements	Expert Witness - PUC Staff
11	EL-021	Complaint filed by Juhl Energy AKA Consolidated Edison regarding avoided cost compensation for wind QFs	Methodology for Avoided Cost	Expert Witness - PUC Staff
12	EL16-037	Commission Staff Motion to Show Cause regarding certain fuel cost recovery through the Fuel Cost Recovery Rider	Prudency of Acquiring Resources	Expert Witness - PUC Staff
13	EL18-004	In the Matter of the Petition of Northern States Power Company dba Xcel Energy for Approval of a Proxy Pricing Proposal to Adjust Certain Fuel Clause Rider Power Purchase Costs	Evaluating Proxy Pricing Methods	Expert Witness - PUC Staff (currently in progress)
14	EL18-021	Otter Tail Power Company Base Rate Application	Least cost resource evaluation and related revenue requirements	Expert Witness - PUC Staff
15	EL19-025	Phase In Rider	Least cost resource evaluation	Expert Witness - PUC Staff
16	EL21-007	MDU - Retirement of three units	Evaluation	Expert Witness - PUC Staff
		Minnesota		
17	E002/GR-13-868	Xcel Energy Base Rate Case Application	Revenue Req., Class Cost of Service Study and Rate Design	Expert Witness - MN Chamber
18	ER017/GR12-961	Xcel Energy Base Rate Case Application	Revenue Req., Class Cost of Service Study and Rate Design	Expert Witness - MN Chamber
19	E017/GR08-1065	Otter Tail Base Rate Case Application	Revenue Req., Class Cost of Service Study and Rate Design	Technical Support - MN Chamber
20	E002/GR07-1178	Xcel Energy Base Rate Case Application	Revenue Req., Class Cost of Service Study and Rate Design	Technical Support - MN Chamber
21	E002/GR10-971	Xcel Energy Base Rate Case Application	Revenue Req., Class Cost of Service Study and Rate Design	Technical Support - MN Chamber
22	E001/GR-10-276	Interstate Power & Light Base Rate Case Application	Revenue Req., Class Cost of Service Study and Rate Design	Technical Support - MN Chamber
23	E-017/M-08-1529	Otter Tail: Renewable Resource Cost Recovery Factor	Revenue Requirements, Cost Allocation and Rate Design	Lead Expert - MN Chamber
24	E-017/GR09-881	Otter Tail: Transmission Cost Recovery Rider	Revenue Requirements, Cost Allocation and Rate Design	Lead Expert - MN Chamber
25	E-017/M-09-1484	Otter Tail: Renewable Resource Cost Recovery Factor	Revenue Requirements, Cost Allocation and Rate Design	Lead Expert - MN Chamber
26	E017/M-10-1061	Otter Tail:Transmission Cost Recovery Rider Annual Adjustment	Revenue Requirements, Cost Allocation and Rate Design	Lead Expert - MN Chamber
27	E-017/M-10-220	Otter Tail: Update Conservation Improvement Rider	Revenue Requirements, Cost Allocation and Rate Design	Lead Expert - MN Chamber
28	E017/M-12-179	Otter Tail: Petition to include CSAPR related costs in FCA	Revenue Requirements	Lead Expert - MN Chamber
29	E017/M-12-708	Otter Tail: Renewable Resource Cost Recovery Factor	Cost Allocation and Rate Design	Lead Expert - MN Chamber
30	E002/M-10-1064	Xcel Energy: Transmission Cost Recovery Rider	Revenue Requirements, Cost Allocation and Rate Design	Lead Expert - MN Chamber
31	E002/M-10-1066	Xcel Energy: Renewable Energy Standard Cost Recovery Rider	Cost Allocation and Rate Design	Lead Expert - MN Chamber
32	MPUC DOCKET NO. E002/M-11-278;MPUC DOCKET NO. E001/M-11-244;MPUC DOCKET NO. E015/M-11-241	Investor owned utilities CIP filings	Class Allocation and Rate Design	Lead Expert - MN Chamber
33	E, G-999/CI-08-133	Review of Financial Incentive Mechanism for CIP Programs	Avoided Costs, Policy Issues	Lead Expert - MN Chamber

Kavita Maini, KM Energy Consulting, LLC - Project Experience

	Docket Number	Type by State/FERC	Major Issues	Role
34	E-999/CI-11-852	Renewable Energy Cost Impacts	Cost Effectiveness of Implementing Renewable Energy Standard	Lead Expert - MN Chamber
35	E017/RP-10-623	Otter Tail: Integrated Resource Plan	Resource Planning	Lead Expert - MN Chamber
36	E017/RP-10-623	Otter Tail: Hoot Lake Baseload Diversification Study	Resource Planning	Lead Expert - MN Chamber
37	E002/RP-10-825	Xcel Energy:Integrated Resource Plan	Resource Planning	Lead Expert - MN Chamber
38	E015/RP-13-53	Minnesota Power - Integrated Res. Plan	Resource Planning	Lead Expert - MN Large Industrial Group
39	E999/AA-12-757	Fuel Cost Recovery -All Utilities	Policy Issues	Lead Expert - MN Chamber
30	E017/M-14-201	OTP CIP Filing	Policy Issues	Lead Expert - MN Chamber
31	E017/RP-13-961	OTP IRP Filing	Resource Planning	Lead Expert - MN Chamber
32	ER002/GR-15-826	Xcel Energy Base Rate Case Application	Revenue Requirement/CCOSS	Expert Witness - MN Chamber
33	ER17/GR-15-1033	Otter Tail Base Rate Case Application	Revenue Requirement/CCOSS	Expert Witness - MN Chamber
34	E-999/CI-03-802	Fuel Cost Reform- All Utilities	Policy Issues	Technical Comments - MN Chamber
35	E002/M-16-777	Xcel Wind Portfolio	Revenue Requirement Issues	Technical Comments - MN Chamber
36	E, G999/CI-17-895	Tax Reform	Recommendations regarding TCJA related savings (in progress)	Technical Comments - MN Chamber
37	Docket No. E002/M-19-688	Xcel Energy Stay Out Proposal	Evaluating Staying Out of Rate Case	Technical Comments - MN Chamber
38	E, G-999/CI-20-492	Xcel Energy Stay Out Proposal	Evaluating Staying Out of Rate Case	Technical Comments - MEC
39	GR-20-719	Otter Tail Base Rate Case Application	Revenue Requirement/CCOSS	Expert Witness - Midwest Large Energy Consumers
		Wisconsin		
40	05-ES-103	Strategic Energy Assessment	Resource Planning	Technical Comments - On behalf of Wiconsin Industrial Energy Group (WIEG) et al
41	05-ES-104	Strategic Energy Assessment	Resource Planning	Technical Comments - On behalf of Wiconsin Industrial Energy Group (WIEG) et al
42	05-ES-105	Strategic Energy Assessment	Resource Planning	Technical Comments - On behalf of Wiconsin Industrial Energy Group (WIEG) et al
43	05-ES-106	Strategic Energy Assessment	Resource Planning	Technical Comments - On behalf of Wiconsin Industrial Energy Group (WIEG) et al
44	05-ES-107	Strategic Energy Assessment	Resource Planning	Technical Comments - On behalf of Wiconsin Industrial Energy Group (WIEG) et al
45	05-ES-108	Strategic Energy Assessment	Resource Planning	Technical Comments - On behalf of Wiconsin Industrial Energy Group (WIEG) et al
46	05-ES-109	Strategic Energy Assessment	Resource Planning	Technical Comments - On behalf of Wiconsin Industrial Energy Group (WIEG) et al
47	05-EI-141	Planning Reserve Margin Requirements	Resource Planning	Technical Comments - On behalf of Wiconsin Industrial Energy Group (WIEG) et al
48	05-EI-148	Advanced Renewable Tariffs	Rates	Technical Comments on behalf of WIEG
49	05-UI-113	Cost allocation associated with Energy Efficiency Programs	Cost Allocation	Technical Comments on behalf of WIEG
50	05-UI-114	Innovative Ratemaking	Rate Design	Technical Comments on behalf of WIEG
51	05-UI-115	Quadrennial Planning Process - Energy Efficiency	Policy Issues	Technical Comments - On behalf of WIEG et al
52	05-UI-116	Demand Response and ARC Participation	Policy Issues	Technical Comments on behalf of WIEG
53	9300-EI-100	Impacts or Activities related to MISO	Policy Issues	Technical Comments on behalf of WIEG
54	05-EI-150	Review Potential Excess Capacity in WI	Policy Issues	Technical Comments - On behalf of WIEG et al
55	6680-GF-126	Wisconsin Power & Light:Experimental Economic Development Rider	Rate Design	Technical Comments on behalf of WIEG
56	6630-GF-134	We Energies: RTMP Rate	Rate Design	Technical Comments on behalf of WIEG
57	3270-UR-117	Madison gas & Electric: SP3 Rate Changes	Rate Design	Technical Comments on behalf of WIEG
58	6680-GF-130	Application of ED Rider by Mercury Marine	Rate Design	Technical Comments on behalf of WIEG
59	1-AC-234	Renewable Resource Credit Rule Revisions after 2009 Wisconsin Act 406	Policy Issues	Technical Comments - On behalf of WI Ind. Associations
60	05-EI-137	Class Cost of Service and Rate Design	Policy Issues	Technical Comments on behalf of WIEG
61	05-FE-100	Quadrennial Planning Process - Energy Efficiency	Policy Issues	Technical Comments - On behalf of WIEG/WPC/WMC
62	6630-BS-100	Presque Isle - WEPCO/Wolverine Transaction	Policy Issues	Technical Comments on behalf of WIEG
63	05-UR-107	WEPCO Base Rate Application	Revenue Requirement	Expert Witness - WIEG and CUB
64	6680-UR-120	WP&L Base Rate Application	CCOSS, Rate Design and Revenue Allocation	Expert witness on behalf of WIEG
65	6630-FR-106	WEPCO 2017 Fuel Cost Plan	Recommendations for Revenues Related to Excess Capacity	Expert witness on behalf of WIEG
66	05-BS-212 and 05-AI-100	WEC transfer of assets to UMERC and related affiliated interest agreements	Protecting interests of WI customers served by WEC	Comments on behalf of WIEG, WPC and CUB
61	9400-YO-100	Wisconsin Gas Earnings Sharing Mechanism	Refund method	Technical comments of behalf of WIEG and CUB
62	05-AE-208	Affiliated Interest Agreement between WPSC and WEPCO - capacity only transaction	Recommendations for accounting treatment and capacity prices	Technical comments of behalf of WIEG, WPC and CUB
63	5-UR-108	Joint Application of WEPCO, Wisconsin Gas and WPSC for Approvals Related to Settlement Agreement	Revenue Requirement Issues	Expert witness on behalf of WIEG and CUB

	Docket Number	Type by State/FERC	Major Issues	Role
64	05-AF-101	TCJA Investigation	Tax Impacts and Related Recommendations	Technical comments of behalf of WIEG, WPC and CUB
65	6680-UR-121	Alliant Rate Case	Revenue Requirements/Settlement Negotiations	Expert witness on behalf of WIEG
66	05-FE-101	Quadrennial Planning Process - Energy Efficiency	Recommendations regarding Cost Effectiveness and Other Aspects	Technical Comments on behalf of Several Wisconsin Industrial Associations
67	05-EF-102	Disbursement of ATC refunds	Policy/Alternatives of returning ATC refunds	Technical comments on behalf of WIEG and WPC
68	5820-UR-114	Superior Water Power and Light Rate Case	Cost of Service, Revenue Allocation and Rate Design	Expert witness on behalf of Enbridge Energy, LLC
69	05-UR-109	WEPCO Base Rate Case	Revenue Requirement/Settlement Negotiation, Cost of Service, Rev	Expert witness on behalf of CUB and WIEG on revenue requirement and WIEG for all else
70	6690-UR-126	WPSC Base Rate Case	Cost of Service, Revenue Allocation and Rate Design	Expert witness on behalf of WIEG
71	05-AF-105;05-UI-120	All Utilities	COVID-19 related dockets	Comments on behalf of CUB and WIEG
72	6680-UR-123	WPL Rate case proposal	Revenue Requirements/Rate proposal evaluation	Comments on behalf of CUB and WIEG
73	05-ES-110	Strategic Energy Assessment	Resource Planning	Comments on behalf of WIEG and WPC
74	05-EI-157	Investigation of Parallel Generation Rates	Parallel Generation Rates	Comments on behalf of WIEG
75	1330-ER-104	Base Rate Application of CWPCo	Rates	Expert Witness on rate issues on behalf of CWPCO
76	05-AF-107,6690-AF-100	WEC Utilities Stay Out/Request for Accounting Treatment	Revenue Requirement/Negotiations	Techical expert on behalf of WIEG
77	4220-UR-125	Xcel Energy Wisconsin	Negotiating Settlement regarding revenue requirement, revenue allocation and rate design	Techical expert on behalf of WIEG
78	6680-UR-123	Alliant Energy	Negotiating Settlement regarding revenue requirement including treatment of premature retirement of generation plant, revenue allocation and rate design	Techical expert on behalf of WIEG
79	3270-UR-124	Madison gas & Electric	Negotiating Settlement regarding revenue requirement, revenue allocation and rate design	Techical expert on behalf of WIEG
		Sasketchewan		
80	2008	Sask Power Rate Case Application	Revenue Requirements, Class Cost of Service, Rate Design	Expert Witness on behalf of ERCO
81	2010	Sask Power Rate Case Application	Revenue Requirements, Class Cost of Service, Rate Design	Expert witness on Behalf of ERCO and Assistance to SIECA
82	2013	Sask Power Rate Case Application	Revenue Requirements, Class Cost of Service, Rate Design	Technical Consultant to SIECA
		Iowa		
83	WRU-2014-0009-0150	Alliant Energy	Revenue Requirement	Expert Witness on behalf of Department of Justice - Office of Consumer Advocate
		Missouri		
84	ER-2014-0351	Empire District Electric Rate Case	FAC, Class Cost of Service, Rate Design	Expert Witness on behalf of MO Energy Consumers Group
85	ER-2016-0023	Empire District Electric Rate Case	Class Cost of Service, Rate Design	Expert Witness on behalf of MO Energy Consumers Group
86	ER-2019-0374	Empire District Electric Rate Case	Class Cost of Service, Rate Design	Expert Witness on behalf of MO Energy Consumers Group
87	ER-2021-0312	Empire District Electric Rate Case	Class Cost of Service, Rate Design	Expert Witness on behalf of MO Energy Consumers Group
	FERC Dockets			
87	ER07-1372	Integrating Ancillary Services into Energy Markets	Market Design and Policy Issues	Joint Protest; Midwest Industrial Customers
88	ER08-394	Resource Adequacy	Market Design and Policy Issues	Joint Protest; Midwest Industrial Customers
89	ER08-404	Schedule 30 - Emergency Demand Response	Compensation/Design/Policy	Joint Protest; Midwest Industrial Customers
90	RM07-19-0000 and AD07-7-0(	Effective Competition in Wholesale Markets	Market Design and Policy Issues	Joint Protest; Wisconsin Industrial Energy Group
91	ER10-1791-000	Multi Value Projects - Transmission	Cost Allocation and Rate Design	Joint Protest; Wisconsin Industrial Energy Group
92	ER11-4337-000	MISO's Order 745 Compliance Filing	Cost Allocation and Other Policy Issues	Joint Protest; Wisconsin Industrial Energy Group
93	ER13-37-000 and ER13-38-00	System Support Resource	Cost Allocation and Other Policy Issues	Joint Protest;MN Industrial Group, Wisconsin Industrial Energy Group and Wisconsin Paper Council
94	RM10-23-000	Transmission Planning and Cost Allocation	Planning and Policy	Joint Protest; Wisconsin Industrial Energy Group
95	ER13-76,ER13-1962	System Support Resource	Cost Allocation and Other Policy Issues	Joint Protest;MN Industrial Group, Wisconsin Industrial Energy Group and Wisconsin Paper Council
96	ER14-1242-000 and ER14-243	System Support Resource	Cost Allocation and Other Policy Issues	Joint Comments - Wisconsin Industrial Energy Group and Citizens Utility Board
97	EL14-34-000	WI Commission Complaint regarding Cost Allocation associated with WEPCO's Presque Isle System Supply Resource	Cost Allocation	Joint Comments (Wisconsin Industrial Energy Group and Citizens Utility Board)
98	E:16-1-000	Petition for Waiver by Heartland Consumers Power District on behalf of itself and of its customers for waivers of Section 292.402 obligations	Primarily lack of standby power provisions	Comments developed in conjunctions with another consultant and Soybean Food Processors
99	Docket No. ER22-995-000	MISO's proposed cost allocation for MVP Projec	Cost Allocation of MVP projects	Joint Protest with several industrial groups

☐ **Non Public Document – Contains Trade Secret Data**
☐ **Public Document – Trade Secret Data Excised**
☒ **Public Document**

Xcel Energy			
Docket No.:	E002/GR-15-826		
Response To:	MN Chamber of Commerce	Information Request No.	104
Requestor:	Larry Schedin, Kavita Maini		
Date Received:	March 18, 2016		

Question:

Please provide any analysis conducted within the past two years by or on behalf of NSP and its affiliate companies or in NSP's possession of the current and future competitiveness of NSP's industrial rates. To the extent there is rate data, please provide in Excel spreadsheet format.

Response:

The following file attachments contain rate survey information or analyses of such information:

- MCC-0104_Attachment A EEI AverageRates.xlsx
  This spreadsheet file contains Industrial average revenue per kWh by utility using as its source the Typical Bills and Average Rate Reports prepared by the Edison Electric Institute (EEI), which is updated twice annually.

- MCC-0104_Attachment B EIA AverageRates.xlsx
  This spreadsheet file contains class average revenue per kWh by utility for the year ending May 2015. The source of this information is the U.S. Energy Information Administration (EIA), Form EIA-826 detailed data, which is available at: http://www.eia.gov/electricity/data/eia826/?scr=email

- MCC-0104 _Attachment C EEI Comparison Study Summer 2015.pdf
  This file is a Company prepared Average Electric Rate Study, based on rates in effect July 1, 2015, using as the data source the Summer 2015 EEI Typical Bills and Average Rate Report.

- MCC-0104_Attachment D EEI Comparison Study Winter 2015.pdf

> This file is a Company prepared Average Electric Rate Study, based on rates in effect January 1, 2015, using as the data source the Winter 2015 EEI Typical Bills and Average Rate Report.

The Company also responds to individual inquiries by current or potential customers regarding rate information and options.

Witness:	Steven V. Huso
Preparer:	Steven V. Huso
Title:	Pricing Consultant
Department:	Regulatory Analysis
Telephone:	612-330-2944
Date:	March 29, 2016

KCPL
Case Name: 2018 KCPL Rate Case
Case Number: ER-2018-0145

Response to Woodsmall David Interrogatories - MECG_20180604
Date of Response: 6/25/2018

Question:5-2

Please provide, since January 1, 2013, KCPL and GMO's responses to surveys conducted by EEI for purposes of its Typical Bills and Average Rates Report.

Response:

KCP&L utilizes the EEI Typical Bills and Average Rates Report and the EEI Rankings report for rate comparisons to other utilities in the region and nation. This copyrighted data can be viewed at KCP&L's headquarters [contact Lisa Casteel at (816) 556-2705] or a copy can be requested from EEI.

Information provided by: Lisa Casteel, Regulatory Affairs

Attachment: Q5-2_Verification.pdf

KCPL GMO
Case Name: 2018 GMO Rate Case
Case Number: ER-2018-0146

Response to Woodsmall David Interrogatories - MECG_20180604
Date of Response: 6/25/2018

Question:5-2

Please provide, since January 1, 2013, KCPL and GMO's responses to surveys conducted by EEI for purposes of its Typical Bills and Average Rates Report.

Response:

GMO utilizes the EEI Typical Bills and Average Rates Report and the EEI Rankings report for rate comparisons to other utilities in the region and nation. This copyrighted data can be viewed at KCP&L's headquarters [contact Lisa Casteel at (816) 556-2705] or a copy can be requested from EEI.

Information provided by: Lisa Casteel, Regulatory Affairs

Attachment: Q5-2_Verification.pdf

KM Schedule - 3

MECG A&E 4NCP COSS SUMMARY AT PRESENT RATES

Evergy West (Docket:ER-2022-0130)

	MO West Retail	Residential	Small General Service	Large General Service	Large Power Service	Thermal Service	Lighting	CCN
REVENUE REQUIREMENT SUMMARY								
Test Year Revenue	$ 719,045,350.43	$ 376,086,292.10	$ 116,686,564.87	$ 88,729,808.22	$ 116,143,926.14	$ 460,184.06	$ 13,006,951.49	$ 33,302.21
Gross Revenue Requirements	$ 692,345,033	$ 384,145,817	$ 96,941,598	$ 79,955,305	$ 114,024,138	$ 439,142	$ 10,583,809	$ 1,049,129
Less Other Revenue	$ (104,791,905.23)	$ (49,977,777)	$ (15,667,789)	$ (15,105,581)	$ (23,241,415)	$ (89,819)	$ (703,113)	$ (6,412)
Net Revenue Requirements	$ 587,553,127.92	$ 334,168,041	$ 81,273,809	$ 64,849,724	$ 90,782,723	$ 349,322	$ 9,880,696	$ 1,042,718
Net Operating Income	**$ 131,492,222.50**	**$41,918,251**	**$35,412,756**	**$23,880,084**	**$25,361,203**	**$110,862**	**$3,126,256**	**($1,009,416)**
RETURN AT PRESENT RATES								
Rate Base	$ 2,484,954,452	$ 1,500,510,217	$ 342,145,860	$ 259,031,838	$ 299,571,954	$ 1,140,834	$ 67,876,471	$ 1,512,850
Net Operating Income at Present Rates	$131,492,223	$ 41,918,251	$ 35,412,756	$ 23,880,084	$ 25,361,203	$110,862	$ 3,126,256	$ (1,009,416)
Rate of Return at Present Rates	**5.29%**	**2.79%**	**10.35%**	**9.22%**	**8.47%**	**9.72%**	**4.61%**	**-66.72%**
Relative Rate of Return	1.00	0.53	1.96	1.74	1.60	1.84	0.87	(12.61)